OVERVIEW

It does not seem a year since the last facilities feature. The theme this year is about heavy-oil upgrading to light oil; although a paper about wax seems to have slipped in too. Heavy oil is an enormous energy resource that still is largely untapped. The challenge is to get the stuff out of the ground as fast as the lighter oil that we currently produce. Unfortunately, the density and viscosity usually make this target very difficult in the end. However, heavy oil is not all bad; on a volume basis, it contains more energy than lighter oil.

Currently, the industry is attempting to justify heavy-oil developments on two fronts: by developing new means for extracting it faster and by increasing its value. This is where the real prize is in heavy oil—its value. Its value currently is largely unrecognized; it sells often much cheaper than lighter oil even though it contains more energy on a volume basis. The industry is currently developing ways to upgrade it to light oil to add value; but there are other ways of adding value, and to find these, one must re-examine the business model of the upstream industry that has not changed in 150 years. We continue to produce and sell crude oil to refiners and let the oil traders set the price. We can, and should, be more proactive in finding ways to exploit the irreplaceable value of oil. **JPT**

__Simon Richards,__ SPE, is Principal Consultant for EPConsult, which specializes in engineering, risk analysis, and integrated optimization studies. He had 22 years' experience with several operators and engineering contractors before joining EPConsult. Richards holds a BSc (Honours) degree in chemical engineering from the University of Birmingham, England. His main professional interests are field-development planning, new technologies, digital oil fields, multiphase flow, flow assurance, conceptual process engineering, and cost estimating. Richards is Executive Editor of the SPE Projects, Facilities & Construction *e-journal and Chairperson of the Production Systems and Facilities Technical Interest Group, and he serves on the* JPT *Editorial Committee and the SPE Production, Facilities, and Construction Advisory Committee. Richards is a Chartered Engineer in the U.K.*

Production/Facilities additional reading available at the SPE eLibrary: www.spe.org

SPE 107958
"Modeling Rapid Multiphase Flow in Wells and Pipelines Under Nonequilibrium and Nonisothermal Conditions" by Guillermo Michel, University of Oklahoma, et al.

SPE 108752
"A Study of Normal Slug Flow in an Offshore Production Facility With a Large-Diameter Flowline" by E. Guzmán Vázquez, National Autonomous University of Mexico, et al.

SPE 104133
"Leak Detection for Gas and Liquid Pipelines by Transient Modeling" by Shouxi Wang, Gas Liquids Engineering, et al.

Heavy-Crude-Oil Upgrading With Transition Metals

The full-length paper discusses the effects of some metallic oxides used to upgrade heavy-crude-oil properties. The objective is to increase oil mobility in the reservoir by reducing viscosity and improving oil quality by use of alumina-supported transition metals and liquid-phase transition-metals catalysts derived from acetylacetonate or alkylhexanoate compounds. Heavy crude oil from the Gulf of Mexico (GOM) was studied. Oil gravity was increased from 12.5 to 21 to 26°API, asphaltene content was reduced from 26 to 7 wt%, and distillable fraction was increased by 20 to 30 wt%.

Introduction

Some of the main problems that heavy crude oil presents are: (1) low mobility through the reservoir because of its high viscosity, which affects the wells productivity index (PI); (2) difficult transportation to the refineries and the high cost of that transportation; and (3) the low processing capacity in the refineries. For these reasons, it is necessary to enhance the heavy crude oil, both above ground and underground. Some of the main processes used are carbon rejection, hydrogen addition, and physical separation. All these processes are focused on converting oil residues into more-valuable products such as gasoline, middle distillate, and fluid-cracking catalytic feedstock.

An interesting alternative to recover the heavy and extraheavy crude oil is downhole catalytic upgrading. This alternative presents several advantages compared with its above-ground counterpart such as an increase in the well PI, a reduction in the lifting and transportation costs to the refining center, the production of more-valuable products as a result of the decreases in viscosity values, resins, asphaltenes, sulfur, and metal contents.

Some of the most important processes that have been studied to enhance heavy and extraheavy crude oil are steam-drive, cyclic steam injection, steam-assisted gravity drainage, fireflood, and downhole catalytic processes. The main objective of these processes is to decrease the viscosity of the heavy crude oil to improve its flow from the reservoir to the producer well. This viscosity reduction can be achieved by increasing the reservoir temperature or by injecting hydrogen-donor compounds. Two ways to improve the quality of heavy crude oil are hydrocracking and hydrotreating such as aromatic hydrogenation and desulfurization. This removal can be achieved by injection of a catalytic solution [organic metallic compounds of molybdenum (Mo), iron (Fe), cobalt (Co), and nickel (Ni)].

The full-length paper examines upgrading heavy crude oil though use of thermal and catalytic hydrocracking by use of both supported and unsupported catalysts. Thermal hydrocracking produced a significant increase in heavy oil gravity. However, it also resulted in an undesirable high coke formation (25 wt%) and a decreasing contaminant content. The catalytic hydrocracking produced not only a smaller increase in gravity than the other, but also a better product quality because of the decreased coke, sulfur, and metal-compounds content. These improvements are the result of the balance between metal and acid functions of the catalysts. Using Mo, Fe, Co, and Ni catalysts that are soluble in hydrogen-donor compounds, alkylhexanoates presented a greater increase in gravity than the supported catalysts but had a lower sulfur and porphyrin removal.

Experimental Method

The heavy-oil experiments using heavy oil from the GOM were carried out in a batch reactor with an 1800-mL capacity. Two supported catalysts were used. One a commercial catalyst with a 256-m^2/g specific area and a 75-Å average pore diameter. Another was an experimental catalyst with a 280-m^2/g specific area and a 78-Å pore diameter. The same support was used in both catalysts.

The supported catalysts were previously tested with a sulfur compound mixed with 20 L of diesel. Operating conditions during the sulfurization stage were 56-kg/cm^2 pressure and reaction times of 4 hours at 533 K and 12 hours at 593 K.

The organometallic catalysts were dissolved in a hydrogen donor, and it was activated with the heavy crude oil at 543 K. Some samples were commercially acquired, while other catalysts were synthesized in the laboratory.

Results

Hydrocracking Without Catalyst. Thermal hydrocracking, or thermolysis, of the heavy crude oil without catalyst increased the gravity from 12.5 to 25.9°API, reduced the kinematic viscosity from 18,130 to 35.86 mm^2/s at 298 K, and reduced sulfur content by 28.5 wt%. However, there was a high coke formation (25 wt%) in the reaction. The coke formation affects

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 107837, "Heavy-Crude-Oil Upgrading With Transition Metals," by ***H.R. Nares, P. Schacht-Hernández, M.A. Ramírez-Garnica,*** *and* ***M.C. Cabrera-Reyes,*** *Inst. Mexicano del Petróleo, and* ***L. Noé-Valencia,*** *U. La Salle, México, prepared for the 2007 SPE Latin American and Caribbean Petroleum Engineering Conference, Buenos Aires, 15–18 April.*

the yield of the distillable fraction mainly in gasoline and diesel production.

The coke formation can be explained through the free-radical chain reactions caused a weak metallic function, or by the absence thereof; the low hydrogen partial pressure; and the high reaction temperature (693 K). The coke formation can be avoided by a hydrogenating metal that can transfer the available hydrogen atoms to the free radicals, preventing condensation, polymerization reaction, and, finally, coke formation.

Catalytic Hydrocracking. The upgrade reaction of the heavy crude oil with the MoCoP/Al_2O_3 commercial catalyst increased the gravity from 12.5 to 21.2°API, reduced kinematic viscosity from 18,130 to 117 mm^2/s, and reduced sulfur content from 5.56 to 1.68 wt%. The resins concentration was reduced from 35 to 15 wt%, and the asphaltene concentration was reduced from 26 to 7 wt%. The paraffin and aromatic concentrations were increased from 18 to 40 wt% and from 22 to 37.5 wt%, respectively. The increase in gravity and the large reduction of the viscosity helps to increase the distillable products (by approximately 18 wt%).

The behavior of the supported catalysts in upgrading heavy crude oil can be explained by their high specific area, large average pore diameter of the Al_2O_3 support, high metal content, high dispersion of the catalytic active species, and an appropriate balance between the metal load and acidity in the support.

The hydrocracking of the heavy crude oil with the MoWNiCoP/Al_2O_3 experimental catalyst was evaluated at the same operating conditions, except that the reaction temperature was reduced by 10 K. Gravity was increased from 12.5 to 23.5°API, kinematic viscosity was reduced from 18,130 to 78 mm^2/s at 298 K, sulfur removal was 67.8%, asphaltene content decreased to 6.0 wt%, resin content was reduced to 14.5 wt%, and the distillable fraction was increased to 20 wt%. The paraffins content and aromatics content were increased to 41 and 38.5 wt%, respectively.

Unsupported Catalysts. The heavy crude oil also was upgraded by use of Mo and Fe catalysts derived from acetylacetonate and a Mo/Fe mixture. Three concentrations of the Mo catalyst were tested. It was necessary to operate the reactor at 673 K, and therefore the residence time was reduced to 4 hours, with a hydrogen pressure of 10.8 MPa. The results using the catalysts showed an increase of the gravity from 12.5 to 19.0, 20.2, and 23.0°API for each of the different concentrations. The viscosities were reduced from 18,130 to 68.6, 52.2, and 27.5 mm^2/s at 298 K, respectively. However, with the Fe acetylacetonate catalysts, there was a higher increase of gravity than with Mo acetylacetonate catalysts—24.4, 24.6, and 26.0°API, respectively—and decreasing viscosity values of 10.54, 9.87, and 9.19 mm^2/s at 298 K. All these results were obtained because of hydrocracking of the high-molecular-weight compound, forming lighter compounds such as gasoline and diesel. Nevertheless, with these kinds of catalysts, there was higher coke formation than with the Mo catalyst. Coke formation was reduced when the catalyst concentration was increased. This behavior can be related to a higher amount of hydrogenating sites.

Conclusions

Thermal hydrocracking increases the API gravity and reduces the viscosity of heavy oil. Probably the introduction of organometallic catalysts with hydrogen donors into the reservoir could improve crude-oil quality and increase the PI. The strong hydrogenation properties reduce the coke formation that could damage some reservoir properties like porosity and permeability.

Supported catalysts are a good alternative to upgrade the heavy crude oil above ground. However, if these catalysts are used to upgrade the heavy crude oil downhole, it is necessary to find a mechanism to inject them into the well in combination with some thermal-recovery method (like steam injection or donor hydrogen) to supply the heat to make the hydrocracking reactions possible.

Catalysts in homogeneous liquid phase that are soluble in hydrogen-donor compounds, and that are relatively inexpensive, could supply the elements necessary for the thermal-hydrocracking process in the reservoir (in-situ process) to enhance oil production, provide surface-facilities savings, and reduce production and transportation costs. **JPT**

A Heavy- to Light-Crude-Oil Upgrading Process

A proprietary heavy- to light-oil (HTL) upgrading technology is designed to process heavy oil cost effectively in the field and provide a stable, significantly upgraded synthetic-oil product along with byproduct energy that can be used to generate steam or electricity. Since the commissioning of a commercial demonstration facility (CDF) for upgrading heavy oil in 2005, a number of crude oils and vacuum-tower-bottoms (VTBs) feedstocks have been tested. Analysis of CDF performance shows that the HTL process is capable of delivering high yields of significantly upgraded product.

Fig. 1—CDF in the Belridge oil field in southern California.

Introduction

In mid-2005, Ivanhoe Energy acquired a new patented process, called rapid thermal (RT) processing, for the field-located upgrading of heavy oil and bitumen. Included in the acquisition was a new CDF in the San Joaquin Valley in southern California that demonstrates a processing capacity of approximately 1,000 B/D of heavy crude oil. **Fig. 1** shows the CDF in the Belridge oil field. There are significant accumulations of heavy crude and bitumen throughout the world that can be targeted by this technology. Both Canada and Venezuela have extensive heavy-oil reserves that compare in size to current reserves in the Middle East. As conventional lighter-crude-oil supplies decline, they will need to be replaced by heavier crudes.

New residue-processing capacity could be added to existing refineries, or it could be built in separate, standalone upgrading facilities. If the oil is too heavy to transport by pipeline, and/or there is the need for heat or energy at the production site, heavy-oil upgrading in the field is attractive and may avoid extensive modifications of existing refineries. Traditional residue processing such as coking or hydrocracking are very expensive processes and require a large scale to be viable. The HTL technology would provide a lower-cost, simpler residue-processing option compatible with field development.

HTL-Technology Development

The development of the RT processing technology began in the early 1980s when it was discovered that a broad array of carbonaceous feedstocks (e.g., wood and heavy oil) could be thermally cracked to obtain valuable products at residence times of a few seconds. The initial commercial focus of the technology, beginning in 1989, was aimed at conversion of wood and wood residues to value-added fuels and chemicals. Seven commercial biomass plants based on this technology have been in operation for many years.

As the biomass side of the business grew and operational and design parameters were optimized, the focus turned toward petroleum feedstocks. The petroleum application of the technology was demonstrated in a pilot plant in Ottawa, Canada, on more than 90 experimental runs using a number of different crude oils and bitumen between 1999 and 2002. Because it was believed that the technology had relatively low capital and operating costs compared to conventional carbon rejection technologies, such as delayed coking, commercialization of the HTL process was initiated.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 108678, "Performance of a Heavy- to Light-Crude-Oil Upgrading Process," by ***E.J. Veith,*** *Ivanhoe Energy, prepared for the 2007 SPE International Oil Conference and Exhibition in Mexico, Veracruz, Mexico, 27–30 June.*

For a limited time, the full-length paper is available free to SPE members at ***www.spe.org/jpt****. The paper has not been peer reviewed.*

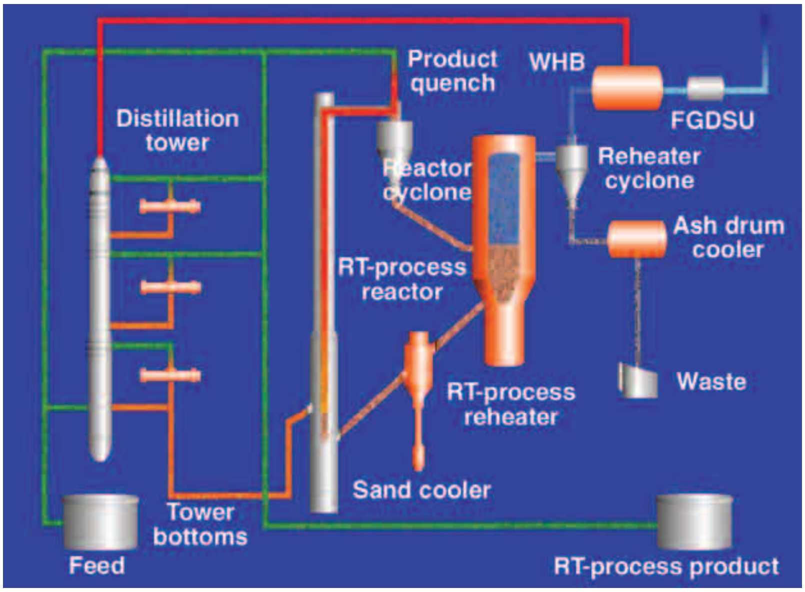

Fig. 2—HTL-process diagram.

HTL-Process Description

HTL upgrading uses a continuous, short-contact-time, thermal-conversion process that takes place at moderate temperatures and at atmospheric pressure. It uses a circulating transported bed of hot sand in the system to heat the feedstock quickly and convert it to more-valuable products in the absence of air. The two general commercial process configurations applicable to heavy-oil or bitumen upgrading are high yield or high quality.

Prefractionation. In a commercial HTL facility, the whole heavy-oil feed is sent to a series of distillation towers, where material with a liquid boiling point below 985 to 1,050°F is removed in a vacuum tower. The lighter material is recombined later with the upgraded liquid product to form transportable synthetic crude. The VTBs are routed to the RT-process reactor.

RT Process. The heavy-oil-residue feed or VTBs are atomized and mixed in the reactor with hot circulating silica sand and transported up through the reaction zone by transport or carrier gas. Recycle product gas (or byproduct gas) is used as the transport gas. Rapid mixing of the oil and sand promotes effective heat transfer and thermal cracking of heavy-oil feedstocks. Carbon is rejected as the long hydrocarbon chains are cracked, and coke is deposited on the sand during thermal conversion. When long-chain hydrocarbons are cracked, the boiling point is reduced and the cracked product is vaporized. The coke-covered sand, vapor (cracked VTBs), transport gas, and feed that survive the first pass in the reactor are separated in a high-temperature-cyclone system. The fluids are quenched rapidly, and vapors are condensed with light oil to maximize liquid yield and minimize undesirable secondary thermal-cracking reactions. A very short residence time is required between the feed injection point and the quench point. Typically, residence times less than a few seconds are targeted.

Product Fractionation. Following quenching, the liquid product can be routed to the product tank for blending (high yield) or recovered in a product-distillation tower for further separation for recycle operations (high quality). Part of the noncondensable gas is recycled to the reactor system to be used as transport gas for the circulating sand, with the balance, or net product gas, used to raise steam and/or power in a waste-heat boiler (WHB). All liquid products, including the light liquids from the whole crude that are separated in the prefractionation step, are blended to make a synthetic-crude product. In the high-yield mode of operation, the resulting quenched product is routed to the product tank where it is blended. In the high-quality mode of operation, the bottoms product from the product-distillation tower is routed back to the reactor to further convert any VTBs that survived the first pass through the reactor.

RT-Process Reheater Section. The coke-covered sand from the RT-process reactor is separated from the product vapor stream by use of a high-efficiency cyclone and is directed to a fluidized bed reheater for carbon removal. Air is used to fluidize the sand and facilitate combustion in the reheater. The temperature of the regenerated sand is adjusted to the proper reactor temperature in a sand cooler, where excess heat is recovered before circulation back to the reactor. High-pressure steam can be generated from the heat recovered in the sand cooler **(Fig. 2).** Operation of the circulating-sand system is similar to that of a conventional fluid catalytic cracker and residue-fluid catalytic cracker.

Byproduct Heat. Sorbent is added to reduce contaminants in the heavy-oil feed. A portion is added to the heavy-oil feed to the distillation-tower section to reduce the total acid number of the feed and to capture sulfur released in the reactor section. The rest is added to the reheater to capture sulfur dioxide (SO_2) that is formed as the normally high-sulfur coke is burned off the sand grains. The sorbent also acts as a site for the metals to be deposited.

Flue gas from the reheater is directed through a cyclone system to remove ash, spent sorbent, and any sand fines from the gas before injection into a power-recovery turbine (Fig. 2). High-pressure steam production is possible by energy recovery from the hot flue gas, plus burning excess byproduct gas in a WHB. This approach maximizes the useful-energy output from the process, either as high-pressure steam or as power available for on-site facility use, with the excess exported for use in heavy-oil oilfield-production operations.

Because sorbent is added to the feed and reacts with sulfur released in the reactor section, the byproduct gas is effectively sulfur free and can be routed to a fuel-gas system and used for another purpose if the steam and/or power requirements can be met by the combustion of the byproduct coke.

Flue-gas polishing through a flue-gas-desulfurization unit (FGDSU) to meet SO_2 emission requirements also is included as part of the flue-gas system. The ash, spent sorbent, and sand fines are routed to an ash cooler and collected in a hopper, ready for disposal as a nonhazardous solid waste.

HTL Advantages

Viscosity Reduction. Significant viscosity reduction and gravity increases are a favorable result of HTL upgrading because asphaltenes, which contribute to the very-high viscosity, are removed or cracked. The fraction of the feed that does not boil under the atmospheric-pressure conditions of the process stays in close contact with the sand, which facilitates its rapid decomposition into smaller molecules and coke. Even in a once-through or high-yield configuration, the HTL process will destroy more than 90% of the asphaltenes.

There is a dramatic reduction in the viscosity with the high-yield configuration. Further reductions in viscosity are achievable by processing in the high-quality mode of operation that uses a recycle stream to reduce the high-boiling-point (+1,000°F) cut in the final product. Because the products are low-viscosity, the need for diluents required for transportation is eliminated because the products meet or exceed pipeline specifications with respect to viscosity. This protects the heavy-oil or bitumen producer from exposure to market conditions related to the purchase of condensate or synthetic crude oils for diluent.

Yield. The HTL process has the ability to achieve higher yields than delayed coking. It is believed the reason for this is the kinetics of the process. A unique combination of very short contact time with sand, short residence time of the flashed distillable oil fraction in the high-temperature zone (helps to minimize secondary cracking reactions), complete lack of porosity and surface catalytic activity of sand, and a high sand/oil ratio helps to achieve higher liquid yields and lower byproduct gas as compared to delayed coking.

Yields are shown in Fig. 7 and Table 1 of the full-length paper for several heavy oils and bitumen as a function of processing configuration. As residue content increases, there is a trade-off in volumetric yield in both the high-yield and high-quality processing configurations. The higher-residue-content feedstocks have a tendency to have a greater propensity to coke, resulting in more carbon being rejected, thereby resulting in a higher yield loss.

Reactions in thin films of Athabasca vacuum residue have been shown experimentally to give lower coke yield and a lighter product. One researcher found that as film thickness approached 20 µm, the transport through the reacting film of lighter cracked products is more easily facilitated as a result of the reduced diffusional resistance, and this resulted in an overall increase in liquid yield.

The HTL upgrading system has an estimated feedstock film thickness of less than 20 µm. The operation of the HTL process results in a thin film of coke being deposited on the sand, which has a beneficial effect on the product quality and yields. Another important aspect of the HTL process is that there are no coke byproducts to dispose of, in contrast to conventional coking technologies, because all the coke is oxidized in the reheater vessel.

Summary

The four key advantages that HTL technology provides to the heavy-oil and bitumen producer are the following.

1. The ability to capture the majority of the price differential between heavy and light oil.
2. An upgraded product that does not require diluents or blending agents to move it through a pipeline.
3. Byproduct energy to generate steam and/or power.
4. A small scale that is appropriate to grow field-site upgrading capacity along with resource development. **JPT**

A Case Study in Wax Removal From a Subsea Flowline

The following stages were key to the successful wax-removal operation: selection and design phase of the chemical application, the environmental chemical-selection criteria, the development of the work scope, and the logistics of the chemical application. The wax-removal process was deemed successful and offered the client significant benefit in terms of increased oil production. Reduced pipeline differential pressure and increased fluid arrival temperatures also indicated that the wax restrictions in the flowlines had been removed.

Introduction

The control and mitigation of wax deposition and its concurrent problems rapidly are becoming critical challenges facing the oil- and gas-production industry as the industry explores and develops in increasingly challenging environments, such as deepwater and subarctic conditions. Wax deposits can occur widely in the production process and often are considered the organic equivalent of scale formation.

Field Description

The Gannet field is 180 km east of Aberdeen in a water depth of approximately 90 m. Since the field was originally discovered, in the 1970s, several satellite fields have been tied into the Gannet facilities. Gannet D is an oil field 16 km northeast of Gannet Alpha. Production is from five wells, with oil transported back to the Gannet Alpha facilities by two looped 6-in. subsea flowlines referred to as Riser 31 and Riser 32. The crude from these reservoirs typically is 41°API, with a wax content of approximately 7% and a wax-appearance temperature of approximately 35.5°C. The Gannet G field also is produced by this system with a single 6-in. flowline tied in at the base of Riser 32, 0.5 km from the Gannet Alpha platform. Riser 31 carries Gannet D crude only, and Riser 32 carries Gannet D and G crude topside onto the Gannet Alpha processing facilities, where the oil is commingled with other Gannet fluids before being exported to the Fulmar platform.

Background

Wax deposition in the Gannet D flowline first was identified in 1999 during the Gannet G tie-in operation when a spool piece removed from the base of Riser 32 was found to contain significant wax deposits. A study to estimate the extent of wax deposition within the Gannet D system indicated that a volume as great as 21 m^3 of wax could be present, with deposition as far as 8 km from the platform. Since this discovery, several remedial proposals have been examined by Shell; however, the perceived risks were felt to be significantly higher than the potential rewards. In early 2005, production-logging tests were performed on all Gannet D wells. It was clear from the results that the cumulative-production potential from the field was significantly higher than that being observed at the platform, further confirming the presence of restrictive deposits within the flowline system. Once again, Shell considered the prospect of implementing a remedial wax-removal program on the Gannet D flowlines. Because the line was going to be depressurized for the wax-dissolver flush and made hydrocarbon-free, the decision was made to combine the flushing program with the installation of subsea chemical-injection lines to deliver wax inhibitor to the flowline. A comprehensive process began of engineering the most suitable way of removing the wax deposits. After extensive consideration of the large number of remedial options available, the decision was made that the treatment offering the greatest chance of success with the lowest risk to personnel, equipment, and the environment was chemical removal of the restrictive wax deposits from the flowline by use of wax-dissolver soaking aided by circulation. The design was to fill the flowline loop with neat wax dissolver (600 m^3) and circulate the dissolver until the wax dissolver became saturated with wax. The plan then was to displace the wax dissolver from the flowline with inhibited seawater and gel pigs through the topside process facilities on the Gannet Alpha platform and export the chemical to the Fulmar export oil pipeline. To gain information on the true extent of wax deposition in the Gannet D flowline and the level of wax removal observed after the treatment, “time of flight” flow measurements were to be performed before and after treatment.

Chemical Selection

Key to the success of the remedial wax-removal treatment would be the selection of the chemical dissolver. Several products covering a range of generic chemistries were tested for suitability. Not only should the chemical wax dissolver dissolve and disperse as much wax as possible, the chemical of choice also must be suitable in terms of risk to

---

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 105048, “A Case Study in the Removal of Deposited Wax From a Major Subsea Flowline System in the Gannet Field,” by ***H.A. Craddock,*** *SPE,* ***K. Mutch,*** *and* ***K. Sowerby,*** *Roemex Ltd., and* ***S. McGregor, J. Cook,*** *and* ***C. Strachan,*** *Shell UK Ltd., prepared for the 2007 SPE International Symposium on Oilfield Chemistry, Houston, 28 February–2 March.*

For a limited time, the full-length paper is available free to SPE members at ***www.spe.org/jpt****. The paper has not been peer reviewed.*

personnel, material compatibility, environmental profile, availability, cost, and effect on the platform and downstream process facilities. After a series of extensive tests using field wax samples under static and agitated conditions at both 4°C (ambient seabed temperature) and 30°C (after heating), a proprietary wax dissolver was selected. The wax dissolver, a proprietary blend of terpenoid extracts, consistently performed well in laboratory tests, in particular at wax dissolution at 4°C, and met the additional health, safety, and environmental criteria required by Shell (Gold with no product warnings for the UK sector and Yellow for the Norwegian sector).

The wax dissolver was supplied in 22×20-ft tanks, which were sea-fastened to a supply vessel for transport offshore. The tanks were aligned in banks of five, with a specially designed 6-in. manifold system that allowed the tanks to be emptied with the minimum amount of manual handling. Once on station, the chemical was pumped from the vessel up to the platform and into the pig-launcher assembly at Riser 31 where it could be circulated around the loop between Riser 31 and Riser 32 through two 20-m^3 break tanks situated topside on the Gannet Alpha platform. The break tanks situated topside were designed to remove any large deposits removed from the flowline and minimize the risk of blockage in the pipework or pumping equipment.

The wax dissolver was circulated, intermittently, for approximately 10 days. The treatment design called for circulation for 5 days; however, this was extended for operational reasons. Throughout the operation, chemists were onboard the Gannet Alpha platform to perform sampling and analysis of the circulating fluids to determine the level of wax removal and the optimum period for circulation. The initial design was to circulate the wax dissolver at a rate sufficient to achieve turbulent flow to ensure that any large pieces of debris were carried out of the risers and would be caught by the two break tanks topside. However, as a result of problems with pumping equipment, the circulation rate was limited to less than 78 m^3/h, with the majority of the circulation being performed at approximately 36 m^3/h.

Samples were taken from Riser 31 and Riser 32 at regular intervals throughout the circulation to determine the wax content in the proprietary wax dissolver. On completion of the circulation phase, a gel pig was inserted into the flowline to remove any loose wax or sand that had not been removed by the wax-dissolver circulation. The wax dissolver was displaced with inhibited seawater in a controlled manner back through the Gannet Alpha production process and exported.

The tie-in of new subsea chemical-injection lines allowed the start of a wax-inhibition program on completion of the remedial wax treatment.

Pretreatment time-of-flight measurements indicated that as much as 81 m^3 of wax was present in the Gannet D flowline. A post-treatment time of flight did not take place because of operational circumstances. Therefore, the success of the remedial wax-removal treatment was determined by analysis of the samples taken during the circulation phase and by the observations made when the Gannet D wells were recommissioned and brought back on line.

Wax Content

Extensive laboratory evaluations were performed before the chemical deployment to determine the most-effective and -accurate means of measuring the wax content of the wax dissolver. A method that would give quick, relatively accurate, and reproducible results was required. Two methods were used offshore to determine the wax content of the wax dissolver being circulated around the flowline, a viscosity measurement and a wax-dissolver flash method. The viscosity method was based on the principle that, at a constant temperature, there is a linear correlation between viscosity measurement and the wax content of the dissolver. The flash method was based on the principle that the wax dissolver completely evaporates at 110°C; thus, the percent solids content obtained could be converted to wax content (g) per 100 mL of dissolver by use of a calibration equation. A calibration graph was developed in the laboratory using Gannet-export wax and a laboratory blend of the proprietary wax dissolver. The procedure for both methods can be found in Appendix 1 in the full-length paper.

The viscometry method takes into account changes only in the continuous phase and not the dispersed wax solids. However, the wax-dissolver flash method takes into account both dissolved and dispersed wax. After initial sampling, it was clear that the viscometry method was not accurate for low dissolved-wax contents and gave lower results than those obtained by the wax-dissolver flash method. For this reason, only results obtained with the wax-dissolver flash method have been reported.

Samples that demonstrated a significant change in the characteristics of the dissolver during the circulation phase were retained for further analysis onshore.

The sample points used to monitor the wax content of the dissolver were located at the top of the pipework. This meant that loose solids present in the circulating wax dissolver may not have been detected during the sampling process, especially considering that the circulation rate was relatively low.

A graph of the average wax content determined by the wax-dissolver flash method during 12-hour monitoring periods shows that the wax content gradually increased with time, suggesting that restrictive wax deposits were being removed from the flowline. Samples obtained during the first 12-hour period showed high wax contents, most likely the result of a short mixing time and spikes in wax content from "lumps" of wax not yet taken out by the break tanks. A steady increase in wax content of the dissolver was observed for subsequent 12-hour monitoring periods.

Offshore Observations

Recommissioning of the Gannet D wells resulted in an additional 480 m^3/d of oil being recovered from the field. Observations offshore also included a reduction in pipeline differential pressure and increased fluid arrival temperature, both indicating that the restrictive wax deposits had been removed. Increased fluid arrival temperatures have obvious benefits in terms of future wax control.

Wax returns were observed topside after recommissioning of the Gannet D wells, indicating that the wax dissolver had become entrained in the flowline deposits and was still working after production had resumed. An accurate estimate of wax removal from the Gannet D flowline was difficult because of sampling errors and insufficient dissolver circulation rate to push larger wax deposits up and out of the riser section. JPT