# "BITUMEN RECOVERY FROM OIL SANDS, USING SOLVENTS IN CONJUNCTION WITH STEAM"

**S.M. FAROUQ ALI B.P. ABAD**

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# Bitumen Recovery from Oil Sands, Using Solvents in Conjunction with Steam

S. M. Farouq Ali and B. Abad,
The Pennsylvania State University,
University Park, Pennsylvania

## Abstract

*Results of an experimental investigation of bitumen recovery from Athabasca oil sand, using solvents in conjunction with steam, are discussed. Most of the runs were carried out in a vertical tar sand pack, with restricted fluid entry near the bottom of the pack, simulating conduction-convection heating with gravity flow. A few runs were conducted in a large three-dimensional model of a five-spot configuration. The synthetic crude manufactured by Great Canadian Oil Sands Ltd. was the principal solvent used. A few runs employed naphtha and the "Mobil Solvent". Actual Athabasca oil sand was used to pack the models, which did not permit scaling.*

*It was found that bitumen recovery is determined by the type of the solvent, the volume used and the solvent placement. For example, when the solvent was injected into the producing well, followed by steam injection into the injection well, the recovery was much higher than when both solvent and steam were injected into the same well. The water-bitumen ratio was higher in this latter case than in the previous injection scheme.*

*The bitumen recovery tended to be higher when using naphtha, however breakthrough occurred rapidly in this case. Also, naphtha caused asphaltene precipitation in several instances. The GCOS synthetic crude did not have these problems, and yielded higher bitumen-solvent ratios. The Mobil solvent matched the performance of the other two solvents, in different respects.*

*Temperatures were measured at many points in both models, at various times. In many cases, cores were extracted and analyzed at the end of a run. These data permitted plotting of the temperature and bitumen saturation contours, which provided valuable insight into the prevalent recovery mechanism.*

Dr. S. M. Farouq Ali is professor of petroleum and natural gas engineering at The Pennsylvania State University, where he has been a faculty member since 1962. Prior to this he has worked as petroleum and mechanical engineer. He holds a B.S. in electrical engineering, a B.Sc. in petroleum engineering, and M.S. and Ph.D. degrees in petroleum and natural gas engineering.

Dr. Farouq Ali has conducted research in miscible displacement, thermal recovery and simulation of oil production processes. He has authored over 110 papers and two books in these areas. He has taught numerous short courses on thermal oil recovery and reservoir simulation, including many abroad. He has served as oil recovery consultant to a number of oil companies in the U.S., Canada, Venezuela, Mexico, etc. He is currently involved in several in-situ oil recovery projects in the oil sands.

Boris P. Abad is a graduate assistant in Petroleum and Natural Gas Engineering at The Pennsylvania State University. He completed his studies in petroleum engineering at the Escuela Superior Politecnica del Litoral in Guayaquil, Ecuador. He earned an MS degree in Petroleum and Natural Gas at Penn State. He will receive his Ph.D. degree in Petroleum and Natural Gas Engineering in November of 1976.

## Introduction

SEVERAL in-situ methods have been successfully field-tested for the recovery of bitumen or very viscous oil from oil sands. These include cyclic steam injection in the Cold Lake region, reverse and forward combustion in the Athabasca region, and conductive heating combined with steamflooding in the Peace River region. Many more in-situ recovery methods have been proposed, including those which rely on solvents to varying degrees. This paper describes the results of such an investigation, being the fourth in a series of experimental studies devoted to the recovery of bitumen from tar sands by the use of a combination of solvents and steam.

## Background, General Considerations and Objectives

Solvents and light ends of crudes are frequently used in heavy oil recovery as diluents to facilitate pumping and pipeline transportation. For example, much of the current production of 80,000 B/D from the Orinoco oil sands, Venezuela, is through downhole dilution with a light crude. The use of solvents has been proposed in combination with steam[1,2], explosives[3], etc. Any in-situ recovery process involving solvents is likely to be expensive, and it is therefore necessary to use the smallest possible volume of the cheapest and most readily available solvent. Earlier work by the authors in this direction involved the application of pure compounds, later substituted by an aromatic naphtha. Current research is based on the utilization of the synthetic crude, manufactured from the Athabasca oil sands by Great Canadian Oil Sands Ltd. in their surface mining operations, as a solvent for the bitumen. Comparison tests were run using naphtha as well as the "Mobil Solvent".

One of the problems in laboratory tests of in-situ recovery processes is the experimental design. For proper scaling of thermal recovery models, it is necessary to choose a suitable porous medium and saturate it with bitumen of other viscous oil. When the use of both solvents and heat is involved, it becomes difficult to satisfy the scaling criteria. These aspects of tar sands in-situ recovery experiments are discussed in a paper by Dr. D. A. Redford and the author[4]. At the same time, it is to be recognized that the actual conditions prevailing in the tar sands formation (e.g. actual tar sand and bitumen) are also important as far as the qualitative behaviour of the recovery process under consideration is concerned. The principal objective of this work was essentially the latter —

TABLE 1 — Some Physical Properties of the Solvents Used

| Solvent | Density (gm/cc) | Specific Gravity | Colour | Viscosity (cp) | Solubility in Bitumen |
|---|---|---|---|---|---|
| GCOS Synthetic crude | 0.827 | 0.829 | Dark Yellow | 4.56 | All proportions |
| Mobil | 0.885 | 0.888 | Black | 4.57 | All proportions |
| Naphtha | 0.7156 | 0.717 | Colourless | 0.4482 | All proportions |

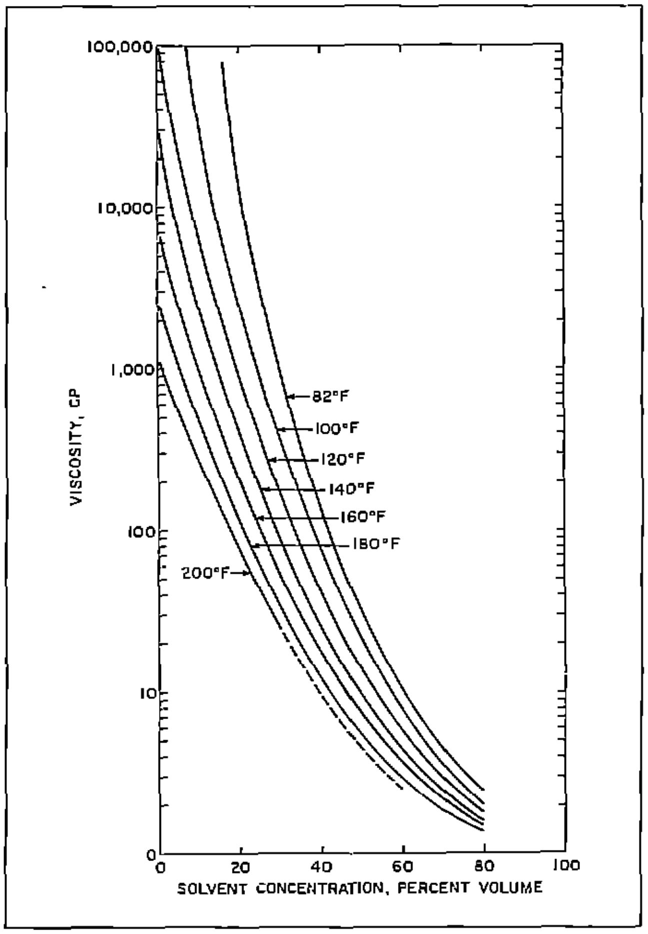


FIGURE 1 — Viscosity as a function of concentration and temperature for Athabasca bitumen-naphtha mixtures.

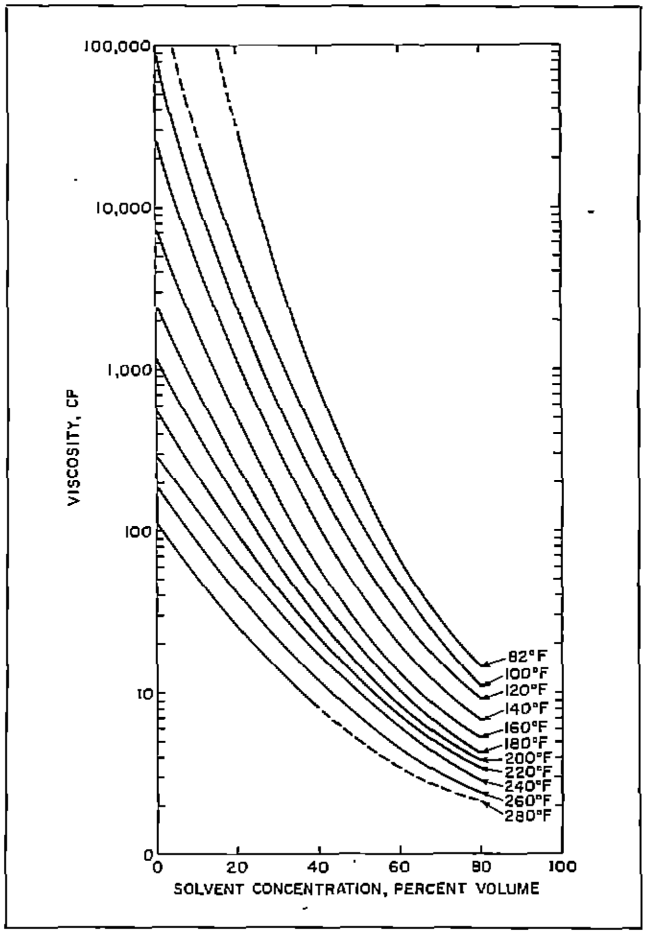


FIGURE 2 — Viscosity as a function of concentration and temperature for Athabasca bitumen - Mobil solvent mixtures.

i. e., obtain qualitative information on the relative effectiveness of three solvents in simple unscaled models to isolate the process variations that warrant further investigation in more elaborate models. In particular, it was desired to assess the effectiveness of GCOS's synthetic crude as the bitumen solvent, when used in conjunction with steam. This is considered to be the principal contribution of this investigation.

## Viscosity of Bitumen-Solvent Mixtures As a Function of Temperature

The viscosity of the bitumen extracted from the Athabasca oil sand was determined by means of a Brookfield viscometer, at temperatures up to 380°F. Viscosities of bitumen-solvent mixtures were also determined by the same procedure, for the three solvents tested. Selected properties of these solvents are given in Table 1.

Figures 1, 2 and 3 show plots of viscosities of bitumen-solvent mixtures, for various temperatures and solvent concentrations, for naphtha, Mobil solvent and the GCOS synthetic crude, respectively. Table 2 gives a tabulation of the data used to prepare these plots. Notice that a number of missing viscosities in Table 2 could not be determined in view of the fact that the particular temperature was higher than the normal boiling point of the mixture involved.

Figures 1 to 3 show that GCOS synthetic crude and the Mobil solvent are nearly equally effective in reducing bitumen viscosity. Naphtha is seen to be more effective in this respect. It should be noted that: (i) a temperature increase caused greater viscosity reduction than moderate concentrations of a solvent; (ii) all three solvents caused almost the same viscosity reduction in concentrations of 10 per cent and lower; and (iii) for temperatures above 240°F, solvent concentrations of 10, 20, and 30 per cent tend to lower the bitumen viscosity by about the same amounts in all three cases. Thus, it could be concluded that at low concentrations and high temperatures, the GCOS synthetic crude should be nearly as effective as the other two solvents in a bitumen recovery process.

## Experimental Apparatus and Procedure

Athabasca oil sand samples were employed in the experimental runs. The bitumen content of the sand was determined for each run, and was found to range from 13.5 to 16.5 per cent by weight. A value of 1.0397 was obtained for the specific gravity of the bitumen at room temperature (82°F). Extensive tests on the loss in the bitumen content of samples on exposure to air showed that the bitumen content stabilized after about 48 hours. In one case, the bitumen content decreased from 16.5 to 14.5 per cent over this period.

### EXPERIMENTAL APPARATUS

Two models were employed in this investigation. The first of these was similar to the one described in reference (2), and had the same dimensions. It was essentially an insulated steel box, 11.5 inches high, 20 inches long and 1.63 inches wide, equipped with injection and production ports near the base. Porous metal plates were used at both ends to prevent sand production and plugging-up, and also to permit uniform distribution of the injected fluids over the injection port. The box was provided with four additional injection ports at the top and one at the bottom, which were used in certain experiments. Twenty thermocouples were fitted on the side of the box, and an automatic temperature scanning and recording arrangement was employed.

The second model used is sketched in Figure 4. It consisted of a steel box, 15 inches square and 10 inches high. A rubber diaphragm was placed on top of the oil sand packed in the box, and pressurized by silicone oil to prevent any channeling. Four 7-inch-long wells were used as injection wells and one 2-inch-long well was used as the production well, as shown in Figure 4. Twenty-one thermocouples were installed in the box, twelve of which were 7 inches long and nine were 3

TABLE 2 — Data for Figures 1, 2 and 3

| Temperature (°F) | Viscosity (cp) 10% (Solv. Con.) Syncrude | Mobil Sol. | Naphtha | 20% (Solv. Con.) Syncrude | Mobil Sol. | Naphtha |
|---|---|---|---|---|---|---|
| 360 | — | 20 | — | — | 12 | — |
| 350 | — | — | — | — | — | — |
| 340 | 25 | 26 | — | — | 14 | — |
| 330 | 27 | — | — | 15 | 16 | — |
| 320 | 36 | — | — | — | 17 | — |
| 310 | — | 38 | — | 15 | 20 | — |
| 300 | 47 | 48 | 40 | 22 | 21 | — |
| 290 | 69 | 53 | 42 | 26 | 24 | — |
| 280 | 65 | 60 | 63 | 30 | 26 | 20 |
| 270 | 78 | 70 | 75 | 40 | 30 | 21 |
| 260 | 96 | 94 | 81 | 45 | 36 | 23 |
| 250 | 116 | 107 | 107 | 59 | 40 | 26 |
| 240 | 131 | 127 | 120 | 68 | 51 | 30 |
| 230 | 178 | 200 | 180 | 86 | 64 | 36 |
| 220 | 235 | 212 | 202 | 108 | 76 | 44 |
| 210 | 300 | 326 | 273 | 138 | 102 | 56 |
| 200 | 500 | 417 | 284 | 193 | 127 | 62 |
| 190 | 551 | 621 | 350 | 260 | 173 | 94 |
| 180 | 826 | 810 | 400 | 346 | 233 | 130 |
| 170 | 1287 | 1179 | 700 | 489 | 322 | 180 |
| 160 | 2050 | 1617 | 940 | 674 | 409 | 250 |
| 150 | 4675 | 3970 | 1700 | 981 | 883 | 310 |
| 140 | 6450 | 4055 | 2400 | 1487 | 1158 | 422 |
| 130 | 9600 | 5415 | 6337 | 2400 | 1851 | 1033 |
| 120 | 15340 | 8450 | 7776 | 4200 | 3022 | 1466 |
| 110 | — | 13573 | 15683 | — | 3387 | 2073 |
| 100 | — | 21900 | 35200 | — | 9115 | 3646 |
| 90 | — | — | 72500 | — | 16366 | 5900 |
| 82 | — | — | — | — | 31700 | 13900 |

| Temperature (°F) | Viscosity (cp) 40% (solv. Con.) Syncrude | Mobil Sol. | Naphtha | 60% (Solv. Con.) Syncrude | Mobil Sol. | Naphtha |
|---|---|---|---|---|---|---|
| 360 | — | — | — | — | — | — |
| 350 | — | — | — | — | — | — |
| 340 | — | 5 | — | — | — | — |
| 320 | — | 6 | — | — | — | — |
| 310 | — | 7 | — | — | — | — |
| 300 | 7.5 | 7.4 | — | — | — | — |
| 290 | 9.5 | 8 | — | — | — | — |
| 280 | 14 | 8.4 | — | — | — | — |
| 270 | — | 10 | — | — | 3.7 | — |
| 260 | 15 | 15 | — | — | 4.5 | — |
| 250 | 17 | 16 | — | 6 | 4.5 | — |
| 240 | 20 | 18 | — | 6.5 | 5.6 | — |
| 230 | 22 | 20 | — | 7.0 | 5.3 | — |
| 220 | 26 | 22 | — | 7.6 | 6.6 | — |
| 210 | 27 | 26 | 12 | 9 | 5.7 | — |
| 200 | 34 | 29 | 15 | — | 7.7 | — |
| 190 | 39 | 37 | 17 | 11 | 7.3 | — |
| 180 | 50 | 44 | 18 | 11.5 | 10.4 | 3.0 |
| 170 | 62 | 51 | 22 | 12.5 | 8.6 | 3.4 |
| 160 | 76 | 64 | 25 | 14 | 14 | 3.8 |
| 150 | 98 | 84 | 29 | 17 | 12 | 4 |
| 140 | 128 | 110 | 34 | 19 | 19 | 4.4 |
| 130 | 175 | 161 | 42 | 24 | 17 | 5 |
| 120 | 236 | 218 | 53 | 27 | 30 | 6 |
| 110 | 338 | 255 | 72 | 37 | 25 | 6.5 |
| 100 | 559 | 425 | 90 | 43 | 46 | 7.8 |
| 90 | — | 593 | 125 | 58 | 38 | 9.2 |
| 82 | 1362 | 767 | 164 | 110 | 65 | 10.2 |

Table 2 — Data for Figures 1, 2 and 3 (Cont.)

| Temperature (°F) | Viscosity (cp) 80% (Solv. Con.) Syncrude | Mobil Sol. | 50% Naphtha | 30% Naphtha |
|---|---|---|---|---|
| 360 | — | — | — | — |
| 350 | — | — | — | — |
| 340 | — | — | — | — |
| 330 | — | — | — | — |
| 320 | — | — | — | — |
| 310 | — | — | — | — |
| 300 | — | — | — | — |
| 290 | — | — | — | — |
| 280 | — | — | — | — |
| 270 | — | — | — | — |
| 260 | 3.2 | 2.5 | — | — |
| 250 | 3.2 | 2.7 | — | — |
| 240 | 3.9 | 3.0 | — | — |
| 230 | 4.2 | 3.3 | — | — |
| 220 | 4.3 | 3.5 | — | — |
| 210 | 5.2 | 4.0 | — | 23 |
| 200 | 4.9 | 4.0 | — | 25 |
| 190 | 5 | 4.7 | 6 | 30 |
| 180 | 6 | 4.3 | 6.5 | 32 |
| 170 | 6.5 | 4.9 | 7 | 37 |
| 160 | 7 | 5.5 | 8 | 42 |
| 150 | 7.7 | 6 | 9.2 | 56 |
| 140 | 8.8 | 6.9 | 10.7 | 73 |
| 130 | 10 | 7.8 | 12.5 | 91 |
| 120 | 12 | 8.9 | 15 | 123 |
| 110 | 14 | 9.3 | 17.5 | 161 |
| 100 | 15 | 11 | 20 | 222 |
| 90 | 19 | 13 | 24 | 329 |
| 82 | 20.5 | 14.7 | 27.5 | 642 |

inches long. The bottom surface of the box was in contact with a sand pack to simulate adjacent formations.

The auxiliary injection and production system was similar to that used in previous investigations. An electrode-type steam boiler, rated at 201,000 Btu/hr at 600 psig, was used for generating steam.

### EXPERIMENTAL PROCEDURE

The primary emphasis in the runs conducted was on the use of the GCOS synthetic crude as bitumn solvent, which was employed in 16 out of the 22 runs (Table 3).

In three runs (Runs 1 to 3), each of the three solvents tested (Table 1) was injected continuously, without the use of steam. In the case of naphtha, the effluent was recirculated, following the procedure described in reference (2).

When steam was used in conjunction with a solvent (Runs 4 to 22), two basically different procedures were adopted. In Runs 5 to 14, the steel box was packed with crushed oil sand, after which the solvent was injected, driven by steam. In Runs 15 to 22, on the other hand, the sand pack was saturated with water prior to solvent and steam injection. This was accomplished by first vacuuming the pack and later saturating it with water, which was circulated by a pump.

Two variations were used in the solvent-steam runs. In Runs 9 to 11, the porous plates at the inlet and outlet parts were removed to simulate steam injection over the entire sand-layer thickness. In Runs 18 to 22, the solvent was injected into the *production* rather than the injection port, whereas in all other runs the same port was employed for both solvent and steam injection.

During each run, temperatures at 20 points in the model were recorded at several time intervals. In Model 2, temperatures were scanned at two different horizontal planes within the model.

At the end of each run, sand samples were extracted from the thermocouple ports and analyzed to determine the residual bitumen saturation distribution in the model. Details of this procedure are described in reference (2).

The effluent samples obtained in each run, consisting of a mixture of bitumen and the particular solvent, were analyzed by means of a Perkin-Elmer infrared spectrophotometer. Solutions containing 40 to 100 per cent solvent in bitumen were prepared, and used to plot the calibration curves. The wavelengths chosen were 9 $\mu$ for naphtha, 8.45 $\mu$ for GCOS synthetic crude and 8.4 $\mu$ for Mobil solvent.

## Discussion of Results

As mentioned previously, the principal objective of this study was to determine the effectiveness of the GCOS synthetic crude as the solvent in the miscible-thermal recovery of bitumen. A secondary objective was to study the effect of solvent placement in the production rather than the injection port, with steam injection into the injection port in both instances. Solvent slugs were approximately 10, 20 and 45 per cent pore volume. Table 3 gives the principal data for the runs conducted.

### SOLVENT INJECTION RUNS

A number of visual studies in vertical glass tubes packed with the Athabasca oil sand showed the predominance of the "wall effect". It is felt that this effect was present in the runs conducted, to varying degrees.

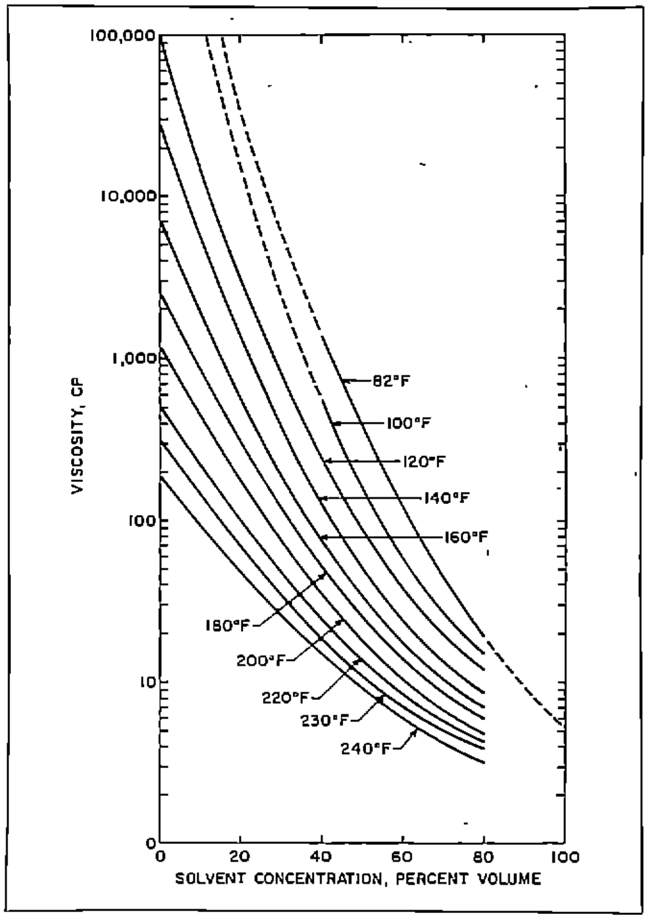


FIGURE 3 — Viscosity as a function of concentration and temperature for Athabasca bitumen - GCOS synthetic crude mixtures.

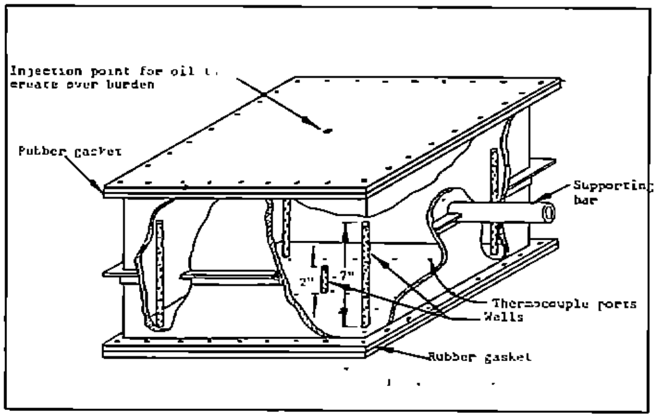


FIGURE 4 — Sketch of Model 2 box, and injection-production well locations.

Three runs (Runs 1 to 3) involved continuous injection of each of the solvents tested. In the case of naphtha, the produced effluent was recycled, because of the low bitumen concentration in the effluent. (The highest bitumen concentration in the samples collected was 41.5 per cent by volume.) However, recirculation proved to be largely ineffective, and the major proportion of the bitumen was obtained during the first pass. In this run (Run 1), severe plugging of the pack due to asphaltene precipitation was in evidence, which necessitated effluent production from one of the outlets at

TABLE 3 — Summary of Experimental Results

| Run No. | Solv. Inj. | Steam Inj. | Pore Vol. (cc) | Por. (%) | Bitumen in Place (cc) | Water Inj. (cc) | Solv. Inj. (cc) | Solv. Inj. Time (hr) | Solv.[d,f] Inj. to BT (cc) | Time to Effluent BT (hr) | Steam[a] Inj. (cc) | Time to Steam BT (hr) | Avg.[b] Inj. Rate (cc/hr) | Solv. Inj. Pr. (psig) | Steam Inj. Pr. (psig) | Total[g] Run time (hr) | Solv.-Bitumen Ratio (cc/cc) | Water[c]-Bitumen Ratio (cc/cc) | Bitumen Rec. (cc) | Bitumen Rec. (% in place) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | N | No | 2,153 | 33.2 | 1,887 | — | 6000 | 26.0 | 1140 | 4.9 | — | — | 3.85 | 45 | — | 26.0 | 9.6 | — | 403 | 21.3 |
| 2 | M | No | 2,167 | 33.4 | 2,022 | — | 4000 | 72.4 | 760 | 20.1 | — | — | 0.92 | 51 | — | 72.4 | 6.2 | — | 651 | 32.2 |
| 3 | S | No | 2,209 | 34.1 | 2,160 | — | 4000 | 76.7 | 1340 | 24.6 | — | — | 1.61 | 51 | — | 76.7 | 11.2 | — | 358 | 16.6 |
| 4 | N | Yes | 2,071 | 32.0 | 1,938 | — | 1400 | 16.0 | 540 | 4.75 | — | — | 1.46 | — | — | 44.0 | — | — | — | — |
| 5 | N | Yes | 2,119 | 30.0 | 2,029 | — | 900 | 10.83 | 900 | 10.83 | 10,867 | 18.3 | 1.4 / 6.7 | 35 | 101 | 29.1 | 0.94 | 11.3 | 957 | 47.2 |
| 7 | N | Yes | 2,084 | 30.3 | 2,044 | — | 900 | 7.6 | 900 | 13.1 | 4,525 | 22.1 | 2.1 / 5.8 | 16 | 100 | 22.1 | 1.08 | 6.8 | 868 | 42.5 |
| 8 | N | Yes | 2,207 | 32.1 | 1,959 | — | 400 | 3.3 | 400 | 4.5 | 7,745 | 12.1 | 2.02/ 8.5 | 19 | 90 | 15.4 | 0.71 | 12.6 | 564 | 28.8 |
| 9 | S | Yes | 2,357 | 34.3 | 1,985 | — | 900 | 4.9 | 900 | 5.85 | 4,036 | 9.0 | 3.06/ 8.2 | 21 | 100 | 9.93 | 1.27 | 4.73 | 708 | 35.7 |
| 10 | S | Yes | 2,395 | 39.2 | 1,801 | — | 1010 | 18.4 | 880 | 12.8 | 5,475 | 4.0 | 0.91/16.7 | 26 | 100 | 26.2 | 1.79 | 9.20 | 565 | 31.4 |
| 11 | S | Yes | 2,339 | 34.0 | 2,071 | — | 400 | 2.92 | 400 | 5.04 | 3,542 | 5.67 | 2.28/ 9.2 | 18 | 100 | 10.9 | 1.00 | 9.88 | 399 | 19.3 |
| 12 | S | Yes | 2,673 | 34.6 | 1,896 | — | 900 | 34.2 | 895 | 12.9 | 9,888 | 19.3 | 0.44/ 7.4 | 24 | 104 | 55.4 | 1.21 | 8.11 | 1085 | 57.2 |
| 13 | S | Yes | 2,668 | 35.0 | 2,213 | — | 400 | 1.45 | 400 | 2.1 | 5,700 | 15.9 | 4.6 / 6.6 | 46 | 93 | 20.1 | 0.67 | 11.0 | 596 | 26.9 |
| 14 | S | Yes | 2,777 | 36.0 | 2,118 | — | 240 | 0.82 | 240 | 2.53 | 3,860 | 3.0 | 4.9 /10.5 | 28 | 85 | 7.68 | 0.61 | 9.72 | 397 | 18.8 |
| 15 | S | Yes | 3,005 | 39.0 | 2,223 | 890 | 900 | 12.1 | 820 | 16.1 | 7,697 | 27.0 | 1.2 / 4.8 | 24 | 81 | 41.7 | 1.10 | 10.22 | 817 | 36.8 |
| 16 | S | Yes | 2,813 | 36.4 | 2,018 | 725 | 410 | 1.20 | 410 | 4.07 | 4,380 | 11.5 | 5.7 / 5.6 | 61 | 86 | 14.7 | 0.61 | 7.25 | 668 | 33.1 |
| 17 | S | Yes | 2,646 | 34.0 | 1,934 | 895 | 220 | 0.53 | 220 | 3.62 | 3,282 | 5.83 | 6.9 / 9.4 | 62 | 86 | 9.8 | 0.56 | 10.84 | 393 | 20.3 |
| 18 | S | Yes | 2,728 | 35.3 | 2,154 | 690 | 900 | 2.77 | 340 | 1.87 | 5,610 | 7.07 | 5.4 / 8.6 | 31 | 80 | 13.2 | 1.11 | 5.62 | 814 | 37.8 |
| 19 | S | Yes | 2,625 | 34.0 | 2,169 | 720 | 400 | 1.30 | 200 | 3.50 | 4,395 | 9.30 | 5.1 / 4.2 | 57 | 82 | 16.1 | 0.32 | 2.96 | 1266 | 58.4 |
| 20 | S | Yes | 2,863 | 37.0 | 2,088 | 800 | 200 | 0.48 | 200 | 2.42 | 6,629 | 17.4 | 6.9 / 5.4 | 58 | 79 | 17.4 | 0.24 | 7.91 | 840 | 40.2 |
| 21[e] | S | Yes | 12,417 | 36.0 | 10,769 | 1420 | 5600 | 31.4 | 130 | 3.15 | 5,130 | 4.37 | 3.0 /19.6 | 35 | 50 | 39.1 | 1.98 | 1.59 | 2834 | 26.3 |
| 22[e] | S | Yes | 12,369 | 36.2 | 11,112 | 1500 | 1240 | 3.35 | 280 | 0.50 | 11,150 | 22.7 | 6.2 / 8.2 | 74 | 30 | 30.0 | 0.31 | 2.17 | 4069 | 36.6 |

Notes: *N* = *naphtha*; *M* = *Mobil solvent*; *S* = *GCOS synthetic crude*; *a* — *as water*; *b* — *average injection rate: first figure is for solvent, second figure is for steam as water*; c — produced; d — refers to effluent breakthrough; e — Runs 21 and 22 were conducted in Model 2; f — when this volume is equal to solvent injected, breakthrough occurred on steam injection; g — this includes any downtime and/or water injection time (Runs 15-22).

the top of the model rather than the one near the base. The average bitumen concentration in the effluent was 15 per cent by volume. When the model was dismantled at the end of the run, it showed signs of solvent channeling in the upper part of the pack. The bitumen concentration at the bottom of the pack was practically unchanged.

Runs 2 and 3, employing the Mobil solvent and the GCOS synthetic crude, respectively, were similar to Run 1. Figure 5 compares the cumulative bitumen recovery curves for the three runs. The injection rates for both GCOS synthetic crude and Mobil solvent were very low. The average bitumen concentration of the effluent was highest in the case of the Mobil solvent.

Figure 5 shows that the GCOS synthetic crude gave the lowest bitumen recovery (16.6 per cent) of the three solvents tested. The volume of the Mobil solvent injected up to effluent breakthrough was only about half of that for naphtha and the GCOS synthetic crude (760 cc vs. 1140 cc and 1340 cc). A comparison of Runs 2 and 3 shows that, at comparable rates, Mobil solvent was more effective in banking-up the bitumen. In all three cases, very little bitumen was recovered after the injection of the first pore volume of the solvent.

The solvent-bitumen ratio in Runs 1, 2 and 3 is seen to be 9.6, 6.2 and 11.2, respectively, and is too high to justify field application.

## NAPHTHA-STEAM INJECTION RUNS

A total of 19 runs were performed using a solvent in combination with steam. Runs 4 to 8 employed naphtha as the solvent.

Runs 4 and 6 could not be carried to completion in view of steam leakage problems. All runs employing naphtha showed: (i) rapid evaporation of naphtha on steam injection, as evidenced by the high naphtha concentration of the samples collected; and (ii) considerable gravity override of the steam injected, as shown by the bitumen concentrations of the sand samples extracted at the end of each run.

Run 5 shows a considerable increase in bitumen recovery due to the use of steam (47.2 vs. 21.3 per cent for Run 1). Plugging problems were severe in this run, as a result of which it was not possible to inject steam continuously. It became necessary to employ a cyclic stimulation type of process to keep the pack open, which caused the total steam injected to be excessive. Run 7 did not encounter this problem, and it was possible to inject steam continuously — the bitumen recovery was only slightly less (42.5 vs. 47.2 per cent) for only half as much steam injection. These two runs, as well as other runs discussed below, tend to show that there is probably an optimum combination of solvent and steam slugs which maximizes recovery. Figure 6 shows the cumulative bitumen recovery curves for Runs 5, 7 and 8. In these, and also the other runs, there was virtually no bitumen production when the tar sand pack was depressurized at the end of a run.

## GCOS SYNTHETIC CRUDE — STEAM INJECTION RUNS

Runs 9 to 14 were carried out using a combination of steam and the GCOS synthetic crude. In Runs 9 to 11, the porous plates at the injection and production ports were removed. Run 9 was similar to Run 7, employing naphtha; however, in this run the effluent breakthrough did not occur until after steam injection was started, and bitumen recovery was lower (35.7 per cent).

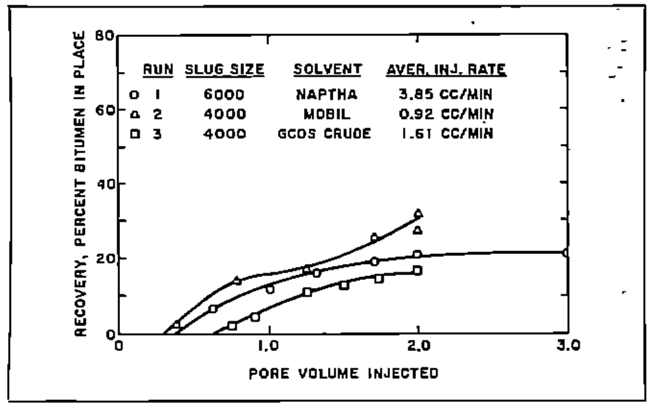


FIGURE 5 — Cumulative bitumen recovery vs. pore volumes injected for straight solvent injection runs.

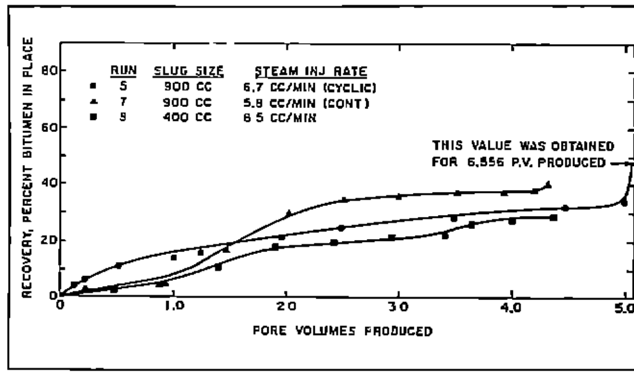


FIGURE 6 — Cumulative bitumen recovery vs. pore volumes produced for naphtha-steam injection runs.

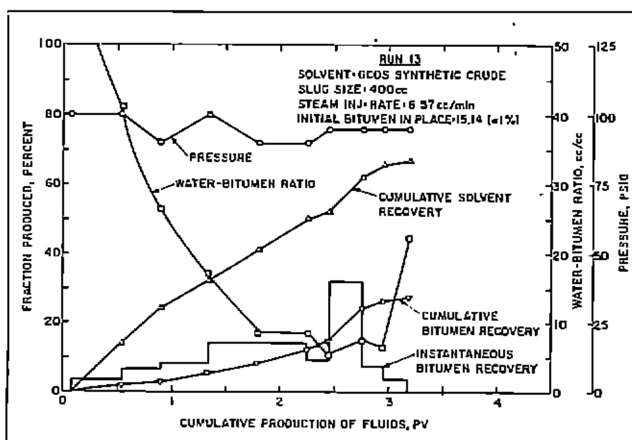


FIGURE 7 — Effluent production and injection pressure history for Run 13, being typical of the runs in Model 1.

Run 10 was similar to Run 9, except that the solvent injection rate was much lower, which led to a somewhat lower bitumen recovery (31.4 vs. 35.7 per cent). When the solvent volume was decreased in Run 11, for roughly the same steam volume, the recovery decreased considerably, as shown in Table 3.

The removal of the porous plates at the injection and production ports in Runs 9 to 11 is equivalent to injection over the entire sand interval. As in the case of the naphtha runs, this gave rise to excessive overriding of steam, evidenced by temperature and residual bitumen saturation distributions.

In Runs 12 to 14, the porous plates were replaced, in effect constraining the steam to penetrate the oil sand layer near the base. Although the steam volume in Run 12 is higher, it is readily evident from Table 3 that this led to a sizeable increase in bitumen recovery (e.g. 19.3 per cent in Run 11 vs. 26.9 per cent in Run 13). This is to be expected on the basis of gravity drainage when a viscous oil bed is heated at the bottom.

Unlike the naphtha runs, GCOS synthetic crude runs did not show any evidence of formation plugging or premature solvent breakthrough. Also, the produced

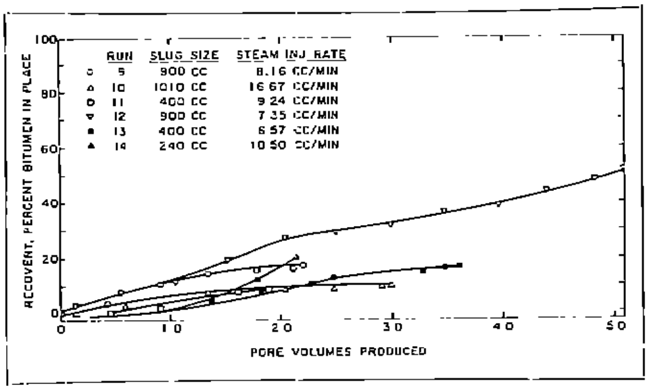


FIGURE 8 — Cumulative bitumen recovery vs. pore volumes produced for GCOS synthetic crude-steam injection runs. (Injection over the total interval in Runs 9 to 11; restricted injection in Runs 12 to 14.)

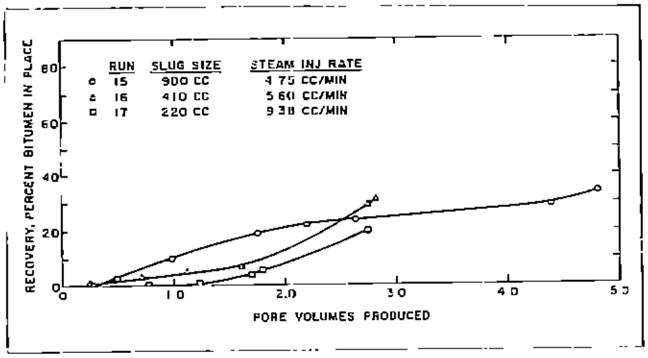


FIGURE 9 — Cumulative bitumen recovery vs. pore volumes produced for GCOS synthetic crude-steam injection runs, with water saturation. Solvent and steam injected into same end.

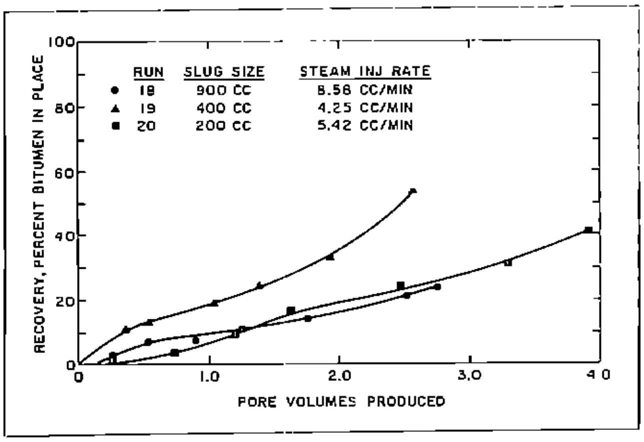


FIGURE 10 — Cumulative bitumen recovery vs. pore volumes produced for GCOS synthetic crude-steam injection runs, with water saturation. Solvent injected into the production end

water-bitumen ratios tended to be lower than those for the naphtha-steam runs. Figure 7 shows the production history for Run 13, being typical of those obtained for all runs conducted. Figure 8 depicts the cumulative recovery curves for Runs 9 to 14.

## GCOS SYNTHETIC CRUDE-STEAM RUNS — OIL SAND PACK SATURATED WITH WATER

Runs 15 to 22 were carried out as before, except that the tar sand pack was saturated with water prior to a run. Water saturation was accomplished by vacuuming and subsequently circulating water through the pack. The purpose of these runs was to study bitumen recovery from a sand pack containing very little or no gas saturation. The solvent slug (10, 20 and 45 per cent pore volume) was injected at the injection end in Runs 15 to 17, and at the production end in Runs 18 to 22. Runs 21 and 22 were conducted in the larger Model 2 (Fig. 4).

It was found that the volume of water produced during the solvent injection phase equalled nearly 90 per cent of the volume of the solvent injected in these runs. Also, the water production decreased to zero on solvent-bitumen breakthrough. It seems that because the GCOS synthetic crude has a viscosity higher than the water viscosity, the displacement of water by the solvent was efficient, and the dispersion of the solvent was affected only slightly by the presence of the water phase, as compared to that in the absence of water, in the previous runs. This is borne out by a number of visual tar sand pack solvent floods, with and without a water saturation, carried out in another investigation[5].

On the other hand, the presence of a water saturation does affect the bitumen recovery and the over-all (solvent-steam) displacement behaviour. For example, the steam injection time increased when a water saturation was present (e.g. 9.27 hr in Run 17 vs. 6.86 hr in Run 14). For solvent slugs of 10 or 20 per cent, bitumen recovery increased (18.8 per cent in Run 14

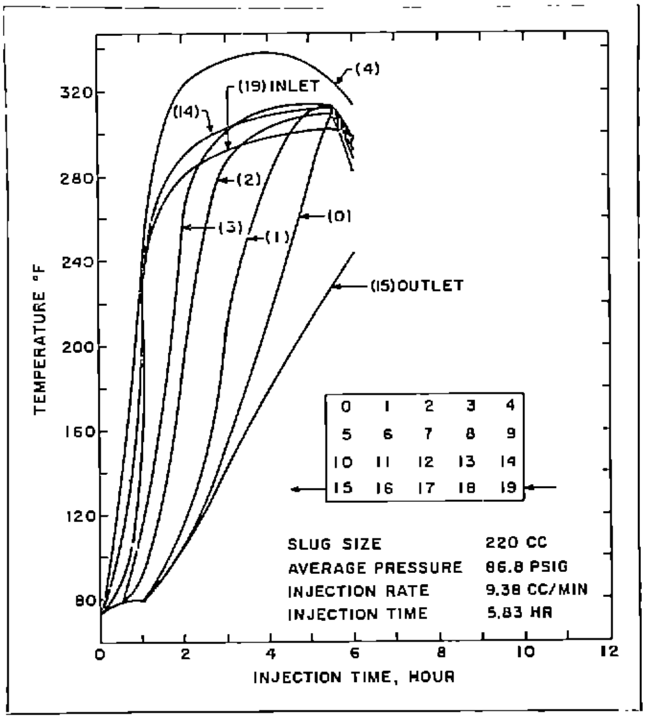


FIGURE 11 — Temperature vs. time curves for selected sampling points in Model 1.

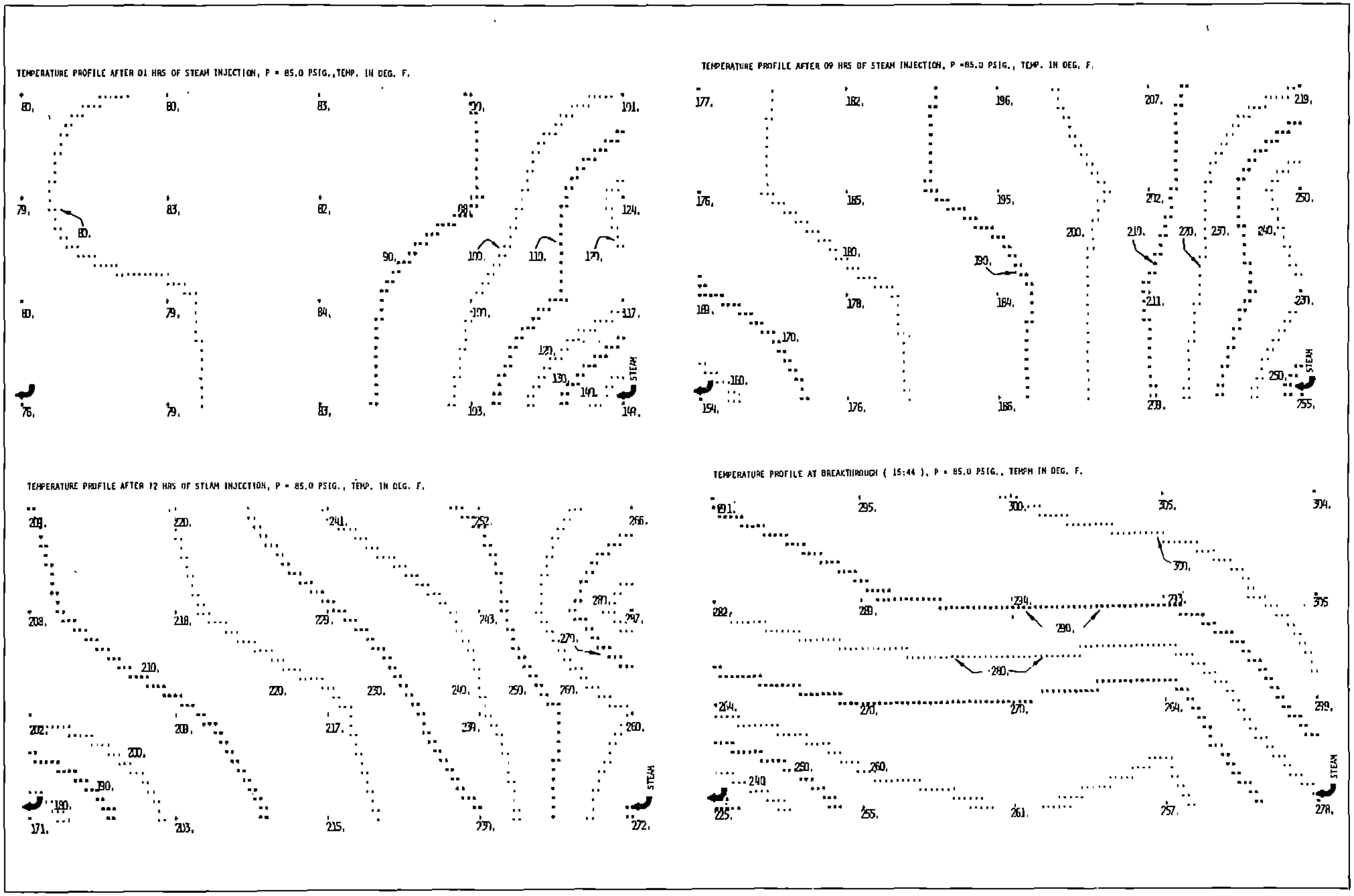


FIGURE 12 — Temperature contours for different times, for run 20 in Model 1.

vs. 20.3 per cent in Run 17; 26.9 per cent in Run 13 vs. 33.1 per cent in Run 16), but it decreased for the larger 45 per cent slug (57.2 per cent in Run 12 vs. 36.8 per cent in Run 15). The decrease in the latter case is partially attributed to the lower steam injection rate rather than the somewhat smaller steam volume in Run 15 as compared to Run 12.

Runs 18, 19 and 20 were similar to Runs 15, 16 and 17, respectively, except that the solvent was injected into the production port. The resulting increase in bitumen recovery in the case of the smaller slugs is dramatic. However, the location of solvent placement did not make much difference to recovery in the case of the larger (45 per cent) slug, as shown by the results for Runs 15 and 18.

On the whole, the production behaviour in these runs was quite different from that in Runs 15 to 17. Pressure and injection rate did not show the fluctuations observed in the latter. Water was produced only up to the point of bitumen breakthrough. The volume of solvent injected to obtain breakthrough was also lower. The solvent-bitumen ratios in Runs 19 and 20 were lower than those for Runs 16 and 17, respectively. In the case of the larger slug (45 per cent), even though bitumen recovery was only slightly improved (Run 18 vs. 15) by solvent placement at the production end, the water-bitumen ratio was about half in Run 18 (5.62) as compared to that in Run 15 (10.22).

Figures 9 and 10 show cumulative recovery curves for Runs 15 to 17 and Runs 18 to 20, respectively.

Temperature surveys were carried out at different times in all runs conducted. These cannot be included here due to space limitations. Figure 11 shows temperatures at several points in the model as a function of time for Run 17. A few selected temperature contours for Run 20 are depicted in Figure 12. These are typical of those obtained in most of the runs: the injected steam at first advances approximately as a vertical front, but later in the run the front becomes more

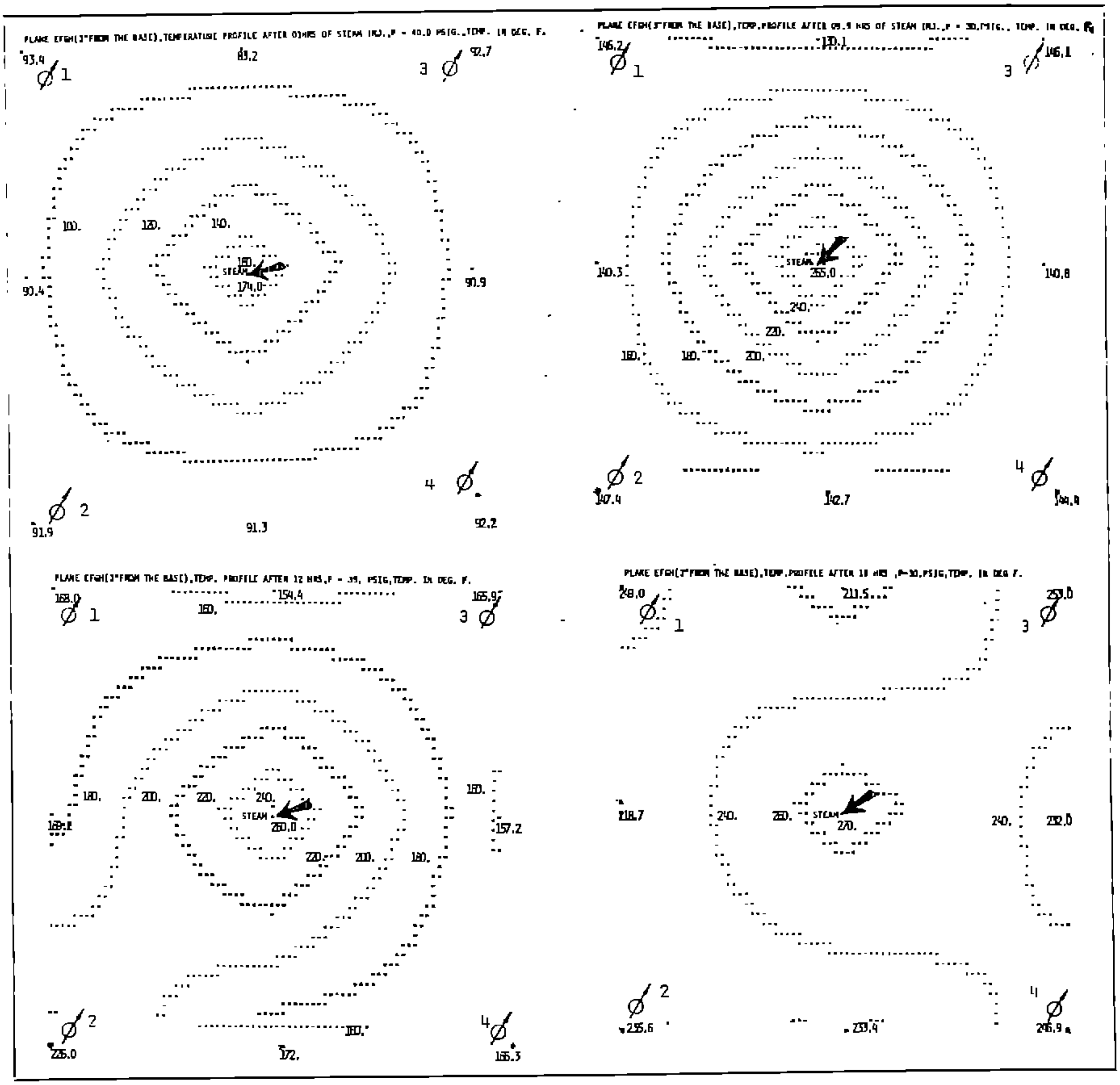


FIGURE 13 — Temperature contours at a plane 3 inches above the base of Model 2, for different times, for Run 22.

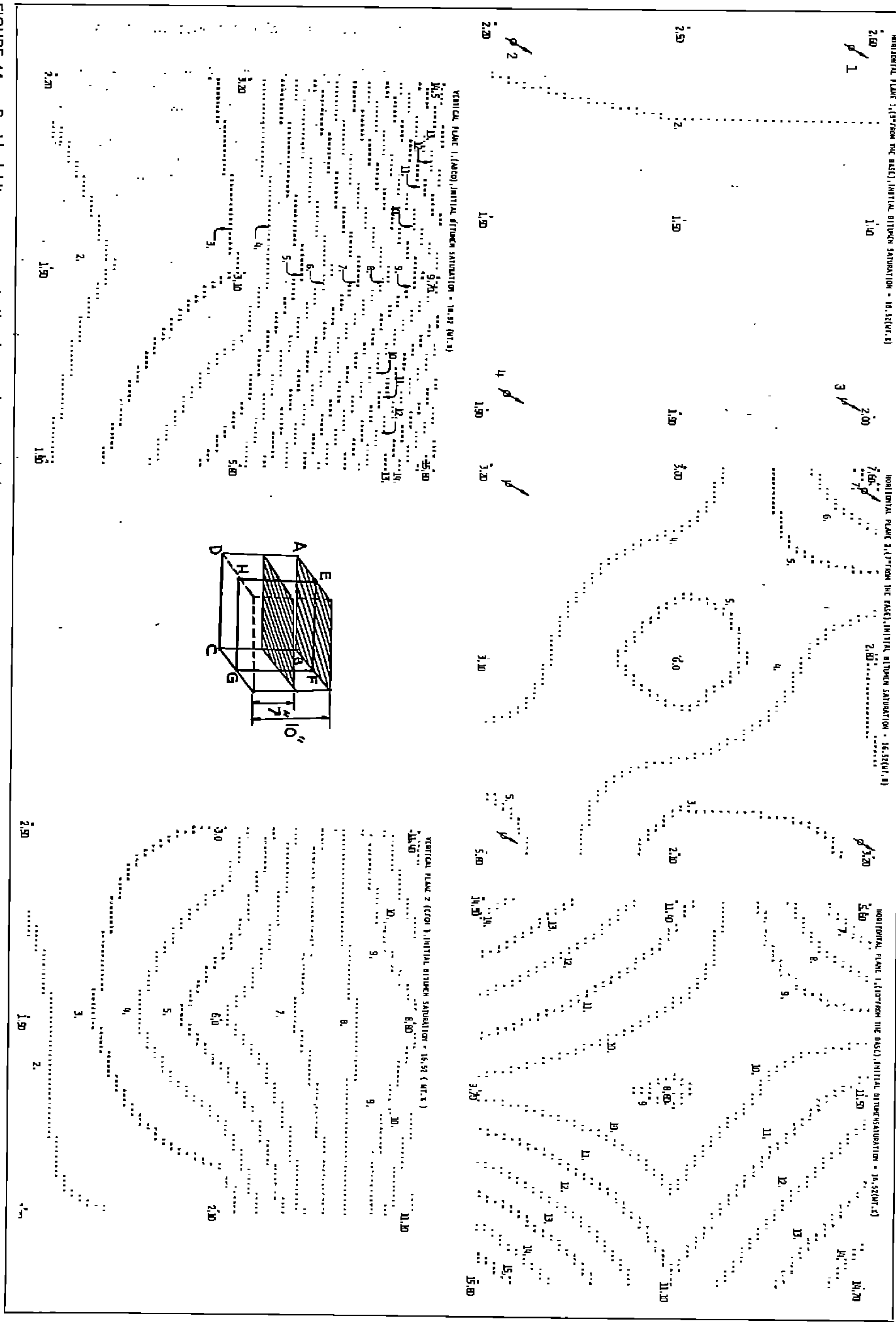


FIGURE 14 — Residual bitumen concentration in two horizontal planes and two vertical planes in Model 2, for Run 22.

nearly horizontal in view of the increased gravity segregation of steam.

Runs 21 and 22 were carried out in the larger Model 2 (Fig. 4). Data for these runs are given in Table 3. It is recalled that injection was through the center well, whereas production was from the corner wells. GCOS synthetic crude was employed in both runs. An overburden pressure of 75 psig was applied to the oil sand pack, which was saturated with water prior to solvent injection. In both runs, effluent breakthrough occurred early, as the data in Table 3 show.

The advance of steam in the oil sand pack was fairly symmetrical. In Run 21, steam was produced from wells, 1, 2, 3 and 4, after 2.48, 2.32, 4.37 and 2.0 hours, respectively.

In Run 22, the production wells, 1, 2, 3 and 4, were opened sequentially at equal time intervals during the solvent injection phase. Steam injection pressure was held at 30 psig. Again, the advance of steam was fairly symmetrical. Temperatures were scanned at points on two horizontal planes 3 inches and 7 inches, respectively, from the base of the model. Figure 13 shows a few temperature contours for the former plane. Figure 14 shows residual bitumen saturation distribution on a horizontal and a vertical plane, as indicated. It is evident that the lower half of the tar sand pack was more completely swept by steam.

It should be noted that the temperature distributions shown in Figures 11-13 are specific to the model employed, which was not scaled. The purpose of these distributions is to qualitatively show the nature of steam front advance, gravity override, etc.

Correlations of bitumen recovery with steam injection rate did not show any consistent trend, except that recovery tends to increase for lower steam injection rates.

## Conclusions

The following conclusions can be derived within the framework of the present experimental investigation:

1. GCOS synthetic crude appears to be ideally suited for the in-situ recovery of bitumen, using a thermal-miscible process. It is readily available, has desirable miscibility characteristics with bitumen and does not seem to cause asphaltene precipitation, over the temperature and concentration ranges employed.

2. The results obtained show that smaller solvent slugs are more effective in bitumen recovery. It seems that there is an optimum combination of the solvent and steam slug sizes which maximizes bitumen recovery. Also important is the steam injection rate. Recovery tends to increase with a decrease in steam injection rate in the thermal-miscible processes of the type tested. Evidently, there is a minimum rate that would maximize recovery.

3. The lowest solvent-bitumen ratio obtained was 0.24 vol./vol. This is still too high to be practical; however, it is felt that it can be lowered through further modifications of the process.

4. The experimental procedure involving the saturation of the tar sand pack by water, prior to solvent-steam injection, seems to be more realistic and reliable.

## Acknowledgments

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