DOE/MC/11076 -- 5057
(DE96000597)
Volume II

Research Investigations in Oil Shale, Tar Sand, Coal Research, Advanced Exploratory Process Technology, and Advanced Fuels Research Volume II -- Jointly Sponsored Research Program

Final Report
October 1986 - September 1993

Verne E. Smith

September 1994

Work Performed Under Contract No.: DE-FC21-86MC11076

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
University of Wyoming Research Corporation
Laramie, Wyoming

DISCLAIMER

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Distribution Category UC-123
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VOLUME II. TABLE OF CONTENTS

VOLUME II. TABLE OF CONTENTS (continued)

FOREWORD

This report summarizes the major research investigations conducted by the Western Research Institute (WRI) under Cooperative Agreement DE-FC21-86MC11076 with the U.S. Department of Energy (DOE) over the period October 1986 through September 1993. In 1989 a Jointly Sponsored Research Program (JSRP) was incorporated into the agreement whereby some of the investigations were conducted as part of the Base Program and some were undertaken with cosponsorship from the commercial sector or other government agencies in the JSRP.

This report is divided into two volumes: Volume I consists of 28 summaries that describe the principal research efforts conducted under the Base Program in five principal topic areas. Volume II describes tasks performed within the JSRP. Research conducted under this agreement has resulted in technology transfer of a variety of energy-related research information. A listing of related publications and presentations is given at the end of each research topic summary. More specific and detailed information is provided in the topical reports referenced in the related publications listings.

ACKNOWLEDGEMENTS

Funding for this research has been provided under U.S. Department of Energy Cooperative Agreement DE-FC21-86MC11076 and by numerous JSRP cosponsors. In addition to the efforts of the authors who prepared the topic summaries, the considerable efforts of the many researchers and support people at Western Research Institute (WRI) who provided essential assistance in the design, conduct, and reporting of the work are greatly appreciated. Special thanks is due the individuals in DOE who have provided input and direction to the research studies and for their review and comments on completed studies.

EXECUTIVE SUMMARY

Numerous studies have been conducted under Cooperative Agreement DE-FC21-86MC11076 since its initiation in October 1986. During the time of the agreement, the most significant change occurred in 1989 when the agreement was redefined as a Base Program and a Jointly Sponsored Research Program (JSRP). Research topics within the Base Program continued, with an emphasis given to exploratory research that might lead to further development under the JSRP.

The JSRP was initiated to foster participation between WRI, industry, and DOE in areas of high industrial interest. With joint funding of tasks, greater levels of effort were carried out, resulting in more significant findings, for each participant's contribution. Under the program, 29 tasks were performed in topics of coal processing, enhanced oil recovery, recovery of oil from tank bottoms, in situ cleanup of organic materials, utilization of coal fly ash for road stabilization and waste containment, natural gas cleanup, oil shale processing, tar sand processing, development of instruments for in situ measurements, nuclear magnetic resonance (NMR) measurement of organic material in sedimentary rocks, development of methods for characterization of petroleum residuals and for leachate extraction, evaluation of materials derived from processing scrap tires as asphalt modifiers, cogeneration from wood-derived fuels or coal, and development of a hydrologic data base system for coal mines. Several of these technologies show good promise for commercialization.

A very promising process developed by WRI for application to environmental mitigation problems is the Contained Recovery of Oily Wastes (CROW™) process. From development in the laboratory, the process is being used in two field demonstration projects. The first site is a wood treating plant in Minnesota where creosote and pentachlorophenol have contaminated the aquifer. A two-well pilot test that injected hot water to displace and recover contaminants was successful. Preparations are proceeding for the full-scale test. The second location is an old manufactured gas plant site in Pennsylvania where the soil is contaminated. Designs and permitting have been completed so the demonstration can proceed. Laboratory testing indicates that up to 90% of the contaminating material may be removed. Both studies have taken longer than anticipated because of the time required to obtain permits.

Another promising process under development at WRI is Tank Bottom Recovery and Remediation (TaBoRR™). This process consists of preheating, flashing, distilling, and pyrolysis of oil-water materials associated with petroleum products. Process modeling was done using data collected from a candidate field site. The modeling results were used to design and fabricate a demonstration unit capable of producing 200 bbl/day of salable material. This unit will be tested in the field. If successful, the process could be used to recover oil and clean up material that is accumulating in this country at the rate of 2,000,000 bbl/year.

An evaluation was made of the potential increase in production that could be obtained from oil wells in Wyoming using the CO_2 huff-n-puff process. Selection criteria were developed and applied to Wyoming oil fields, resulting in the selection of 11 study wells. Cyclic CO_2 stimulations were carried out on the wells and product samples were collected and analyzed. Eight of the study wells were found to be successful in increasing oil production.

Enhanced oil recovery techniques were evaluated for application to a horizontal gravity-drained reservoir. It was determined from a screening of possible methods that waterflooding or steamflooding had the most potential for successful application. Numerical modeling of the two processes indicated that waterflooding would provide a better sweep of the reservoir, but steamflooding would give slightly better recovery. Physical simulations of the two processes were conducted using blocks of material from the reservoir formation. The steamflood test yielded 80% more oil than did the waterflood test, indicating that steamflooding may be the best approach, depending on the costs related to steam generation and distribution.

Several processes were studied to determine a method of oil production from minable oil resources. Water extraction and solvent extraction were found to have drawbacks in comparison to thermal processing. From bench-scale tests of two thermal processes, fluidized-bed processing was determined to have the most likely potential for success. A pilot unit was designed, constructed, and tested at a site in Wyoming. Although problems were encountered in the field demonstration, fluidized-bed technology can be used on near-surface oil reserves.

A shallow oil field, containing high viscosity oil, was evaluated for the application of enhanced oil recovery techniques. Horizontal wells had previously been drilled in the Chetopa field in Kansas. Screening of possible techniques led to the conclusion that in situ combustion was the most feasible process for the site. Two bench-scale tests were run to help define the field test conditions. Poor recovery was obtained in the field test. This is attributed to positive pressure in the production well and low heat transfer from the burn zone.

A steam injection system for enhanced oil recovery using a double-walled tubular product has been privately developed to reduce heat losses between the steam source and the oil reservoir. A flow loop was constructed and tested by WRI to evaluate the system. It was found that annular insulation very significantly reduced heat loss. Heat losses at couplings was high, indicating the need for using thermal-resistant materials or redesigning the couplings. A new numerical model was developed for simulating the thermal hydraulics of saturated steam in wellbore configurations. The model provides more accurate predictions than previously developed models.

Nitrogen contaminates a significant amount of available natural gas resources, requiring its removal for the natural gas to salable. A series of experiments was run to evaluate molecular sieve carbon as a pressure swing adsorbent for nitrogen removal. Results of the tests indicated that such a system is technically feasible, but further study is needed to determine if it would be economically viable.

Although many techniques exist for characterization of petroleum residua, there is little established systematic methodology. An analytical scheme was developed in which asphaltenes were removed prior to fractionation and then analyzed for chemical and physical characteristics. The procedure was successfully applied to residua from six different heavy crude oils.

WRI has been developing an inclined fluidized-bed process for drying and stabilization of coal. A series of tests was conducted on coal from the Usibelli Coal Mine. Evaluation of the products indicated that the process could be used successfully with this coal.

A technical evaluation was made on the K-Fuel®Series B Process. This process removes moisture, decarboxylates, and removes some sulfur-containing compounds from coal, resulting in a dry, improved heating value, low-sulfur coal. Batch tests run on four coals substantiated the results of earlier testing.

A wood-fired gas turbine system is being developed for cogeneration purposes. A series of preliminary tests was run in a wood-fired combustor to obtain information on the entrained ash and on the fate of alkali and other materials that might cause deposition and corrosion problems. It was found that particulates present in the gas are likely to deposit and there is a potential for alkali corrosion. Conventional treatment, such as washing or nut shelling and alkali gettering, can alleviate these problems.

A concern in modified in situ retorting of oil shale is the release of chemical compounds in local groundwater. Laboratory-scale simulations were conducted to evaluate methods for post-retorting control of impacts on groundwater. Combinations of quenching, deluge, and reverse combustion were applied after retorting. Reverse combustion was found to be the most effective method for removing organic material in the simulated retorts.

The Recycle Oil Pyrolysis and Extraction (ROPE™) process developed by WRI was applied to Sunnyside tar sand. The tests were conducted with no major operational difficulties and the product oils could be used as blending stock for diesel fuel.

As part of the development of a process for recovering useful products from scrap tires, WRI evaluated the solid residue from processing scrap tires as asphalt modifier. Asphalt cements modified with residue had greater viscosities, less elasticity, and better performance in freeze-thaw cycle tests.

Development of reliable instruments to detect and monitor groundwater contaminants is needed for environmental management. To this end, a prototype field test kit for determining diesel and other fuel types in soil has been built and tested. Also, initial experimental work was done on methods to measure volatile organic compounds in groundwater.

Established methods exist for characterizing materials leached from solid wastes. However, they are based on a single extraction procedure. More meaningful information can be derived from sequential batch extractions. WRI developed such a method that has been independently tested and established as a standard test method by the ASTM.

Definition of the organic carbon structure of hydrocarbon source rocks in essential to modeling the nature of hydrocarbon resources. Solid-state NMR measurements were made on coal and shale samples from several sedimentary basins to provide information on the maturity and generative capacity of the organic material.

The utilization of ash from coal combustion can provide beneficial applications while reducing solid waste disposal requirements. Fly ash materials were tested in the laboratory for soil stabilization and cement replacement applications. These tests indicated that the fly ash materials have good potential for such applications if carefully processed in the construction phase. A field demonstration study was conducted in which fly ash was mixed with existing road material on a section of unpaved road. Performance was quite good on the segments of roadway in which the mixing and wetting were properly done. Poorly mixed areas soon formed washboards and had other deterioration.

Solid waste materials generated by clean coal technologies could have application for hazardous waste stabilization. Four clean coal technology materials were evaluated for their ability to stabilize four hazardous organic or inorganic wastes. In some cases, the waste mixtures were too complex to evaluate. However, the clean coal technology solid wastes did appear to be effective in containing certain metals and organic materials from hazardous wastes.

A hydrologic data management system was improved by the development of menu-driven access to the data and data entry forms. The system provides hydrologic information on surface coal mines in Wyoming.

PILOT TEST OF THE CROW^{TM} PROCESS AT THE BELL LUMBER AND POLE SITE

L. John Fahy
Lyle A. Johnson, Jr.

Background

Beginning in 1990, efforts were initiated in conjunction with the Bell Lumber and Pole Company to implement an in situ remediation project to address the creosote and pentachlorophenol (PCP) contaminated surficial aquifer at the Bell Pole site. The remediation project involves the application of the Contained Recovery of Oily Wastes (CROW^{TM}) process which consists of hot-water injection to displace and recover non-aqueous phase liquids (NAPL).

Wood treating activities began in 1923 at the Bell Pole site in New Brighton, Minnesota. Wood treating activities have included the use of creosote and PCP in a fuel oil carrier. Creosote was used as a wood preservative from 1923 to 1958. A 5 to 6% mixture of PCP in fuel oil was used as a wood preservative from 1952 to the present.

Characterization of the contaminated area at the Bell Pole site has been ongoing for several years. The two uppermost geologic formations identified beneath the Bell Pole site include the New Brighton and Twin Cities Formations. The contaminated New Brighton Formation contains a 23-47 ft thick, surficial aquifer consisting of uniform silty, fine to medium, gravel/sand. This formation is recharged through precipitation and by percolation, with groundwater flowing primarily to the southwest and discharging to a county drainage ditch. The Twin Cities Formation is a till material which creates an effective aquitard, separating the New Brighton Formation from lower aquifers.

As an interim response action, a two-well pilot test of the CROW process was conducted. The test consisted of injecting hot, potable water into the NAPL saturated area of the aquifer, producing groundwater (and NAPL) from an existing production well, PW1, and treating the produced water for sanitary sewer discharge.

Objectives

The objectives of the pilot test were to compare predicted injection and production rates with actual field data, demonstrate the ability to heat the aquifer to the 49 to 60°C (120 to 140°F) range, demonstrate the ability to hydraulically control the injected water to prevent spreading contamination, confirm treatment system effectiveness in reducing PCP and polynuclear aromatic hydrocarbons (PAHs) prior to sanitary sewer discharge and predict anticipated operating conditions for a full-scale CROW application.

Procedures

The pilot-test location was selected based on the NAPL isopach mapping and the location of the existing production well, PW1. The injection and production wells were located in the area that contains high NAPL accumulations.

The pilot test began on September 24, 1991. Over the entire test, the pumping rate of PW1 averaged 6.5 gpm. The hot-water injection rate averaged 4.5 gpm. The pumping rate was consistently higher than the injection rate throughout the test. Water levels and temperatures in the aquifer were monitored throughout the test. Wellhead injection and production temperatures and the downhole temperatures were continuously recorded for certain monitor wells. Manual temperature readings were also taken daily.

Results

Early temperature data indicated that the hot water might be having a tendency to override and travel predominantly across the top of the aquifer. But by the end of the test the highest temperatures were more toward the center of the zone, indicating that the hot water was not just traveling across the top of the zone but was heating the entire interval uniformly. In all cases, a temperature equal to or greater than the targeted 60°C (140°F) was achieved in the interior monitor wells. Downhole temperature measurements also indicated that 66°C (150°F) fluids had reached the production well prior to the conclusion of the hot-water injection phase.

NAPL arrival at the production well was noted by increased levels of floating oil at the top of the water table, only 6 days before breakthrough of the hot-water front. After the test was concluded, two boreholes were drilled to estimate the amount of oil remaining after hot-water injection. The post-test coring data indicated that, after the first 20 pore volumes of water were injected, the process efficiency declined drastically. Additional pore volumes of water injected will displace increasingly smaller amounts of NAPL.

Two samples were chosen from the soil samples for PCP analysis. One sample was taken from the injection well core in an area containing the highest NAPL saturation. A corresponding sample was taken from the closer borehole, at the same depth, to represent post-test conditions. Before hot-water injection, the PCP concentration was 2,100 mg/kg. After hot-water injection, the PCP concentration was reduced to approximately 3.6 mg/kg, greater than a 500 fold decrease in concentration.

Conclusions

The pilot test provided sufficient hydraulic information to design the full-scale CROW remediation system. The pumping test portion of the pilot test indicated uniform aquifer properties. The entire thickness of the aquifer reached the target temperature range and containment of the injected hot water was achieved. Pretest injection and production rate predictions were achieved.

The post-test soil boring data indicated hot-water injection displaced greater than 80% of the NAPL near the injection well. The data indicates that a NAPL saturation of approximately 19% (pore volume basis) and a 500 fold decrease in PCP concentration can be achieved with 20 pore volumes of flushing.

The treatment system used during the pilot test was effective in reducing PCP and PAH compounds to concentrations acceptable for sanitary sewer discharge. The microbial assay of the post-test samples found an encouraging increase in microbial population compared to earlier data collected before the pilot test.

Related Publications, Presentations, and Patents

Publications

Conestoga-Rovers and Associates Limited and Western Research Institute, 1990, Interim Response Action Work Plan Bell Lumber and Pole Company Site. New Brighton, MN, Unpublished Report, 40 p.

Fahy, L.J. and L.A. Johnson, 1992, Bell Pole Pilot Test Evaluation. Laramie, WY, WRI-92-R033

Presentations

Fahy, L.J., L.A. Johnson Jr., D.V. Sola, S.G. Horn, and J.L. Christofferson, 1992, Bell Pole Pilot Test Evaluation. Presented at the Colorado Hazardous Waste Management Society Annual Conference, October 1992, Denver, CO.

Patents

Johnson, L.A., and B.C. Sudduth, Contained Recovery of Oily Waste, July 18, 1989, U.S. Patent No. 4,848,460. Western Research Institute, Laramie, WY.

IN SITU TREATMENT OF MANUFACTURED GAS PLANT CONTAMINATED SOILS, DEMONSTRATION PROGRAM

Lyle A. Johnson, Jr.

Background

The Contained Recovery of Oily Wastes (CROW™) process removes organic contaminants from the subsurface by adaptation of technology used for secondary and heavy oil recovery (Johnson and Leuschner 1992). The CROW technology has been successfully tested in the laboratory as part of a project for the U.S. Environmental Protection Agency (EPA) SITE Program's Emerging Technology Program (Johnson and Guffey 1990). The development consisted of several one- and three-dimensional physical simulations of the process. The preliminary testing has shown that hot-water flushing could reduce contaminant content by approximately 60 wt %. Additional testing with totally biodegradable chemicals indicated that the removal rate could be increased to approximately 90%, as shown in Figure 1. Based on the laboratory performance of the process, the EPA advanced the process to the SITE Demonstration Program.

Further development of the process has included the completion of a pilot test at an active wood treatment facility. The pilot test provided additional information for the design of a field-scale remediation effort, in addition to verifying several of the pre-pilot design specifications and predictions.

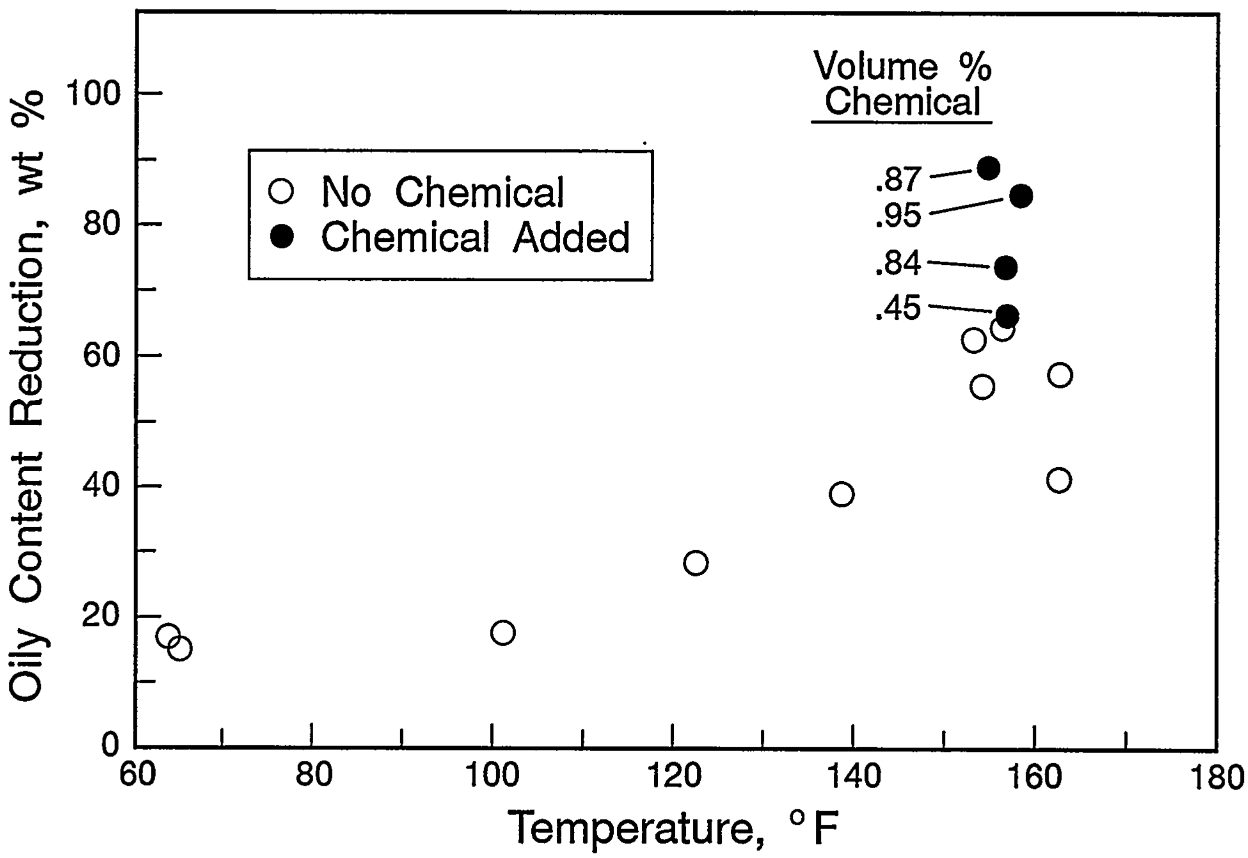

Figure 1. One-Dimensional CROW™ Tests

Verified by the pilot test were the ability to: (1) establish and maintain desired injection and production rates, (2) heat the test area to the desired temperature, (3) achieve non-aqueous phase liquid removal rates equivalent to laboratory rates, and (4) show that the produced fluid can be easily treated for reinjection or disposal (Fahy et al. 1992).

Objective

The objective of this study is to demonstrate and evaluate the CROW process and bioremediation to remediate a site contaminated with a dense organic fluid. The goal is to achieve treatment levels in the field that are comparable to prior laboratory studies.

Procedures

The following procedures will be followed to conduct the project:

- Develop and submit a detailed work plan.
- Identify and secure all required construction and environmental permits.
- Prepare and submit for approval a 30% complete design for the field layout and operation.
- Prepare and submit a 95% design for the field layout and operation. All equipment, well construction, and operating routines will be fully specified.
- Prepare a final project design based on the review comments from the 95% design submission.
- Procure all required equipment and construct the field facilities.
- Operate the field demonstration.
- Dismantle the field facility.
- Analyze the data from the field demonstration and report the results to the DOE, EPA, and cosponsors.

The site selected for this demonstration project is a former manufactured gas plant site located in Stroudsburg, Pennsylvania. The site is a Superfund site owned by Pennsylvania Power and Light. The funding support for the project is provided by the U.S. Department of Energy, Pennsylvania Power and Light, Gas Research Institute, and Electric Power Research Institute. Western Research Institute (WRI) in conjunction with Remediation Technologies Inc., is designing and operating the project. Other participants working at the site include Atlantic Environmental Services Inc, (site characterization), Michigan Biotechnical Institute (water treatment for disposal), and the U.S. EPA SITE Demonstration Program (process monitoring, analysis, and evaluation).

The work plan for the field demonstration submitted to and approved by the EPA Region 3 office included a three-step system design and approval sequence. Also identified were all the environmental and construction permits required.

Results

The 30% design and the 95% design of the field installation and operating scheme have been prepared and submitted to the EPA Region 3 office as part of the EPA site requirements. The Pennsylvania Department of Environmental Resources (PADER) was also included in the review of the design and operational requirements of the project. Review comments on both design phases have been received and addressed. The final design has been prepared based on the comments to the prior design phases and has been submitted to EPA and PADER. Procurement of long lead-time equipment for the site operations has been completed.

The present schedule for the project is for drilling and construction to begin at the site about June 1, 1994. Operation of the facility should begin around August 15, 1994.

Conclusions

The progress of the project has been slowed because of problems encountered in the recharacterization of the site as requested by the EPA, and the lengthy and complex EPA design and approval protocol. Planning of future field tests, whether for environmental or energy production projects, should include sufficient time for the proper environmental permitting of the project.

OPERATION AND EVALUATION OF THE CO_2 HUFF-N-PUFF PROCESS

Lyle A. Johnson, Jr.
Robert M. Satchwell
Harry A. Deans
Kenneth P. Thomas

Background

Two basic types of carbon dioxide injection processes are used for enhanced oil recovery. These processes are termed immiscible and miscible displacement processes, depending on the solubility of the CO_2 in the crude oil. Several variations of the immiscible process have been tried, including continuous CO_2 injection, carbonated water injection, a variation of the water-alternating-gas process, and the CO_2 cyclic stimulation (huff-n-puff) process. In the cyclic stimulation process, a slug of carbon dioxide is injected, allowed to soak, thereby allowing the production mechanisms to develop, and then produced back into the injection well. Commonly, this cyclic process is repeated as oil production decreases.

Although Wyoming is ranked sixth in oil production in the United States, production is declining at a rate of about 10% per year. Under present market conditions, there is little incentive to develop new production. Based on the type of oil and the reservoir size, miscible flooding, particularly with CO_2, probably has the widest potential applicability for enhanced oil recovery in Wyoming reservoirs. Also, a large supply of CO_2 is available for oil field use from the Madison Formation in southwest Wyoming.

A number of reservoirs with good potential for CO_2 flooding have been defined in the major producing basins of Wyoming. An average CO_2 utilization factor of 7,000 standard cubic feet per barrel of oil recovered has been quoted for Permian Basin CO_2 flooding. If 350 mmscfd of CO_2 from southwest Wyoming can be put to work at this same efficiency, 50,000 bbl of oil per day are potentially available from Wyoming fields by the late 1990s. This would amount to more than 25% of the state's production by that time.

The Enhanced Oil Recovery Institute (EORI) of the University of Wyoming (UW) performed a CO_2 cyclic stimulation as a demonstration, to develop interest in supporting research on the process. With technical assistance from WRI, support was obtained for the program from the Wyoming Legislature and the Science, Technology, and Energy Authority (STEA) of Wyoming. Significant in-kind contributions were also provided by the operators of wells in the form of workovers required for the tests, separation and testing equipment, daily sampling of the wells, and other expenses associated with performing the stimulations.

Objective

The program developed by WRI and UW had the objective of evaluating the potential of cyclic CO_2 stimulation of marginal oil wells in Wyoming for increased oil production.

Procedures

Solicitation for candidate wells was accomplished by sending a letter and information form to essentially all operators of wells in Wyoming. The operators were requested to propose one or more wells for the program. The information received on potential study wells was reviewed and the candidate wells were selected by a panel made up of individuals from UW, STEA, EORI, and WRI.

The criteria for designing the cyclic stimulation was based on previous tests reported in the literature, and on limited laboratory/simulation results.

The essential elements of the design were: CO_2 should penetrate between 50 and 200 ft into the target formation; the CO_2 phase would occupy about 50% of the pore space; injection of CO_2 should be at the highest practical rate; the liquid CO_2 would be heated, after being pumped to injection pressure, to at least 4°C (40°F); and a shut-in (soak) period, between the end of injection and the start of production, in the range of 2 to 4 weeks would be used.

Single-well chemical tracer (SWCT) tests were performed in the candidate wells for CO_2 injection. The SWCT tests were used to provide information concerning reservoir flow characteristics, as well as the residual oil saturations in the target zones, prior to the CO_2 injection. In order to estimate the amount of remaining oil which will be contacted by CO_2 during a cyclic treatment, it is necessary to know the remaining oil saturation in the target formation. The wells chosen for the demonstration program were all stripper producers (i.e., near the end of their productive lives). All of the candidate wells except one were producing at high water cuts. Thus, they were close to waterflood residual oil saturation near the wellbore, where the CO_2 treatments would be applied. The radius of investigations for the SWCT tests ranged from 6.4 to 16.4 ft. The mass balance tracers used for these tests were isopropyl alcohol, n-propyl alcohol, and/or methyl alcohol. The reactive tracer was either ethyl acetate or ethyl formate, with the resultant product being ethyl alcohol.

Eleven wells comprised the stimulation testing program. Two other wells were evaluated with a SWCT test, but the test results eliminated them from the program. The 11 program wells represented 10 fields and four basins in Wyoming. Also included in the program were the collection of data and/or production samples from 45 other CO_2 cyclic stimulations conducted independently by operators. All operators contacted were very cooperative in providing test results and/or samples.

For each well tested, initial samples of the produced oil and gas were collected to provide baseline data. After production was reestablished following the shut-in period, samples of the produced gas and fluids were collected on a routine basis. Sampling time was generally daily at the beginning of the production period, with the sampling interval increasing as the production period increased. Samples were collected on a weekly basis by WRI from both program wells and from any well tests conducted independently by operators participating in the program.

During the study, 1867 gas and 1623 liquid samples were collected from 34 of the 56 CO_2 cyclic stimulations conducted in Wyoming. The 34 wells represent 25 fields in five major producing basins. Of these samples, 1675 of the gas samples and 203 of the liquid samples were analyzed.

The produced liquids (water and oil) were obtained either from the wellhead or a separator or treater that had been placed on-line to monitor the production. If the liquid sample was obtained from a separator or treater, it was assured that only the stimulated well was flowing to the treater at the time of sample collection. Samples (water and oil) obtained from a separator-treater were entirely single phase (water or oil). However, samples obtained from the production wellhead were a mixture of water and oil.

Routine analysis of the oil samples was conducted usually on a 1- to 2-week basis and included the determination of specific gravity and viscosity. In addition, the distillate range and the percentage of pentane asphaltenes and wax were determined usually on a 2- to 3-month basis. The recovery of a sufficient amount of oil dictated the number and type of analyses that could be conducted on each sample. Also the elemental composition (carbon, hydrogen, nitrogen, and sulfur) of the produced oil was determined at least once during each individual test.

The analysis of the water samples involved primarily the determination of pH. This measurement was conducted routinely about every fourth day and only on water samples from some of the field tests. In addition, specific metals and the mineral carbon content of selected water samples were determined to determine if specific ions were being mobilized during the process.

Chemical and physical properties of the crude oils and their distillate and residue fractions were measured (1) so they could be incorporated into the development of a mathematical model of the CO_2 cyclic stimulation process and (2) to initiate the development of a capillary gas chromatographic, simulated distillation method that would extend the measured boiling range of high-boiling materials beyond 538°C (1000°F). This model uses continuous thermodynamics for the mathematical treatment of the data. This has several advantages over the more conventional approach that utilizes the data in a pseudocomponent format.

Chemical and physical properties were determined for two crude oils (the Beaver Creek and Little Buffalo Basin - North Dome fields). Their distillate and residue fractions included: distillate range, elemental composition (carbon, hydrogen, nitrogen, and sulfur), molecular weight, specific gravity, viscosity, the percentage of aromatic carbons and hydrogens, and the percentage of carbon types present in selected distillates and the residue from the crude oil from the Beaver Creek field.

A numerical simulator was to be developed for the prediction of the CO_2 cyclic stimulation process through the integration of the simulation with geologic and laboratory data. The first step was the selection of an established compositional simulator to which the modification necessary to predict the cyclic stimulation process could be made. The computer models considered were the TSRS, a thermal-compositional simulator developed by WRI, the MORE simulator developed by Reservoir Simulation Research Corporation (not a public domain simulator), and the UTCOMP simulator developed by the University of Texas with industry and federal support. After a lengthy evaluation, the UTCOMP simulator was selected.

Results

A summary of the results for the 12 SWCT tests performed are given in Table 1. For all but three of the individual projects (both those part of the WRI/UW Program and those that are not) the physical properties (distillate range, specific gravity, and viscosity) of the oil produced by the CO_2 cyclic stimulation process did not vary with time. This indicates that either the mechanisms responsible for oil production were the same throughout the enhanced production period or the properties monitored were not affected by the production mechanisms. In addition, the percentage of asphaltenes and wax did not vary significantly during the production period. This implies that plugging of the formation by these components was not a problem during the production period. The elemental composition data, although limited, also do not appear to vary during production.

Conclusions

Criteria were developed for accepting or rejecting candidate wells for the CO_2 cyclic stimulation process. These criteria include reservoir flow characteristics and residual oil saturations.

For the selected study wells, the SWCT tests were capable of determining residual oil saturations as well as reservoir flow characteristics such as crossflow, drift, and flow irreversibilities. The residual oil saturations for the fields tested ranged between 13 and 40 pore volume %. The results showed that the field data could be predicted reasonably well with the appropriate simulator.

Eight of the 11 wells that were part of the WRI/UW program could be considered technically successful in that they did produce incremental oil. However, only the Crooks Gap (both cycles)and the Osage wells, P-3 and P-4, would be considered to be highly successful, with Crooks Gap being economically successful and Osage marginally successful because of increased production from offset wells. Program wells in Beaver Creek, North Grieve, Bonanza Buck Creek, and West Fiddler Creek fields were the marginal technical successes. Reasons that WRI/UW program wells were considered marginally or not technically successful include: Cole Creek and Bonanza (production equipment problems), Beaver Creek and Grass Creek (reservoir flow problems), and West Fiddler Creek and North Whitetail (lack of CO_2 containment caused by lack of reservoir pressure).

Regarding wells that were not part of the WRI/UW program, insufficient data are available to determine technical and economic successes. However, three companies did provide analysis as to the success of their individual wells. Conoco Inc. stated that three of the six stimulations they conducted could be classified as technically or marginally technically successful, with one of those, the South Glenrock test, being a technical success. Amoco Productions projected that they had at least nine marginally to completely successful technical demonstrations, six in the Wertz-Lost Soldier area and three in the Salt Creek field. Of these nine wells, only four in the Wertz-Lost Soldier area were considered to be economically successful. Petrospec, the operator of the LAK field, indicated that their test was a complete success.

Although not part of this study, it is of interest that Amoco Production has demonstrated the technical feasibility of field-wide carbon dioxide flooding in the Wertz and Lost Soldier fields near Bairoil Wyoming. Results from the Osage and West Fiddler Creek wells in the WRI/UW study also support this observation.

Related Publication

Johnson, L.A., Jr., R.M. Satchwell, H.A. Deans, and K.P. Thomas, Operation and Technical Evaluation of the CO_2 Huff-N-Puff Process. Laramie, WY, WRI-94-R030.

Table 1. SWCT Test Summary

Test No.	Field	Model[a]	Drift ft/day	Crossflow bbl/day	Irreversibility Ratio	$(S_{or})_{avg}$ %
1	Beaver Creek	SS	0	4.0	2.87	23
2	Bonanza	SS	0	0	1.28	23
3	Buck Creek	SS	0	0	1.21	20
4	Crooks Gap	SS	0	0	1.12	26
5	Fiddler Creek	SS	0	0	1.54	20
6	Garland	C	0	0	na	39
7	Grass Creek	SS	0	31.6	6.52	23
8	Osage	SS	0	10.7	1.24	28
9	Salt Creek	D	3.3	0	na	13
10	Steamboat Butte	SS	0	7.6	3.47	20
11	Wertz	SS	0	0	1.50	15
12	N. Whitetail	SS	0	0	1.18	40

[a] SS - Sandstone Model; C - Carbonate Model; and D - Drift Model

OIL FIELD WASTE CLEANUP USING THE TANK BOTTOM RECOVERY AND REMEDIATION PROCESS

Robert M. Satchwell
Vijay K. Sethi
Lyle A. Johnson, Jr.

Background

During oil production, wastes are generated that are stored either in open pits or in storage tanks. These wastes, known as tank bottoms, typically contain substantial quantities of oil mixed with solids, free water, and emulsified oil and water. Several processes are being tried to recover oil from these wastes. So far, mechanical separation techniques have not been successful in removing solids or water from the oil. WRI has developed a thermal recovery process that, in bench-scale testing, has shown that salable products can be recovered from tank bottoms. The process, termed TaBoRR^{TM} (Tank Bottom Recovery and Remediation), has been patented and is being readied for demonstration with support from Envir-Oil Inc. of Kaycee, Wyoming.

Objectives

The objectives of this study were to design, construct, and test a TaBoRR plant capable of producing 200 bbl/day of salable product from tank bottoms.

Procedures

The TaBoRR process involves a two-step scheme for separating water and solids out of the tank bottoms. A conceptual schematic of the process is shown in Figure 1. As depicted, the tank bottom wastes are heated under pressure followed by a flash operation. This flash operation provides a means of vaporizing and removing the water from the tank bottom waste. Water-free waste is then treated in a stripping operation, whereby a large amount of the hydrocarbons are distilled away from the solids.

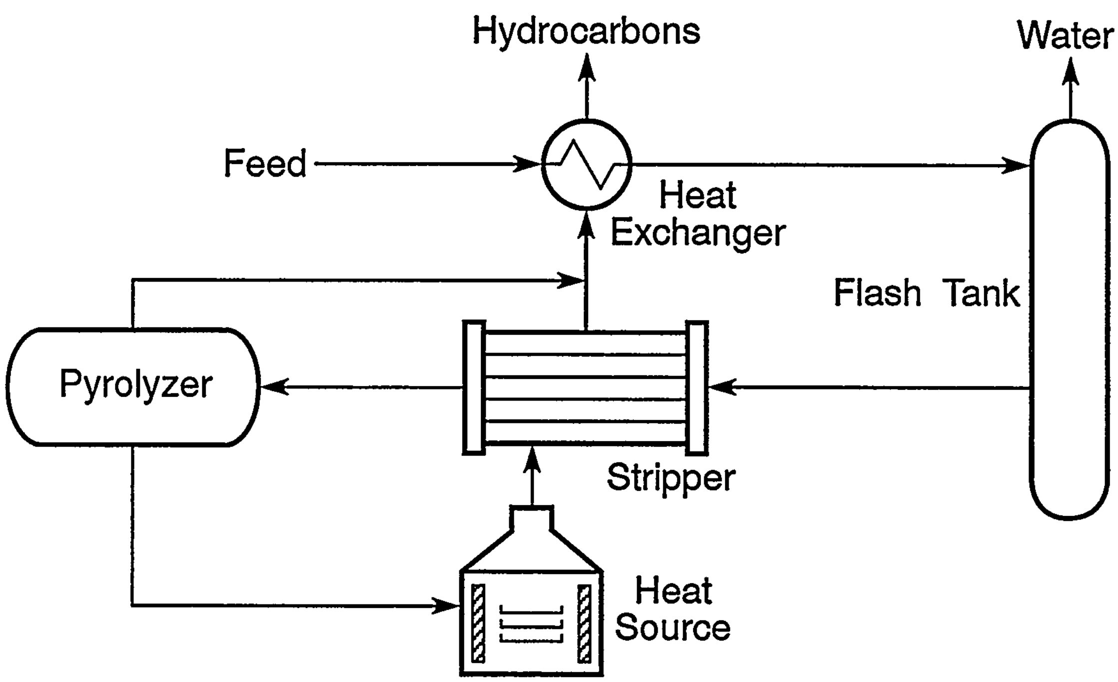

Figure 1. Conceptual Schematic of the TaBoRR^{TM} Process

To improve the economics of the process, the vaporized hydrocarbons produced in the stripping operation are used to preheat the feed stream entering the flash operation, and then sent to a condenser where a salable product is recovered. All noncondensible materials are sent to a flare, and the stripper waste stream, consisting of solids and heavy hydrocarbon liquids, is returned to the pit.

For this study, a candidate pit-site was selected and samples of stored waste were analyzed. These analyses served as a guide for devising a reference feed material composition. The model feed material composition was then used for process modeling.

Process modeling was undertaken to develop design criteria for various components and streams. HYSIM, an interactive process model designed for gas processing, oil refining, petrochemical, chemical, and synthetic fuels processing, from Hyprotech Ltd. was used to establish optimum processing parameters for the flash and stripper operations. Results were also used to size the process components, transfer lines, and pumps, and also to establish thermal loads. The effect of varying feed material composition on the process was also investigated.

Based on the results from numerical simulations, design specification and duty requirements for various components were established. Major components were fabricated and assembled as a skid-mounted plant at the Envir-Oil facilities in Kaycee, Wyoming.

Results

Table 1 lists the analysis of the tank bottom waste from the candidate pit. The table also displays the values and ranges used for the reference feed material in the numerical simulation of the process.

Process modeling confirmed that the optimum process conditions for the flash and stripper operations are sensitive to the feed material composition, and other properties. For a given feed material, process yield can be maximized by increasing the stripping temperature. However, increasing temperature increases the likelihood of hydrocarbon losses to coking. Similarly, overall thermal requirements for the process can be minimized by the proper selection of pressure and temperature of the fluids being flashed. Process modeling showed that the stripper overheads contain enough heat to sustain optimum flash operation, however, an alternate heat source is required during startup.

Table 1. Numerical Simulation Initial and Input Conditions

Description	Source Material	Data Investigated
Temperature, °F	~70[a]	40
Pressure, psia	12.4[a]	14.5
Mass Flow, lb/hr	na	4000
Standard Density, lb/ft^3	56.2	60.0 - 64.5[b]
Solids, wt %	1.38	0 - 10
Water, wt %	3.50	10 - 16
Hydrocarbon, wt %	95.12	74 - 90

na - not applicable
[a] - at time of sampling
[b] - dependent on composition

Based on the results from the process modeling, mass flows and energy requirements for various components were compiled assuming the reference feed material. These are compiled in Table 2. Based on the data, specifications for major components were prepared. All vessels were specified to be constructed from 316 stainless steel with external insulation to minimize thermal losses. Weld quality and finish were specified to be in accordance with ASME code section VIII, Division 1 and TEMA Standards. For heat exchangers, 20% excess surface area of the tubes was included as a safety factor. All vessels were specified for construction with adequate expansion joints to reduce stresses under elevated temperature conditions.

The plant is divided into five major systems. These systems are: (1) the feed system, (2) the flash process, (3) the stripper, (4) product recovery system, and (5) support systems. The finalized plant schematic is shown in Figure 2. The feed system consists of a positive displacement pump, and two heat exchangers for heating the feed material to the desired temperature for flash, namely feed preheater and flue gas preheater. The flash system includes the flash valve, flash tank, and the flash tank pump. The stripper system consists of the stripper, a tube-and-shell heat exchanger, with provisions for quiescent boiling of hydrocarbons in four stages by installing weirs, and a sparger arrangement whereby sweep gas also serves as a mild agitator to prevent solids accumulation. The product recovery system consists of a condenser, separator, and blower. The support system includes a heat source capable of delivering all the process heat requirement (a dual-fuel burner) and a flare.

The skid-mounted layout for the plant is shown in Figure 3. The plant is being readied for a shakedown at the Envir-Oil facilities. After a brief shakedown, the plant will be shipped to the candidate pit-site for extended operations and testing.

Conclusions

WRI's patented process for thermal recovery and remediation of tank bottom wastes is being developed for field demonstration. Based on numerical simulations of the process, a 200 bbl/day plant has been designed and fabricated. The plant is to be operated at a candidate pit-site for extended periods.

Related Publication

Satchwell, R.M., V.K. Sethi, and L.A. Johnson, 1994, Oil Field Waste Cleanup Using the Tank Bottom Recovery and Remediation (TaBoRR^{TM}) Process. Laramie, WY, WRI-94-R029.

Patent

Patent Number 5,259,945, Process for Recovery of Tank Bottom Wastes

Table 2. Component Design Data

Design Data	Feed Pump	Feed Preheater	Flue Gas Preheater	Flash Valve	Stripper	Condenser
Feed Rate, lb/hr	4000	4000	4000	4000	2858[a]	2858[a]
Solids, wt %	7 - 10	7 - 10	7 - 10	7 - 13	6 - 20	0
Water, wt %	13 - 18	13 - 18	13 - 18	13 - 18	0	0
Temperature Range, °F	40	40 - 600	40 - 600	425 - 600	300 - 850	400 - 150
Pressure Range, psia	12 - 1000	600	600	337 - 19	25 - 8	25 - 8
Heat Required[b], MMBtu/hr	na	1.0	0 - 1.0	na	1.7	-0.4

na - not applicable
[a] - dependent on feed composition
[b] - input or removal

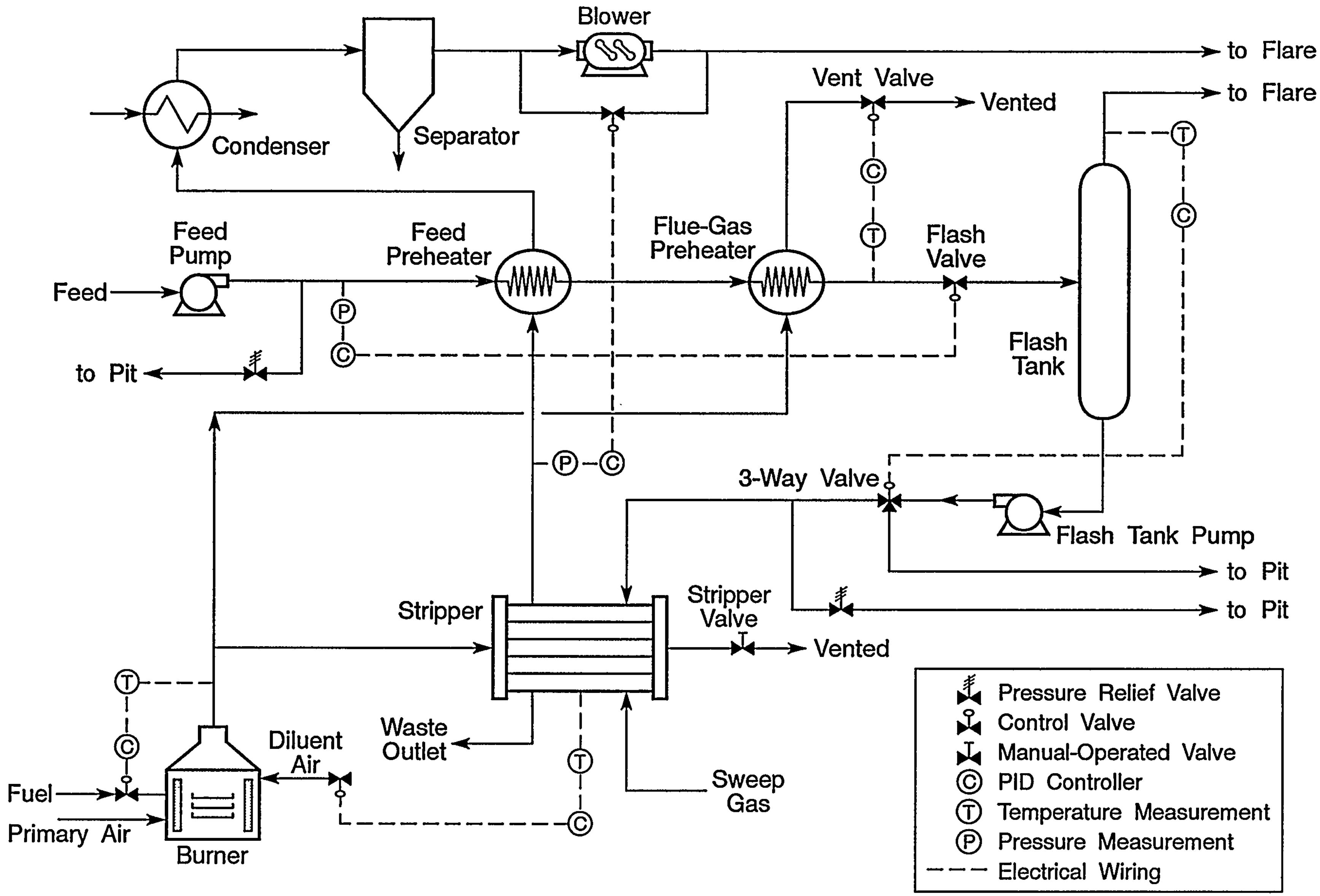

Figure 2. Finalized Plant Schematic

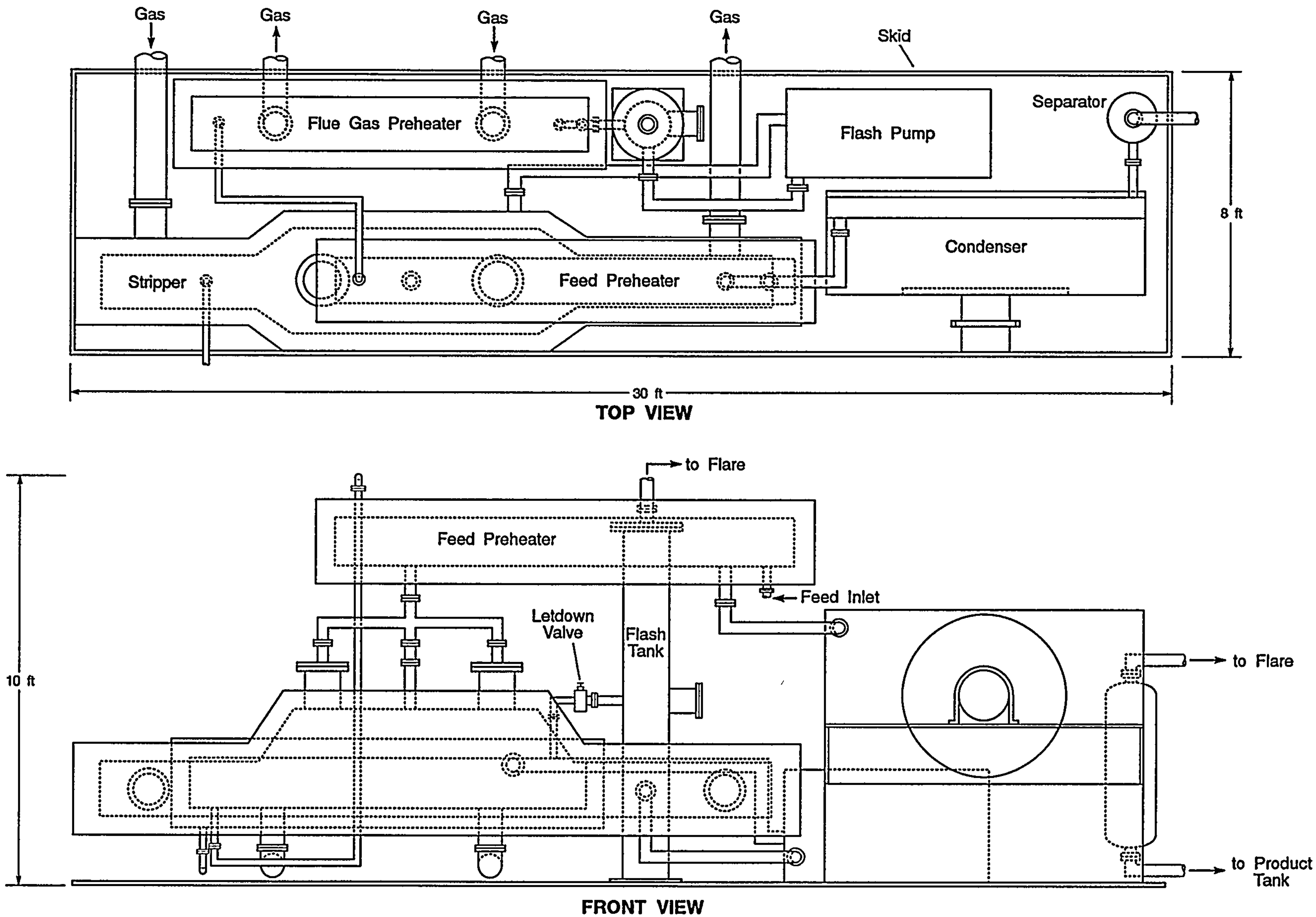

Figure 3. Skid-Mounted Plant Layout

ENHANCED GRAVITY DRAINAGE OF OIL IN THE NORTH TISDALE RESERVOIR

Lyle A. Johnson, Jr.
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Alan L. Merrill

Background

A commercial oil mining project exists at the North Tisdale field located on the western flank of the Powder River Basin in Johnson County, Wyoming. The project consists of a horizontal tunnel conventionally mined into a hillside to gain access to the low-pressure, medium gravity oil (28.5°API), located at an approximate depth of 250 ft in the Cretaceous Lakota Sandstone reservoir. From the tunnel, drill rooms were constructed from which horizontal holes were drilled. The reservoir is currently producing at low rates through the dominant gravity drainage mechanism.

Objective

The objective of this study was to evaluate the feasibility of applying secondary and tertiary techniques to accelerate recovery from the Lakota reservoir.

Procedures

Miscible, immiscible, chemical, and thermal processes were screened for applicability to the horizontal well system in the Lakota reservoir. The screening criteria developed by Taber and Martin (1983) were used to evaluate the processes. Economic and safety factors were also used in the selection of the oil recovery processes to be investigated in detail. From the review, waterflooding and steamflooding were determined to have the greatest potential for enhancing production.

A numerical simulation study of the two processes was conducted using the simulation program TETRAD marketed by Dyad 88 Corporation, Calgary, Alberta, Canada. The TETRAD simulator was used in the thermal mode to run both simulations. The estimate of oil and water production rates in horizontal wells with waterflood and steamflood processes under varied reservoir and operating conditions and well configurations were the evaluation criteria used in the numerical simulations. The study consisted of a wellbore pattern study and a reservoir parameter sensitivity study. A different model configuration was used for each part of the study.

The reservoir model configuration used in the wellbore pattern study was a half-symmetry pattern representing two horizontal wells which were 1000-ft long. One well in the pattern was a steam or water injector, while the other well simulated a producer. The reservoir simulation configuration was blocks, with 10 cells of 100 ft in the x-direction, 7 cells of 30 ft in the y-direction, and 5 cells of 6 ft in the z-direction. The wells were located in the center of the grid blocks. Injection rates and the productivity and injectivity indexes of the wells were halved to simulate the half-symmetry pattern. Five well configurations of various vertical, horizontal, and diagonal offset configurations were used to determine which was the most efficient pattern (Figure 1). The edges of the model consisted of no-flow boundaries.

The reservoir parameter sensitivity study was conducted to determine the effect of varying the permeability, oil saturation, and gas saturation. The model configuration used was the same as that in the pattern study, except the lengths of the wells and reservoir were shortened from 1000 ft to 500 ft. During the parameter study, distillation effects of the oil were not taken into account because of a lack of detailed distillation data. However, distillation appears to be an important factor in the case of Lakota oil. Preliminary distillation data indicated that 18% of the oil can be distilled at 200°C (392°F) and 760 mm mercury.

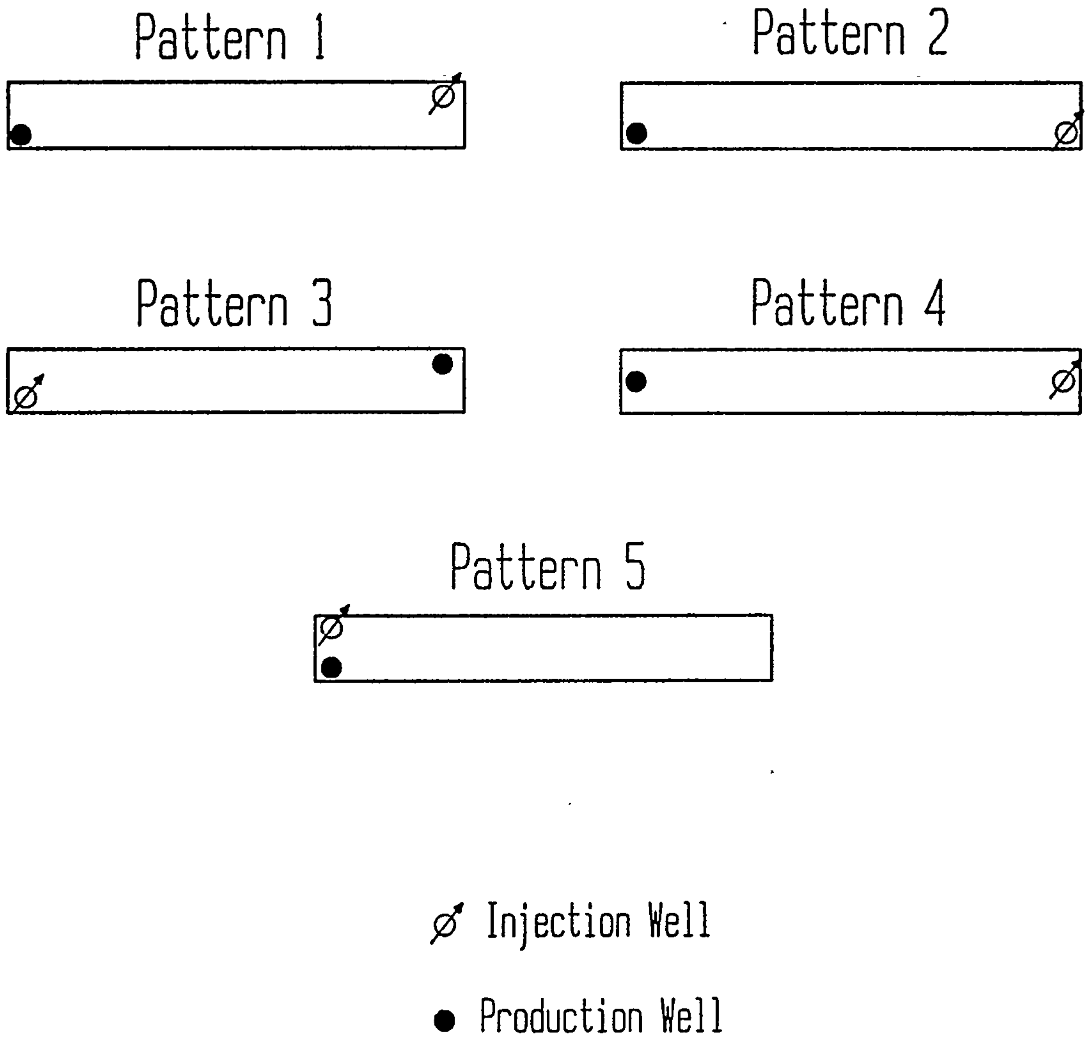

Figure 1. Pattern Study–Wellbore Configuration

Water/oil and gas/liquid relative permeabilities were estimated for the reservoir because laboratory data were unavailable. Water/oil relative permeability was estimated from resistivity logs and oil and water production ratios. Oil and water saturations were calculated from the resistivity logs and matched with water/oil ratios to obtain an estimated relative permeability curve. The gas/liquid relative permeability curve was modified from published data for similar reservoirs.

The samples used in the physical simulations were consolidated blocks, weighing approximately 800 lb each, of Lakota Sandstone removed from the North Tisdale oil mine. The reservoir material was analyzed and found to have an average porosity of 23% and an average horizontal permeability to air of 1100 md.

The blocks were shaped into 2 x 2 x 1.5-ft rectangular blocks and horizontal production and injection wells were drilled into them. The shaped blocks were grouted into steel reactor boxes. The well pattern was designed to simulate the spacing and configuration of horizontal wells in the North Tisdale oil mine. Temperature monitoring wells with four thermocouples per well were installed in the steamflood block on an evenly spaced grid to monitor vertical and horizontal temperature fronts.

To resaturate a block to near reservoir conditions, oil and water were slowly pumped from the bottom of the block through special ports, towards the top, until the oil and water saturations were restored to approximately the original reservoir saturation conditions.

For the waterflood simulation, injection was initially established at 7 cc/min and held at that level for 7.5 hours. It was then raised to 10 cc/min. At 29.5 hours, the rate was raised to the final rate of 15 cc/min. The injection rates were increased in this manner to maintain a near constant flux rate at the flood front and to indicate any possible rate-dependent behavior. The oil and water production rates were measured by weighing the quantities of the produced fluids at 1-hour intervals.

For steamflood simulation, cold-water-equivalent (CWEQ) steam injection rates were the same as the water-injection rates in the waterflood simulations. Steam injection was initially established at 7 cc/min CWEQ for 7.5 hours, raised to 10 cc/min until 29.5 hours when the rate was increased to 15 cc/min. Total injection time was 72 hours. Injection temperature and pressure increased with increased injection rate. Oil and water production were measured on an hourly basis. Samples were taken and centrifuged when the produced fluid consisted of an emulsion.

After completion of the simulations, core samples were taken from each block to determine the distribution of residual oil and water saturations.

Results

In the screening study, miscible processes were eliminated from consideration because of the low reservoir pressure and shallow depth. Immiscible processes consisting of using water or a gas such as air, nitrogen, or flue gas were all technically feasible processes. Air injection is currently being used to enhance recovery from the Lakota reservoir. However, damage to the reservoir due to oxidation of oil may be occurring.

One of the immiscible processes, water injection, was selected for further investigation. Water injection was selected over gas injection because of improved mobility ratios and less severe channeling problems. Polymer and surfactant additives may be feasible, but they were not investigated in detail because of economic limitations for field applications. Alkaline processes were ruled out because the Tisdale crude oil is not acidic, with a pH of 7.5. Thermal processes were screened, with both steam and combustion meeting most of the selection criteria. Steamflooding was selected for detailed investigation. However, steamflooding did not meet the minimum depth criteria of the high permeability (1100 md) and the use of horizontal injection wells would permit high steam injection rates without fracturing the reservoir. Combustion processes were not considered because of the hazards they would create for personnel in the oil mine.

In the wellbore pattern numerical simulations, the pattern study was conducted to investigate the consequences of locating the injection wells either high or low in the reservoir. All simulations for the pattern study were run for 1,000 days. Steam and water injection rates were held constant at 150 CWEQ bbl/day. The pore volume (PV) injection rate was 0.000566 PV/day with a total of 0.566 PV injected.

Comparison of the well patterns under steamflood conditions showed that all patterns with the producer and the injector vertically offset had essentially the same oil recoveries, 46.1 to 48.0%. The oil and water production rates were also similar for the patterns. However, rapid steam breakthrough occurred in the pattern with the injector and producer vertically in line, lowering oil recovery to 17.7%.

Comparison of steamflood and waterflood in the same pattern showed that waterflooding provided better sweep of the reservoir than steamflooding, based on a lower water/oil ratio for the waterflood. But the recovery predicted for waterflooding was slightly lower than that predicted for steamflooding, 45.0% versus 47.7%.

For the numerical simulations study of reservoir parameter sensitivity, the factors investigated included (1) permeability variation, (2) oil saturation, and (3) presence of a gas saturation. The steam and water injection rate was held constant at 250 CWEQ bbl/day over the entire simulation period. The pore volume injection rate was 0.0001888 PV/day for 500 days for a total of 0.944 PV injected. A simulation run of both waterflooding and steamflooding was completed with each of the four cases investigated. Case 1 consisted of a homogenous reservoir with $S_O = 0.55$, $S_W = 0.45$, a horizontal permeability (K_H) of 300 md, and a vertical permeability (K_V) of 150 md. Case 2 had the same saturations as Case 1, but three 10-ft layers were used. The top layer had a K_H of 333 md and K_V of 67 md, the middle layer had a K_H of 333 md and a K_V of 167 md with the bottom layer having a K_H of 667 md and K_V of 500 md. It was believed that the permeabilities used in Case 2 were the closest match to the actual reservoir and were also used in Case 3 and Case 4. In Case 3, the saturations were changed to $S_O = 0.50$, $S_W = 0.50$. In Case 4, a gas saturation was added for a saturation distribution of $S_O = 0.475$, $S_W = 0.475$, and $S_G = 0.05$. Case 4 was run because a large amount of air has been injected into the reservoir in an effort to maintain oil production levels.

Both the steamflood and waterflood simulations showed slightly decreasing oil recovery with increased heterogeneity, decreased oil saturation, or the presence of a gas saturation. The steam-to-oil ratios for the steamflood were about the same for Cases 1, 2, and 3, but in Case 4 the steam-to-oil ratio rose dramatically after about 200 days. The rise in the steam-to-oil ratio for Case 4 is attributed to the gas saturation allowing the steam to move rapidly through the reservoir, thus a quicker breakthrough of steam at the production well. A comparison of steamflood and waterflood recoveries for all cases showed higher oil recoveries for the steamflood.

For the first 7 hours of the steamflood physical simulation, only oil was produced due to the relatively high initial oil saturation of 73.6%. For the next 30 hours, the water production rate increased and the oil rate decreased. For the remainder of the test, the oil production only slightly decreased. The steam-to-oil ratio gradually increased from 1 to 10 cc CWEQ/cc during the test.

Temperature profiles for the steamflood block were used to determine the sweep efficiency. The temperature distribution was mapped at 10, 25, 40, and 60 hours into the test. Heat, spreading out from the injection well, heated the top of the block first, then progressed downward in the block. The bottom of the block never became fully heated. This suggests that placing the steam injector nearer the bottom would be more efficient than placing it at the top.

In the steamflood block, the post-test oil saturation was reduced below 10% near the injection well in the middle of the block. The top of the block was swept with steam, although the residual oil saturation appeared to be slightly higher at the top than in the middle section of the block where the injection well was located. The bottom of the block was not well swept by the steam with the exception of the area below the injection well. The relatively high oil saturation in the bottom of the block was caused by a gravity override effect of the steam.

The initial oil production rate for the waterflood block was quite high, with a low water cut for the first 10 hours of the test. Initial oil saturation was 69.4%. After 10 hours, the oil production rate began a steep decline and the water production rate increased rapidly until the water cut reached levels above 95% at 30 hours. From 30 hours until the end of the test very small amounts of oil were produced.

The waterflood block had a high average uniform residual waterflood oil saturation of 43%. The uniform residual oil indicates that, while the sweep efficiency was quite good, the displacement efficiency was poor in this test.

The steamflood process recovered a significantly greater amount of oil when compared against waterflooding in the physical simulations, 63.5 versus 37.9% original oil in place. Both processes recovered oil at approximately the same rate for the first 30 hours of the tests. After 30 hours, the water cut from the waterflood block increased rapidly to levels above 95%, and the oil production fell sharply. In the steamflood block, the water cut increased to approximately 80% and remained steady for the duration of the test. At approximately 30 hours, an oil-in-water emulsion appeared in the produced fluids from the steamflood. This emulsion consisted of approximately 80% by volume water.

Conclusions

Conclusions of the numerical simulation studies were:

- Numerical simulations indicated that locating horizontal producers or injectors either high or low within the formation had an insignificant effect on oil recovery for well spacings of approximately 200 ft.
- Oil recovery decreased for steamflooding and waterflooding processes with increased heterogeneity and decreased oil saturation.
- Steamflooding showed only small increases in oil recovery when compared with waterflooding using numerical simulation. This small increase was inconsistent with the physical simulation data, where a considerable increase in oil recovery by steamflooding was noted.

Conclusions of the physical simulation studies were:

- Steamflooding yielded 80% more oil than waterflooding.
- A residual oil saturation of 27% was left after steamflooding, compared to 43% for waterflooding.
- An oil-in-water emulsion may be formed when steamflooding the North Tisdale Lakota reservoir

The physical simulations showed that steamflooding produced significantly more oil than waterflooding. Therefore, steamflooding may be an economical alternative to waterflooding, depending on the unit cost of fuel to generate steam and the increased capital costs of a steam generator and water treating facilities. Economic evaluation of the two processes should be used to determine which process is best for the North Tisdale field.

Related Publication

Merrill, A.L., L.A. Johnson, Jr, and R.M. Satchwell, 1992, Three-Dimensional Physical and Numerical Simulation of Steamflooding and Waterflooding of the North Tisdale Reservoir. Laramie, WY, WRI-92-R023.

ASSESSMENT, DESIGN, AND TESTING OF OIL RECOVERY AND PROCESSING TECHNOLOGIES FOR NEAR-SURFACE RESERVES

Robert M. Satchwell
Lyle A. Johnson, Jr.
Vijay K. Sethi

Background

Recovery and production of oil is an integral part of Wyoming's and the national economy. Geological studies have shown that Wyoming has many minable rock formations which contain substantial concentrations of oil. Some of the highest concentrations of oil in such occurrences exist in Big Horn, Natrona, Fremont, and Crook Counties in Wyoming. The formations typically consist of unconsolidated or friable sandstone that is unsuited for development by conventional oil recovery techniques. Nevertheless, the rock material acts as a trap for oil, containing millions of barrels per occurrence. At the present time, such resources are undeveloped and do not provide any economic benefits to Wyoming, nor do they enter into the national energy independence equation.

WRI has developed a broad base of technologies for processing and recovering oil and other hydrocarbons from organically-rich materials such as tar sand, oil shale, tank bottoms, and coal. Realizing that some of these technologies can be applied to the surface recovery of oil from the oil-bearing, minable, surface and near-surface rock formations, WRI obtained support from the State of Wyoming, Economic and Community Development Division for this two-phase study.

Objectives

The main objectives of this study were to develop and demonstrate an economic surface processing scheme for recovering oil from surface and near-surface oil bearing outcrops. Specific objectives in phase 1 were: (1) to select and characterize a target oil reservoir; (2) to perform bench-scale tests to determine the suitability of various thermal processes using reservoir material; (3) to perform linear gravity drainage tests to determine if conventional recovery techniques, such as horizontal wells, are feasible; and (4) to evaluate processes and their products. The objectives of phase 2 were: (1) based on the bench-scale test results, to design and build a scale-up of the most promising configuration of the process to a field-pilot scale and (2) to perform a field demonstration of the process.

Procedures

Phase 1 of the study consisted of bench- and laboratory-scale work to evaluate the viability of the existing technologies for surface thermal processing of oil-bearing rock. This phase also included gravity drainage tests to determine if recovery techniques such as horizontal drilling could be applied. Work was also conducted to identify the optimum processing conditions for these materials, and based on the economics and other factors such as complexity and scale-up considerations, to identify the best candidate for field demonstration.

The reservoir selected for the testing and development of the technology was the Sherard Dome reservoir located in the Big Horn Basin. This reservoir has been previously characterized by the U.S. Geological Survey (USGS) and several developers. Previous estimates have shown that approximately 6 million barrels of oil are present in the readily accessible Sherard Dome.

Two one-dimensional gravity drainage simulation tests were performed in laboratory reactors. Gas permeabilities were also determined. Sand was packed in the tubular reactors and saturated with water and oil at levels far in excess of those typical of the reservoir. Gravity drainage and other pertinent data were monitored over a 7-month period.

Three different surface recovery options were investigated. These included water extraction, solvent extraction, and thermal processing using either a variation of the WRI's ROPE^{TM} technology in an externally heated screw reactor, or thermal processing in a fluidized-bed reactor. Water extraction was rejected because of two major drawbacks: (1) relatively small recovery achieved by others in previous recovery attempts and (2) the fact that large volumes of process waters are required, that in turn lead to large amounts of alkaline effluent.

The option of using solvent extraction employing a light hydrocarbon as the solvent also suffers from two major drawbacks: (1) the excessive cost of the solvent and (2) complete recovery of the solvent requires subsequent thermal processing of the spent sand, increasing the cost of the process.

Phase 2 of the study was planned to evaluate the best candidate process in detail, leading to the design and evaluation of an economically and technically viable process, including a field site demonstration.

A schematic flow diagram of the pilot facility designed for the field demonstration is given in Figure 1. The facility was designed to process approximately 100 tons per day of oil sand. Equipment sizing was based on mass-flow rate, and energy balances.

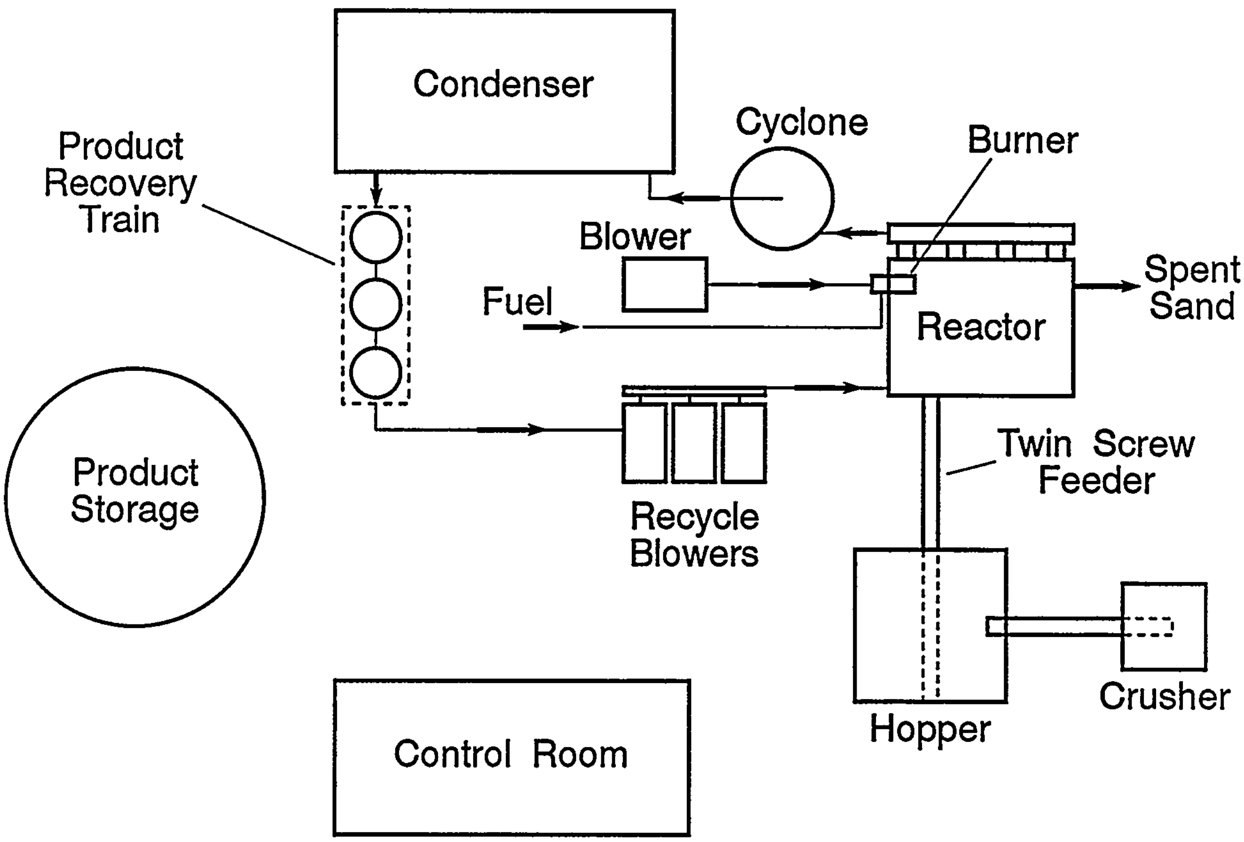

Figure 1. Schematic Representation of the Pilot Facility Layout

The pilot facility consisted of three major systems: (1) a feed system consisting of a crusher, conveyor, surge hopper, and a twin feed screw, (2) a fluidized-bed reactor and associated subsystems, such as particulate cleanup and burner assembly, and (3) a cooling, condensing, and product recovery system. The design considerations for sizing the reactor are given in Table 1.

Table 1. Reactor Design Criteria

Fluidizing Velocity	up to 4 fps
Feed Rate	10,000 lb/hr
Bed Height	18 - 36 inches
Temperature	750 - 850°F
Bed Area	15 ft^2

The distributor design was of the bubble cap type. An uncooled, type 310 stainless steel plate was used. Type 304 stainless steel bubble caps were made from 1-inch schedule 80 tube nipples and attached to the 310 stainless steel plate by welding.

The reactor was a refractory-lined box, 5.5-ft long by 3.5-ft wide. The height of the reactor was about 7 ft. Provisions for temperature and pressure measurements were incorporated in the reactor design. The primary particulate cleanup device was a set of four cyclones that were installed in parallel inside the reactor. The cyclones were suspended in the freeboard area. Collected solids were removed through an inclined tube exiting the reactor. A secondary, high efficiency cyclone was used external to the reactor. The secondary cyclone was constructed from type 304 stainless steel. The cyclone was externally insulated to minimize thermal losses without adversely impacting performance.

Particulate-free gases passed through an air-cooled condenser. Cooled gases and mist then passed through a series of knock-out pots to remove the liquids. Gases exiting the knock-out pots entered a recycle blower train. A portion of the stream was recycled to the main reactor bed and mixed with the fluidizing gas, while the rest was sent to a flare.

The pilot facility was assembled at the field site and operated for a period of approximately 1 month.

Results

The geologic interpretation of the Sherard Dome Formation was consistent with that determined earlier by the USGS. Sherard Dome is a small faulted anticline. Based on the records and logs of previous cores and wells available at the Wyoming Oil and Gas Conservation Commission, it is postulated that some of the earlier estimates of oil-in-place were exaggerated because they failed to include some of the known surface geology. Geological evaluation also showed that conventional oil recovery from the outcrop will be difficult because there is not enough reservoir energy, and because there are some sandstone laminations that flow water while others flow oil. Large diameter holes might be used for recovery if only the oil saturated portions are penetrated. However, a very small portion of the oil-in-place will be recovered. The Third Frontier sand, because of its higher oil content over a 9-acre area at the crest of Sherard Dome, was selected for the demonstration site.

The revised estimate of the oil-in-place in the minable area of the Sherard Dome outcrop (approximately 34.3 acres) is about 1.13 MMbbl. It is estimated that the oil from this area can be recovered at a ratio of 1 bbl/1.6 cubic yd of overburden. The ratio for the area selected for the field demonstration is estimated to be about 1 bbl/0.7 cubic yd.

Core samples, taken for laboratory testing and characterization were analyzed for water and oil content. On the average, the samples contained about 5 wt % oil and 10 wt % water. The range of values observed was 1.4 to 10.8 wt % for oil, and 6.0 to 13.7 wt % for water. No discernible trends were detected in the oil content as a function of the depth. Lack of any discernible trends in the data suggested the presence of barriers at various depths and a large degree of heterogeneity in the reservoir. It should be pointed out that the laboratory samples for analyses and bench-scale processing were collected after the sand was allowed to drain. Actual oil content of the sand is believed to be considerably higher than that indicated by the data.

The recoveries achieved in the one-dimensional gravity drainage tests were in the 20 to 35% range. However, the residual oil concentrations were about two times those measured in the reservoir samples. These results demonstrated the futility of using gravity drainage as a means of oil production from the resource.

Both of the thermal recovery options were tested at the bench scale. ROPE tests conducted with a two-inch screw reactor showed promising recovery rates. Carbon recovery in the tests was in the 85 to 90% range for processing temperatures in the 454 to 524°C (850 to 975°F) range. Limited data obtained during short-term, steady-state tests showed that oil recovery may be related to the residence time in the hot zone of the reactor. At short residence times and higher feed rates, the oil recovery was much higher than at longer residence times. Similar data were also obtained in a fluidized-bed reactor at comparable temperatures. However, because of some equipment constraints, the entire gas stream could not be condensed. Gas data, in conjunction with the spent solids chemistry, indicated that the oil recovery was comparable to that achieved in the screw reactor.

The process selected for field demonstration was the fluidized-bed technology. The main advantages of this technology over the screw reactor were the process scale-up considerations and the need to achieve high heating rates and shorter residence times than those possible in the screw reactor system. Fluidized-bed technology also offered an additional advantage in that higher throughput is possible in a relatively small-scale reactor.

In the field testing in phase 2, several problems were experienced related to the feed system, burner operations as affected by changes in the ambient temperature, product collection system, and the variations in the feedstock. Nevertheless, the operations showed that fluidized-bed technology can be adopted for the recovery of oil from minable oil reserves.

Conclusions

An investigation was made into developing an oil recovery process for near-surface petroleum deposits that are impractical to develop by conventional technologies. The Sherard Dome reservoir was selected as a suitable resource for study. A review of the geological characterization of the reservoir indicated that the oil-in-place in the minable area is about 1.13 MMbbl, with an oil to overburden ratio of 1 bbl/0.7 cubic yd for the field demonstration site. Data from analyses of core samples did not show any discernible trends, indicating likely barriers at different depths and a large variability in the reservoir. Laboratory tests demonstrated that gravity drainage is not a suitable means for resource production.

Three surface recovery options were evaluated. Hot-water extraction and solvent extraction were rejected in favor of thermal processing. Two thermal recovery options were tested at bench scale, from which it was concluded that the fluidized-bed process was the best candidate for field testing.

Several problems were encountered in the field demonstration, but it was shown that fluidized-bed technology can be applied to minable oil reserves. Additional testing is required to develop this technology to its potential capability.

Related Publications

Satchwell, R.M., L.A. Johnson, Jr., and V.K. Sethi, 1993, Assessment, Design and Testing of Oil Recovery and Processing Technologies for Near-surface Reserves. Laramie, WY, WRI-93-R029.

Sethi, V.K., R.M. Satchwell, and L.A. Johnson, Jr., 1994, Surface Process Study for Oil Recovery Using a Thermal Extraction Process. Laramie, WY, WRI-94-R020.

SHALLOW OIL PRODUCTION USING HORIZONTAL WELLS WITH ENHANCED OIL RECOVERY TECHNIQUES

Robert M. Satchwell
Lyle A. Johnson, Jr.

Background

An early steamflood project in the Chetopa field was performed by Tenneco between 1965 and 1967 that produced approximately 68,000 barrels of oil. Approximately 70% was used as fuel, resulting in a net production of 21,000 barrels. Efforts by Kaycee Oil Company and Shallow Oil Limited in 1987 used horizontal wells and a steam huff-n-puff process. Failure of the project was attributed to insufficient heat input and an inadequate drive mechanism.

Objectives

This study was undertaken with support from Kaycee Oil Company to determine the causes of failure of previous attempts and to devise appropriate enhanced oil recovery (EOR) strategies for the Chetopa field. The initial part of the study included reservoir characterization and EOR process screening using laboratory tests. Based on the screening results, a pilot demonstration test was performed using the most technically feasible EOR technique.

Procedures

After assessing the site geology, EOR techniques were screened to find the most technically feasible process for the Chetopa field. The techniques included thermal, chemical, miscible, and non-miscible processes. The initial review used criteria established by Taber and Martin (1983). The review revealed that miscible gas and chemical processes were not suitable for this field. The initial screening favored thermal stimulation. Heating the oil to 121°C (250°F) would make the oil more mobile. This heating could be accomplished by either steam injection or in situ combustion. Therefore, advanced screening was performed for both steam injection and in situ combustion.

Steamflooding was further reviewed by using criteria and correlations compiled by Chu (1985). Results of this evaluation showed that steam injection was not an attractive alternative, since the shallow depth and thinness of the reservoir would limit heat injection and increase heat losses, respectively. Advanced screening of the in situ combustion process used guides provided by Poettmann (1964), Geffen (1973), Lewin and Associates Inc. (1976), Chu (1977, 1982), and Iyoho (1978). The major items of concern that were identified were the high crude oil viscosity and the shallow depth of the reservoir. These could result in low recoveries and fracturing to the surface.

Results

The Chetopa field is located in southeastern Kansas. The production horizon consists of Bartlesville sandstone within the Krebs Subgroup of the Cherokee Group. According to Johnson (1973), the Bartlesville sandstone of the Chetopa field was deposited primarily as a point bar with associated channel fill surrounding the sand body.

Log analyses indicate that the porosity ranges from 26 to 30% from the top to the base of the point bar. In the region of interest, the water saturation ranges from 29 to 38%. Oil-in-place was approximately 1.61 MMbbl (9.1 Mbbl/acre). The pay zone (12 ft) has been limited to only the continuous and permeable portion of the point bar and omits any of the adjacent channel fill sands. Figure 1 illustrates the highly permeable point bar and presents the highest oil saturated sands which are up-dip of the water-oil contact.

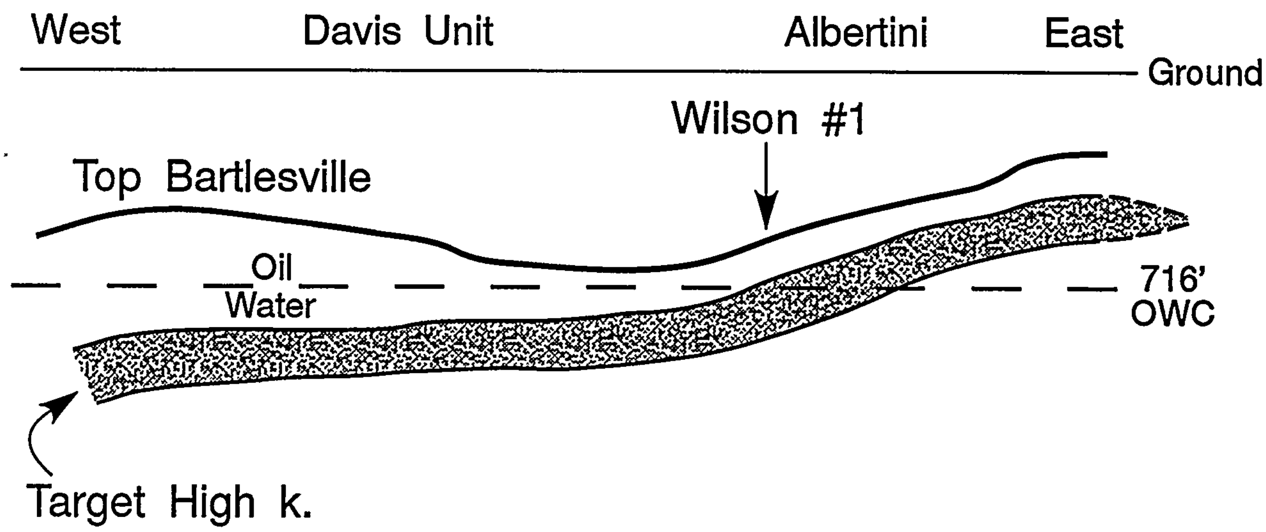

Figure 1. Schematic of Permeable Point Bar

The results of the EOR screening suggested that in situ combustion is the most technically feasible process for the site. From the advanced screening study it was determined that injection rate limitations caused by the shallow depth of the reservoir and the large oil viscosity could be detrimental to the in situ combustion process. To determine if these concerns were justified, combustion tube tests were performed.

The two vertical combustion tube tests were performed with reservoir material to access fuel deposition and associated air requirements. These tests also defined the effects of oil saturation and reduced air injection rate. Both tests produced upgraded oils and indicated that sufficient oil volumes and fuel contents are present in the Chetopa field. Lower oil saturations, higher water saturations, and lower air injection rates resulted in lower peak temperatures, higher fuel contents, and higher produced volumes of carbon dioxide. These results were consistent with data reported in the literature.

Based on the existing horizontal well pattern and vertical wells located between the horizontal wells, and assuming a burning rate of 0.125 ft per day and a volumetric sweep efficiency of 100%, the maximum oil production rate was projected to be approximately 21.3 bbl/day, with the total oil recovered to be approximately 813 bbl/acre-ft. Since the oil-in-place is approximately 1086 bbl/acre-ft, then the potential recovery would be approximately 74.8%. The data also indicate that lower injection rates and pressures could be employed while still sustaining combustion.

From the work of Thomas (1963), it was estimated that the maximum radial distance that would sustain combustion was less than 150 ft. To obtain a vertical coverage of 70% for the combustion front, over a distance of 100 ft, a gas injection rate of 377 scf per ft-hr was required. However, a maximum injection rate of only 300 scf per ft-hr could be achieved, since larger injection rates would result in higher injection pressures that could cause fracturing in the formation.

Thomas (1963) indicated that higher combustion front temperatures occur above the horizontal plane of the ignited interval. Thus, in order to minimize gas production and maximize oil production, the location of the horizontal production wells in the lower portion of the target zone seemed adequate. Furthermore, since the horizontal wells were located approximately 50 ft on either side of the vertical wells, the production wells would act as containment of the combustion front, as shown in Figure 2.

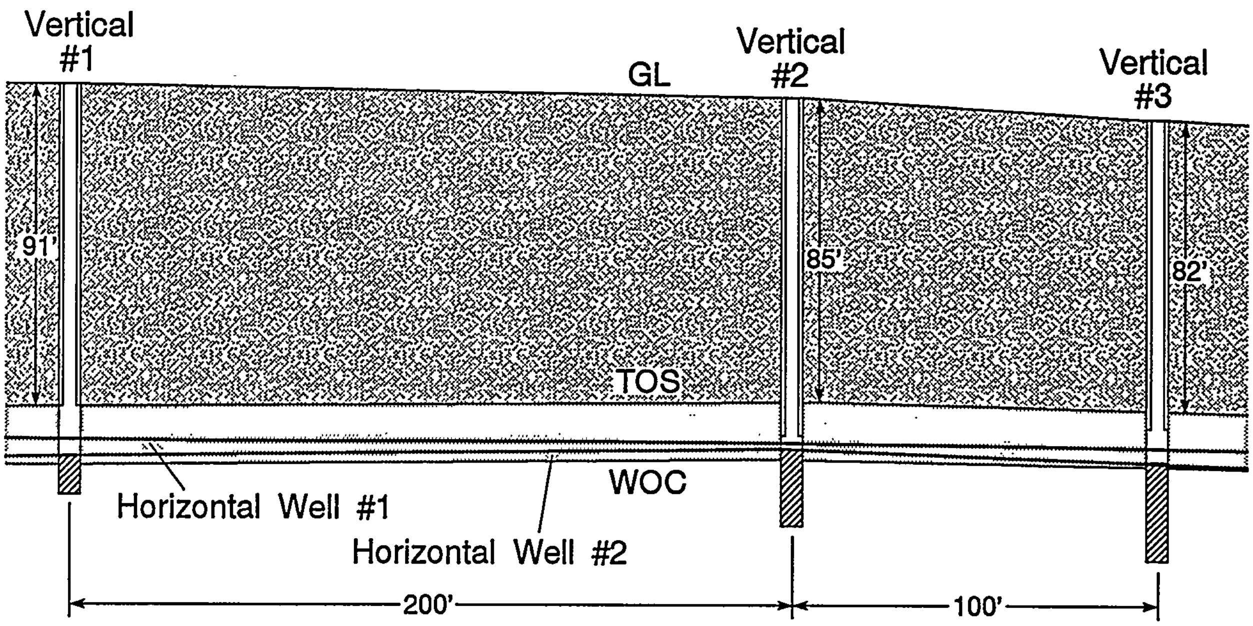

Figure 2. Vertical and Horizontal Well Orientations

Following ignition with a propane and air burner, air injection was continued for 80 days. A total of 40 barrels of oil were produced. Gases were sampled and analyzed from both horizontal production wells. The two production wells did not produce similar gas analyses. Carbon dioxide concentrations as high as 20% were observed. Other interesting observations included the failure to detect increased temperatures in the production wells and the lack of any upgrading of the crude oil.

High oxygen and low carbon dioxide concentrations observed in horizontal production well #1 indicate that the combustion front moved mainly toward horizontal production well #2. If the combustion front moved preferentially toward horizontal well #2 in a radial shape, then the combustion front should have reached the well after approximately 29 days. The high carbon dioxide concentration and absence of oxygen in horizontal well #2 during the 31-40 day period tend to support this hypothesis. The preferential burning direction could have been caused by failure to sustain complete ignition around the wellbore, directional permeability, or a combination of both factors.

Since there was no upgraded oil production nor any increase in temperature, it appears that the combustion front was located in the upper portion of the formation. Assuming a 6-inch thick combustion front would produce a 4.2% volumetric sweep efficiency, then the sweep efficiency for the reservoir stimulated by the process but not burned and the overall recovery efficiency can be determined using the method prescribed by Nelson and McNeil (1959). The sweep efficiency of the unburned zone was determined to be approximately 13.2% with an overall recovery efficiency of 16.0%.

The poor overall recovery efficiency can be attributed to two major factors. First, production was created exclusively by reservoir pressure. This prevented the creation of a pressure sink that would permit the hotter oil to enter the wellbore and hence improve the overall sweep efficiency. Second, the transfer of heat from the burned zone was minimal, which reduced the volumetric sweep efficiency because a reduction in viscosity was not achieved.

Conclusions

This study evaluated the use of horizontal wells with in situ combustion in a heavy oil reservoir. The causes of failure of previously attempted oil production techniques were determined and an EOR strategy was tested in the Chetopa field.

Screening identified in situ combustion as the most viable EOR process for the study site. The process was tested in the forward mode in laboratory tests and then used in the field pilot demonstration. The field test showed that in situ combustion could be sustained at shallow depths. Gas analyses identified the movement of the combustion front to and past one of the production wells.

The overall recovery efficiency was determined to be approximately 16%. This poor oil production was a result of the inability to remove the heavy oil from the production wellbores and the frontal advancement characteristics of forward in situ combustion. Improvements in recovery could be obtained by implementing a closed loop pump system that would preheat the production wellbore. By changing the frontal advancement characteristics of the combustion front, such as by using a water-alternating-gas injection process, improved sweep efficiencies and higher recovery would result.

Related Publication

Satchwell, R.M. and L.A. Johnson, Jr., 1994, Shallow Oil Production Using Horizontal Wells with Enhanced Oil Recovery Techniques. Laramie, WY, WRI-94-R009.

MODEL DEVELOPMENT AND TESTING OF STEAM INJECTION TUBULARS

Robert M. Satchwell
Lyle A. Johnson, Jr.

Background

Efficient methods of transferring the energy of steam from the surface to the oil reservoir can reduce the cost of enhanced oil recovery. Furthermore, increased production rates and oil recoveries can be attributed to higher sandface steam qualities. Thus, the use of insulated tubulars can reduce the thermal losses and make the economics of steam injection projects even more favorable.

To evaluate the feasibility of a steam injection project, an accurate estimate of the heat carried by the injection fluid is extremely important. Knowing the temperature, pressure, and quality of the fluid at the formation sandface is necessary to calculate heat content. However, at the present time, a physical method for measuring these bottom hole parameters is not available. An accurate computer model must be used to estimate these parameters.

A double-walled tubular product has been privately developed that has the potential for use as a steam injection string. However, laboratory verification of the performance of the system was needed. To that end, this study was undertaken with support from Inter-Mountain Pipe Company.

Objectives

The objectives of this study were to evaluate a double-walled tubular product using steam injection and to develop a computer model to simulate the transient effect of steam injection under field conditions.

Procedures

Laboratory testing was accomplished by constructing a flow loop system to determine heat losses from the double-walled tubing. The major components of the flow loop system were a steam boiler, a vertical test section, a horizontal test section, a water recovery system, and a data acquisition system. Each test section was composed of an entrance subsection, a test subsection, and an exit subsection. The subsection lengths were selected based on boundary layer theory for establishing stabilized flow conditions in each test section.

Four different experimental configurations of the double-walled tubular were tested. These were: (1) no annular insulation, no vacuum; (2) no annular insulation, with vacuum; (3) annular insulation, no vacuum; and (4) annular insulation, with vacuum. Each of the configurations were tested at steady-state flow conditions for a duration of approximately 4 hours.

The heat injection rate through the flow loop during each test ranged from 227 to 257 MBtu/hour. The steam quality varied from 93.9 to 97.3%. The total cold-water-equivalent flow rate varied from 725 to 819 gallons per day.

To evaluate tubulars over extended periods a computer model was developed to simulate single- and doubled-walled tubing performance under a variety of conditions. A review of the literature found that wellbore heat loss models have become more accurate and sophisticated, using more advanced numerical solutions with a reduction in the many assumptions. However, discrepancies still exist between observed data and predicted results; therefore, an accurate model for comparative purposes was required. For the model developed in this study, improved accuracy was accomplished with the use of several theoretical, semi-theoretical, and mathematical correlations (Satchwell and Johnson 1992).

The model's technique uses a finite difference simulation in length, at a specific time level. It has been specifically designed to simulate the flow of a hot-injection fluid from its source to the sandface. To simulate transient effects, simulation runs are required for successive time steps. The model is capable of simulating surface piping configurations that include buried, unburied, insulated or uninsulated conditions. The wellbore modeling can simulate single- or double-walled tubing with or without insulation, multiple casing strings, different gases in the casing or tubing annulus with or without a vacuum, and multiple downhole formations.

To evaluate model variation with parameter changes, several different cases were investigated. Parameters investigated were: (1) single tubing versus dual tubing string configurations, (2) insulation thickness, (3) injection rate, and (4) injection temperature and pressure. Other parameters that were not investigated, but entered as input parameters included the heat transfer properties of steel, other insulating material, and the surrounding formations, and surface pipe heat loss configurations.

To determine the effects of time and provide a comparison of the single tubing string to the double-walled tubing string, numerical simulations were performed with constant input parameters for various completion cases to a depth of 4,000 ft. The completion cases were:

Case A - Single tubing string (2.992 x 3.500 inches) with casing (8.017 x 8.625 inches) cemented in a 11.0-inch hole;

Case B - Single tubing string (2.992 x 3.500 inches) with 2.0 inches of external insulation, with casing (8.017 x 8.625 inches) cemented in a 11.0-inch hole;

Case C - Double-walled tubing string (inner pipe - 2.992 x 3.500 inches, outer pipe - 4.950 x 5.500 inches) with casing (8.017 x 8.625 inches) cemented in a 11.0-inch hole;

Case D - Double-walled tubing string (inner pipe - 2.992 x 3.500 inches, outer pipe - 4.950 x 5.500 inches) with 1.45 inches of annular insulation, with casing (8.017 x 8.625 inches) cemented in a 11.0-inch hole;

Case E - Double-walled tubing string (inner pipe - 2.992 x 3.500 inches, outer pipe - 4.950 x 5.500 inches) with 1.45 inches of annular insulation and 2.0-inch external insulation, with casing (8.017 x 8.625 inches) cemented in a 11.0-inch hole.

Results

The physical test results for heat losses were determined for several combinations of independent variables that included: the test section orientation (either horizontal or vertical), the pipe body or coupling, insulation installed or not installed, and vacuum in the annulus (with or without). Statistical analysis was performed with respect to heat loss and the independent variables. The analysis showed that insulation and location terms were the only significant variables. The insignificance of the vacuum variable can be attributed to the fact that a reasonable vacuum could never be maintained in the annular space.

Results of the tests on the 3-ft test sections indicated that the insulated pipe body had an average heat loss rate of about 105 Btu/hour, whereas the uninsulated pipe body had an average heat loss rate of 4,703 Btu/hour. The application of insulation to the annular portion of the tubular resulted in a 98% reduction in the overall heat loss. The 6-inch long insulated pipe coupling had a heat loss rate of 3,384 Btu/hour, whereas the uninsulated coupling averaged a heat loss rate of 3,575 Btu/hour. Insulation in the annular portion of the coupling achieved only a 6% reduction in the heat loss rate. This relatively minor reduction in the heat loss rate in the insulated coupling is a direct consequence of the major heat loss path through the metal to metal contact of the inner tube support steel ring located in the coupling.

Published field data for steam temperature (Bleakley 1964) were used for validation of the developed model and also as a comparison to previously published models.

The new model more accurately predicted steam temperature than either the Farouq Ali (1981) or the Durrant and Thambynayagam (1986) model. A comparison of these models to the new model shows that the steam qualities differ by more than 30% at steam qualities lower than 0.35%.

Results of tests of the model sensitivity to parameter changes indicate that for constant heat input conditions, heat loss was reduced as insulation thickness increased. As the injection rate increased, the temperature and steam quality at the bottom hole depth increased, resulting in a reduction in the net heat loss. Another phenomena predicted by the model is the existence of a critical flow rate below which adverse conditions persist, an interesting aspect of wellbore heat transfer not normally found in the literature. This phenomena showed that saturation pressures and temperatures could be larger at the stated depth than under wellhead injection conditions.

Results of the tubing string simulations are given in Figures 1 and 2 for heat losses and steam quality, respectively, as a function of time. In Figure 2, an average increase of steam quality of 44% was obtained when comparing double-walled tubing with insulated annulus to an uninsulated tubing string (Case D to Case A). Also, there was little net change in heat loss and steam quality by using external insulation on the double-walled tubing (Case E to Case D). Another interesting result was the small difference in steam quality and heat loss between the uninsulated double-walled tubing string and the insulated single tubing string (Case C to Case B).

Conclusions

A flow loop was designed and constructed to test a double-walled tubular product. Insulation applied to the annular portion of the double-walled tubing pipe body resulted in a 98% reduction in heat losses. Only a minor reduction of 6% was obtained by applying insulation to the double-walled tubing coupling.

Coupling heat losses could be reduced by using a thermal resistant support, instead of the presently used carbon steel support ring, and/or by using a smaller cross-section area in the new or existing ring. The change in cross-section area may be accomplished with the use of knife-edges. An alternate solution would require a new design that would eliminate the metal-to-metal contact between the two pipes.

A modification to the seals used in the coupling design is recommended. This seal modification is required to ensure that steam does not leak into the annular portion of the pipe. In addition, a positive (pressure-vacuum) seal would allow a vacuum to be maintained in the annular portion of the pipe. By lowering and maintaining an annular vacuum less than 0.1 torr, further reductions in heat loss should be attainable.

A new model for simulating the thermal hydraulics of saturated steam was developed. The model is capable of simulating a variety of surface and wellbore configurations. The model was shown to be more accurate in predicting bottom hole steam temperatures over a wider range of operating ranges than any of the previously published models.

Sensitivity studies showed that the heat loss experienced by the injection fluid decreased with an increase in either injection rate, insulation thickness, or injection time. The model showed that a minimum injection rate exists below which severe heat loss occurs. The depth at which these adverse effects occur can be determined using the new model. Results of the completion simulations indicate that an average increase of 44% in steam quality can be achieved over a year when a double-walled, annular insulated string is used instead of a single uninsulated string.

Related Publication

Satchwell, R.M. and Johnson Jr., L.A., 1992, Testing of and Model Development for Double-Walled Thermal Tubular. Laramie, WY, WRI-92-R044.

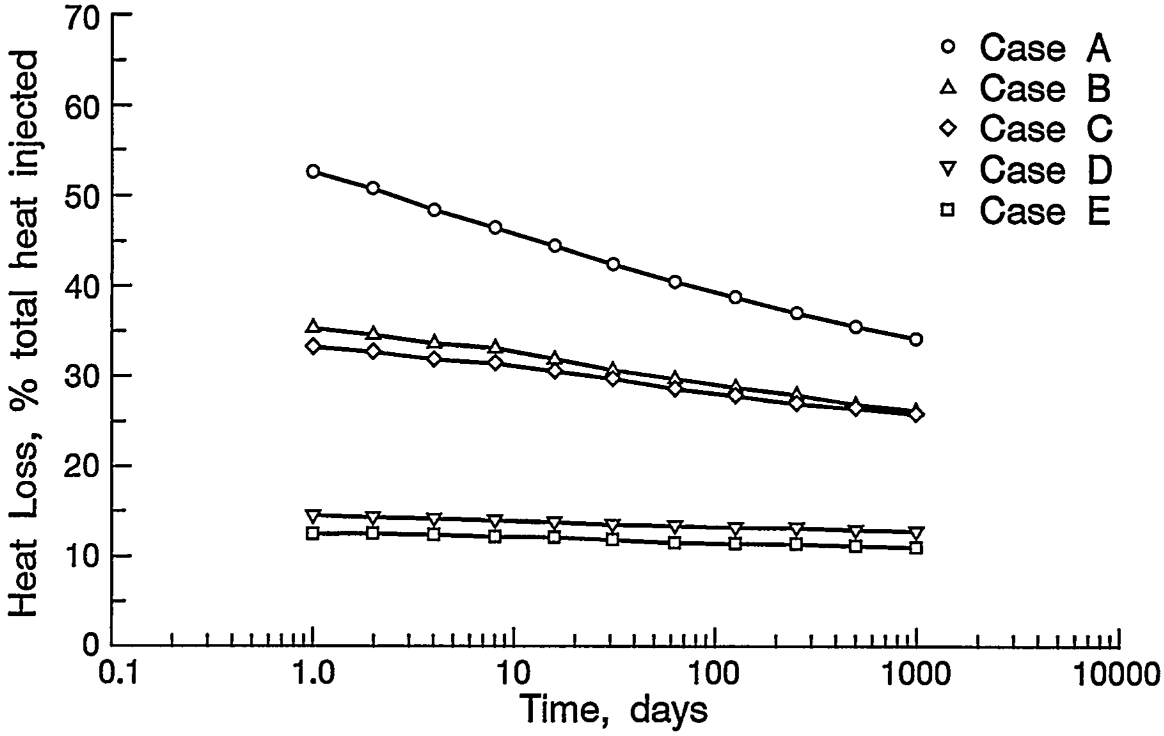

Figure 1. Heat Losses for the Numerical Simulation Cases

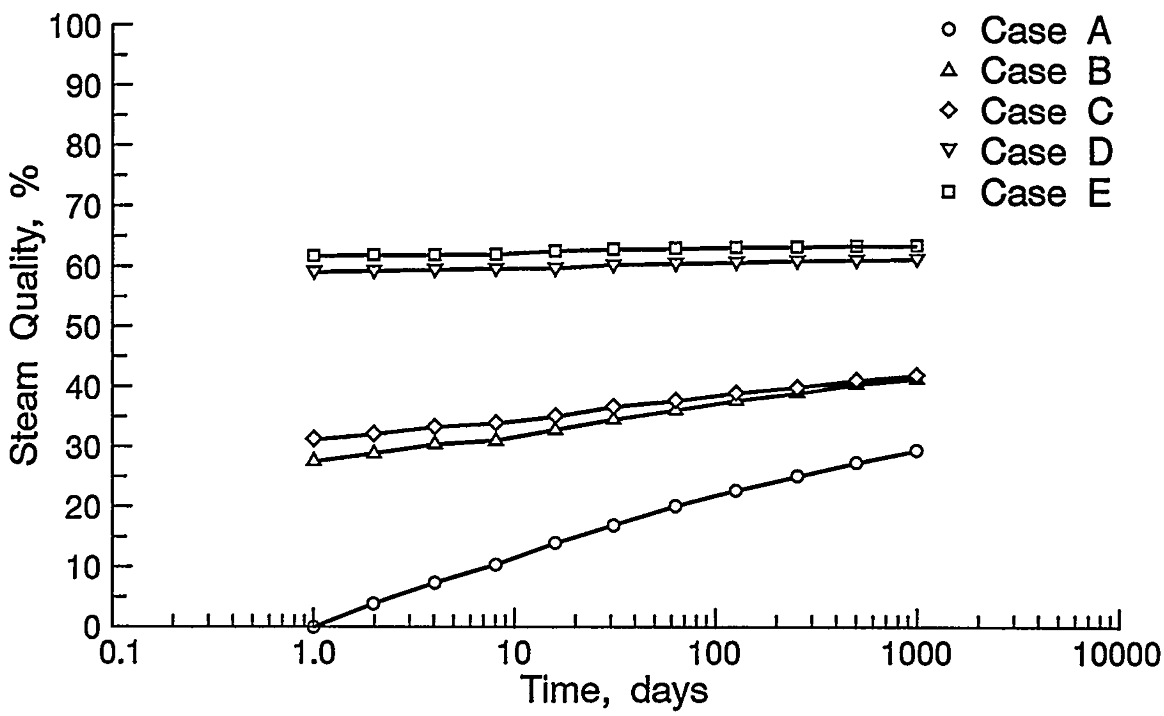

Figure 2. Steam Qualities of Numerical Simulation Cases

EVALUATION OF A MOLECULAR SIEVE CARBON AS A PRESSURE SWING ADSORBENT FOR THE SEPARATION OF NITROGEN FROM NATURAL GAS

R. William Grimes

Background

About one-half of the natural gas produced in the United States is low-quality natural gas, contaminated by other gases or water to the extent that it cannot be used without processing. Technologies for dehydration of low quality gas are used extensively, but application of available technologies for the separation of other contaminants, particularly nitrogen, from natural gas has been limited because of economic considerations.

In the past decade, an increasing number of gas separation problems have been solved economically by the use of pressure swing adsorption (PSA) systems. These systems make use of various microporous solids that preferentially adsorb certain components from a gas mixture, thereby separating it into adsorbed and non-adsorbed fractions. The solid adsorbent has an increased capacity for the sorbate at elevated pressure; therefore, a cycle based upon adsorption at higher pressure followed by desorption as the pressure is reduced can be used to separate a gas mixture into its component streams. The characteristics of the adsorbent, particularly with respect to the ease with which desorption takes place, dictate the economics of a pressure swing separation process.

Objective

As part of an effort to develop an economically viable PSA system to remove nitrogen from a natural gas stream, WRI undertook a series of laboratory experiments, jointly sponsored by DOE and Williams Technologies Inc. The experimental work was to determine the effect caused by varying adsorption cycle parameters on the performance of a molecular sieve carbon (MSC) used as a pressure swing adsorbent for the separation of methane/nitrogen mixtures. The principal steps to do this were: (1) to assemble and calibrate a PSA test apparatus and (2) to test an MSC in a simulated PSA cycle at various pressures, flow rates, and temperatures.

Procedures

A PSA test apparatus, consisting of a feed gas supply and measurement system, adsorption column, and effluent gas collection and measurement system, was supplied by Williams Technologies Inc. During assembly three-way valves were added at each end of the adsorption column to allow for easy reversal of column flow at selected points in the pressure cycle. Pressure transducers and gauges were calibrated using a dead weight gauge calibrator. Inlet gas volume measurements were checked by water displacement using the effluent gas collection cylinders.

Adsorption testing began with a simple two-step adsorption cycle and progressed to a five-step cycle commonly used in multiple-column bulk separation systems. The experimental work involved systematically changing adsorption cycle parameters and observing the effect upon performance in the separation of a mixture of 70% methane and 30% nitrogen. Separation performance for all tests was evaluated in terms of product purity, product recovery, and sorbent productivity. Successive tests used the best conditions established in previous tests as a starting point; therefore, a steady increase in purity, recovery, and sorbent productivity was noted during the test program.

Tests with the two-step cycle used a constant pressurization flow rate and adsorption pressures of 20, 30, and 50 psig. Cocurrent and countercurrent depressurization were tried as well as several rates of flow from the outlet end of the column during pressurization.

Most of the testing was conducted using four-step and five-step pressure swing cycles. The five-step cycle consisted of pressurization, feed-at-pressure, depressurization, blow-down, and purge. For the four-step cycle the feed-at-pressure step was eliminated.

The first tests using the four-step cycle were conducted to determine the effect of changing purge rate and volume and to establish values for these parameters to be used in subsequent tests. The four-step cycle was used to investigate the effect of changing pressurization and depressurization rates, increasing adsorption pressure, and holding the column at pressure between the pressurization and depressurization steps. Countercurrent blow-down and purge steps were also tested using the four-step cycle.

In tests using the five-step cycle, separation performance was evaluated for three feed rates and four adsorption pressures. A final test series was conducted to determine the effect of increasing purge volume using the five-step cycle.

Results

The best separation performance for the two-step cycle was attained in a test where the adsorption pressure was 20 psig and 62% of the pressurization gas stream was allowed to escape from the column outlet as the column was pressurized. For this test, product purity was 79.96%, product recovery was 18.30%, and sorbent productivity was 3.79 $cm^3/g/cycle$.

Initial testing with the four-step cycle was conducted to establish the purge volume to be used in subsequent tests. Purge gas to pressurization gas volume ratios ranging from 11 to 38% were tried. For these tests the column was purged with the feed gas mixture (70% CH_4, 30% N_2) after a two-stage depressurization step. The methane purity of the effluent from the purge step began to decline at a purge/pressurization ratio of about 0.25. The purge volume corresponding to this ratio was used for most of the subsequent tests.

Purge gas flow rates ranging from 59 to 326 mL/min were tried with no significant effect on separation performance. Product purity, product recovery, and sorbent productivity were all increased with countercurrent flow in the blow-down and purge steps.

Purging the column with 100% methane instead of the feed gas mixture resulted in a slight increase in product purity (86.60 versus 85.69%). This increase was more than offset by decreased recovery (39.30 versus 49.26%) and decreased sorbent productivity (7.42 versus 8.72 $cm^3/g/cycle$).

Pressurization gas flow rates of 132.3, 13.92, 4.89, and 1.86 L/min were tried using the four-step cycle and an adsorption pressure of 50 psig. Separation performance was not affected by the pressurization flow rate except at the highest rate, where purity, recovery, and productivity all declined. Separation performance was not affected by delays of 0, 20, 30, and 60 seconds between the pressurization and depressurization steps.

In tests using the four-step cycle with adsorption pressures of 30, 38, 50, and 59 psig, product purity increased with increasing adsorption pressure. Methane purities of 80.7, 82.4, 85.4, and 85.7% were obtained as the adsorption pressure was increased. In all four tests the column was purged with 590.8 cm^3 of the feed gas mixture. For the four-step cycle using an adsorption pressure of 50 psig product purity was 85.4%, product recovery was 49.3%, and sorbent productivity was 8.72 $cm^3/g/cycle$.

The first test series using the five-step adsorption cycle compared separation performance for feed rates of 1.74, 1.16, and 0.58 L/min with 50 psig adsorption pressure. These feed rate changes had no significant effect on separation performance. The five-step cycle with 50 psig adsorption pressure gave a purity of

85.9%, recovery of 56.7%, and sorbent productivity of 14.5 cm^3/g/cycle. With the five-step cycle product recovery and sorbent productivity were increased significantly when compared to the four-step cycle.

A series of tests was conducted using the five-step cycle, adsorption pressures of 20, 30, 50, and 60 psig, 1 minute of feed at 1.16 L/min, and purge with the feed gas mixture. In this series product purity increased from 82.5% at 20 psig to 88.4% at 60 psig. Product recovery was 52.6% at 20 psig and 51.3% at 60 psig. Sorbent productivity increased from 10.1 to 14.7 cm^3/g/cycle as the adsorption pressure was increased from 20 to 60 psig.

For the final test series the blow-down step was begun at lower pressure (6 versus 10 psig) and the purge volume was increased. The blow-down effluent and the first 63.6% of the effluent from the purge step were collected as product, with the remainder of the effluent gas going to the waste stream. With an adsorption pressure of 60 psig this cycle gave a product purity of 91.6%, a recovery of 37.1%, and a sorbent productivity of 11.1 cm^3/g/cycle.

Conclusions

A pressure swing adsorption system using a molecular sieve carbon adsorbent can successfully separate a mixture of nitrogen and methane without the use of a vacuum regeneration step. The tests showed that the saturated adsorbent can be regenerated by purging with the feed gas mixture. Flow rate in the feed and pressure changing steps was not an important factor in separation performance. Separation performance seemed to improve with increasing adsorption pressure through the range tested, but because of the limited nature of this study and the interrelation of process variables, further study will be required before a positive conclusion can be reached.

The results indicate that a multiple-bed PSA system using a molecular sieve carbon adsorbent for the separation of nitrogen from low quality natural gas is technically feasible. The fact that flow rates have little effect on separation performance indicates that the various cycle steps can be coordinated in a multi-bed system. More work is needed to determine the economic viability of such a system.

Related Publication

Grimes, R.W., 1993, Natural Gas Cleanup, Evaluation of a Molecular Sieve Carbon as a Pressure Swing Adsorbent for the Separation of Methane/Nitrogen Mixtures. Laramie, WY, WRI-93-R035.

CHARACTERIZATION OF PETROLEUM RESIDUA

John F. Schabron

Background

The precise chemical and physical constitution of petroleum residua is not well understood because of the overall lack of well-documented and acceptable analytical procedures. Many techniques are applicable to the characterization of residua, but few have been developed to a satisfactory stage of systematic methodology. To investigate the development of such methods, Mobil Research and Development Corporation supported this study for the definition and demonstration of a characterization scheme for petroleum residua.

To study residua in detail, it is necessary to subdivide them into several well-defined fractions. This can best be achieved by removing the asphaltenes prior to fractionation, using solid adsorbents. Trace metals that can have a deleterious effect on catalysts are then concentrated in the asphaltenes.

Objective

The purpose of this study was to develop a better understanding of the chemical composition of crude oil residua through the coordinated application of existing characterization methods. This involved demonstrating a standardized approach for a well-balanced, cost-effective characterization program. Application of the characterization scheme should provide data that can be used to improve the economic viability of processing operations.

Procedures

Since the major complex constituents of crude oils are concentrated in the residua, the characterization scheme was applied to six residua from different heavy crude oils. Each residuum was deasphaltened in heptane, and the heptane-soluble materials were separated into saturate, aromatic, and polar fractions on activated silica gel. The asphaltenes were separated into four fractions according to apparent molecular size by preparative size exclusion chromatography (SEC). The whole residua were evaluated for elemental composition, trace metals content, carbon residue, simulated distillation profile, specific gravity, pour point, and rheological profile. The asphaltenes and silica gel chromatographic fractions were evaluated for elemental composition, trace metals content, molecular weight, carbon residue, analytical SEC profiles, and aromaticity by nuclear magnetic resonance (NMR) spectroscopy. The preparative SEC fractions from the asphaltenes were evaluated for sulfur content, molecular weight, and trace metals content.

Results

All but two of the residua, which were waxy, had specific gravities greater than 1. The pour points of the six residua ranged from 32 to 96°C (90 to 205°F). The rheological profile results for all six residua show reasonable Newtonian flow over three orders of magnitude of shear rate. Heptane asphaltene contents ranged from 4.4 to 32.4 wt % for the six residua. Pentane asphaltene values were uniformly higher, ranging from 7.7 to 35.8 wt %. Saturate fraction content ranged from 6.3 to 45.7 wt % for the six residua, with the two highest values observed for the two waxy residua. Aromatic fraction content ranged from 29.8 to 61.2 wt % for the six residua. Polar fraction content ranged from 11.1 to 37.4 wt %. Total recoveries for the separations for the six residua were good, ranging from 99.5 to 102.8 wt %.

The elemental analyses for the six residua and their fractions showed good closure and material balances. The hydrogen-to-carbon (H/C) values for the individual residua decreased from saturate to aromatic to polar fractions. The asphaltenes from one of the waxy residua had a higher H/C ratio than the corresponding polar fraction, due to waxes which occurred in the heptane asphaltenes.

The sulfur content for the six residua ranged from 0.4 to 5.6 wt %. For any particular residuum, the sulfur content was less for the saturate fraction than for the aromatic and polar fractions and asphaltenes. There was no clear trend for sulfur distribution for the aromatic and polar fractions and asphaltenes. Nitrogen content ranged from 0.4 to 1.4 wt % for the six residua. In general, the saturate fractions contained no detectable nitrogen. Most of the nitrogen occurs in the polar fractions and asphaltenes, with lesser amounts present in the aromatic fractions. Oxygen content ranged from 0.5 to 1.0 wt % for the six residua. The oxygen content of the polar fraction typically was greater for a particular residuum than the other fractions and asphaltenes. In general, the metals content (Ni,V,Cu,Fe) for the six residua increase in the order: saturate < aromatic < polar < asphaltenes.

The Conradson carbon residue values for the residua correlated well with the corresponding microcarbon residue (MCR) values. For the individual residua studied, the MCR values increased according to the series: aromatic < polar < asphaltenes. This indicates that the greatest residue/coke forming species are in the asphaltene material.

In general, an increase in molecular weights were observed for individual residua in the order: saturate < aromatic < polar < asphaltenes. For the four SEC fractions from the asphaltenes, the apparent molecular weights decreased about an order of magnitude from the highest to lowest molecular weight fraction. The material balances calculated for the SEC molecular weights were good, indicating that the very large apparent molecular weights observed for the high molecular weight fractions for the six residua appear to exist in the total asphaltene material as well as in the isolated fraction. The high molecular weight fractions from residua asphaltenes could provide a useful material for studying the coking process.

NMR aromaticity results showed very little aromatic structures in the saturate fractions for the six residua, with significant aromatic structures in the aromatic and polar fractions and asphaltenes.

The material balances for the various characterization parameters were consistent with proportional contributions from the various fractions for all six residua. This indicates that the contributions from the parts add up to the whole. It should be possible, therefore, to study and modify important properties such as coking tendency and the effect of variables such as metals, elemental, and aromatic content for individual fractions and relate them to properties of the whole material.

Conclusions

Petroleum residua can be effectively characterized using the analytical scheme developed in this study. The material balances show that the data obtained on the fractions and asphaltenes account for the data obtained on the original material. Thus, it is possible to study the contribution of the fractions and asphaltenes to properties observed in the whole residuum. Additional residua can be separated, and the results compared with data obtained on the six residua in the present study. Correlations between the characterization results and the behavior of a whole residuum, its fractions, or asphaltenes in processing or production processes can also be studied.

Related Publication

Schabron, J.F., G.W. Gardner. J.K. Hart, N.D. Niss. G. Miyake, and D.A. Netzel, 1993, The Characterization of Petroleum Residua. Laramie, WY, WRI-93-R023.

MILD GASIFICATION OF USIBELLI COAL

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Background

Western Research Institute, in cooperation with DOE, has been developing the Inclined Fluidized-Bed (IFB) Coal Drying and Stabilizing Process. In this process, coal is dried to near-zero moisture and partially pyrolyzed in the first of two IFB reactors. The partially pyrolyzed coal is then fed into the second IFB, where it is rapidly quenched with cool carbon dioxide liberated from coal to keep the produced tar on the coal particles. This remaining tar, as well as adsorbed carbon dioxide, stabilizes the dried coal. The IFB reactor is also an excellent classifier. Consequently, coal fines are easily separated during drying. The amount of fines separated can be controlled by the fluidizing gas flow rate or gas-to-solid ratio. This study was undertaken with support from Usibelli Coal Mines, Inc. to apply the process to Usibelli coal.

Objectives

The objectives of this task were to determine the quantity of liquid produced by mild gasification of Usibelli coal and to characterize the products from mild gasification of Usibelli coal.

Procedures

A process research unit dryer was used to dry 1163 lb of minus 16-mesh Usibelli coal at a feed rate of 95 lb/hr and a recycle gas flow of 76 scfm at 371°C (700°F) as fluidizing gas. The flow rate of 76 scfm is somewhat higher than what is needed to fluidize the minus 16-mesh coal, but this rate was used to be sure that sufficient flow of heat was carried into the dryer. The high gas flow rate relative to the small particle size contributed to the high production of fines from the dryer. (Typically, 5 to 7 wt % of the raw coal is produced as fines when drying minus 8-mesh Wyodak coal. The fines production is the minus 100-mesh fraction in the feed coal).

A series of mild gasification tests was conducted on the dried coal. The series consisted of six 8-hour tests, one 6-hour test, and one 24-hour test. The tests were run at a dry-coal feed rate of 7.5 lb/hr, which is equivalent to a wet-coal feed rate of 10 lb/hr, and maximum bed temperatures of 566, 593, 621, 649, and 677°C (1050, 1100, 1150, 1200, and 1250°F).

Results

Mild gasification of the dried coal resulted in production of 44 to 56 wt % of the dried coal as char, 10 to 13 wt % as liquids, 17 to 28 wt % as gas, and 8 to 21 wt % as fines (Figure 1). Numbers on the graph in Figure 1 refer to test run numbers. The yield of moisture- and ash-free (MAF) liquids varied from 11.4 to 14.2 wt % of the dried coal feed.

Hardgrove grindability indices were 28 for the raw coal, 49 for the dried coal, and 82 for the char. The char produced contained 16 to 22 wt % volatiles and had gross heating values ranging from 10,500 to 11,600 Btu/lb. The char equilibrium moisture content was measured at 10 wt %, whereas the raw coal contains 22 wt % moisture at equilibrium.

The liquids collected from one test were separated by distillation into a -371°C (-700°F) boiling distillate (40 wt %) and a +371°C (+700°F) boiling residue (60 wt %). The distillate contained 23.5 wt % alkanes, 26.2 wt % alkenes, and 22.7 wt % aromatic hydrocarbons; plus 26.9 wt % of polar heteroatomic-containing compounds, for which group-type analysis could not be done. The distillate also contained 0.4 wt % sulfur, 0.3 wt % nitrogen, and 4.1 wt % oxygen. These are relatively low values for an untreated coal distillate.