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Thermal-Miscible Displacement Studies in Athabasca Tar Sands

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by

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I. INTRODUCTION

The world oil reserves are estimated to be 546,373,626,000 bbls. of oil and 2,220,442 x 10^6 cubic feet of gas for the year 1973; the world demand is 55,331,000 barrels of oil per day (34). Considering the increase in demand in particular in the United States, Europe and Japan and dwindling oil reserves in these countries it is possible to understand the current concern over energy shortages.

Tar sand deposits have been known to occur in a number of countries, however, their exploitation and development was not considered to be commerical until 1962, when a 45,000 BPD plant was constructed at Ft. McMurray in Canada, by the Great Canadian Oil Sands, Lts.

Tar sand has been defined as sand containing highly viscous hydrocarbon material not recoverable in its natural state through a well by ordinary production methods. Twenty major tar sand occurrences around the world have been reported, in the literature (29). These are listed in Table 1, which also gives the location, formation name, and reserves. These twenty deposits add up to 1,099,409x10^6 bbl of oil which could play a significant role to the oil supply picture of the world.

Major tar sand deposits occur in eight countries. The apparent uneven distribution is partially due to the occurrence of natural asphalt in rocks other than sandstone, namely limestone, shale serpentine, etc., and partially

Table 1

Major Tar Sand Deposits of the World

Deposit	Location	Geological Formation, Age Reserves In Place	MMBLS.
Athabasca ✓	Alberta, Canada	Lower Cretaceus	895,000
Melville Is.	Marie Bay, Canada	Triassic, Bjorne Formation	?
Oficina-Temblador ✓	Venezuela	Oligocene, Ofi~~n~~cina Formation	600,000
Bemolanga	Morafenobe, Malgasy	Lower Isalo Grup,(Triassic)	1,750
Asphalt Ridge	Vernal, Utah, U.S.A.	Upper Cretaceus, Mesaverde Oligiocene Duchesne River Formation	900
Sunny Side	Utah, U.S.A.	Wasatch, and Lower Green River, Eocene	500
Selenizza	Valdna, Albania	Middle-Upper Miocene, and Plioce~~n~~ce	371
White Rocks	Vernal, Utah, U.S.A.	Middle Jurasic, Navajo Formation	250
Edna	Edna, California, U.S.A.	Mio-Pliocene Pismo Formation	165
Peor Spring	Utah, U.S.A.	Edcene, Wasatch Formation	87
Guandco ✓	Eastern Venezuela	Las Piedras Formation, Mio-P~~o~~Liocene	62
Labrea	Gulf of Paria,	Miocene, Upper Morne l'Enfer Sandstone	60

Table 1 (continued)

Deposit	Location	Geological Formation, Age Reserves In Place	MMBLS.
Santa Rosa	New Mexico, U.S.A.	Upper Triasic, Santa Rosa Formation	57
Sisquoc	Salmon Hill, Calif. U.S.A.	Upper Pliocene	50
Asphalt	Kentucky, U.S.A.	Pennsylvanian Postville Formation	
Davis-Dismal Creek	Kentucky, U.S.A.	Pennsylvanian Postville Formation	88
Kyrock	Kentucky, U.S.A.	Pennsylvanian Postville Formation	
Derna	Oradia, Rumania	Pliocene, Pannomian Formation	25
Cheildad	Kobystan, USSR	Middle Miocene	24
Santa Cruz	California, U.S.A.	Miocene Monterrey An Vaqueros Formation	20

to the lack of information, on tar sand deposits in many countries.

Athabasca Tar Sands ✓

2

The Athabasca tar sands cover an area of 12,500 millon square miles in the north-eastern part of Alberta as shown in Figure 1. (This figure as well as others involving structural and geological cross-sections are reproduced from several papers and reports.) The three main formations in Alberta are:

McMurray - Wasbiskaw
Bluesky - Gething
Grand Rapids

Even though the present study does not involve geological aspects, description of the geology of the formations is presented for the sake of completeness.

According to Phizackerly and Scott (29), the major McMurray - Wasbiskaw deposits are located toward the base of the formation and are characteristically cross-bedded coarse grits and gritty sandstones, all unconsolidated or cemented by tar. The sandstone is believed to be derived from pre-cambrian rocks outcropping about 100 miles to the north-east near Lake Athabasca. The facies of the lower part of the McMurray - Wasbiskaw sands varies from fluivatile to deltaic. Until the Hauterivian break in sedimentation, a lake and swamp environment developed probably as a result of subsidence. Marine conditions prevailed in the deposition of the Wasbiskaw member of

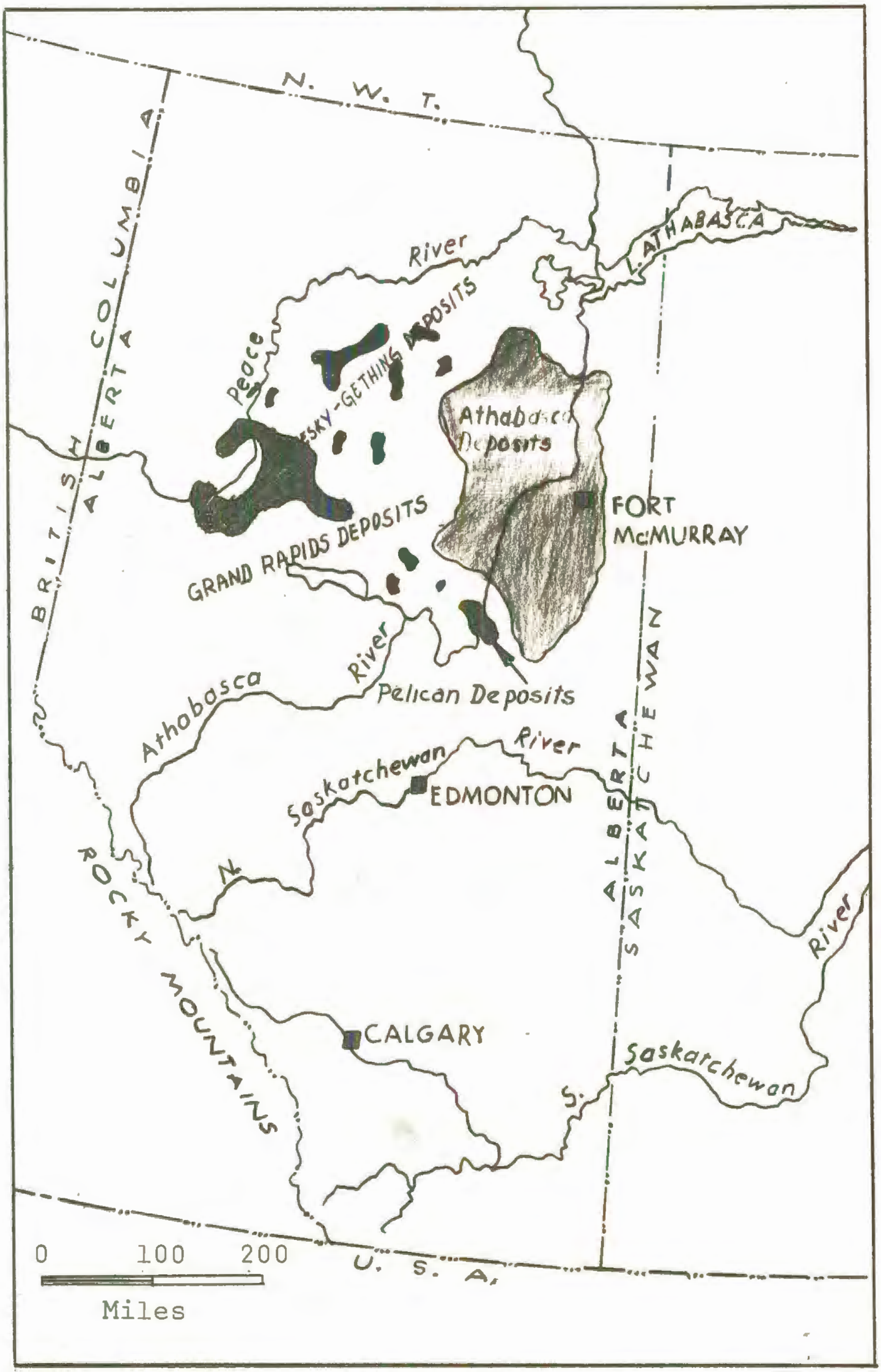


Figure 1 Geographical Location of The Athabasca Tar Sands.

Clearwater formation. The McMurray - Wabiskaw tar sands overlie an irregular topography formed on the surface of westerly dipping Pre-Cambrian to Jurassic sediments. These formations cover an area of 9,000 square miles with thicknesses ranging from 0 to 375 feet, with 0 to 1,900 feet of overburden.

Bluesky - Gething formations are probably Aptian age, and are composed of sub-angular quartz and well rounded chert grains. Sandstones of these deposits are frequently glauconic and have a calareous matrix. The facies are generally that of near shore environment. Coal deposits occur in these formation, they overlie several unconformities between the Missisippian and Jurassic. The Bluesky - Gething formations cover an area of 1,875 square miles with thickness ranging from 0 to 400 feet, the overburden have a thickeness of 700 to 2,600 feet.

The Grand Rapids formtions are Albian in age, and as the Blusky - Gething formations are formed of sub-angular quartz and well-rounded chert grains. They cover an area of 1,625 square miles with an overburden of 300 to 1,400 feet and have an average thickness of 280 feet.

Figure 2 shows the location of the above mentioned tar sand deposits, and Figure 3 is a schematic geological E-W cross section showing the gelogical setting of the Athabasca Tar Sands.

Figures 4 and 5 show pictures of tar sand, before and after washing with solvent. As stated before,

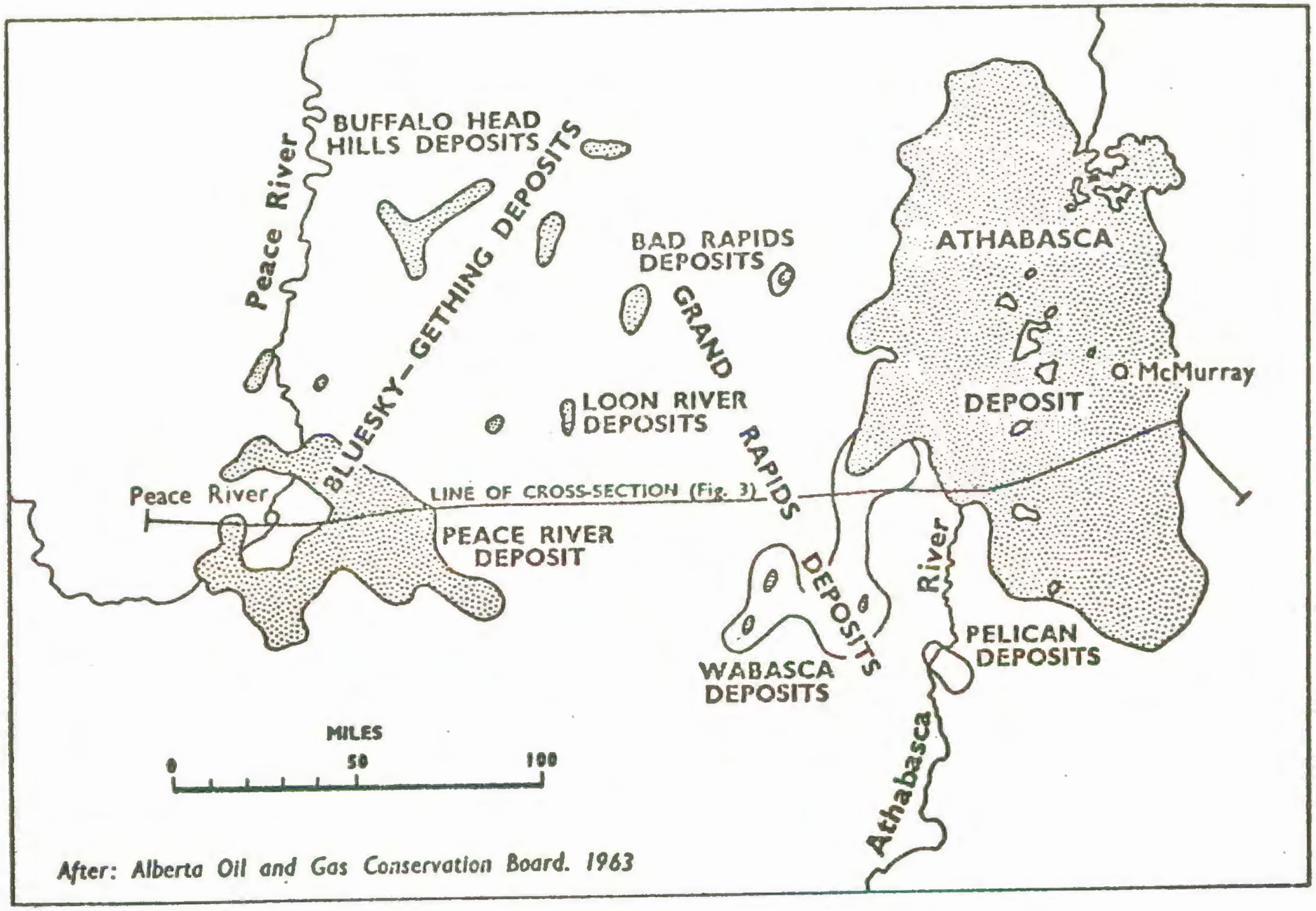
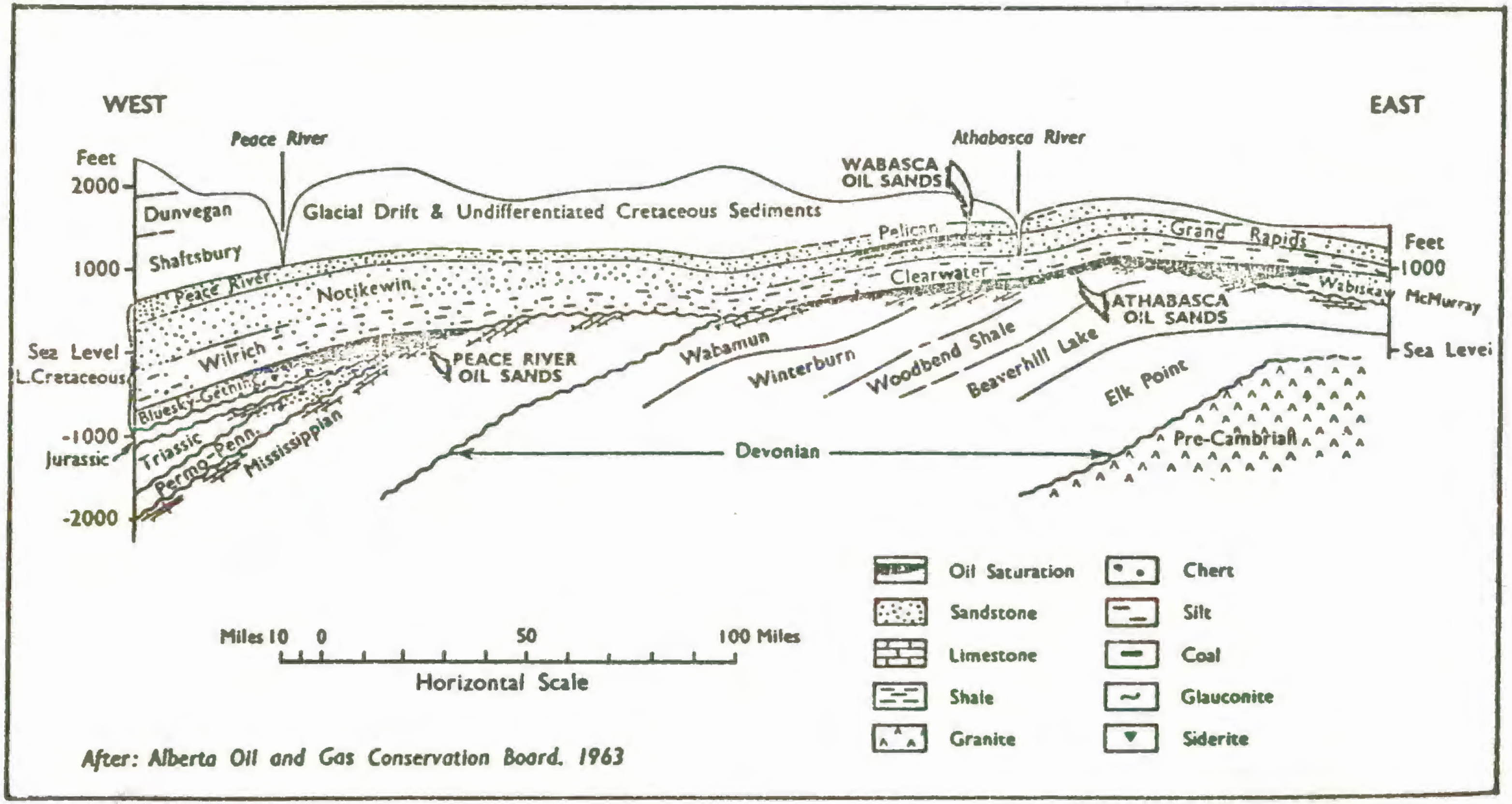


Figure 2   Map Showing the Location of the Line of Cross-Section.



After: Alberta Oil and Gas Conservation Board. 1963

Figure 3 E-W Cross Section Showing the Geological Setting of the Athabasca Tar Sands.

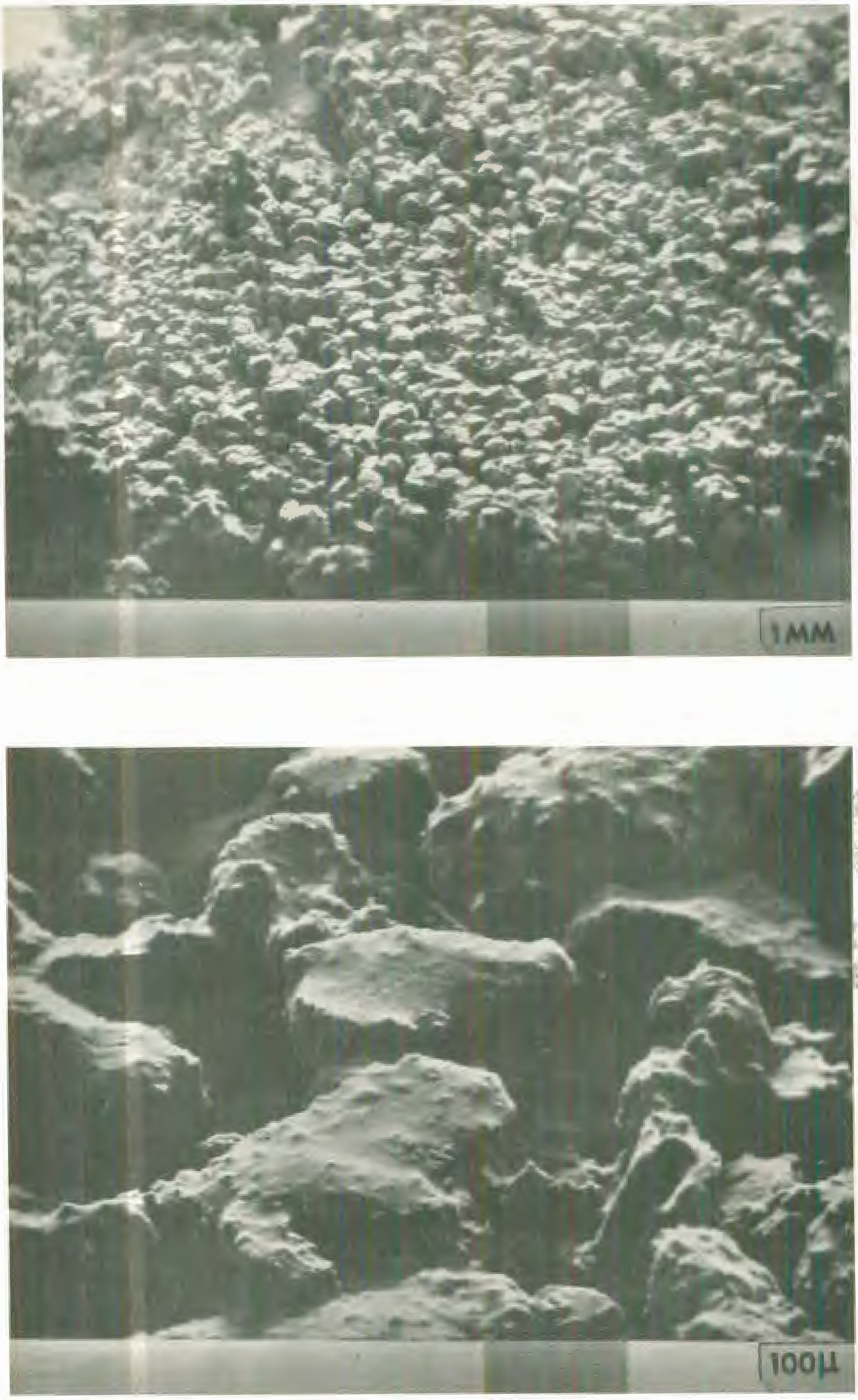


Figure 4 Microscopic photographs of original tar sands

Figure 5 Microscopic photographs of washed tar sands

tar serves to cement the grains, which become completely loose after being washed.

Around ten percent of the tar sands deposits of Athabasca can be exploited by surface mining methods. In the mining of tar sands, a number of problems are encountered which are known to the engineer in the mining of lignite, hard coal, and certain other minerals. Also, there are additional problems because of the nature of the tar. Gold (19) notes the factors that must be considered in the exploitation of the deposits:

> the thickness of overburden, the thickenss of the tar sand deposit, and the ratio of the overburden thickness to the thickness of the tar sand formation,
> the oil yield of the tar sand, and the quality of the oil,
> the mine losses which in underground mining sometimes amount to 50 percent and more,
> removal of the overburden, which can be critical in the economics of the project,
> disposal of large amounts of sand after processing the tar.

The process used to separate the bitimen from sand is the so called Clark hot water process. In this process, oil is separated from the hot mixture of oil, water and minerals obtained when heating the tar sands with steam and diluting with hot water. The problems encountered in this process show that the only way to develop tar sand deposits in the long run is in situ recovery, cyclic steam stimulation, steamflooding, solvent flooding, and in situ combustion methods. A number of problems such as the handling of large amounts of overburden, disposal of tailings etc., could be solved in in situ recovery, However, the in situ methods have other problems of their own.

It is considered instructive to discuss in some detail the limitations and problems associated with the recovery methods for tar sands. Techniques such as in situ combustion, hydraulic or explosive fracturing, solution and emulsification processes, steam injection, nuclear detonation, oxidation and hydrogenation processes, and combination of these will be discussed.

The goal of any in situ process is to increase the mobility of the very viscuos oil that is contained in the tar sands. At the original reservoir temperature of 50°F the viscosity of the bitumen is several million centipoises. However, when heated to 350-400°F, the viscosity is lowered to around 5 to 10 centipoises.

Even though heating is an excellent way to increase mobility, it is not the only one. When a highly aromatic solvent is added to the bitumen a considerable reduction in viscosity occurs, although the solution tends to reach a saturation point, the viscosity of the solution does decrease quite rapidly. The use of aqueous emulsifying solutions is still another possibility. The resulting solution will have a viscosity of the order of that of the external aqueous phase. The Athabasca tar sand deposit in its original state has zero permeability, then there is no communication between injection and production well(s). It is necessary to establish some kind of channeling or communication between the wells mainly to create a path which can be followed by the steam when its injection begins.

Then for an in situ process to be successful, low viscosity and channels through the formation must exist.

Hubbard (10) stipulated the conditions under which fractures of various oreientations might be realized in subsurface formations. An important conclusion of his study is that vertical fractures, rather than horizontal ones are more likely to occur. The chances of connecting an array of injection and production wells with vertical fractures are not very high. However, in Shell Canada operations (12) relatively standard hydraulic fracturing procedures were used in addition to some the emprical techniques which are belived to increase the tendency of the fracture to tilt. These techniques included selective or limited exposure of the vertical section an a previous mechanical and hydraulic penetration in the formation. The Shell experiments were conducted in the McMurray formation, which because of its shallow depth, unconsolidated nature, and geological history has been successfully fractured horizontally. It is possible to create or find in this formation very few and limited (vertical extent) communicating paths between injection and production wells.

Because of the lack of communication between wells, the choice of an in situ recovery method becomes rather limited. Miscible fluids (solvents) have been considered as a recovery tool for tar sands. Even in formations with non-zero permeability over the entire reservoir thickness it is difficult to apply miscible displacement, because of viscous fingering and gravity overlay effects.

The use of an emulsifying liquid, which after emulsifying significant amounts of bitumen has a viscosity close to the original viscosity has certain advantages over solvents, not only because the viscosity of the emulsion is lower than that of the comparable solvent-bitumen solution but also because flow occurs through the wetting phase (water) and the oil bank ahead is not moved. However, with these emulsifying fluids, the permeable path is limited to a relatively small zone, (fracture) as a result of which the vertical sweep efficiency is low.

Diffusion of the active chemicals through the aqueous phase would be the principal mechanisim through which the solution will propagate through the formation, in addition to the original ~~faracture~~ fracture or permeable path.

The absence of any general developed permeability over the oil saturated section of a tar sand deposit is also a limiting factor for in situ fire flooding, which is another technique considered for the recovery of bitumen. In order for the fire to be propagated, there must be adequate permeability in order to obtain a high oxygen flux. This is only realized in zones with fractures or high permeability strata. Heat generation, and a result oil flow, will be restricted to these zones only, which consititute a small proportion of the formation thickness.

One of the major difficulties in conducting a successful combustion process is that too much heat is generated in too short a time. To remedy this steam can be used, since it has high temperature and will maintain it until condensation by contact with the cold formation.

It can be concluded that because of the physical characteristics of the tar sand formations, the high viscosity of the crude, steam flooding with prior creation of communication between the injection and producing wells seems to be most effective.

II. REVIEW OF LITERATURE

Miscible Displacement

Recovery of oil by miscible displacement has been widely investigated in the laboratory and already applied to many field tests.

LPG, rich gas bank, gas-water injection, high-pressure gas-driven LPG-bank process, water solvent mixtures, alcohol-water, are the most common miscible displacement techniques. In the alcohol slug process, water and oil are displaced in the reservoir, while in the other, hydrocarbons are displaced alone.

Taylor (33), and later von Rosenberg (30), studied and summarized the simplest case of miscible displacement process, the displacement of one fluid by another in a single capillary tube under laminar flow conditions. Taylor determined that the length of the two-component mixing zone is proportional to the square root of the distance traversed, and the mixing zone length is directly proportional to the square root of the flow velocity and inversely proportional to the square root of the molecular diffusion coeffieicnt. Even if these conclusions apply to flow behavior in capillary tubes, they do not necessarily hold for flow in reservoir rocks.

Path length effects were studied by several investigators, Von Rosenberg (30) conducted studies in 1, 2, and 4 feet unconsolidated cores, Koch and Slobod (22) made similar studies in longer (123 ft.) cores and arrived at conclusions similar to those of Taylor (33). Later, Cashdollar (8) using unconsolidated cores of 9, 18, 50, and 100 feet lengths, indicated again that the length of the mixing zone is directly proportional to the square root of the path length. However, Hall and Geffen (20) found that the mixing zone grows at a steadily decreasing rate, and later stabilizes; after this, further growth is impossible to determine experimentally. Lacey (24) also observed similar behavior in his study.

$\ell_z \propto \sqrt{L_m}$

The effect of viscous fingering in oil recovery has been measured in terms of mobility ratios. Offeringa (27), and Blackwell et al. (3) found that some oil is bypassed even in homogeneous sands when viscous fingering is present and as a consequence, oil recovery at breakthrough decreases as mobility ratio increases.

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Blackwell (3) investigated miscible displacement at very low rates. He found out that mixing both in the direction of mean flow is dominated by molecular diffusion, and at higher flow rates mixing is governed by convection.

Perkins and Johnston (28) reviewed the diffusion and dispersion literature and established the variables involved in dispersion: Particle size distribution, particle shape, packing or permeability heterogeneities, viscosity ratios, gravity forces, amount of turbulence, effect of immobile phase, and edge effect in packed tubes.

Blackwell et al. (4) presented results of a laboratory investigation of the efficiency of water-solvent mixtures in oil recovery. They found that higher volumes of oil can be recovered by using water-solvent displacement fluids rather than using water alone, or practial volumes of solvent alone.

Arnold, et al. (1) studied the efficiency of small banks of enriched gas driven by methane in displacing oil from porous media, and the effect of variation in bank size and composition. As a result of this investigation they concluded that in reservoirs where strong bypassing of oil does not occur, small banks of enriched gas driven by methane may be used to effect an oil recovery similar to the one produced by continuous injection of enriched gas. Also where no bypassing of oil occurs, the dispersion of an oil-immiscible enriched-gas bank is controlled by distribution of various hydrocarbons between gas an oil according to the laws of equilibrium phase behavior. They conclude that by using oil-miscible bank: (a) more oil can be recovered, (b) the total gas injection for ultimate recovery is smaller and, (c) when a long flow system is being considered, smaller minimum bank sizes and smaller quantitites of enriched materials are necessary.

Benham, Dowden, and Kunzman (2) presented a method for calculating the approximate conditions for a miscible displacement of reservoir fluid by a rich, light hydrocarbon gas or LPG mixtures. They found that miscibility is favored by increasing pressures, decreased temperatures, light reservoir fluids, and light-hydrocarbons displacing fluids rich in heavier components.

E. J. Koval (23) simulated the fingering of solvent into oil. Using the K-factor method, it is possible to predict the interaction of macroscopic heterogenities and viscous fingering. In the K-factor method, it is assumed that a single parameter can be used to represent the viscosity effects. This parameter is called effective viscosity ratio E, which is given by

$$E = \left[(.78 + .22(V))^{.25}\right]^4$$

where V is the viscosity ratio of the pure materials, μ_o/μ_s.

Solvents and Explosives Methods

Larman, et al. (25) reported preliminary results of an explosive fracturing-solvent injection in heavy oil recovery experiment conducted by the Bureau of Mines at a reservoir near Bartlett, Kansas, the method combines modern chemical explosive fracturing techniques with heat and solvent treatments to extract the heavy oil. Investigations were conducted to find an inexpensive solvent that would lower the viscosity without precipitating asphaltenes. The solvents considered were limited to those with boiling point above 300°F, for two reasons, first the solvent had to be injected hot and because of the need for distilling the solvent from the oil after production.

Thermal-Miscible Methods

Hernandez and Farouq Ali (21) investigated oil recovery from Athabasca tar sands, using a number of solvents with and without steam injection. Five solvents were used: Carbon tethrachloride, Toluene, Benzene, Naptha and Soltrol 170. Of the five, the highest recovery was obtained using carbon tetrachloride (98.5%) and the lowest was for naphtha (37.2%). They found that bitumen recovery was a function of the injection rate being lower at higher rates, and that solvent recirculation was helpful in improving oil recovery from tar sands. When using a combination of slovent slug and steam (0.5 pore volume slug of carbon tetrachloride) recovery was 76.8 percent, however using steam alone the recovery was even higher. The mathematical model used to calculate the steam front gave results which were in poor agreement with the experimental results, the mathematical model used was developed by Magnani (26). From the experiments with solvent and steam it was found that recovery increased with an increase in slug size. However, if smaller slugs helped open a channel for subsequent steam flooding, the larger slugs caused permeability block largely reducing steam flow. Snyder (32) investigated the recovery of bitumen from Athabasca tar sands in a two dimensional vertical modes (the same one used in the present study). He investigated the recovery efficiency of naphtha, injection at different rates, effectiveness of gravity segregation, conductive heating with highly permeable channels joining the inlet and the outlet of the pack, and steam injection. From the results of his investigation he concluded that naphta was technically successful in recovering bitumen, but the process was not economical because of the amount of solvent (3.8 pore volumes) used. The dependence of recovery on flow rate was observed, recovery was higher at lower rates.

Gravity segregation was found to be important for high recoveries, naphtha opens a flow channel through the pack, but sweeps the inlet portion of the pack more than the outlet portion.

Naphtha injection can lead to asphaltene flocculation and as a consequence to the plugging of the formation, but he found flocculation only after injection large amounts of solvent.

Conductive heating as well as gravity segregation were found to be unsuccesful when the high permeability channel at the bottom of the pack was present. Even steam injection is a succesfull recovery technique, the steam action was concentrated in the neighborhood of the injection point and did not contact the majority of the pack.

Naphtha injection prior to steam flooding when the high permeability channel was present was not succesfull, because naphtha is vaporized immediately and produced.

Finally when naphtha was injected prior to steam into an homogeneous pack, the steam was concentrated more toward the outlet increasing significantly the recovery of bitumen.

The problem of asphaltene flocculation when stimulating heavy oils was studied by David (9). When stimulating heavy oil with solvent, several problems may develope if the asphaltene content of the oil is high. From experimental results he concluded that the following parameters increase the flocculation of asphaltenes and formation plugging: lower molecular weight and higher concentration of solvent, higher asphaltene content in the oil and lower rock permeability. The effect of temperature on plugging was found to be dependent on the type of oil.

Field Test of In Situ Recovery Methods

Today, at least 11 experimental in situ recovery projects are in operation in the tar sand area in Alberta, and a larger number is planned for the next two years. S. M. Farouq Ali (14) reports that more than 20 projects have already been conducted and terminated for several reasons.

From 1957 to 1962, Shell Canada Lts. conducted steam drive field tests (17) in tar sand deposits located some 40 miles north of Ft. McMurray, Alberta, Canada. Doscher, et al. (11) reported that in a 10 year program of field experiments, by the injection of 10 tons of steam per day along with a slug of critically prepared alkaline solution 200 bbls of bitumen can be recovered from a 5-spot pattern 4 acre spacing.

In 1956, some experiments conducted by Shell led to the discovery that certain aqueous alkaline solutions of detergents were capable of wetting and emulsifying the oil from the McMurray formation. Further experiments revealed that critically prepared solutions of sodium hydroxide were even more efficient in emulsifying the oil. When the alkaline solution of detergent was injected into the formation, solutions containing 4 to 30% of bitumen were produced. Later it was observed that steam capable of increasing the action of these critically prepared alkaline solutions.

In 1960 a large pilot plan combining the use of alkaline solutions and steam was started in an bitumen saturated interval in a single 5 spot pattern. Farouq Ali (17) in his discussion pointed out that, if, even a thin but continuous shaly zone was present in the McMurray formation, good oil displacement occured up to 50 feet above the base of the sand, but the presence of such a thin impereable zone may interfere and reduce the importance of gravity flow to the base (where the fracture is created in the Shell technique) of the formation, and part of the Shell process relies on this gravitational process.

Even though recoveries were high, for reasons of economics the project eas abandoned in 1968.

Cyclic steam stimulation have been conducted by several companies (Imperial Oil, Texaco, Great Plains, and some others) in the tar sands of Athabasca.

Samoil (31) described a single well stimulation test carried out by Great Plains in Cold Lake in 1965. Initially hot water was circulated in the well with the idea of increasing the quality of steam. Due to the lack of data, the total oil displaced is not known.

Imperial Oil is working these days in a pilot project consisting of 23 wells on a 5 acre spacing unit. The current oil production rate from this project is around 2000 B/D.

The most succesful cyclic steam stimulation reported to be the most succesful today involves the injection of a large slug of natural gas followed by a large slug of steam.

Amoco Canada, since 1958, has been testing an in situ combustion project in the Athabasca tar sands. The process used is a combination of forward combustion and water flooding (COFCAW). The tests were carried out in the lower unit of the McMurray formation under 780 ft of overburden (average). The procedure is to hydraulically fracture the formation, and preheat the formation to 200°F using combustion, at this temperature the viscosity of bitumen is low enough to permit displacement of oil by the COFCAW method.

Under the present project (Phase V of the one initiated in 1958) the formation was fractured with a good response from three of the four wells treated, later combustion was initiated, and after a 7 month heating period and a month shut in period, an average rate of 70 B/D was obtained for the first six months. Over the fourteen months of production 25,000 bble (43% of bitumen in place) were recovered from two wells.

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Several other sophisticated recovery techniques have been proposed, such as atomic fracturing, in situ gasification of the hydrocarbons, in situ hydrogenation of bitumen, carbon dioxide injection, and many others, but its discussion is beyond the scope of this thesis.

III. APPARATUS, MATERIALS AND PROCEDURE

Models and Materials

Two models were used in this investigation. The first one was designed by Snyder (32). A detailed sketch of this model is given in Figure 6. Five injection points were used, four at the top and one at the bottom of the box. Porous plates were located at the inlet and at the outlet of the pack to avoid sand production and plugging up. Figure 7 is a flow diagram for the experimental apparatus used for model 1.

The fluids used in each run were stored in two calibrated burettes (1000 cc). They were connected to two Lapp Pulsa feeder pumps[1], which can handle liquid in quantities that can be controlled by a micrometer which regulates the length of the stroke. Copper tubing of 1/4" O.D. site were used for flow lines. An 8 μ millipore[2] filter was placed in the flow system to avoid plugging at the inlet of the pack. Hoke[3] valves were located strategically along the system to control flow.

Pressure was recorded using two gauges, one with a range of 0-30 psig, for low pressures and the other one with a range of 0-600 psig for higher pressures.

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[1] Lapp Insulator Co., Inc., LeRoy, N. Y.

[2] Millipor Filter Corporation, Bedford, Mass.

[3] Hoke Incorporated, Cresskill, New Jersey

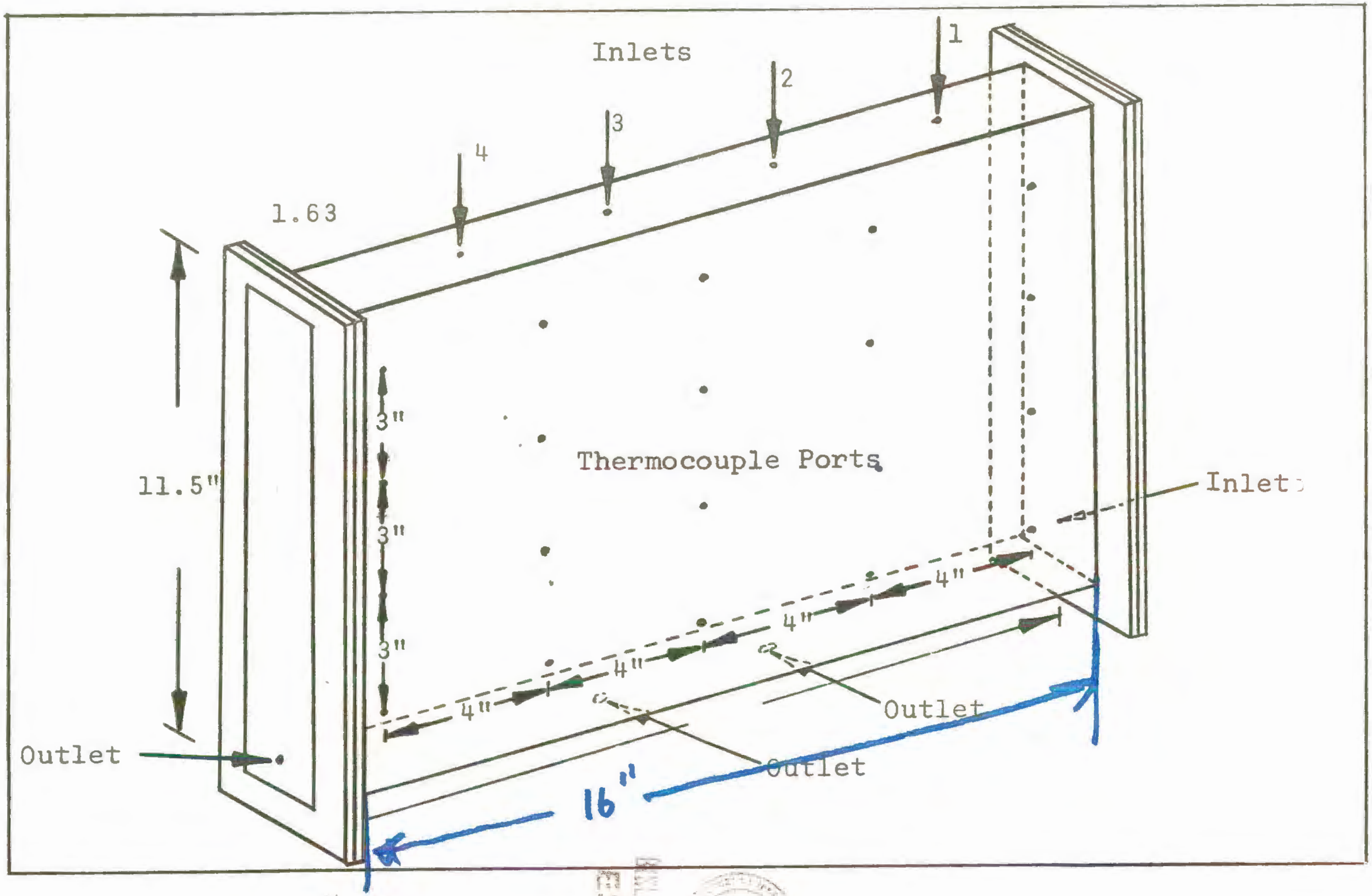

Figure 6 Sketch of Model 1.

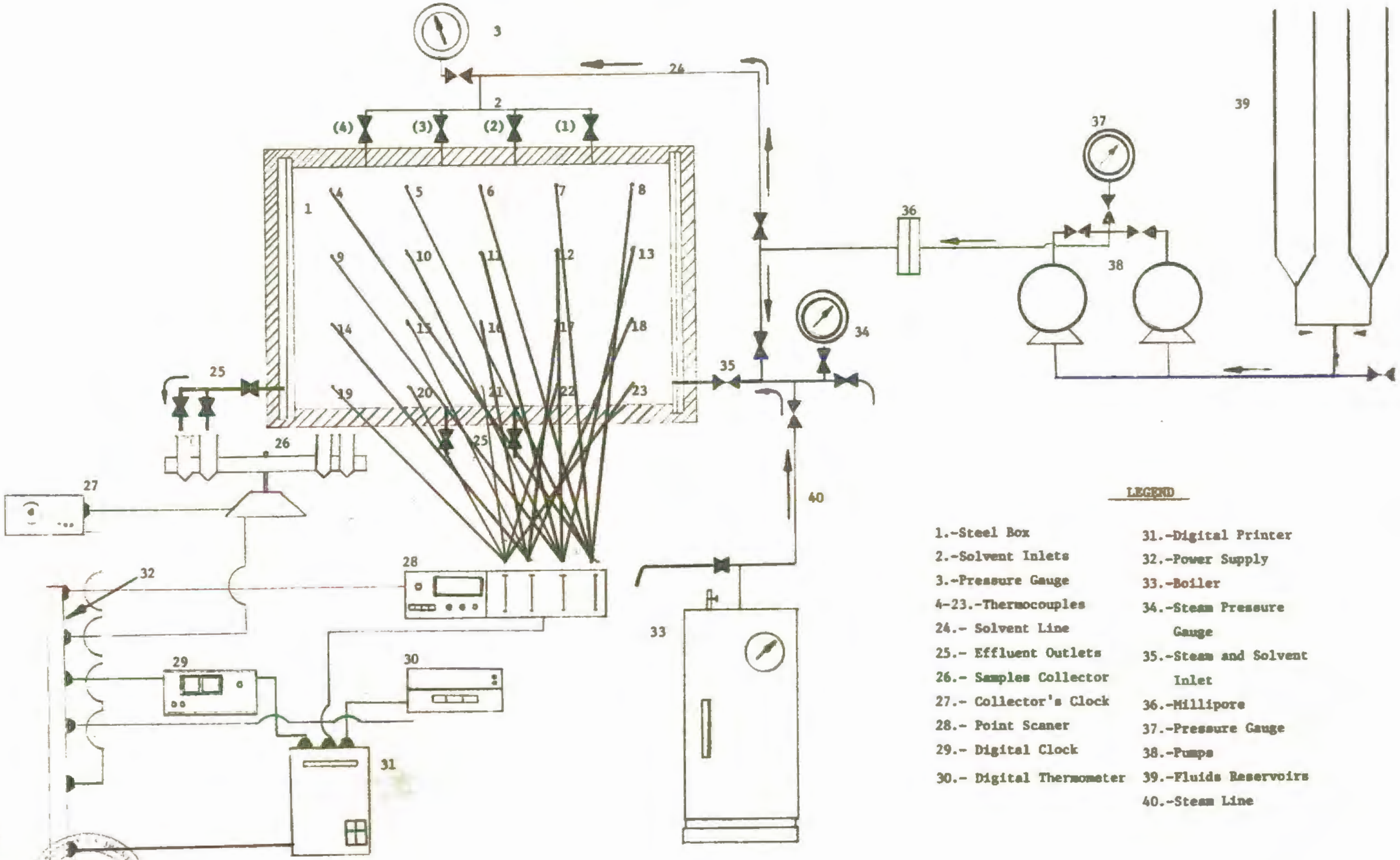

Figure 7 Flow Diagram of Model 1.

Steam was generated by an electrode type boiler[1], designed to deliver 95 percent quality steam, at a maximum pressure of 600 psig and an output of 201,000 BTU/hr. A 1/4" O.C. steel pipe was used to connected the boiler to the steel box of the model. Fiber glass sheets and asbestos cloth were used as the insulating materials. Steam pressure was controlled by a 0-300 psig gauge.

Twenty thermocouples[2] were fitted on the side of the steel box to register temperature distribution in the pack. The thermocouples were connected to a scanner[3], which sent impulses to a digital thermometer[3]; a 24 hour clock[3] was used to recored the time of the measurement. These three instruments were connected to a printer[3], which recorded, three variables: thermocouple number, temperature, and time of recording. The samples were collected by a Misco[4] sample collector activated by a Misco[5] interval timer. Centrifuge tubes of 100 cc capacity were used to collect the samples when injecting solvent, but during steam injection, the large volumes of water produced (from steam condensation) made it necessary to use larger (500 and 1000 cc) tubes. Model 2 was connected to the same flow and

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[1] Electric Boiler Corporation of America, Worcester, Mass.

[2] Conax Corporation, Buffalo, New York.

[3] Digitex Corporation, Cayton, Ohio

[4] Micro Chemical Specialities Co., Berkeley, Calif.

[5] Eagle Signal Corp., Moline, Illinois.

measurement system. Figure 8 shows a sketch for this model, and Figure 9 gives detailed characteristics of the box. Four 7 inch long wells were used as production points, and one 2 inch well as the production point. These wells were made of a preperforated brass tubing covered with a wire mesh to avoid sand production. The four injection wells were connected to a main injection line. By closing a valve any section of the system would be isolated.

Twenty-one thermocouples were used in this model, twelve of which were seven inches long and nine of which were three inches long. The thermocouple located by the steam injection point was connected to a constant temperature recorder thermometer[1].

Sobrecarga

The most important feature of Model 2, was the presence of overburden pressure, simulated by the use of the axial pressure exerted by a rubber diaphragm, pressurized by silocone oil[2]. The oil was pumped from a Ruska oil pump[3] with a scale and micrometer to control the volume injected. Figure 10 shows the modifications for this model.

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[1] Conax Corporation, Buffalo, New York.

[2] Arthur H. Thomas Company, Philadelphia, Pa.

[3] Ruska Instrument Corporation, Houston, Texas.

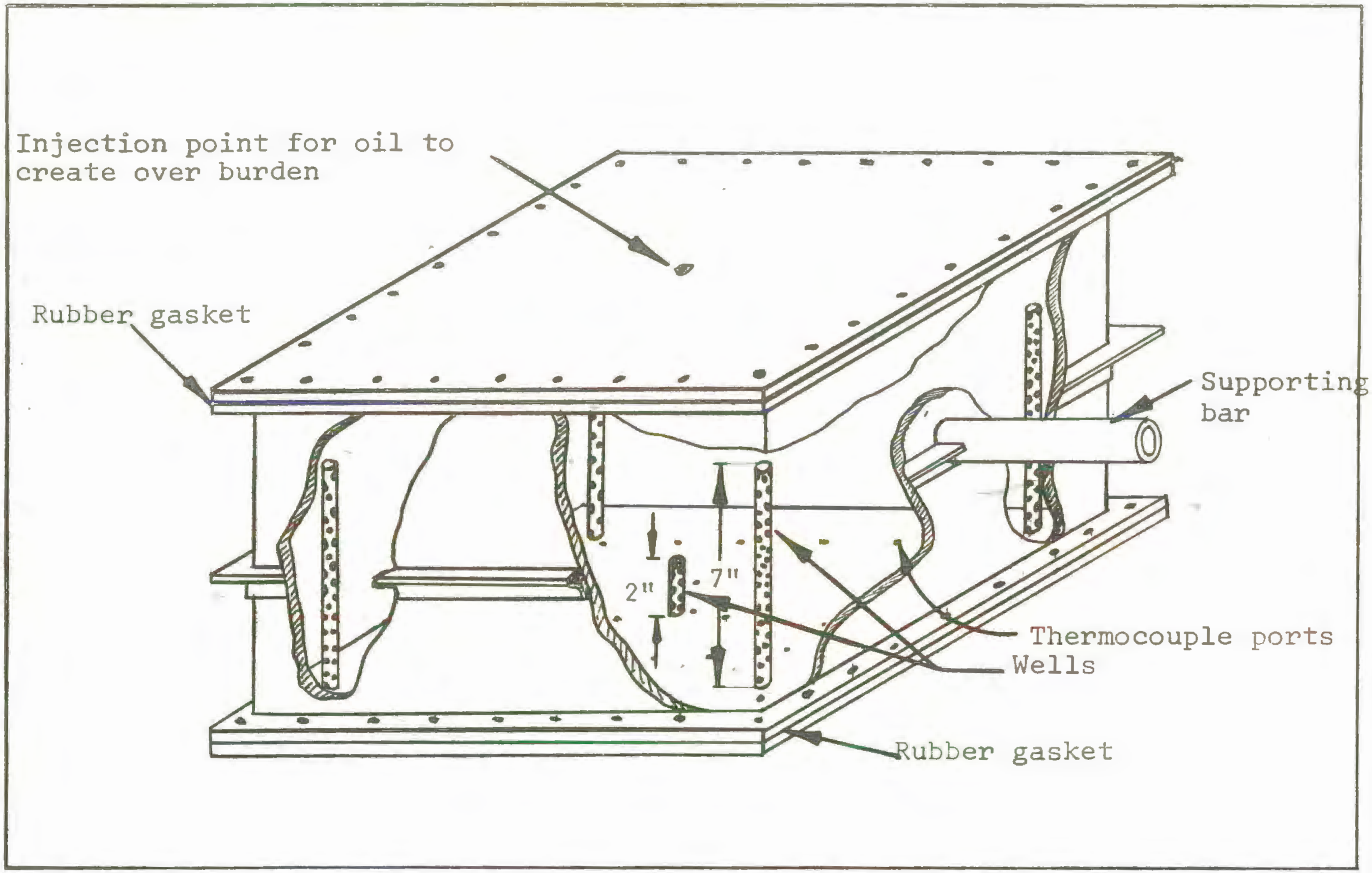


Figure 8 Sketch of Model 2.

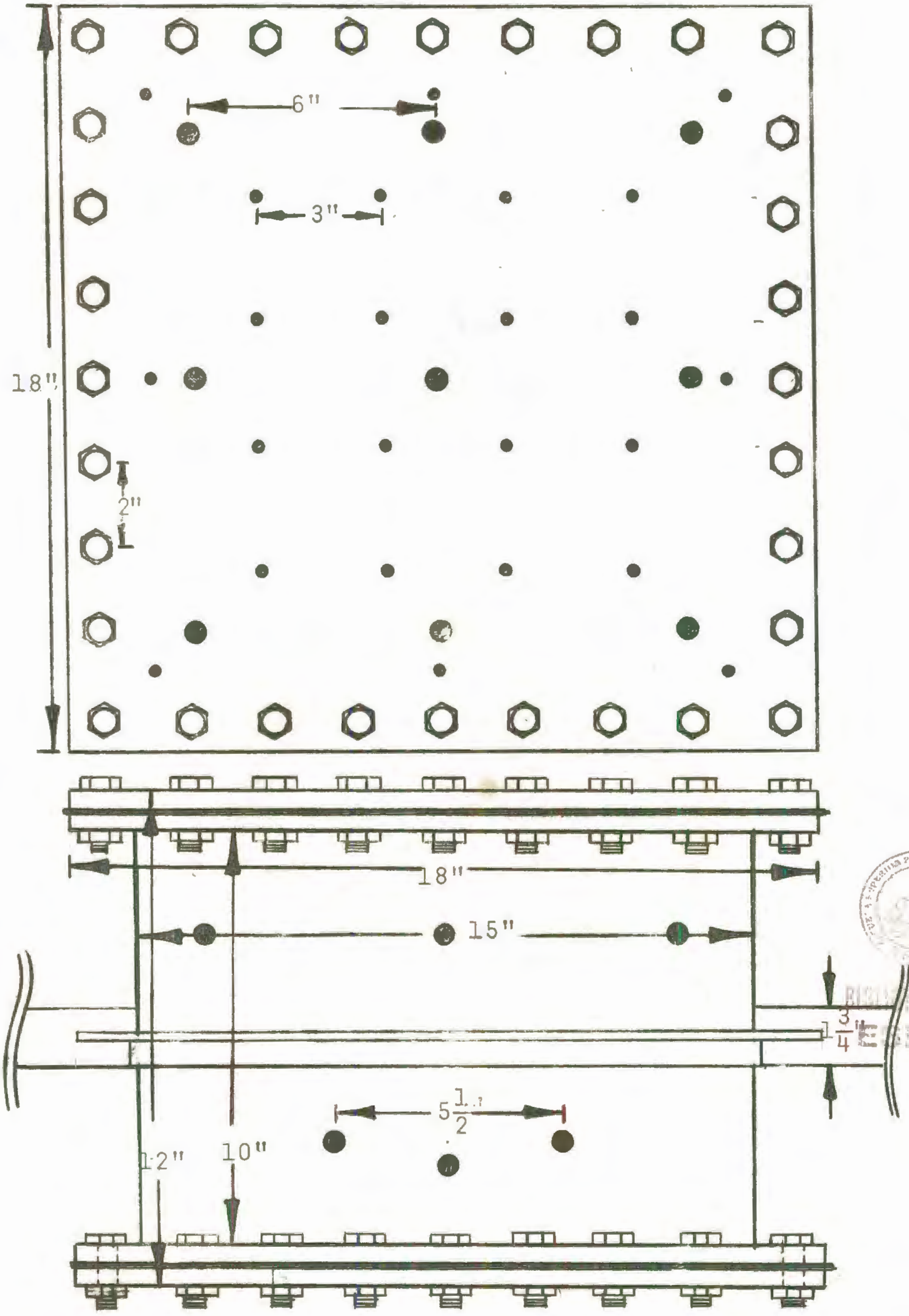
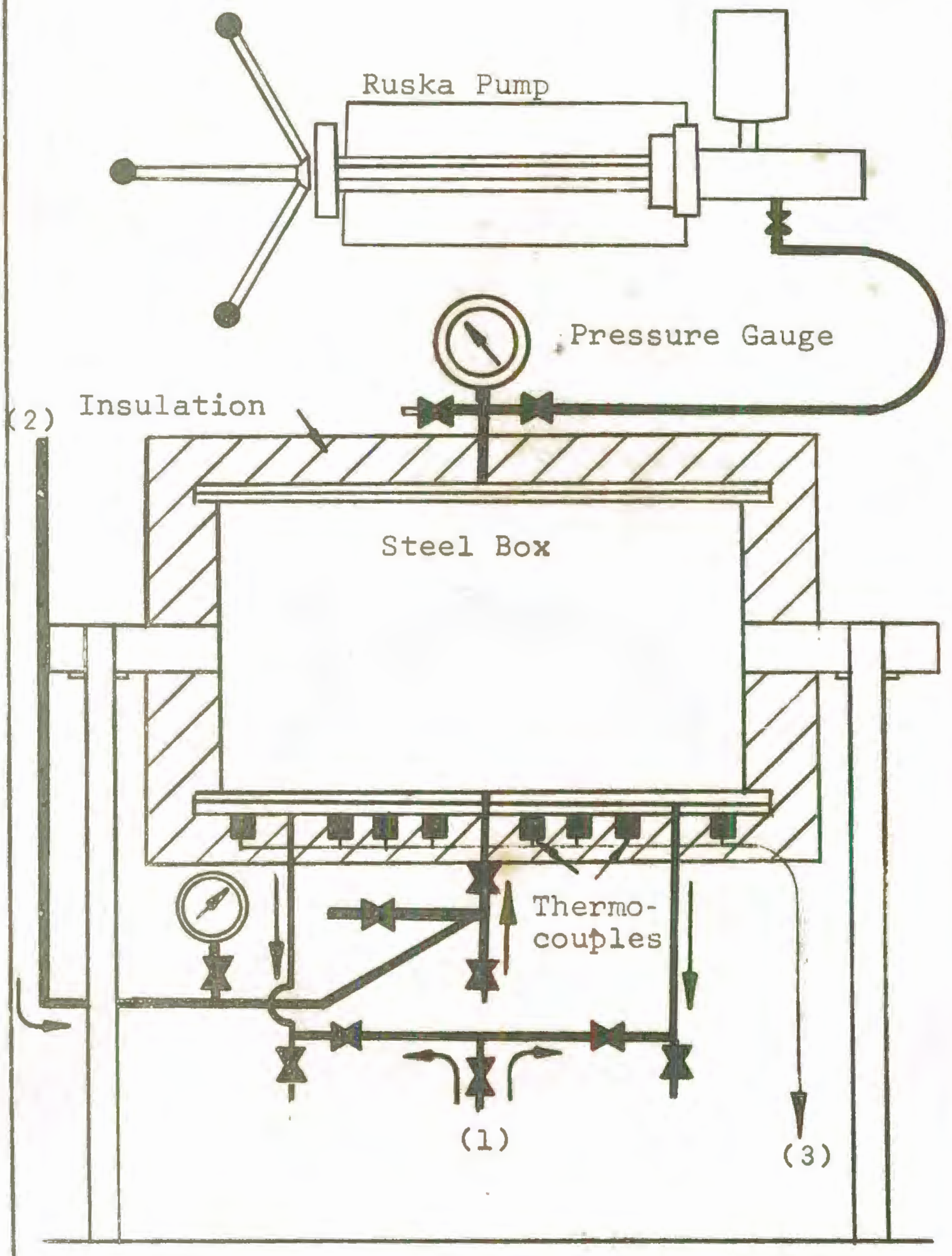


Figure 9 Plant and Side View of Model 2.



(1) From Solvent Pumps
(2) From Steam Generator
(3) To Point Scaner and Other Controls

Figure 10 Flow Diagram Modifications for Model 2.

Experimental Procedure

Solvent Injection Runs. Three different solvents were used: naphtha, Mobil solvent, and GCOS synthetic crude. In every case the tar sand was crushed and any rocks as well as other impurities were removed. The packing of the model was done manually. Solvent was injected at a very low flow rate through the injection points (through the top and bottom in Model 1 and through the bottom in Model 2). Injection was continued until no increase in solvent concentration was observed in the effluent samples. At times, the model outlet was closed and the model was pressurized for several hours. Production was then restarted. The effluent produced when injecting naphtha was recirculated.

Solvent-Steam Injection Runs. Two different procedures were followed when conducting solvent-steam runs. In one case, a solvent slug (three slug sizes were used, 45% PV, 20% PV, and 10% PV) was injected into the tar sands pack saturated with bitumen and air. Only GCOS synthetic crude and naphtha were used as solvents for such solvent-steam injection experiments. In the other case, a solvent slug was injected into the pack previously saturated with water and bitumen. Steam at different rates was injected into the pack in both cases. In some runs, the porous plates were removed from the injection and production ports. Also, in some suns, the solvent slug was injected into the steam injection well, while in others the slug was injected into the production well. Table 2 gives a summary of the run performed. When analyzing and collecting the samples from solvent-steam injection runs, it was necessary to add measured quantities of solvent to the samples collected, because the effluent produced was so viscuos that upon cooling, the tar remained in globules, or stuck to the walls, which made it impossible to read the volume produced. The average steam (as condensate) injection rate was calculated using the approximate method given by Farouq Ali and El-Saleh (13). This is as follows: After a run through a pack saturated with bitumen and water was completed, water was injected until 100% saturation of the pack was reached; then, the steam injected (as condensate) is given by the difference between the total effluent volume and the volume of the water used to saturate the pack after the run. This volume is divided by the time of steam injection to obtain the average steam injection rate. The technique is based upon a very simple material balance analysis:

V_{T_P} = Volume of total effluent produced.

V_{wp} = Volume of water produced.

V_{BP} = Volume of bitumen produced.

V_{Bi} = Volume of bitumen originally in place.

V_{wi} = Volume of water originally in place.

$V_{w_{inj}}$ = Volume of water injected to saturate the pack after a run was completed.

V_S = Volume of steam (as condensate) injected.

V_{W_R} = Volume of residual water in the pack.

V_{BR} = Volume of residual bitumen in the pack.

then,

$$V_{T_P} = V_{wp} + V_{BP} \qquad (1)$$

$$V_{w_{inj}} = (V_{wi}+V_{Bi}) - (V_{W_R}+V_{BR}) \qquad (2)$$

$$V_{BP} = (V_{Bi}-V_{BR}) \qquad (3)$$

$$V_{wp} = V_S+(V_{wi}-V_{W_R}) \qquad (4)$$

then replacing (3) and (4) in (1)

$$V_{TP} = (V_S+(V_{wi}-V_{W_R})) + (V_{Bi}-V_{BR})$$

recordering terms,

$$V_{TP} = V_S + \underbrace{(V_{wi}+V_{Bi}) - (V_{W_R}+V_{BR})}_{V_{w_{inj}}}$$

then,

$$V_{T_P} = V_S + V_{w_{inj}}$$

$$V_S = V_{T_P} - V_{w_{inj}}$$

$$q = \frac{V_{T_P} - V_{w_{inj}}}{t}$$

where: t = steam injection time)cc/min).

This method will hold also for the case when the tar sands pack is saturated with bitumen and air, the only change will be that

$$V_{wi} = 0.0$$

and the equations will have these forms:

$$V_{w_{inj}} = V_{Bi} - (V_{Br} + V_{wr}) \qquad (2')$$

$$V_{T_P} = V_S + (V_{Bi} - (V_{Br} + V_{wr})) \qquad (4')$$

then:

$$V_{T_P} = V_S + V_{inj}$$

$$V_S = V_{T_P} - V_{inj}$$

For the three-dimensional model, the procedure was almost the same. Only two runs were carried out using this model because of the complexity of handing this model.

After a run was completed, core samples were extracted from the models to determine residual bitumen saturation. The core samples were analyzed following the procedure described by Snyder (32). Core samples containing, bitumen, water, and solvent were removed from each one of the thermocouple ports. The samples were immediately placed in graduated tubes, to which known volumes of solvent were added. After mixing the solvent and the sand samples fluids, samples were taken to be analyzed by the infrared spectrophotometer. This gave the percentage of bitumen

Table 2

Classification of Run Types

Core saturated with air and bitumen solvent and steam injected through the steam-injection well.	Continuous steam injection	Solvent Saturation Experiments		1. GCOS synthetic crude
				2. Mobil solvent
				3. Naphtha
		Naphtha (with porous plates)		1. 900 c.c.(45% PV)[a]
				2. 400 c.c.(20% P)[a]
		GCOS Synthetic Crude	No porous plates	1. 900 c.c.(45% PV)[a]
				2. 400 c.c.(20% PV)[a]
				3. 200 c.c.(10% PV)[a]
			With porous plates	1. 900 c.c.(45% PV)[a]
				2. 400 c.c.(20% PV)[a]
				3. 200 c.c.(10% PV)[a]
	Cyclic steam injection, Naphtha (with porous plates)			900 c.c.(45% PV)[a]

Table 2 (continued)

Core sautrated with water and bitumen	Solvent and steam injected through the steam injection well		1. 900 c.c.(45% PV)[a]
			2. 400 c.c.(20% PV)[a]
			3. 200 c.c.(10% PV)[a]
	Solvent injected into the production well	Two dimensional model	1. 900 c.c.(45% PV)[a]
			2. 400 c.c.(20% PV)[a]
			3. 200 c.c.(10% PV)[a]
		Three dimensional model	1. 5647 c.c.(45% PV)[a]
			2. 1240 c.c.(10% PV)[a]

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[a] Refers to slug size.

present in the effluent. The samples were washed completely and dried in an oven. Again a measured amount of solvent was added to each sample and the volume was recorded. This yielded the volume of pure sand in the sample. This volume substracted from the total volume registered after the first addition of solvent gave the total liquid volume of the sample. Finally, multiplication of this volume by the bitumen percentage of the effluent analyzied gave the amount of bitumen in each sample. The value were expressed as residual bitumen saturation in weight percent. (Weight of bitumen divided by the weight of the core.)

These values as well as the temperature profiles for each run were contoured.

IV. PHYSICAL PROPERTIES OF THE ATHABASCA TAR SANDS

Brief Note on Tar Sands

Carrigy (6) and Bowman (5) made comprehensive studies on the physical, chemical, molecular and interfacial properties of the Athabasca tar sands. Carrygy (6) describes the sands as randomly interbedded, uncemented coarse-grained and fine-grained sand. Silt and poorly compacted clay make the correlation of these beds even in wells drilled at close spacing (200 ft. apart) difficult. He classified the sands as three types.

i. Poorly sorted coarse-grained quartzose sandstone and pebble conglomerates deposited in old river channels.

ii. Fine-grained well-sorted quartzose sands found in deposits characterized by small scale cross bedding of small deltas.

iii. Thinly bedded horizontal micaceous sands and silts, very poorly saturated with bitumen. These constitute the overburden.

Bowman (5) gives a complete discussion of the mineral content of the sands. He describes the sands as being predominantly quartz in the 30 to 325 mesh size, with large amounts of finely divided clays and small amounts of heavy minerals.

Carrigy also pointed out the existence of a thin coal layer interbedded with the tar sands deposits.

In the present study, clean samples of sand were observed and photographed. Figure 5, as well as many other pictures not included in this work, show the random classification of the grain size, as well as depositions of quartz and mica. Athabasca tar sands are unconsolidated sands; the cementing agent is the bitumen. When the bitumen is washed out, these sands become completely loose, which may help to explain the setting of the pack observed in some of the runs carried out. The density of the sand determined in the present study was 2.684 gm/c.c.

Bitumen Content and Loss of Weight

The literature gives a wide range of values for the bitumen content of Athabasca tar sands. Phizackerley and Scott (29) established that Athabasca tar sands have a bitumen content of 2 to 18% (by weight). Carrigy (7) established a content above 10% (wt.). Snyder (32) gave a value of 16.6% (wt.), but after exposing the sample to atmosphere, four days later, bitumen content is registered to be 12.6% (wt.). Hernandez (21), reported 14.58% (wt.) of bitumen originally in place.

It was decided that the bitumen content of the sands would have to be determined every time a run was made. Values were found to range from 16.5 to 13.5%. These values are plotted in Figure 11. Usually higher values of bitumen content correspond to fresh samples from recently opened barrels of tar sands, in two cases water in large amounts was found in the samples.

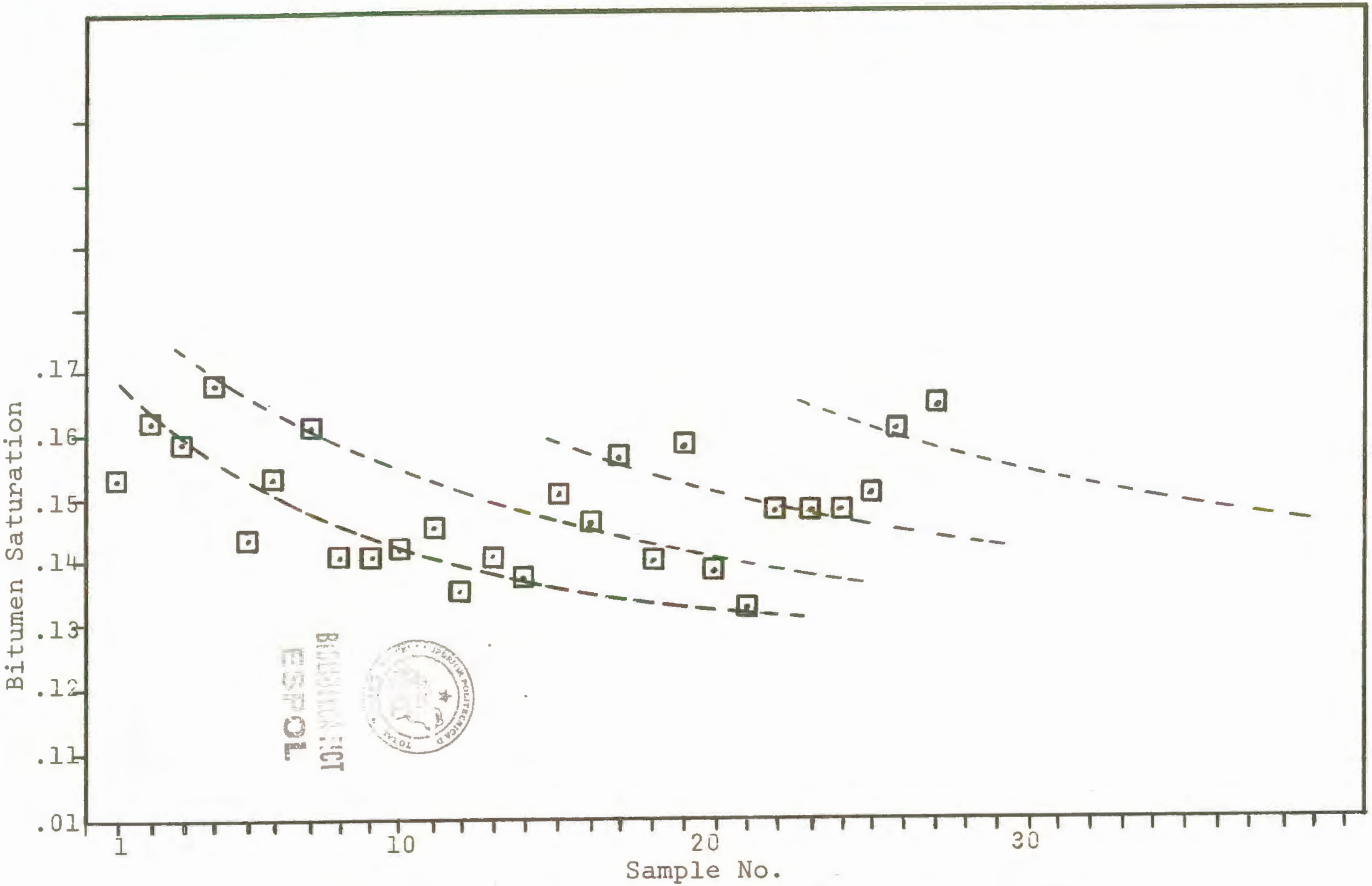

Figure 11 Bitumen Content of Samples Analyzed, Ordered In Time.

It is practically impossible not to expose tar sand to atmosphere, at least for several hours during the handling and packing of the model.

In order to determine how much of the light ends of the bitumen are lost due to evaporation, a fresh sample (sample 1; this sand was used from run 1 to 14) was removed from the 50-gallon barrel, which was properly closed. The sample was immediately weighed using an electronic balance[1]. There after, every 24 hours, its weight was recoreded until no further decrease in weight was observed. The sample was then completely washed and dried in an oven. The weight of the clean sand was substracted from the observed weights. This divided by the weight of the sample gave the bitumen content as a function of time. When beginning run 15 a new barrel of tar sand was opened, apparently the sand was much more plastic than the first, it was decided to perform again the loss of weight calculations, even though the original content of bitumen was lower than sample 1, this sample was more richer in lighter components. This can be easily seen in the graphic, sample 1 did not decrease below 15%, but sample 2 decreased up to 12.49% due to higher concentration in lighter components sample 2 appeared to be more plastic and richer in bitumen, due to evaporation, the lighter components tend to concentrate in the upper part of the barrel; also, a strong

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[1] Fisher Scientific Company, New York

smell of hydrocarbons was observed when opening the barrel. In both cases significant weight loss was observed during the first two days, later the loss of weight is no appreciable as can be observed from the graph. Figure 12 shows the loss of weight as a function of time.

Porosity

Porosity was determined by two different methods. First, from the weight of the pack, and second, from the cores withdrawn from the thermocouple ports. The first method is considered more accurate, and gave results which are in a narrow range.

The procedure was as follows:

W_{B_b} = Weight of the tar sand packed plus steel box, gm.

W_b = Weight of the steel box, gm.

V_b = Volume of the steel box, cc.

S_B = Saturation of tar in the sample (wt.%).

W_B = Weight of bitumen, gm.

W_s = Weight of pure sand, gm.

d_s = Density of sand, gm/cc.

d_B = Density of bitumen, gm/cc.

V_e = Empty space in the steel box, cc.

W_{SP} = Weight of tar sand packed, gm.

$$W_{SP} = W_{B_b} - W_b$$

$$W_B = S_b \cdot W_{SP}$$

$$V_B = W_B/d_B$$

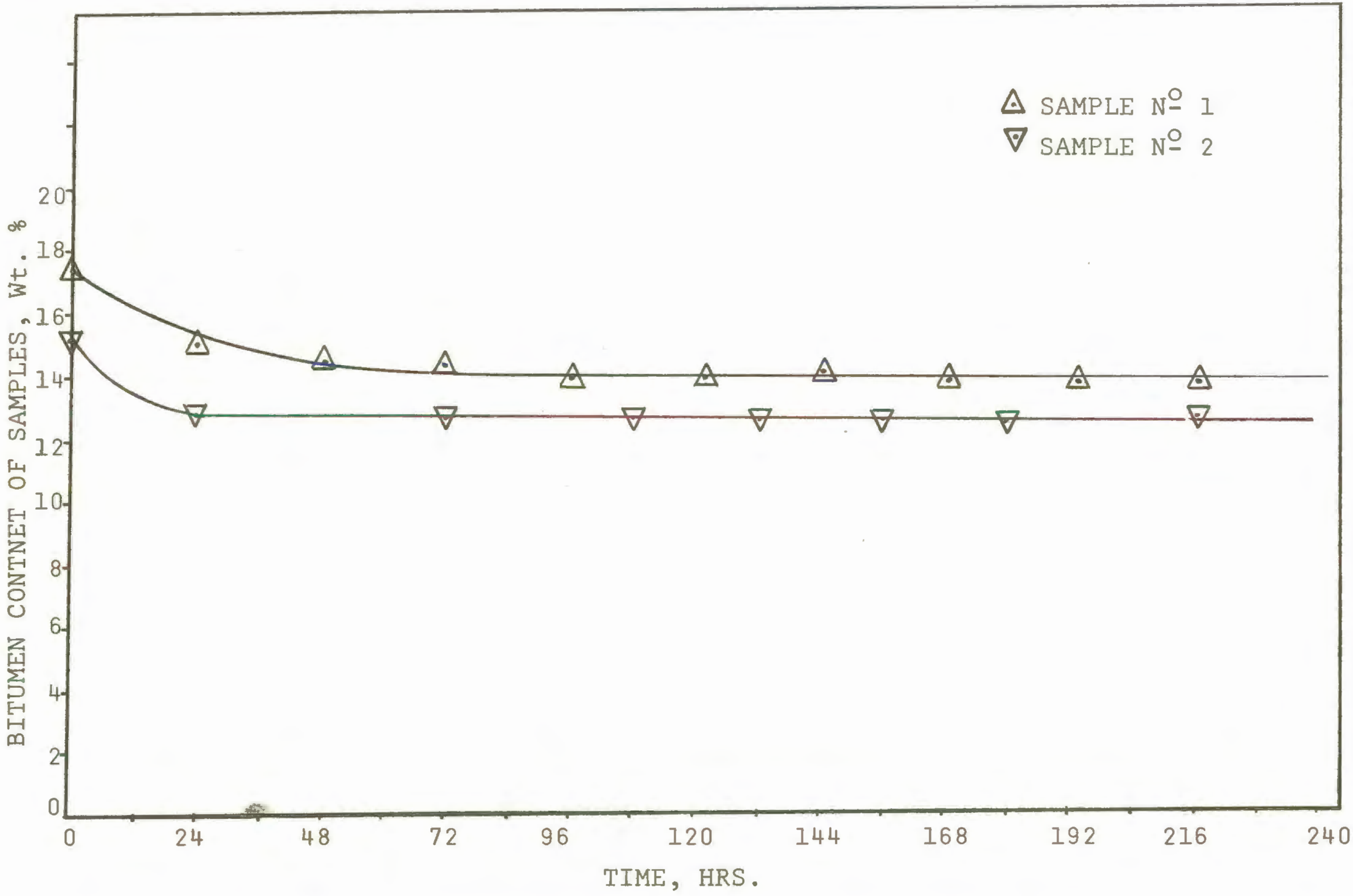

Figure 12 Loss of Weight with Time of Expossure to Air.

$$W_s = W_{SP} - W_B$$

$$V_s = W_s/d_s$$

$$V_e = V_b - (V_s + V_B)$$

$$\text{Pore Volume} = V_\phi = V_B + V_e$$

$$\phi = \frac{V_\phi}{V_b}$$

As can be implied porosity is dependent on the degree of compaction of the tar sand when packing the model. Another way to determine porosity was measuring the volume of the cores withdrawn from the thermocouple ports. This method is not accurate. It gave too wide a range of porosity values to make any sense. Results from both methods are presented in Figure 13.

<u>Specific Gravity of Bitumen and Solvents Used</u>

<u>Specific Gravity of Bitumen</u>. The specific gravity of bitumen was determinedusing a procedure outlined in the "Standard Methods for Testing Petroleum and its Products" ASTM designation IP 59/49.

Specific gravity is given by the formula

$$\text{Sp. Gr} = \frac{W_{P_s} - W_P}{W_W - W_{psw} + W_{P_s}}$$

where:

W_{P_s} = Weight of the pycnometer and bitumen

W_P = Weight of the pycnometer

W_w = Water equivalent

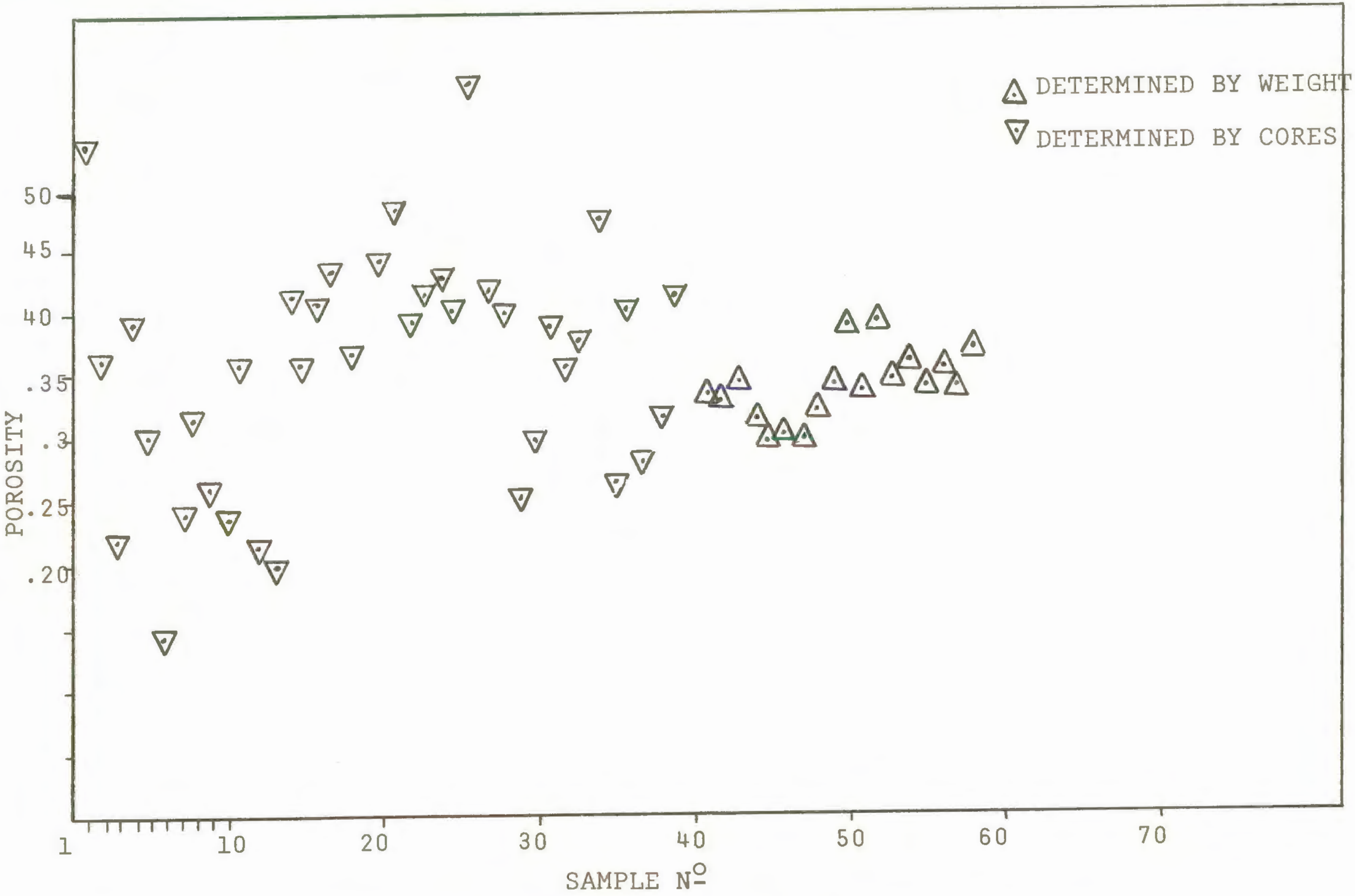

Figure 13 Porosity Determined from Weight and Coring.

The reason for this "water equivalent," is that it is not possible to completely fill up the pycnometer with bitumen. Freshly distilled water is added to fill up the pycnometer and the whole system is weighed. The difference between this weight and W_{P_s} gives W_n.

W_{P_sw} = weight of the pycnometer filled up with distilled water

Using the above method, a value of 1.0397 was obtained, which is in good agreement with the value obtained by Hernandez (21) (1.0318) and Carrigy (6) (1.0318). The measurement was made at room (78°F) temperature.

Specific gravity of Solvents. The hydrometer was considered to be accurate enough for all these determinations. This method is classified as ASTM-D1298-67 (also API standard 2547, IP designation: 160/68).

Specific gravity of the solvents was also measured using a 10 c.c. glass pycnometer. Good agreement was found between these two methods.

Specific gravity, as well as other physical properties of the solvents used are presented in Table 3.

Viscosity Studies

Viscosity of Solvents Used. The viscosities of the solvents used was determined by means of Oswald viscosimeters. The principle of operation of these viscosimeters is based upon Poiseulle's law of fluid flow in capillary tubes. It is an indirect measurement, because it is necessary to conduct the experiment first with a fluid of known viscosity (distilled water). The flow times for equal amounts of the liquid of known viscosity, and the fluid to be measured are recorded and the following relationship is established:

$$\frac{\mu_1}{\mu_2} = \frac{d_2 \; t_2}{d_1 \; t_1}$$

where:

μ = Viscosity in centipoises

d = Density, gm/cc

t = time of flow, sec.

The subscripts 1 and 2 indicate the known and unknown fluid respectively. The density was previously determined using a precision balance and a glass pycnometer. All these measurements were conducted at a temperature of 86°F. Several viscosimeters were used and the values averaged; this value is also reported in Table 3.

<u>Viscosity of Athabasca Bitumen</u>. In order to obtain bitumen for these experiments, it was necessary to extract tar sand with toluene, and later using a distillation column, the toluene was separated from the bitumen. This procedure was followed until 1000 cc of bitumen were obtained.

Table 3

Some Physical Properties of the Solvents Used

Solvent	Density gm/c.c.	Specific Gravity	Color	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	Colorless	0.4482	All proportions

Experimental Procedure

A large sample of bitumen was heated and poured into a 500 c.c. beaker and the whole system was placed in a constant temperature bath. Temperature was steadily increased until viscosity for the Athabasca bitumen in the desired range was obtained.

Later, three large samples of bitumen were placed in three different 500 c.c. beakers. First, a volume of solvent equivalent to 10% of the bitumen in the beaker was added. This was done for the three solvents. Viscosity of each sample was measured containing 10% of Naphtha, Mobil solvent and the GCOS synthetic crude respectively. The measurements were made between 82°F and 360°F.

Later, the solvent concentration was increased to 20% and so on, until the desired range of solvent concentrations was covered (10 - 80%). The handling of the GCOS synthetic crude bitumen, and Mobil solvent-bitumen mixtures is not difficulty, because these two solvents have a relatively high boiling point. This is not so for naphtha, which has a low boiling point. It was necessary to prepare fresh samples for every measurement. Because of the losses due to evaporation of naphta, it was necessary to make constant corrections in order to have the correct volume.

Analysis of Results

It was impossible to determine viscosity of the bitumen at 82°F (room temperature), Carrigy (6) reports viscosity of the Athabasca bitumen to be 600,000 poise at 150°F.

Figure 14 was constructed varing the temperatures from 120°F to 380°F. The range of viscosity variation was 32.5 cp (380°F) to 96,500 cp (120°F). Table 4 gives the complete experimental data obtained. As expected (the relationship between viscosity and temperature is exponential for most materials except some suspensions), and exponential type curve was obtained. The experimental values obtained were plotted on semi-log paper as shown in Figure 14.

Kinematic viscosity is defined as the quotient of dynamic viscosity divided by density. When plotted on a special graph paper (ASTM standard viscosity-temperature charts for liquid petroleum products) the relationship between kinematic viscosity and temperature is a straight line. Figure 15 shows this relationship. It is important to notice that it was not possible to measure the density of bitumen at high temperatures. As a result the value of density used in this experiment was that determined at room temperature (1.0370 gm/c.c.). At temperatures above 300°F the data do not fit the straight line shown in Figure 15.

Figure 14 shows that the most significant reduction in viscosity was registered between 120°F and 200°F, viscosity reductions above 300°F are not so significant, and above this temperature the process is much more difficult to handle, becuase of the instability of the solutions (due to the high temperatures solvent evaporation is strong, and the solutions are constantly changing its

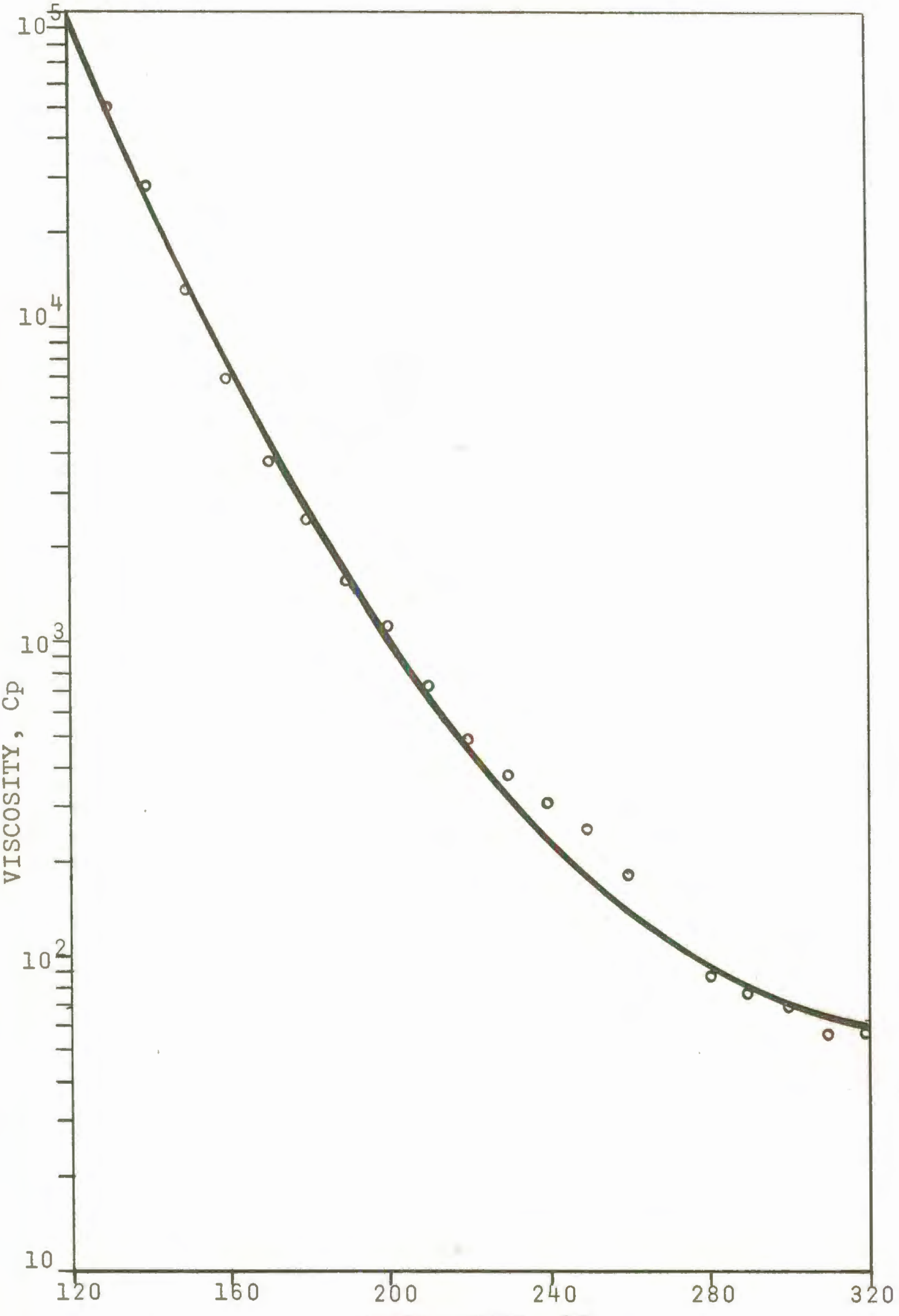

Figure 14 Viscosity-Temperature Curve for Athabasca Bitumen.

Table 4

Viscosity and Kinematic Viscosity Variation with Temperature for Athabasca Bitumen

Temperature (°F)	Viscosity (cp)	Kinematic Viscosity (c. Stokes)
380	32.5	31.4
360	35.0	33.8
350	30.0	29.0
340	37.5	36.2
330	50.0	48.3
320	56.2	54.3
310	57.5	55.8
300	70.0	67.6
290	75.0	72.5
280	87.5	84.6
270	-	-
260	187.5	181.2
250	255.0	246.5
240	307.0	297.0
230	381.0	368.2
220	500.0	483.3
210	630.0	608.9
200	1125.0	1087.0
190	1570.0	1517.0
180	2500.0	2416.0
170	3880.0	3750.0

Table 4 (continued)

Temperature (°F)	Viscosity (CP)	Kinematic Viscosity (C. Stokes)
160	7000.0	6765.0
150	13300.0	12855.0
140	24300.0	28320.0
130	49900.0	48231.0
120	96500.0	93272.0

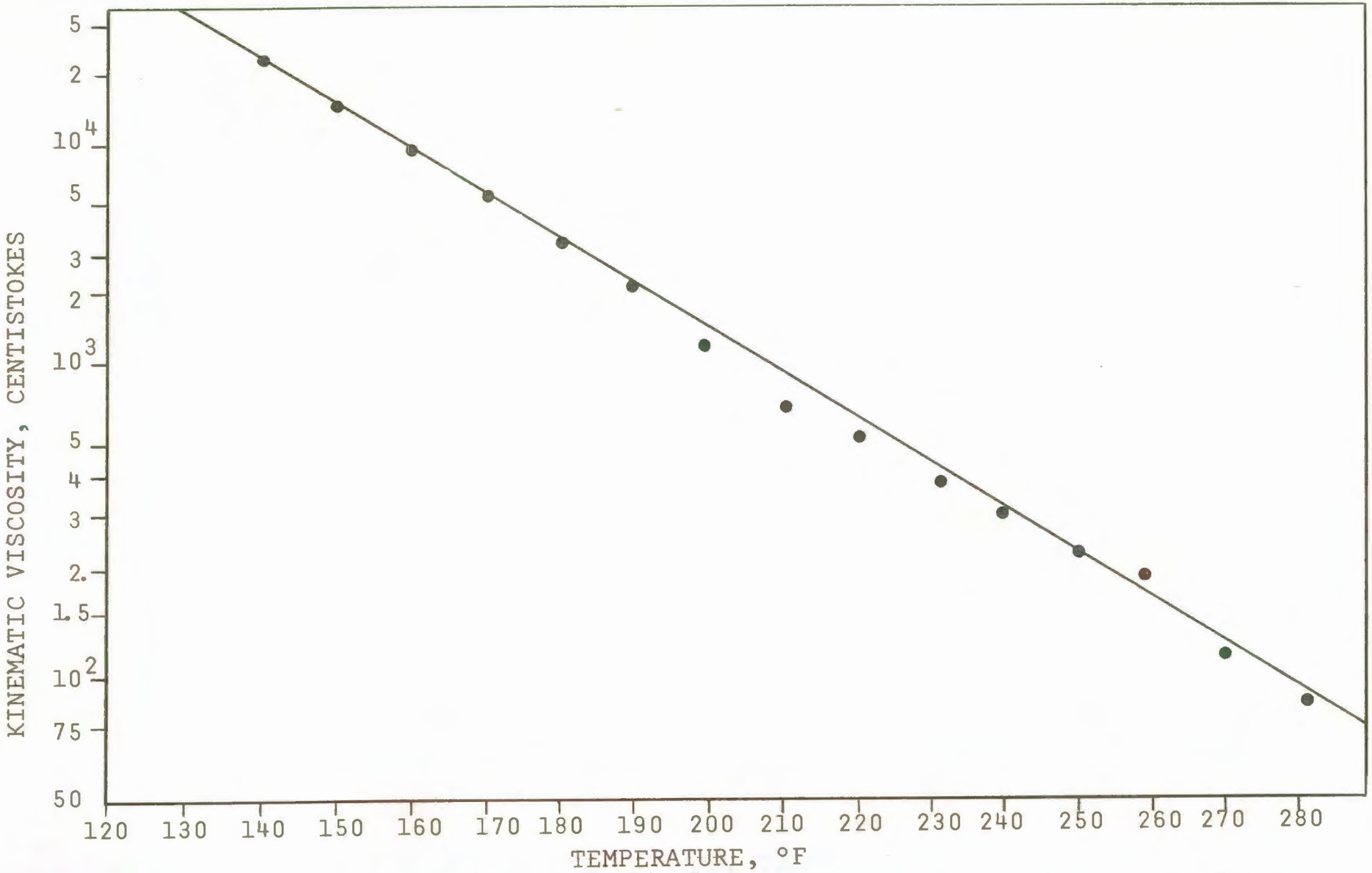

Figure 15 A.S.T.M. Standard Viscosity-Temperature Graph for Athabasca Bitumen, Kinematic Viscosity.

solvent concentration), heating of the instrument, and mainly becuse many times the solutions reached boiling point (for concentrations of solvents above 20%).

The graphs shown in Figures 16 through 21 were plotted to study the behavior of Athabasca bitumen at various temperatures, for various kinds of solvents, and solvent concentrations.

The behaviors of the GCOS synthetic crude and Mobil solvent were found to be very similar, and viscosity changes for identical conditions of concentration and temperature were found to be more pronounced for the Mobil solvent than for the GCOS synthetic crude, for all ranges of concentrations and temperature. Figure 19 is a comparision of these curves. An analysis of these curves shows that the three solvents used were effective in reducing the viscosity of Athabasca bitumen, even for small solvent concentrations and temperature increases.

Naptha gave greater viscosity reductions for all concentrations above 10% (solvent). It can be seen from Figure 19 that 60% naphtha concentration gives higher viscosity reductions that 80% concentration of Mobil solvent or GCOS synthetic crude for all ranges of temperature.

For low solvent concentrations (10%, 20% and 30%), at high temperatures (above 240°F), the curves representing viscosity-temperature relationships (at constant solvent concentration) tend to be similar implying that at high temperatures the nature and amount of solvent are not important. This is so, because at high temperatuees naptha is vaporized and does not help much in lowering viscosity. (It must be understood that the experiment was at 14.6 psia.) This is not so for the GCOS synthetic crude and Mobil solvent, which have high boiling points, but in any case the effect of temperature upon viscosity is much more drastic than the effect of solvent concentration increase, especially for low solvent concentrations, which are more likely to occur in a field project.

Figures 19, 20 and 21 show the curves obtained for viscosity-solvent concentration relationship for a constant temperature. From these curves, it is possible to observe again the effect of temperature. Take for example Figure 19, when the temperature is low, 82°F, up to 180°F, viscosity is significantly lowered by solvent addition but above this temperature, viscosity is indeed lowered but not as much. Now, consider Figure 21 (naptha-bitumen), the behavior is completely different, because at 200°F (this was the highest temperature at which sufficient data to plot the curve were available) the reduction in viscosity by adding small amounts of solvent is still very important. Unfortunately, it is difficult to obtain reliable data at high temperatures and high naphtha concentrations. In any case, when temperature goes above 200°F, naphtha does not remain in solution with bitumen, since the measurements were not made under pressures.

During these experiments it was observed that naphtha does not dissolve bitumen upon immediate contact, and it is necessary to stir and agitate the fluids strongly in order to have a good solution. A simple experiment was conducted to observe the rate of reaction of bitumen with each solvent. Small samples of bitumen were placed on filter paper, and the solvent was added to each.

Naphtha had low reaction with bitumen and the solvent was dispersed through the paper without carrying any bitumen, with GCOS synthetic crude the reaction was faster, but Mobil solvent it was extremely fast.

Conclusions

1. Analysis of the curves show that the three solvents used work well in reducing viscosity of the Athabasca bitumen.
2. Naphtha gave higher viscosity reductions for all ranges of temperatures and concentrations, except at 10% (and below) where the three solvents gave almost the same viscosity reductions.
3. For temperatures above 240°F solvent concentrations of 10%, 20% and 30% tend to lower viscosity by almost the same amount.
4. It can be said that temperature causes a greater viscosity reduction than moderate concentrations of a solvent.
5. It was observed that the velocity of solution between solvent and bitumen was related to the

color of the solvent, the darker was Mobil solvent, then GCOS synthetic crude, and finally naphtha; the velocity of bitumen solutions was of the same order.

6. Naphtha-bitumen solutions became unstable above 200°F.

Apparatus

Viscosity was measured using a Brookfield synchro-lectric Viscometer[1] model LVF, with a maximum range of 0-100,000 cp, and a minimum range of 0 - 10 cp (the last one is obtained using a special adaptor) (UL adaptor). The principle of operation is simple: the viscometer rotates a cylinder or disc in a fluid and measures the torque necessary to overcome the viscous resistance to the induced movement. The immersed element which is a spindle, registrates the degree of this torque through a beryllium copper spring which is shown on the viscometer dial by a red pointer. The degree of deformation is proportional to the viscosity of the fluid for any given rotational speed and spindle size. The model used has four different rotational speeds of 6, 12, 30 and 60 RPM, and four spindles.

Viscosity was measured at four rotational speeds to obtain a better value for the desired viscosity and also to evaluate the rheological properties of the material, because a basic requirement for good measurements is that

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[1] Brookfield Engineering Laboratories Inc., Stoughton, Mass.

Table 5

Data for Figures 16, 17, and 18

Temperature °F	Viscosity (cp.)					
	10% (Solv. Con.)			20% (Solv. con.)		
	Syncrude	Mobil Sol.	Naphtha	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

Table 5 (continued)

Temperature °F	Viscosity (cp.) 10% (Solv. Con.) Syncrude	Mobil Sol.	Naphtha	20% (Solv. Con.) Syncrude	Mobil Sol.	Naphtha
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

Table 5 (continued)

Temperature °F	Viscosity (cp.) 40% (Solv. Con.) Syncrude	Mobil Sol.	Naphtha	60% (Solv. Con.) Syncrude	Mobil Sol.	Naphtha
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	867	164	110	65	10.2

Temperature °F	Viscosity 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	-	-

Table 5 (continued)

Temperature °F	Viscosity 80%(Solv. Con.)			
	Syncrude	Mobil Sol.	50% Naphtha	30% Naphtha
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

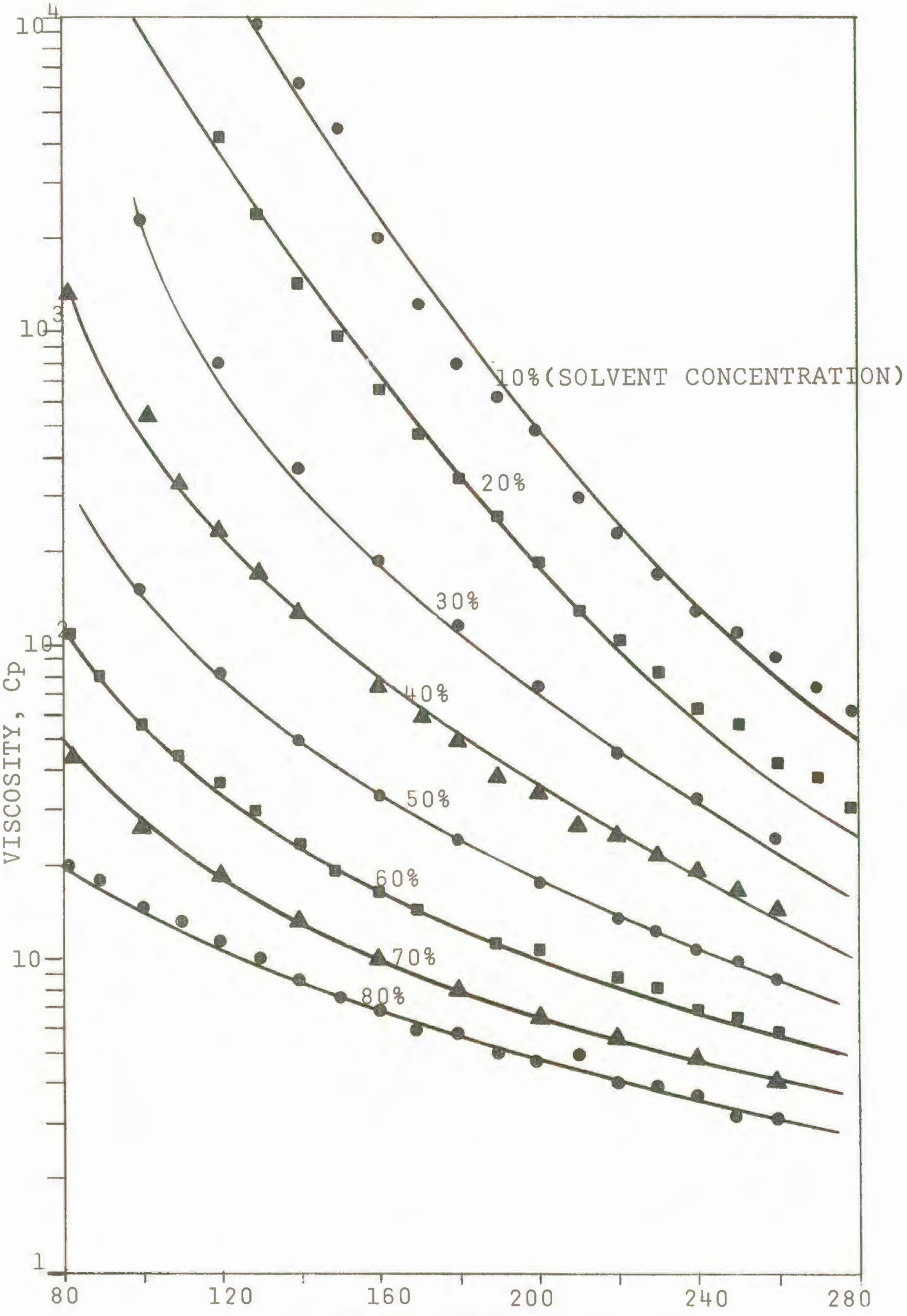

Figure 16 Viscosity-Temperature Graph for Bitumen-Syncrude Solutions.

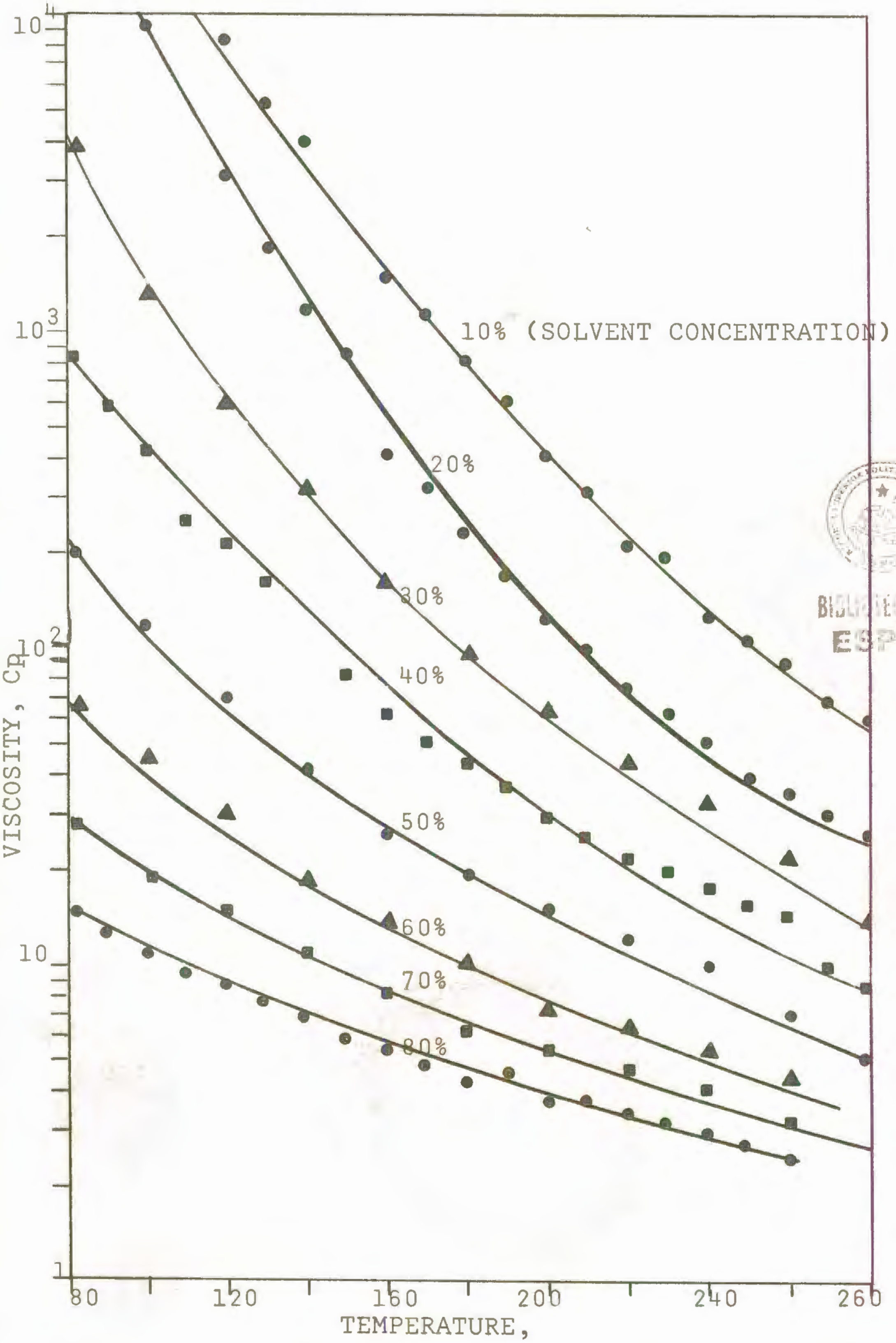

Figure 17 Viscosity-Temperature Graph for Bitumen-Mobil Solutions.

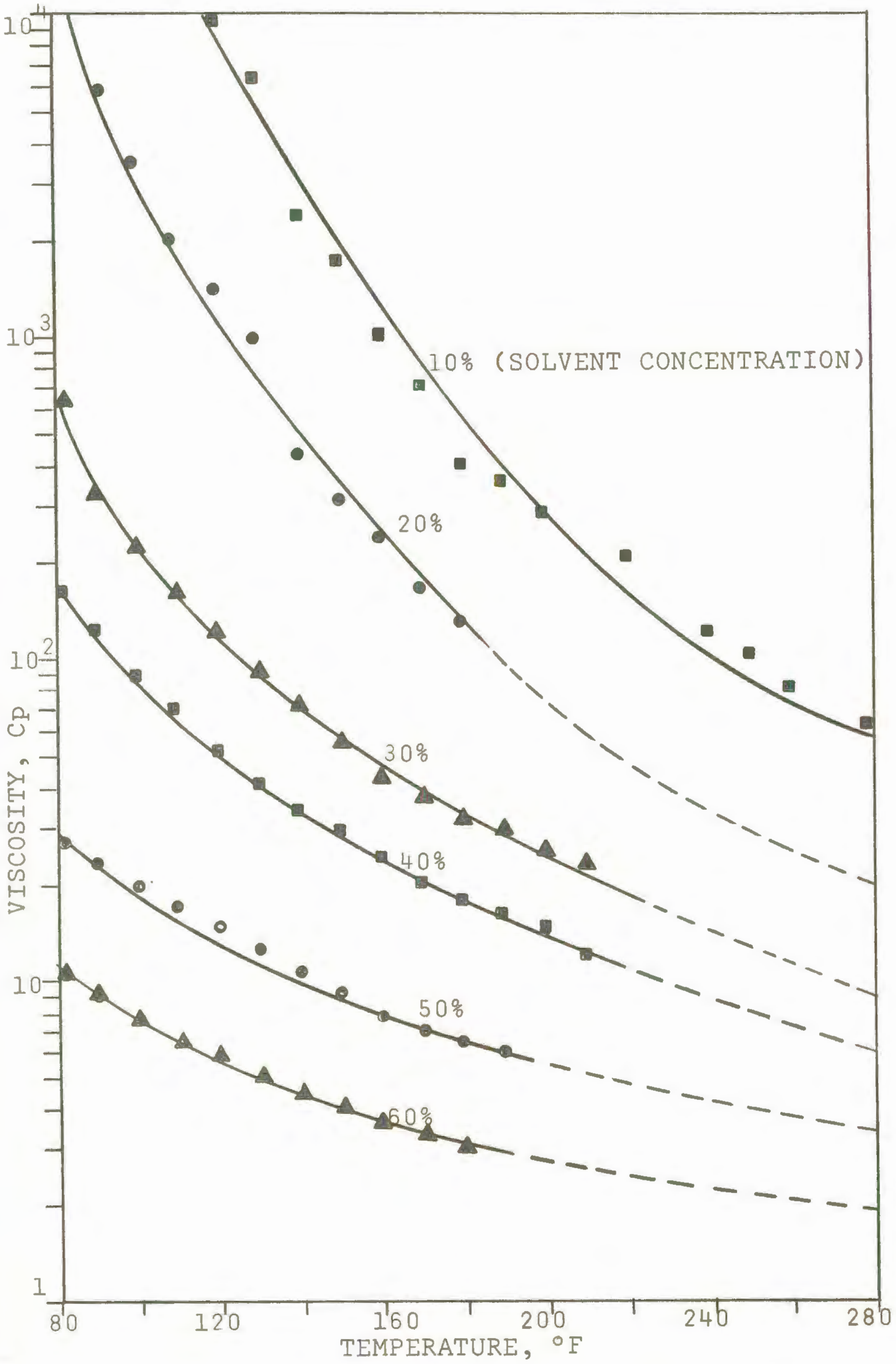

Figure 18 Viscosity-Temperature Graph for Bitumen-Naphtha Solutions.

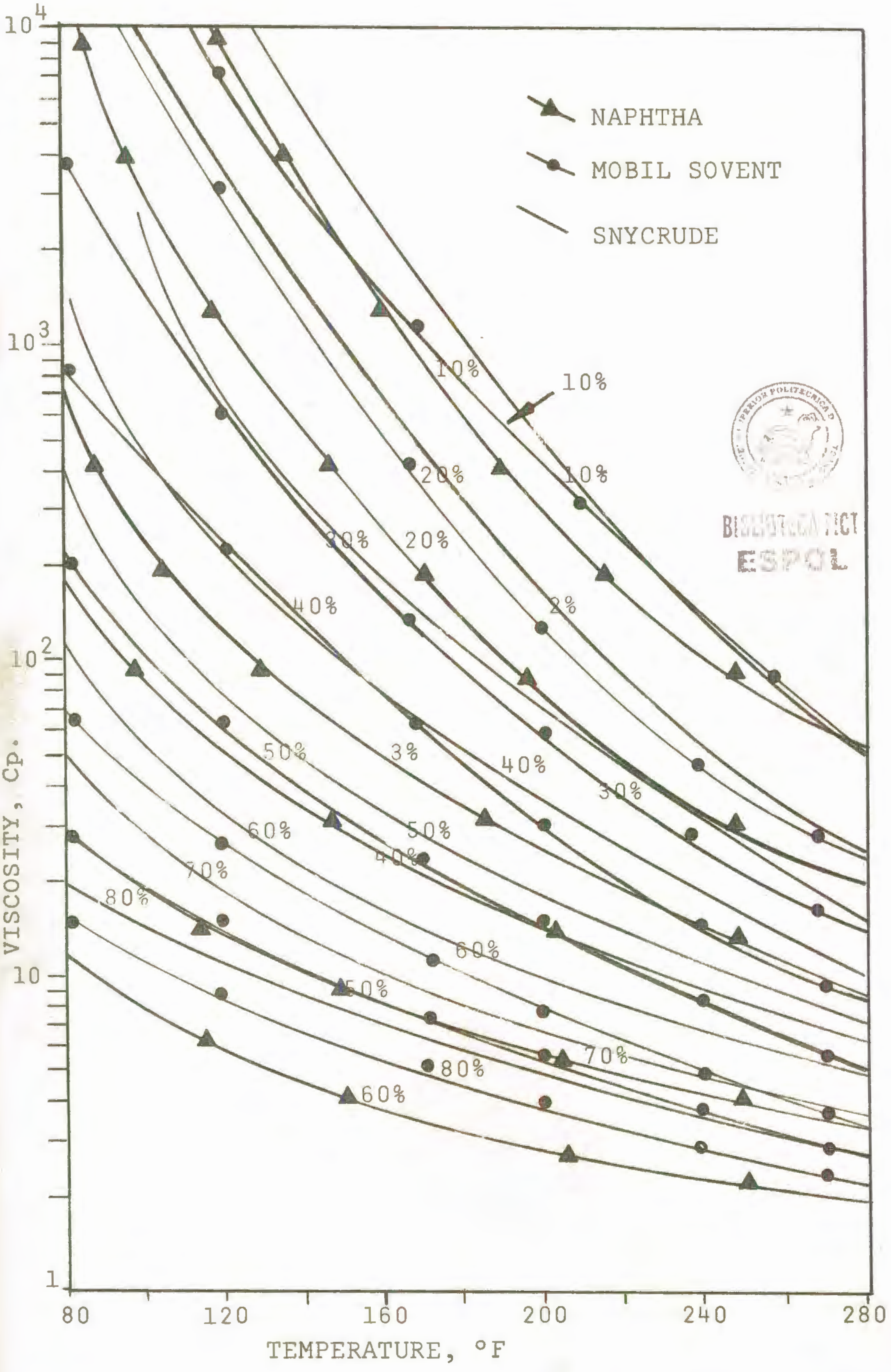

Figure 19 Comparison of the Viscosity-Temperature Graphs.

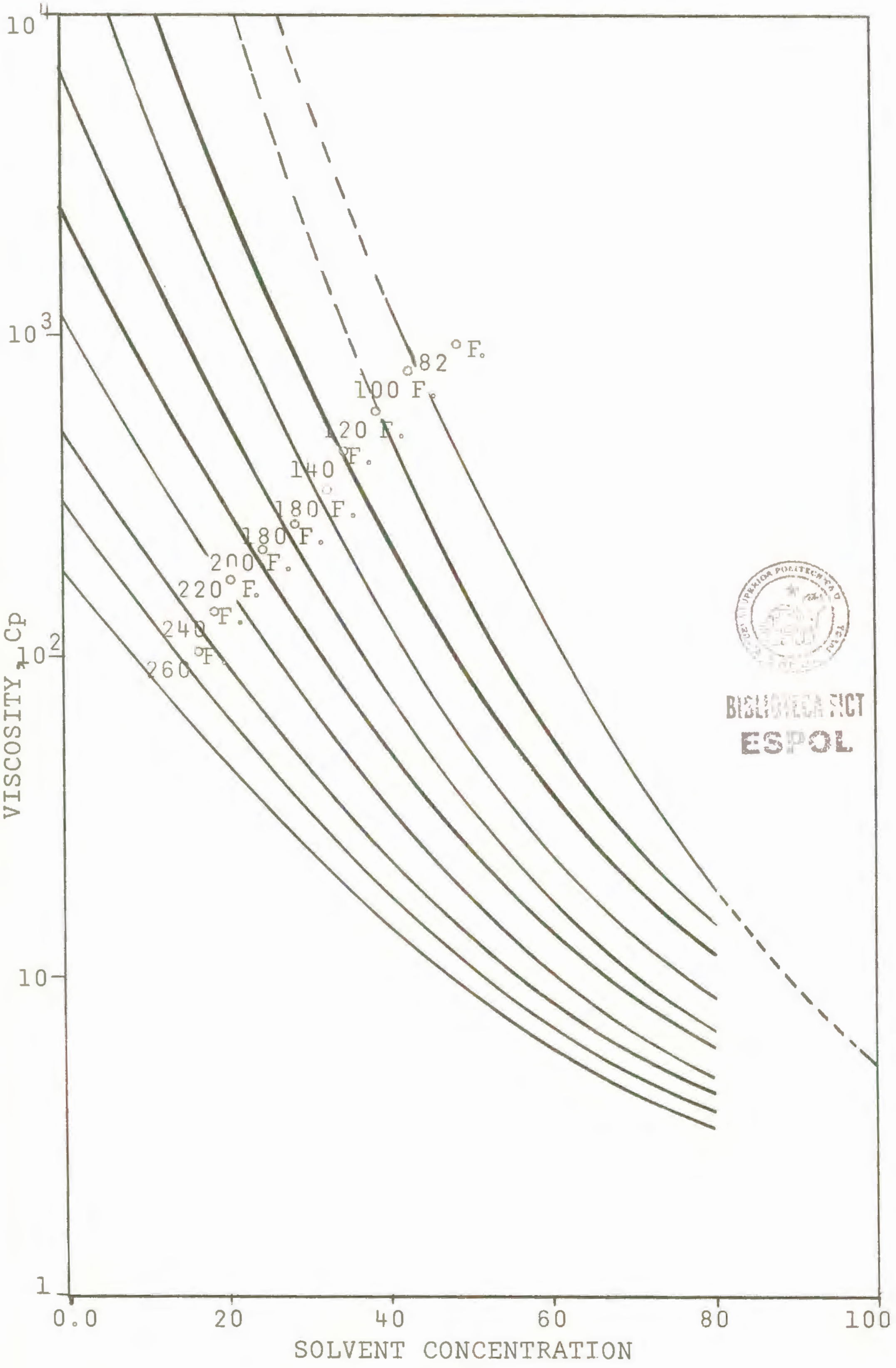

Figure 20 Viscosity Change with Increasing Syncrude Concentration.

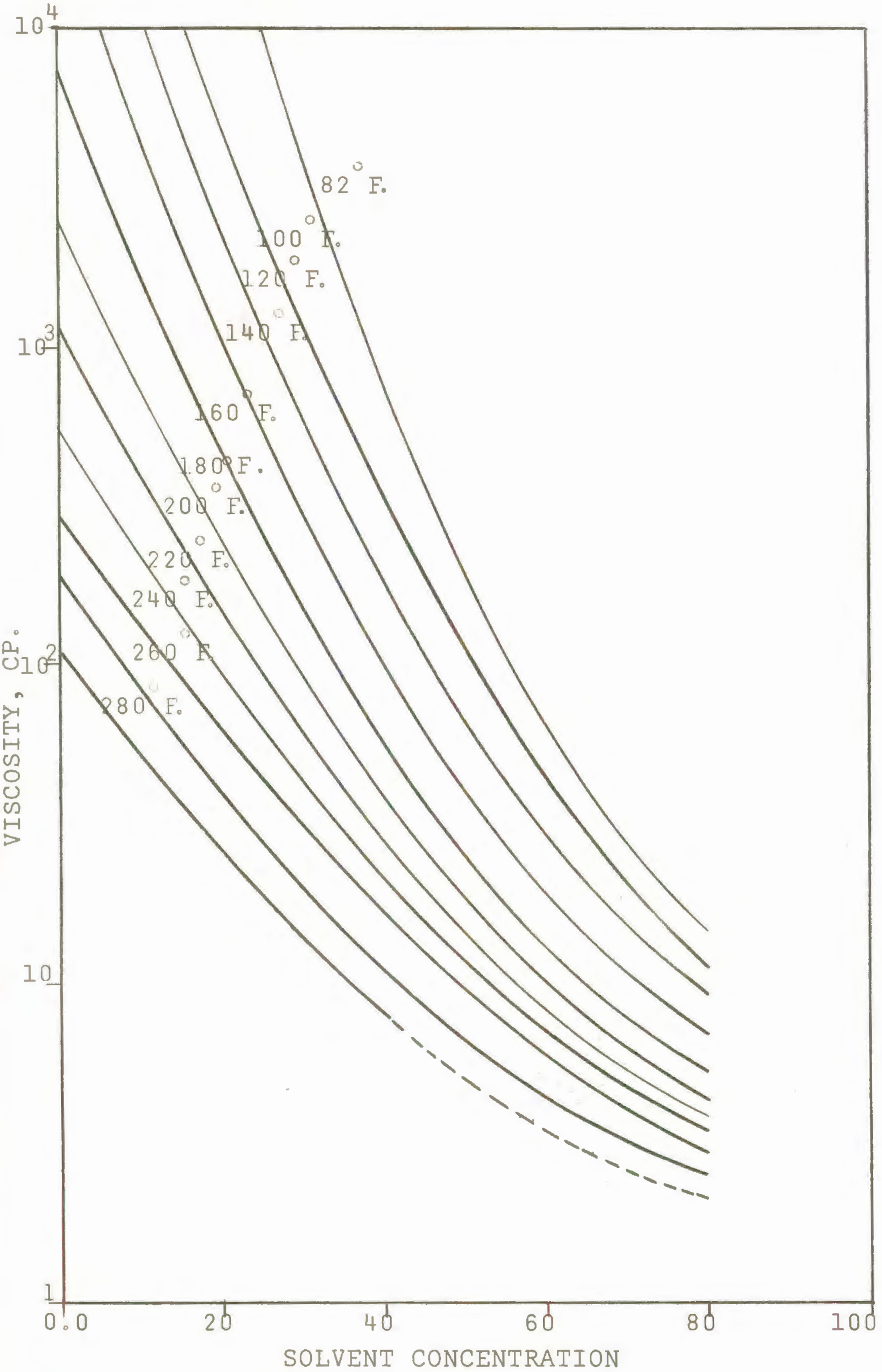

Figure 21 Viscosity Change with Increasing Mobil Solvent Concenration.

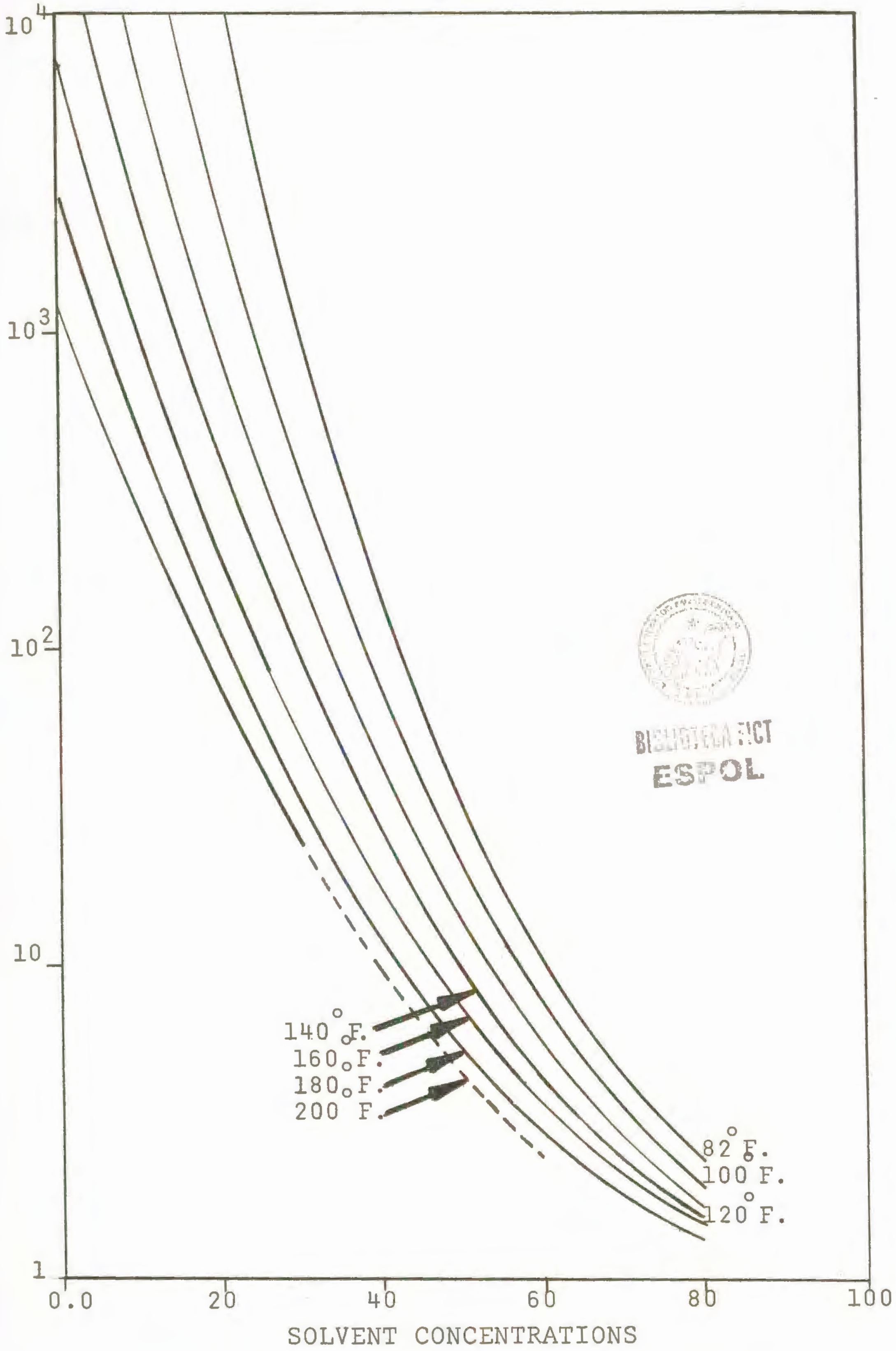

Figure 22 Viscosity Change with Increasing Naphtha Concentration.

the fluid should be Newtonian, i.e., the relationship between the shear force (F') and the rate of shear (s) should be a straight line.

The instrument gives measurements with an accuracy of ± 1%.

A silicone oil constant temperature bath was used to maintain the temperature at the desired level. A stove[1] with a temperature regulator was also used to obtain a finer control of temperature adjustments. The temperature was measured with a 0 - 500° F range thermometer.

Figure 23 shows a schematic representation of the apparatus used for viscosity measurements.

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[1] Lab-Line Instruments, Inc., Melrose Park, Illinois.

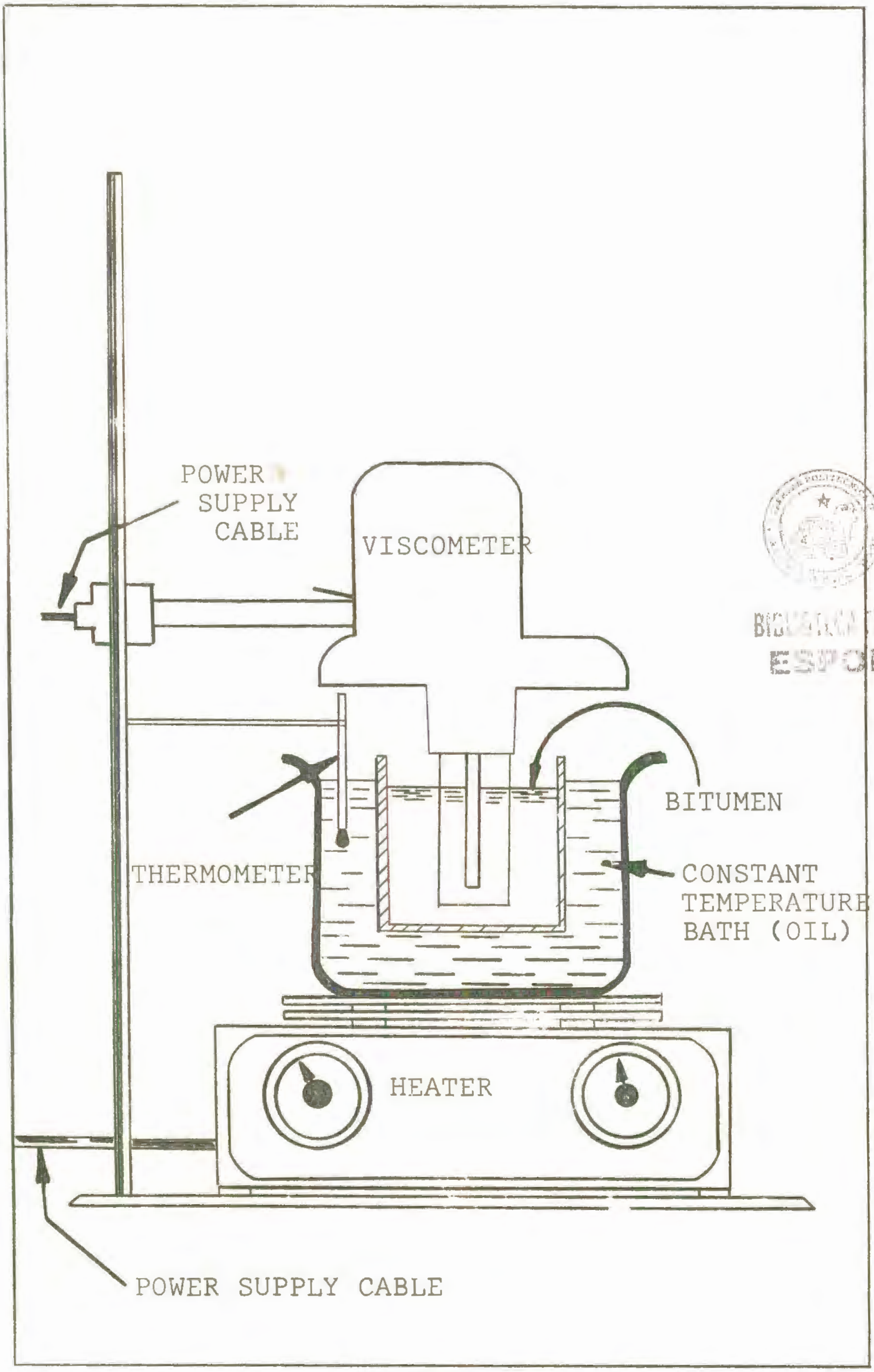

Figure 23 Schematic Drawing of the Viscosity Measurement Apparatus

V. METHOD OF ANALYZING THE LIQUID SAMPLES

Brief Description of the Theoretical Foundations of Spectrophotometric Analysis

The liquid samples of effluent were analyzed using a Perkin-Elmer[1] infrared spectrophotometer.

Some of the theoretical foundations of infrared spectrophotometry will be disclosed. Infrared radiation is a portion of the electromagnetic spectrum. Infrared radiation as well as all the other types of radiation, are light energy waves moving in accordance with the law:

$$\lambda \dot{\nu} = c$$

where:

λ = wave length of the light in cm.

$\dot{\nu}$ = frequency in cycles per second.

c = velocity of light

The units used for measuring the position in the infrared range of the electromagnetic spectrum are, the wave length (λ) unit, the micron (μ) ($1\mu = 10^{-4}$cm $= 10^{4}$ Å), and the frequency or wavenumber (ν) unit, waves per cm. which is written as cm^{-1}.

When radiant energy falls upon a transparent body, part of this energy is reflected, part is absorbed and part is transmitted. The magnitudes of these processes is measured as reflectance, absorbance, and transmittance,

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[1] The Perkin-Elmer Corporation, Norwalk, Conn.

respectively. The infrared spectrophotometer measures transmittance or absorbance of radiant energy. The infrared spectrum is a graphical plot of this transmittance or absorbance versus the frequency of the light waves. When a particular compound, such as a solvent-bitumen solution, is exposed to the infrared light it produces a spectrum which cannot be duplicated by any other compound. This is a "fingerprint" of the solution; the whole process of measurement is based upon this principle.

When a pure substance is analyzed, it produces a spectrum which is its characteristic. Because the spectral characteristics are largely retained in a mixture of the pure substance and variable proportions of another substance (which is bitumen in this particular study), it can be said that the spectrum of a mixture is a superposition of the spectrum of the individual components with allowance for the concentrations present. From atomic chemistry fundamentals the characteristic absorption frequencies are dependent upon three molecular characteristics:

1. The atoms.
2. Chemical bond forces.
3. Spatial geometry.

Now, if two molecules have these three characteristics in common, they are identical. If they differ in one of the above they are different. From this principle it is assumed that the infrared adsorption spectrum of a compound is likely to be unique to that compound.

The Lambert-Beer Law gives the theoretical relationship between the amount of light removed from a monochromatic beam that passes through the absorption medium (which is the solvent-bitumen solution for this particular experiment). The Lambert-Beer Law states that the radiant energy of wave length incident on the absorber and the enrgy transmitted are related by:

$$\frac{I}{I_o} = \exp(-KCL)$$

where:

I = Transmitted energy.

I_o = Radiand energy.

K = adsorption coeffient of the medium at frequency $\hat{\nu}$ and wavelength λ.

L = Length of the cell containing the absorption medium.

C = Concentration of the material (solvent) being studied.

The basic assumption in using Beer's Law is that of simple additivity of absorbance, i.e., the wavelength (λ) of a mixture is equal to the sum of the wavelenth (λ) of each of the components present.

Rewriting the Lambert-Beer Law as:

$$\text{Log}_{10} \frac{I}{I_o} = KCL$$

for n components.

$$\log_{10} \frac{I_o}{I} = K_1C_1L_1 + K_2C_2L_2 + K_3C_3L_3 + \ldots + K_nC_nL_n$$

If, in a two-component mixture (as in this case) two suitable wavelengths are chosen and designated by the superscripts 1 and 2, the absorbance at the two wavelengths will be given by:

$$\log \frac{I_{o1}}{I} = K_1^1C_1L + K_2^1C_2L$$

$$\log \frac{I_{o2}}{I} = K_1^2C_1L + K_2^2C_2L$$

L is constant if the same cell is used for all measurements and so it can be absorbed in the constant K, so that the above two equations take the following form:

$$\log \frac{I_{o1}}{I} = (K_1^1)^1C_1 + (K_2^1)^1C_2$$

$$\log \frac{I_{o2}}{I} = (K_1^2)^1C_1 + (K_2^2)C_2$$

To solve these equations it is necessary, first, to know the value of K's. If the concentration of a given material is known (C_1, or C_2, for this particular experiment, 100, 90, 80, 70, 60, 50, and 40% solvent concentration compounds were prepared), then selecting in the infrared spectra a particular wavelenght (i.e., 8.45 for Bitumen-GCos synthetic crude solutions as shown in Figure 24) where the absorbance (or transmittance) for the compound is particulary strong for the compound involved and weak for another, the relationship I_{oi}/I (transmittance or absorbance ratio) can be read from the chart (Figures 25, 27, or 29). Once C_1C_2, I_{o1}/I, and I_{o2}/I are known, K is evaluated.

When many analyses are involved, it is more convenient to solve the above equations by matrix methods:

$$\begin{bmatrix} C_1 \\ C_2 \\ \\ C_n \end{bmatrix} = \begin{bmatrix} (K_1^1)^1 & (K_2^1)^1 & \cdots & (K_n^1)^1 \\ (K_1^2)^1 & (K_2^2)^1 & \cdots & (K_n^2)^1 \\ & & & \\ (K_1^n)^1 & (K_2^n)^1 & \cdots & (K_n^n)^1 \end{bmatrix} \cdot \begin{bmatrix} \frac{I_{o1}}{I} \\ \frac{I_{o_2}}{I} \\ \frac{I_{on}}{I} \end{bmatrix}$$

The applicability of the method depends on the extent to which the Lambert-Beer Law is obeyed. When the experiment is conducted, the relationship between concentration of the solvent and transmittance, when plotted, must be a straight line, and the procedure can be followed immediately. When the graph deviates from a straight line, the process is more complex and corrections for nonlinearity must be considered. Then when considering the method of analysis, the main consideration should be to determine experimental conditions such that the Lambert-Beer Law is followed as closely as possible.

Several factors affect the Lambert-Beer Law and cause deviations from the straight line.

1. The absorption coefficient is exact only for a monochromatic beam of radiation. Because wavelength varies along the spectral slit width, only an average value of K is possible. This average value can hold at only one wavelength. From experiments conducted it is possible to see that the narrower the slit width the more linear is the plot.
2. Molecules with smaller intramolecular forces tend to obey the Lambert-Beer Law better. Hydrocarbons, for instance, will give fairly linear relationships.
3. At higher concentrations of one of the components nonlinearity is stronger. For this particular experiment deviations from the straight line were observed above 70% solvent concentration.
4. Analytical wavelengths chosen for the readings are usually those for which the component shows strong absorbance (or transmittance), while absorption (or transmittance) for other components remain low.

<u>Procedure</u>

Solutions containing 100, 90, 80, 70, 60, 50, and 40% solvent concentration were prepared for the three solvents to be used. Once the spectra were drawn for the three solvents, particular wavelengths were chosen for each solvent (9 microns and 1115 cm^{-1} for Naphtha, 8.45 microns and 11-5 cm^{-1} for syncrude, and 8.4 microns and 1190 cm^{-1}

for Mobil solvent). Figures 24, 26, and 28 show the portion of the spectrum chosen for each bitumen-solvent solution. Transmittance of the solutions was divided by the values of transmittance for the pure solvent, and these values were plotted. Figures 25, 27, and 29 show these relationships, which are fairly linear at low solvent concentrations. These base curves provided the tool for the sample analyses. When samples of the effluent were obtained and analyzed by the spectrophotometer the relation of the observed transmittance to 100% solvent transmittance was measured and using these "base curves," the solvent concentration (by difference the concentration of bitumen) in the sample was found.

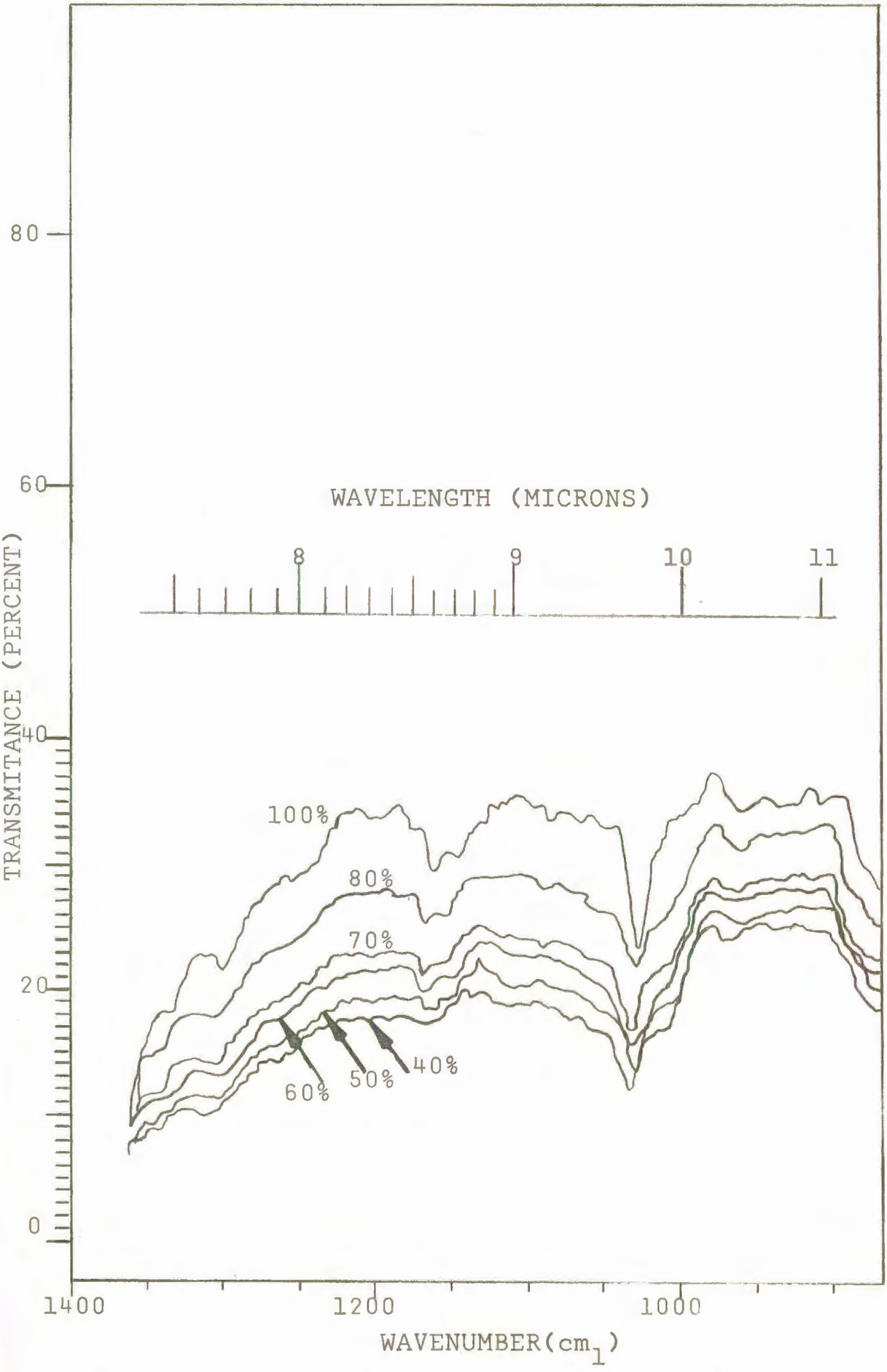

Figure 24 Transmitance Spectra for Bitumen-Syncrude Solutions.

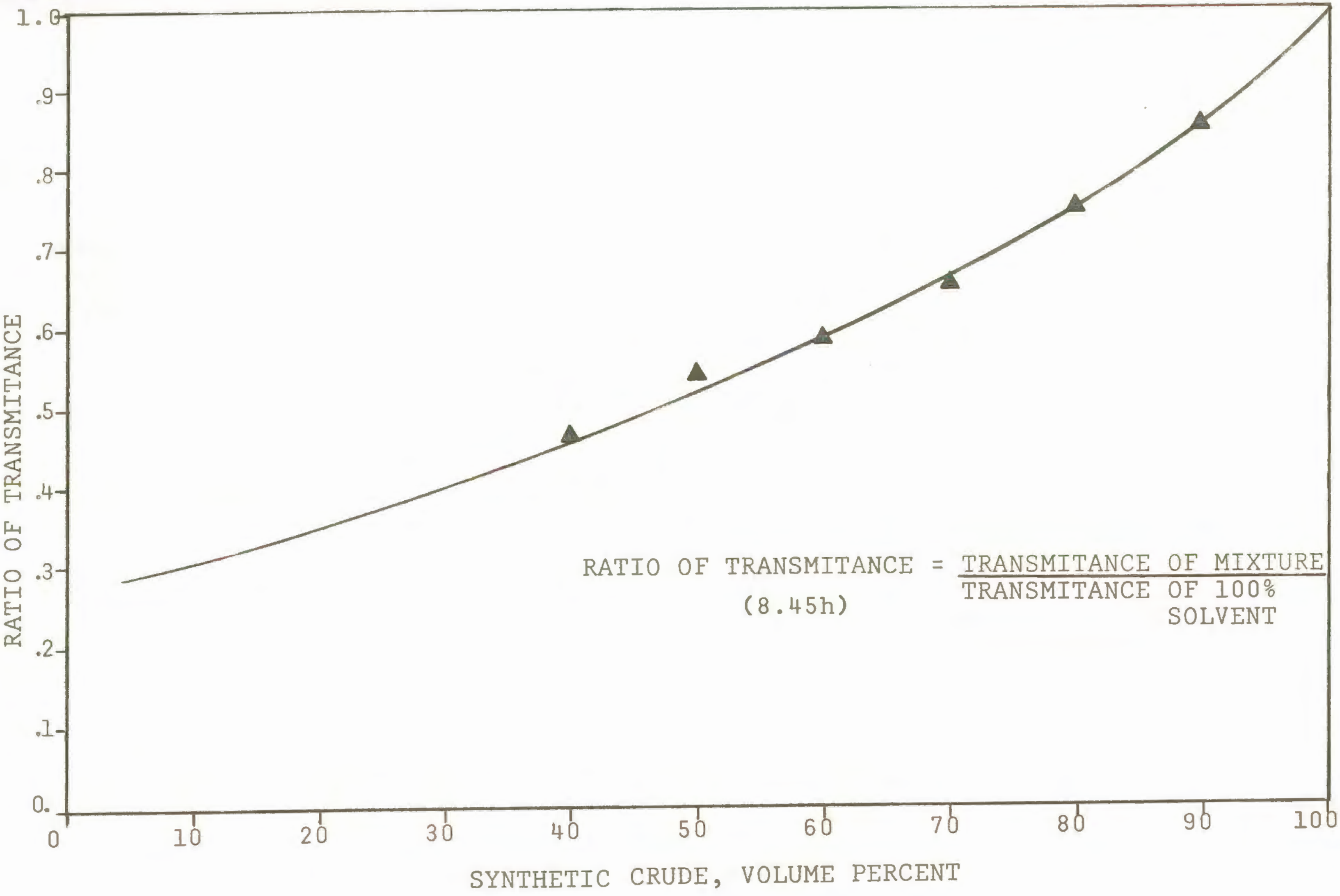

Figure 25 Calibration Curve for Bitumen-Syncrude Solutions.

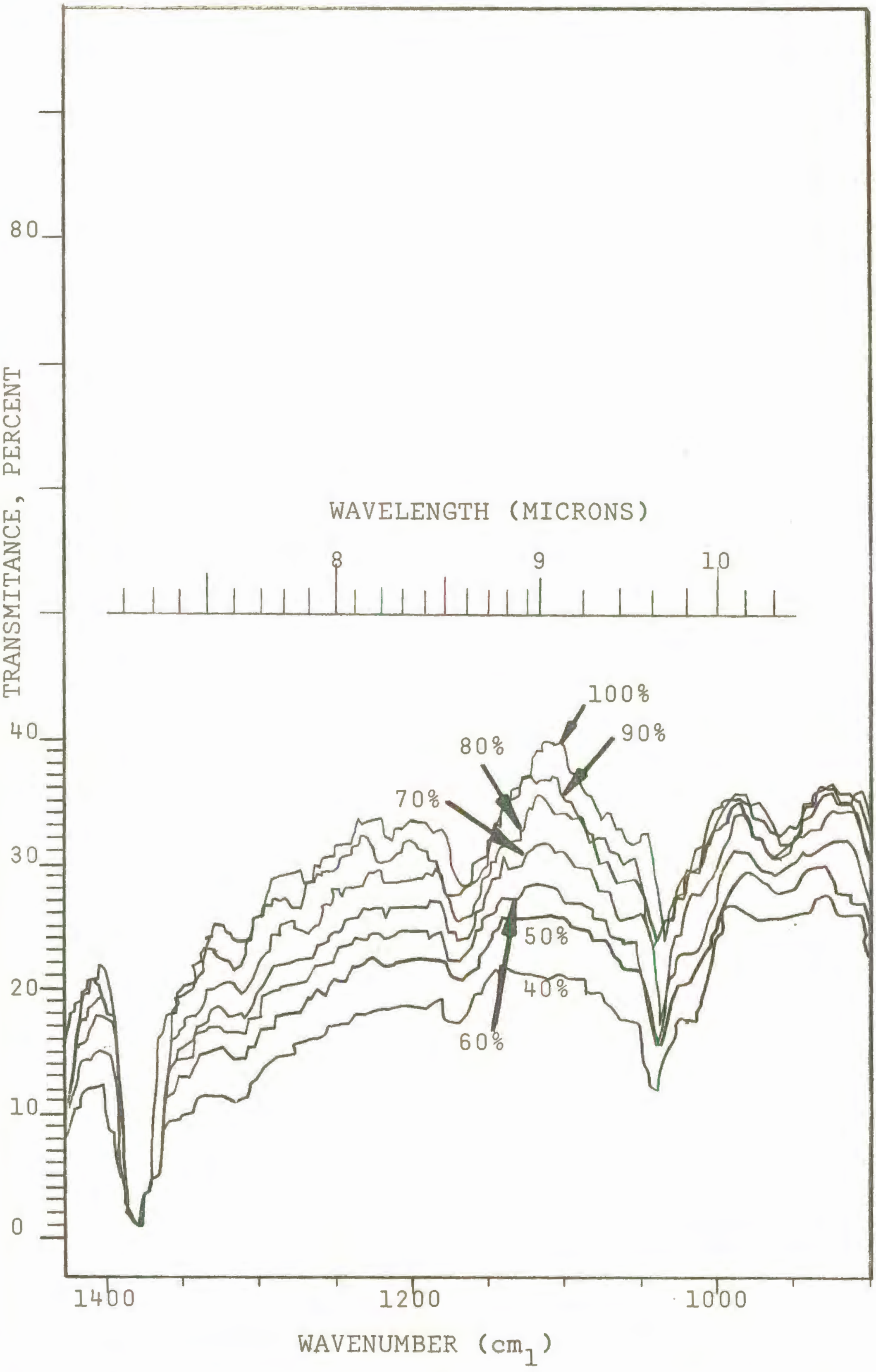

Figure 26 Transmitance Spectra for Bitumen-Mobil-Solvent Solutions.

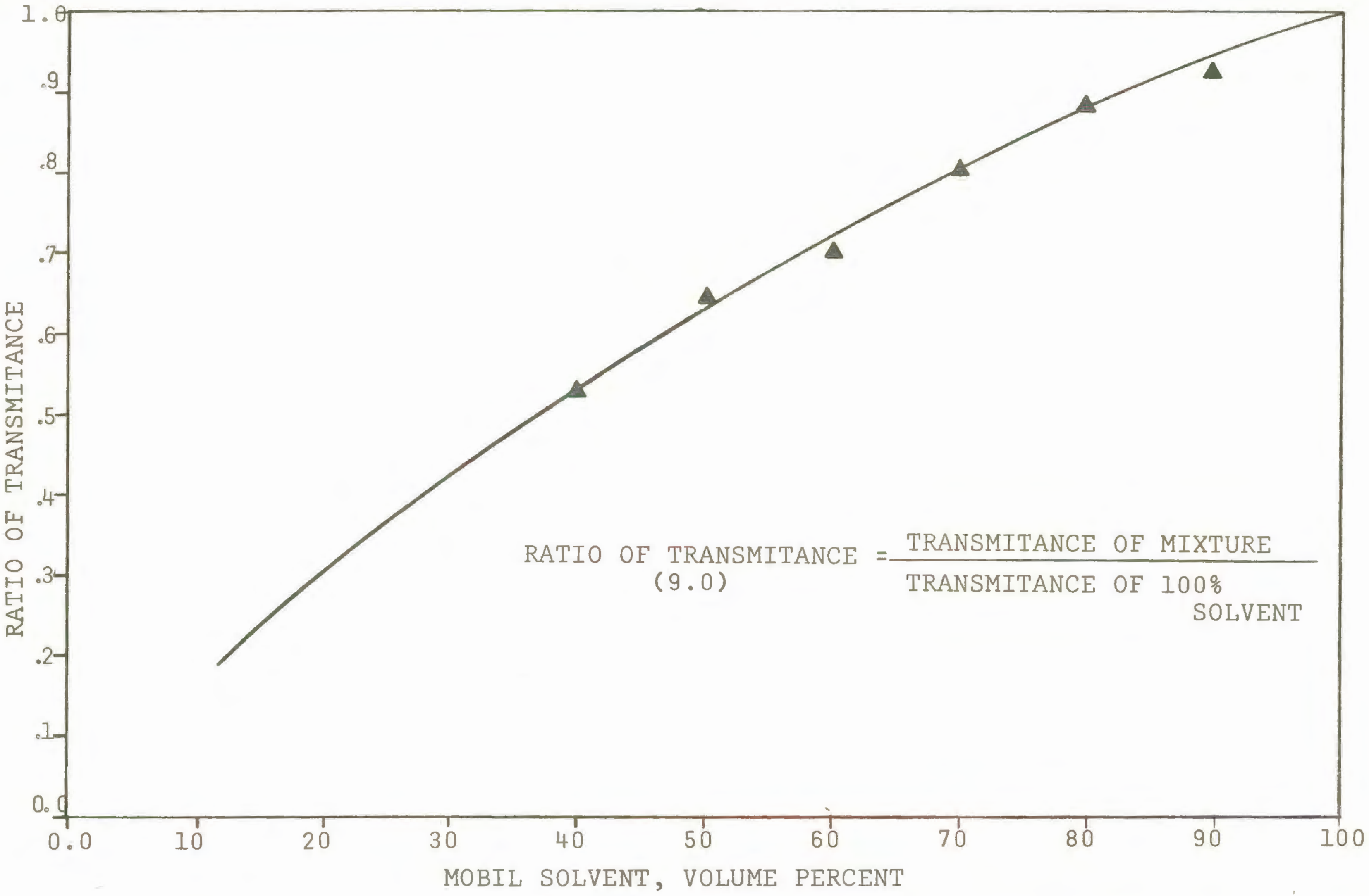

Figure 27 Calibration Curve for Bitumen-Mobil Solvent Solutions.

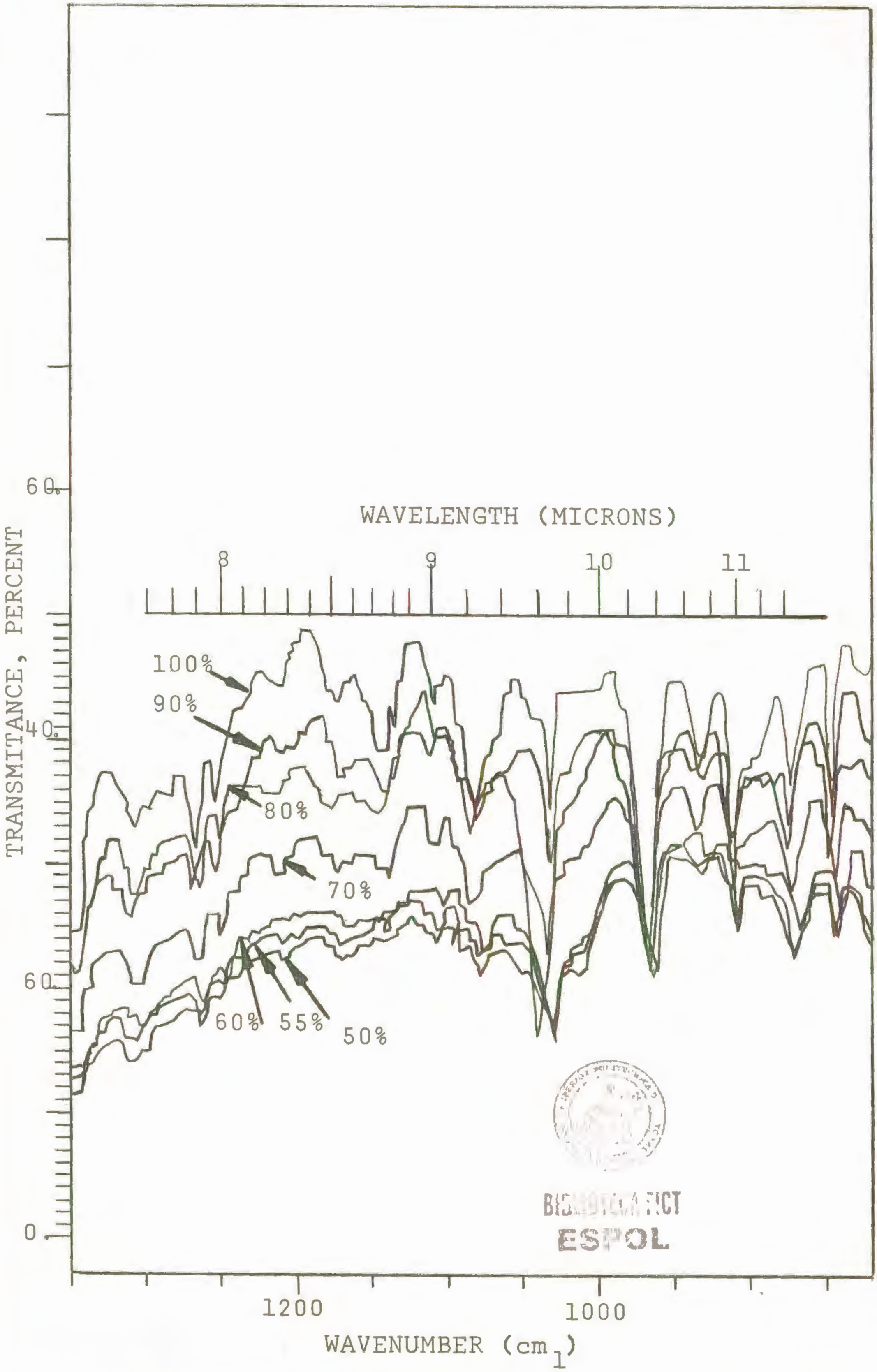

Figure 28 Transmitance Spectra for Bitumen Naphtha Solutions.

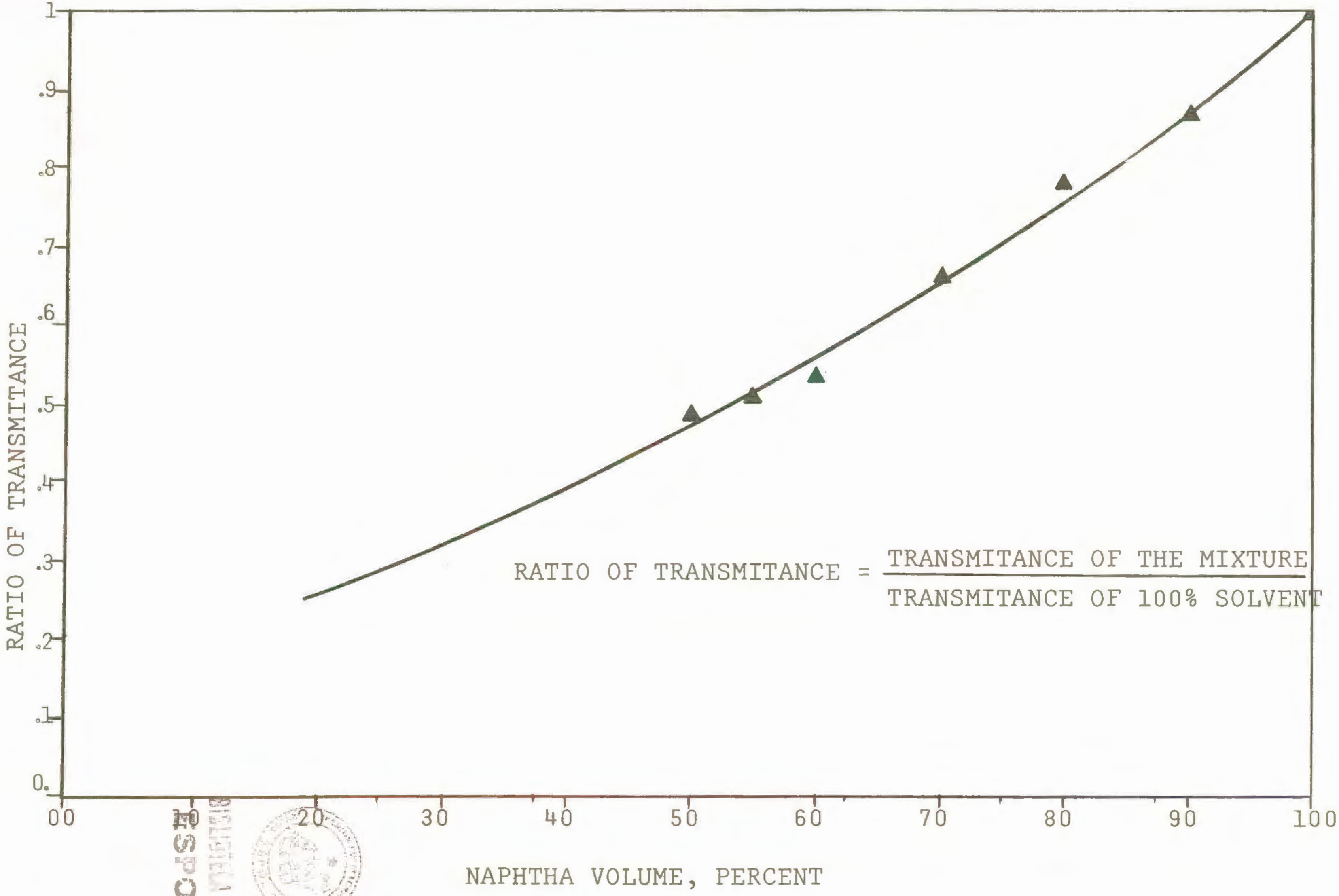

Figure 29 Calibration Curve for Naphtha-Bitumen solutions.

VI. STATEMENT OF THE PROBLEM

The purpose of the present study was to investigate the recovery of bitumen from the Athabasca tar sand samples by miscible and thermal-miscible displacements in an essentially two-dimensional flow vertical model and in a three-dimensional flow model.

The main objectives were as follows:

1. To investigate the recovery efficiency of GCOS synthetic crude, Mobil solvent and naphtha injection into a homogeneous tar sand pack saturated with bitumen and air.
2. To investigate the recovery efficiency of GCOS synthetic crude injection into a homogeneous tar sand pack saturated with bitumen and water.
3. To investigate the effectiveness of naptha-steam combinations in the recovery of bitumen.
   (i) non-continuous steam injection,
   (ii) continuous steam injection for two slug sizes, 45% PV, and 20% PV.
4. To investigate the effectiveness of GCOS synthetic crude-steam combinations as compared to naphtha-steam combinations.
5. To investigate and compare the effect of changing the location of the solvent slug from the steam injection well side, to the effluent production well side.

6. To investigate the importance of steam injection rate in the recovery of bitumen.
7. To investigate the effect of an overburden pressure in the flow of solvent and steam into a tar sand pack.
8. To investigate the compaction of tar sand packs under solvent-steam injection.

VII. DISCUSSION OF RESULTS

When injecting solvent and steam (or either one) into a homogeneous pack of tar sand, many factors control the recovery of bitumen. It is the purpose of the present research to investigate some of these factors. To achieve this goal, three solvent injection runs, and 19 solvent-steam injections were conducted. Three different solvents were used: naphtha, GCOS synthetic crude, and the Mobil solvent. The effects of slug size and slug injection location were thoroughly studied. Injection of different slug sizes and types, combined with steam injection into a medium saturated with bitumen and air, as well as with bitumen and water, was investigated. Two kinds of model were used; a vertical two dimensional model, and a three-dimensional model.

Experiments with Tar Sand Columns

This was a very simple experiment but provided considerable insight on solvent stimulation of bitumen. Gates and Caraway (18) studied solvent stimulation of viscous-crude-oil production, using glass columns of unconsolidated sand, which were saturated with the viscous oil to be stimulated. In the present investigation, two columns of 50 cc were filled with tar sand and packed carefully. One of the columns was placed touching the surface of a liquid (naphtha) contained in a beaker. Now the 10 cc of solvent was placed on top of another tar sand column (1). Figure 34 is a schematic representation of the apparatus used. In both cases, it was observed that the fluid tends to penetrate into the column, but the rise of the fluids at the walls of the glass columns is much higher than the actual position of the front which is far behind. This is actually a serious problem in any kind of experiment, it is not possible to correct it, mainly because when the sand is being compacted the contact between wall and sand is not as good as the contact of the sand grains themselves. This causes a high permeable channel to remain between the model wall and the sand pack. This can be an explanation for the flow of solvent through the thermocouples observed in Run 6. It was observed also, that the solvent, when placed in contact with the tar sand, tends to penetrate the pack at first at a relatively high velocity, but later stabilizes, and reachers equilibrium. This shows that the action of capillarity is also important in the production of bitumen, and that the wall effect is also present in this process. Actually what occurred was an interchange between solvent and bitumen, becuase as the solvent was penetrated in the column, bitumen and sand flowed down into the beaker and quilibrium was established. When analyzed, the effluent samples from both columns, even the one for column 1 was richer in bitumen. The effluent from column 2 also had significant amounts of bitumen.

Solvent Injection Runs

Run 1 was made to investigate the behavior of the tar sand pack under naphtha injection. Table 6 gives the general characteristics of the run as well as the results obtained.

Injection was initiated through the wells at the top, trying to saturate the sand pack evenly. After 4.93 hours of injection (1140 cc breakthrough occurred but no large decrease in pressure was observed. After several hours of solvent injection, when well 2[1] was opened to injection (and all the others closed) a sharp increase in pressure was observed (up to 175 psig, pressure was normally around 35 psig), formation plugging occurred in the neighborhood of well 2, due perhaps to asphaltene flocculation. When well 4 was opened to injection, pressure dropped immediately, and when analyzing the effluent samples a decrease in bitumen concentration was noticed for these particular samples. The production line was closed, and recycling of the effluent was initiated, the pack was pressurized (60 psig) and left closed overnight to observe the effect of diffusion of solvent into the pack. This procedure was repeated several times until 2000 cc were recycled.

When analyzing the samples in the infrared spectrophotometer, it was observed that the highest recoveries were obtained at the beginning of the production. The first sample collected (60 cc contained a concentration of 27.5% bitumen, which represents 22.5 cc of bitumen,

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[1] All the runs up to 20 were performed using model 1.

considering that a total of 378 cc of bitumen were recovered, this represents 5.9% of the total recovery. When the model was closed and produced 8 hours later, an increase in bitumen concentration of the effluent was obtained (41.5% bitumen) and from 46 cc of effluent analyzed this 41.5% represents 5.05% of the volume recovered. Samples always presented a decreasing concentration in bitumen, even though the model was closed two more times (8 hours each time) no further increase in bitumen concentration was recorded.

When the effluent produced was recirculated, effluents with an average solvent concentration of 86% were recovered. Considering that the solvent concentration in the injection solution was also 86% no improvement in bitumen recovery was obtained. It is important to notice that recirculating the effluent caused plugging in the lines, valves and especially in the millipore filter which had to be removed and changed constantly.

Considering that the pore volume was 2153 cc and that 1140 cc of solvent was injected before any production, only 53% of the pore volume was contacted by the solvent before effluent breakthrough. The samples recovered were generally lower in bitumen concentration as the injection proceeded, even when the outlet was closed and the pack was pressurized for 8 hours or more. This indicates rather slow diffusion. Apparently once a path is created, the fluid stays in it without contacting fresh tar sand. Figure 30 shows the production history for this run.

When the pack was opened, and analyzied, it was found that the sand was very clean toward the top of the model, and it was especially clean just in a few parts. Considering that the fluid was being injected through the top, a few inches below the injection points, channeling was observed especially toward the walls of the model. Through these channels, solvent-bitumen solution was conducted toward the bottom of the pack, where sand was saturated with a very dark solution with a high concentration of bitumen which was not recovered.

With the experience obtained from the previous run, it was decided to inject solvent at the base of the model in order to sweep perpendicular to the fluid displaced from the top of the model. Mobil solvent was injected in this run (Run 2). The behavior of this solvent in comparison to naphtha was completely different. It required very slow injection rates, the run took around 72 hours to be completed, and recovery was much higher. Table 7 gives detailed information for Run 2.

The first 2000 c.c. of solvent were injected through the wells located at the top of the model, and 2000 c.c. were injected through the injection point at the base.

Solvent soaking and pressurizing of the model proved to be a little better for Mobil solvent than for naphtha, even the bitumen content of the samples were markedly higher for this solvent, the first volumes of effluent recovered being the best for the whole process.

Figure 31 represents the production history for Run 2. In Run 3, GCOS synthetic crude was used as the solvent. The observed behavior was similar to that for Run 2. Figure 33 compares the cummulative bitumen recoveries for the runs where solvent was used. It can be seen that the Mobil solvent gave the highest recovery, followed by naphtha and GCOS synthetic crude.

When naphtha and GCOS synthetic crude were injected, the amount of solvent retained by the pack almost equalled the volume of solvent injected, before having breakthrough (see Tables 6, 7, and 8) of effluent. This was not the case for Mobil solvent. In this case, the volume of solvent retained by the pack was twice as great as the volume injected before breakthrough. If the amount of solvent retained by the pack at the end of the run is approximately the same as the volume injected before effluent breakthrough, the solvent establishes a path (or paths) between the inlet and the outlet, and tends to stay in it without opening new channels. That is why the recoveries were so low for solvent stimulation, and in all three cases it was found that the higher concentrations of bitumen were at the beginning when the first samples were collected. Very little bitumen was recovered after the first pore volume of solvent was injected, showing that the solvent did not open more paths through the sand, and that the small amounts of bitumen recovered in the samples collected after the injection of the first pore volume of solvent were due to diffusion or a small increase in sweep by the solvent. It was observed also that later in a run the injection and production rates stabilized with no significant increase in bitumen concentration at which time the injection was stopped. For Mobil solvent the behavior was different; only 760 c.c. of solvent were necessary to cause effluent breakthrough (1140 c.c. were required for naphtha, and 1340 c.c. for GCOS synthetic crude), but the amount retained by the pack was almost twice as large (1486 c.c.). From Figure 31 it can be seen that significant recoveries were obtained even after the first pore volume was injected. This last solvent was more efficient for dissolving bitumen and opening channels in the sand, which led to a higher bitumen recovery.

In each case, the amount of solvent injected was extremely large to be considered for a field test. It is impractical to inject more than one tenth of the pore volume for stimulation purposes. The ratio solvent-bitumen in these runs was over 5.0, which shows clearly the impracticality of the solvents used to recover bitumen. These test will have only experimental value, helping to understand the flow of fluids through tar sands. It is also believed that solvents are necessary to stimulate tar sands prior to a steam injection recovery process.

Snyder (32) and Hernandez (21) also experimented with naphtha. They obtained recoveries higher than in the present experiment. Hernandez reported a recovery of 37.2%, but the model used was a cylindrical core, with a small cross sectional area, and eight pore volumes of solvent were injected. Synder found recoveries as high as 58.7%, using the same model as employed in these experiments. This high recovery was obtained because of the poor consolidation of the tar sand, (he reported that after the experiment a void space of 2017 cc was found in the pack). When the sand is poorly packed the characteristics of flow change completely, mainly because of the poor contact among the sand grains. Under these conditions if the right amount of solvent is used it is possible to extract these tar sands totally.

Run 6 was intended to be a solvent-steam injection run, but due to sever leakage in the gaskets the run had to be terminated. Any how, certain interesting aspects of solvent flow were observed in this run. Naphtha was injected using the steam and solvent inlet (see Figure 6). When the leakage made it necessary to stop injection, 820 cc of solvent had already been injected at a rate of 2.23 cc/min. Even when injection was taking place through a low point in the pack, solvent was distributed all along the pack. When the thermocouples were removed, effluent flowed through points 5, 6, 7, 8 10, 11, 12, 13, 15, 16, 17, 18, 20, 21, 22 and 23, showing that capillarity was strong at least at this level of saturation of the pack. The advance and distribution of the fluid was quite uniform. This can be a consequence of a low injection rate which gave time to the fluid to flow in all direction uniformely.

The flow of solvent in tar sands is difficult to understand because of the different mechanisms present as well as the interaction among them. The experiments conducted gave certain qualitative ideas of the process, but it is necessary to investigate these aspect further to obtain quantitative concepts of dispersion, diffusion, capillarity, etc.in a porous medium partially saturated with bitumen. The experiments to be described in the following gave additional understanding of the flow of solvent in tar sand packs, but the interest was mainly focused on the action of temperature in the production of bitumen. It is belived that temperature has a more important role in the recovery of heavy oils and bitumen.

Solvent-Steam Injection Runs

A total of 19 runs were performed using combinations of solvent and steam. The goal of these experiments was to investigate the recovery of bitumen from Athbasca tar sands using different solvents, slug sizes, mediums initially saturated with air, water and bitumen. Changing the stimulation with solvent from injection to production well and using two physical models, a two-dimensional vertical model and a three-dimensional model.

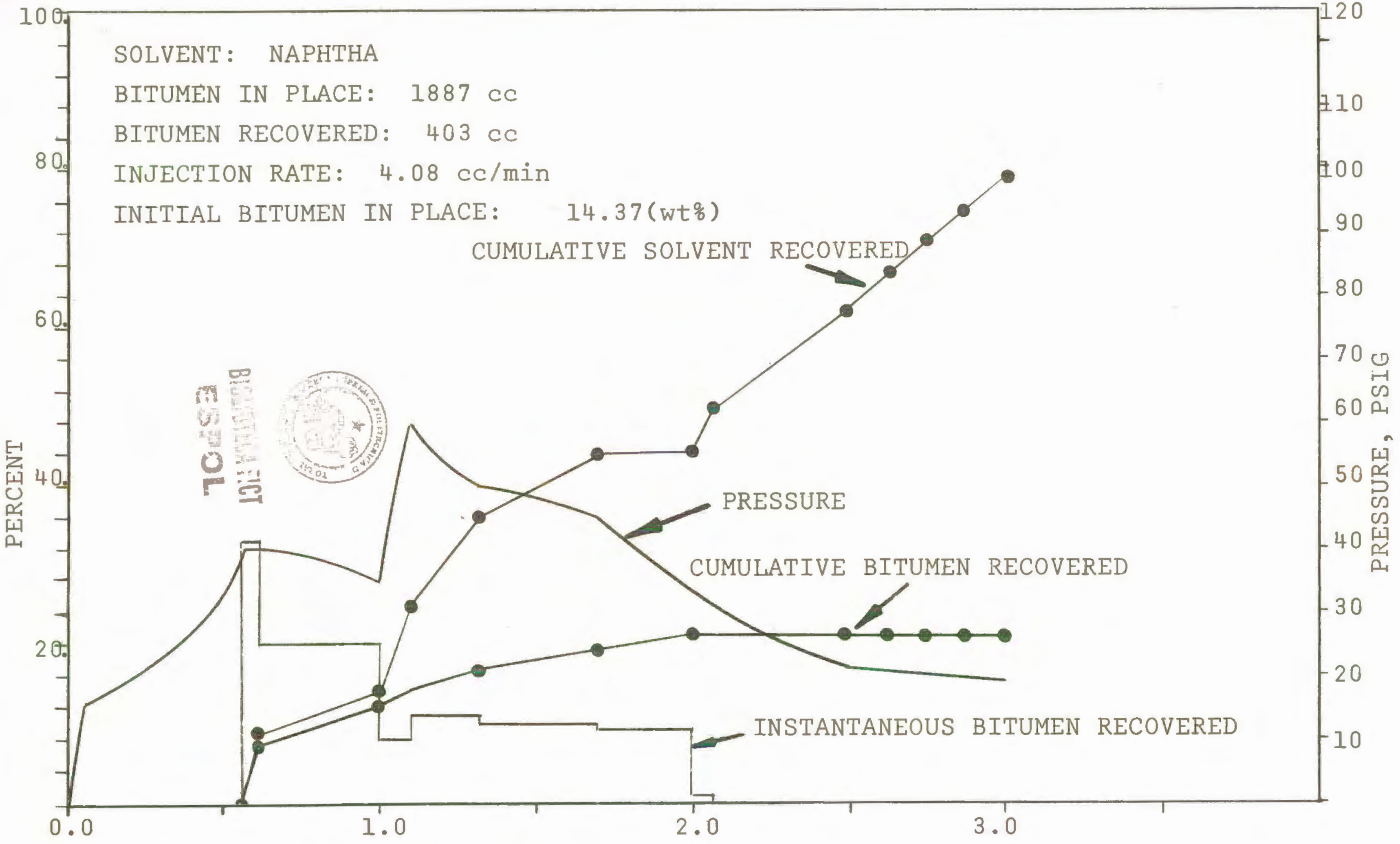


Figure 30 Production History for Run 1.

Table 6

General Characteristics and Results for Run 1

Amount of tar sand packed	13562 gms.
Bitumen content of the tar sand	1437 (wt%)
Weight of bitumen in place	1948 gms.
Volume of bitumen in place	1881 cc
Solvent used	Naphtha
Weight of clean sand	11613.7 gms
Volume of clean sand	4327 cc
Volume of the steel box	6480 cc
Void space in the model	271.8 cc
Pore volume	2153 cc
Porosity	33.2%
Total solvent injected	4000 cc
Amount of solvent retained by the pack	1051 cc
Solution recycled	2000 cc
Total run time	24.3 hrs.
Time for effluent breakthrough	4.9 hrs.
Solvent injection time	21.08 hrs.
Volume of solvent inj. before effluent B.T.	1140 cc
Average injection rate before B.T.	3.85 cc/min
Average flow rate	4.75 cc/min
Average pressure	45 psig
Solvent injected - bitumen ratio	9.6 $\frac{ccs}{ccb}$
Solvent produced - bitumen ratio	7.08 $\frac{ccs}{ccb}$
Total bitumen recovered	416.62 cc
Recovery	21.35%

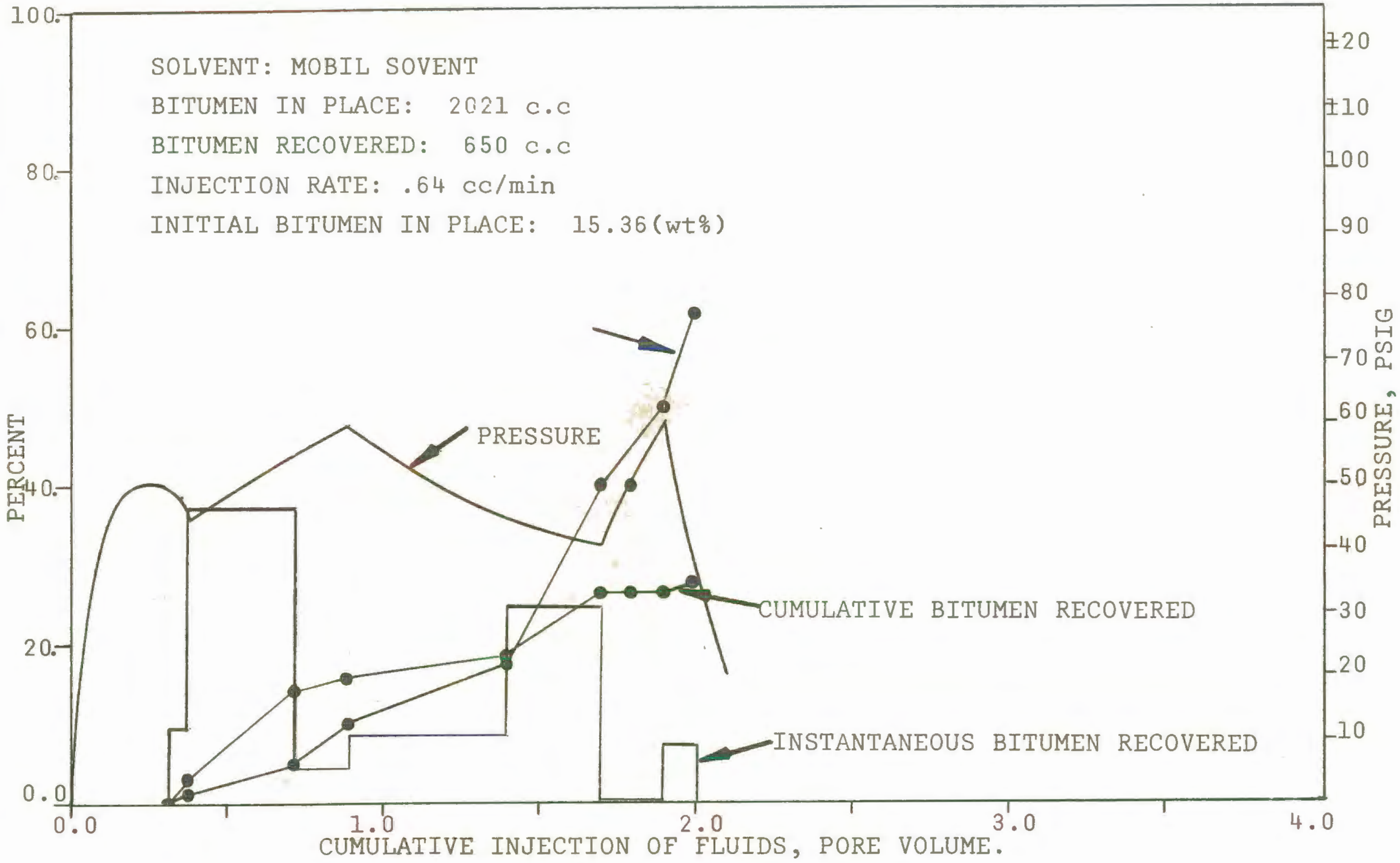


Figure 31 Production History for Run 2.

Table 7
General Characteristics and Results for Run 2

Amount of tar sand packed	13671 gms.
Bitumen content of the tar sand	15362 (wt%)
Weight of bitumen in place	2094.5 gms.
Volume of bitumen in place	2021.7 cc
Solvent used	Mobil
Weight of clean sand	11577 gms.
Volume of clean sand	4313.4 cc
Volume of the steel box	6480 cc
Void space in the model	145 cc
Pore volume	2166.6 cc
Porosity	.334
Total solvent injected	4000 cc
Amount of solvent retained by the pack	1486 cc
Total run time	72.45 hrs.
Time for effluent breakthrough	20.13 hrs.
Solvent injection time	72.45 hrs.
Volume of solvent inj. before effluent B.T.	760 cc
Average injection rate before B.T.	629 cc/min.
Average flow rate	92 cc/min.
Average pressure	51 psig
Solvent injected - bitumen ratio	6.15 cc/cc
Solvent produced - bitumen ratio	3.87 cc/cc
Total bitumen recovered	650.8 cc
Recovery	32.2%

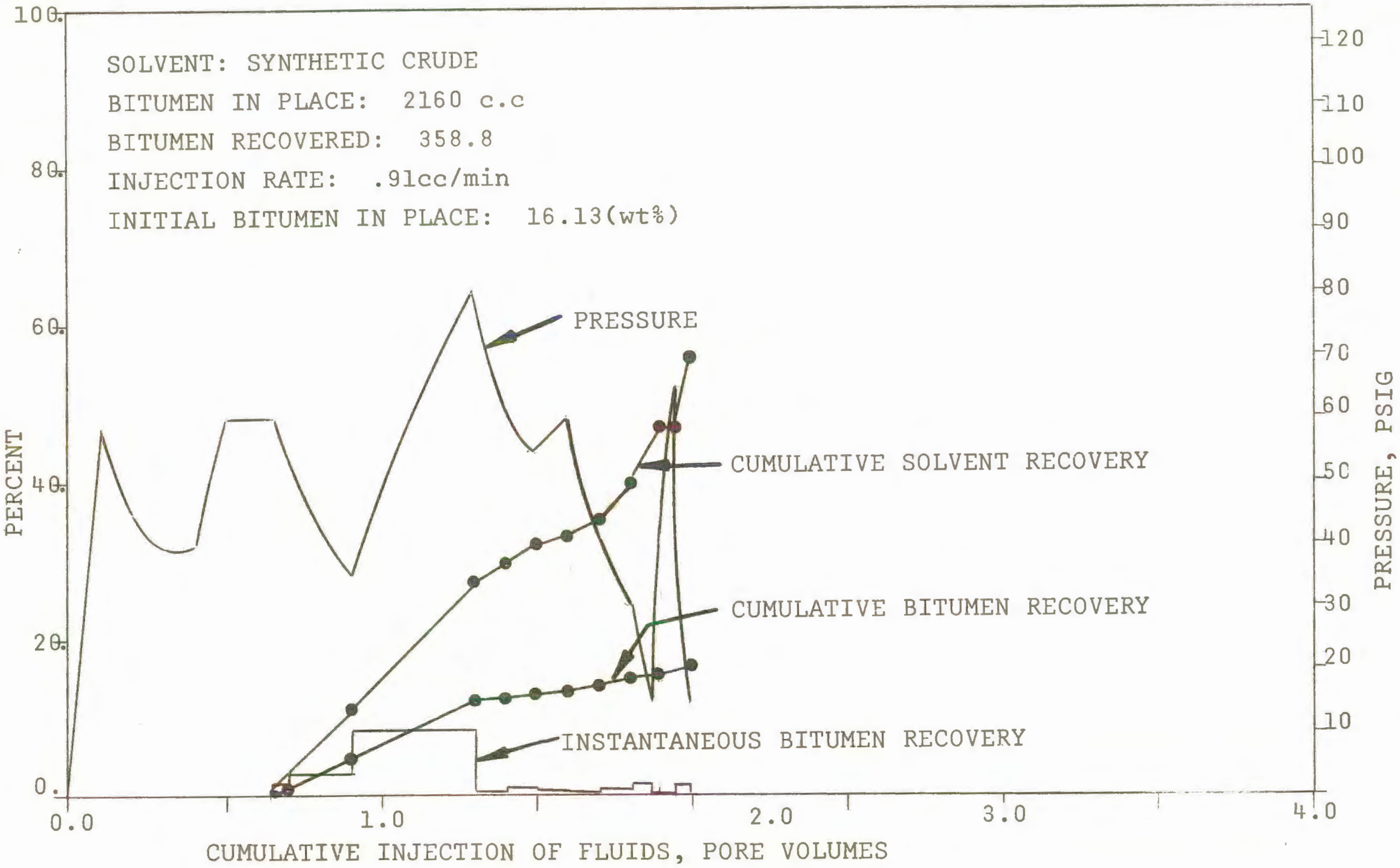


Figure 32 Production History for Run 3.

Table 8
General Characteristics and Results for Run 3

Amount of tar sand packed	13699 gms.
Bitumen content of the tar sand	16134 (Wt%)
Weight of bitumen in place	2238 gms.
Volume of bitumen in place	2160 cc
Solvent used	Syncrude
Weight of clean sand	11461 gms.
Volume of clean sand	4270 cc
Volume of the steel box	6480 cc
Void space in the model	49.13 cc
Pore volume	2209 cc
Porosity	.341
Total solvent injected	4000 cc
Amount of solvent retained by the pack	1615 cc
Total run time	76.67 hrs.
Time for effluent breakthrough	24.6 hrs.
Solvent injection time	76.67 hrs.
Volume of solvent inj. before effluent B.T.	1340 cc
Average injection rate before B.T.	91 cc/min.
Average flow rate	1.61 cc/min.
Average pressure	50.9 psig
Solvent injected - bitumen ratio	11.17 cc/cc
Solvent produced - bitumen ratio	6.6 cc/cc
Total bitumen recovered	358 cc
Recovery	16.6%

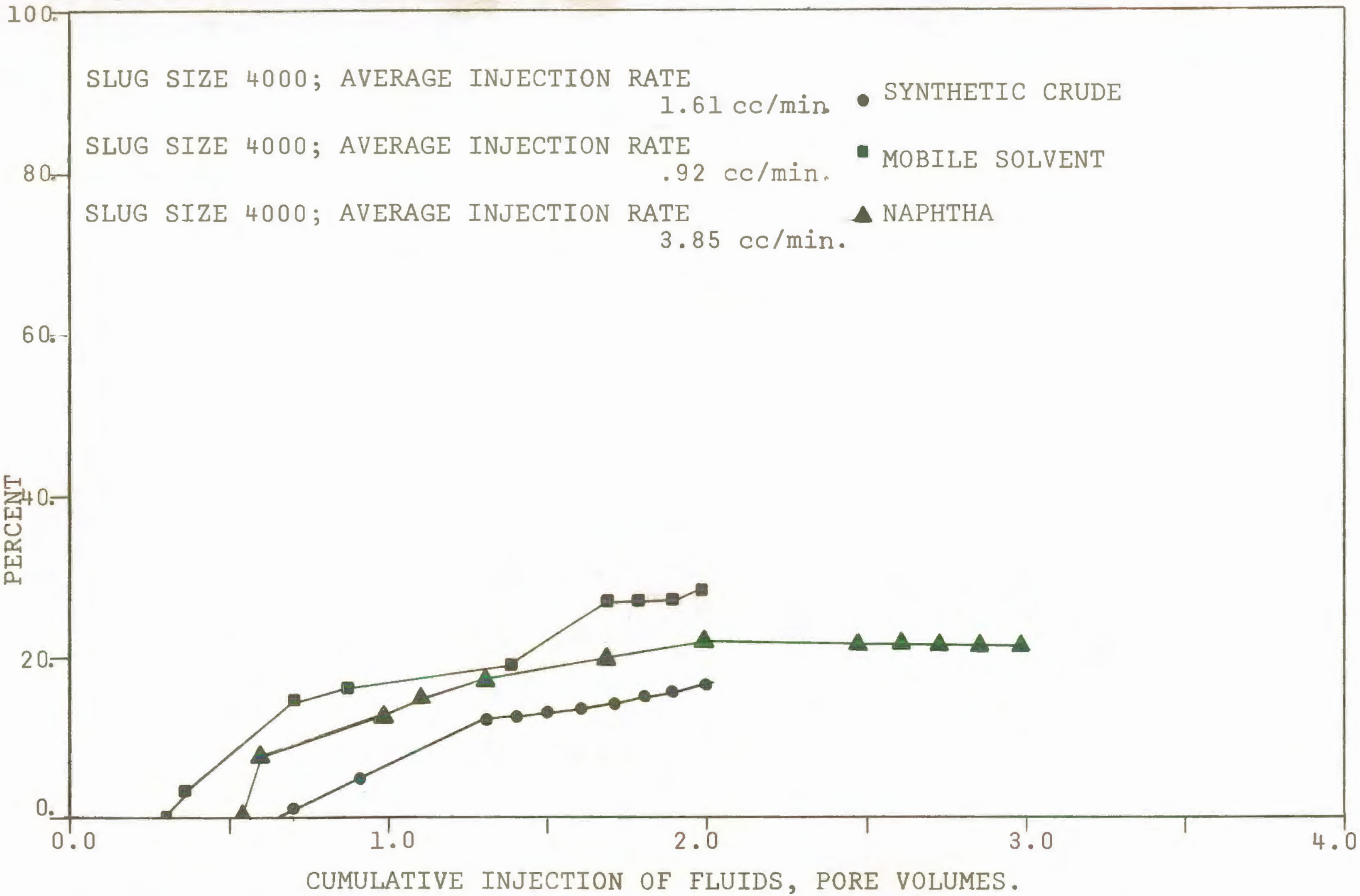


Figure 33 Comparation of Cumulative Recoveries for Runs 1,2, and 3.

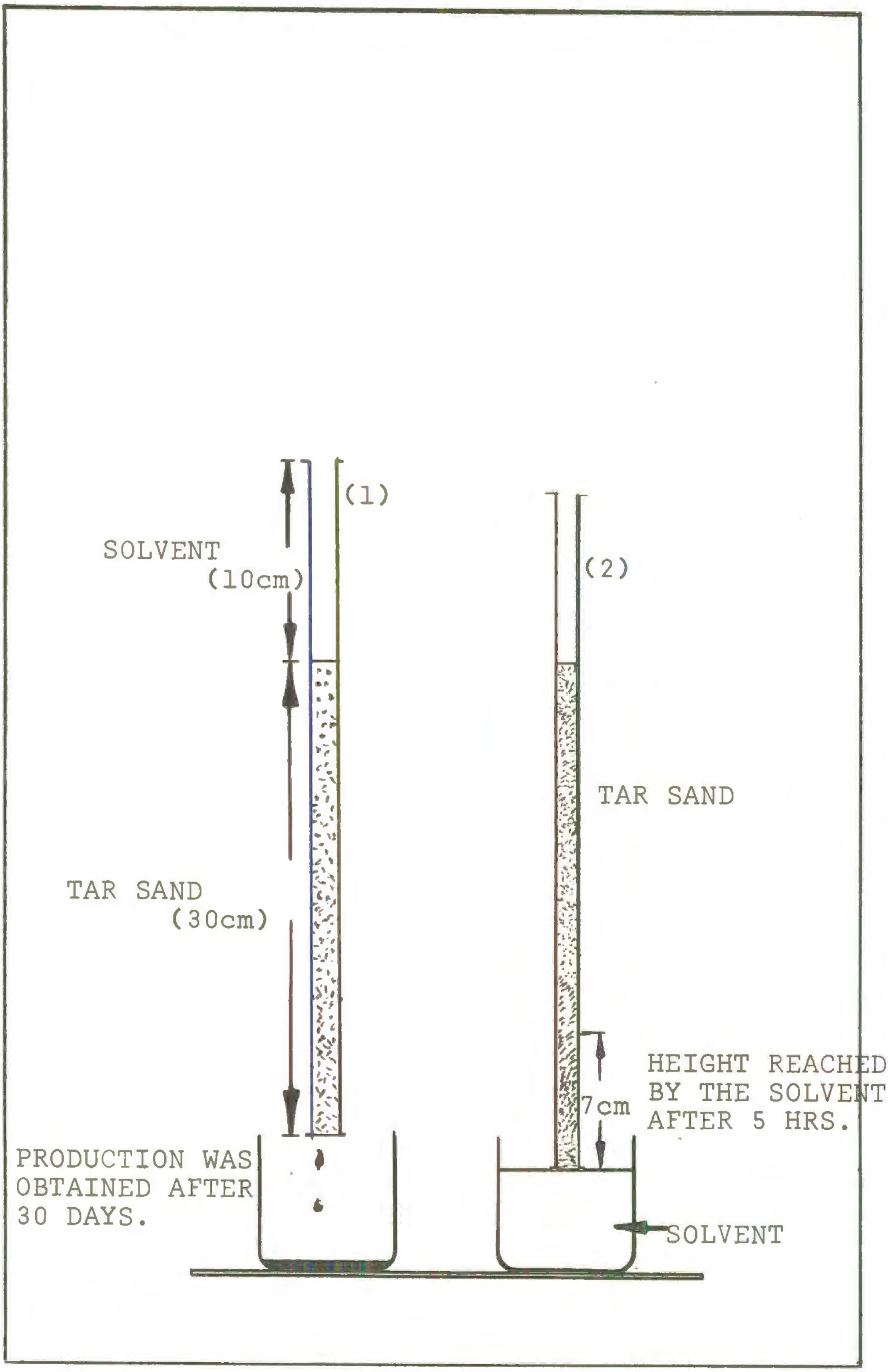


Figure 34 Experiments with Tar Sand Columns,

Table 2 shows the classification of these runs. A separate discussion will be presented for every set of runs. The results and physical characteristics as well as the general data concerning each of the runs are summarized in several tables presented for every run.

Naphtha-Steam Runs

Run 4 was the first run where steam injection operations were involved. Due to leakage of steam, the production data for this run were not consistent, and it was decided not to include it in the present theses; even though important data was lost, many interesting observations were made.

When solvent was being injected through the top injection wells, the boiler was tested, apparently the valve closing the steam line was not in good condition because some steam went inside the pack, as observed from increase in temperature registered by the thermocouple at the steam inlet. The physical conditions for this run were similar to those for Run 1. Due to steam leakeage, breakthrough of the effluent occurred when 540 cc of solvent had been injected. This gave an idea of the effect of steam in increasing the mobility of solvent in the pack. The low boiling point of naphtha led to evaporation of the naphtha when it came in contact with hot water and steam and this traveled much faster in the sand pack towards the outlet.

The sand pack was saturated in two directions, first vertically, through injection poins (1), (2), and (3) (see Figure 7) and when breakthrough occurred, injection was switched to point (35). Once the production flow rate was equal to the injection rate, it was decided to stop solvent injection.

After a few minutes of steam injection a flow rate of 16.6 c.c./min. was obtained. Production of effluent with high concentrations of naphtha was characteristic of the first samples collected. Naphtha, due to its low boiling point is vaporized and immediately finds its way out of the system. After a few hours of steam injection, most of the solvent was produced. Shortly after producing 187 c.c. of effluent, production stopped completely, and the temperature in the sand pack began to decrease. At this point, steam injection was terminated overnight. After 6 hours of steam soaking, operations were restarted. When the drain at the inlet was opened, 100 c.c. of solution were recovered. The temperature in the pack at this time was 100°F, and steam injection began with a pressure of 80 psig. After several hours of steam injection, only a slight increase in temperature was registered, showing that no steam was going into the model, the small increase in temperature was due only to the heating of the steel box. This effect was characteristic of this run. After several variations in steam pressure, it was concluded that some kind of plugging was occurring in the pack. The injection of steam was terminated, and the drain was opened. Immediately afterward, a dark, dense, heavy mixture of bitumen, water, silt and other solids flowed out of the drain. Because of the original distribution of bitumen in the pack (approximately the same along the sand pack), bitumen which was contacted by steam, due to the sharp reduction in viscosity and because of the solvent in solution with bitumen, flowed immediately toward the outlet as well as toward the inlet, due to the high effect of gravity segregation was building up around the inlet of steam, and actually confined the steam outside the pack. When steam injection was stopped, this solution was able to flow out. The outlet was also drained, and some of this mixture flowed out also. After the plugging was released the increase in temperature was normal.

When the run was completed, the model was opened to clean out the sand. A big hole was observed at the top of the sand pack, due to excessive compaction. Observing Figure 4 it can be seen that bitumen covers and cements the sand grains, and when bitumen is washed out by solvent or steam, these grains are left clean, and they tend to reaccomodate it in the structure. If this effect is added to the effect of the steam which is being injected at a high pressure and is actually displacing not only bitumen but sand also, it is possible to understand compaction of these unconsolidated sands.

In Run 4, steam was injected for 28 hours, production of bitumen was high (50 or 60% of the bitumen originally in place), the effect of compaction was one of the more severe observed during these experiments. It might be conjectured that some quantitative relationship exists among compaction, volume of steam injection, size of the solvent slug, recovery of bitumen and steam injection rate.

Run 5 showed a considerable increase in bitumen recovery as compared to the solvent injection runs. Solvent was injected first with the purpose of creating a channel in the sand pack. Injection was stopped when the first drop of effluent was produced. Solvent was injected through the base injection point. The problem observed in Run 4 was also present at the beginning of Run 5; i.e., the temperature did not increase and steam was not flowing into the sand pack. Steam injection was stopped, and the injection well was drained out, large amounts of water along with considerable quantities of bitumen were recovered.

Four injection cycles were carried out in Run 5 of 3, 7, 7.5 and 11.5 hours, respectively. The first injection cycle did not give much effluent production mainly because of the complication from the plugging of the porous plates, lines and possibly the formation, of the total bitumen recovered, only 13.5% was recovered in this cycle, but also only 2.6% of the total water produced was collected in this stage. The second cycle lasted 7 hours, and plugging again made recovery very low; 15.32% of the total bitumen recovered was produced in this stage. Even though it lasted twice as long as the first cycle, now the volume of water produced was much higher than before, but in general, the behavior of this cycle was very similar to cycle 1 and Run 4. Cycles 3 and 4 did not present plugging, but it was necessary to drain the inlet of the water saturation buildup around the injection point. Recoveries were very substantial and also the water-bitumen ratios were high. Table 10 gives a comparison of these four cycles for Run 5, which is the only one involving non-continuous steam injection. Table 11 and Figure 35 give the injection history for Run 5; Table 12 and Figure 36 give the production history. When the operations were terminated (shortly after steam breakthrough), the model was allowed to cool and 20 core samples were taken from the thermocouple ports, in order to determine the residual bitumen saturation. When the box was opened, no compaction was observed, but the sand was so loose that it was possible to compact it without any effort. Figure 37 shows the residual saturation contour for Run 5; considering that the initial bitumen concentration (Wt%) was 14.1% the contours show the actual saturation of bitumen (Wt%) remaining in the sand.

From the temperature distribution contours for Run 5, it was possible to observe in the fourth injection cycle (where breakthrough of steam occurred) that the steam actually tries to flow through the top of the model, and the breakthrough of steam occurs early because of this overriding effect. This was characteristic for all the runs performed in the two-dimensional model; regardless of the size and nature of the slug, as well as the porous medium, steam injection rate, etc., steam flowed preferentialy through the upper part of the sand.

Figure 43 shows small increases in temperature due to plugging in the sand pack which was mentioned before. Temperature profiles for the third cycle show that the plugging was released to some extent, but the increase in temperature was not as high as that observed under similar conditions of steam pressure were plugging did not occur.

Runs 7 and 8 were conducted using naphtha as the solvent, but continuous injection of steam was considered for two slug sizes: 45% pore volume (Run 7) and 20% pore volume (Run 8). Also, with the experience gained on the overriding effect of steam during Run 5, it was decided to open the outlets at the bottom of the model, once steam breakthrough occurred at the main outlet.

Both of these runs presented the same difficulties as observed in Run 5, i.e., plugging of the outlet as well as in the inlet.

The effect of the slug size was found to be important for this kind of solvent, because in Run 7 (45% pore volume slug size), recovery was 42% and in Run 8 (20% pore volume) recovery was 28.8%.

In both runs, naphtha was produced almost completely at the beginning of the process, but as the naphtha was being produced, large amounts of bitumen were being displaced also (see Production History for Run 7). Once the naphtha was almost completely produced the behavior of both runs was almost the same.

When the wells in the bottom were opened, recoveries were not so high, mainly because of the plugging in the line due to the high production of sand, silt, and undoubtedly asphaltene flocculation.

Regardless of the plugging when producing through the bottom of the model, recovery was improved significantly because the steam acts like a piston, pushing and displacing bitumen from the top to the bottom, the only complication is the plugging of the neighborhood of the production point.

David (15) investigated asphaltene flocculation in solvent stimulation of heavy oils. Some of the parameters that he found to increase the flocculation of asphaltenes were present in these experiments: Low molecular weight and high concentrations of solvent, high asphaltene content (experiments performed for separation of bitumen with light hydrocarbon compounds, as naphtha, benzene and toluene (6) showed that the asphaltene content could be as high as 28.8% Wt.) of the bitumen, and low permeability of the formation. David also found that the plugging that may occur to a certain temperature is released when the temperature is raised. This was also observed in these experiments, because of high temperatures (above 210°F) plugging was no longer a problem.

Temperature profiles for Run 7 are presented in Figures 47 through 50. It is possible to observe clearly the overriding effect of the steam, and the high temperatures developed in this run when producing through wells 1 and 2.

When steam injection was stopped, even when the pack (Run 8) was at a very high temperature (average 290°F) no flow of bitumen was registered (this phenomenon was observed in all runs performed). It is seen that for the production of bitumen it is not only important to have a temperature increase but also it is necessary to have a pressure gradient. When Synder (32) in his studies considered conductive heating of the tar sand pack, naphtha was injected after the pack was heated to an average temperature of 187°F. Significant recovery of bitumen was reported, but no production was recorded before the injection of naphtha. Also heating the pack prior to the injection of naphtha only increased the recovery of bitumen by 10% when equal amounts of naphtha were injected with and without previous heating.

Analyzing the core samples for Runs 5 and 7, it was observed that bitumen had a relatively moderate mobility when the injection of steam was stopped. In view of gravity effects and the overriding effects of steam, the cores withdrawn from the central part of the pack at the base showed an increase in the bitumen content. The samples were not withdrawn until the pack was completely cold; thus bitumen had time to flow toward the base of the pack increasing in this way the original bitumen saturation of this portion of the pack.

Such behavior was not observed in the analysis of cores from Run 8, where large amounts of bitumen from the neighborhoods of wells 1 and 2 were produced.

Even though conclusions for these experiments will be presented together with the conclusions from other runs, it is considered advisable to make certain observations on the naphtha-steam runs in order to preserve the continuity of the present discussion.

For the five experiments performed using naphtha stimulation prior to steam injection, it can be said that recovery improved significantly in comparison with the solvent flooding experiments.

Cyclic steam stimulation yielded higher recoveries of bitumen (47% of original bitumen in place) than continuous injection of steam (42% of original bitumen in place), for similar conditions of slug type and size (see Runs 7 and 5), and steam pressure. Cyclic steam stimulation required higher amounts of steam (10,867 c.c. of water) and time (29.3 hours of steam injection) than continuous steam injection (4525 c.c. of water, and 14 hours of steam injection). Slug size was found to be important in the recovery of bitumen especially in the early stages of bitumen recovery when the pack was not heated. After a certain time, most of the naphtha was evaporated and bitumen was produced just by the displacing action of steam.

Overriding effect of steam was the main reason for early steam breakthrough.

When performing naphtha-steam stimulations, plugging by asphaltene flocculation may occur for certain ranges of temperatures and pressures. Mobility of bitumen in the pack is substantially increased, both by steam and solvent.

Compaction of the formation is to be expected in cases of long periods of steam injection (implying high recoveries of bitumen), high injection pressure of steam (above 100 psig), and several slug sizes (70% PV, 40% PV, and 20% PV). Even if compaction is not present (Runs 5 and 7), sand in the upper part of the model was so loose that if any overburden pressure had existed compaction of the formation would have been present.

Steam injection rate was the most important factor affecting recovery of bitumen.

Solvent is more or less evenly distributed throughout the pack rather than channeling.

Slippage of solvent and steam through the walls, may be the other reason for early breakthrough.

Table 9
General Characteristics and Results of Run 4

Amount of tar sand packed	14029.8 gms.
Bitumen content of the tar sand	1431 (Wt%)
Weight of bitumen in place	2007.7 gms.
Volume of bitumen in place	1937.91 cc
Solvent used	Naphtha
Weight of clean sand	12022.18 gms.
Volume of clean sand	4479.2 gms.
Volume of the model	6480 cc
Void space in the model	62.9 cc
Pore volume	2070.56 cc
Porosity	.3195
Total solvent injected	1400 cc
Total run time	44 hrs.
Time for effluent breakthrough	4.75 hrs.
Solvent injection time	16 hrs.
Volume of solvent inj. before effluent B.T.	540 cc
Average injection rate before B.T.	1.89 cc/min.
Average flow rate	1.46 cc/min.

Table 10
Comparative Table for the Steam Injection Cycles Performed in Run 5

Cycle #	Time (hrs)	Volume Produced (cc)	Water Produced (cc)	Average Flow Rate (cc/min.)	Average Steam Press. (psig)	Bitumen Recovered (cc)	Percent Recovered (%)
1	3.35	532.0	285.0	2.65	100.0	129.2	13.5
2	7.13	1534.0	1278.0	3.59	100.0	145.0	15.2
3	7.35	5811.0	5099.0	13.18	100.0	302.0	31.7
4	11.35	5235.0	4235.0	7.69	100.0	380.0	39.7

Table 11

Injection History for Run 5

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
0.0	0.0	0.0	0.0	0.0	0.0
42.0	42.0	80.0	80.0	1.9	6.0
71.0	113.0	180.0	260.0	2.53	25.0
99.0	212.0	170.0	430.0	1.71	40.0
123.0	335.0	80.0	510.0	.65	30.0
56.0	391.0	30.0	540.0	.54	32.5
23.0	414.0	60.0	600.0	2.6	42.0
38.0	452.0	60.0	660.0	1.58	52.0
89.0	541.0	120.0	480.0	1.35	42.0
40.0	581.0	40.0	820.0	1.00	39.0
34.0	615.0	20.0	840.0	.589	40.0
35.0	650.0	60.0	900.0	1.71	40.0

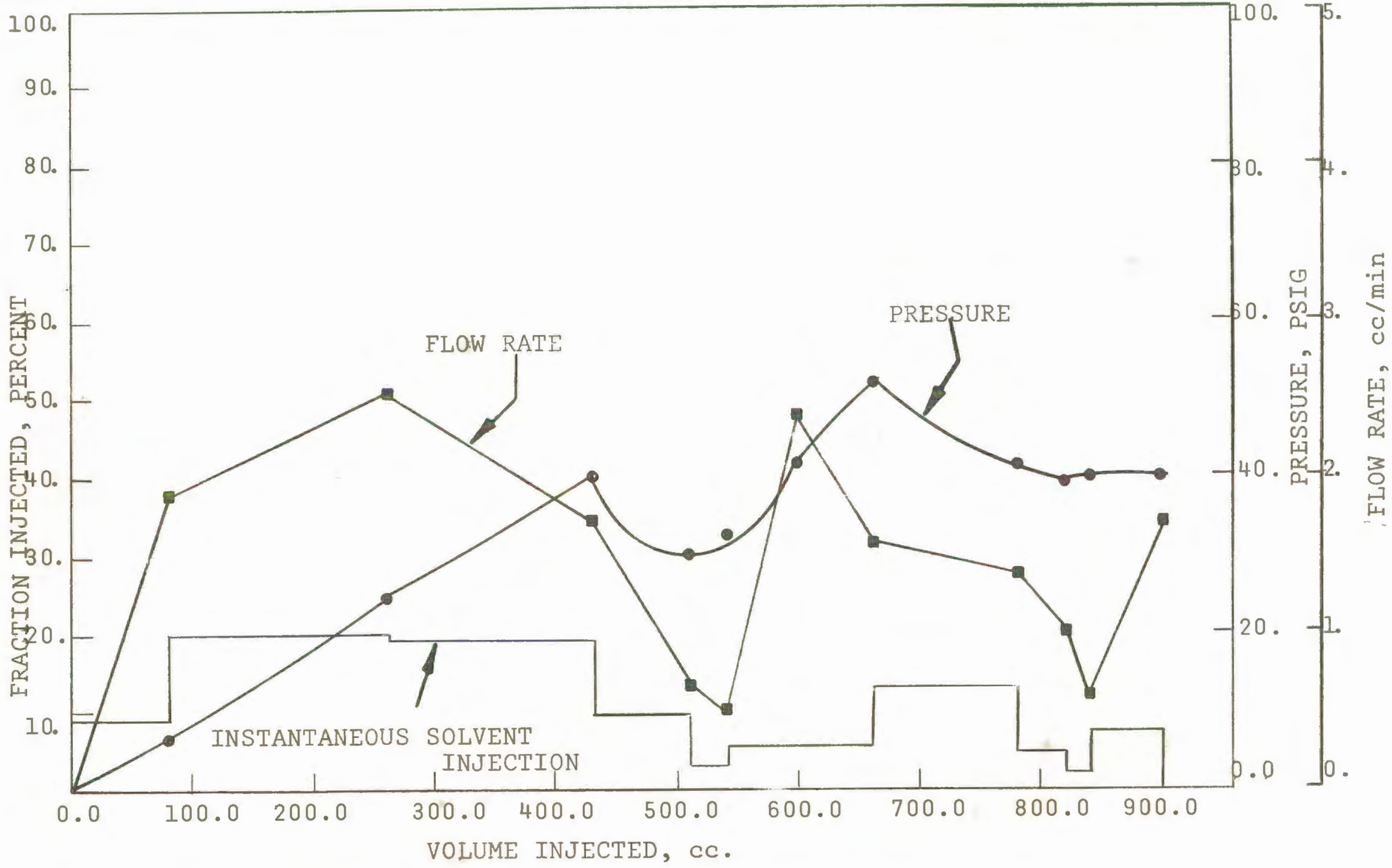


Figure 35 Injection History for Run 5.

Table 12
Production History for Run 5

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)
1	90.0	90.0	250.0	250.0	90.0	90.0	78.8	78.8
2	110.0	201.0	292.0	532.0	195.0	295.0	51.1	129.0
3	248.0	440.0	577.0	1109.0	449.0	734.0	90.0	210.0
4	441.0	890.0	957.0	2066.0	889.0	1623.0	56.4	275.4
5	75.0	965.0	491.0	2557.0	455.0	2078.0	40.0	315.4
6	34.0	999.0	320.0	2877.0	270.0	2351.0	37.0	352.4
7	101.0	1100.0	1000.0	3877.0	850.0	3207.0	49.6	402.0
8	231.0	1331.0	1900.0	5777.0	1675.0	4992.0	125.2	527.2
9	220.0	1551.0	1900.0	7577.0	1750.0	6632.0	48.8	576.0
10	213.0	1764.0	1900.0	9577.0	1720.0	8352.0	81.0	657.0
11	178.0	1942.0	1900.0	11477.0	1618.0	9970.0	171.0	828.0
12	50.0	1992.0	1135.0	13312.0	897.0	10867.0	129.0	957.0

Table 12 (continued)

I W.B.R.[a] (cc/cc)	I S.B.R.[b] (cc/cc)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cummulative Solvent (cc)
1.14	1.03	2.78	100.0	91.2	81.2
3.82	.70	2.54	100.0	35.9	117.10
4.99	.42	2.33	100.0	38.0	155.0
15.76	.21	2.17	100.0	11.6	166.70
11.38	0.0	6.55	100.0	0.0	166.70
7.30	.35	9.41	100.0	13.0	179.70
17.14	2.02	9.90	100.0	100.4	280.00
13.14	.80	8.23	100.0	100.0	380.10
35.86	2.07	8.64	100.0	101.2	481.30
21.23	1.22	8.92	100.0	99.0	580.30
9.46	.65	10.7	100.0	111.0	691.30
6.95	.84	22.7	100.0	109.0	800.30

[a] I W.B.R. = Instantaneous water bitumen ratio.

[b] I S.B.R. = Instantaneous solvent bitumen ratio.

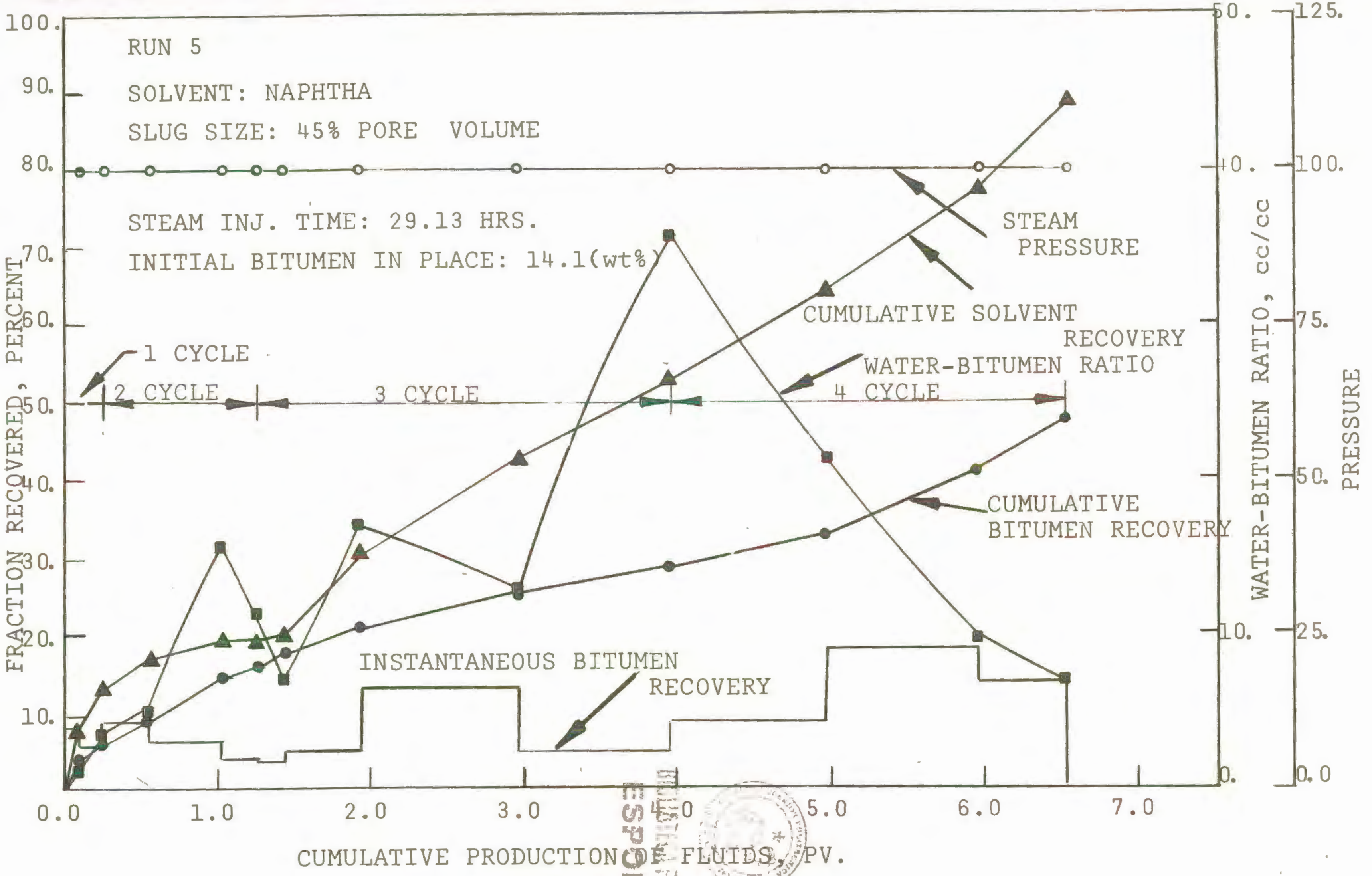


Figure 36 Production History for Run 5.

Table 13
General Characteristics and Results for Run 5

Amount of tar sand packed	14912 gms.
Bitumen content of the tar sand	.141
Weight of bitumen in place	2102 gms.
Volume of bitumen in place	2020 cc
Solvent used	Naphtha
Weight of clean sand	12809 gms.
Volume occupied by the porous plates	161.58 cc
Volume of the steel box	7054 cc
Volume of clean sand	4772.5 cc
Void space in the model	90.34
Pore volume	2119 cc
Porosity	.30
Total solvent injected	900 cc
Amount of solvent retained by the pack	99.7 cc
Total run time	29.12 hrs.
Time for effluent breakthrough	10.83 hrs.
Solvent injection time	10.83 hrs.
Volume of solvent inj. before effluent B.T.	900 cc
Average injection rate before B.T.	1.38 $\frac{cc}{min.}$
Average flow rate	1.38 $\frac{cc}{min.}$
Average pressure for solvent injection	35.32 psig
Total steam injected (as water)	10867 cc
Average pressure for steam injection	100.75 psig
Time of steam injection	29.3 hrs.

Table 13 (continued)

Time for steam breakthrough	18.29 hrs.
Water-bitumen ratio	11.26 cc/cc
Solvent-bitumen ratio	.94 cc/cc
Total bitumen recovery	957.4 cc
Steam injection rate (as condensate)	47.17%
Recovery	621 cc/min.

RUN 5

RUN 7

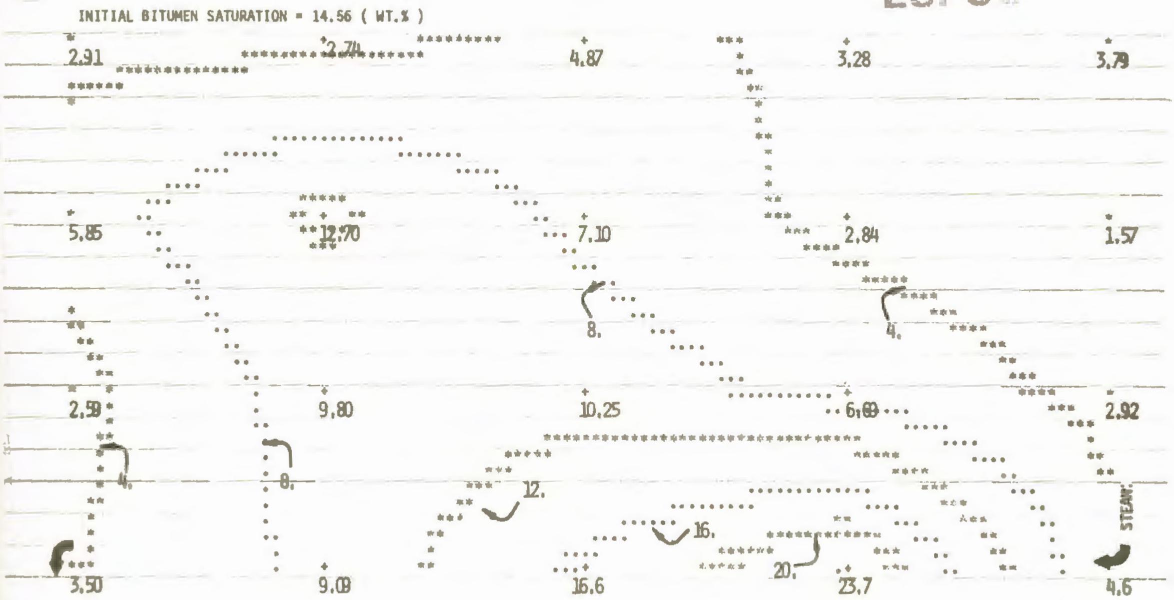


Figure 37 Residual Saturation Contours for Runs 5 and 7.

Table 14

Injection History for Run 7

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
0.0	0.0	0.0	0.0	0.0	0.0
10.0	10.0	20.0	20.0	2.0	1.0
15.0	25.0	40.0	60.0	2.66	2.0
45.0	60.0	100.0	100.0	3.22	5.5
71.0	131.0	200.0	360.0	2.81	14.0
47.0	178.0	120.0	480.0	2.55	18.5
41.0	219.0	80.0	560.0	1.05	19.0
23.0	242.0	70.0	630.0	3.04	19.0
76.0	318.0	130.0	760.0	1.71	23.0
60.0	378.0	70.0	830.0	1.66	19.5
19.0	397.0	40.0	870.0	2.10	21.5
37.0	434.0	37.0	907.0	1.0	22.5
23.0	451.0	33.0	940.0	1.43	22.5

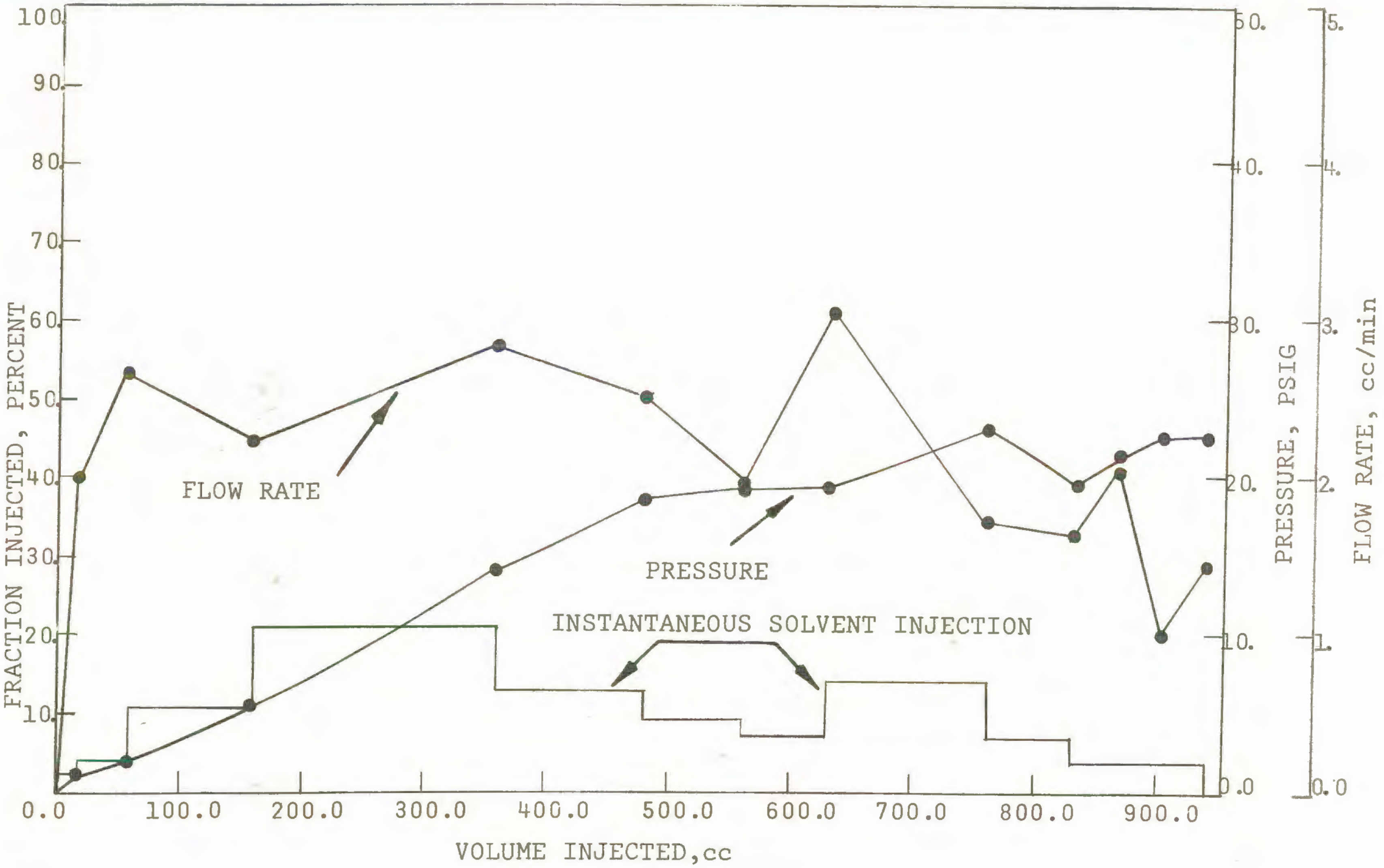


Figure 38 Injection History for Run 7.

Table 15

Injection History for Run 8

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
0.0	0.0	0.0	0.0	0.0	0.0
11.0	11.0	20.0	20.0	1.82	1.0
13.0	24.0	22.0	42.0	1.69	1.0
14.0	38.0	18.0	60.0	1.29	2.5
25.0	63.0	80.0	140.0	3.20	7.0
15.0	78.0	30.0	170.0	2.0	13.7
16.0	94.0	40.0	210.0	2.5	21.5
23.0	117.0	50.0	260.0	2.17	22.8
26.0	143.0	50.0	310.0	1.92	28.5
16.0	159.0	30.0	340.0	1.88	32.5
14.0	173.0	20.0	360.0	1.43	32.5
11.0	184.0	20.0	380.0	1.82	32.5
12.0	196.0	20.0	400.0	1.67	32.5

Table 16
Production History for Run 7

Sample #	Time (min.)	Cummulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)
1	-	-	850.0	850.0	600.0	600.0	47.6	47.6
2	-	-	800.0	1650.0	600.0	1200.0	33.0	80.6
3	130.0	130.0	944.0	2594.0	350.0	1550.0	248.5	329.1
4	153.0	183.0	1080.0	3674.0	650.0	2200.0	265.0	594.1
5	93.0	276.0	890.0	4564.0	730.0	2930.0	104.0	698.1
6	128.0	404.0	870.0	5434.0	860.0	3790.0	10.0	708.1
7	38.0	437.0	880.0	6314.0	870.0	4660.0	10.0	718.1
8	54.0	491.0	770.0	7084.0	700.0	5360.0	70.0	788.0
9	30.0	521.0	400.0	7484.0	350.0	5710.0	50.0	838.1
10	25.0	546.0	200.0	7684.0	270.0	5880.0	30.0	868.1

Table 16 (continued)

I[a] W.B.R. (cc/cc)	I[b] S.B.R. (cc/cc)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent (cc)
12.61	4.24	-	100.0	202.0	202.0
18.18	5.06	-	100.0	167.0	369.0
1.41	1.39	7.26	100.0	345.0	714.0
2.45	0.62	20.38	100.0	165.0	879.0
7.02	0.54	9.57	100.0	56.0	935.0
86.0	0.0	6.80	110.0	0.0	935.0
86.0	0.0	26.67	100.0	0.0	935.0
10.0	0.0	14.26	100.0	0.0	935.0
7.0	0.0	13.30	100.0	0.0	935.0
5.67	0.0	8.80	100.0	0.0	935.0

[a] I W.B.R. = Instantaneous water bitumen ratio.

[b] I S.B.R. = Instantaneous solvent bitumen ratio.

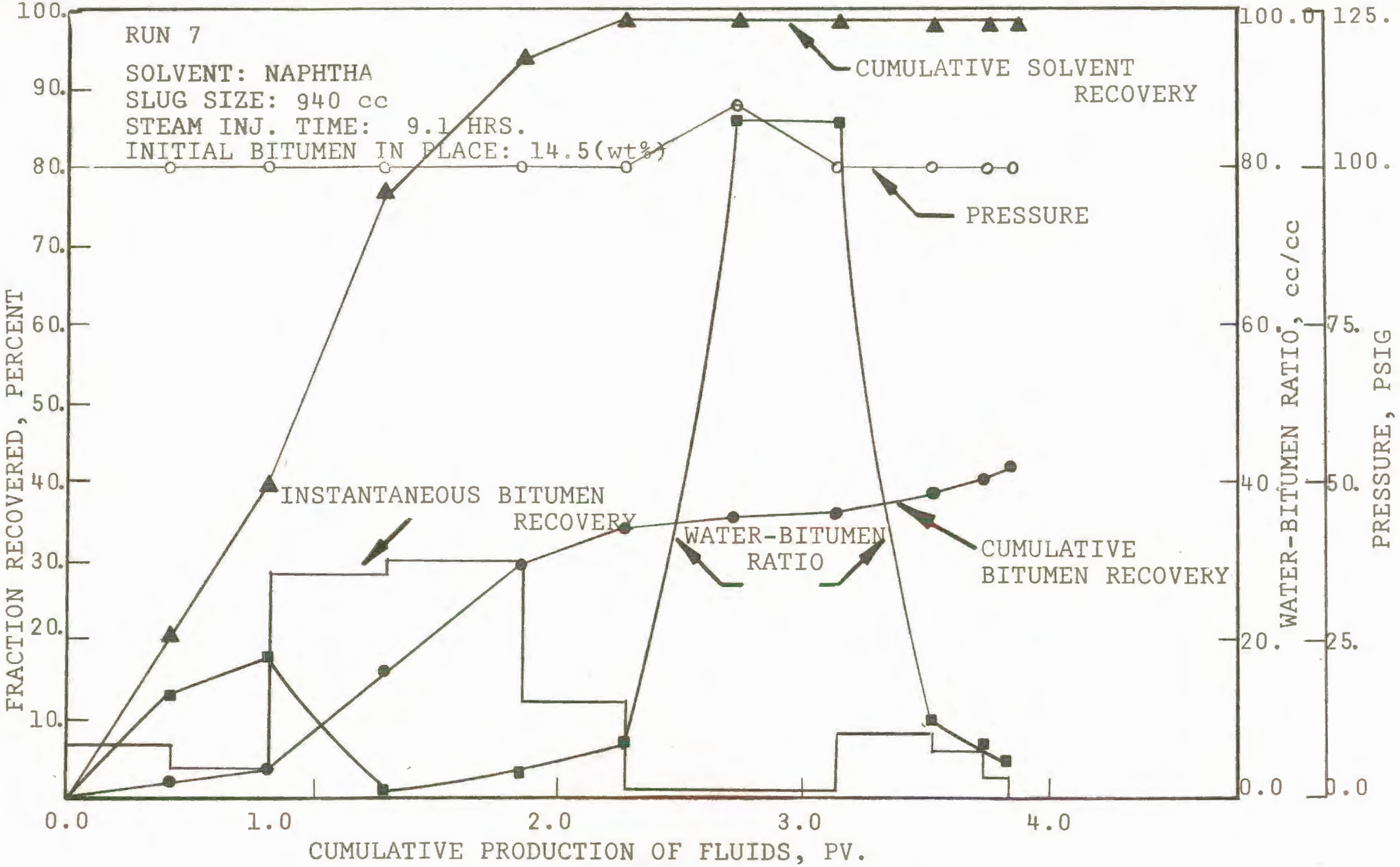


Figure 39 Production History for Run 7.

Table 17
Production History for Run 8

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)
1	85.0	85.0	290.0	290.0	290.0	290.0	0.0	0.0
2	181.0	166.0	850.0	1140.0	750.0	1040.0	39.0	39.0
3	05.0	261.0	810.0	1950.0	540.0	1580.0	70.2	109.2
4	228.0	489.0	900.0	2850.0	700.0	2280.0	96.0	205.2
5	250.0	730.0	1900.0	3750.0	720.0	3000.0	156.8	362.0
6	-	-	1000.0	3750.0	950.0	3950.0	28.0	390.0
7	-	-	920.0	5670.0	830.0	4780.0	32.0	422.0
8	-	-	880.0	6550.0	850.0	5630.0	23.0	445.0
9	-	-	400.0	6950.0	300.0	5930.0	100.0	545.0
10	-	-	540.0	7490.0	529.0	6459.0	11.0	556.0
11	-	-	640.0	8130.0	630.0	7091.0	8.0	564.0

Table 17 (continued)

I[a] W.B.R. (ccw/ccb)	I[b] S.B.R. (ccs/ccb)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent (cc)
-	0.0	3.41	100.0	0.0	0.0
19.23	1.56	4.70	100.0	61.0	61.0
9.12	1.43	8.53	100.0	100.0	161.0
8.33	1.08	3.95	100.0	100.0	265.0
4.59	.15	3.60	100.0	23.0	288.0
35.71	.79	-	95.0	22.0	310.0
27.5	2.13	-	100.0	68.0	378.0
38.3	.30	-	90.0	7.0	385.0
4.0	0.0	-	100.0	0.0	385.0
44.0	0.0	-	100.0	0.0	385.0
80.0	0.0	-	100.0	0.0	385.0

[a] I W.B.R. = Instantaneous water bitumen ratio.

[b] I S.B.R. = Instantaneous solvent-bitumen ratio.

Table 18

General Characteristics and Results for Run 7

Amount of tar sand packed	14601.4 gms.
Bitumen content of tar sand	.145
Weight of bitumen in place	2177.2 gms.
Volume of bitumen in place	2043.63 cc
Solvent used	Naphtha
Weight of clean sand	12424.2 gms.
Volume of clean sand	4628.9 cc
Volume of steel box	6874 cc
Volume of porous plates	161.58 cc
Void space in the model	40 cc
Pore volume	2083.63
Porosity	.3031
Total solvent injected	940 cc
Amount of solvent retained by the pack	5 cc
Total run time	21.37 hrs.
Time for effluent breakthrough	13.14 hrs.
Solvent injection time	7.62 hrs.
Volume of solvent inj. before effluent B.T.	940 cc
Average inj. rate before effluent B.T.	2.05 $\frac{cc}{min.}$
Average flow rate	2.05 $\frac{cc}{min.}$
Average pressure for solvent injection	16.15 psig
Average pressure for steam injection	100 psig
Time of steam injection	14 hrs.
Time for steam breakthrough	22.12 hrs.

Table 18 (continued)

Water-bitumen ratio	6.77 $\frac{cc}{cc}$
Total steam injected (as condensate)	4525 cc
Steam injection rate	5.39 $\frac{cc}{min.}$
Total bitumen recovery	868 cc
Recovery	42%

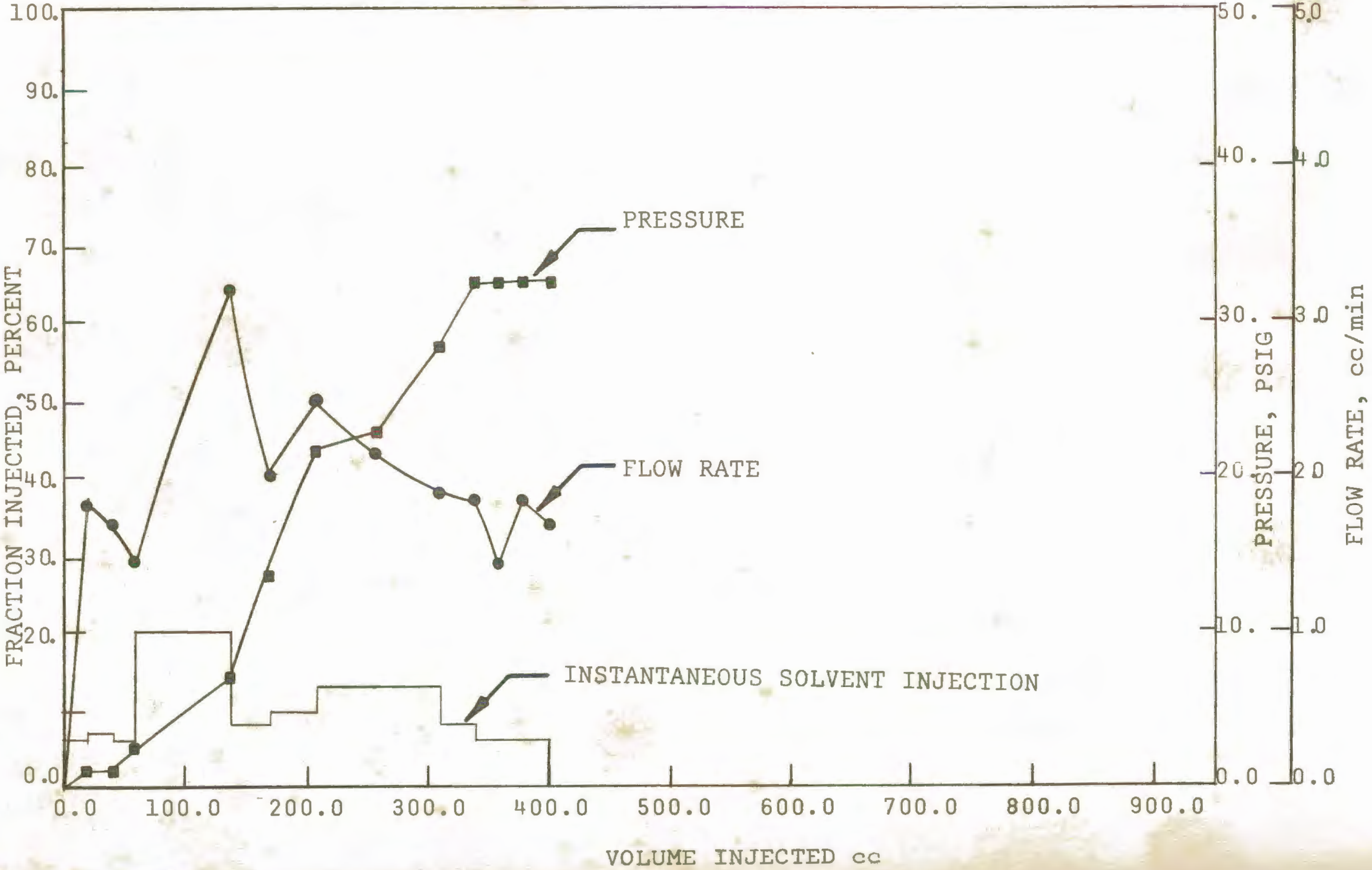


Figure 40 Injection History for Run 8.

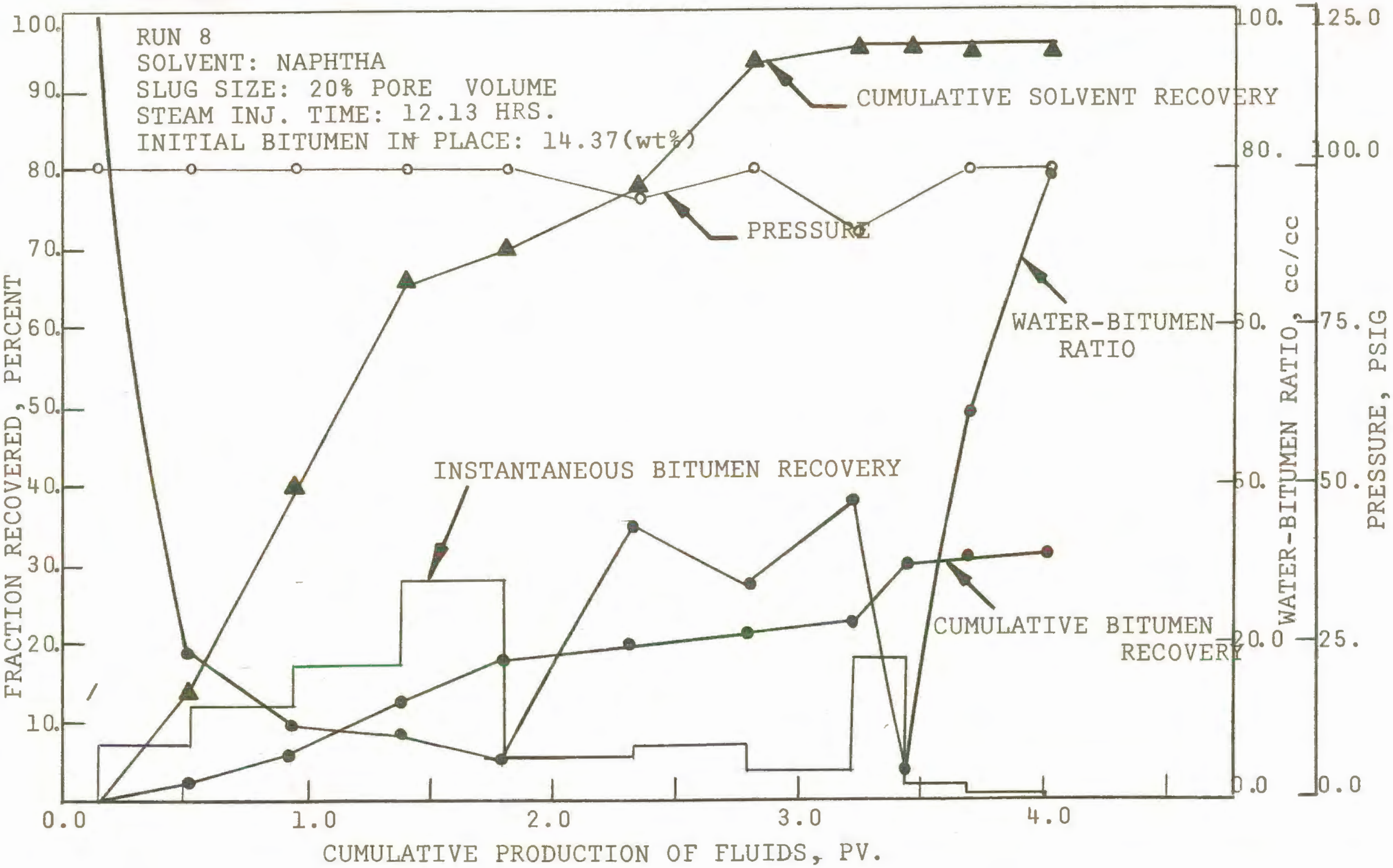


Figure 41 Production History for Run 8.

Table 19

General Characteristics and Results for Run 8

Amount of tar sand packed	14120 gms.
Bitumen content of tar sand	.1437
Weight of bitumen in place	2020 gms.
Volume of bitumen in place	1958.6 cc
Solvent used	Naphtha
Weight of clean sand	12091.4 gms.
Volume of clean sand	4505 cc
Volume of steel box	6874 cc
Volume of porous plates	161.5 cc
Void space in the model	248.7 cc
Pore volume	2207.4 cc
Porosity	.3211
Total solvent injected	400 cc
Amount of solvent retained by the pack	15 cc
Total run time	15.4 hrs.
Time of solvent injection	3.27 hrs.
Time of steam injection	12.13 hrs.
Time for effluent breakthrough	4.52 hrs.
Volume of solvent inj. before effluent B.T.	400 cc
Average injection rate before effluent B.T.	2.04 $\frac{cc}{min.}$
Averag flow rate	4.85 $\frac{cc}{min.}$
Average pressure for solvent injection	19 psig
Average pressure for steam injection	90 psig

Table 19 (continued)

Time for steam breakthrough	12.13 hrs.
Water-bitumen ratio	12.57 $\frac{cc}{min.}$
Total steam injected (as condensate)	7745 cc
Steam injection rate	10.38 $\frac{cc}{min.}$
Total bitumen recovery	564.24 cc
Recovery	28.8%

RUN 8

RUN 9

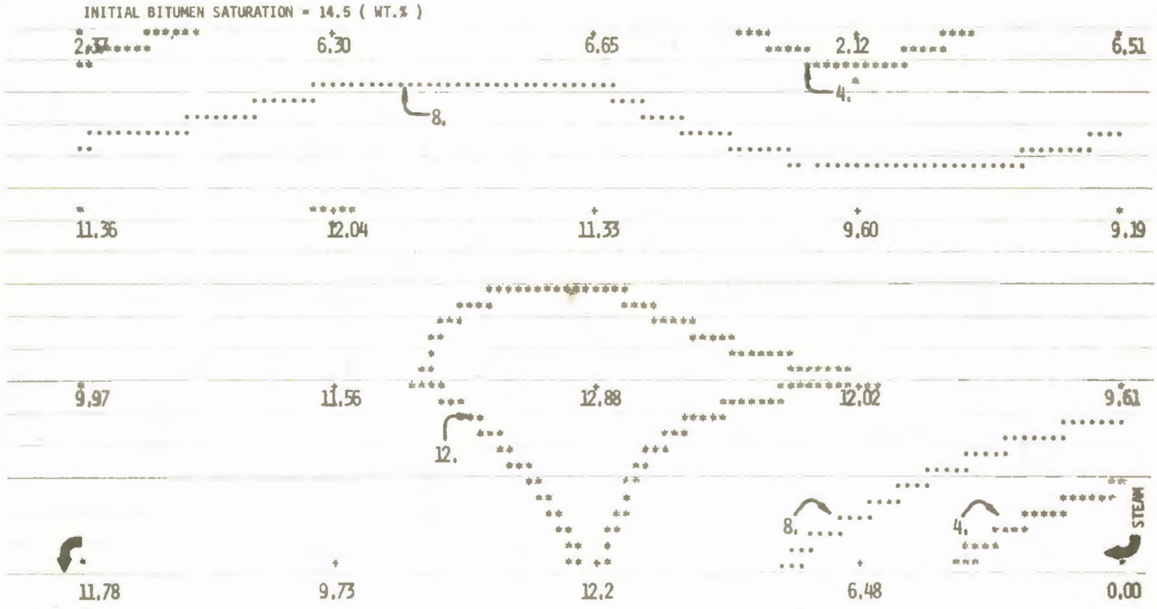
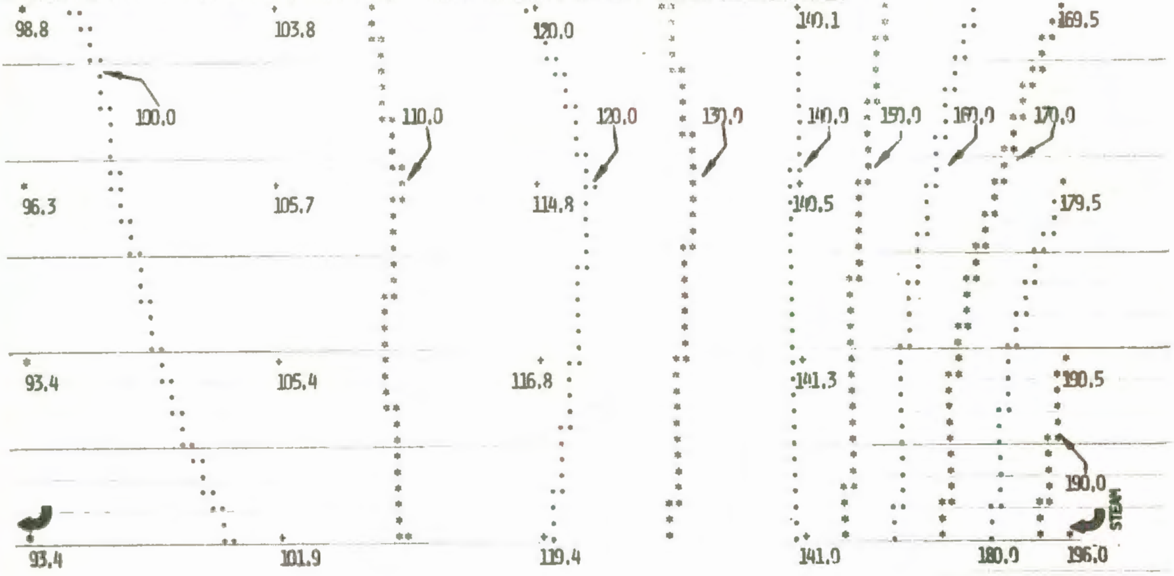


Figure 42 Residual Saturation Contours for Runs 8 and 9.

TEMPERATURE PROFILE AFTER 03 HRS OF STEAM INJ.,P = 120.0 PSIG.,TEMP. IN DEG. F (SECOND INJECTION CYCLE)



TEMPERATURE PROFILE AFTER 06.25 HRS OF STEAM INJ.,P = 100.0 PSIG.,TEMP. IN DEG. F. (SECOND INJECTION CYCLE)

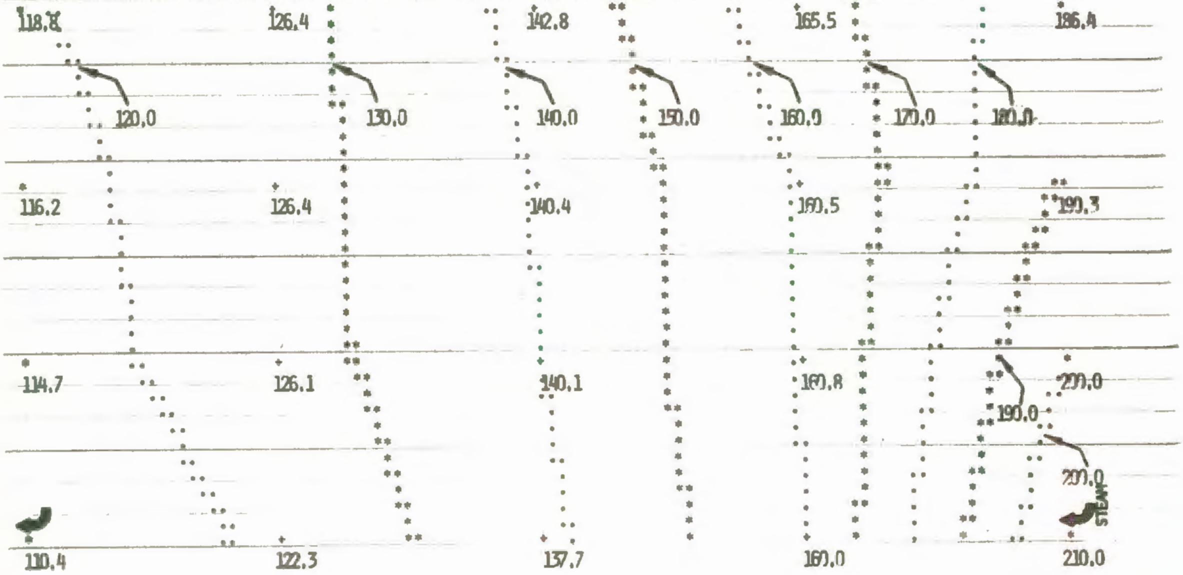
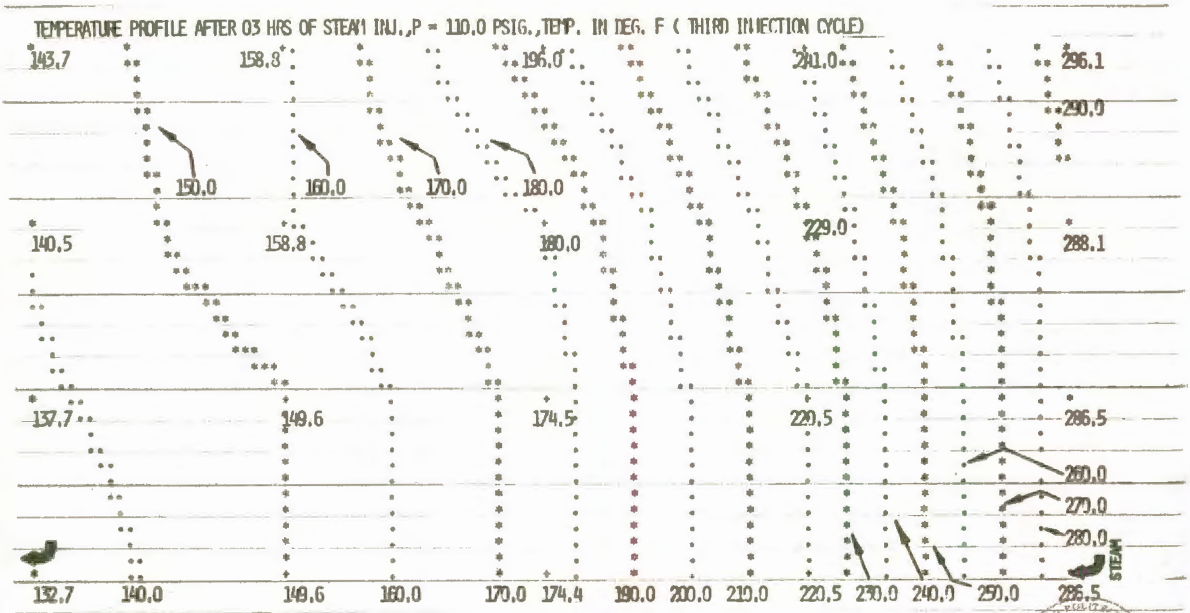


Figure 43 Temperature Profiles for Run 5.



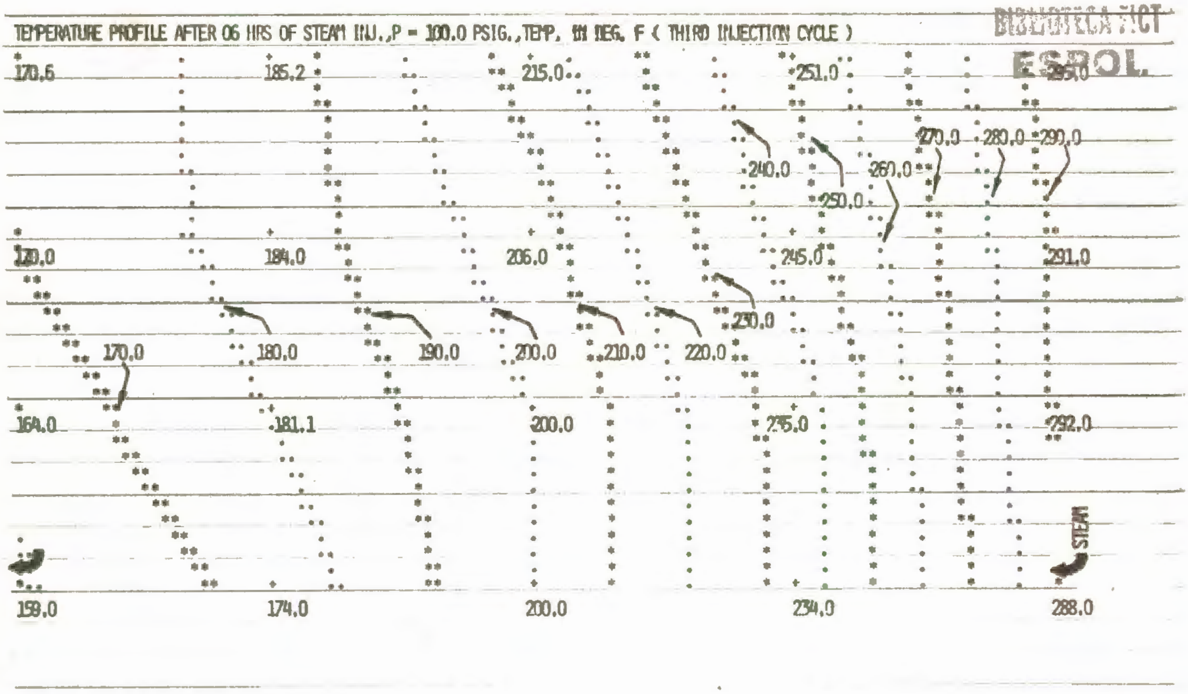
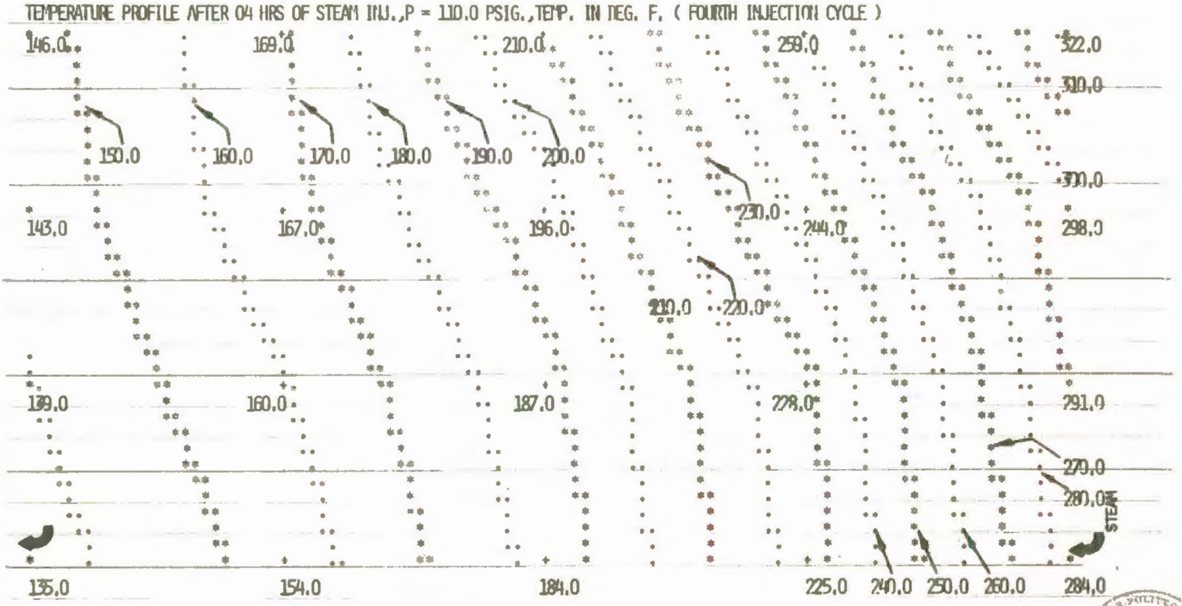


Figure 44 Temperature Profiles for Run 5.


TEMPERATURE PROFILE AFTER 04 HRS OF STEAM INJ.,P = 110.0 PSIG.,TEMP. IN DEG. F. (FOURTH INJECTION CYCLE)

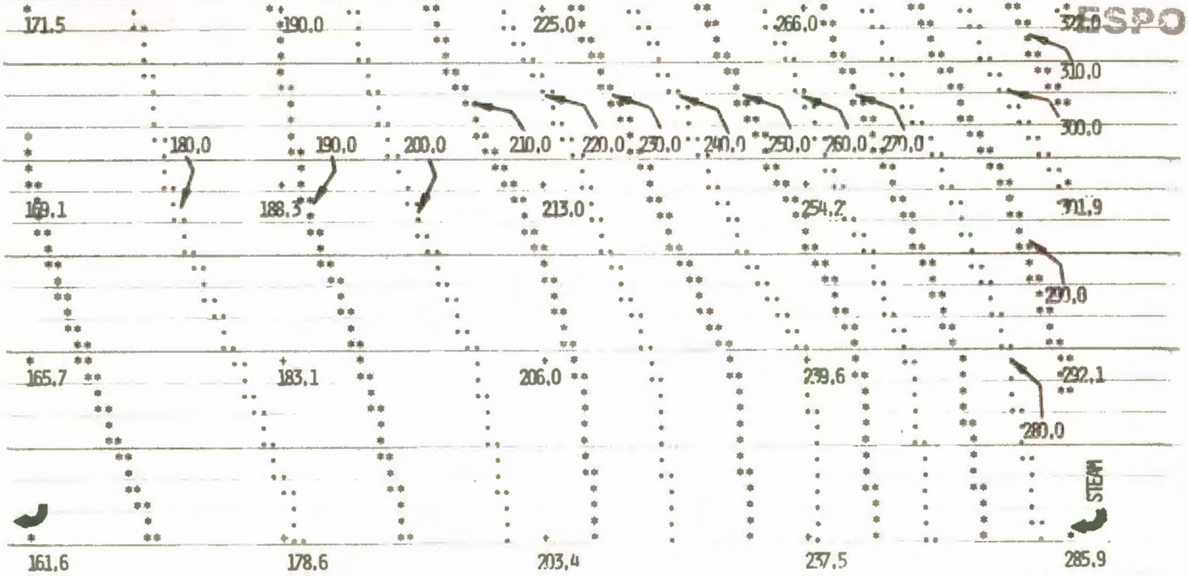
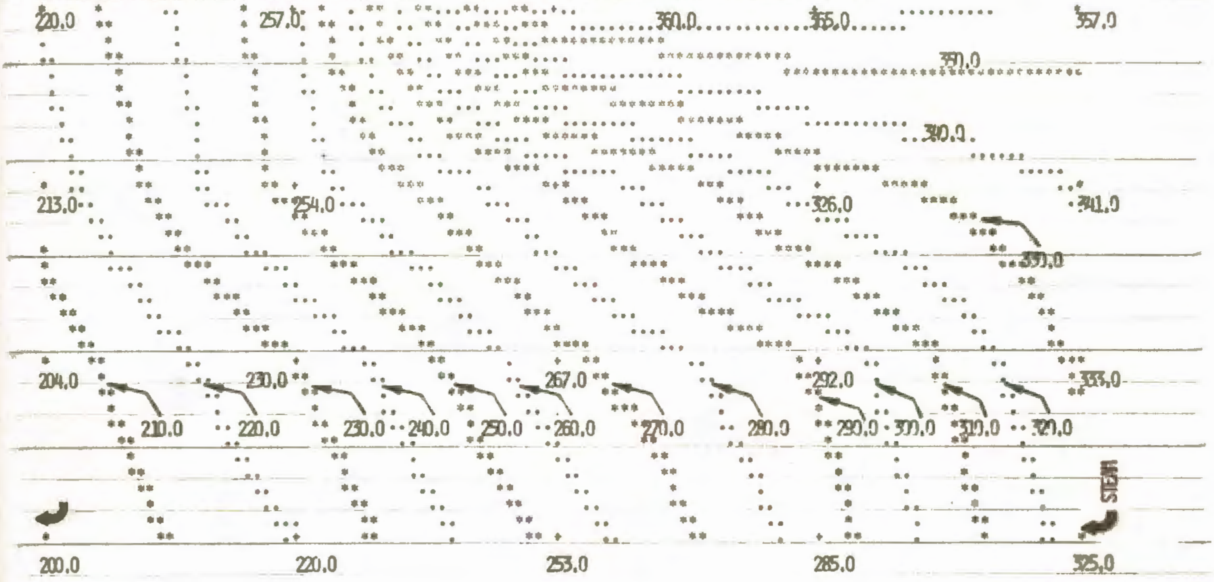

TEMPERATURE PROFILE AFTER 06 HRS OF STEAM INJ.,P =110.0 PSIG.,TEMP. IN DEG. F. (FOURTH INJECTION CYCLE)

Figure 45 Temperature Profiles for Run 5.

TEMPERATURE PROFILE AFTER 09 HRS OF STEAM INJ.,P = 90.0 PSIG.,TEMP. IN DEG. F. (FOURTH INJECTION CYCLE)



TEMPERATURE PROFILE AT STEAM BREAKTHROUGH (11,17),P = 90.0 PSIG.,TEMP. IN DEG. F. (FOURTH INJECTION CYCLE)

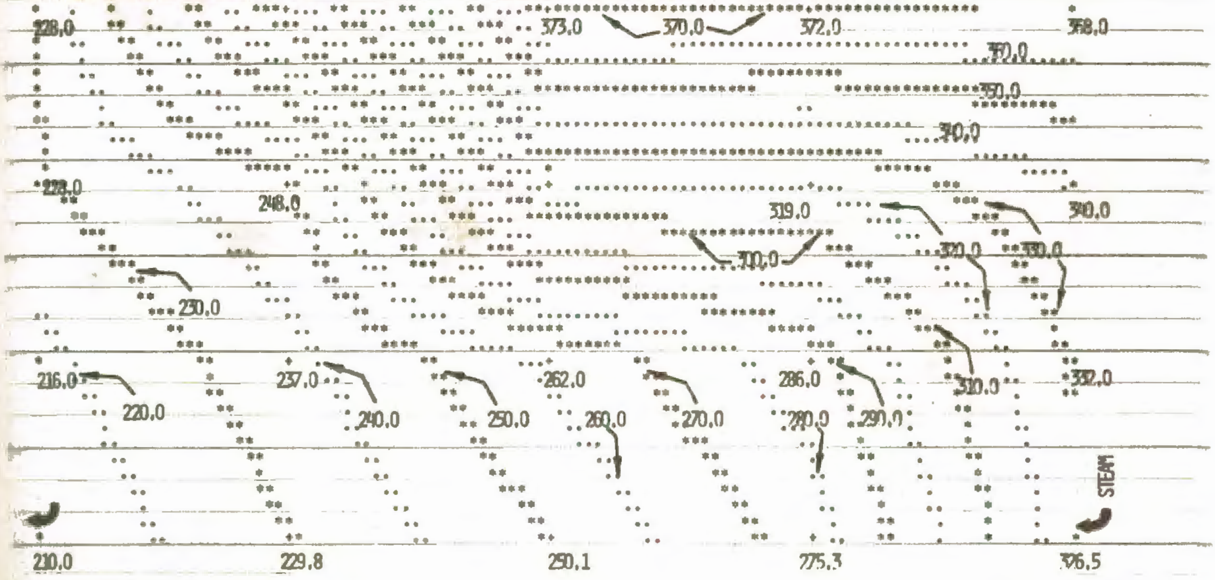
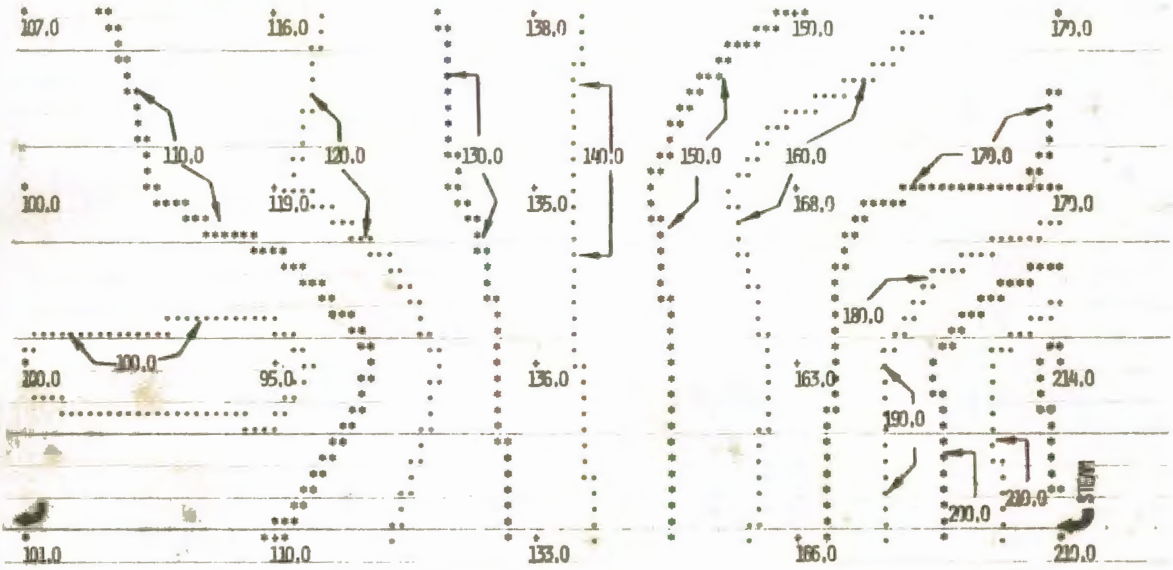


Figure 46 Temperature Profiles for Run 5.

TEMPERATURE PROFILE AFTER 03 HRS OF STEAM INJ.,P = 100.0 PSIG.,TEMP. IN DEG. F



TEMPERATURE PROFILE AFTER 04 HRS OF STEAM INJ.,P = 100.0 PSIG.,TEMP. IN DEG. F

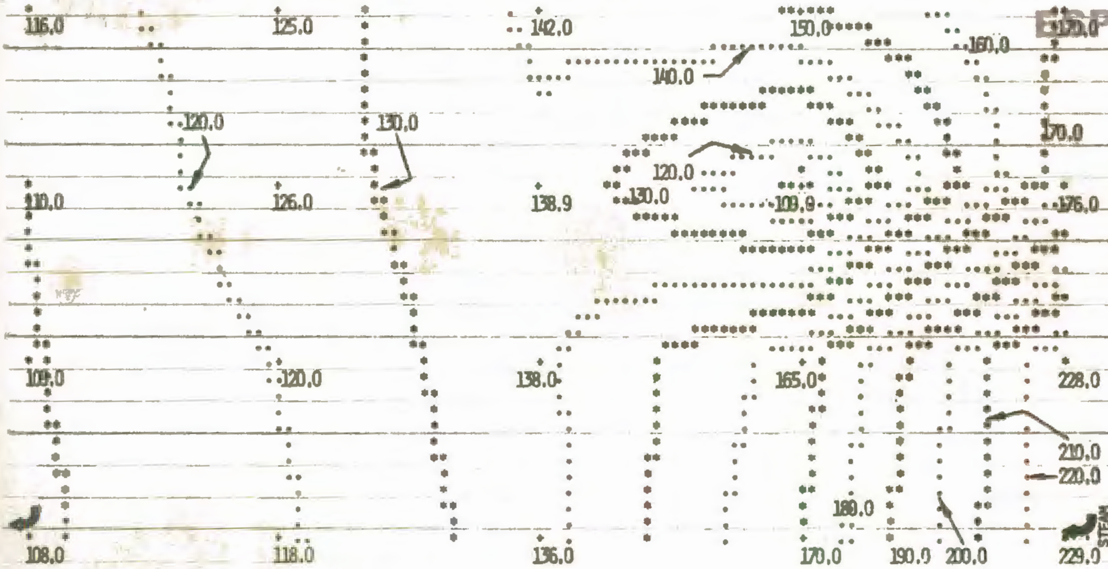
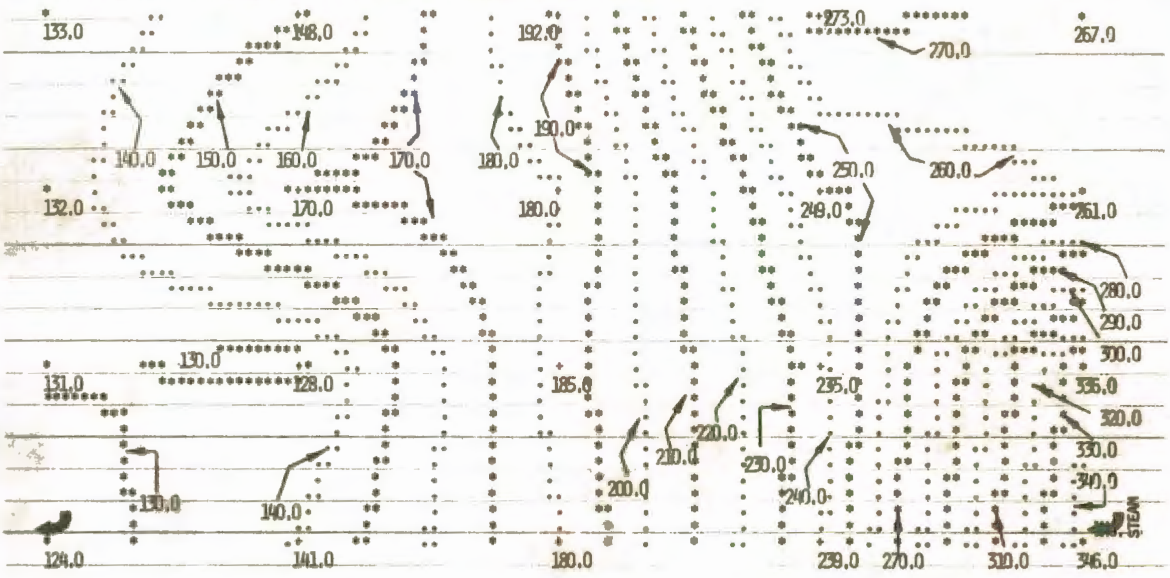


Figure 47 Temperature Profiles for Run 7.

TEMPERATURE PROFILE AFTER 06 HRS. OF STEAM INJ.,P = 100.0 PSIG.,TEMP. IN DEG. F



TEMPERATURE PROFILE AFTER 08 HRS OF STEAM INJ.,P = 110.0 PSIG.,TEMP. IN DEG. F

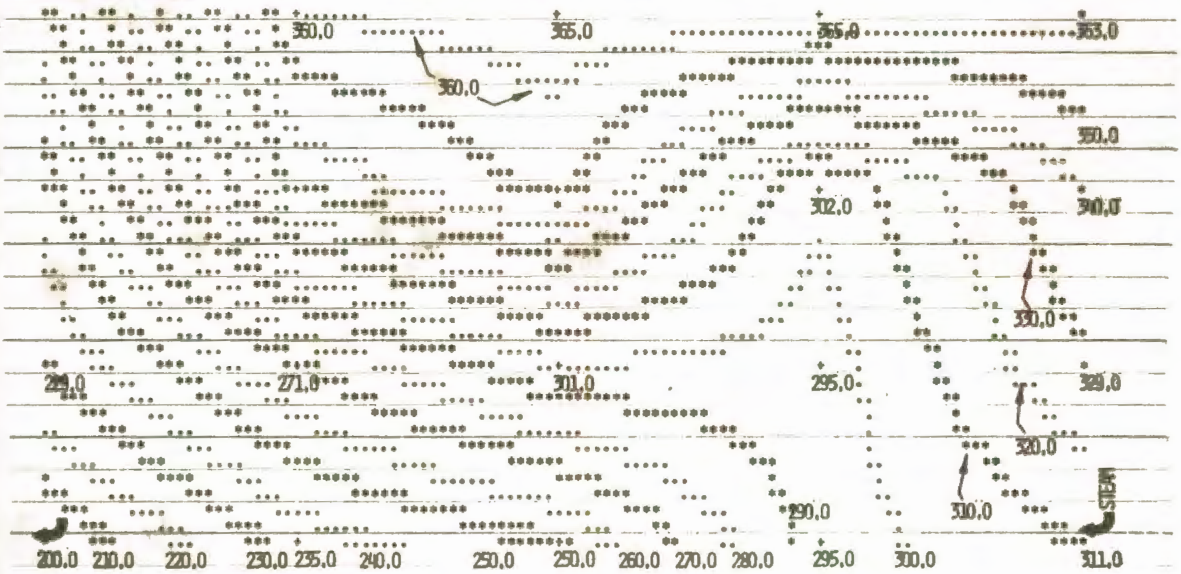
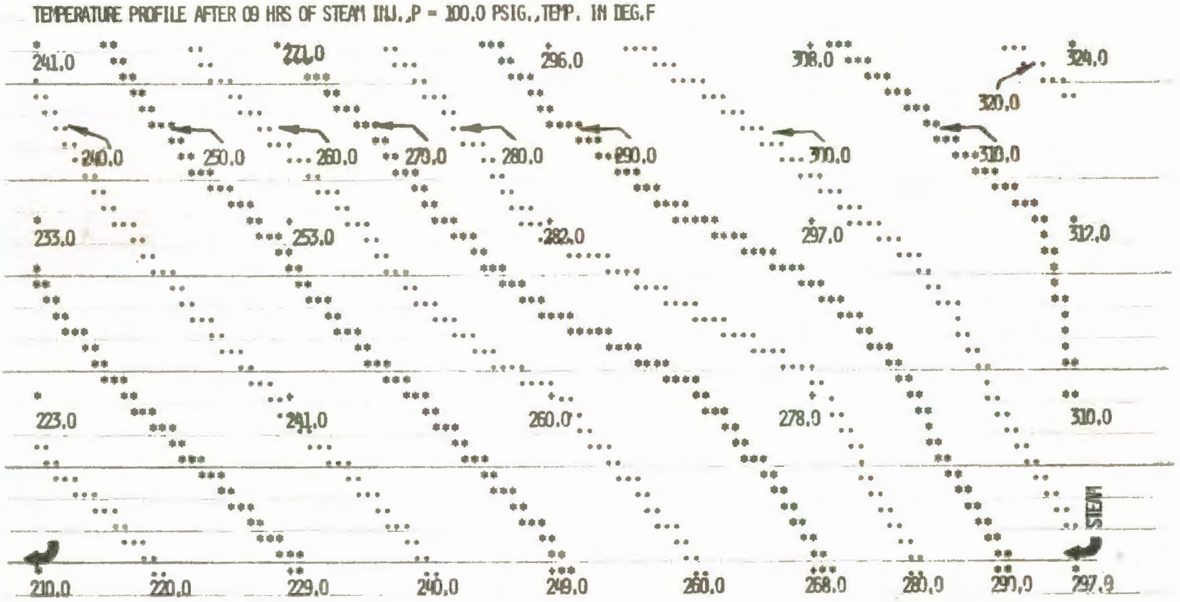


Figure 48 Temperature Profiles for Run 7.



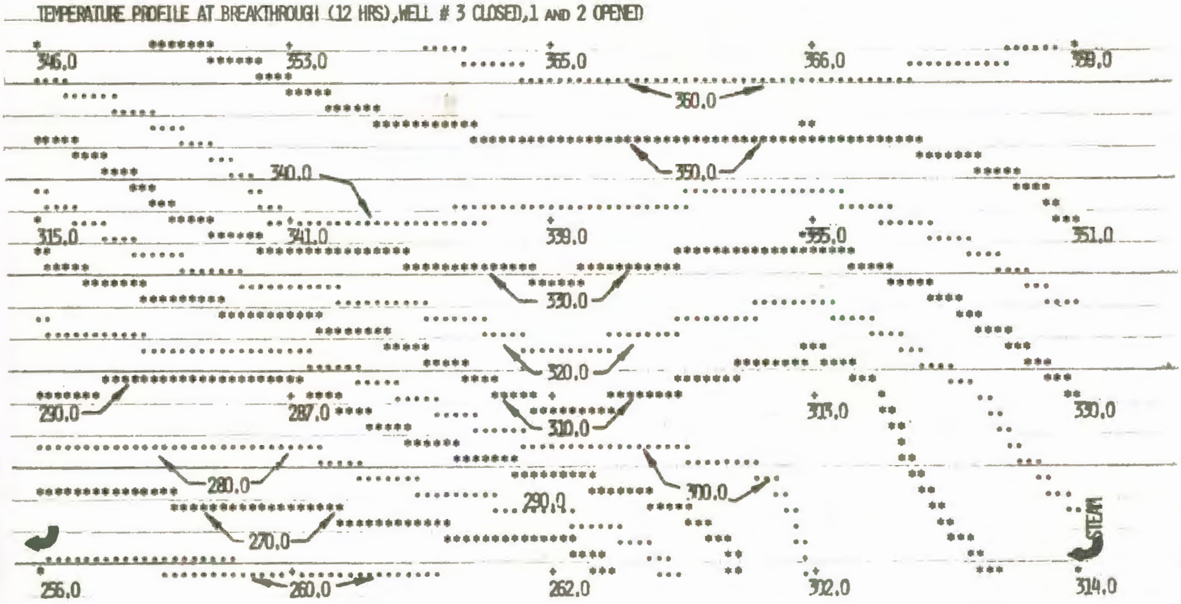
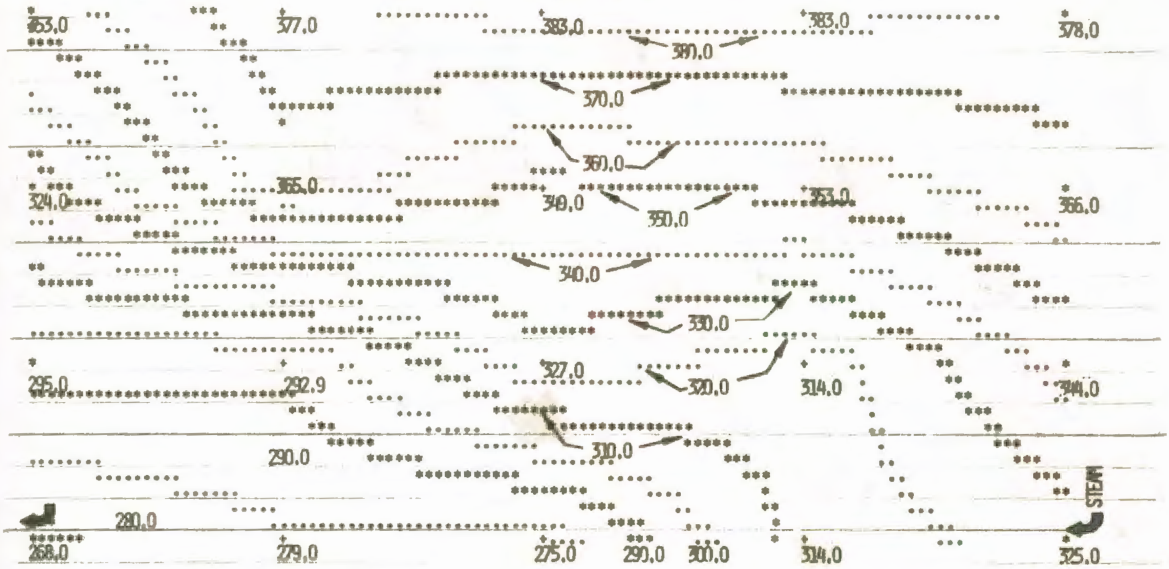


Figure 49 Temperature Profiles for Run 7.

TEMPERATURE PROFILE AFTER 13.25 HRS OF STEAM INJ.,P = 140.0 PSIG.,TEMP. IN DEG. F



TEMPERATURE PROFILE AT BREAKTHROUGH (14 HRS),P = 120.0 PSIG.,TEMP. IN DEG. F

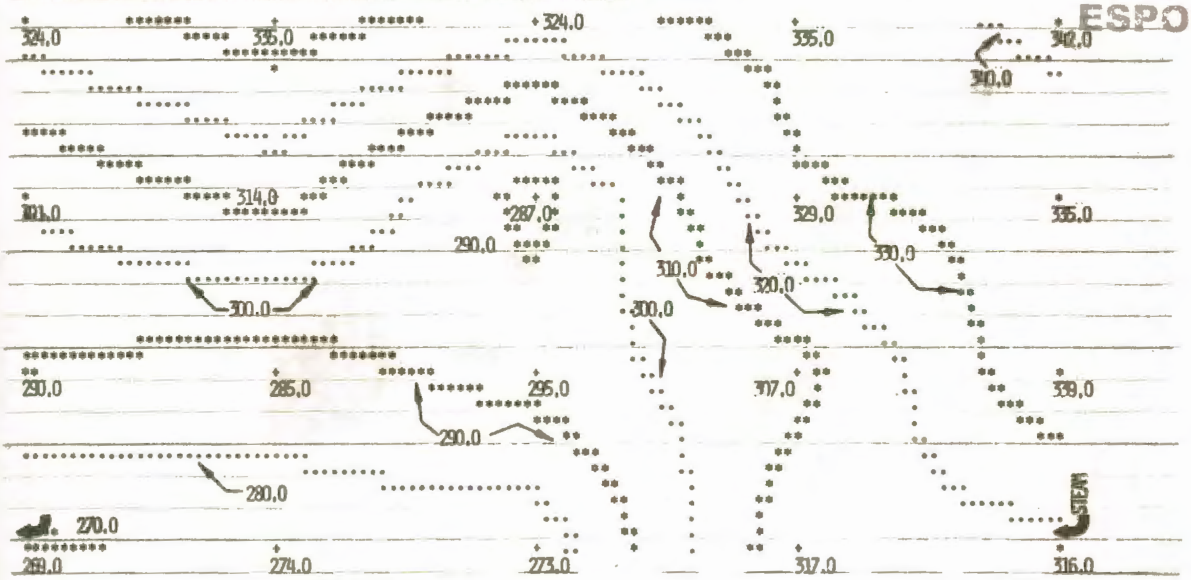


Figure 50 Temperature Profiles for Run 7.

GCOS Synthetic Crude-Steam Runs

Tar Sand Pack Saturated with Bitumen and Air

Runs 9, 10 and 11 were made using the GCOS synthetic crude as solvent, followed by steam injection. When experimenting with naphtha, plugging of the pack was attributed to plugging in the porous plates. It was decided to remove the plates in the next three runs (9, 10 and 11). But, later it was discovered that plugging was not occurring because of the plates, but because of asphaltene flocculation when using naphtha as a solvent.

Run 9 was carried out to reproduce as closely as possible Run 7. Even though similar volumes of solvent were injected, in Run 9 breakthrough of effluent did not occur. Table 20 and Figure 51 give the injection history for this run. The production characteristics for this run were completely different from those of Run 7. Because of the removal of the porous plates, steam breakthrough occurred after 4.5 hours of steam injection, and the recovery of bitumen was lower also (36%), but water-bitumen ratios remained low until the solvent was produced. Afterward, a sharp increase was observed. Figure 52 and Tables 21 and 22 give the production history for this run as well as the results obtained.

Run 10 was made with the idea of having effluent breakthrough before steam injection, even though breakthrough occurred when 880 c.c. of solvent were injected, injection continued up to 1010 c.c.

Table 23 and Figure 53 present the injection history for Run 10.

Runs 10 and 9 were alike, even though Run 9 yielded a higher bitumen recovery (36%) than Run 10 (31.4%) the general trends followed were in close agreement. Table 24 and Figure 54 give the production history for Run 10. Table 25 gives all the information relative to this run.

Run 11 was made to observe the behavior of the process using a 400 c.c. slug size (20% PV) of GCOS synthetic crude. Table 26 and Figure 55 present the injection history for Run 4.

Recovery was much lower for Run 11 (19.3%) than for Run 8 (28.8%), where similar conditions were involved but the naphtha and the porous plates were not removed.

Figure 56 and Table 27 present the production history for this run, Table 28 gives the general characteristics and results for Run 11.

As a result of the removal of the porous plates from the outlet and the inlet, the characteristics of the experiment changed completely. The void space in the pack increased, and the steam found less resistance to the flow in the upper part of the sand pack, and as a consequence, the recovery was lowered because of the early breakthrough of steam.

Temperature was recorded for all these runs, but only temperature profiles for Run 9 are presented in Figures 60 and 61. Due to the removal of the plates, after 2 hours of injection, the overriding effect of steam was already observed, and finally breakthrough occurred in the three runs after only 4-5 hours of steam injection.

Even though the time of steam injection was short, recoveries followed the trend observed in Runs 5, 7 and 8, where the larger slugs yielded higher recoveries. During the course of the runs, no plugging was observed; even though some sand was produced, the lines were never plugged.

After steam breakthrough occurred, the pack was allowed to cool, and 20 core samples were withdrawn for every case. Figure 59 gives the residual saturation contours for Runs 10 and 11. In the contour for Run 11 it is possible to observe the increase in bitumen concentration at the base of the pack. When the steelbox was opened, cavities were present in the sand, not of the same type as the ones observed in Runs 4 and 8, but vertically located along the face through which steam was being injected. Again the removal of the porous plates caused these cavities, because the empty space left between the sand and the box was larger when the porous plates were removed, and the steam experienced less resistance to flow in the upward direction. Runs 12, 13 and 14 were conducted using 45, 20 and 10% slug sizes, respectively, but now the porous plates were placed again at the outlet as well as in the inlet of the model.

In general, recoveries increased for both slug sizes used. Run 12 (45% PV) yielded 57% recovery, Run 13

(20% PV) yielded 27%, while Run 14 (10% PV) gave 18.75% recovery.

During these runs no plugging was observed, and steam injection did not involve the complications of Runs 5, 7 and 8 where naphtha was the solvent used. In all the runs involving GCOS synthetic crude, injection port plugging never occurred for any size of slug or any temperature. Asphaltenes are not precipitated by this type of solvent for any of the conditions studied.

It was observed that most of the naphtha injected was recovered during the early stages of production and the residual saturation of naphtha was almost zero. This was not the case for the runs involving GCOS synthetic crude injection, where residual saturation of solvent ranged from 47% (of the original solvent injected) in Run 11, to 16% in Run 12.

Figure 62 and Table 29 show the injection history for Run 12, Figure 63 and Table 30 represent the production history for Run 12 and Table 31 gives the data and results for this run.

In these three runs, the strong dependence of recovery on solvent slug size was again evident. This dependence was observed when using naphtha as a solvent, and when the porous plates were removed from the box and GCOS synthetic crude was injected.

The nature of the solvent was also found to be important for the recovery of bitumen. GCOS synthetic crude is a liquid of higher viscosity (4.56 cp) than naphtha (0.448 cp), and its boiling point is much higher also. When steam is injected, the temperature is increased in the sand pack, and even before having steam in the pack, naphtha is vaporized and produced ahead. That is why almost no naphtha is left behind when the overriding effect of the steam causes breakthrough to occur. This was not the case for the GCOS synthetic crude. Because of its higher boiling point (higher than water), it is displaced much more slowly than naphtha. As a consequence, residual saturations are higher for this solvent, but the displacement of bitumen is much more efficient yielding higher recoveries of bitumen.

Run 14 was the first involving a 10% PV slug size. The reduction in recovery was large, but also the steam injection time, as well as the amount of steam injected was much lower than in any other case. Even though the tar sand packs were packed very carefully, it is impossible not to have a void space in the model. When the slug is injected, it tends to saturate the whole pack (as observed in several experiments). Thus, it was necessary to inject 900 c.c. of solvent (which is more or less the empty space remaining in the sand pack) prior to effluent breakthrough. When a large slug was injected (45% PV), almost no void space remained in the sand pack, and when steam was injected, a water-solvent interface existed in the model, which offered resistance to the overriding effect of the steam, and as a logical consequence recovery increased. When the size of the slug is decreased, so is the resistance to the overriding effect of the steam, and recoveries are lowered. Figure 68 shows the effect of the slug size on the recovery of bitumen. Regardless of the solvent used, recoveries were higher for larger slugs. Figures 60 to 72 show temperature profiles for Run 12 (45% PV slug size). Only after 13 hours of steam injection, the overriding effect of the steam is observed. While in the temperature profiles for Run 9 (Figures 60 and 61) the overriding effect was present even after 3 hours of steam injection.

When the box was opened no compaction was observed in these runs, but in Run 12 and 13, the sand at the top of the model was completely loose, and if any overburden pressure had existed, compaction of the formation would have been present.

Thus, in general it is more advisable to use the GCOS synthetic crude as a solvent rather than naphtha for large slugs (45% PV), because it not only yielded higher recoveries, but the water-bitumen ratios observed for the GCOS synthetic crude-steam combinations were much lower than those for the naphtha-steam combinations. Observing Figure 39, it is possible to see that the WBR (Water-Bitumen Ratios) for Run 7 are always increasing, and increases in bitumen recovery imply an increase in water production. This was not the case for Run 12, where a slug of the same size was injected but GCOS synthetic crude instead of naphtha was used. WBR were much lower for this case, and increases in instantaneous bitumen recovery imply decrease in WBR and vice versa.

For Runs 8 and 13, similar behavior was observed, but in this case due to the decrease in slug size, and because of the volatility of naphtha as compared to GCOS synthetic crude, the WBR for both runs was high at the initial stages of steam injection, and later tends to be lower for naphtha-bitumen solutions. But if the curve for cumulative recovery of solvent is observed, it is clearly seen that the production of solvent is much higher at the beginning for Run 8, while later it stabilizes. On the contrary the one for GCOS synthetic crude-bitumen keeps increasing till the end of the run, and the WBR stays low. If the WBR is low, and the recovery is high, the water (as steam) requirements are much lower, and not only the mechanisim of the process improves, but also it economics.

Tar Sand Pack Saturated with Bitumen and Water

In its original state, tar sands are saturated with bitumen and water. The purpose of Runs 15, 16 and 17 was to investigate the recovery of bitumen from a tar sand pack saturated with bitumen and water.

After packing and closing the model, injection of water was initiated until a volume close to the void space was injected. Initially, the injection pressures were low, but on reaching the saturation point the pressure increased sharply and injection of water was stopped. As

Table 20

Injection History for Run 8

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
0.0	0.0	0.0	0.0	0.0	0.0
13.0	13.0	40.0	40.0	3.08	7.8
17.0	30.0	60.0	100.0	3.53	5.2
116.0	146.0	440.0	540.0	3.79	24.0
17.0	163.0	60.0	600.0	3.53	27.0
19.0	182.0	55.0	655.0	2.89	29.0
13.0	195.0	35.0	690.0	2.69	30.0
32.0	227.0	70.0	760.0	2.19	28.0
13.0	250.0	60.0	870.0	4.62	22.0
30.0	280.0	60.0	880.0	2.0	20.2
13.0	293.0	20.0	900.0	1.54	20.0

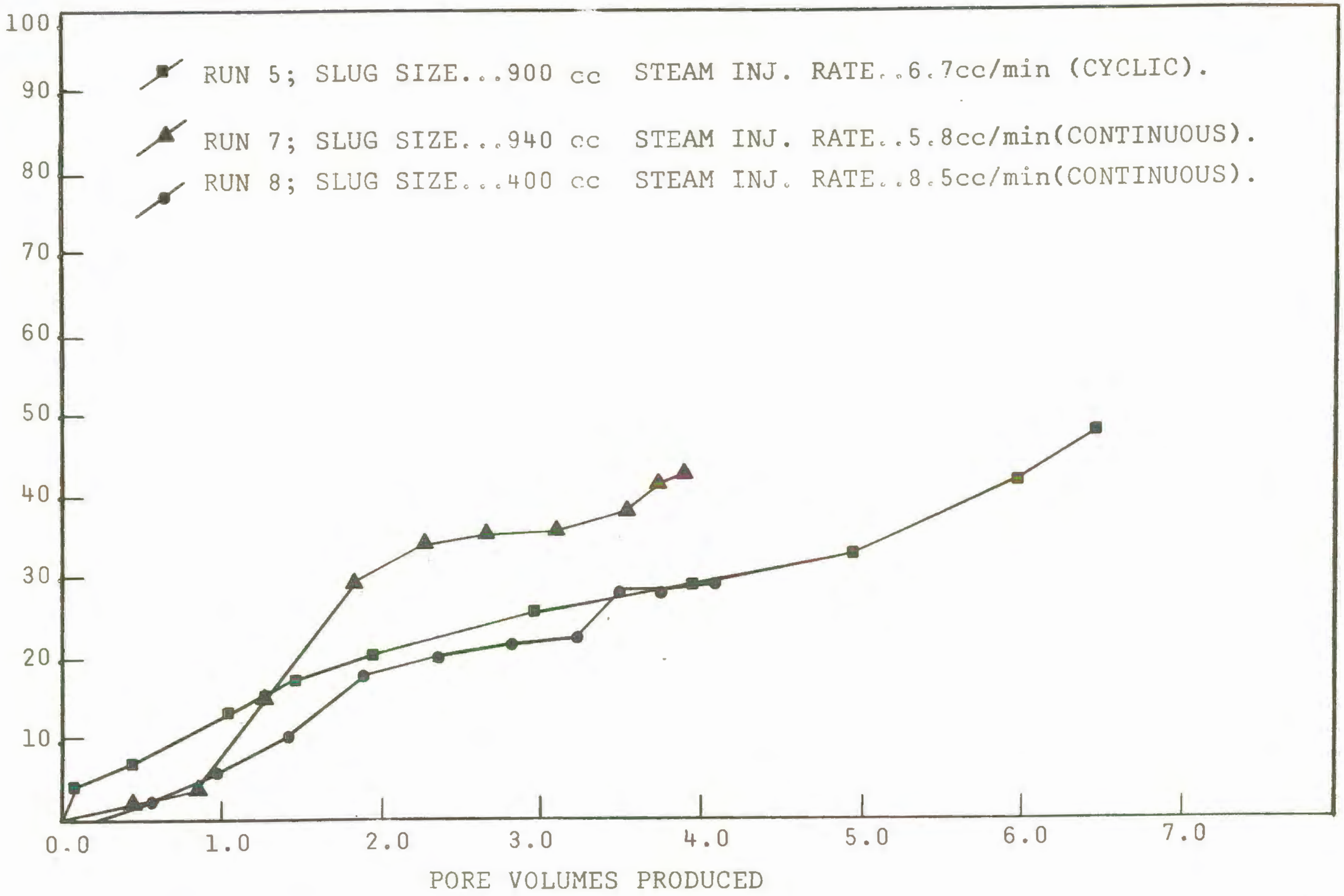


Figure 51 Comparison of Cumulative Recoveries for Runs 5, 7, and 8.

Table 21
Production History for Run 9

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)	I[a] W.B.R. (cc/cc)	I[b] S.B.R. (cc/cc)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent (cc)
1	131	131.0	1000.0	1000.0	600.0	600.0	180.0	180.0	3.33	1.22	7.63	100.0	220.0	220.0
2	70	201.0	1019.5	2019.5	550.0	1150.0	229.5	409.5	2.40	1.05	14.56	100.0	240.0	460.0
3	44	245.0	954.0	2973.5	550.0	1700.0	204.0	613.5	2.70	.98	21.68	100.0	200.0	660.0
4	28	273.0	926.0	3899.5	900.0	2600.0	26.0	639.5	34.62	0.0	33.07	100.0	0.0	660.0
5	-	-	691.6	4591.1	650.0	3250.0	41.6	681.1	15.81	0.0	-	100.0	22.0	682.2
6	-	-	127.0	4718.1	100.0	3350.0	27.0	708.1	3.70	0.0	-	100.0	0.0	682.2

[a] I W.B.R. = Instantaneous water-bitumen ratio.

[b] I S.B.R. = Instantaneous solvent-bitumen ratio.

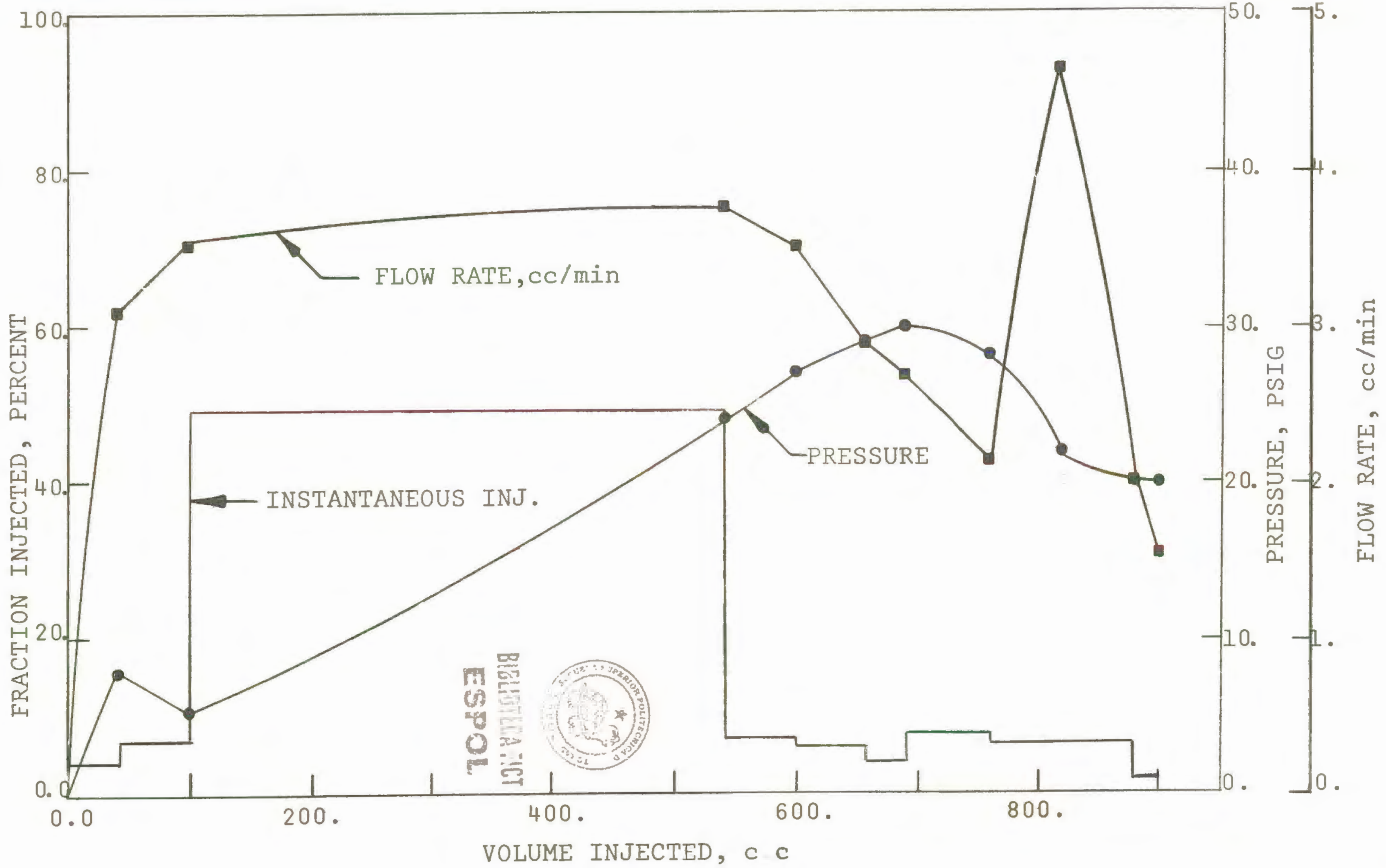


Figure 52 Injection History for Run 9.

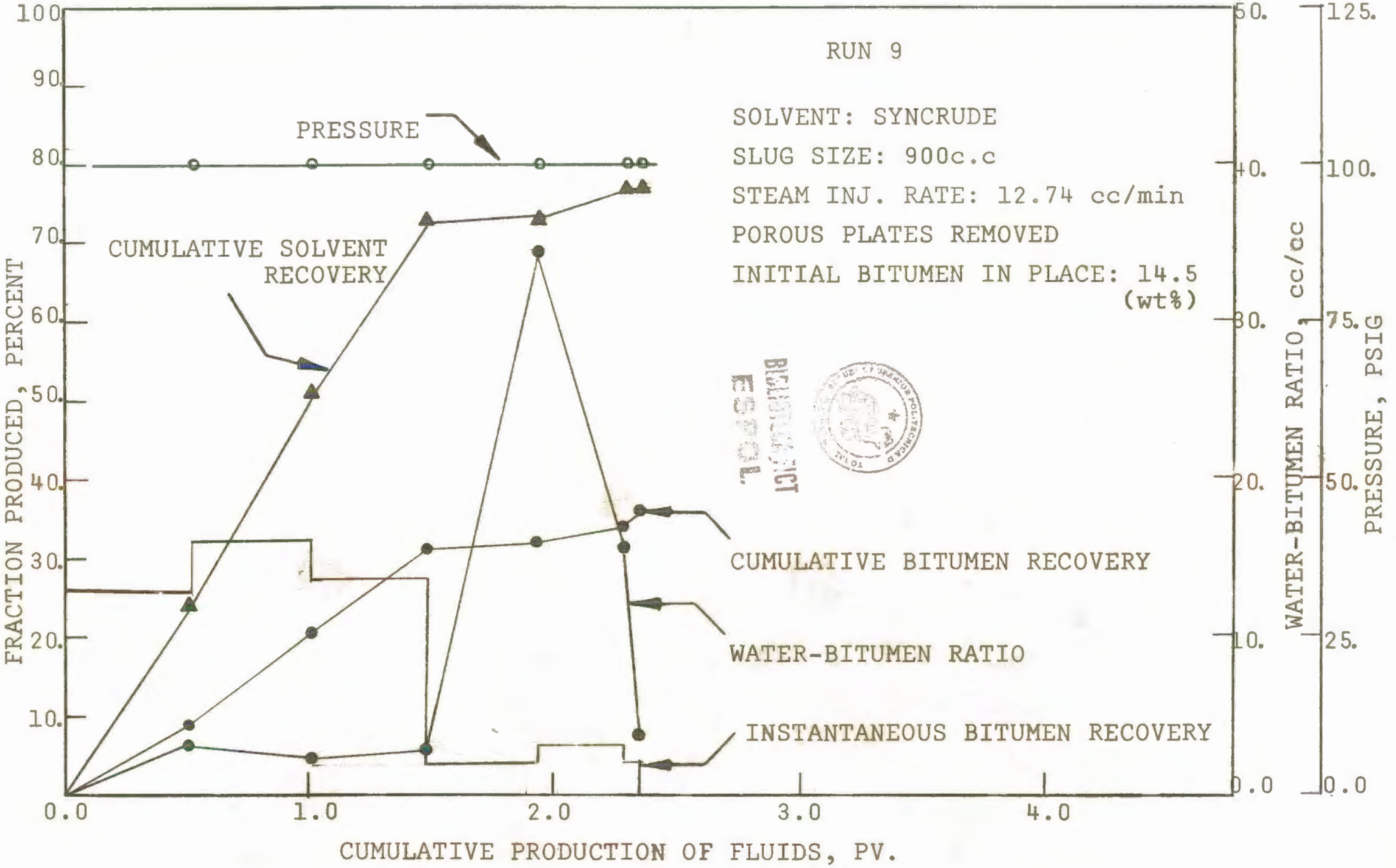


Figure 53 Production History for Run 9.

Table 22

General Characteristics and Results for Run 8

Amount of tar sand packed	14179.5 gms.
Bitumen content of tar sand	.145
Weight of bitumen in place	2050 gms.
Volume of bitumen in place	1984.6 cc
Solvent used	GCOS Synthetic Crude
Weight of clean sand	12123.5 gms.
Volume of clean sand	4517 cc
Volume of steel box	6874 cc
Void space in the model	372.45 cc
Pore volume	2357 cc
Porosity	.3429
Total solvent injected	900 cc
Amount of solvent retained by the pack	217.8 cc
Total run time	9.93 hrs.
Time of solvent injection	4.88 hrs.
Time of steam injection	5.50 hrs.
Time for effluent breakthrough	5.85 hrs.
Volume of solvent inj. before effluent B.T.	900 cc
Average inj. rate before effluent B.T.	3.07 $\frac{\text{cc}}{\text{min.}}$
Average flow rate	13 $\frac{\text{cc}}{\text{min.}}$
Average pressure for solvent injection	21.32 psig
Average pressure for steam injection	100 psig
Time for steam breakthrough	9.02 hrs.
Water-bitumen ratio	4.73 cc/cc

Table 22 (continued)

Total steam injected (as water)	4036 cc
Steam injection rate	12.23 $\frac{cc}{min.}$
Total bitumen recovery	708.1 cc
Recovery	36%

Table 23

Injection History for Run 10

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
0.0	0.0	0.0	0.0	0.0	0.0
30.0	30.0	80.0	80.0	2.67	4.6
41.0	71.0	120.0	200.0	2.93	18.1
44.0	120.0	110.0	310.0	2.24	30.0
80.0	200.0	120.0	420.0	1.50	36.0
40.0	240.0	40.0	460.0	1.0	35.0
106.0	346.0	150.0	610.0	1.42	36.0
129.0	475.0	110.0	720.0	.85	26.0
95.0	570.0	60.0	780.0	.63	23.3
237.0	807.0	100.0	880.0	.42	21.7
185.0	992.0	80.0	960.0	.43	17.0
110.0	1102.0	50.0	1010.0	.45	16.0

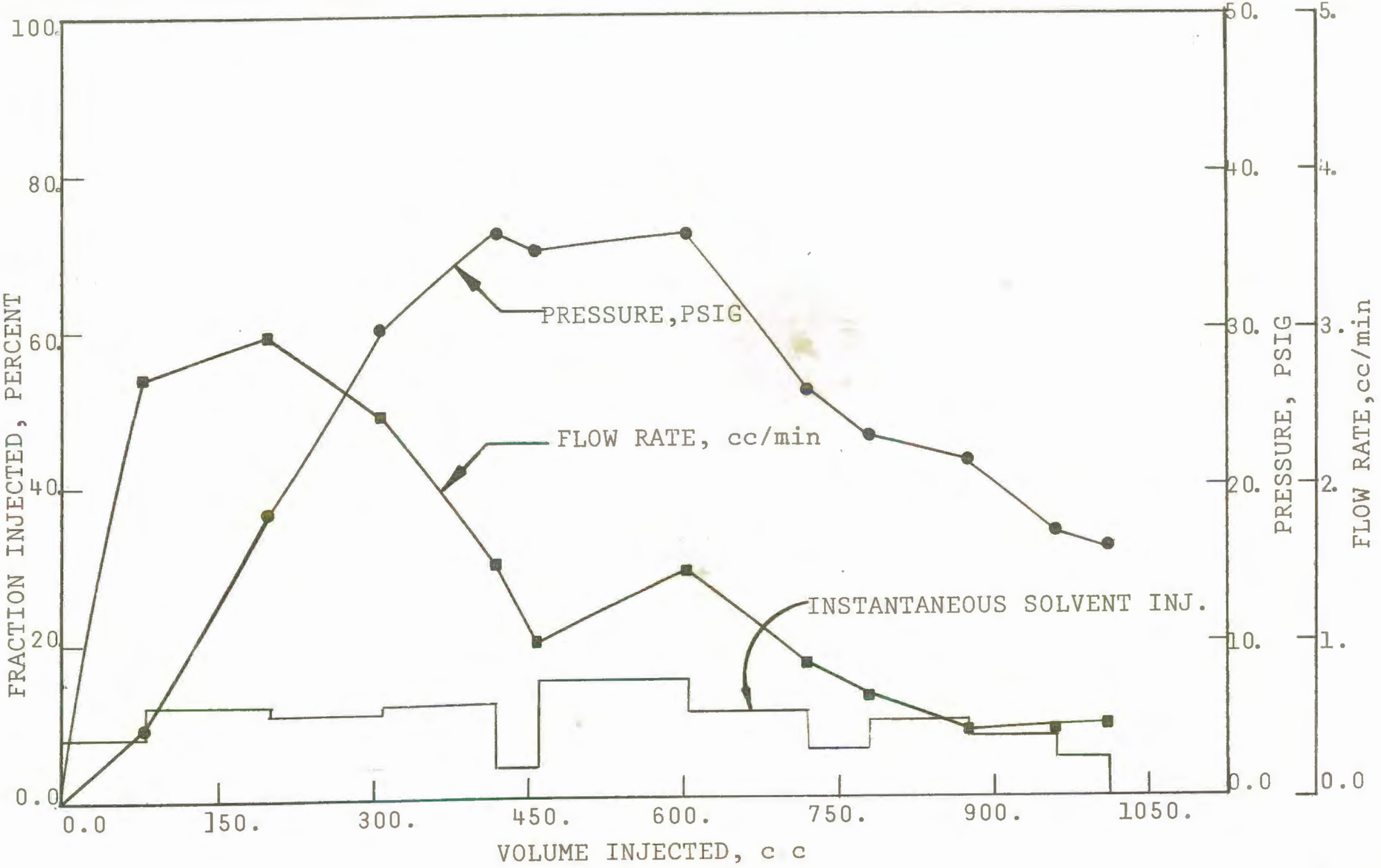


Figure 54 Injection History for Run 10.

Table 24
Production History for Run 10

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)
1	532.6	532.6	302.0	302.0	-	-	65.0	65.0
2	98.0	630.6	950.0	1252.0	800.0	800.0	92.0	157.0
3	133.0	763.6	1812.0	3064.0	1500.0	2300.0	176.0	333.0
4	51.0	814.6	415.0	3479.0	250.0	2250.0	77.0	410.0
5	38.0	852.6	932.0	4411.0	900.0	3450.0	32.0	442.0
6	32.0	884.6	849.0	5260.0	800.0	4250.0	33.0	475.0
7	60.0	944.6	916.0	6176.0	850.0	5100.0	48.0	523.0
8	10.0	954.6	152.6	6328.6	100.0	5200.0	42.6	565.6

Inst. W.B.R. (ccw/ccb)	Inst. S.B.R. (ccs/ccb)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent (cc)
0.0	3.80	.57	85	247	247
8.70	.63	9.59	100	58	305
8.52	.77	13.82	100	136	441
0.25	1.14	8.14	80	88	539
28.13	0.0	24.53	80	-	539
24.24	.48	26.53	80	16	555
17.71	.38	15.27	80	18	573
2.35	.23	15.26	-	10	583

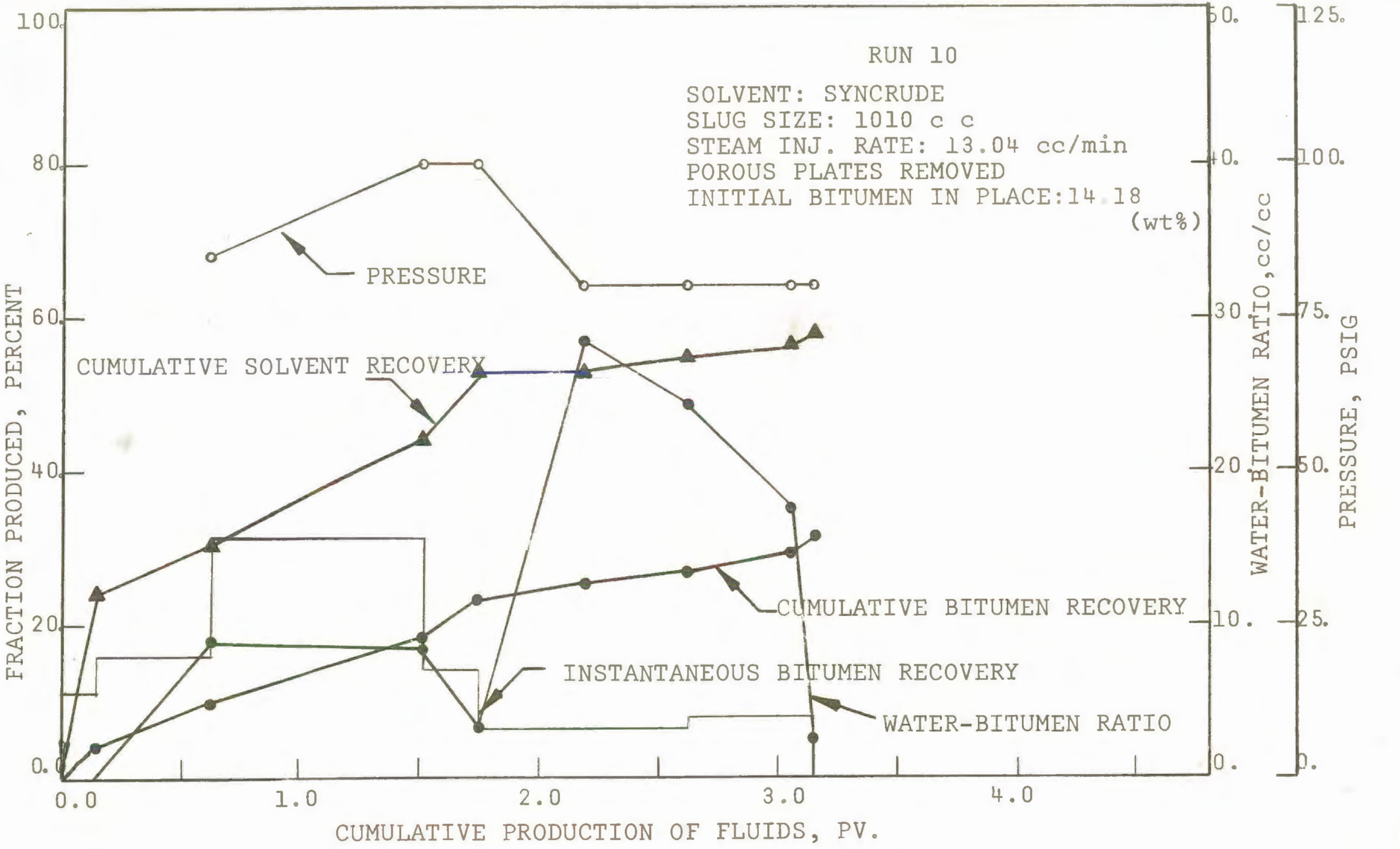


Figure 55 Production History for Run 10.

Table 25

General Characteristics and Results for Run 10

Amount of tar sand packed	13834.8 gms.
Bitumen content of tar sand	.1349
Weight of bitumen in place	1866.31 gms.
Volume of bitumen in place	1801.46 cc
Solvent used	GCOS synthetic crude
Weight of clean sand	11968.4 gms.
Volume of clean sand	4178.9 gms.
Volume of steel box	6874 cc
Void space in the model	893.6 cc
Pore volume	2395 cc
Porosity	.3921
Total solvent injected	1010 cc
Amount of solvent retained by the pack	427 cc
Total run time	26.17 hrs.
Time of solvent injection	18.37 hrs.
Time of steam injection	7 hrs.
Time for effluent breakthrough	12.83 hrs.
Volume of solvent inj. before effluent B.T.	880 cc
Average inj. rate before effluent B.T.	1.14 $\frac{cc}{min.}$
Average flow rate	13.19 $\frac{cc}{min.}$
Average pressure for solvent injection	26.32 psig
Average pressure for steam injection	100 psig
Time for steam breakthrough	4 hrs.

Table 25 (continued)

Water bitumen ratio	9.20 $\frac{cc}{cc}$
Total steam injected (as water)	5475 cc
Steam injection rate	13.04 $\frac{cc}{min.}$
Total bitumen recovery	564.6
Recovery	31.4%

Table 26

Injection History for Run 11

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
0.0	0.0	0.0	0.0	0.0	0.0
12.0	12.0	30.0	30.0	2.5	6.0
14.0	26.0	30.0	60.0	2.14	11.0
17.0	43.0	50.0	110.0	2.94	14.0
13.0	56.0	30.0	140.0	2.31	14.8
34.0	90.0	80.0	220.0	2.35	16.0
10.0	100.0	20.0	240.0	2.00	17.0
21.0	121.0	50.0	290.0	2.38	21.0
32.0	153.0	70.0	360.0	2.19	26.0
10.0	163.0	20.0	380.0	2.0	28.0
12.0	175.0	20.0	400.0	1.67	30.0

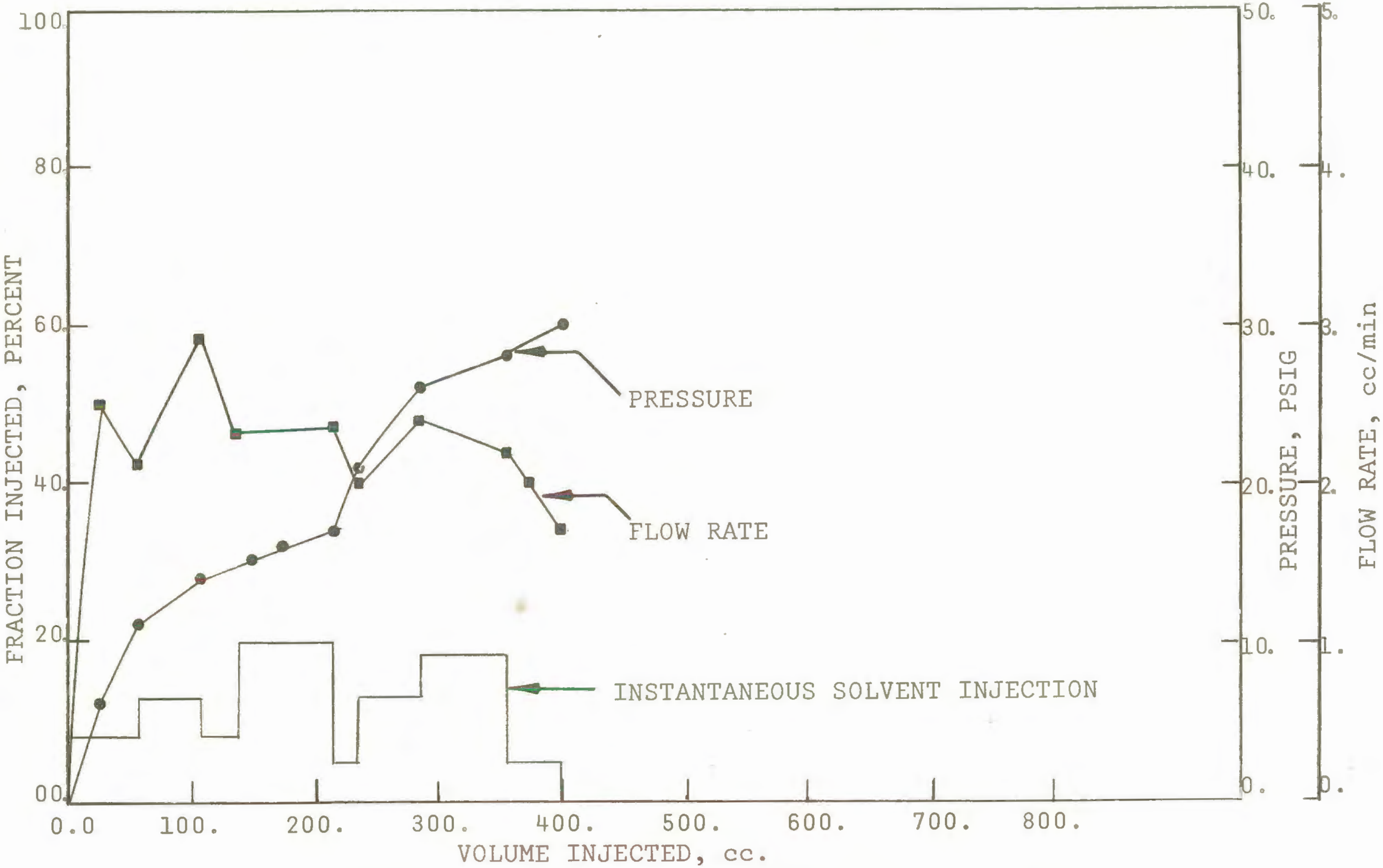


Figure 56 Injection History for Run 11.

Table 27
Production History for Run 11

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)
1	110.0	110.0	900.0	900.0	900.0	900.0	-	-
2	110.0	220.0	820.75	1720.75	768.0	1668.0	27.95	27.95
3	83.0	303.0	962.80	2683.55	775.0	2443.0	104.0	131.95
4	51.0	354.0	1100.0	3783.55	700.0	3143.0	267.0	398.95

Inst W.B.R. (ccw/ccb)	Inst S.B.R. (ccs/ccb)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cummulative Solvent (cc)
0.0	0.0	8.18	95	0.0	0.0
27.47	0.887	7.46	100	24.8	24.8
7.45	0.537	11.66	100	55.85	80.65
2.62	0.498	21.57	100	133.0	213.65

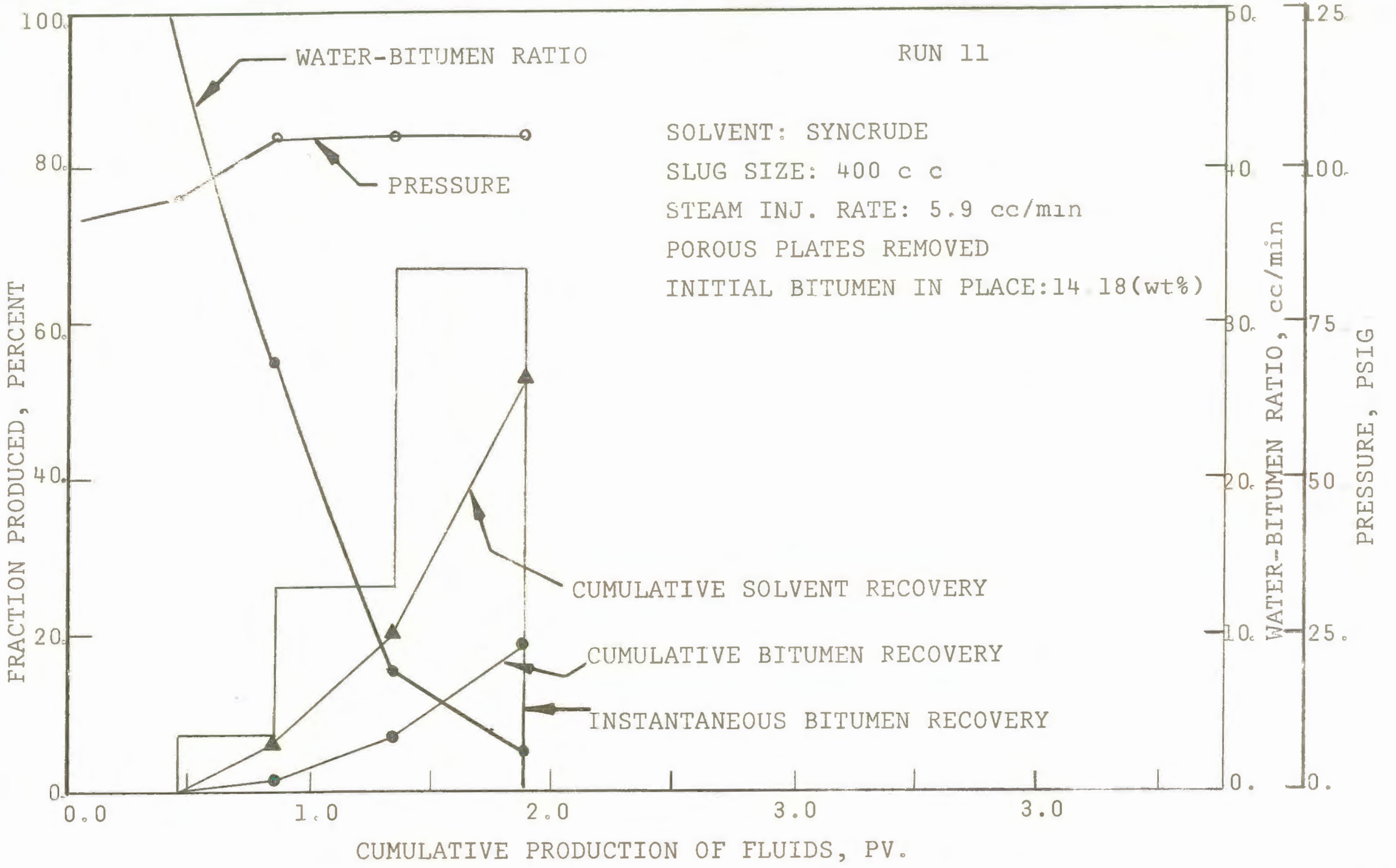


Figure 57 Production History for Run 11.

Table 28

General Characteristics and Results for Run 11

Amount of tar sand packed	15133.9 gms.
Bitumen content of tar sand	.1418
Weight of bitumen in place	2145.9 gms.
Volume of bitumen in place	2071.4 cc
Solvent used	GCOS synthetic crude
Weight of clean sand	12987.9 gms.
Volume of clean sand	4534.9 cc
Volume of steel box	6874 cc
Void space in the model	267.67 cc
Pore volume	2339.09 cc
Porosity	.3403
Total solvent injected	400 cc
Amount of solvent retained by the pack	186.35 cc
Total run time	10.92 hrs.
Time of solvent injection	2.92 hrs.
Time of steam injection	6 hrs.
Time for effluent breakthrough	5.04 hrs.
Volume of solvent inj. before effluent B.T.	400 cc
Average inj. rate before effluent B.T.	2.28 $\frac{cc}{min}$
Average flow rate	10.69 $\frac{cc}{min.}$
Average pressure for solvent injection	18.3 psig
Average pressure for steam injection	100 psig
Time for steam breakthrough	5.67 hrs.

Table 28 (continued)

Water bitumen ratio	7.88 cc/cc
Total steam injected (as water)	3541.95 cc
Steam injection rate	9.84 cc/min.
Total bitumen recovery	398.95
Recovery	19.26%

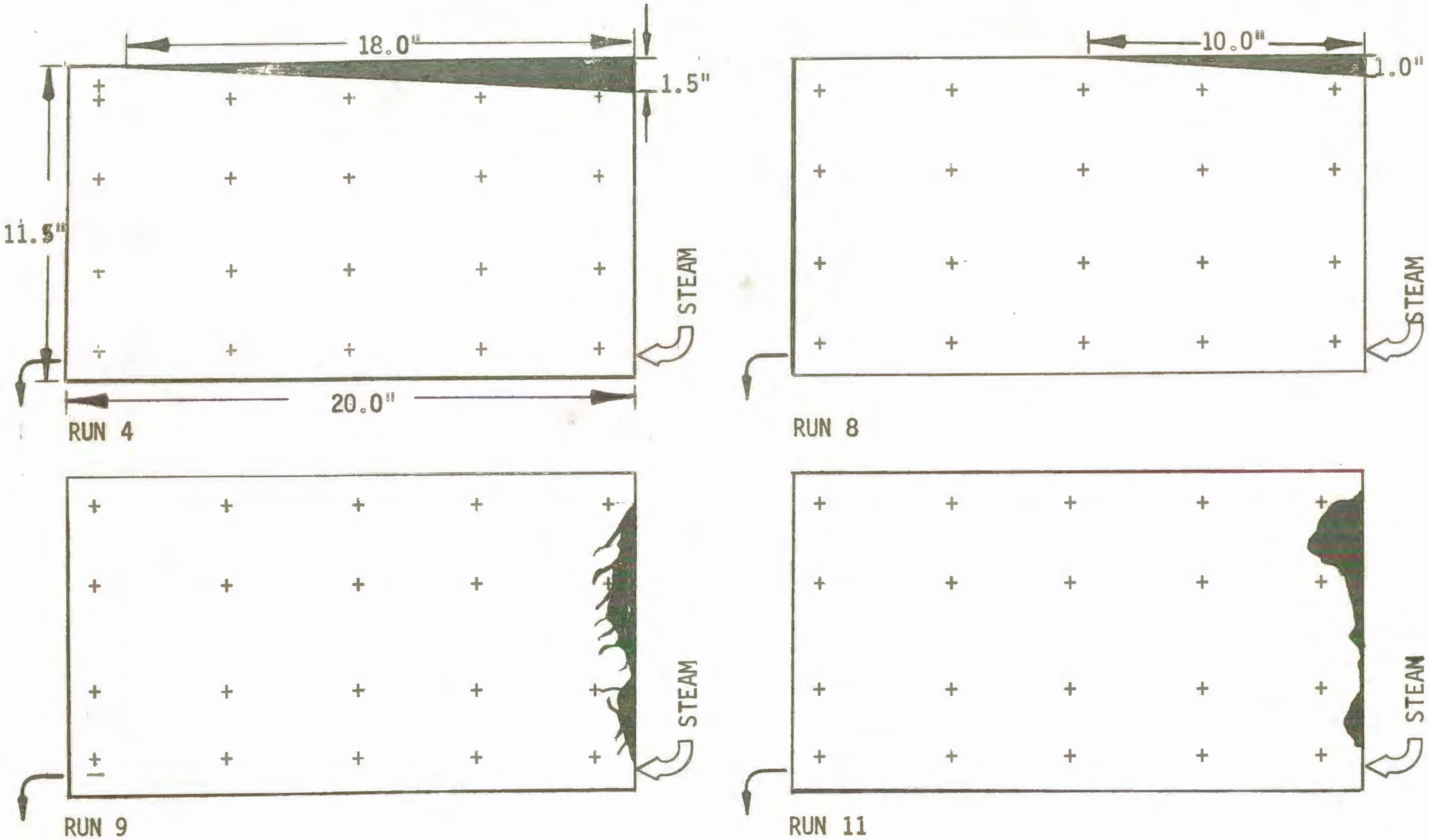
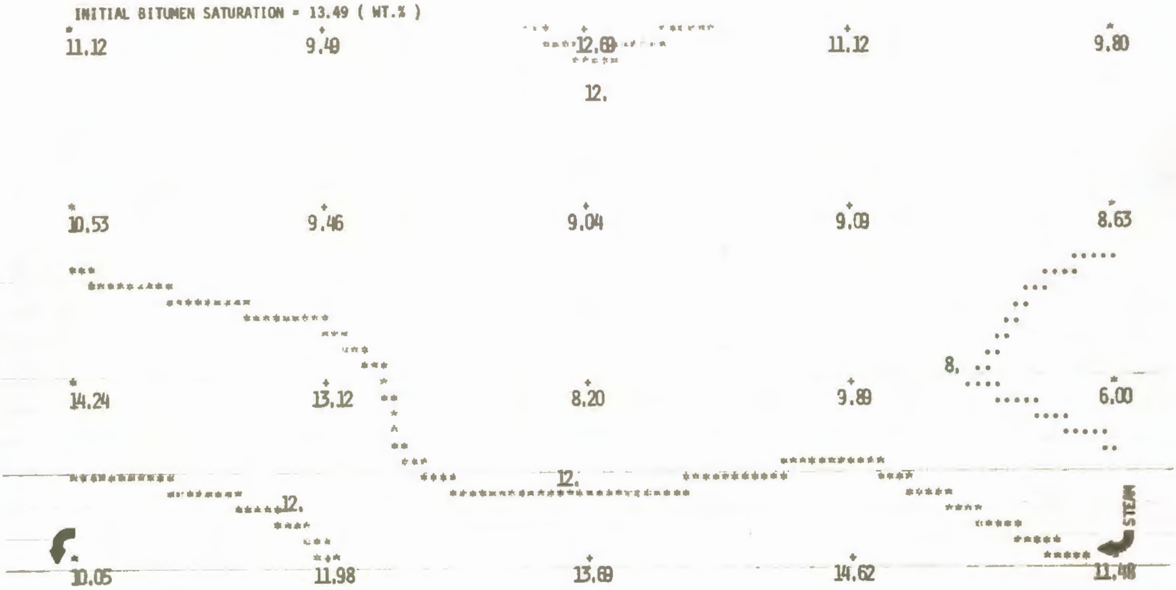


Figure 58 Void Space Observed after Steam Injection.

RUN 10



RUN 11

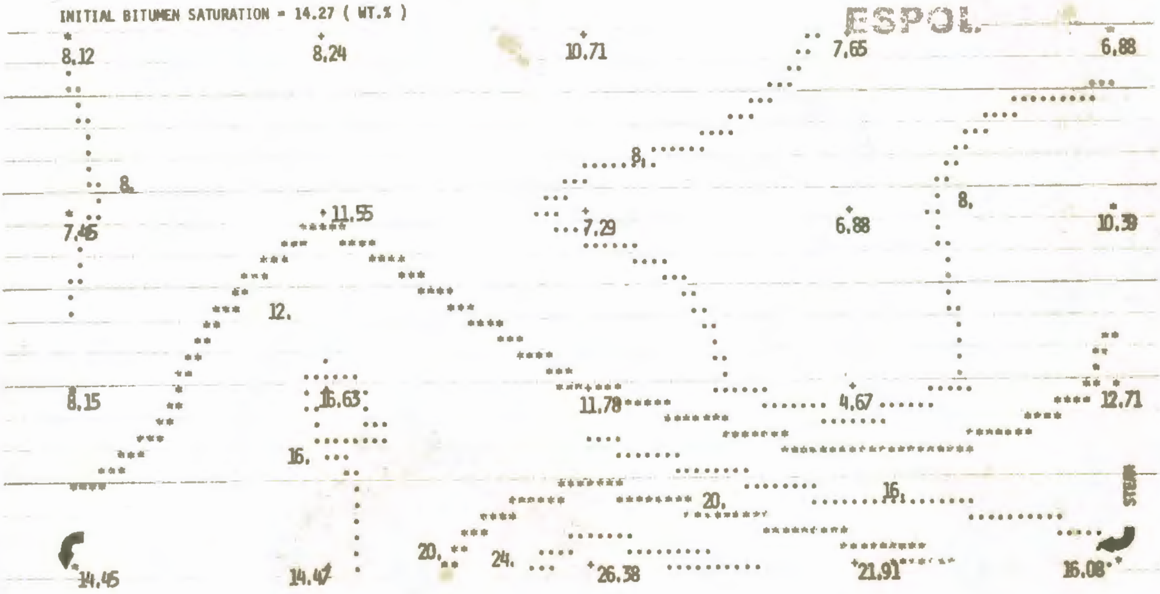
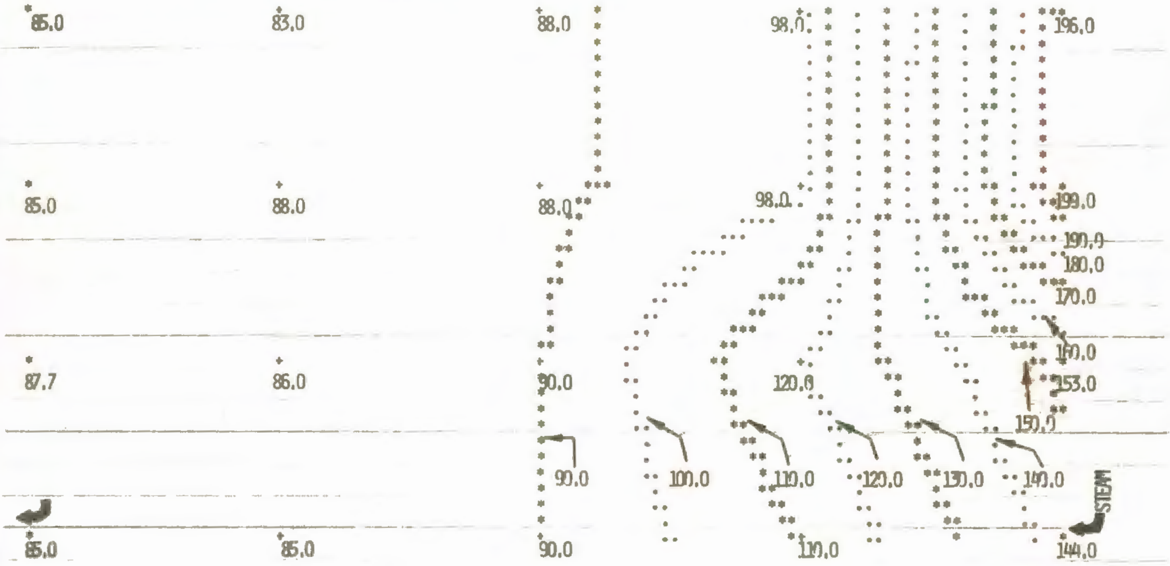


Figure 59 Residual Saturation Contours for Runs 10, and 11.

TEMPERATURE PROFILE AFTER 01 HRS OF STEAM INJ.,P = 80.0 PSIG.,TEMP. IN DEG. F



TEMPERATURE PROFILE AFTER 02 HRS OF STEAM INJ.,P = 85.0 PSIG,TEMP. IN DEG. F

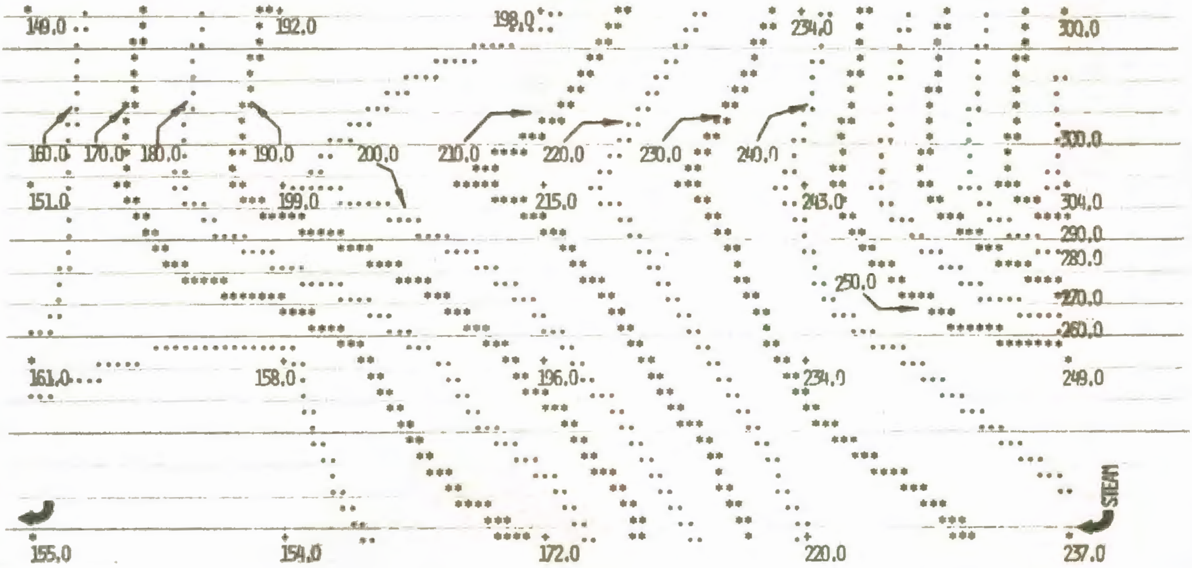
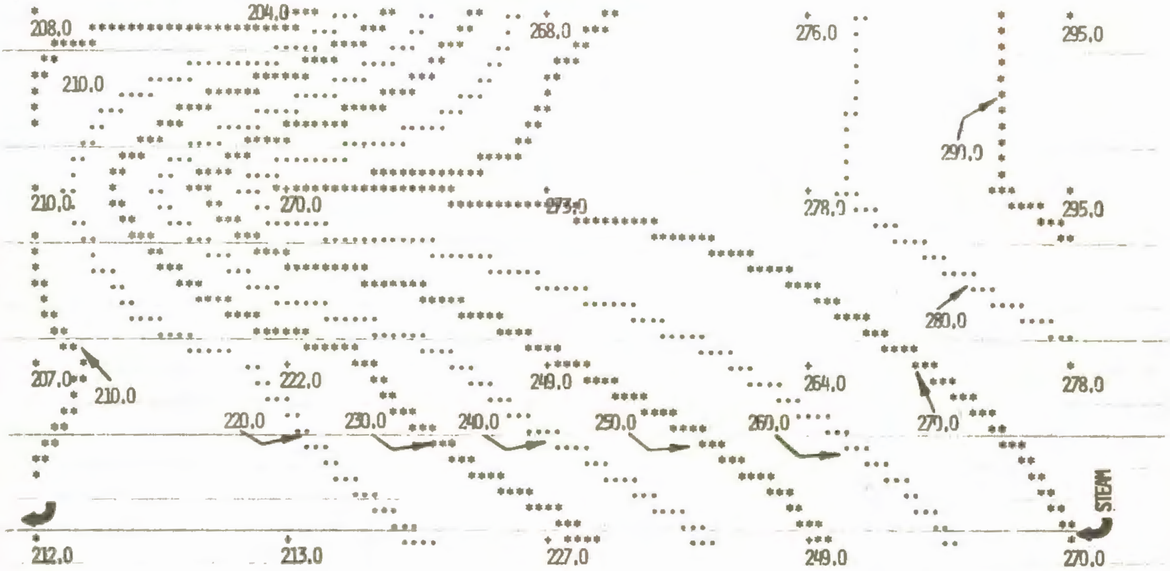


Figure 60 Temperature Profiles for Run 9.

TEMPERATURE PROFILE AFTER 03 HRS OF STEAM INJ.,P = 100.0 PSIG.,TEMP. IN DEG. F



TEMPERATURE PROFILE AT BREAKTHROUGH (4.05 HRS),P = 90.0 PSIG.,TEMP. IN DEG. F

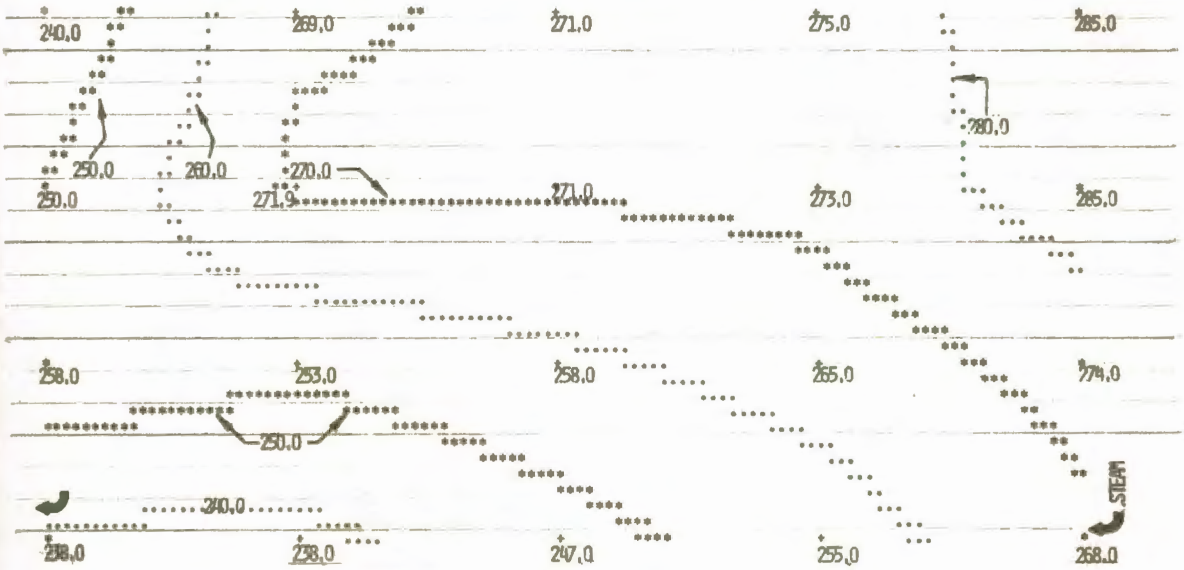


Figure 61 Temperature Profiles for Run 9.

Table 29
Injection History for Run 12

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
26	26	60.0	60.0	2.31	16.0
21	47	40.0	100.0	1.90	14.0
50	97	90.0	190.0	1.80	21.5
32	129	50.0	240.0	1.56	27.5
60	189	60.0	300.0	1.0	40.0
66	255	60.0	360.0	.91	35.0
100	355	40.0	400.0	.40	26.0
358	713	60.0	460.0	.17	20.4
180	893	40.0	500.0	.22	11.0
374	1267	100.0	600.0	.27	16.7
588	1855	100.0	700.0	.17	20.5
132	1987	100.0	800.0	.76	44.0
30	2017	60.0	860.0	2.0	39.0
30	2056	90.0	900.0	1.03	35.0

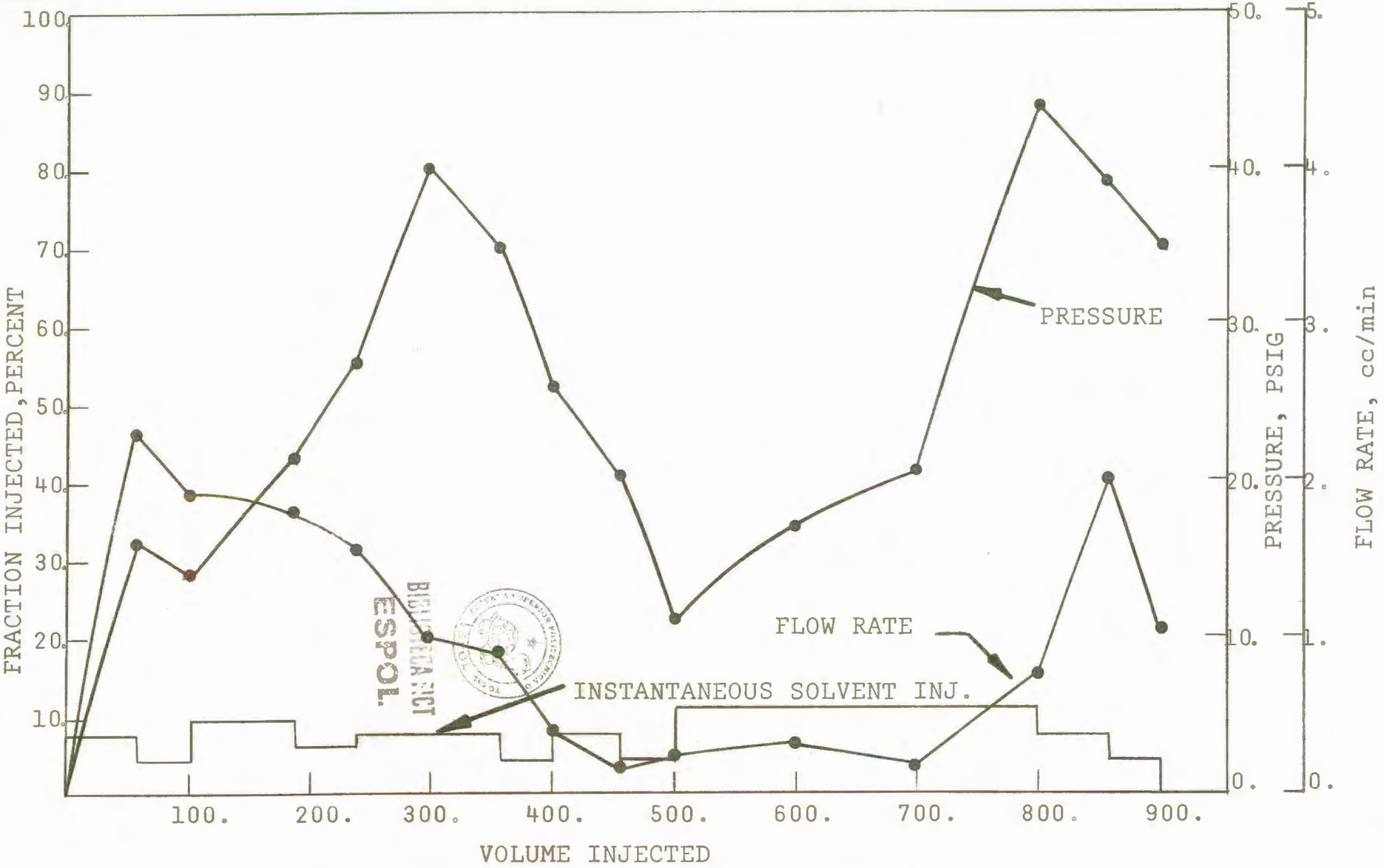


Figure 62 Injection History for Run 12.

Table 30
Production History for Run 12

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Volume (cc)
1	-	-	304.0	304.0	138.0	138.0	75.0	75.0
2	82	82	911.0	1215.0	750.0	888.0	80.0	155.0
3	87	169	939.0	2154.0	680.0	1568.0	126.0	281.0
4	114	283	951.0	3105.0	740.0	2308.0	139.0	420.0
5	150	433	1133.0	4238.0	800.0	3108.0	169.0	589.0
6	120	553	861.0	5099.0	780.0	3888.0	37.0	626.0
7	125	678	908.0	6007.0	825.0	4713.0	56.0	682.0
8	108	786	1007.0	7014.0	800.0	5513.0	91.0	773.0
9	95	881	984.0	7798.0	880.0	6393.0	72.0	845.0
10	94	975	900.0	8898.0	800.0	7193.0	100.0	945.0
11	99	1074	900.0	9798.0	820.0	8013.0	80.0	1025.0
12	69	1143	700.0	10498.0	650.0	8663.0	50.0	1075.0
13	36	1179	150.0	10648.0	140.0	8803.0	100.0	1985.0

Inst. W.B.R. (ccw/ccb)	Inst. S.B.R. (ccs/ccb)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solv. Recovery (cc)
1.84	1.21	-	-	91.0	91.0
9.38	1.01	11.11	100	81.0	172.0
5.40	1.06	10.70	100	133.0	305.0
5.32	0.82	8.34	100	72.0	377.0
4.73	0.97	7.55	95	164.0	541.0
21.08	1.19	7.18	90	44.0	585.0
14.13	0.48	7.86	85	27.0	612.0
8.79	1.27	9.32	90	16.0	728.0
12.22	0.44	10.36	106	32.0	760.0
2.0	0.0	9.57	120	-	760.0
10.25	0.0	9.09	125	-	760.0
13.0	0.0	10.14	120	-	760.0
14.0	0.0	4.17	120	-	760.0

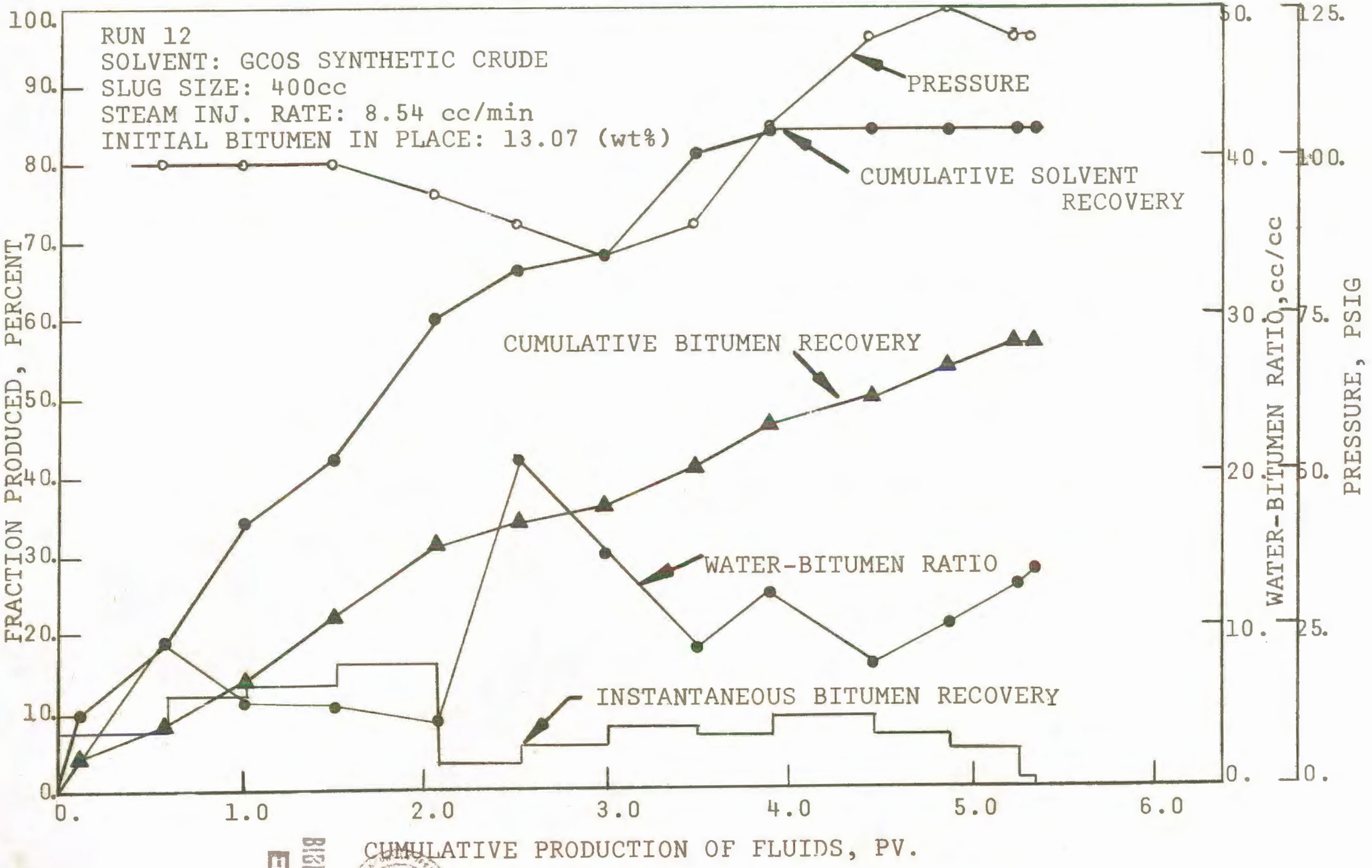


Figure 63 Production History for Run 12.

Table 31

General Characteristics and Results for Run 12

Amount of tar sand packed	15023 gms.
Bitumen content of tar sand	.1307
Weight of bitumen in place	1964.3 gms.
Volume of bitumen in place	1896.03 gms.
Solvent used	GCOS synthetic crude
Weight of clean sand	13058 gms.
Volume of clean sand	4865.5 cc
Volume of steel box	7720 cc
Volume of porous plates	181.58 cc
Void space in the model	777 cc
Pore volume	2673 cc
Porosity	.346
Total solvent injected	900 cc
Amount of solvent retained by the pack	140 cc
Total run time	55.4 hrs.
Time of solvent injection	34.2 hrs.
Time of steam injection	19.3 hrs.
Time for effluent breakthrough	12.9 hrs.
Volume of solvent inj. before effluent B.T.	895 cc
Average inj. rate before effluent B.T.	1.16 $\frac{cc}{min.}$
Average flow rate	7.74 $\frac{cc}{min.}$
Average pressure for solvent injection	24.25 psig
Average pressure for steam injection	104.25 psig

Table 31 (continued)

Time for steam breakthrough	19.3 hrs.
Water bitumen ratio	8.11 cc/cc
Total steam injected (as water)	9888 cc
Steam injection rate	8.53 cc/min.
Total bitumen recovery	1085 cc
Recovery	57%

Table 32

Injection History for Run 13

Time (min.)	Cumulative Time (min.)	Volume Injection (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
0.0	0.0	0.0	0.0	0.0	0.0
8.0	8.0	40.0	40.0	5.0	15.0
13.0	21.0	70.0	110.0	5.38	26.5
15.0	36.0	70.0	180.0	4.67	37.0
14.0	50.0	40.0	220.0	2.86	39.0
12.0	62.0	80.0	300.0	6.67	57.5
8.0	70.0	40.0	340.0	5.0	65.0
6.0	76.0	20.0	360.0	3.33	64.0

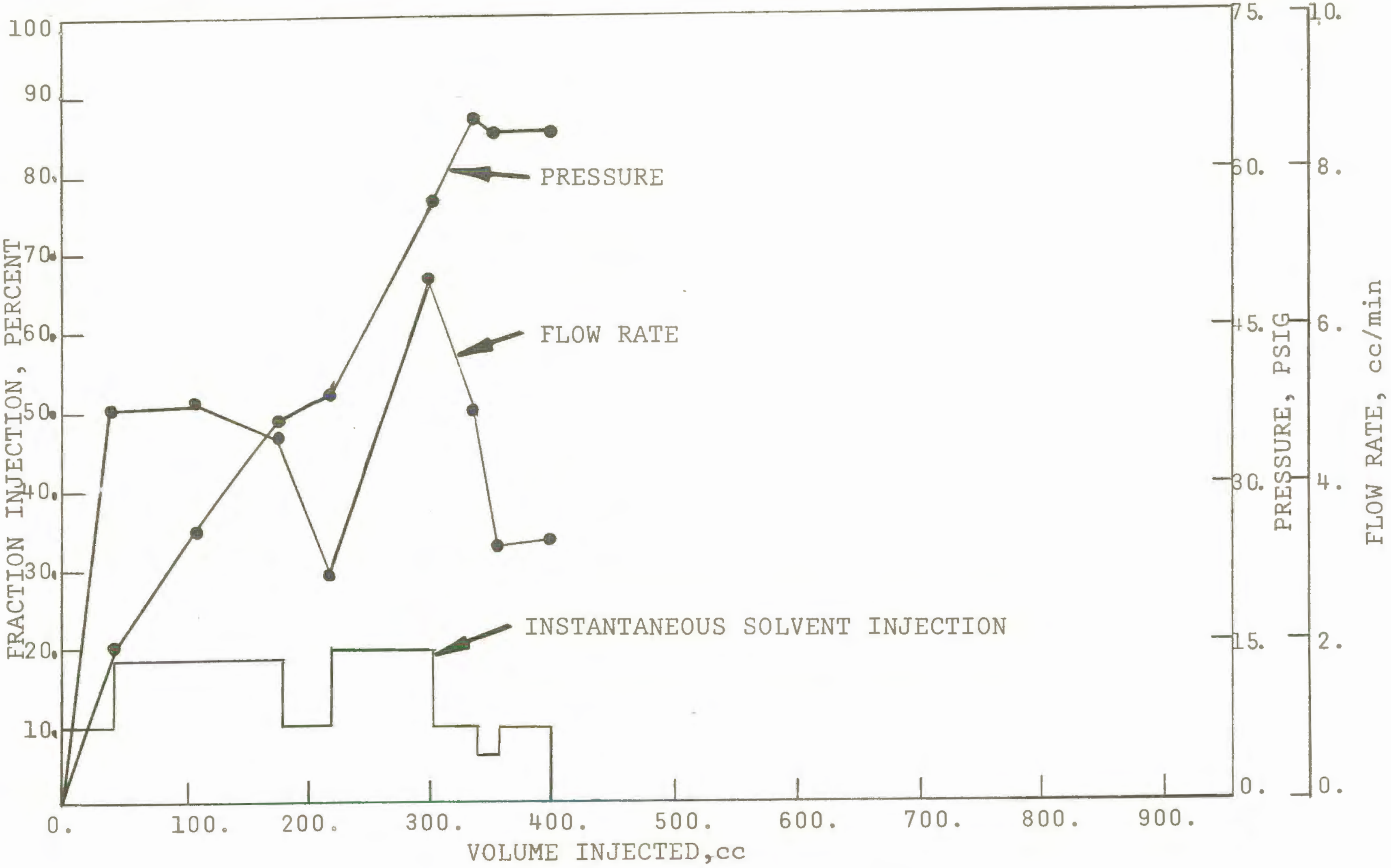


Figure 64 Injection History for Run 13.

Table 33
Production History for Run 13

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)	Inst. W.B.R. (ccw/ccb)	Inst. S.B.R. (ccs/ccb)	Steam Pressure (psig)	Solvent Recovery (cc)	Flow Rate (cc/min.)	Cumulative Solv. Recovery (cc)
1	35	35	230	230	230	230	0	0	-	-	100	0.0	6.57	0.0
2	116	151	900	1130	820	1050	20	20	41.0	3.0	100	60.0	7.76	60.0
3	84	235	900	1830	630	1680	34	54	26.25	1.06	90	36.0	8.83	96.0
4	106	341	910	2740	830	2510	50	104	16.60	.60	100	30.0	8.58	126.0
5	100	441	900	3640	780	3290	83	187	9.4	.45	90	37.0	9.0	165.0
6	95	536	900	4540	780	4070	84	271	9.4	.43	90	36.0	9.47	201.0
7	42	578	400	4940	330	4400	64	335	5.16	.09	95	6.0	9.52	207.0
8	177	755	1600	6540	1370	5770	189	524	7.25	.22	90	41.0	9.04	248.0
9	41	796	400	6940	330	6100	53	577	6.23	.32	90	17.0	9.76	265.0
10	35	831	450	7390	430	6530	19	596	22.63	.05	90	1.0	12.86	266.0

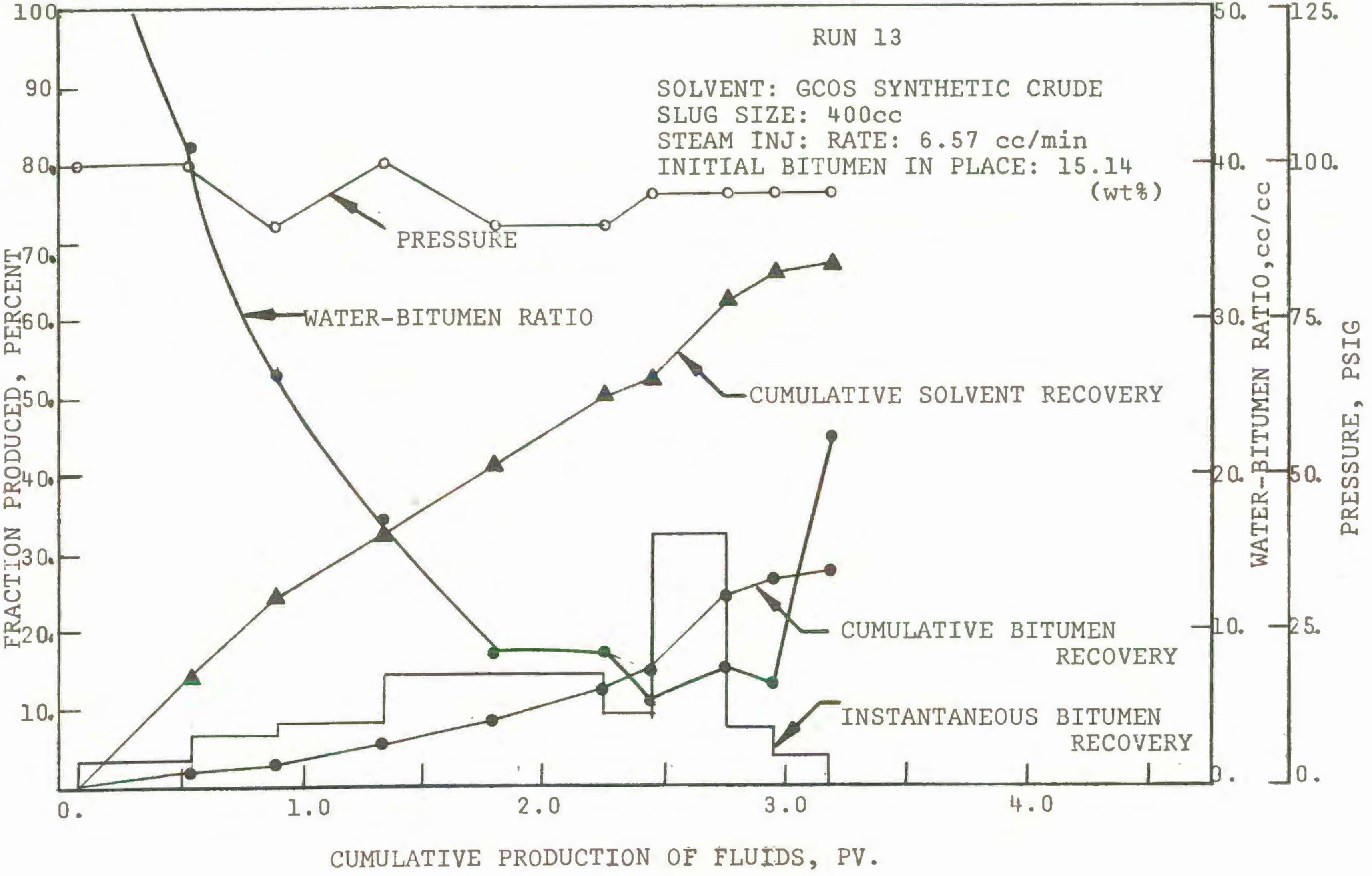


Figure 65 Production History for Run 13.

Table 34

General Characteristics and Results for Run 13

Amount of tar sand packed	15141.17 gms.
Bitumen content of tar sand	.1514
Weight of bitumen in place	2292.37 gms.
Volume of bitumen in place	2212.72 cc
Solvent used	GCOS synthetic crude
Weight of clean sand	12848.8 gms.
Volume of clean sand	4870.66 cc
Volume of the model	7720 cc
Volume occupied by porous plates	181.58 cc
Void space in the model	455.7 cc
Pore volume	2667.7 cc
Porosity	.35
Total solvent injected	400 cc
Amount of solvent retained by the pack	134 cc
Total run time	20.13 hrs.
Time for effluent breakthrough	2.1 hrs.
Time for steam breakthrough	15.9 hrs.
Solvent injection time	1.45 hrs.
Volume of solvent inj. before effluent B.T.	400 cc
Total steam inected (as water)	5700 cc
Average pressure for solvent injected	46 psig
Average pressure for steam injection	93.18 psig
Water bitumen ratio	10.96 cc/cc

Table 34 (continued)

Solvent bitumen ratio	.58 cc/cc
Total recovery	596 cc
Steam injection rate	6.57 cc/min.
Recovery	27%

Table 35

Injection History for Run 14[a]

Time (min.)	Cumulative Time (min.)	Volume Injection (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
0.0	0.0	0.0	0.0	0.0	0.0
7.0	7.0	40.17	40.0	5.71	1.0
4.0	11.0	20.08	60.0	5.0	2.0
7.0	18.0	40.17	100.0	5.71	7.5
5.0	23.0	25.10	125.0	5.0	16.0
4.0	27.0	15.06	140.0	3.75	23.0
5.0	32.0	30.13	170.0	6.0	28.0
4.0	36.0	10.04	180.0	2.5	33.0
4.0	40.0	20.08	200.0	5.0	36.0
5.0	45.0	20.08	220.0	4.0	41.0
4.0	49.0	20.08	240.0	5.0	43.0

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[a] Forty c.c. were drained out when initiating steam injection.

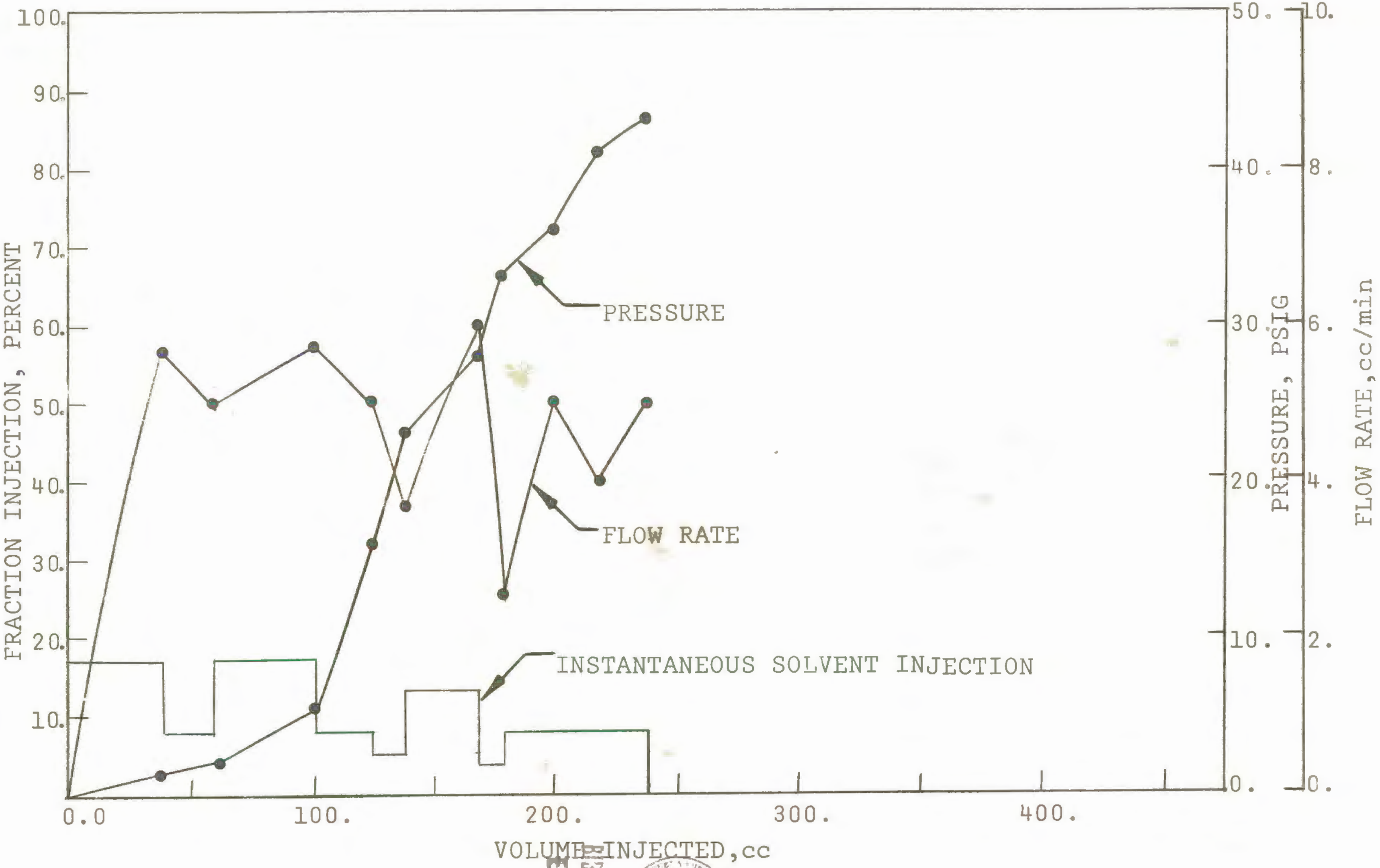


Figure 66 Injection History for Run 14.

Table 36
Production History for Run 14

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)
1	75	75	800.40	800.40	800	800	-	-
2	51	126	1000.50	1800.90	920	1720	38.0	38.0
3	41	167	900.45	2700.35	840	2560	59.0	97.0
4	147	314	900.45	3600.80	750	3310	150	257.0
5	70	384	700.35	4300.15	550	3860	150	397.0

Inst. W.B.R. (ccw/ccb)	Inst. S.B.R. (ccs/ccb)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent (cc)
-	-	10.67	90	-	-
30.15	1.37	19.61	78	52.0	52.0
16.41	.02	21.95	85	1.0	53.0
5.0	0	6.12	85	-	53.0
3.67	0	5.49	90	-	53.0

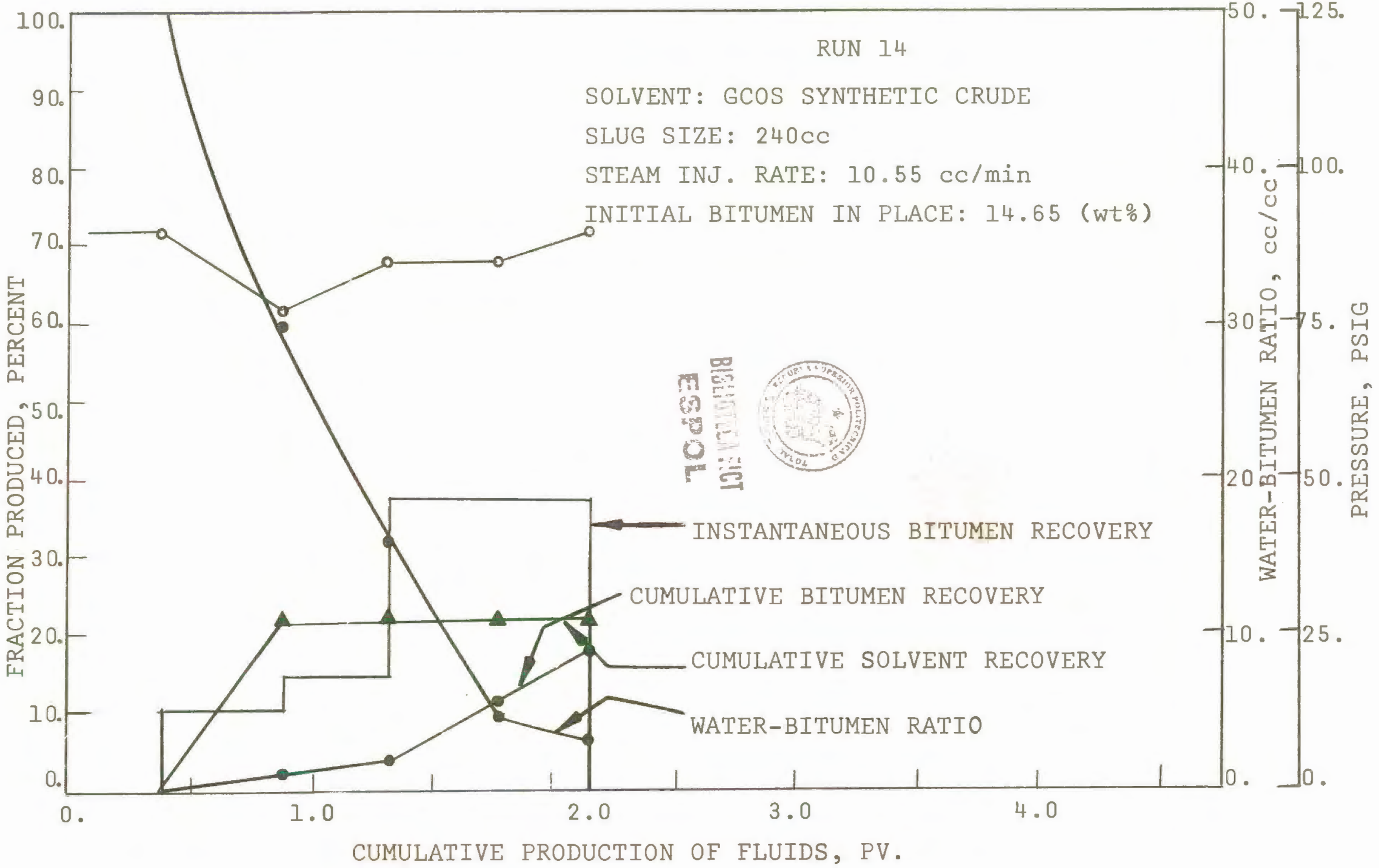


Figure 67 Production History for Run 14.

Table 37

General Characteristics and Results for Run 14

Amount of tar sand packed	14968.8 gms.
Bitumen content of the tar sand	.14658
Weight of bitumen in place	2194.127 gms.
Volume of bitumen in place	2117.883 cc
Solvent used	GCOS synthetic crude
Weight of clean sand	12774.670 gms.
Volume of clean sand	4761.338 cc
Volume of the model	7720 cc
Volume occupied by porous plate	181.58 cc
Void space in the model	659.199
Pore volume	2777.082
Porosity	.36
Total solvent injected	240 cc
Amount of solvent retained by the pack	187 cc
Total run time	7.68 hrs.
Time for effluent breakthrough	2.53 hrs.
Time for steam breakthrough	3 hrs.
Solvent injection time	.82 hrs.
Volume of solvent inj. before effluent B.T.	240 cc
Total steam injected (as water)	3680 cc
Average pressure for solvent injected	28.44 psig
Average pressure for steam injection	85.25 psig
Water bitumen ratio	9.72 cc/cc

Table 37 (continued)

Solvent bitumen ratio	.13 cc/cc
Total recovery	397 cc
Steam injection rate	10.05 cc/min.
Recovery	18.75%

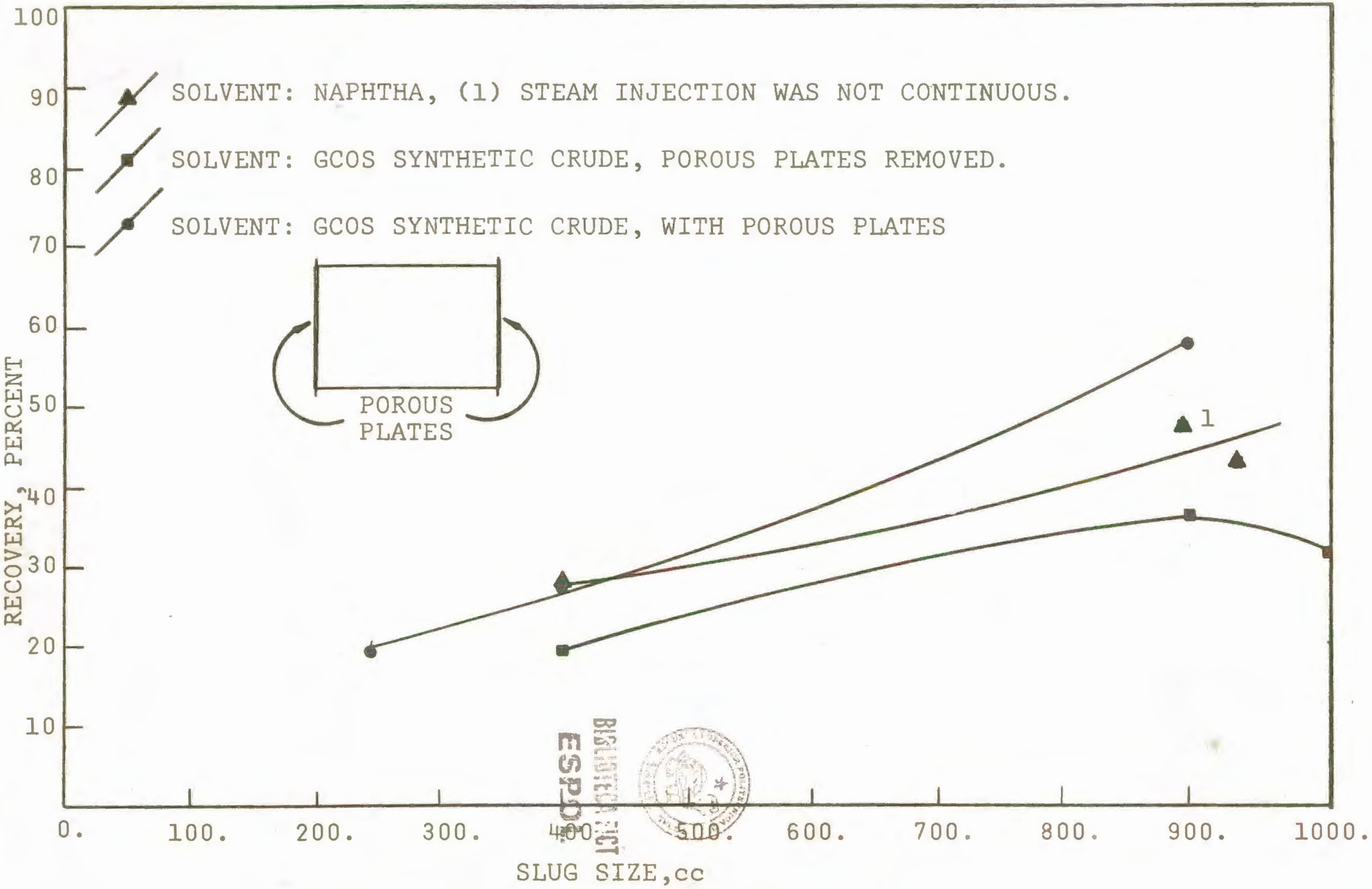
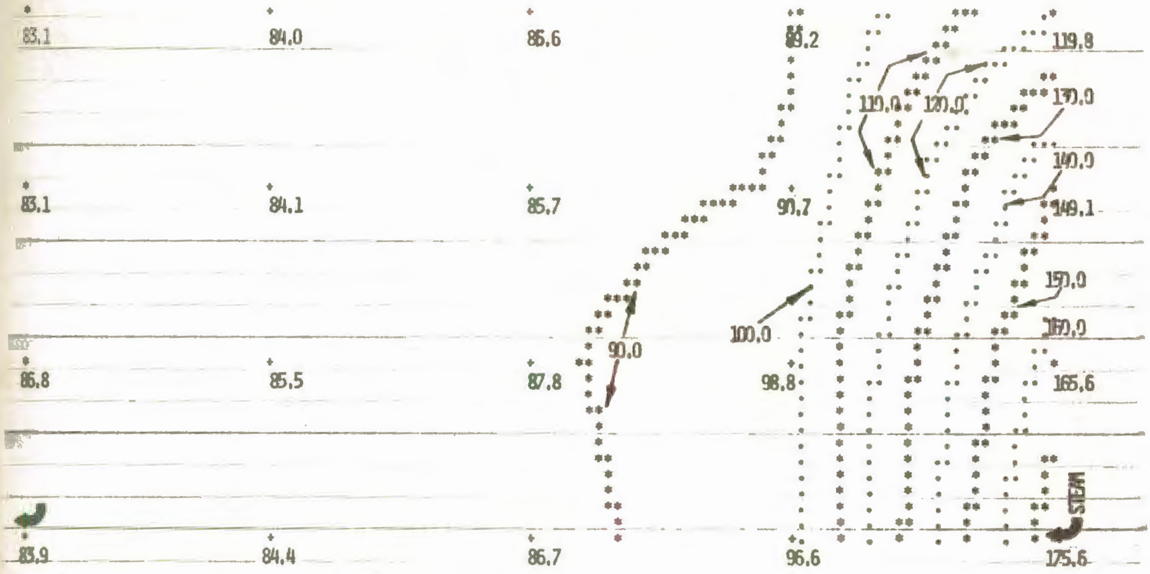


Figure 68 Effect of Slug Size in Recovery

TEMPERATURE PROFILE AFTER 01 HRS OF STEAM INJ.,P = 100.0 PSIG.,TEMP. IN DEG. F



TEMPERATURE PROFILE AFTER 03 HRS OF STEAM INJ.,P = 100.0 PSIG.,TEMP. IN DEG. F.

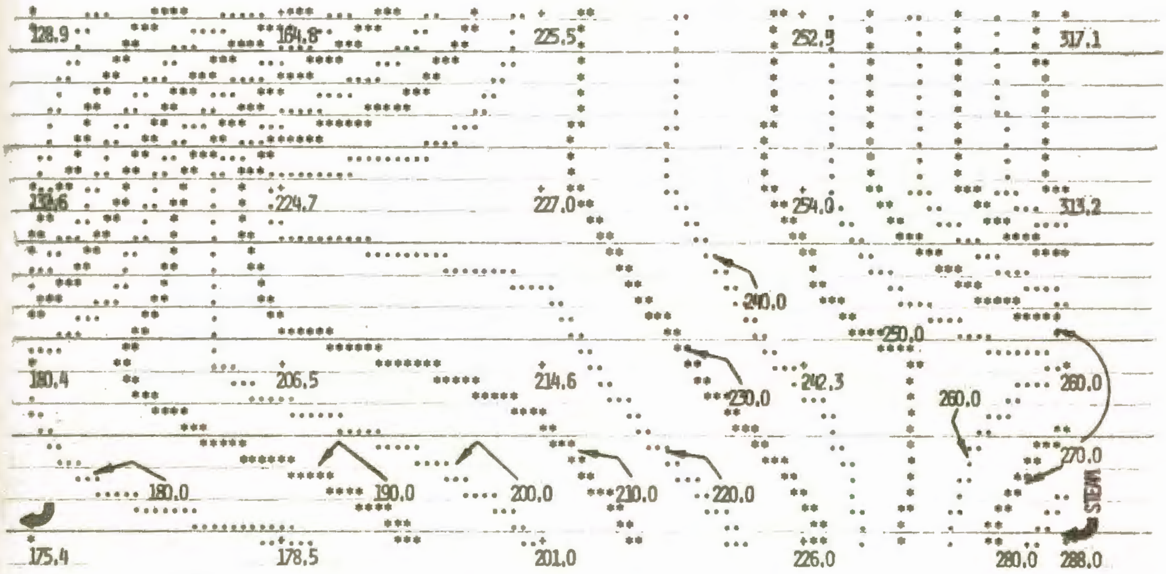
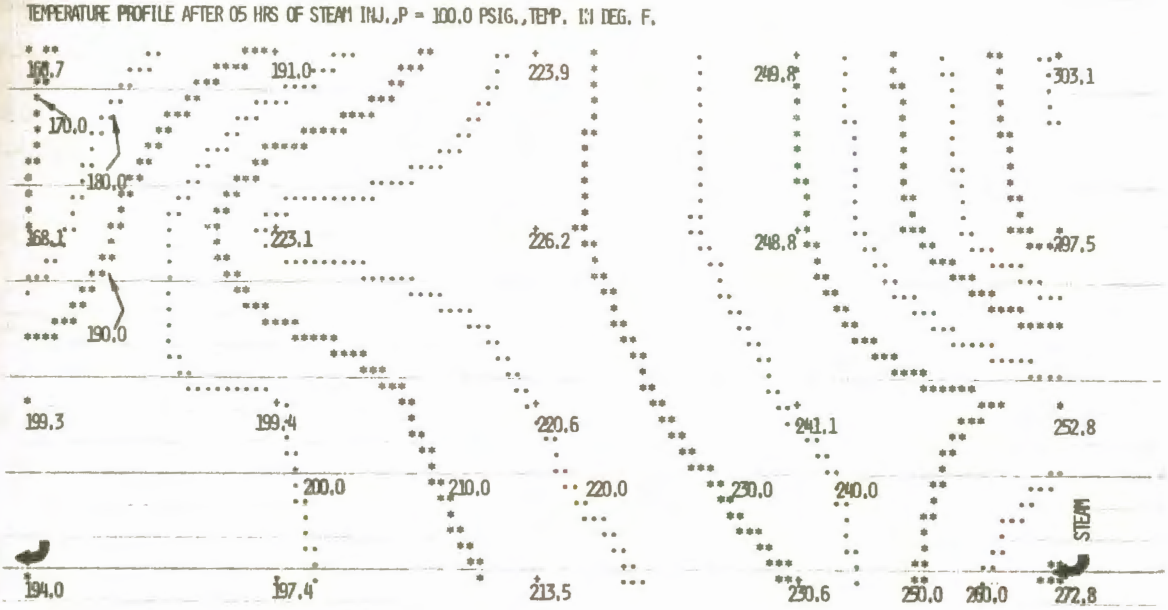
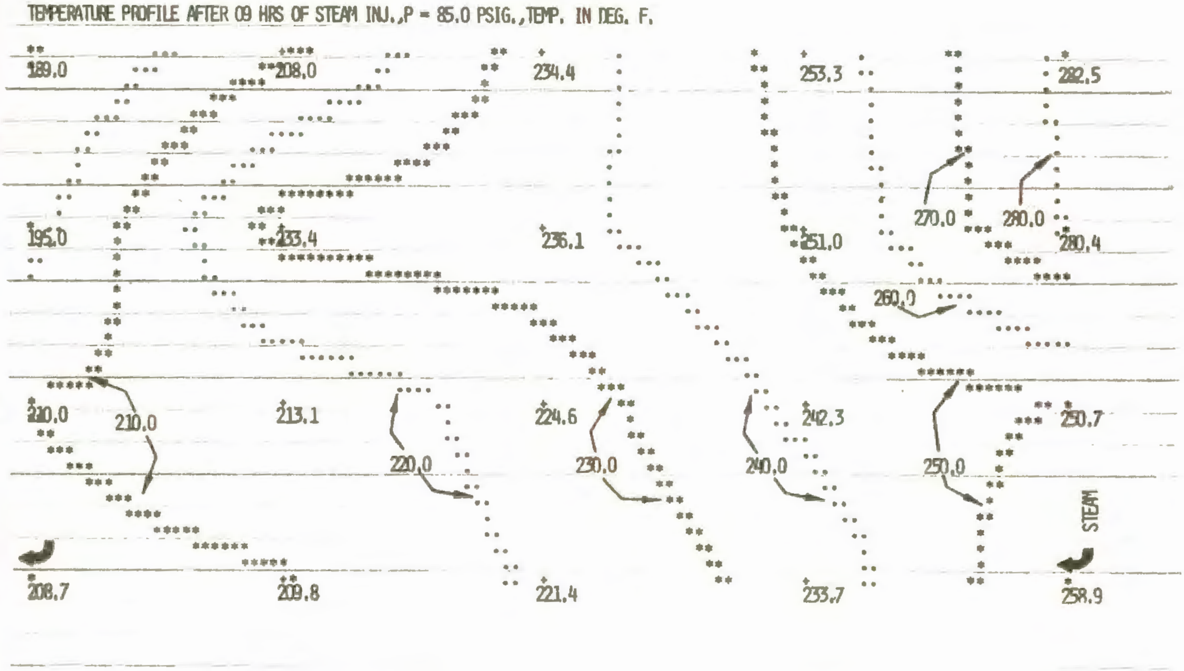


Figure 69 Temperature Profiles for Run 12.

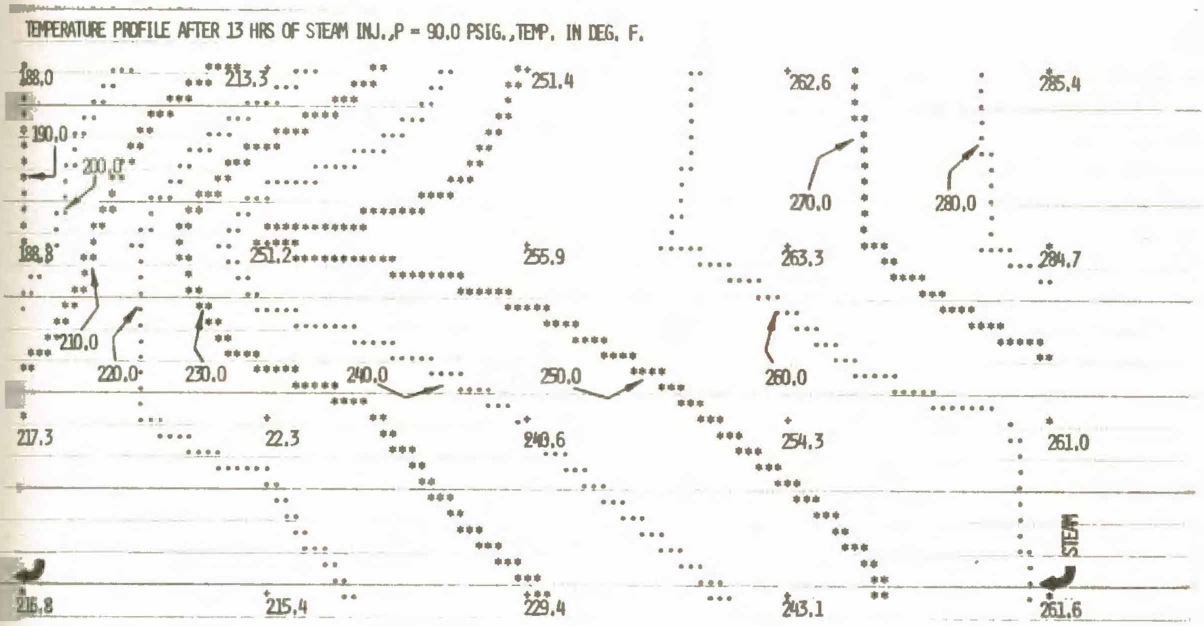


TEMPERATURE PROFILE AFTER 05 HRS OF STEAM INJ.,P = 100.0 PSIG.,TEMP. IN DEG. F.



TEMPERATURE PROFILE AFTER 09 HRS OF STEAM INJ.,P = 85.0 PSIG.,TEMP. IN DEG. F.

Figure 70 Temperature Profiles for Run 12.



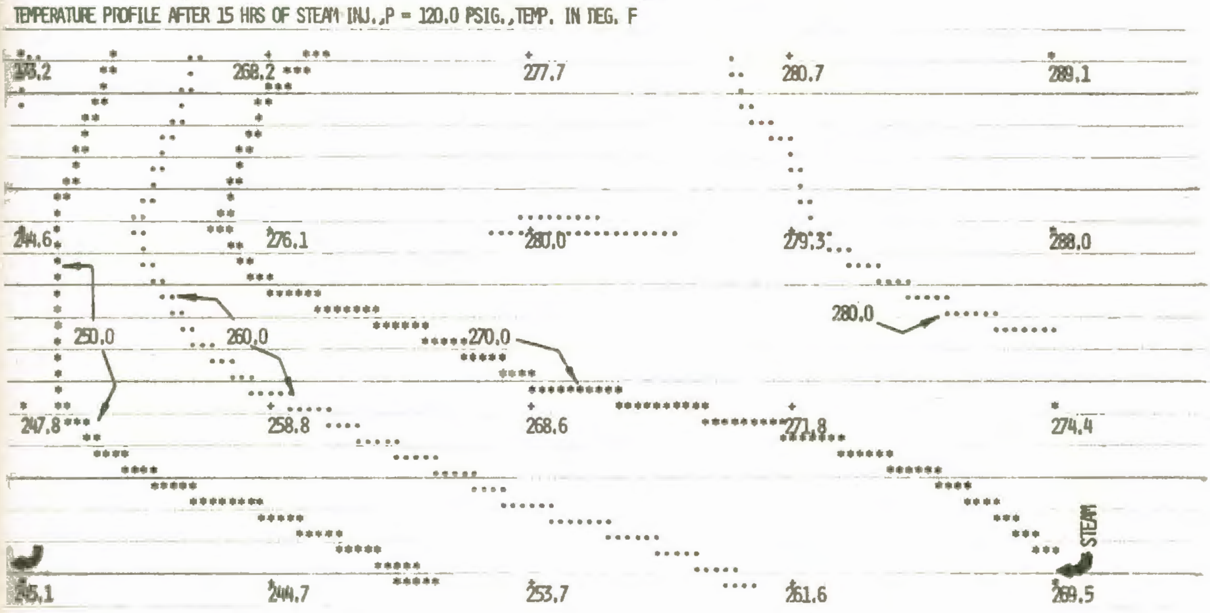
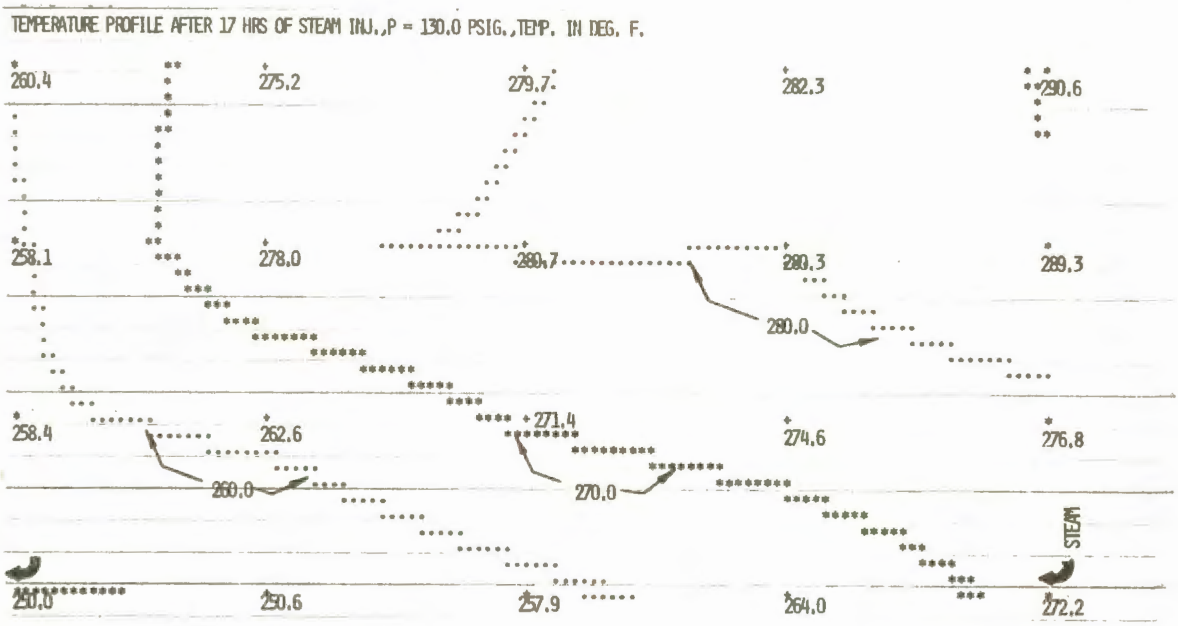
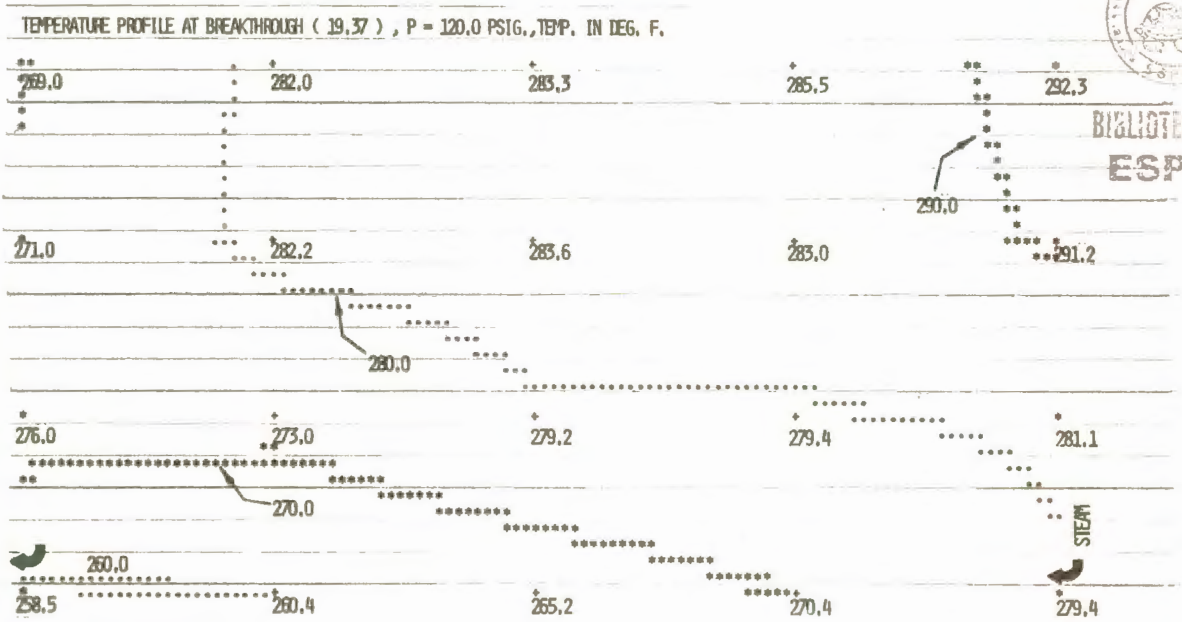


Figure 71 Temperature Profiles for Run 12.



TEMPERATURE PROFILE AFTER 17 HRS OF STEAM INJ.,P = 130.0 PSIG.,TEMP. IN DEG. F.



TEMPERATURE PROFILE AT BREAKTHROUGH (19.37) , P = 120.0 PSIG.,TEMP. IN DEG. F.

Figure 72 Temperature Profiles for Run 12.

will be understood later, it is important to notice that water, solvent, and steam were injected through the same port in these three runs.

Figures 73, 75 and 77 present the injection histories for these runs. It is interesting to note that for the three cases studied (45, 20 and 10% PV slug size), the amount of water produced during the injection of solvent was almost equal to the volume of solvent injected. For example, in Run 15, 90 percent of the water injected to saturate the pack was produced, considering that 890 cc of water were injected and 801 cc were produced. This was observed also in Runs 16 and 17.

It is interesting to note that after effluent breakthrough occurred, water production decreased to zero, and only solvent-bitumen solutions flowed out of the pack. When solvent is being injected, there is an interface between the solvent-bitumen solutions and the water being displaced. No viscous fingers develop because of the low injection rate, and the interface must be a more or less well defined front. That is why the volume of the solvent injected is almost the same as the volume of water produced throughout the entire injection period. When the front is very close to the production well, and most of the water has been produced breakthrough of effluent occurred and just 10% of the water injected is confined in the pack.

Eventhough breakthrough of solvent-bitumen solutions did not occur for Runs 16 and 17, the behavior was similar. When injecting steam, Run 15 showed an increasing WBR, and a recovery (37% OBP) which was lower than the one obtained in Run 12 (57% OBP). Also, in Run 12, 84% of the original solvent was recovered, meanwhile in Run 15 only 51% was recovered. Steam injection rate was lower in Run 15 (4.75 cc/min.) of that in Run 12 (8.53). Eventhough too high a steam injection rate tends to lower bitumen recovery, too low rates increase only the water production. It was observed also that for a long period of time (722 minutes), the steam pressure was too low (65 psig) in Run 15. It is believed that this low steam injection rate for this long period of time was the reason for the low recovery. Runs 16 and 17 exhibited very large WBR at the beginning of the steam injection. It must be considered that effluent breakthrough did not occur because of the size of the slug, and only water was produced from the sand pack in the initial stages of steam injection.

In Runs 15 and 16 recovery of the solvent injected was lower than in Runs 12 and 13, especially in Runs 13 and 16. In Run 13 almost 70% of the solvent injected was recovered, while in Run 16 less than 30% was recovered. On the other hand, the recovery of bitumen was larger in Run 16 (33.1% OBP) than in Run 13 (27% OBP). Analyzing the temperature profiles for Run 16 presented in Figures 83, 84 and 85, it is possible to see that the overriding effect of the steam was strong only after 7 hours of steam injection, and even the higher temperatures were at the top of the sand pack, the temperatures at the bottom were not much lower as observed in Run 13.

As a consequence of the injection of water to saturate the sand pack, the steam injection time increased for Run 17 (5.83 hours) as compared with Run 14 (3 hours); and eventhough the difference in steam injection times were large, the increase in recovery was not. An increase in the recovery of the solvent injected was observed showing that the stimulation by this small slug was almost insignificant for Run 17. Observing Figure 82, it is possible to see that most of the solvent was recovered in the initial stages of steam injection when most of the steam was condensed due to the low temperature of the sand pack.

In Runs 18, 19, and 20, the injection location of the solvent slug was changed from the steam injection well to the production well. The sand pack was saturated with water, which was injected through the side of the steam injection well. When saturation of the pack was obtained, injection of solvent was started through the production well.

The characteristics of these three runs were completely different from those of Runs 15, 16, and 17, where the solvent slug was injected through the steam injection well. Pressure and injection rates did not show the fluctuations observed in the previous runs. Water was produced only up to the moment of effluent breakthrough. The most remarkable characteristic was the lowering in the volume of the solvent required to obtain effluent breakthrough. In all the previous runs it was observed that the volume of solvent required to breakthrough was around 900 cc (which represents 45% of the total volume of bitumen in place). In Runs 18, 19, and 20 this volume decreased to 200-300 cc.

It is possible to see that in these three cases the solvent opened a channel in the sand pack, and created a path to be followed by the steam.

Once effluent breakthrough occurred, production of water stopped completely. This was observed also in Run 15 where breakthrough of effluent also occurred. Actually, the flow of solvent-bitumen solutions does not allow the water to flow, which is desirable since the recovery is increased and the solvent is confined also to certain regions of the pack which are washed almost completely and a path for the steam is created helping in this way to decrease the tendency of the steam to override the sand pack.

It was noticed also that the displacement of bitumen by the solvent alone was much more efficient than in all the other runs. The SBR (Solvent Bitumen Ratio) in Runs 18 and 19 was 0.64 ccs/ccb showing that one volume of solvent displaced nearly two volumes of bitumen. Again the explanation could be that even though a smaller volume of bitumen was contacted by the solvent, the parts of the sand pack contacted were efficiently swept by the solvent slug.

Figures 86, 91, and 96 present the injection histories for Runs 18, 19, and 20.

Most of the solvent injected in Runs 18 and 19 was recovered, 93% in Run 18 and 82% in Run 19. Even though Run 18 yielded a recovery (38% OBP) slightly better than in Run 15 (37% OBP), the conditions were much more favorable in Run 18. Take for example, the water-bitumen ratios, for Run 18; they were much lower than in Run 15, showing a substantial decrease in steam injection time and water requirements, as well as in water production. The same was observed in Runs 19 and 18, but in these cases recovery of bitumen increased more than twice as compared to the recoveries for Runs 16 and 17.

In Figures 101, 102 and 103, comparisons of Runs 15 and 18, 16 and 19, 17 and 20 are made. It is possible to see that the recoveries were improved by changing the position of the slug placement. When the solvent slug was placed in the neighborhood of the producing well the size of the slug was not important, as in the previous runs, where reduction in the slug size implied reduction in recovery, the highest recovery was obtained when a 20% PV slug size was used, and even the 10% PV slug yielded a recovery higher than Run 18 where a 45% PV slug was used.

Figure 104 shows the variation in bitumen recovery for several slug sizes and conditions.

When the slug is injected into the sand pack through the effluent production well, most of the solvent remains in the neighborhood of this well, and the viscosity of the bitumen is highly reduced in the vicinity of the well. When injection of steam begins, the hot water flowing ahead of the steam is capable of displacing the effluent because of the low viscosity of the effluent. The two displacement mechanisms were much more efficient for this last set of experiments; the miscible displacement was improved because of the low volume of the solvent required to establish communication between injection and production wells, and because the displacement of bitumen was more efficient for this case. While injection of solvent was taking place, the water did not allow the solvent to spread itself all over the pack and the flow of effluent did not allow the water to flow outside of the pack.

When injection of steam began, the steam found much better communication between injection and production wells at the base of the model, and the overriding effect of the steam which causes early and abrupt steam breakthrough was less pronounced in these three cases. Temperature profiles are presented for Runs 18, 19, and 20, in Figures 88, 89, 90, 94, 95, 98, 99, and 100. In Figure 89, after six hours of steam injection, the temperature was higher at the top of the model, as well as throughout the sand pack.

In Figure 90, at steam breakthrough, the outlet was at 277°F and the inlet was at 303°F.

In Figures 93, 94, and 95, which give the temperature profiles for Run 19 (the highest bitumen recovery was obtained in this run, 58% OBP) the overriding effect of the steam was even less pronounced in the initial stages of steam injection. But when breakthrough occurred, the difference in temperature between the inlet and the outlet was 110°F.

Run 20 was the last conducted using the two dimensional model. A 10% PV slug was used. Although the effluent breakthrough did not occur, effluent was produced almost immediately after beginning steam injection, which confirmed what was observed in Runs 18 and 19, that only 200-300 cc of solvent were necessary to cause effluent breakthrough, and that for the case of having the sand pack saturated with bitumen and water, and when solvent is injected in the neighborhood of the producing well, the solvent creates better communication between the production and injection wells. Bitumen recovery was higher in comparasion to Run 17, where a similar slug was injected through the steam injection well.

Again the overriding effect of the steam took several hours to occur, and breakthrough was delayed. In Run 17 steam breakthrough occurred after 5.83 hours of steam injection, while in Run 20 it took 17.4 hours. Figures 106 and 107 show the changes in temperature with time for

Runs 17 and 19, respectively. It is possible to see that in Run 17 the overriding effect of the steam was present almost from the beginning of steam injection, because the temperature of point 4, after one hour of steam injection, was always higher than the temperature of point 19 which was closer to the steam injection point. This was not the case for Run 19, where the behavior was more normal (this is to say that the higher temperatures were at the neighborhood of the steam injection port) and points 19 and 14 were the ones with higher temperatures almost through the whole steam injection process. Just before breakthrough, the temperatures of points 4, 3, 2, 1, and 0 increased fast, and attained values higher than the temperatures of points 19 and 14.

Usually large bitumen recoveries were associated with long periods of steam injection. In Run 20, for example, the steam injection time was 17.4 hours and the recovery 40%. In Run 12, the steam injection time was 19.3 hours, and the recovery 57%, on the other hand, generally short steam injection times were associated with low recoveries. In Run 14, recovery was 18.75% and the steam injection time was 3 hours. In Run 11, recovery was 19.26%, and the steam injection time was 6 hours. Run 19 (where 58% of the original bitumen in place was recovered, and steam was injected by 9.3 hours) was the exception, but in this run the recovery by steam injection was only 44%, because 14% was recovered by solvent injection. In Run 18 (where the bitumen recovery was 38% and the steam injection time was 7.07 hours), 19% of the bitumen was recovered by solvent injection. Steam injection rate was more critical than steam injection time in the bitumen recovery. When small solvent slugs were injected, large steam injection rates produced low bitumen recoveries (e.g., 19.3% recovery in Run 11, Table 28, for a 9.84 cc/min. steam injection rate, and 19% recovery in Run 14, Table 37 shows a 10.05 cc/min. steam injection rate, as compared to 40.2% recovery in Run 20, Table 55 for a 6.35 cc/min. steam injection rate; also see Figures 57, 67, and 97, respectively). When a large solvent slug was injected, very low steam injection rates increased the water bitumen ratio without increasing the bitumen recovery (e.g., 37% recovery in Run 15, Table 40, with 10.22 cc/cc WBR, for a 4.75 cc/min. steam injection rate, as compared to 57% recovery in Run 12, Table 31, with 8.11 cc/cc WBR, for a 8.53 cc/min. steam injection rate; also see Figures 74 and 63, respectively).

Figure 105 shows the effect of steam injection rate on bitumen recovery for the conditions studied. In Runs 15, 16, 18, 19, and 20, bitumen recovery was above 30%, and as a consequence compaction of the sand pack occurred in all these runs. It must be remembered that bitumen is the cementing agent for the sand grains. When bitumen is produced from the tar sand pack, the void space increases and the pressure exerted by the steam on the sand grains causes compaction of the tar sand pack. Figure 108 shows the void space found in these runs.

Three-Dimensional Model

Two runs were conducted using Model 2 (Figures 8, 9, and 10 give the characteristics and dimensions of this model). The purpose was to investigate the efficiency of miscible and thermal-miscible displacements from a 5-spot tar sand system which included simulation of the overburden pressure and a pack saturated with bitumen and water.

The handling of this model was very complicated because of the large weight of the box (335 lbs. packed) and the long run time (39 and 30 hours for Runs 21 and 22, respectively).

Run 21. When water injection was completed, and the overburden pressure stabilized at 75 psig, a 45% PV solvent slug was injected through the four production wells. The injection history for Run 21 is shown in Table 56 and Figure 109. Breakthrough occurred after 165 cc of solvent had been injected. Assuming that equal amounts of solvent were being injected through each well, it was necessary to inject only 41.25 cc of solvent to open a path between production and injection wells. The distance from injection to producing well was 8.49 inches, whereas this distance was 20 inches in Model 1. From these figures it can be conjectured that the reason for so early an effluent breakthrough is that the distance between the wells is smaller, but it must be remembered that Model 2

Table 38

Injection History for Run 15

Time (min.)	Cumulative Time (min.)	Volume Injection (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
0.0	0.0	0.0	0.0	0.0	65.0
7.0	7.0	15.02	15.0	2.14	11.7
16.0	23.0	25.03	40.0	1.56	12.0
20.0	43.0	40.04	80.0	2.0	12.8
70.0	113.0	115.13	195.0	1.64	27.8
139.0	252.0	160.18	355.0	1.15	26.0
25.0	277.0	25.03	380.0	1.0	25.3
61.0	388.0	50.06	430.0	.82	25.5
73.0	461.0	80.0	510.0	1.10	26.0
79.0	540.0	110.12	620.0	1.39	29.5
62.0	602.0	80.09	700.0	1.29	27.2
73.0	675.0	120.13	810.0	1.64	31.5
38.0	713.0	40.04	860.0	1.05	28.8
15.0	728.0	40.04	900.0	2.67	28.5

Water Production (cc)	Cumulative Production (cc)	Effluent Production (cc)	Cumulative Production (cc)
0.0	0.0	0.0	0.0
30.0	30.0	0.0	0.0
30.0	60.0	0.0	0.0
40.0	100.0	0.0	0.0
125.0	225.0	0.0	0.0

Table 38 (continued)

Water Production (cc)	Cumulative Production (cc)	Effluent Production (cc)	Cumulative Production (cc)
135.0	380.0	0.0	0.0
20.0	400.0	0.0	0.0
50.0	450.0	0.0	0.0
77.0	527.0	0.0	0.0
33.0	560.0	0.0	0.0
67.0	627.0	0.0	0.0
150.0	777.0	0.0	0.0
35.0	807.0	35.0	35.0
0.0	807.0	40.0	75.0

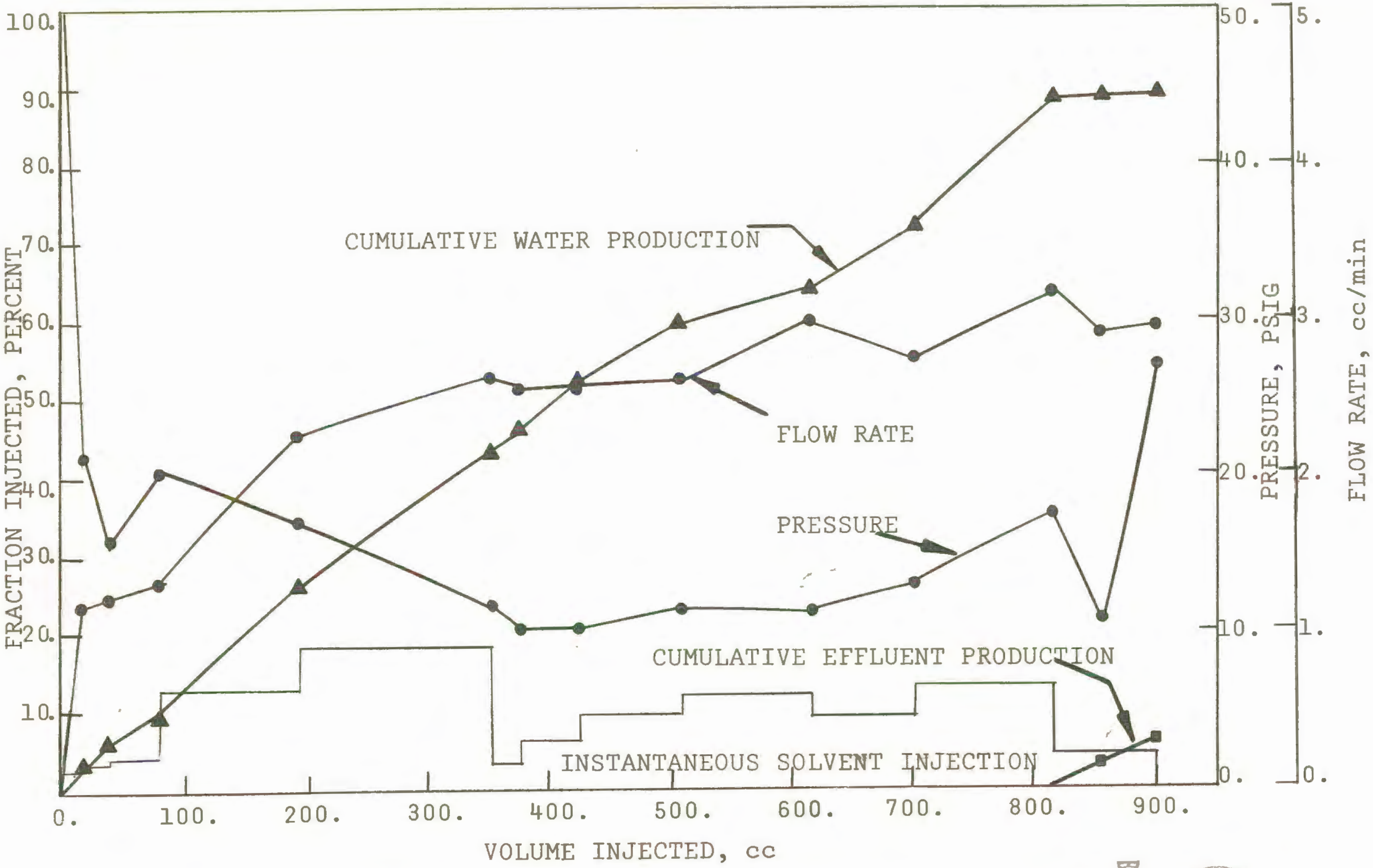


Figure 73 Injection History for Run 15.

Table 39
Production History for Run 15

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)	I[a] W.B.R. (cc/cc)	I[b] S.B.R. (cc/cc)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent (cc)
1	461	461	527.26	527.26	527	527	0.0	0.0	-	-	1.14	-	-	0
2	467	928	400.33	987.40	280	807	67.0	67.0	4.74	1.69	.99	-	113.0	113.0
3	61	989	900.45	1877.94	540	1347	170.0	237.0	3.58	.72	14.75	95	123.0	236.0
4	226	1215	1630.82	35171.76	1300	2647	212.0	440.0	6.59	.56	7.21	80	118.0	354.0
5	207	1422	900.45	44172.21	810	3457	73.0	522.0	12.73	.23	4.35	75	17.0	371.0
6	176	1598	880.44	52979.65	820	4277	44.0	566.0	18.64	.36	5.00	90	16.0	387.0
7	722	2320	35301.77	88274.41	3310	7587	151.0	717.0	26.27	.46	4.89	65	69.0	456.0
8	31	2351	860.43	96874.84	760	8347	100.0	817.0	7.6	-	27.74	90	0.0	456.0

[a] I W.B.R. = Instantaneous water-bitumen ratio.

[b] I S.B.R. = Instantaneous solvent-bitumen ratio.

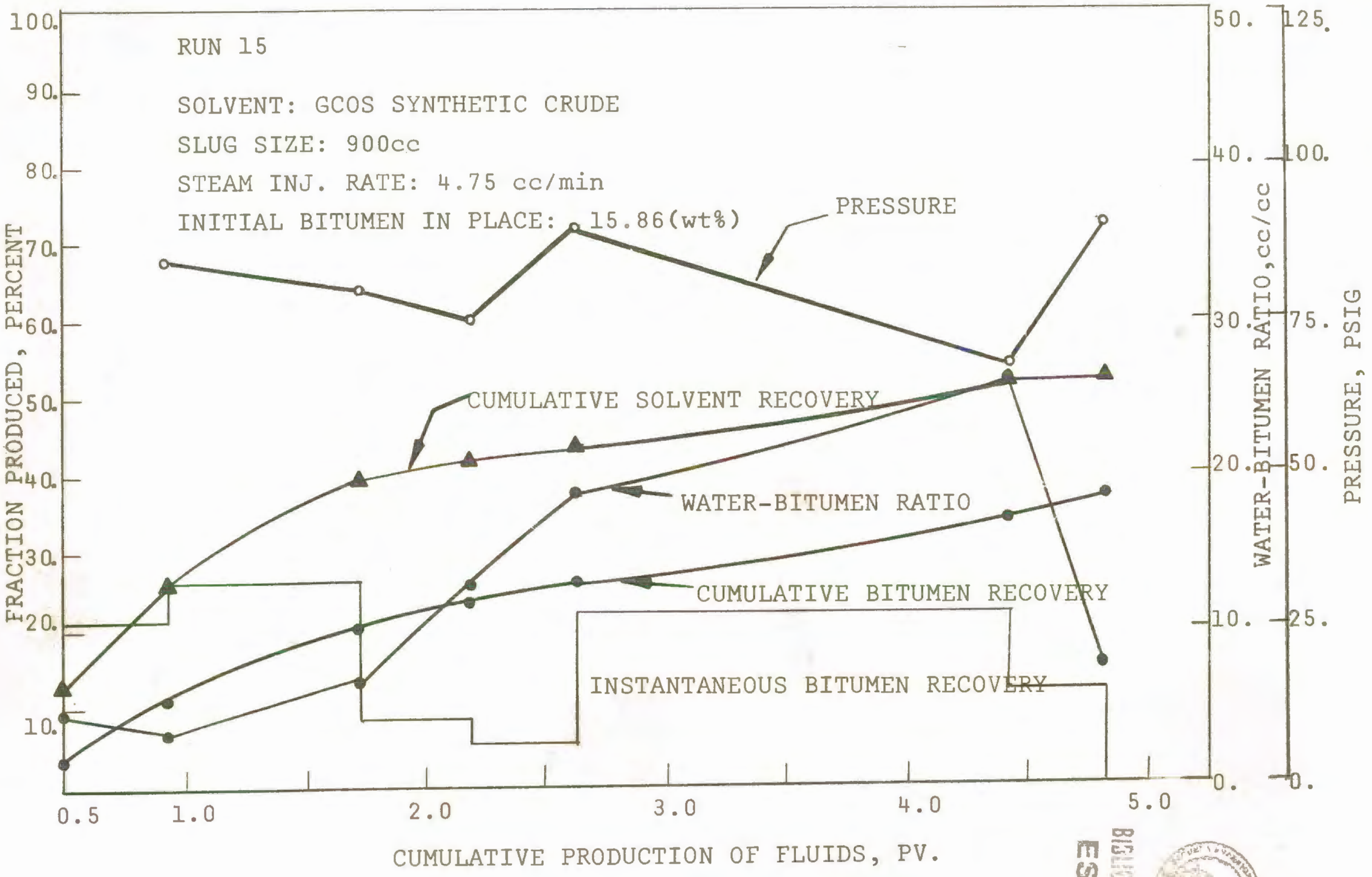


Figure 74 Production History for Run 15.

Table 40

General Characteristics and Results for Run 15

Amount of rar sand packed	14515.2 gms.
Bitumen content of the tar sand	.15867
Weight of bitumen in place	2303.13 gms.
Volume of bitumen in place	2223.07 cc
Solvent used	GCOS synthetic crude
Weight of clean sand	12212.07 gms.
Volume of clean sand	4533.34 cc
Volume of the model	7720 cc
Volume occupied by porous plates	181.58 cc
Void space in the model	782.01 cc
Pore volume	3005 cc
Porosity	.39
Total water injected to saturate the pack	890 cc
Total solvent injected	900 cc
Amount of solvent retained by the pack	444 cc
Total run time	41.72 hrs.
Time for effluent breakthrough	16.1 hrs.
Time for steam breakthrough	27 hrs.
Total steam injected (as water)	7697 cc
Steam injection rate	4.75 $\frac{cc}{min.}$
Average pressure for solvent injection	23.6 psig
Average pressure for steam injection	80.8 psig
Water bitumen ratio	10.22 $\frac{cc}{cc}$.

Table 40 (continued)

Solvent bitumen ratio (injection)	1.1 $\frac{c.c.}{c.c.}$
Volume of solvent inj. before effluent B.T.	820 cc
Solvent injection time	12.13 hrs.
Total recovery	817 cc
Recovery	37%

TEMPERATURE PROFILE AFTER 01 HRS OF STEAM INJECTION,P = 85.0 PSIG.,TEMP.IN DEG. F.

TEMPERATURE PROFILE AFTER 03 HRS OF STEAM INJECTION,P = 75.0 PSIG.,TEMP. IN DEG. F.

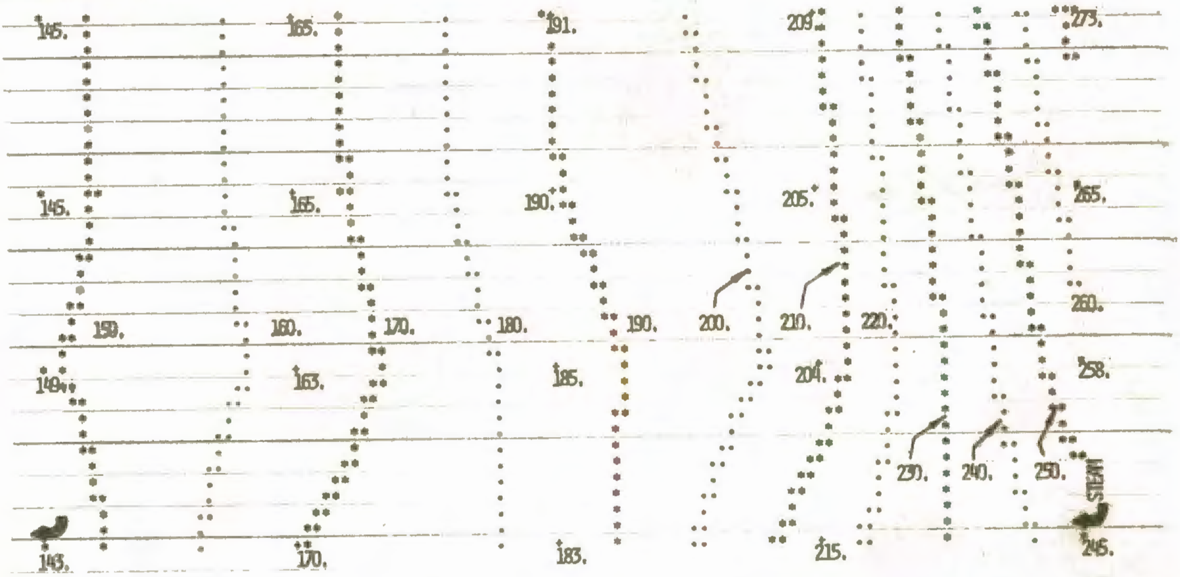
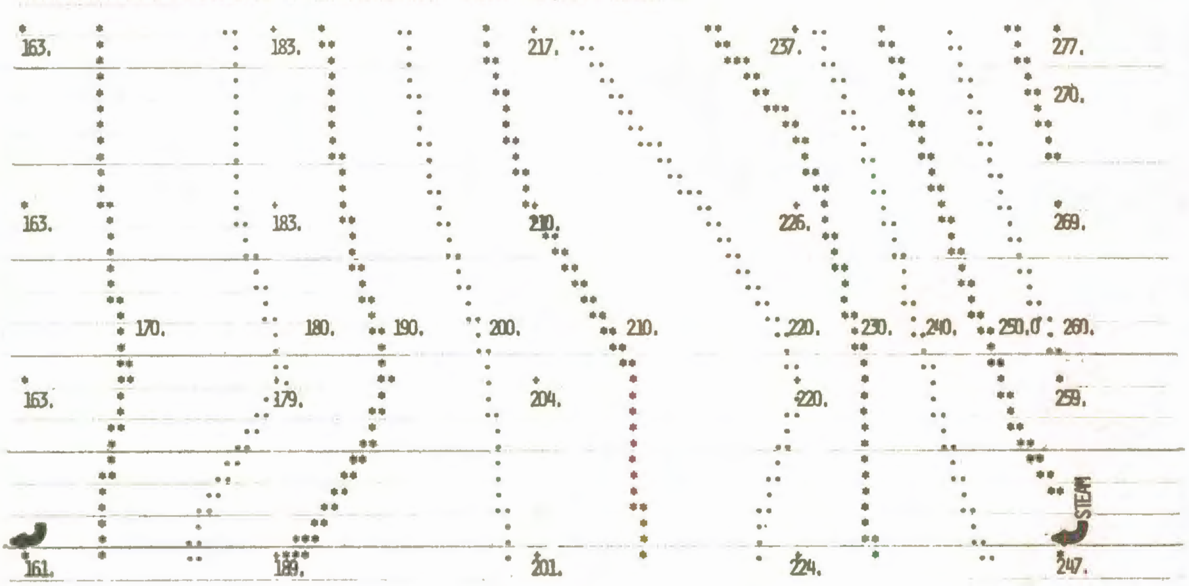
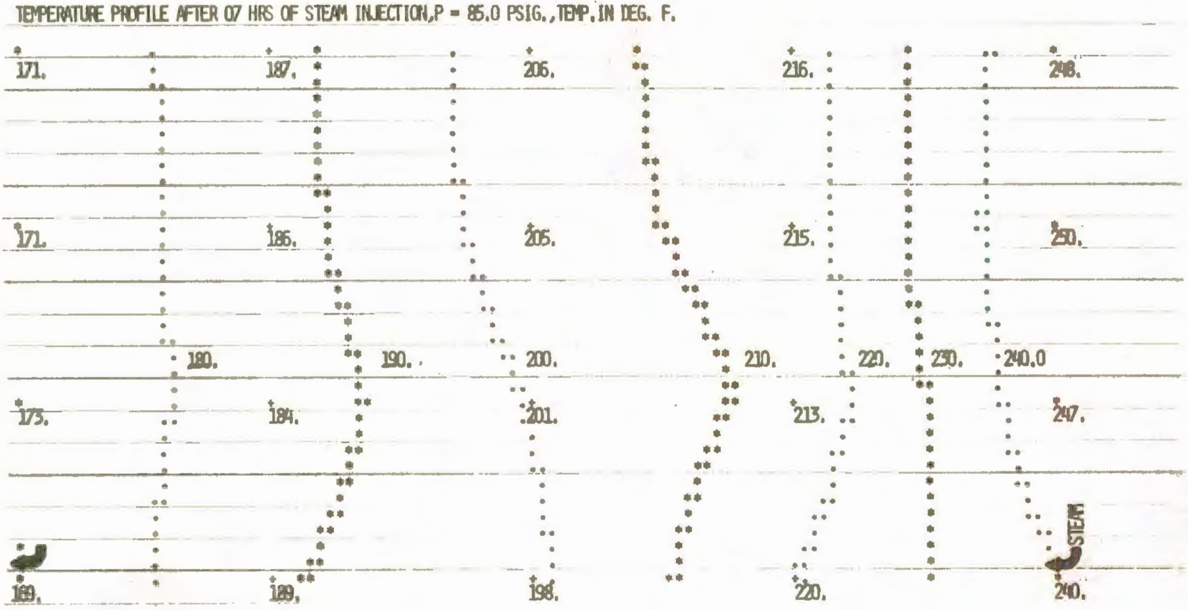


Figure 75 Temperature Profiles for Run 15.

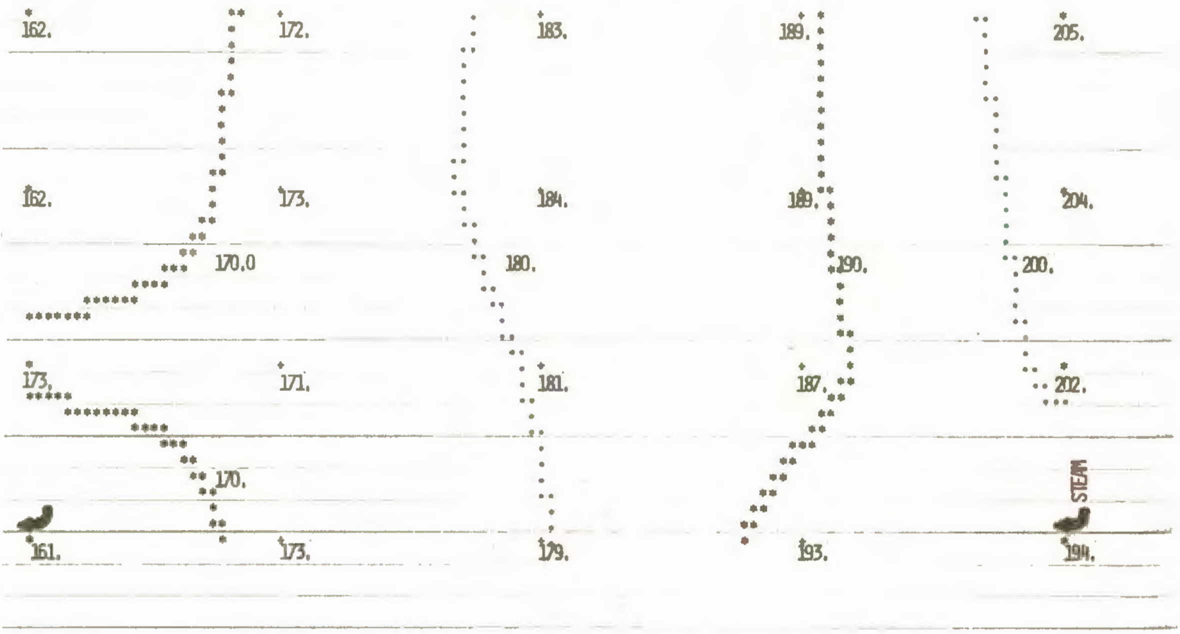


TEMPERATURE PROFILE AFTER 05 HRS OF STEAM INJECTION,P = 80.0 PSIG.,TEMP. IN DEG. F.

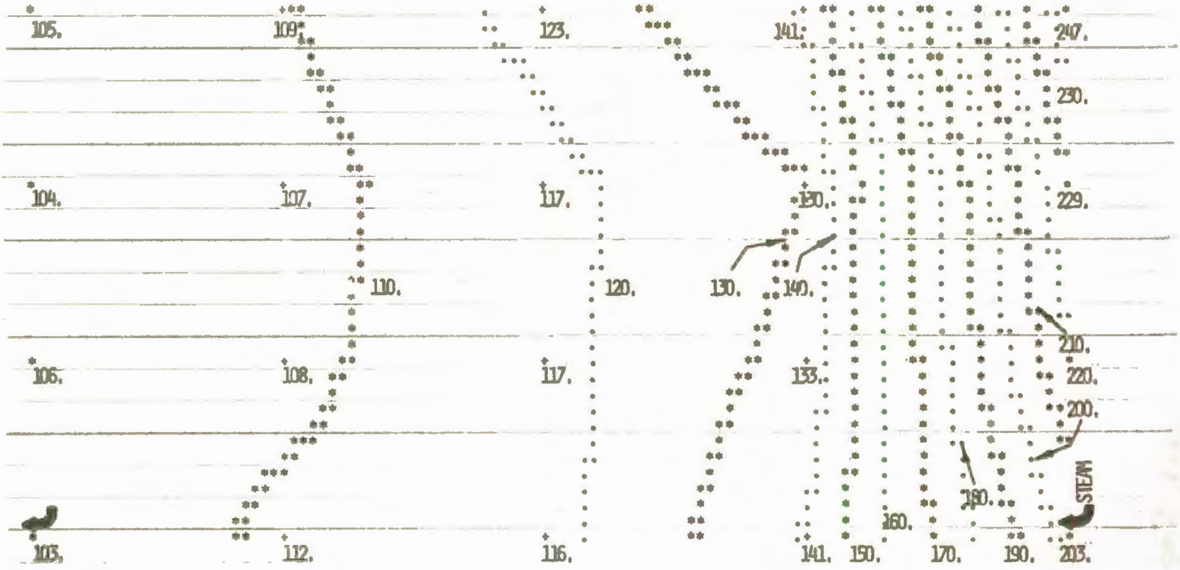


TEMPERATURE PROFILE AFTER 07 HRS OF STEAM INJECTION,P = 85.0 PSIG.,TEMP.IN DEG. F.

Figure 76 Temperature Profiles for Run 15.



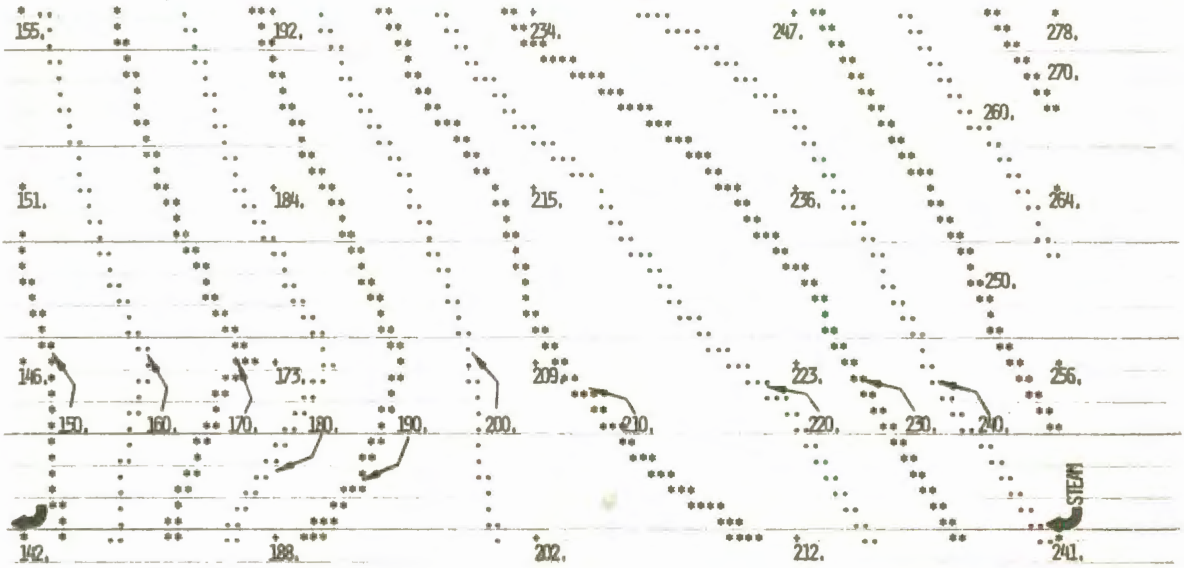
TEMPERATURE PROFILE AFTER 10 HRS OF STEAM INJECTION,P = 80.0 PSIG.,TEMP. IN DEG. F



TEMPERATURE PROFILE AFTER 19 HRS OF STEAM INJECTION,P = 95.0 PSIG.,TEMP. IN DEG. F.

Figure 77 Temperature Profiles for Run 15.

TEMPERATURE PROFILE AFTER 21 HRS OF STEAM INJECTION,P = 90.0 PSIG.,TEMP. IN DEG. F.



TEMPERATURE PROFILE AT BREAKTHROUGH (22.5),P = 90.0 PSIG.,TEMP. IN DEG. F.

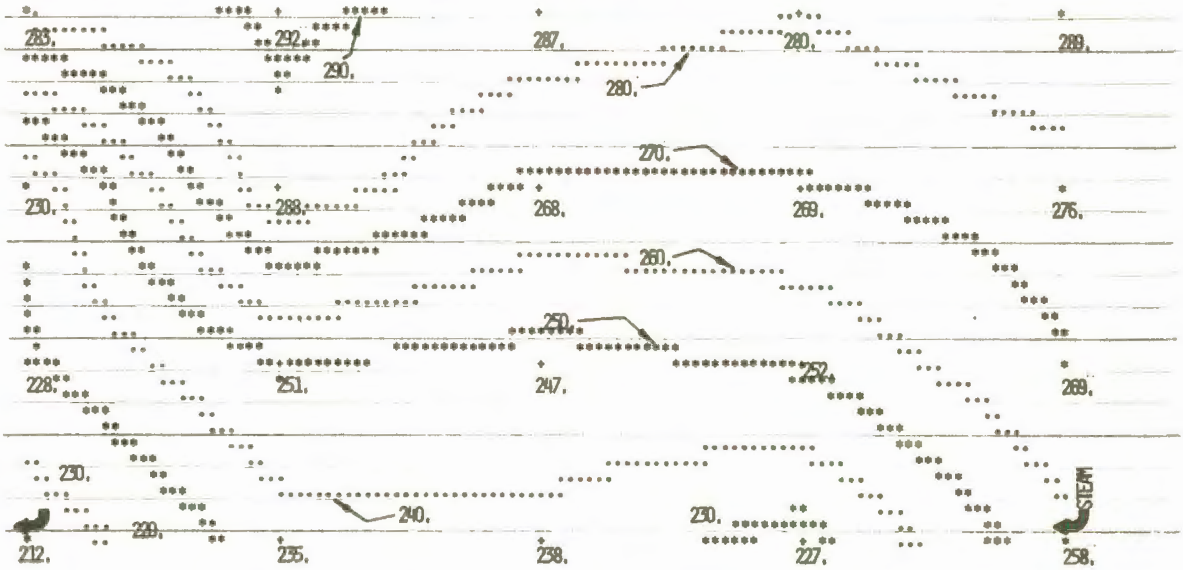


Figure 78 Temperature Profiles for Run 15.

Table 41
Injection History for Run 16

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)	Water Production (cc)	Cumulative Production (cc)
6	6	40.10	40	6.67	22.5	0	260
8	14	97.24	137	12.13	72	10	270
10	24	53.13	190	4.3	73	20	290
9	33	50.12	240	5.56	68	10	300
10	52	100.24	340	5.26	63	30	330
5	57	20.05	360	4.0	63	80	410
3	60	20.05	380	6.67	63	30	440
6	66	30.07	410	5.0	63	25	475

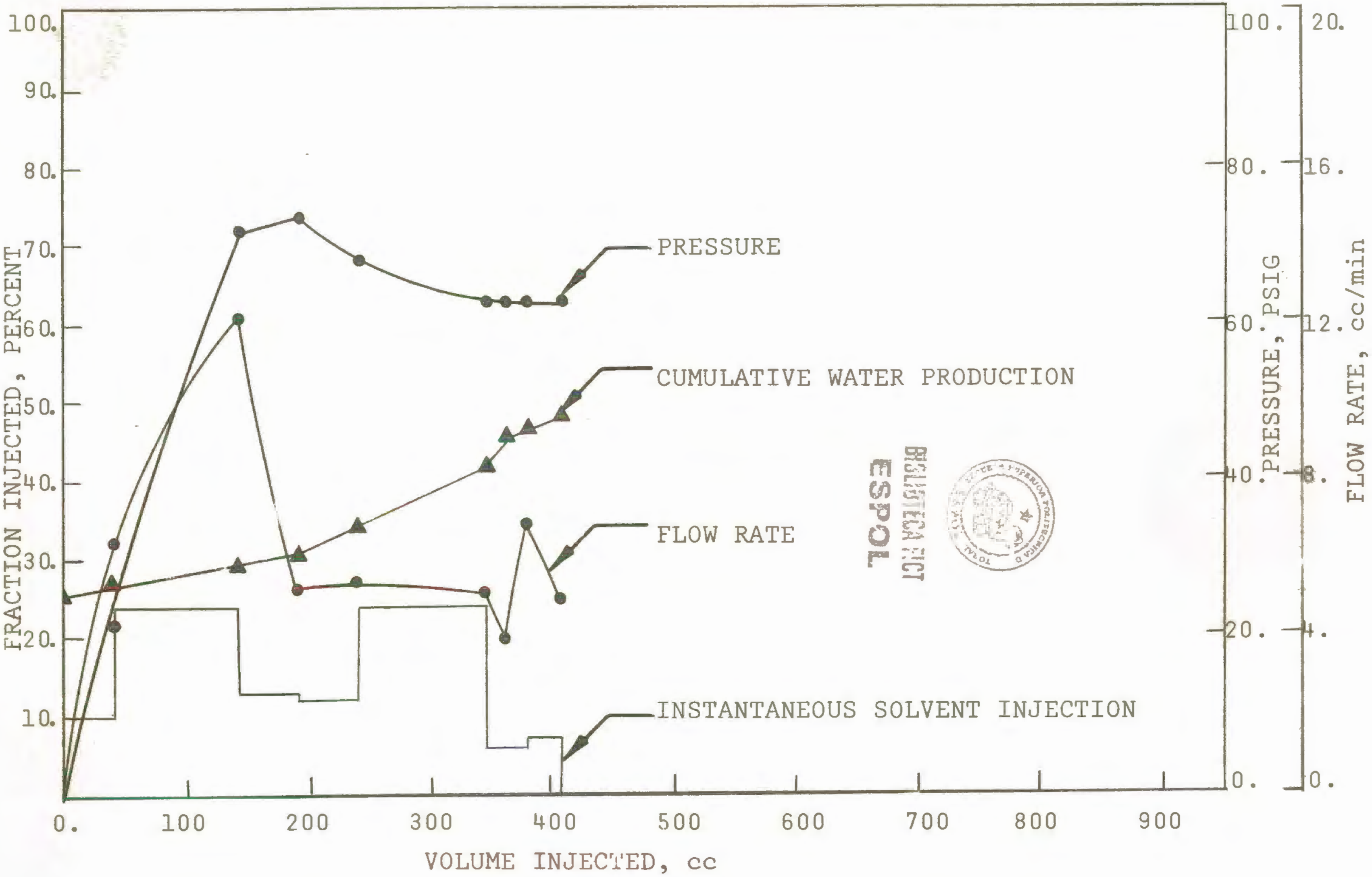


Figure 79 Injection History for Run 16.

Table 42
Production History for Run 16

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)
1	79	79	500.25	500.25	440	440	19.0	19.0
2	134	213	930.465	1430.715	889	1329.0	41.0	60.0
3	129	342	900.45	23301.165	830	2159.0	50.0	110.0
4	93	435	910.455	32401.62	854	3013.0	48.0	158.0
5	157	592	22501.25	34902.745	1718	4731.0	490.0	648.0
6[a]	-	0	130.065	56202.81	110	4841.0	20.0	668.0

Inst. W.B.R. (ccw/ccb)	Inst. S.B.R. (ccs/ccb)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent (cc)
23.16	2.16	6.33	65	41.0	41.0
21.68	0	6.94	83.5	-	41.0
16.60	.40	6.98	81	20	61.0
17.80	.17	9.78	90	8.0	69.0
3.51	.09	3.80	67.5	42.0	111.0
5.50	.00	-	-	-	111.0

[a] This ample was recovered when steam injection was stopped.

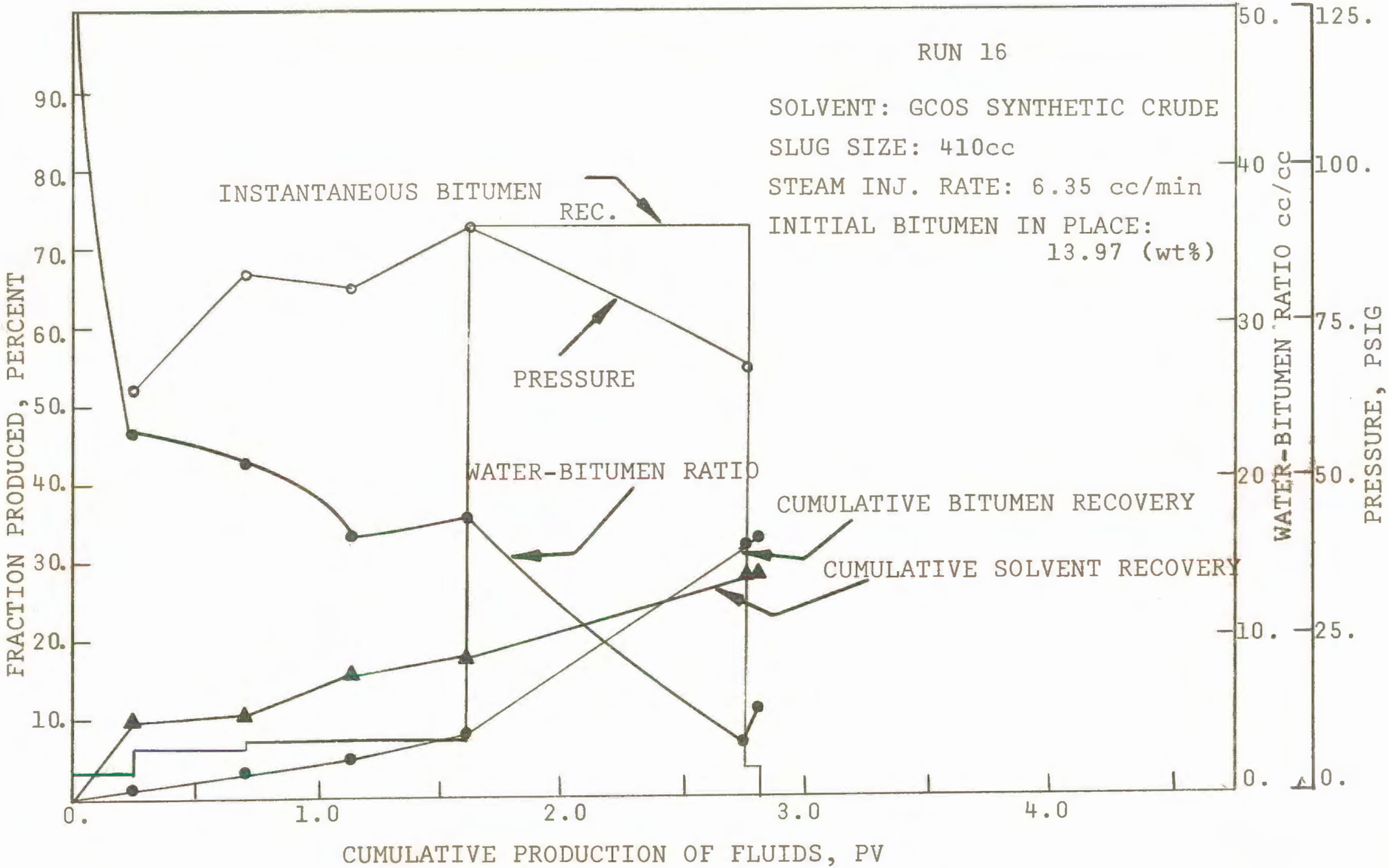


Figure 80 Production History for Run 16.

Table 43

General Characteristics and Results for Run 16

Amount of tar sand packed	14968.8 gms.
Bitumen content of the tar sand	.1397
Weight of bitumen in place	2091.14 gms.
Volume of bitumen in place	2018.48 cc
Solvent used	GCOS synthetic crude
Weight of clean sand	12877.66 gms.
Volume of clean sand	4797.9 cc
Volume of the model	7720. cc
Void space in the model	722. cc
Pore volume	2813.14 cc
Porosity	.364
Total water injected to saturate the pack	725. cc
Total solvent injected	410. cc
Amount of solvent retained by the pack	299. cc
Total run time	14.68 hrs.
Time for effluent breakthrough	4.07 hrs.
Time for steam breakthrough	11.5 hrs.
Solvent injection time	1.2 hrs.
Volume of solvent inj. before effluent B.T.	410 cc
Total steam injected (as water)	4380 cc
Average pressure for solvent injection	61 psig
Average pressure for steam injection	85.67 psig
Water bitumen ratio	7.25 cc/cc

Table 43 (continued)

Solvent bitumen ratio (injection)	61 cc/cc
Steam injection Rate	6.35 cc/min.
Total bitumen recovered	668
Volume occupied by porous plates	181.58 cc
Recovery	33.1%

Table 44

Injection History for Run 17

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
0.0	0.0	0.0	0.0	0.0	16.0
3.0	3.0	20.09	20.0	6.67	36.0
6.0	9.0	50.23	70.0	8.33	46.0
11.0	20.0	70.32	140.0	6.36	68.0
5.0	25.0	40.18	180.0	8.0	62.0
7.0	32.0	40.18	220.0	5.71	60.0

Water Production (cc)	Cumulative Production (cc)
100.0	100.0
10.0	110.0
15.0	125.0
65.0	190.0
20.0	210.0
30.0	240.0

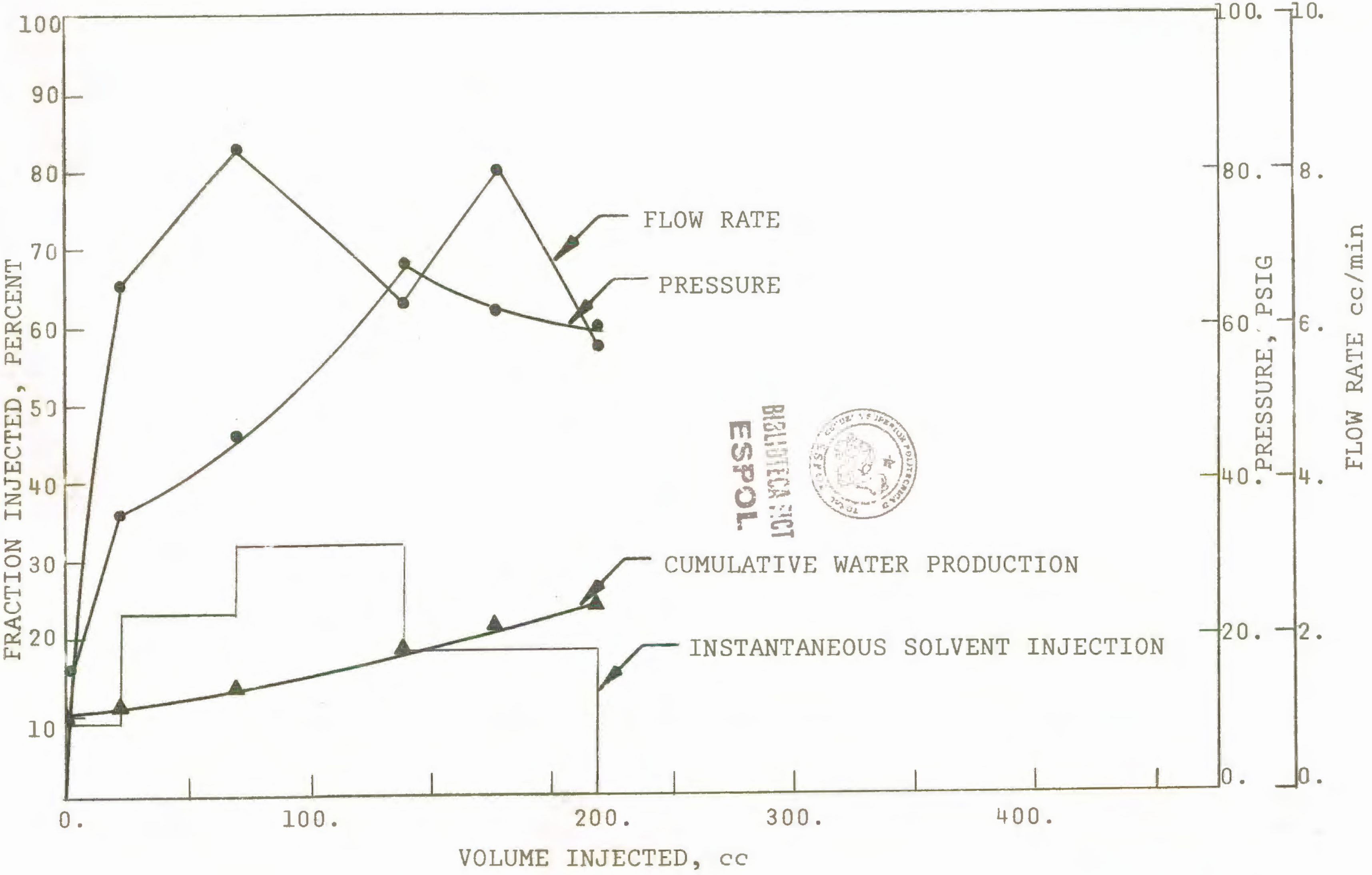


Figure 81 Injection History for Run 17.

Table 45
Production History for Run 17

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)	Inst. W.B.R. (ccw/ccb)	Inst. S.B.R. (ccs/ccb)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent (cc)
1[a]	587	-	500.25	500.25	500	500	-	-	-	-	2.11	-	-	0
2	70	70	500.25	1000.50	500	1000	-	-	-	-	7.14	60	-	0
3	37	107	540.27	1540.77	530	1530	9.0	9.0	59.0	.11	14.59	90	1.0	1.0
4	95	202	910.46	24501.23	719	2249	31.0	40.0	23.0	5.16	9.58	85	160.0	161.0
5[b]	92	204	960.48	34101.71	850	3099	42.0	81.0	20.0	.43	10.43	80	18.0	179.0
6	10	304	210.11	36201.81	160	3250	41.0	123.0	4.0	.22	21.0	80	9.0	188.0
7	86	390	1280.64	49002.40	1000	4259	270.0	393.0	3.7	.04	14.42	95	10.0	198.0

[a] The time for this sample is not registered for the cumulative value because it was recovered overnight (from 240 cc - 500 cc).

[b] Fifty cc of sand were produced here.

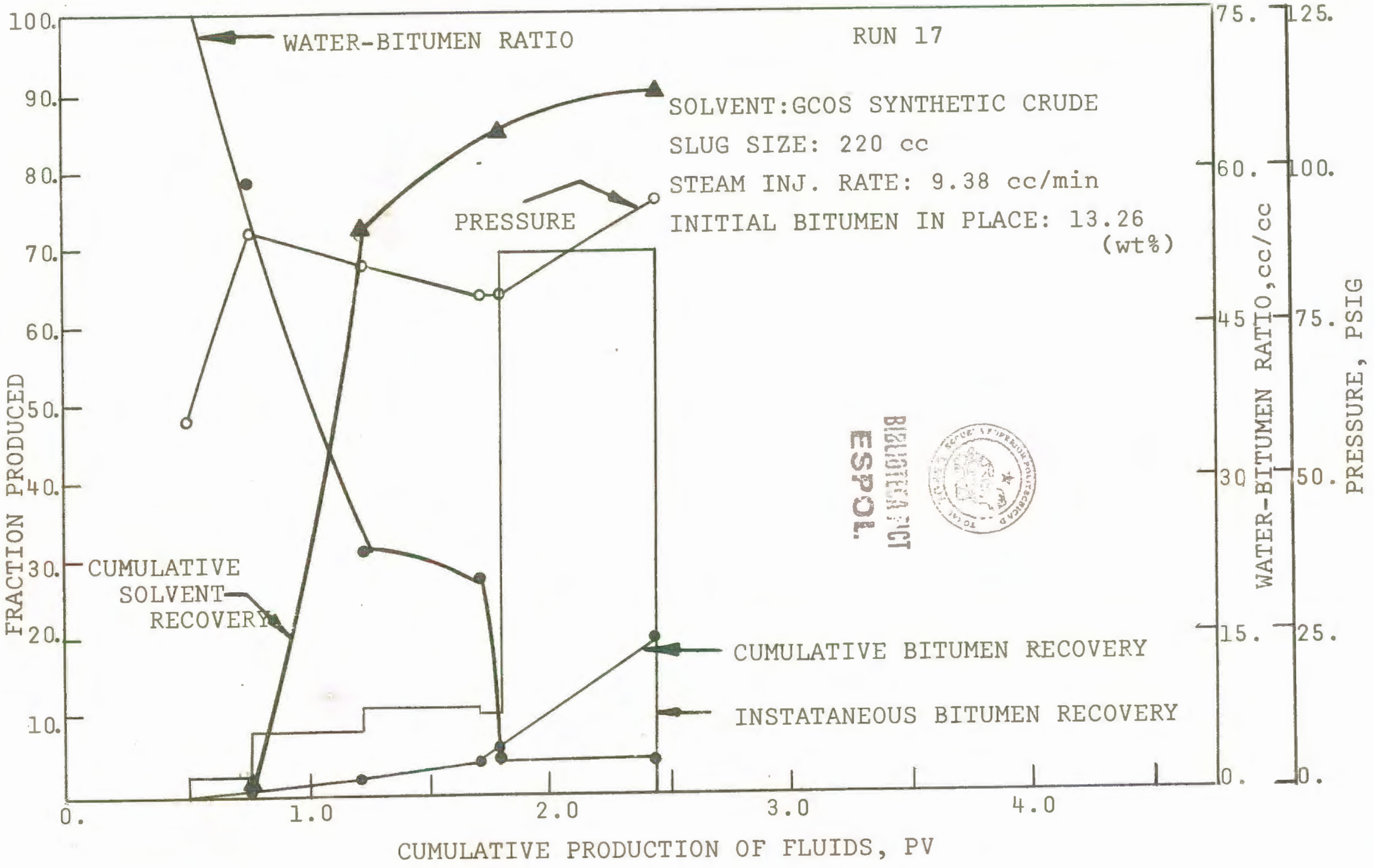


Figure 82 Production History for Run 17.

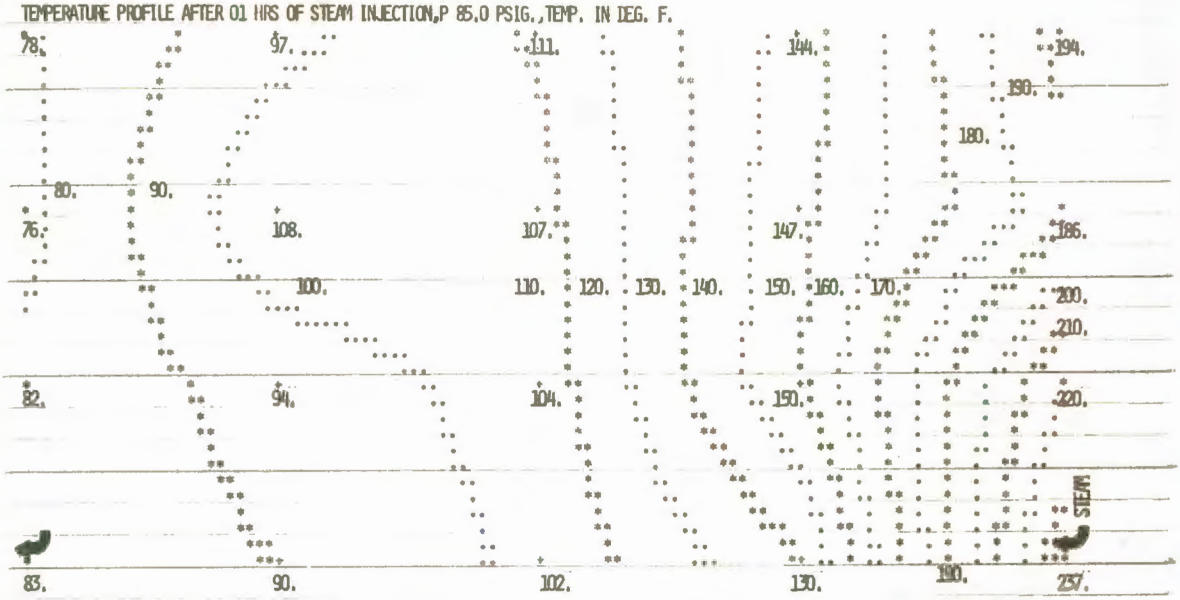
Table 46

General Characteristics and Results for Run 17

Amount of tar sand packed	15138.90 gms.
Bitumen content of the tar sand	.1326
Weight of bitumen in place	2007.42 gms.
Volume of bitumen in place	1937.66 cc
Solvent used	GCOS synthetic crude
Weight of clean sand	13131.48 gms.
Volume of clean sand	4892.5 cc
Volume of the model	7720 cc
Volume occupied by porous plates	181.58 cc
Void space in the model	738.5 cc
Pore volume	2645.92 cc
Porosity	.34
Total water injected to saturate the pack	895 cc
Total run time	9.8 hrs.
Total solvent injected	220 cc
Amount of solvent retained by the pack	141.01 cc
Time for effluent breakthrough	3.62 hrs.
Solvent injection time	.53 hrs.
Time of steam injection	6.01 hrs.
Volume of solvent inj. before effluent B.T.	220 cc
Total steam injected (as water)	3282 cc
Average pressure for solvent injection	51.57 psig
Average pressure for steam injection	86.82 psig

Table 46 (continued)

Water bitumen ratio	10.84 cc/cc
Solvent bitumen ratio	.56 cc/cc
Steam injection rate	9.38 cc/min.
Total bitumen recovery	393 cc
Time for steam breakthrough	5.83 hrs.
Recovery	20.3%



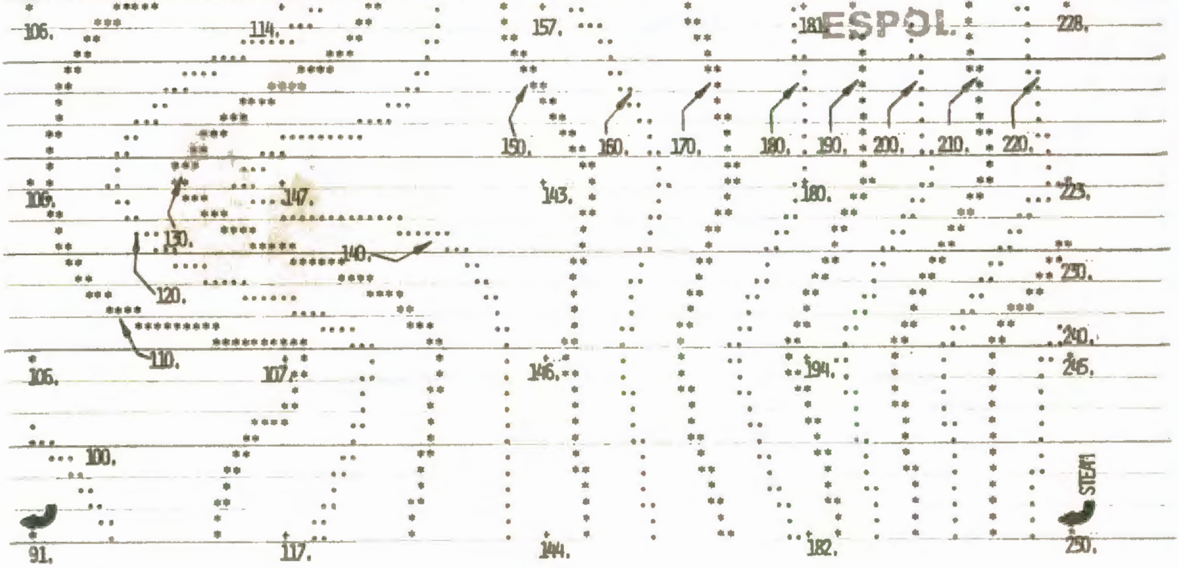
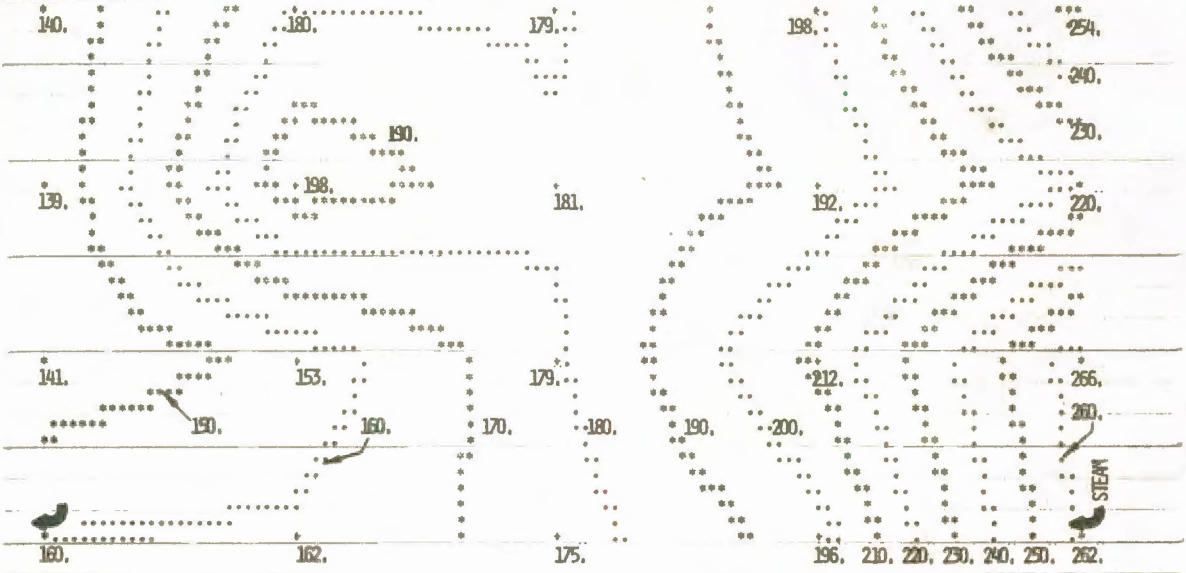


Figure 83 Temperature Profiles for Run 16.

TEMPERATURE PROFILE AFTER 05 HRS OF STEAM INJECTION, P = 85.0 PSIG.,TEMP. IN DEG. F.



TEMPERATURE PROFILE AFTER 06 HRS OF STEAM INJECTION, P = 91.0 PSIG.,TEMP. IN DEG. F.

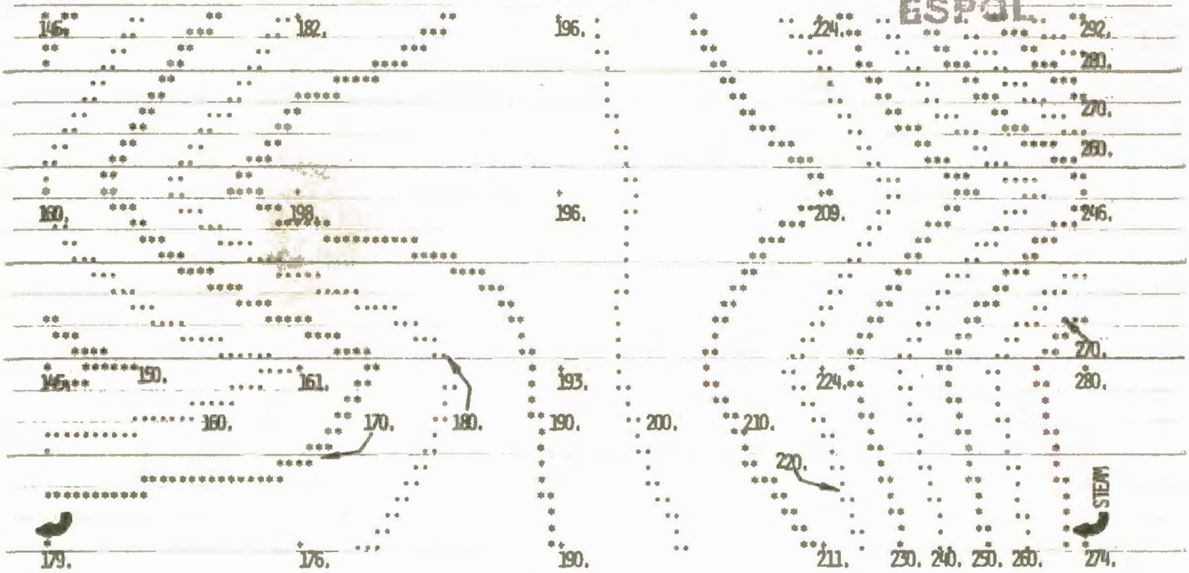


Figure 84 Temperature Profiles for Run 16.

TEMPERATURE PROFILE AFTER 07 HRS OF STEAM INJECTION, P = 85.0 PSIG.,TEMP. IN DEG. F.

TEMPERATURE PROFILE AFTER 10 HRS OF STEAM INJECTION, P = 80.0 PSIG.,TEMP. IN DEG. F.

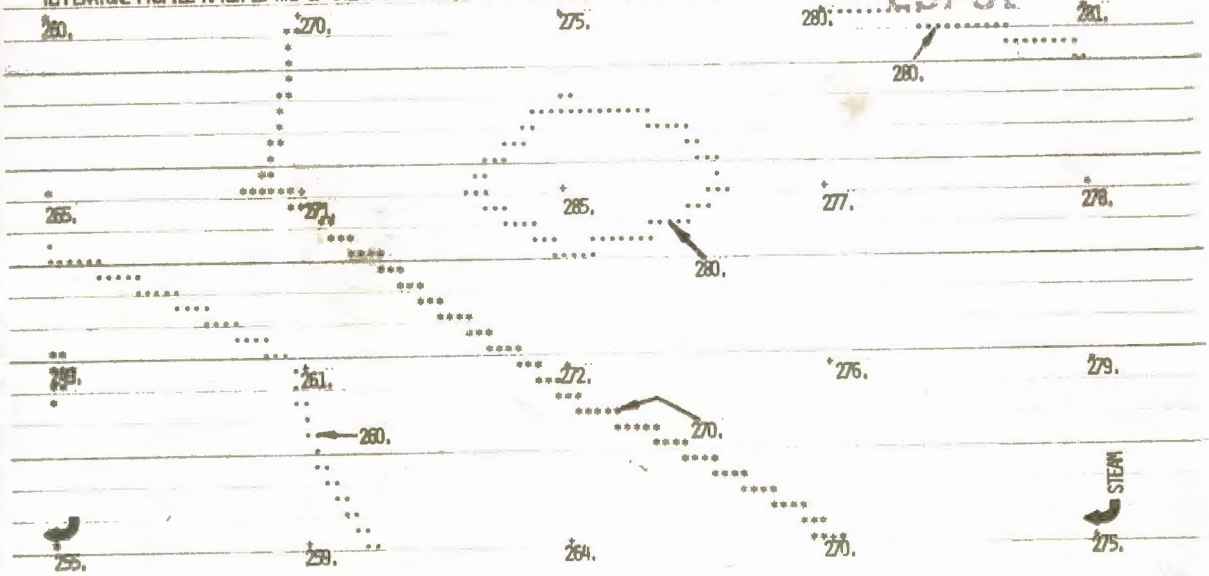


Figure 85 Temperature Profiles for Run 16.

Table 47

Injection History for Run 18

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
0.0	0.0	0.0	0.0	0.0	50.0
8.0	8.0	60.07	60.0	7.5	31.0
5.0	13.0	40.04	100.0	8.0	37.0
16.0	20.0	100.11	200.0	6.25	33.0
21.0	50.0	140.16	340.0	6.67	33.0
17.0	67.0	120.13	460.0	7.06	33.0
7.0	74.0	35.04	405.0	5.0	33.0
10.0	84.0	45.05	540.0	4.5	33.0
12.0	96.0	60.07	600.0	5.0	33.0
68.0	164.0	300.33	900.0	4.41	35.0

Water Production (cc)	Cumulative Production (cc)	Effluent Produced (cc)	Cumulative Production (cc)
20.0	20.0	0.0	0.0
130.0	150.0	0.0	0.0
70.0	220.0	0.0	0.0
60.0	280.0	0.0	0.0
10.0	290.0	30.0	30.0
50.0	340.0	160.0	190.0
0.0	340.0	305.0	495.0
0.0	340.0	50.0	545.0
0.0	340.0	55.0	600.0
0.0	350.0	280.0	880.0

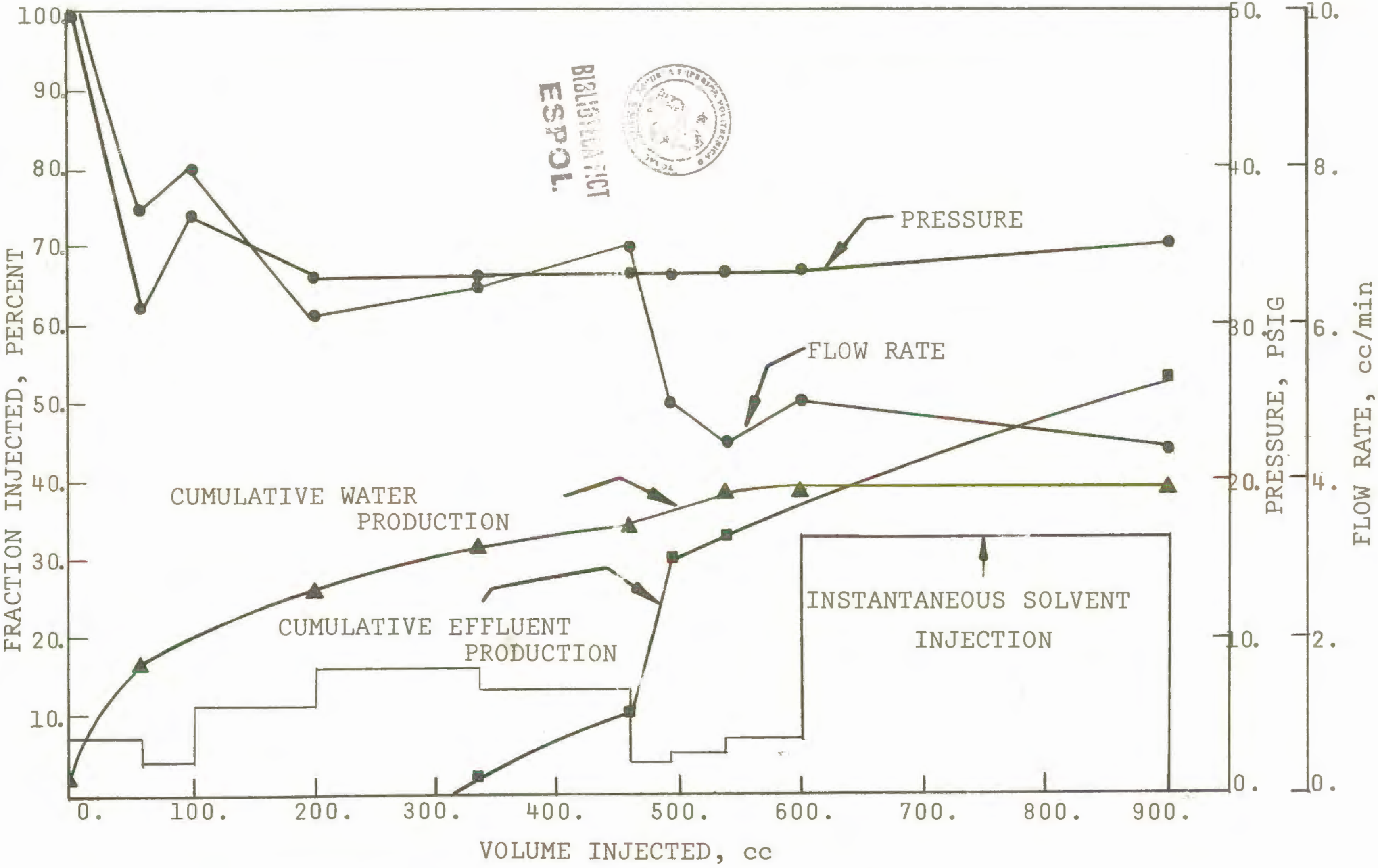


Figure 86 Injection History for Run 18.

Table 48
Production History for Run 18

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)
1	126	126	700	700	340	340	220	220
2	74	200	445	1195	340	680	43	263
3	90	290	605	1800	0	680	148	411
4	63	353	500	2300	400	1080	39	450
5	94	447	900	3200	830	1910	60	510
6	141	588	960	4160	900	2810	60	570
7	112	700	1620	5780	1420	4232	176	746
8	95	795	420	6200	340	4572	68	814

Inst. W.B.R. (ccw/ccb)	Inst. S.B.R. (ccs/ccb)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent (cc)
1.55	.64	5.56	-	140	140
7.91	2.6	6.69	-	112	252
0	3.0	6.78	-	457	709
10.2	1.56	7.94	60	61	770
14.0	.17	9.57	80	10	780
15.0	0.0	6.81	90	0	804
8.0	.14	14.46	85	24	828
5.0	.18	4.42	85	12.0	840

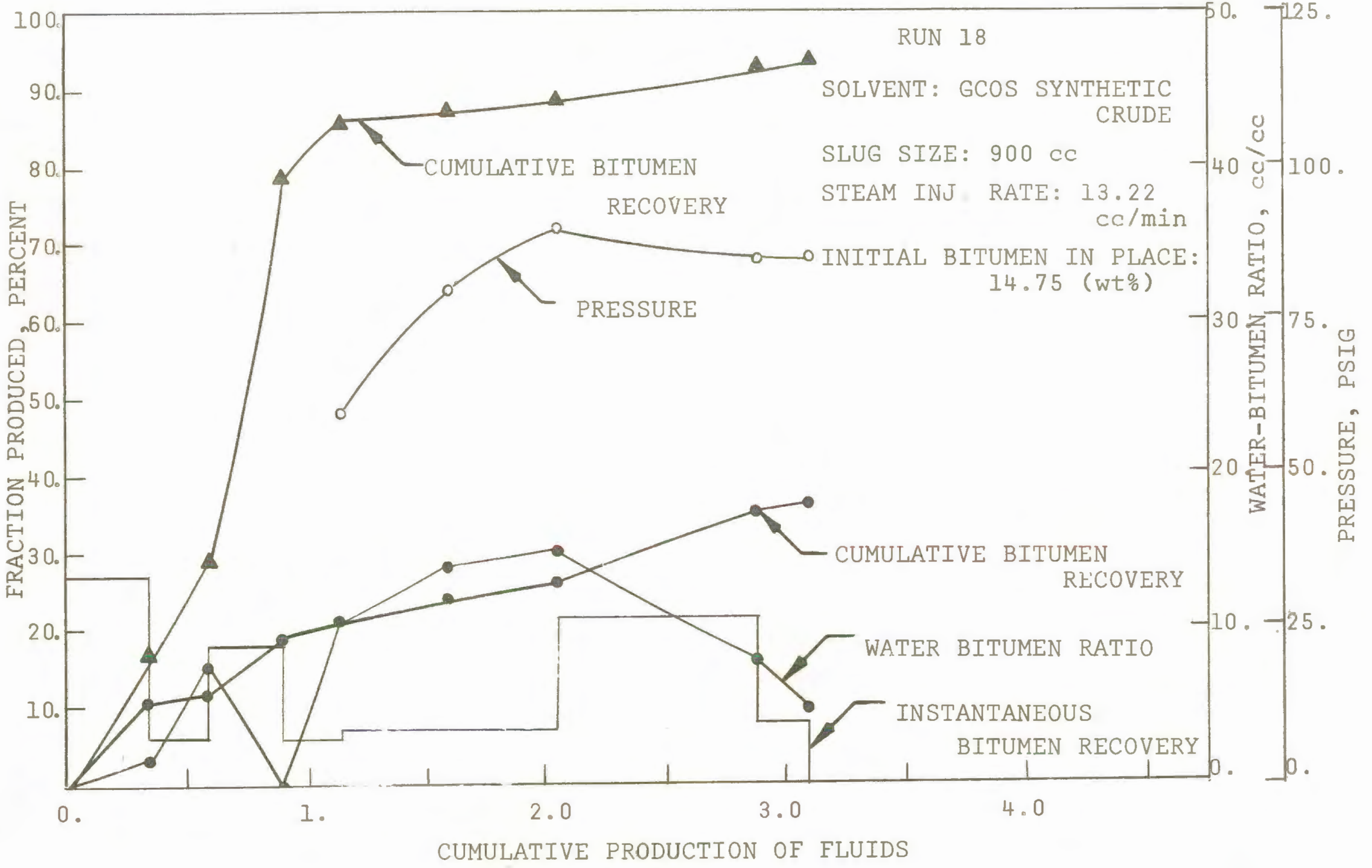


Figure 87 Production History for Run 18.

Table 49

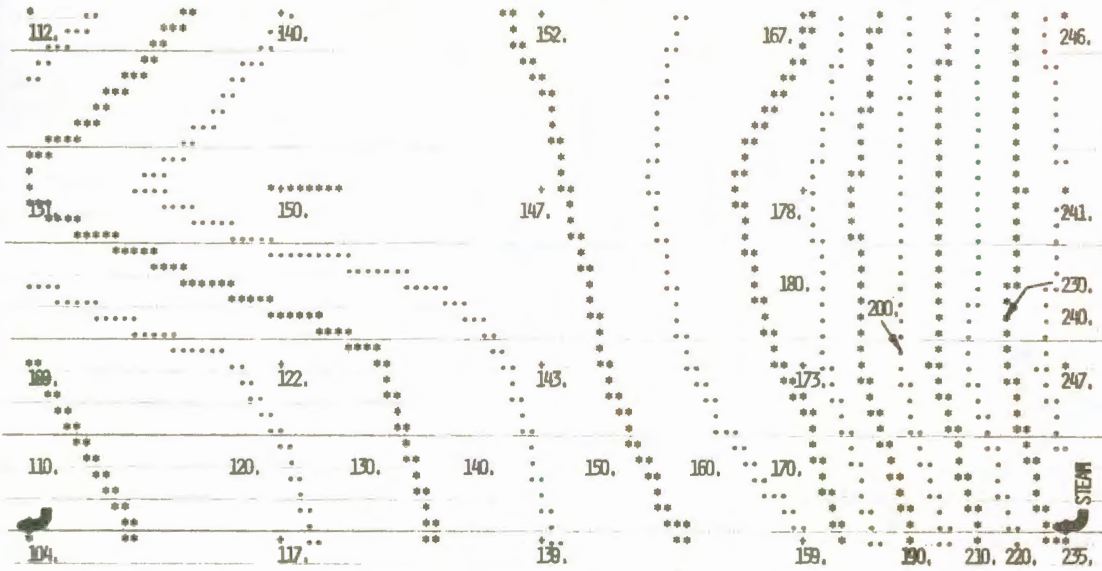
General Characteristics and Results for Run 18

Amount of tar sand packed	15138.9 gms.
Bitumen content of tar sand	.1474
Weight of bitumen in place	2231.47 gms.
Volume of bitumen in place	2153.9 cc
Solvent used	GCOS synthetic crude
Weight of clean sand	12907.43 gms.
Volume of clean sand	4810.82 cc
Volume of the model	7720 cc
Volume occupied by the porous plates	181.5 cc
Void space in the model	573.78 cc
Pore volume	2727.68 cc
Porosity	.353
Total water injected to saturate the pack	690 cc
Total solvent injected	900 cc
Amount of solvent retained by the pack	60 cc
Total run time	13.25 hrs.
Time for effluent breakthrough	1.87 hrs.
Time for steam breakthrough	7.07 hrs.
Solvent injection time	2.77 hrs.
Volume of solvent inj. before effluent B.T.	340 cc/min.
Total steam injected (as water)	5610 cc
Steam injection rate	13.22 cc/min.
Average pressure for solvent injection	30.7 psig

Table 49 (continued)

Average pressure for steam injection	80 psig
Water bitumen ratio	5.62 cc/cc
Solvent bitumen ratio	1.11 cc/cc
Total recovery	814 cc
Recovery	38%

TEMPERATURE PROFILE AFTER 01 HRS OF STEAM INJECTION, P = 55.0 PSIG.,TEMP. IN DEG. F.



TEMPERATURE PROFILE AFTER 03 HRS OF STEAM INJECTION,P = 100.0 PSIG.,TEMP. IN DEG.

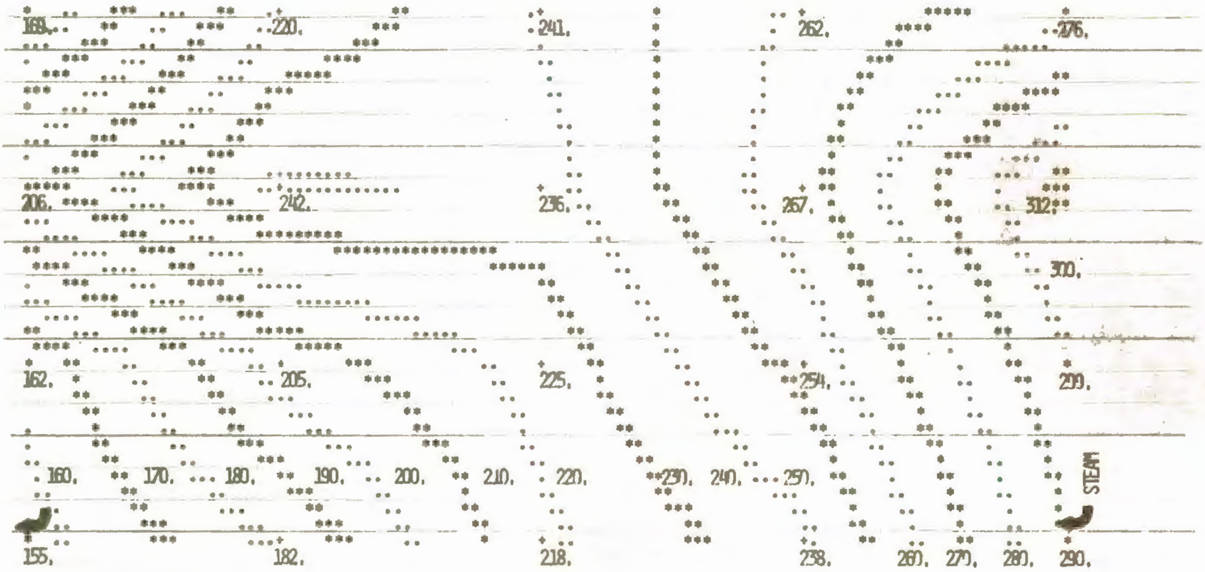
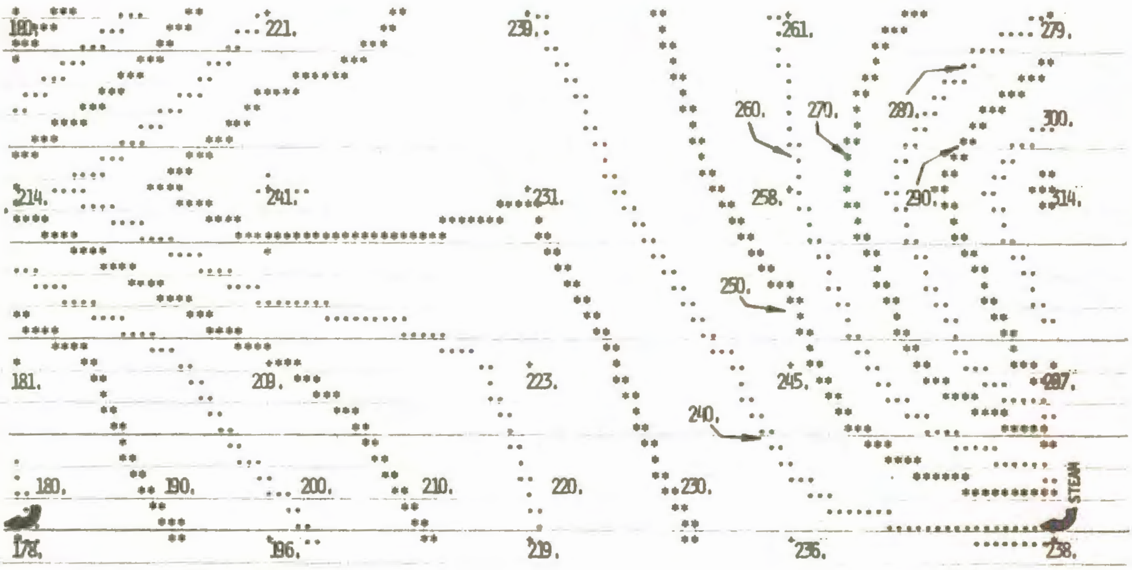


Figure 88 Temperature Profiles for Run 18.

TEMPERATURE PROFILE AFTER 05 HRS OF STEAM INJECTION,P = 80.0 PSIG.,TEMP. IN DEG. F.



TEMPERATURE PROFILE AFTER 06 HRS OF STEAM INJECTION, P = 85.0 PSIG.,TEMP. IN DEG. F

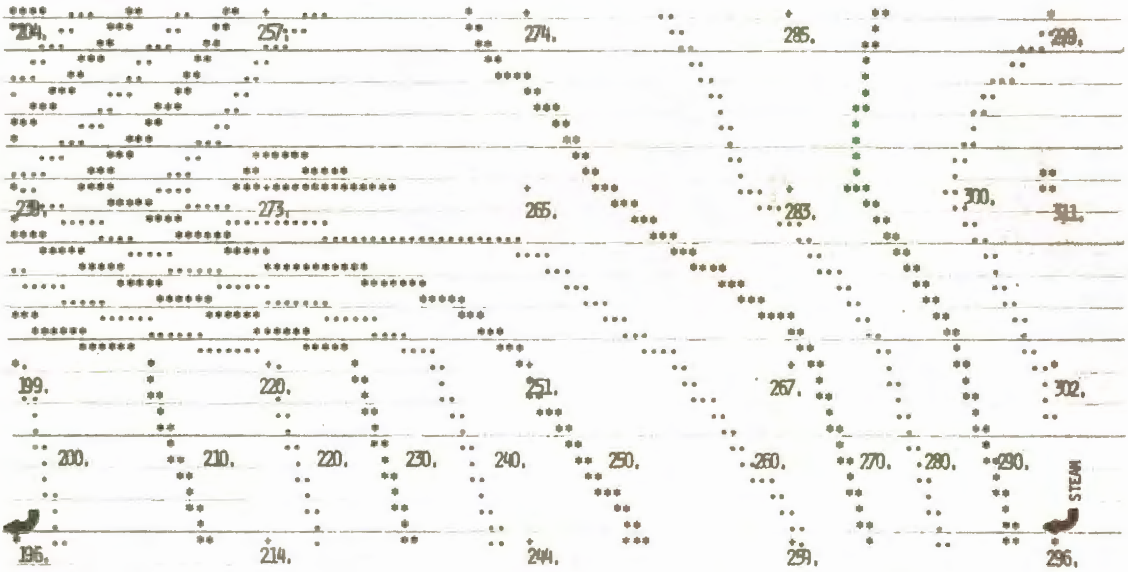
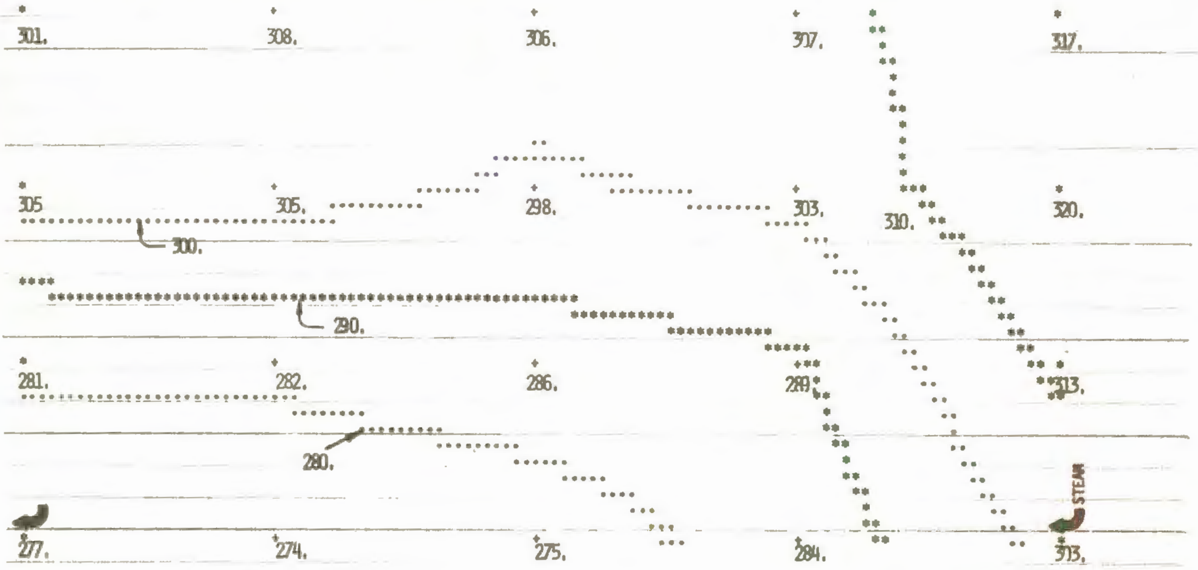


Figure 89 Temperature Profiles for Run 18.

TEMPERATURE PROFILE AT BREAKTHROUGH (7.05),P = 85.0 PSIG.,TEMP. IN DEG. F.



TEMPERATURE PROFILE AFTER 07.25 HRS OF STEAM INJECTION, P = 85.0 PSIG.,TEMP. IN DEG_ F.

Figure 90 Temperature Profiles for Run 18.

Table 50
Injection History for Run 19

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Water Produced (cc)	Cumulative Injection (cc)	Cumulative Production (cc)	Injection Flow Rate (cc/min.)	Pressure (psig)
0	0	0	10	0	10	-	64
16	16	70.18	40	70	50	4.38	70
45	61	130.33	120	200	170	2.89	68
11	72	60.15	0	260	170	5.45	46
9	81	40.10	180	300	180	4.44	50
9	90	40.10	0	340	180	4.44	52
12	102	60.15	0	400	180	5.0	48

Effluent Produced (cc)	Cumulative Production (cc)
0	0
0	0
180	180
10	190
30	220
10	230
90	320

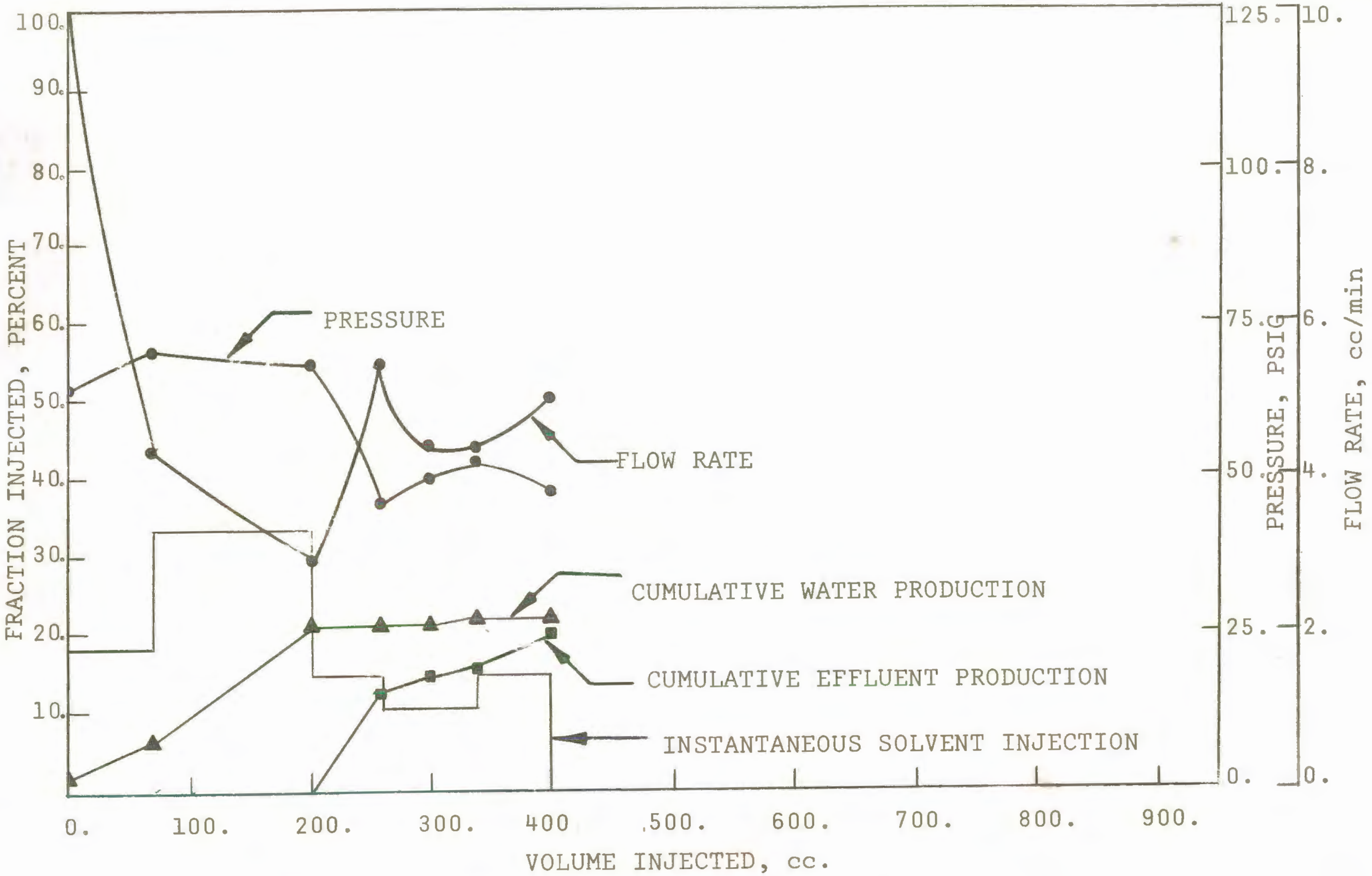


Figure 91 Injection History for Run 19.

Table 51
Production History for Run 19

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)
1	86	86	700	700	200	200	305	305
2	109	195	470	1170	330	530	520	357
3	153	348	900	2070	750	1280	127	484
4	96	444	670	2740	550	1830	118	602
5	115	559	1000	3740	770	2600	224	826
6	140	699	1495	5235	1040	3640	440	1266

Inst. W.B.R. (ccw/ccb)	Inst. S.B.R. (ccs/ccb)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent Recovery (cc)
.66	.64	8.14	-	195	195
6.35	1.69	4.31	80	88	283
5.91	.18	5.88	80	23	306
4.66	.02	6.98	80	2	308
3.5	.03	8.70	80	6.9	314
2.36	.03	10.68	80	15	329

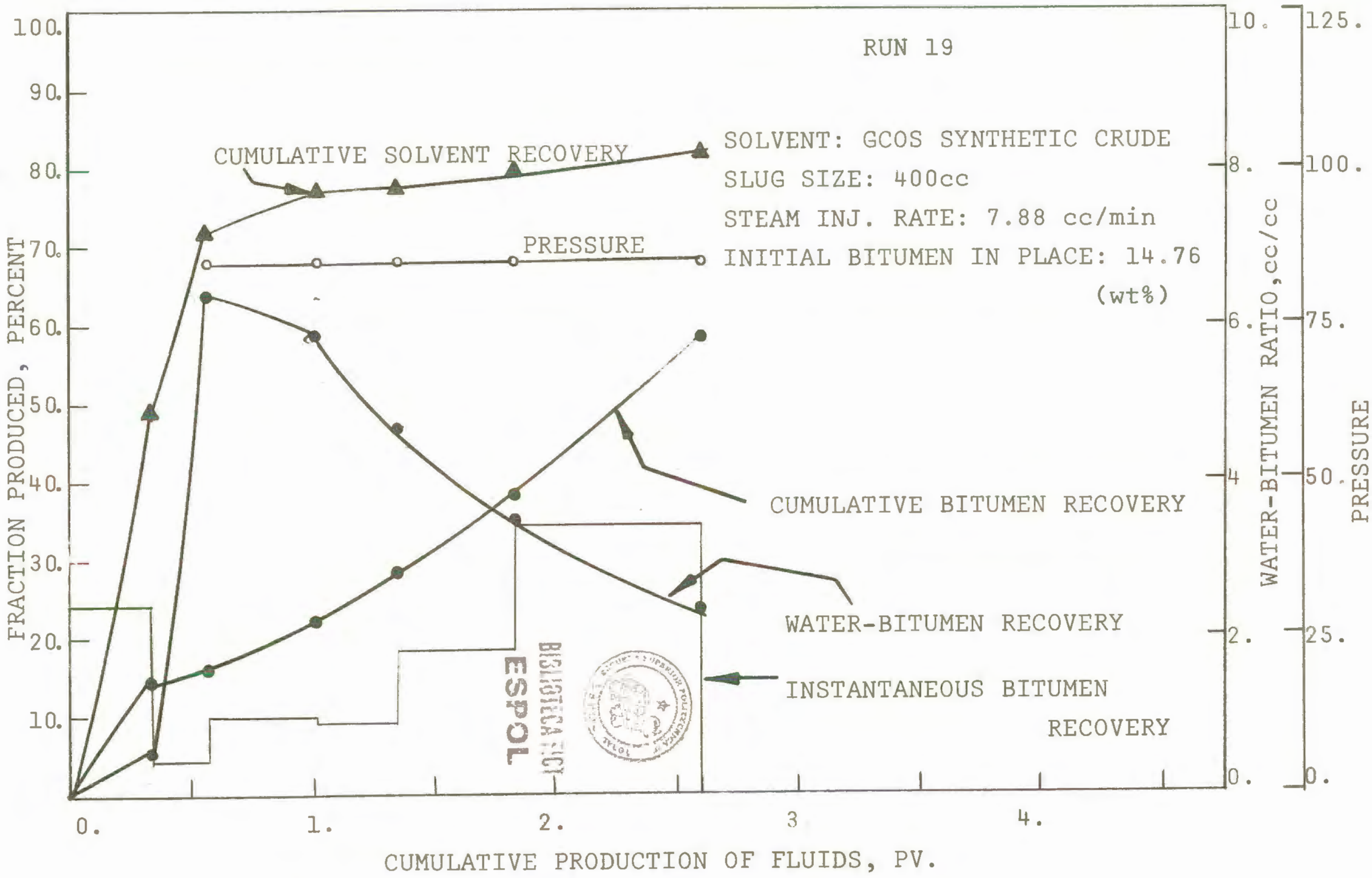


Figure 92 Production History for Run 19.

Table 52

General Characteristics and Results for Run 19

Amount of tar sand packed	15223.95 gms.
Bitumen content of tar sand	.1476
Weight of bitumen in place	2247.055 gms.
Volume of bitumen in place	2168.972 cc
Solvent used	GCOS synthetic crude
Weight of clean sand	12976.89 gms.
Volume of clean sand	4834.904 cc
Volume of the model	7720 cc
Volume occupied by porous plates	181.5 cc
Void space in the model	456.6 cc
Pore volume	2625.5 cc
Porosity	.34
Total water inj. to saturate the pack	720 cc
Total solvent injected	400 cc
Amount of solvent retained by the pack	71 cc
Total run time	16.1 hrs.
Time for effluent breakthrough	3.5 hrs.
Time for steam breakthrough	9.3 hrs.
Solvent injection time	1.3 hrs.
Volume of solvent inj. before effluent B.T.	200 cc
Total steam injected (as water)	4395 cc
Steam injection rate	7.88 cc/min.
Average pressure for solvent injection	56.86 psig.

Table 52 (continued)

Average pressure for steam injection	82 psig.
Water bitumen ratio (aver.)	2.96 cc/cc
Solvent bitumen ratio (aver.)	.32 cc/cc
Total recovery	1266 cc
Recovery (%bitumen in place)	58%

TEMPERATURE PROFILE AFTER 01 HRS OF STEAM INJECTION, P = 80.0 PSIG.,TEMP. IN DEG. F.

TEMPERATURE PROFILE AFTER 03 HRS OF STEAM INJECTION, P = 86.0 PSIG.,TEMP. IN DEG. F.

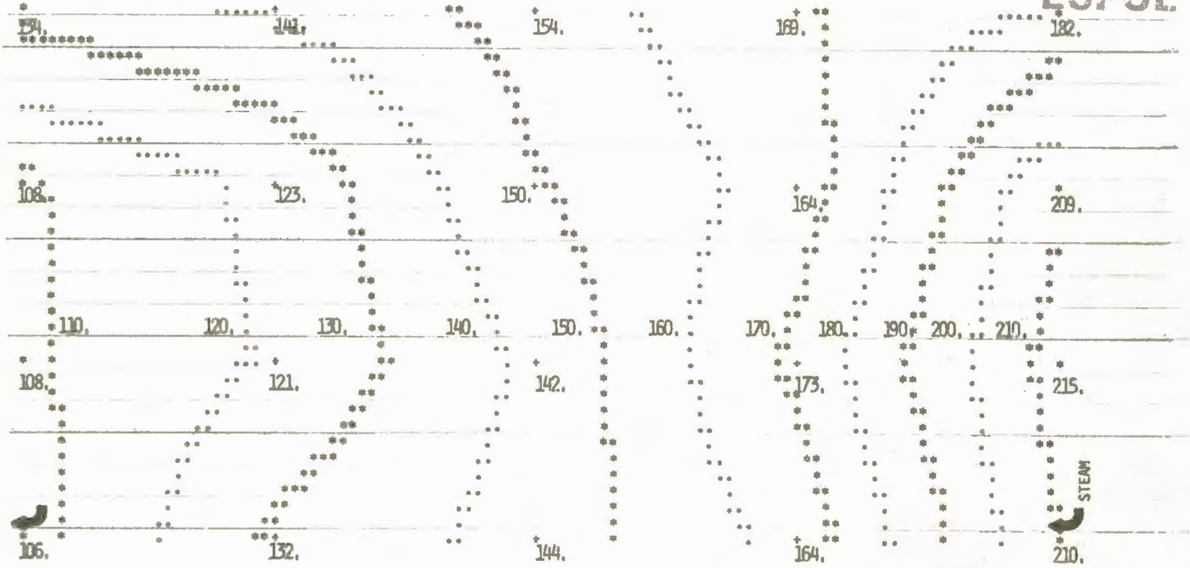


Figure 93 Temperature Profiles for Run 19.

TEMPERATURE PROFILE AFTER 05 HRS OF STEAM INJECTION, P = 80.0 PSIG.,TEMP. IN DEG. F.

TEMPERATURE PROFILE AFTER 07 HRS OF STEAM INJECTION, P = 85.0 PSIG.,TEMP. IN DEG. F.

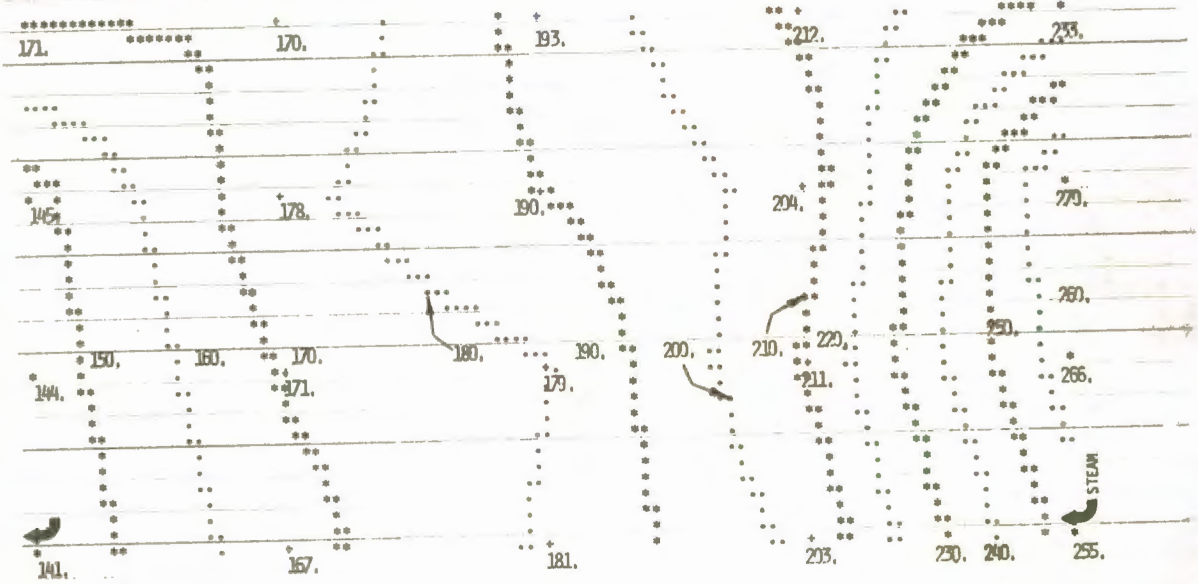
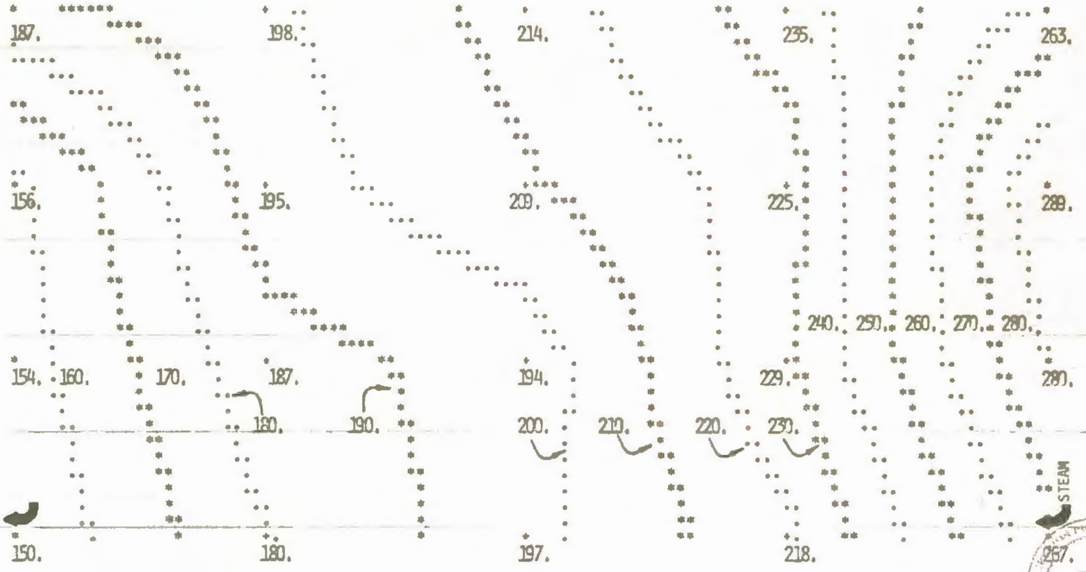


Figure 94 Temperature Profiles for Run 19.

TEMPERATURE PROFILE AFTER 08 HRS OF STEAM INJECTION, P = 80.0 PSIG.,TEMP. IN DEG. F.



TEMPERATURE PROFILE AT BREAKTHROUGH (9.18), P = 80.0 PSIG.,TEMP. IN DEG. F.

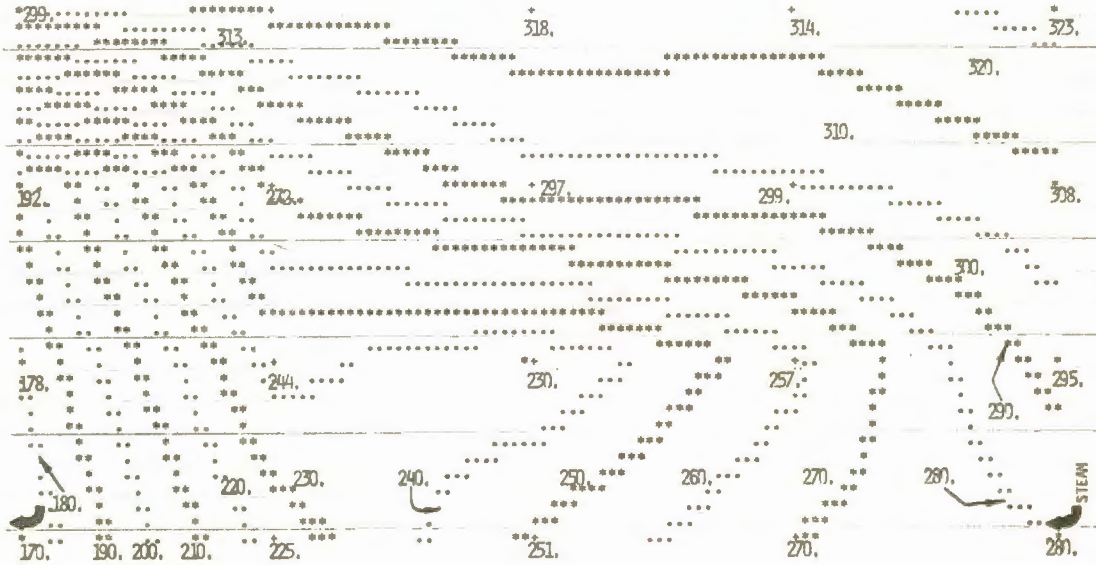


Figure 95 Temperature Profiles for Run 19.

Table 53
Injection History for Run 20

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Water Produced (cc)	Cumulative Injection (cc)	Cumulative Water (cc)	Injection Flow Rate (cc/min.)	Pressure (psig)
0	0	0	50	0	50	-	52
3	3	20.10	50	20	100	6.67	58
6	9	40.20	50	60	150	6.67	58
6	15	40.20	30	100	180	6.67	60
5	20	40.20	45	140	225	8.0	58
4	24	20.10	25	160	250	5.0	60
5	20	40.20	25	200	275	8.0	58

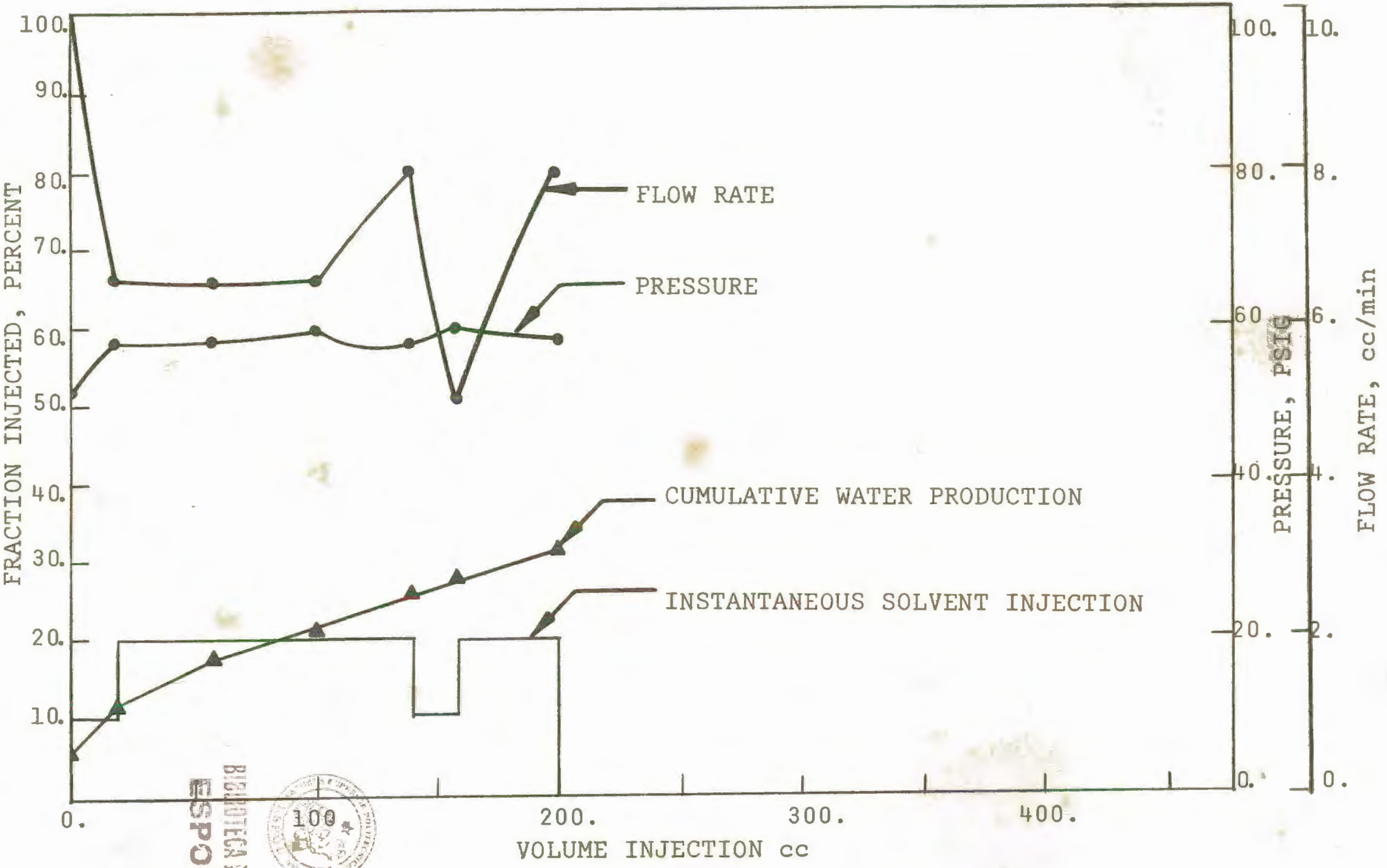


Figure 96 Injection History for Run 20.

Table 54
Production History for Run 20

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)
1	86	86	500	500	425	425	22.85	22.85
2	130	216	980	1480	870	1295	47.6	70.45
3	128	344	900	2380	770	2065	119.6	190.05
4	153	497	900	3280	750	2815	150	340.05
5	214	711	1640	4920	1500	4315	140	480.05
6	165	876	1660	6580	1500	5815	160	640.05
7	69	945	1030	7610	830	6645	200	840.05

Inst. W.B.R. (ccw/ccb)	Inst. S.B.R. (ccs/ccb)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent Recovery (cc)
18.60	2.28	5.81	80	52.15	52.15
18.28	1.31	7.54	80	62.4	114.55
6.44	.09	7.03	80	10.4	124.25
5.00	0.0	5.88	80	0.0	124.25
10.71	0.0	7.66	70	0.0	124.25
9.38	0.0	10.06	85	0.0	124.25
4.15	0.0	15.06	80	0.0	124.25

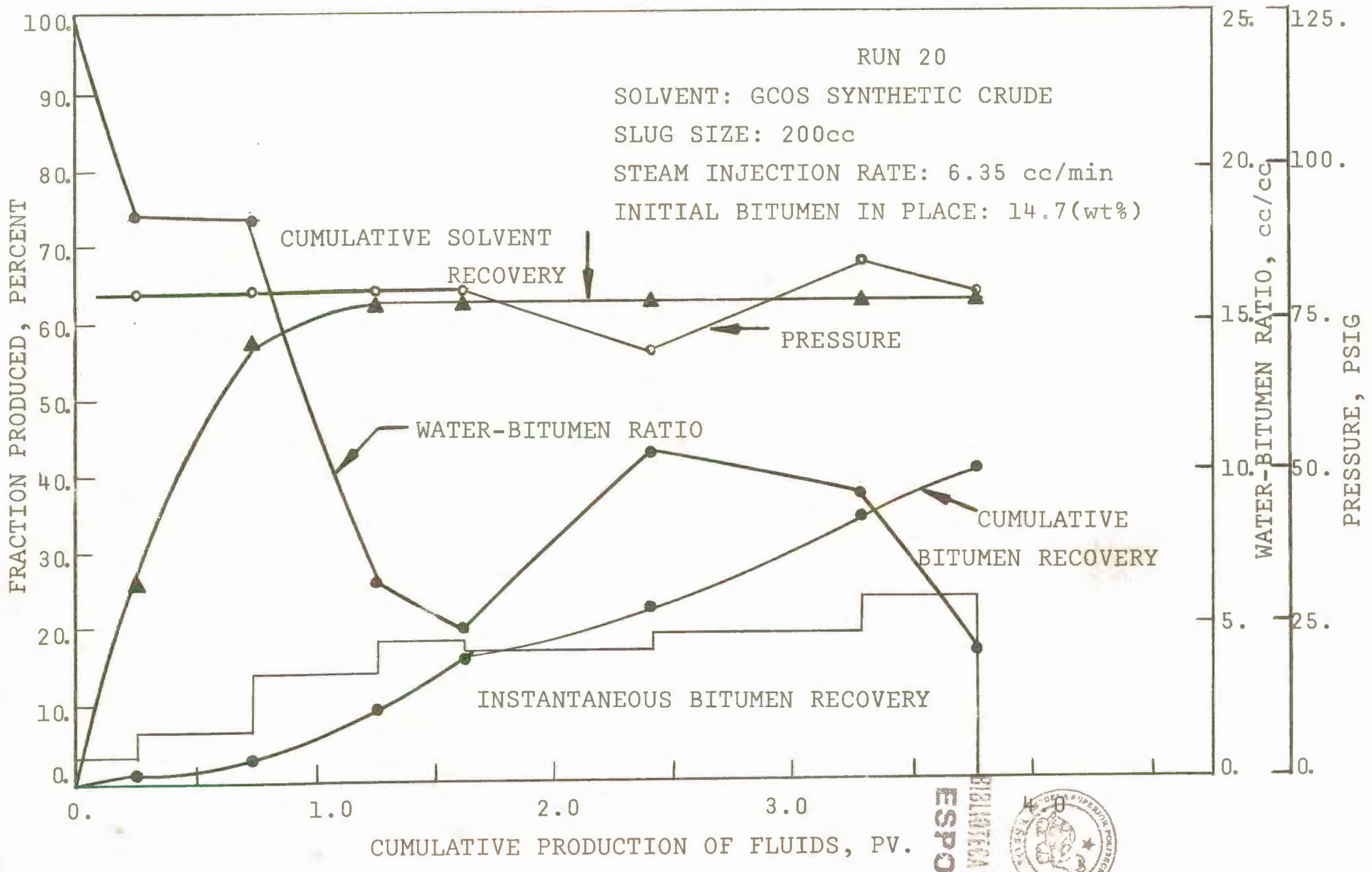


Figure 97 Production History for Run 20.

Table 55

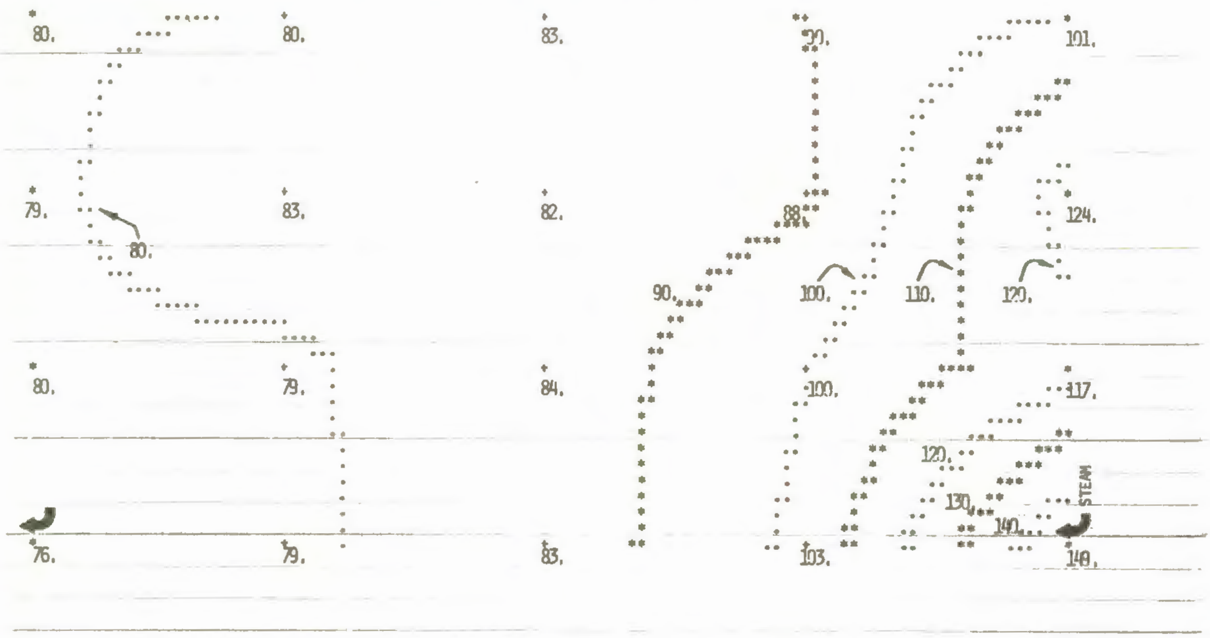
General Characteristics and Results for Run 20

Amount of tar sand packed	14713.65 gms.
Bitumen content of tar sand	.147
Weight of bitumen in place	2162.9 gms.
Solvent used	GCOS synthetic crude
Volume of bitumen in place	2087.74764
Weight of clean sand	12550.7 gms.
volume of clean sand	4676.13 cc
Volume of the model	7720 cc
Volume occupied by the porous plates	181.5
Void space in the model	775.37
Pore volume	2863.11
Porosity	.37
Total water injected to saturate the pack	800 cc
Total solvent injected	200 cc
Amount of solvent retained by the pack	75.5 cc
Total run time	17.42 hrs.
Time for effluent breakthrough	2.42 hrs.
Time for steam breakthrough	17.40 hrs.
Solvent injection time	.48 hrs.
Volume of solvent inj. before effluent B.T.	200 cc
Total steam injected (as water)	6629 cc
Steam injection rate	6.35 $\frac{\text{cc}}{\text{min.}}$
Average pressure for solvent injection	57.71 psig.

Table 55 (continued)

Average pressure for steam injection	79.29 psig.
Water bitumen ratio (aver.)	7.91 $\frac{cc}{cc}$
Total recovery	840.05
Recovery (% bitumen in place)	40.24%

TEMPERATURE PROFILE AFTER 01 HRS OF STEAM INJECTION, P = 85.0 PSIG.,TEMP. IN DEG. F.



TEMPERATURE PROFILE AFTER 04 HRS OF STEAM INJECTION, P = 80.0 PSIG.,TEMP. IN DEG. F.

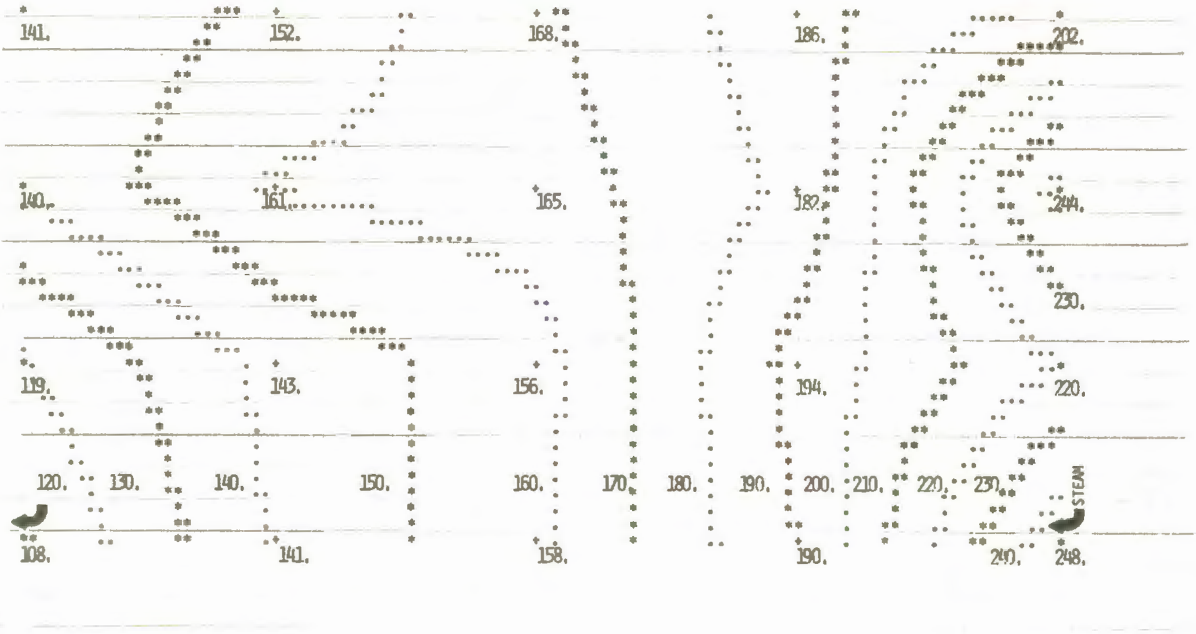
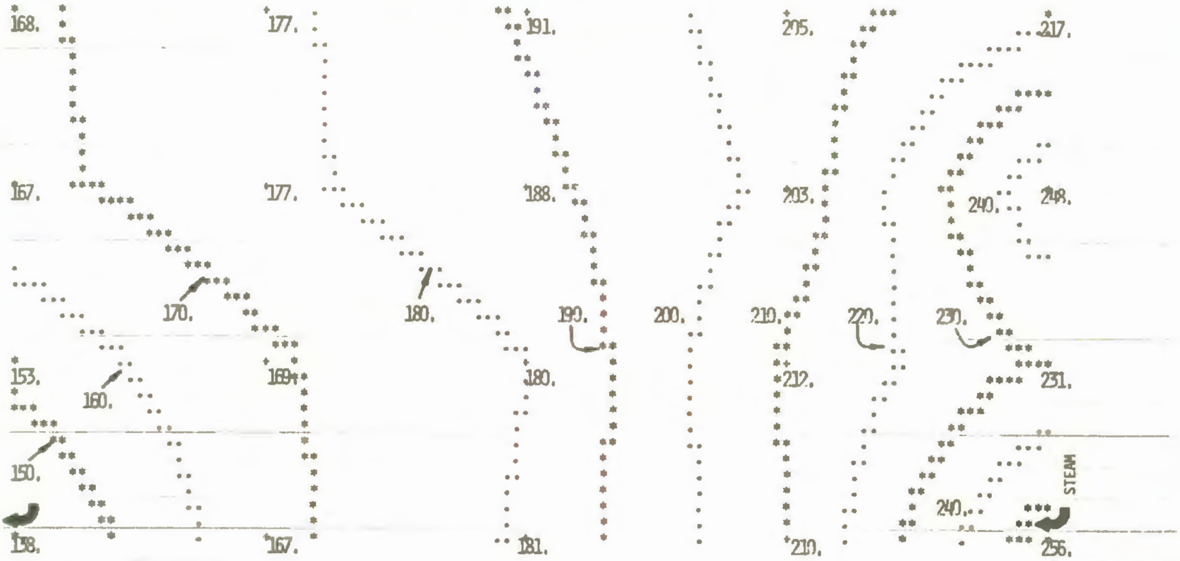


Figure 98 Temperature Profile for Run 20.

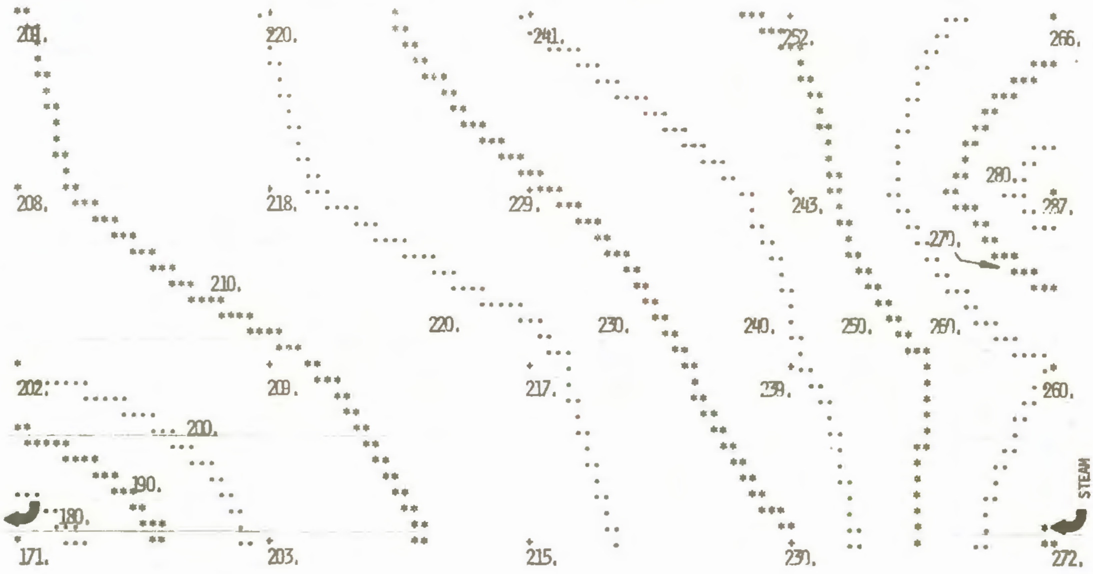
TEMPERATURE PROFILE AFTER 06 HRS OF STEAM INJECTION, P = 85.0 PSIG.,TEMP. IN DEG. F.



TEMPERATURE PROFILE AFTER 09 HRS OF STEAM INJECTION, P =86.0 PSIG., TEMP. IN DEG. F.

Figure 99 Temperature Profiles for Run 20.

TEMPERATURE PROFILE AFTER 12 HRS OF STEAM INJECTION, P = 85.0 PSIG., TEMP. IN DEG. F.



TEMPERATURE PROFILE AT BREAKTHROUGH (15:44), P = 85.0 PSIG., TEMPM IN DEG. F.

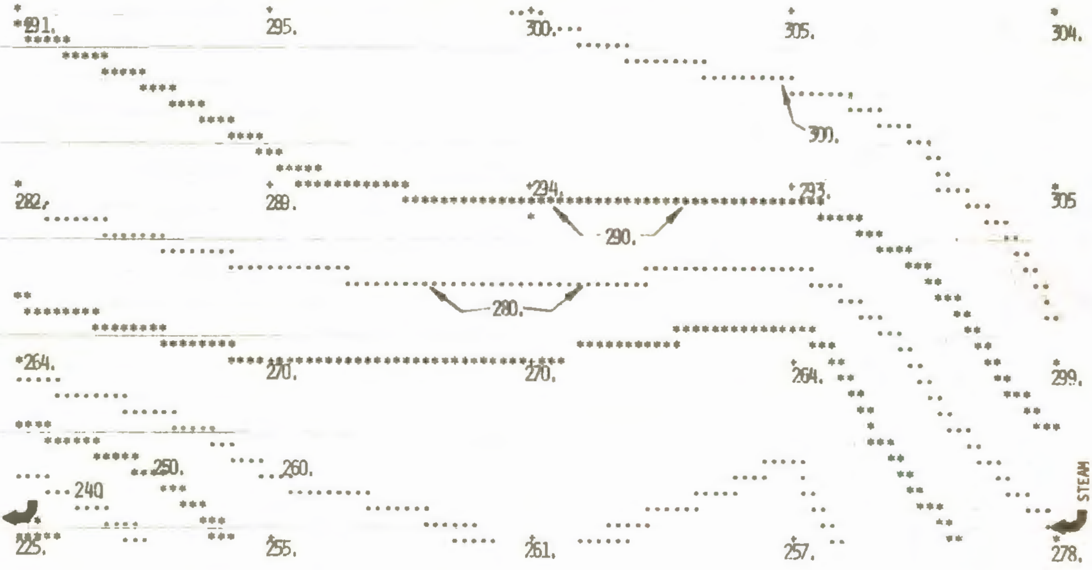


Figure 100 Temperature Profiles for Run 20.

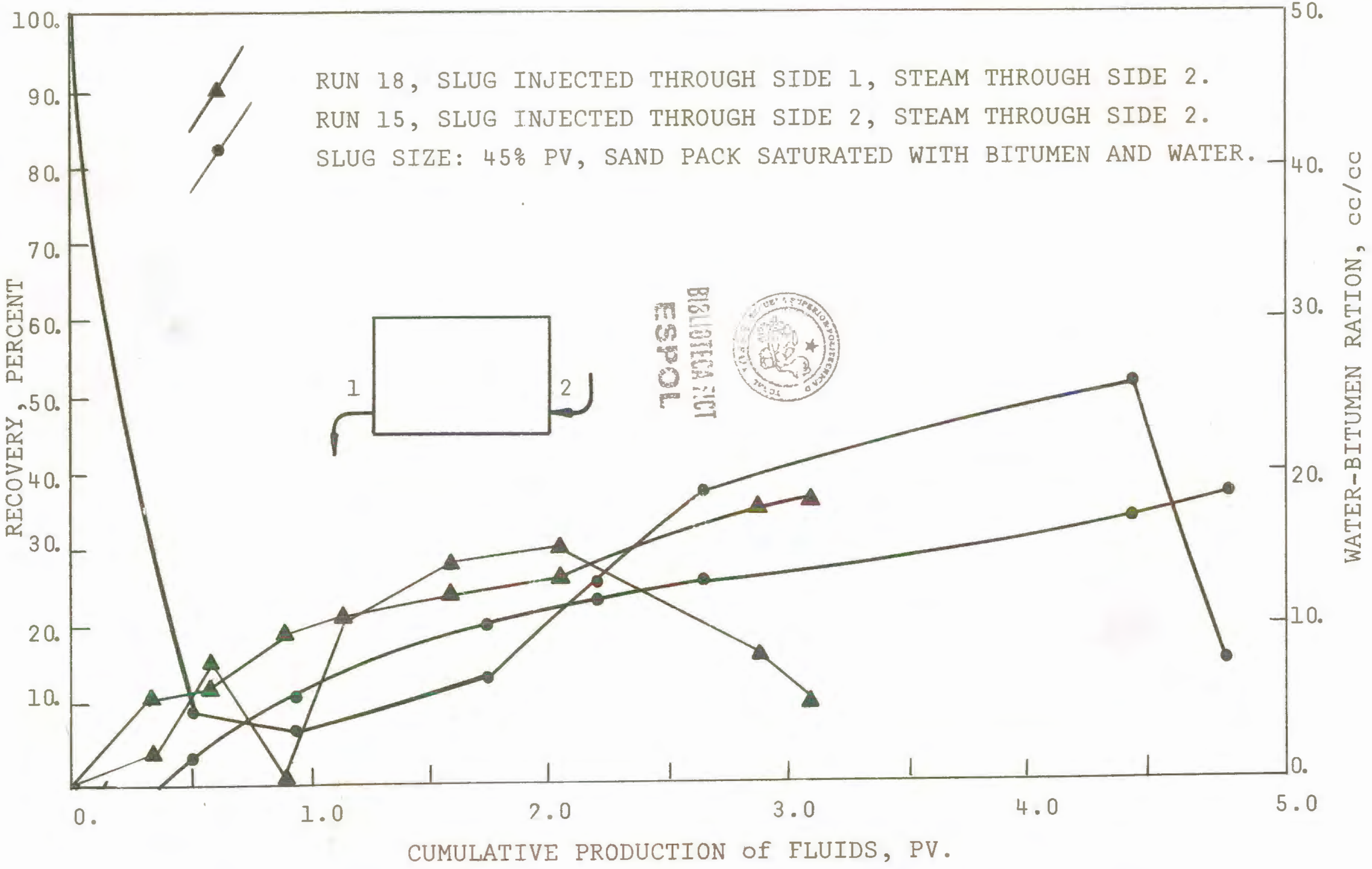


Figure 101 Effect of Changing the Location of the Slug, Runs 15, and 18.

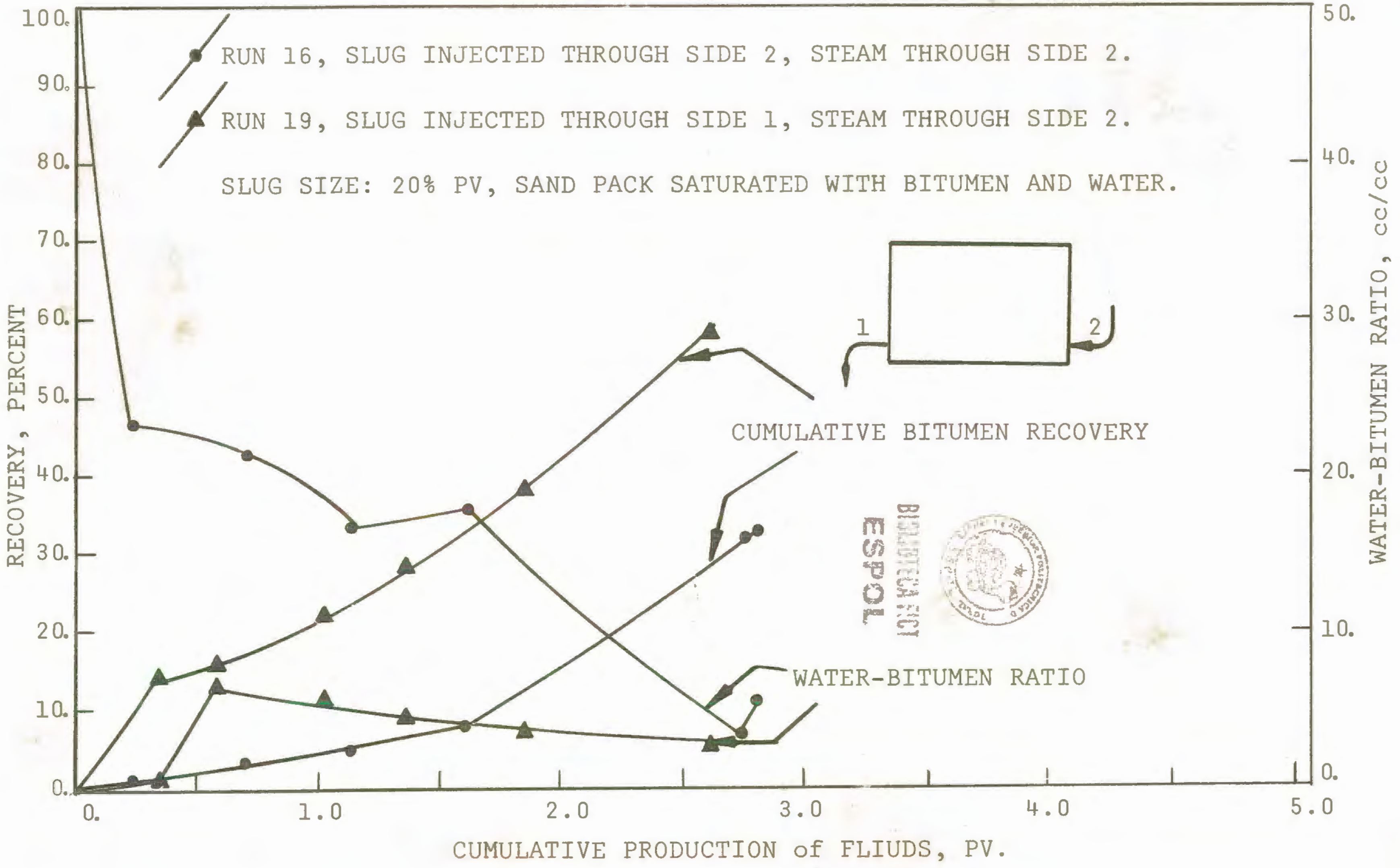


Figure 102 Effect of Changing the Location of the Slug, Runs 16, and 19.

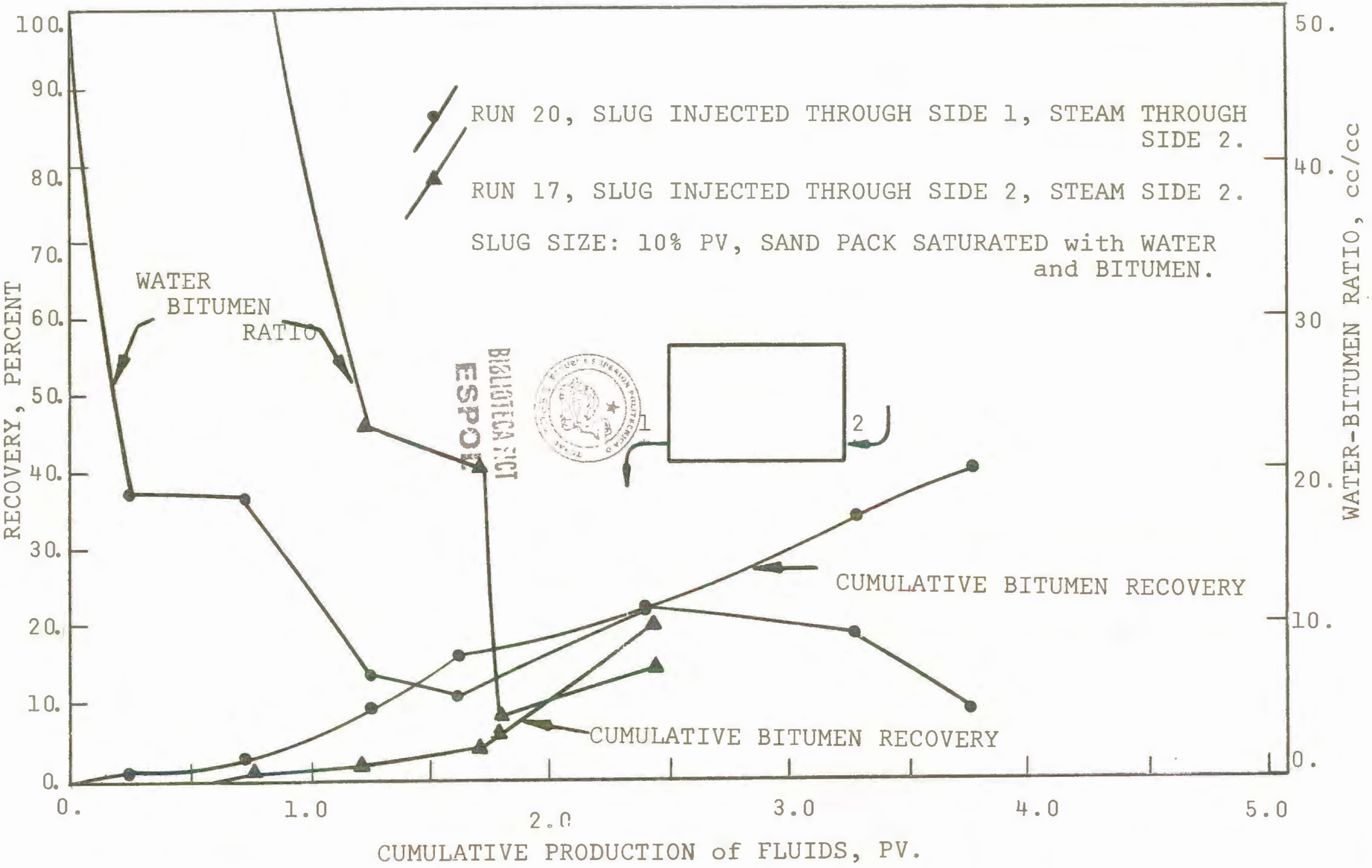


Figure 103 Effect of Changing the Location of the Slug, Runs 17, and 20.

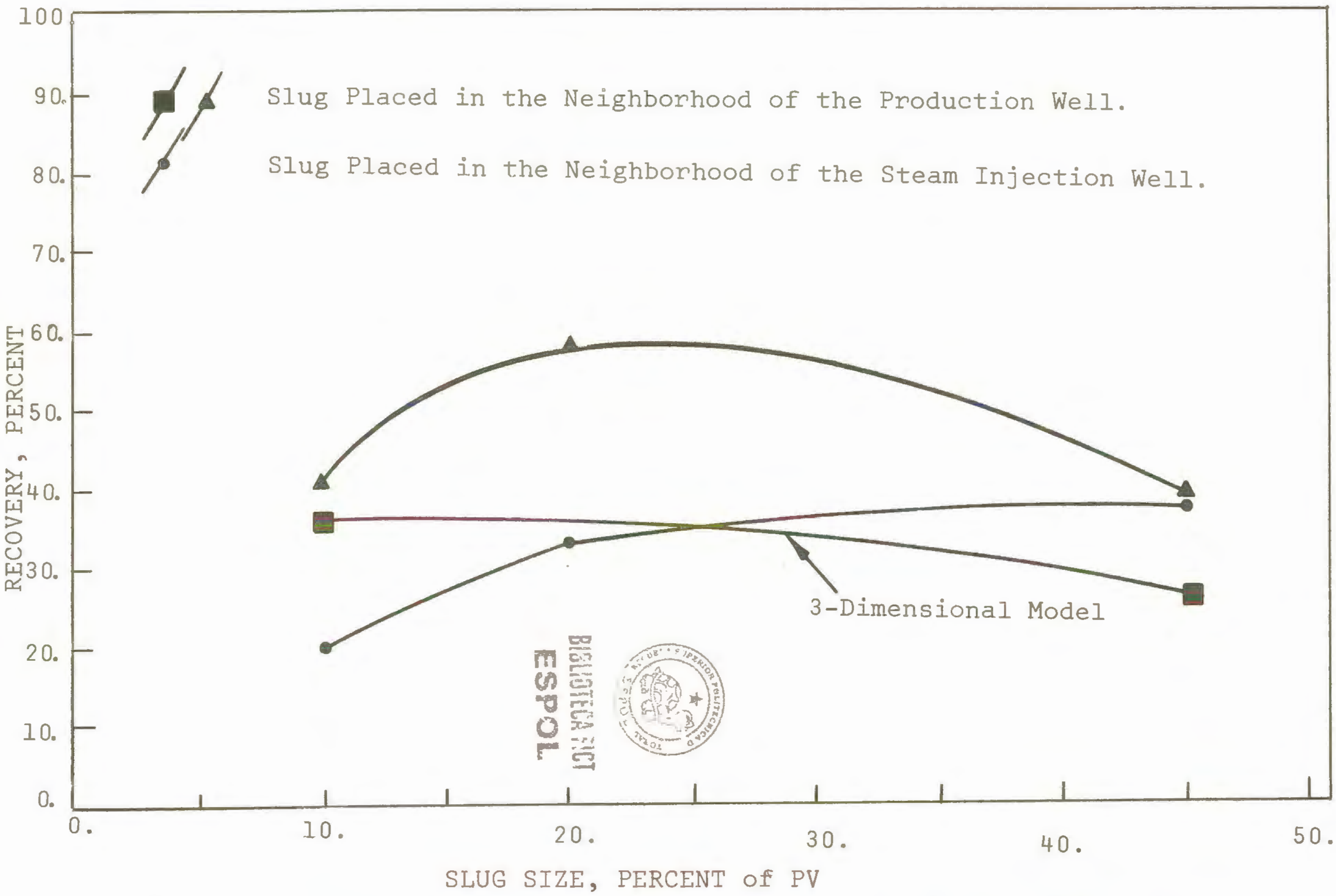


Figure 104 Effect of Slug Size in the Recovery of Bitumen, Runs 15-22.

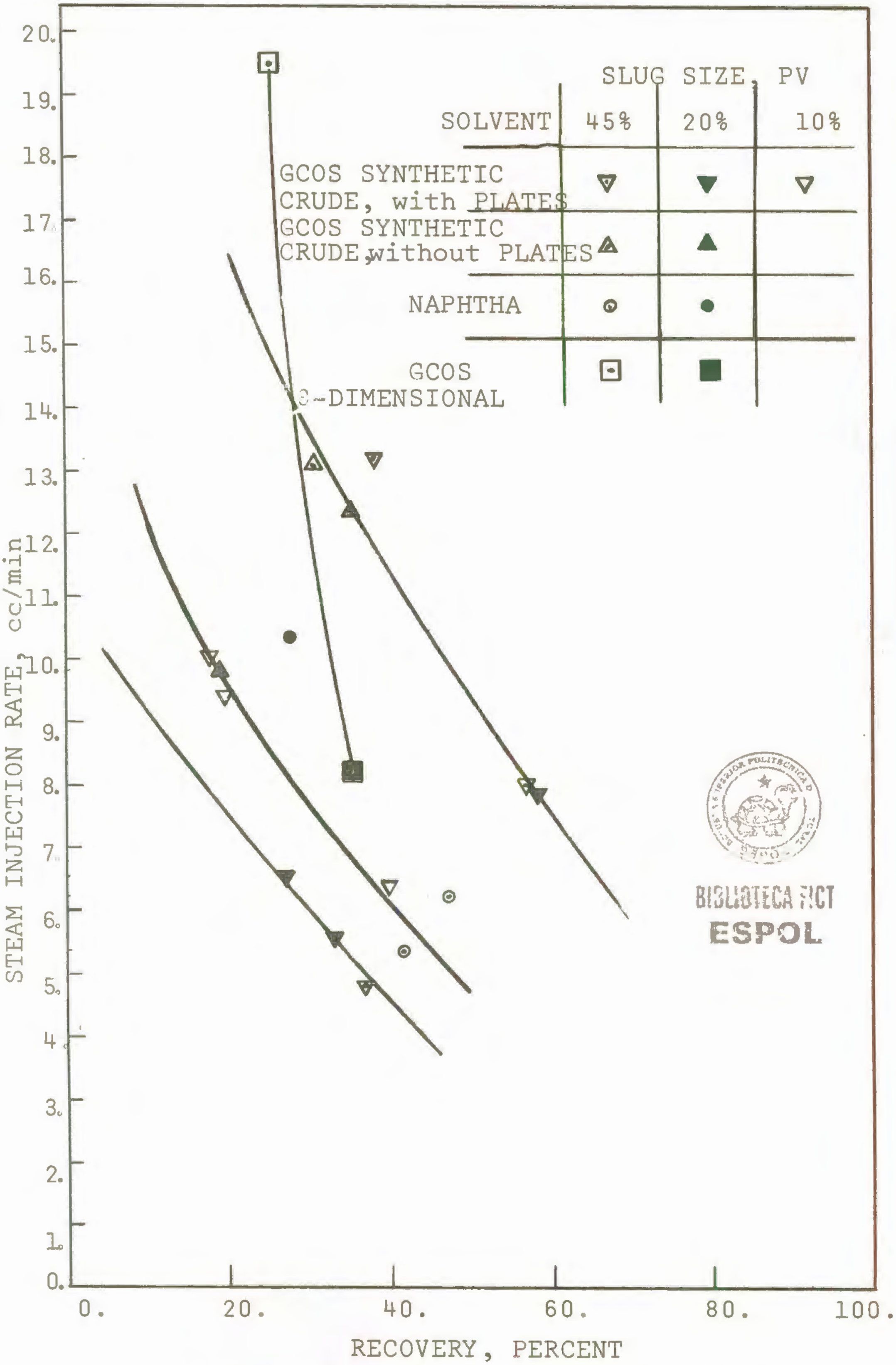


Figure 105 Effect of Steam Injection Rate in the Recovery of Bitumen.

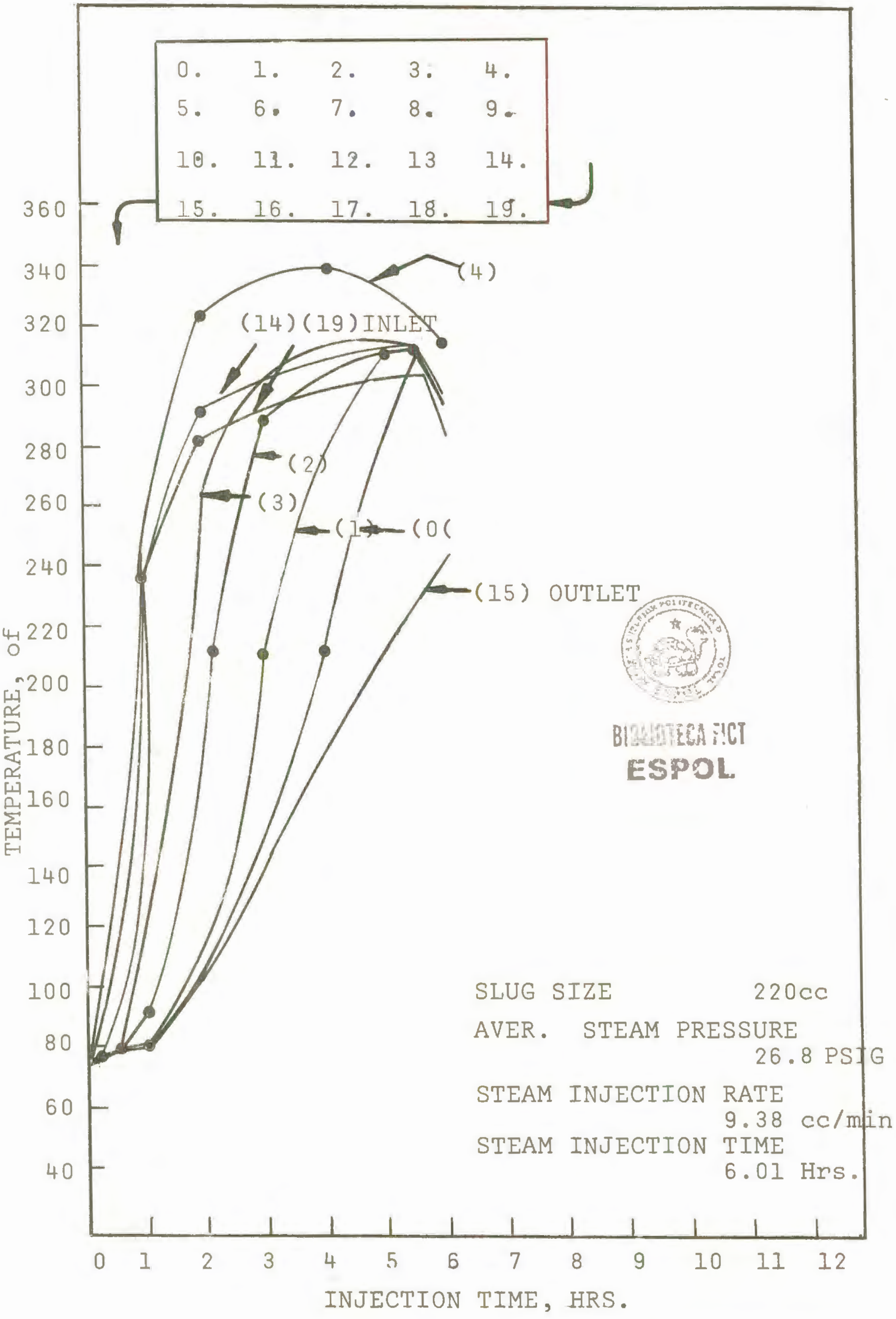


Figure 106 Change of Temperature with Time, Run 17.

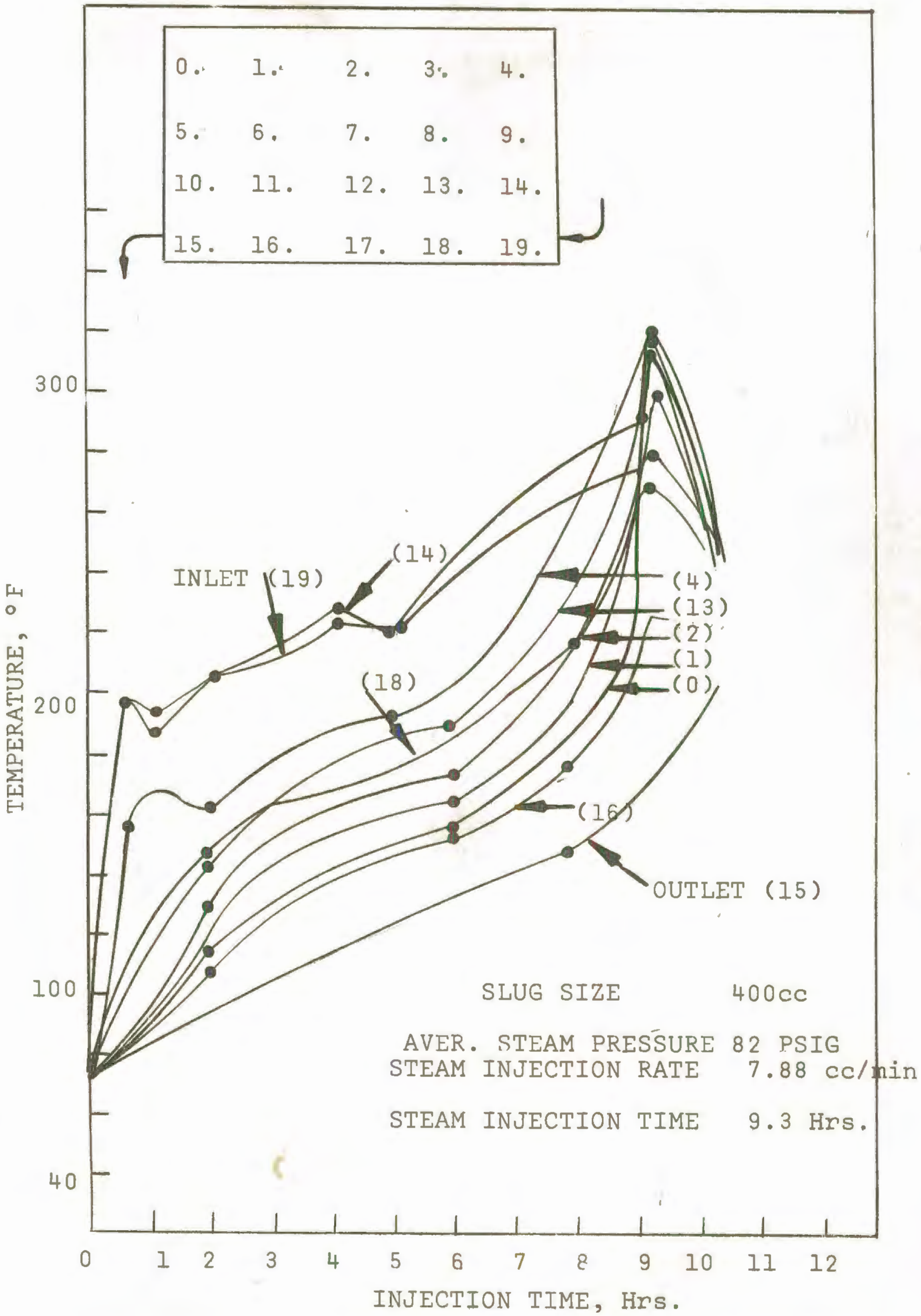
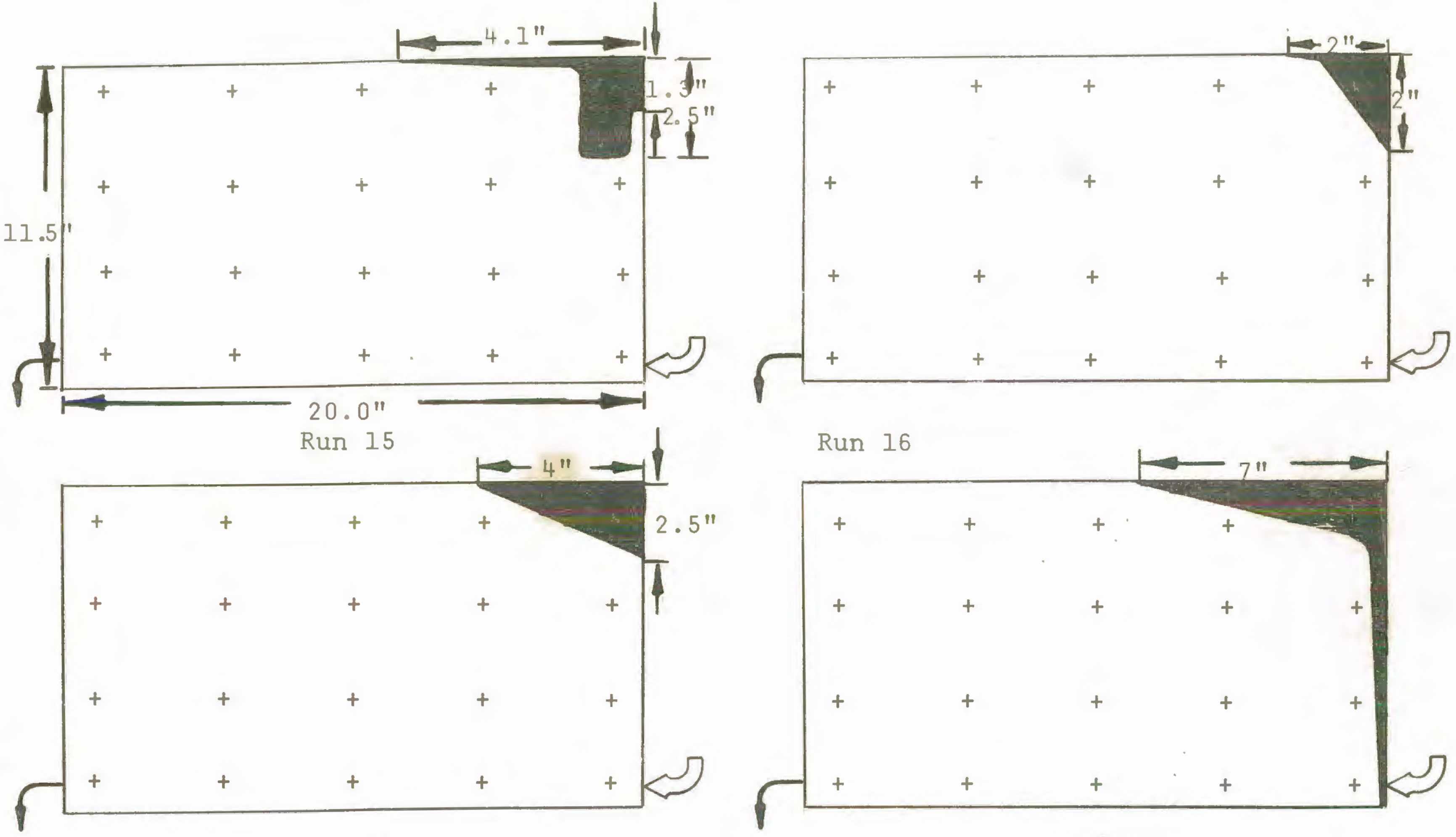


Figure 107 Change of Temperature with Time, Run 19.



Run 15

Run 16

Run 18

Run 19

Figure 108 Void Space Observed after Steam Injection.

Table 56
Injection History for Run 21

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
43	43	165	165	3.84	70
51	94	155	320	3.04	30
34	128	220	540	6.47	26
121	249	330	870	2.73	29
32	281	325	1195	10.1	21
290	571	852	2047	2.94	16
186	757	323	2370	1.74	18
67	824	350	2720	5.22	75
192	1016	620	3340	3.23	16
55	1071	440	3780	8.00	16
312	1383	520	4300	1.67	9
210	1593	740	5040	3.52	9
81	1674	160	520	1.98	70
141	1815	120	5320	.85	23
68	1883	280	5600	4.12	100

Volume Produced (cc)	Cumulative Production (cc)	Bitumen Produced (cc)	Cumulative Production (cc)	Solvent Produced (cc)	Cumulative Production (cc)	Water Produced (cc)	Cumulative Production (cc)	Flow Rate ($\frac{cc}{min}$.)
250	250	0.0	0.0	0.0	0.0	250	250	5.81
275	525	23	23	204	204	48	298	5.39
410	935	17	40	289	493	104	402	12.06
254	1189	9	49	209	702	36	438	2.10
325	1514	11	60	310	1012	4	442	10.16
940	2454	33	93	897	1909	10	452	3.24
390	2814	27	120	363	2272	0	452	2.63
0	2844	0	120	0	2272	0	452	0.0

Table 56 (continued)

Volume Produced (cc)	Cumulative Production (cc)	Bitumen Produced (cc)	Cumulative Production (cc)	Solvent Produced (cc)	Cumulative Production (cc)	Water Produced (cc)	Cumulative Production (cc)	Flow Rate ($\frac{cc}{min.}$)
500	3344	27	147	473	2745	0	452	2.60
810	4154	28	175	782	3527	0	452	14.73
435	4589	41	216	394	3921	0	452	2.04
650	5239	43	259	607	4528	0	452	3.10
0	5239	0	259	0	4528	0	452	0
300	5534	10	278	281	4809	0	452	2.13
0	5539	0	278	0	4809	0	452	0
700	6239	56	334	644	5453	0	452	-

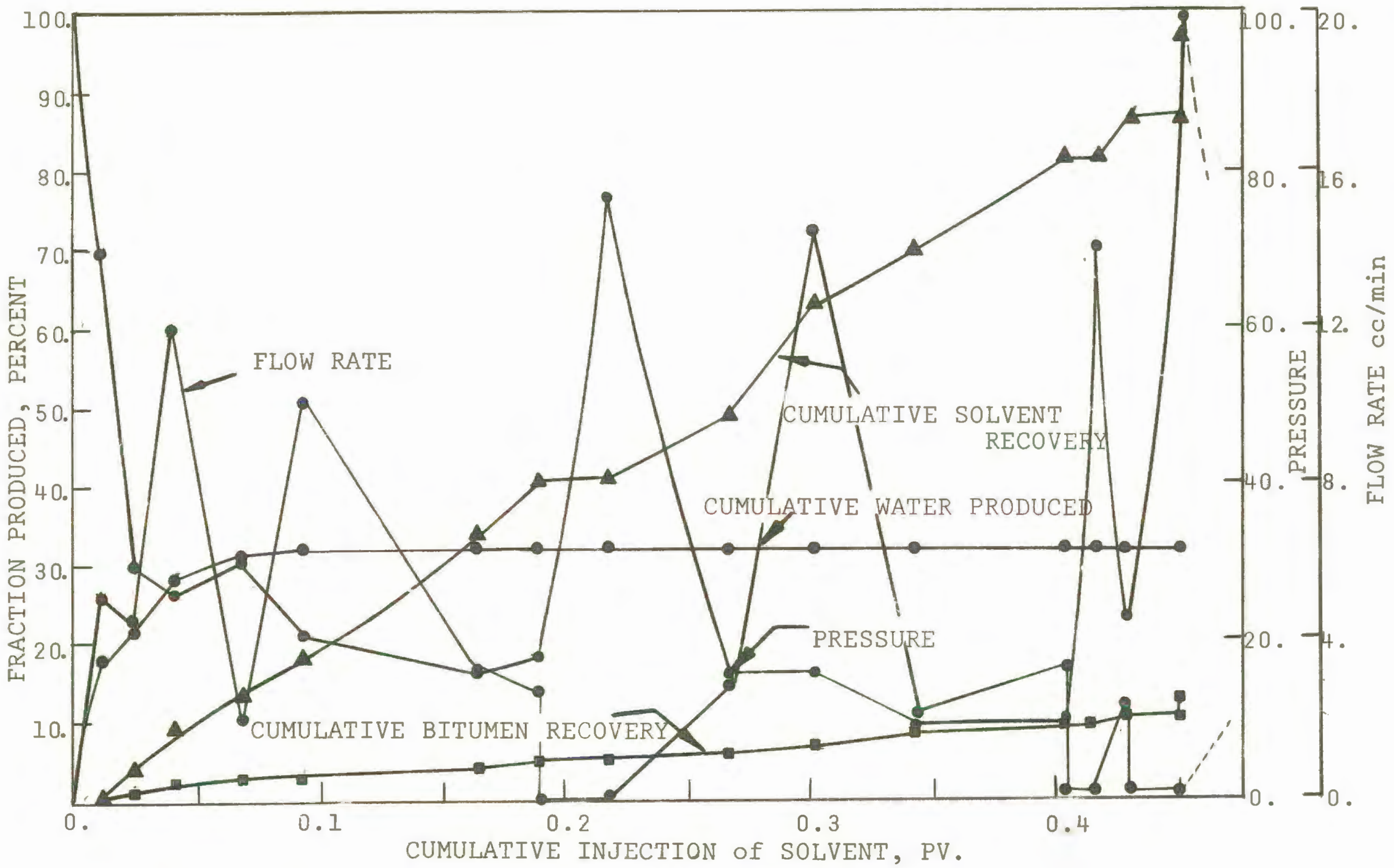


Figure 109 Injection History for Run 21.

is several times wider than Model 1, and that injection of solvent in Model 1 was carried through a restricted fluid entry. If these factors are considered, it must be concluded that the overburden pressure and the water injected previously confined the flow of solvent to a well-defined path. Later, when analyzing the effluent in the infarred spectrophotometer it was observed that the concentration of bitumen in the effluent produced was always in decreasing quantities. If Figure 109 is observed, it can be seen that 97% of the solvent injected was produced before injecting any steam, also as observed in Runs 15, 18, and 19, water production stopped the moment effluent began to be produced. The model was closed and pressurized several times (notice the sharp increases in pressure and decreases in flow rate in Figure 109) but no increase in bitumen concentration was observed in the effluent recovered. Throughout the solvent injection process, the pressure of the overburden was not affected.

Several hours later steam injection was initiated through the steam injection well (Figure 113 shows the position of the wells and the temperature recording intervals of Model 2). Steam was produced through wells 4, 2, and 1, after 2, 2.32 and 2.48 hours of steam injection respectively, which shows that the pack was channalized almost symetricaly, well 3 produced steam after 4.37 hours of steam injection. Steam injection pressures were held at lower values than those in Model 1, considering that the distance between wells was smaller, and that the sand pack was so bulky that high steam injection pressures causes premature steam breakthrough without allowing flow of bitumen to the channels opened by the solvent. Table 57 and Figure 110 represent the production history for Run 21.

Run 22. With the experience gained in Runs 18, 19, 20, and 21, with regard to the slug size when the solvent is injected through the production well, a 10% PV slug was injected, but now only well 1 was opened and when 25% of the slug was injected, later this well was closed and well 2 was opened, later well 3 and finally well 4. Figure 111 represents the injection history for Run 22. In Table 59 it is possible to see that increasing amounts of bitumen were recovered, showing that every time a well was opened fresh tar sand was contacted. Before initiating steam injection 81% of the solvent injected was recovered, showing again that the solvent was confined just to very definite paths in the pack.

Steam injection pressure was held at 30 psig most of the time with the purpose of heating the pack in a more uniform fashion, in this way bitumen would have more time to flow to the channels and to the wells. When steam was injected into the two dimensional model, the overriding effect of the steam confined a large section of the pack, and even gravity segregation was strong bitumen was not recovered in volume that could be recovered if this effect had not existed. In Runs 21, and 22 the overriding effect of the steam was not present, because due to size of the model, the walls of the box were far away from the steam injection point and the wall effect was no longer a problem. Temperature was recorded for both Runs 21 and 22, but only profiles for Runn 22 are presented in Figures 114 to 121, temperature was registered for two planes, 7 and 3 inches from the base of the model. In both runs it was very interesting to observe the symmetry of the temperature profiles which are almost perfect circumferences (plane EFGH), mainly because of the low steam injection pressure and the homogeneous medium considered. After 9 hours of steam injection in plane ABCD (7 inches from the base) profiles began to have ellypse like form. At 11:46 steam breakthrough occurred through well 2 and if the temperature profile after 12 hours of steam injection is observed (Figure 120) it is clearly seen that the line of 200°F going around well 2 and then to the steam injection well. Later (at 16:10) breakthrough occurred through well 3, it is possible to observe also, in the temperature profile after 16.25 hours of steam injection (Figure 121) how steam is flowing from the steam injection point to well 3. When steam was produced through the four wells, injection was stopped, and after injecting water to determine the volume of steam injected (as condensate), 27 core samples were withdrawn from the planes shown in Figure 122.

From these figures (123, 124, and 125) it is possible to see that most of the bitumen was produced in large amounts from planes 2 and 3, (Figures 123 and 124), while plane 1 presented high residual bitumen saturations. The production wells (Figure 8) were four seven inch tubes covered by a wire screen, and the injection well was a two inch long tube, then most of the bitumen came from the portion of the sandpack within the wells. The higher temperatures were recorded in the plane EFGH, 3 inches from the base (Figures 119, 120, and 121), this means that steam swept more efficiently through this portion of the sand. Figure 127 shows the low residual saturations of this plane. The three vertical planes sampled show higher residual saturation of bitumen at the upper section of the sand pack, showing again that most of the bitumen recovery came from the section within the wells. Vertical plan 2 (EFGH, Figure 125) shows that bitumen was displaced more efficiently in this section, this is because the injection of steam took place in this plane.

Compaction of the pack was also observed in these last two experiments. Before beginning steam injection the overburden pressure was set to be 75 psig. At the beginning of steam injection, the heating effect of the steam being injected caused expansion of the sand and the formation fluids, later when fluids were being produced from the box, it was necessary to pump more oil with the Ruska pump in order to maintain a constant pressure. This effect was stronger in Run 22 where the recovery was higher than in Run 21 (e.g., 36.6% recovery in Run 22, Table 61, compared to 26.3% recovery in Run 21, Table 58; also see Figures 112 and 110 respectively). As observed in the experiments conducted with the two-dimensional model, compaction of the sand was in direct proportion to the amount of bitumen recovered.

Table 57
Production History for Run 21

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)	I W.B.R. (cc/cc)	I W.B.R. (cc/cc)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent (cc)
1	149	-	1010	1010	800	800	100	100	8.0	1.1	6.78	40	110	110
2	139	-	1000	2010	700	1500	300	400	2.33	0.0	7.19	40	0.0	110
3	253	-	1000	3010	100	1600	900	1300	.11	0.0	3.45	40	0.0	110
4	121	-	1000	4010	750	2350	250	1550	3.0	0.0	8.26	40	0.0	110
5	-	-	1050	5060	760	3110	290	1840	2.62	0.0	-	40	0.0	110
6	-	-	770	5830	500	3610	270	2110	1.85	0.0	-	60	0.0	110
7	-	-	440	6270	200	3810	240	2350	.83	0.0	-	60	0.0	110
8	-	-	400	6670	250	4060	150	2500	1.67	0.0	-	60	0.0	110

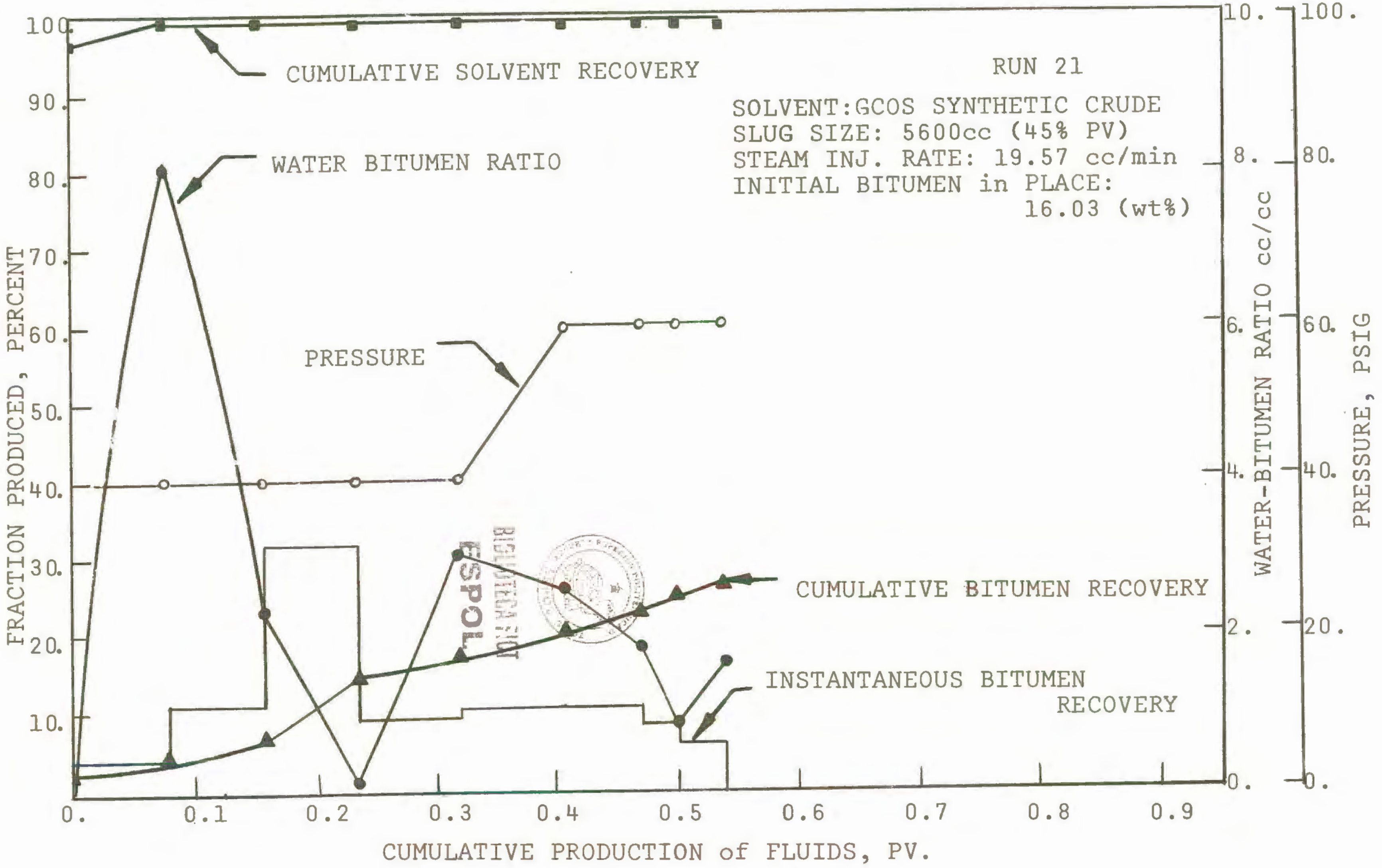


Figure 110 Production History for Run 21.

Table 58

General Characteristics and Results for Run 21

Amount of tar sand packed	69599 gms.
Bitumen content of tar sand	.1602
Weight of bitumen in place	11157 gms.
Volume of bitumen in place	10769 cc
Solvent used	GCOS synthetic crude
Weight of clean sand	58442.5 gms.
Volume of clean sand	21782 cc
Volume of steal box	34200 cc
Void space in the model	1648.5 cc
Pore volume	12417 cc
Porosity	.36
Total solvent injected	5600 cc
Amount of solvent retained by the pack	37 cc
Total run time	39.07 hrs.
Time of solvent injection	31.38 hrs.
Time of steam injection	4.37 hrs.
Time for effluent breakthrough	3.15 hrs.
Volume of solvent inj. before effluent B.T.	130 cc
Average injection rate before effluent B.T.	3.02 $\frac{cc}{min.}$
Average flow rate	2.97 $\frac{cc}{min.}$
Average pressure for solvent injection	35.2 psig.
Average pressure for steam injection	50 psig.
Time for steam breakthrough	4.37 hrs.

Table 58 (continued)

Water bitumen ratio	1.59 cc/cc
Total steam injected (as water)	5130 cc
Steam injection rate	19.57 $\frac{cc}{min.}$
Total bitumen recovery	2834 cc
Recovery	26.3%

Table 59
Injection History for Run 22

Volume Produced (cc)	Cumulative Production (cc)	Bitumen Produced (cc)	Cumulative Production (cc)	Solvent Produced (cc)	Cumulative Production (cc)	Water Produced (cc)	Cumulative Production (cc)	Flow Rate (cc)
92	92					92	92	18.4
14	106					14	106	2.0
12	118					12	118	3.0
74	192					12	130	8.8
46	238	13	13	21	83	12	142	11.5
48	286					31	173	16.0
100	386					20	193	11.0
200	586					22	215	18.2
90	676	28	41	52	410	10	225	6.4
84	760					30	225	4.7
138	898					8	263	6.0
28	926					12	275	3.5
100	1026	33	77	67	674	0	275	4.5
66	1092					12	287	4.7
246	1338					48	335	9.5
148	1486	48	125	84	1010	16	331	6.2

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
5	5	60	60	12	83
7	12	76	136	10.8	90
4	16	59	195	14.7	97
9	25	85	280	9.4	100
4	29	30	310	7.5	100
3	32	40	350	13.3	99
9	41	90	440	10	91
11	52	100	540	9.09	70

Table 59 (continued)

Time (min.)	Cumulative Time (min.)	Volume Injected (cc)	Cumulative Volume (cc)	Flow Rate (cc/min.)	Pressure (psig)
14	66	80	620	5.71	50
18	84	75	795	4.17	75
23	107	105	800	4.57	62
8	115	40	840	5.0	60
22	137	90	930	4.09	47
14	151	75	1005	5.36	65
26	177	125	1130	4.81	51
24	201	110	1240	4.58	40

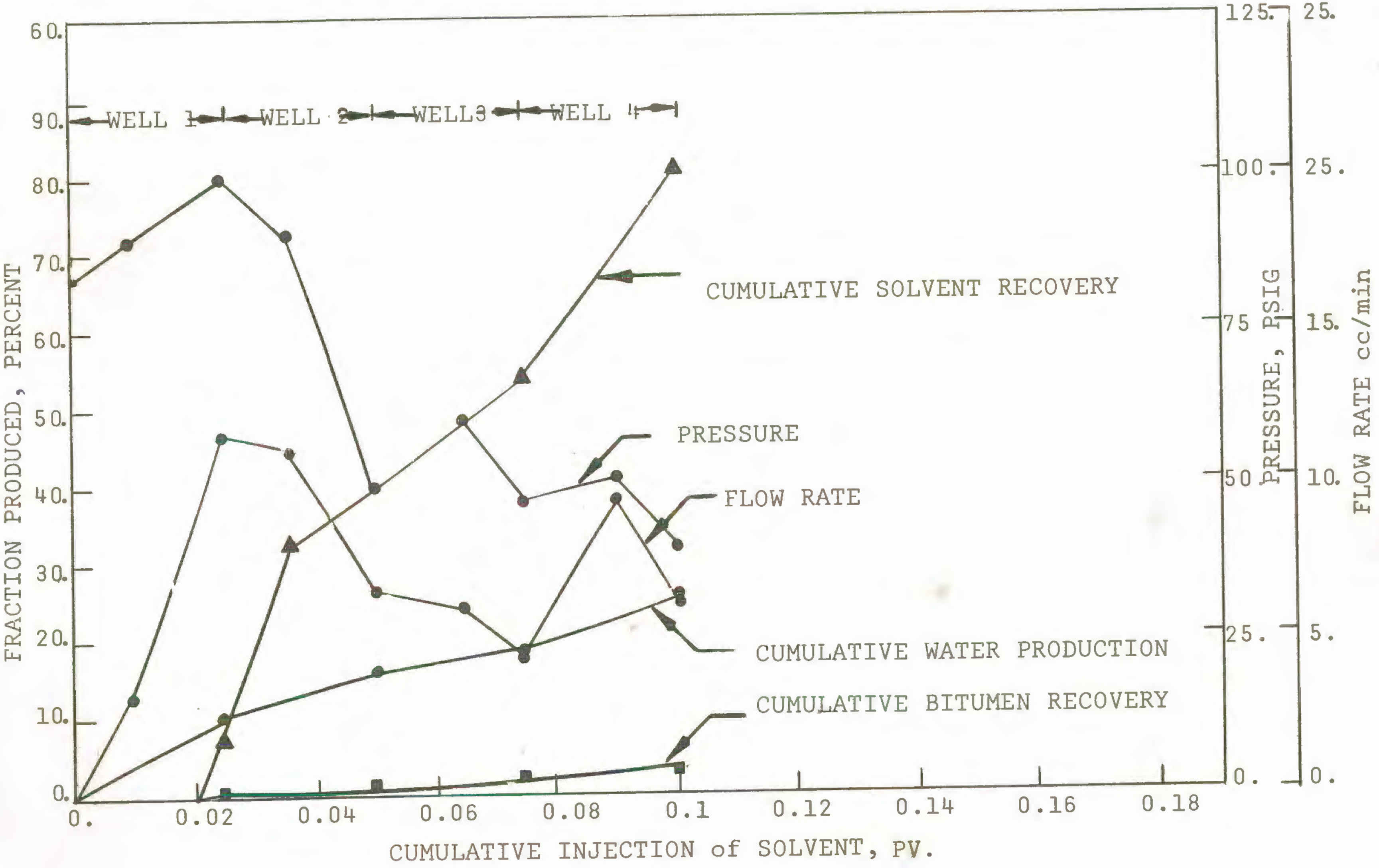


Figure 111 Injection History for Run 22.

Table 60
Production History for Run 22

Sample #	Time (min.)	Cumulative Time (min.)	Volume Produced (cc)	Cumulative Volume (cc)	Water Produced (cc)	Cumulative Water (cc)	Bitumen Produced (cc)	Cumulative Bitumen (cc)
1.1	344	-	900	900	800	800	100	100
1.2	548	-	930	1830	850	1650	80	180
1.3	517	-	900	2730	750	2400	150	330
1.4	572	-	820	3550	650	3050	170	500
2.1	383	-	780	4330	630	3680	150	650
2.2	101	-	950	5280	800	4840	150	800
2.3	351	-	900	6180	400	4880	500	1300
2.4	438	-	900	7080	200	5080	700	2000
3.1	238	-	950	8030	700	5780	250	2250
3.2	360	-	670	8700	600	6380	70	2320
3.3	228	-	1000	9700	700	7080	300	2620
3.4	-	-	850	10550	450	7530	400	3020
4.1	-	-	1000	11550	300	7830	700	3720
4.4	-	-	750	12300	550	8380	200	3920
over-night	-	-	350	12650	190	8570	24	3944

I W.B.R. (cc/cc)	I S.B.R. (cc/cc(	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cummulative Solvent (cc)
8.0	0.0	2.62	40.0	0.0	-
10.6	0.0	1.72	32.5	0.0	-
5.0	0.0	1.74	32.5	0.0	-
3.8	0.0	1.43	32.5	0.0	-
4.2	0.0	2.04	30.0	0.0	-
5.3	0.0	5.9	30.0	0.0	-
.8	0.0	2.56	30.0	0.0	-
.3	0.0	2.05	30.0	0.0	-

Table 60 (continued)

I W.B.R. (cc/cc)	I S.B.R. (cc/cc)	Flow Rate (cc/min.)	Steam Pressure (psig)	Solvent Recovery (cc)	Cumulative Solvent (cc)
2.8	0.0	3.99	30.0	0.0	-
8.6	0.0	1.86	30.0	0.0	-
2.3	0.0	4.39	35.0	0.0	-
1.13	0.0	-	30.0	0.0	-
.43	0.0	-	30.0	0.0	-
2.75	0.0	-	30.0	0.0	-
7.92	0.0	-	-	136	136

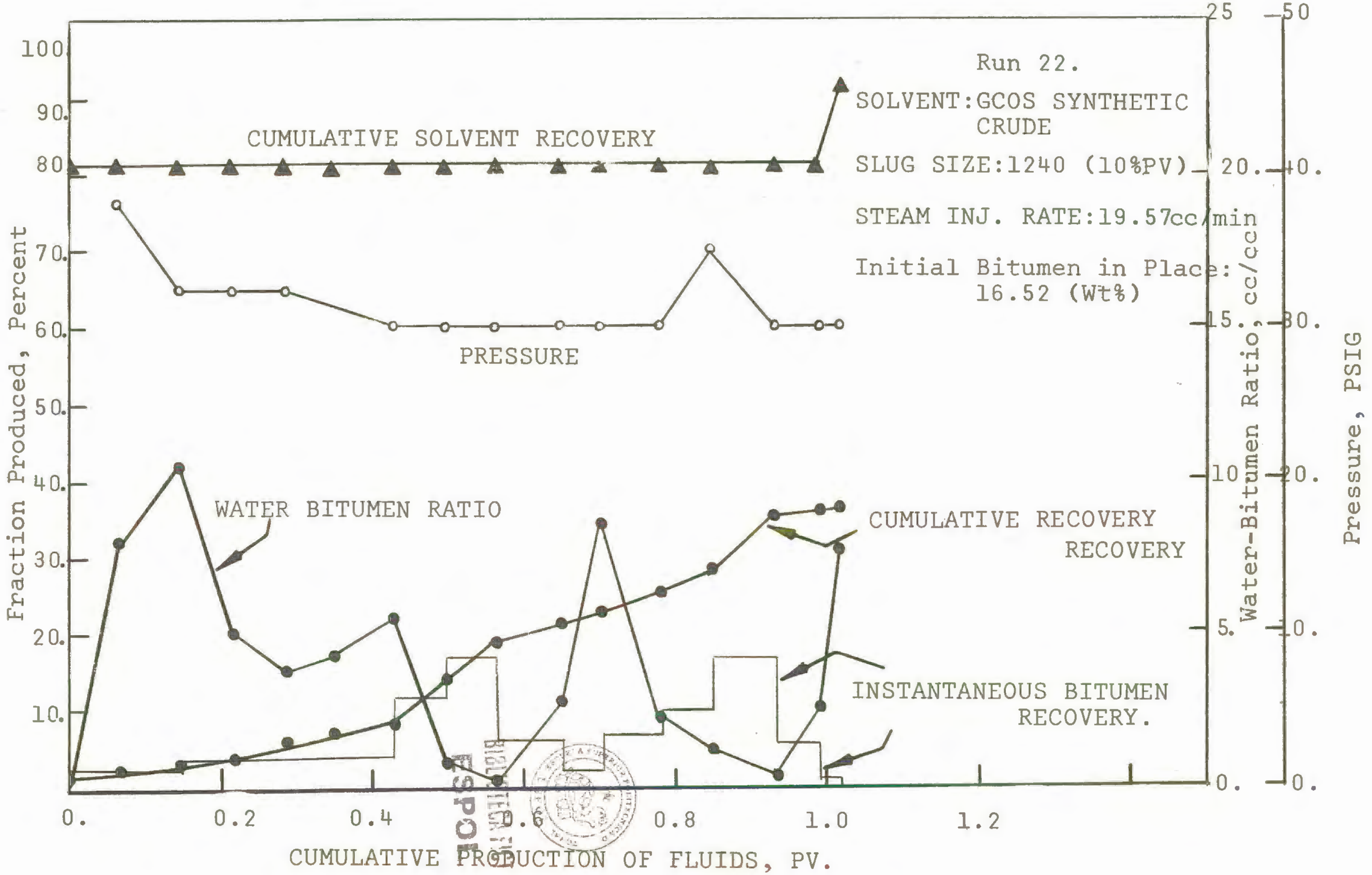


Figure 112 Production History for Run 22.

Table 61

General Characteristics and Results for Run 22

Amount of rar sand packed	69684.3 gms.
Bitumen content of tar sand	.1652
Weight of bitumen in place	11511.8 gms.
Volume of bitumen in place	11111.8 cc
Solvent used	GCOS synthetic crude
Weight of clean sand	58572.5 gms.
Volume of clean sand	21830 cc
Volume of steel box	342000 cc
Void space in the model	1257 cc
Pore volume	12369 cc
Porosity	.362
Total solvent injected	1240 cc
Amount of solvent retained by the pack	94 cc
Total run time	30 hrs.
Time of solvent injection	3.35 hrs.
Time of steam injection	22.7 hrs.
Time for effluent breakthrough	.5 hrs.
Volume of solvent inj. before effluent B.T.	280 cc
Average injection rate before effluent B.T.	9.33 $\frac{cc}{min.}$
Average flow rate	6.17 $\frac{cc}{min.}$
Average pressure for solvent injection	73.7 psig
Average pressure for steam injection	30 psig
Time for steam breakthrough	22.7 hrs.

Table 61 (continued)

Water bitumen ratio	2.17 $\frac{cc}{min.}$
Total steam injected (as water)	11150 cc
Steam injection rate	8.17 $\frac{cc}{min.}$
Total bitumen recovery	4069 cc
Recovery	36.6%

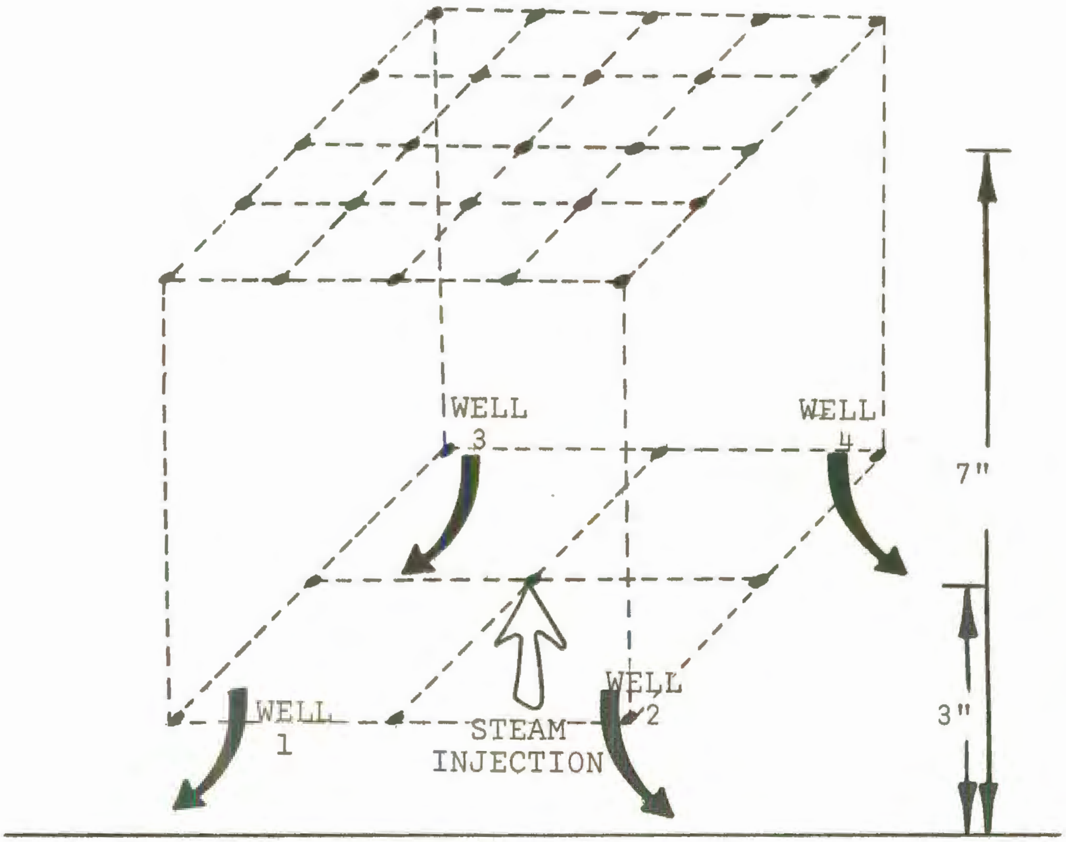


Figure 113 Temperature Recording Intervals of Run 22.

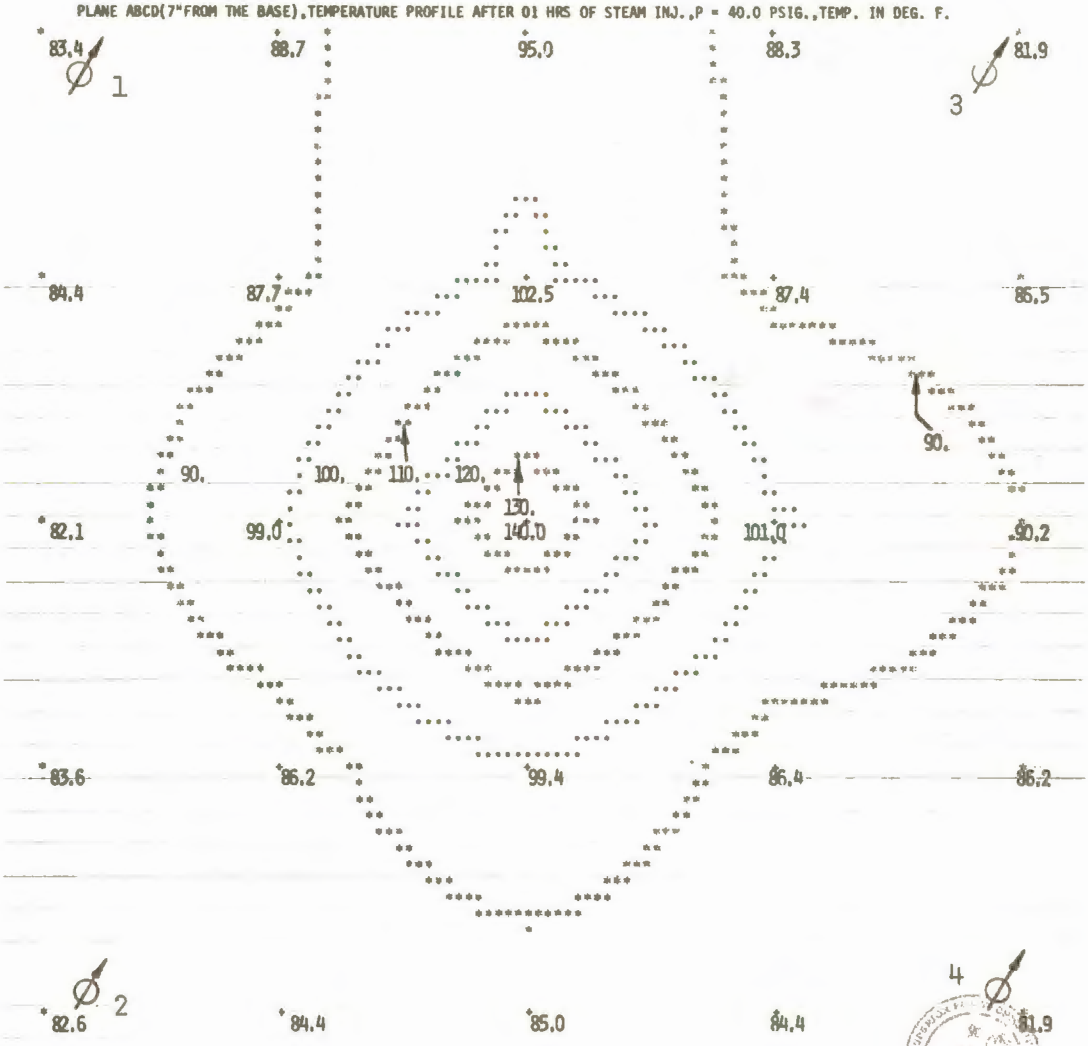


Figure 114 Temperature Profile for Run 22.

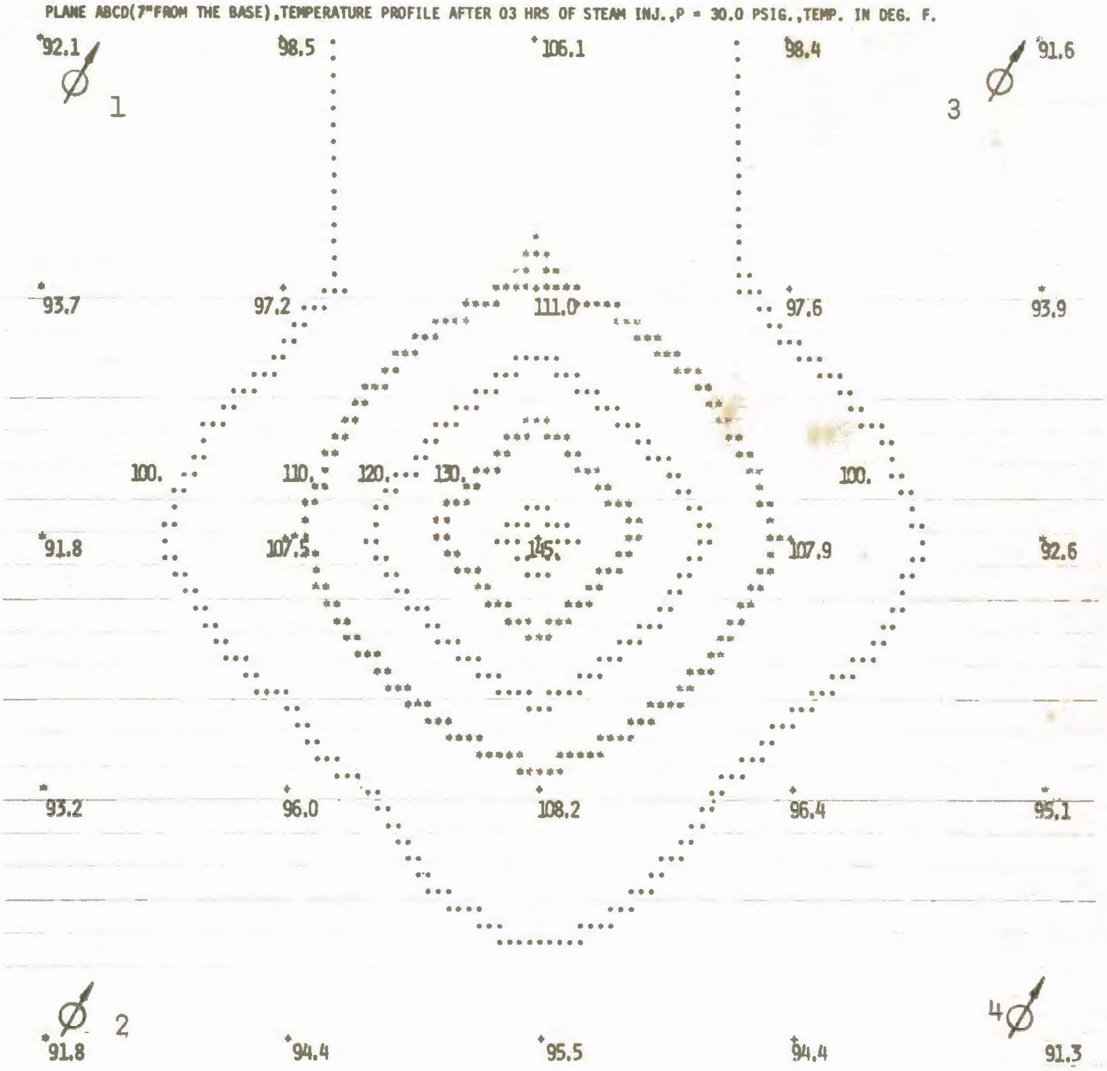

PLANE ABCD(7"FROM THE BASE),TEMPERATURE PROFILE AFTER 03 HRS OF STEAM INJ.,P = 30.0 PSIG.,TEMP. IN DEG. F.

Figure 115 Temperature Profile for Run 22.

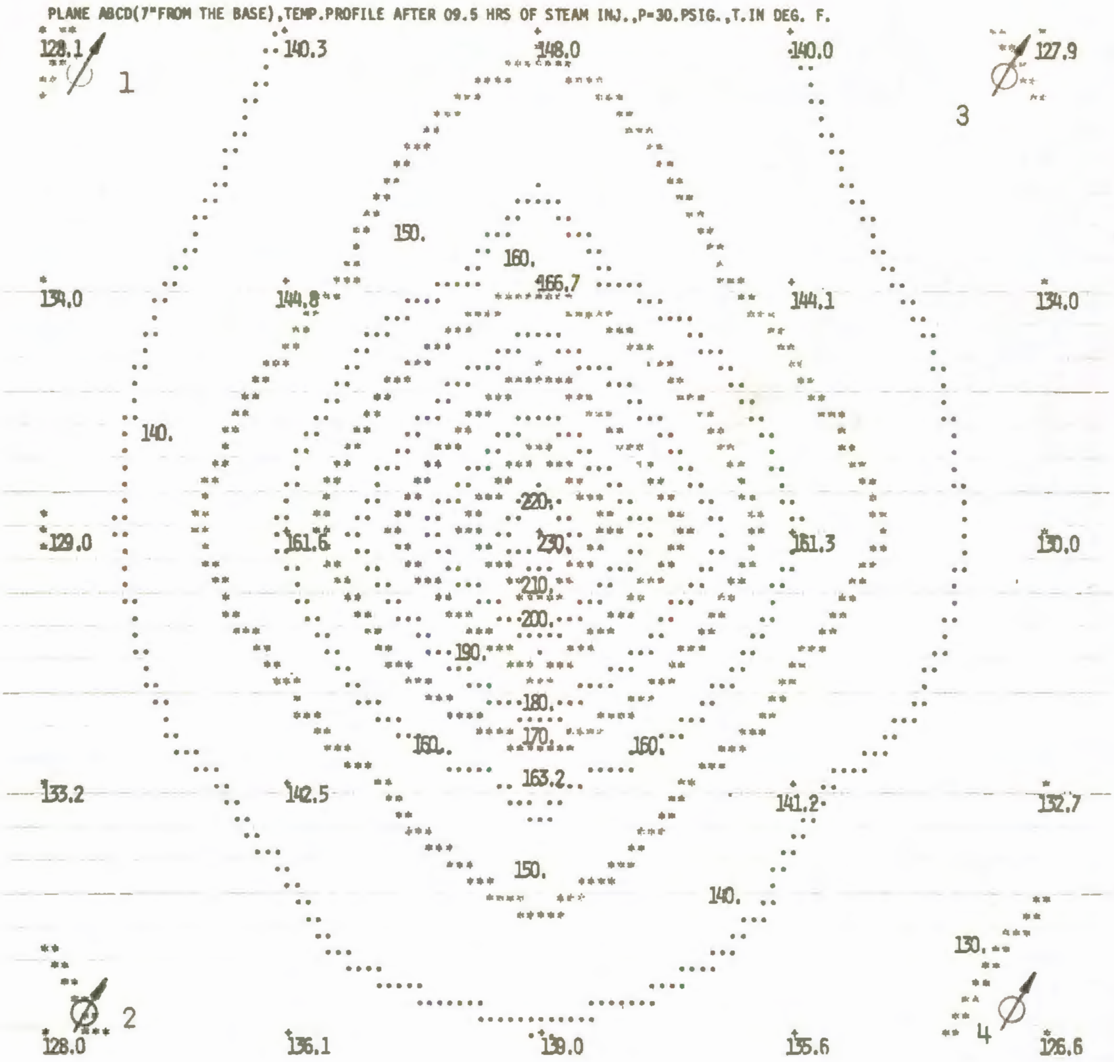

PLANE ABCD(7"FROM THE BASE),TEMP.PROFILE AFTER 09.5 HRS OF STEAM INJ.,P=30.PSIG.,T.IN DEG. F.

Figure 116 Temperature Profiles for Run 22.

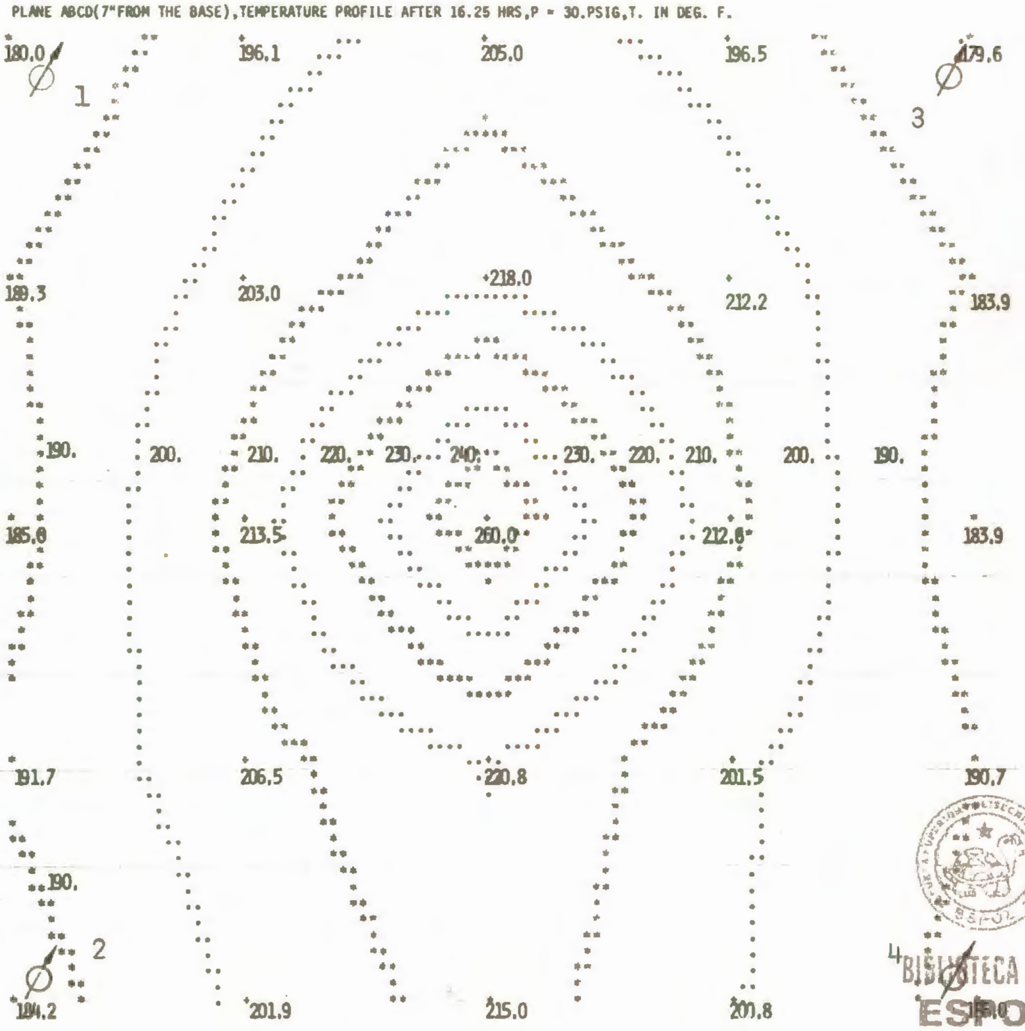


Figure 117 Temperature Profiles for Run 22.

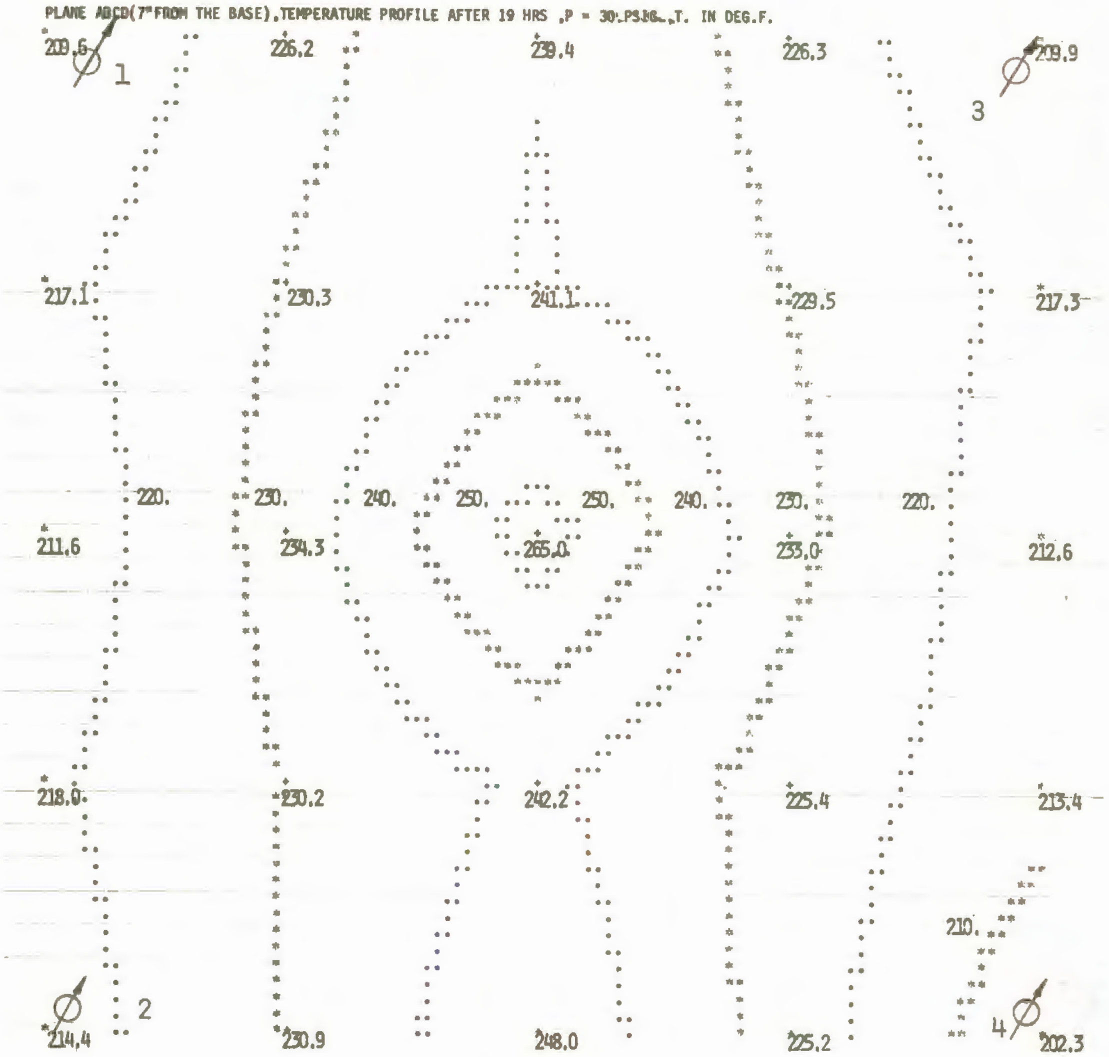


Figure 118 Temperature Profile for Run 22.

PLANE EFGH(3"FROM THE BASE),TEMPERATURE PROFILE AFTER 01HRS OF STEAM INJ.,P = 40.0 PSIG.,TEMP. IN DEG. F.

PLANE EFGH(3"FROM THE BASE),TEMPERATURE PROFILE AFTER 03 HRS OF STEAM INJ.,P = 30.0 PSIG.,TEMP. IN DEG. F.

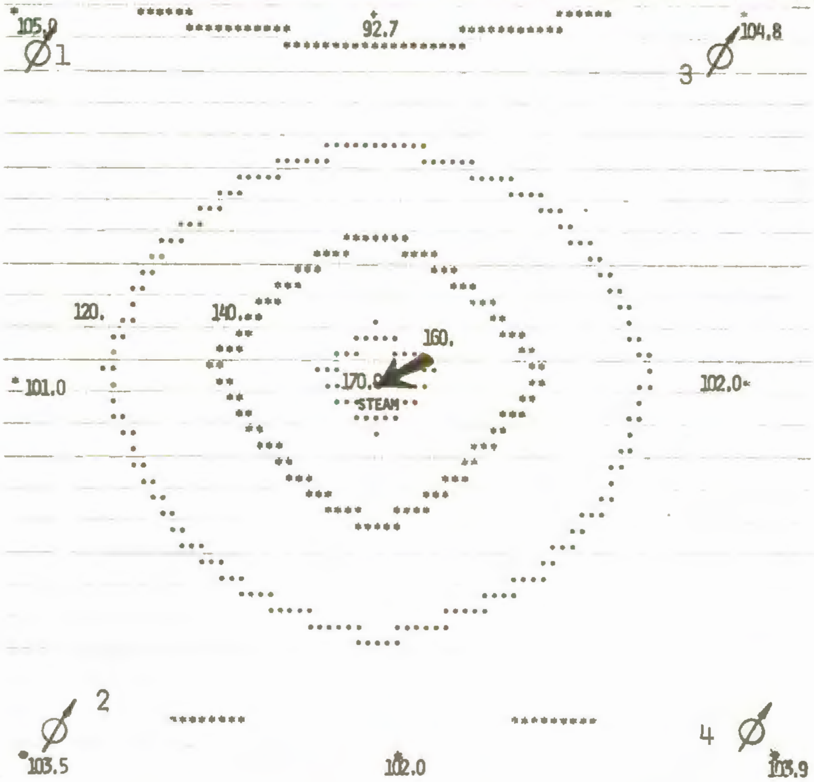
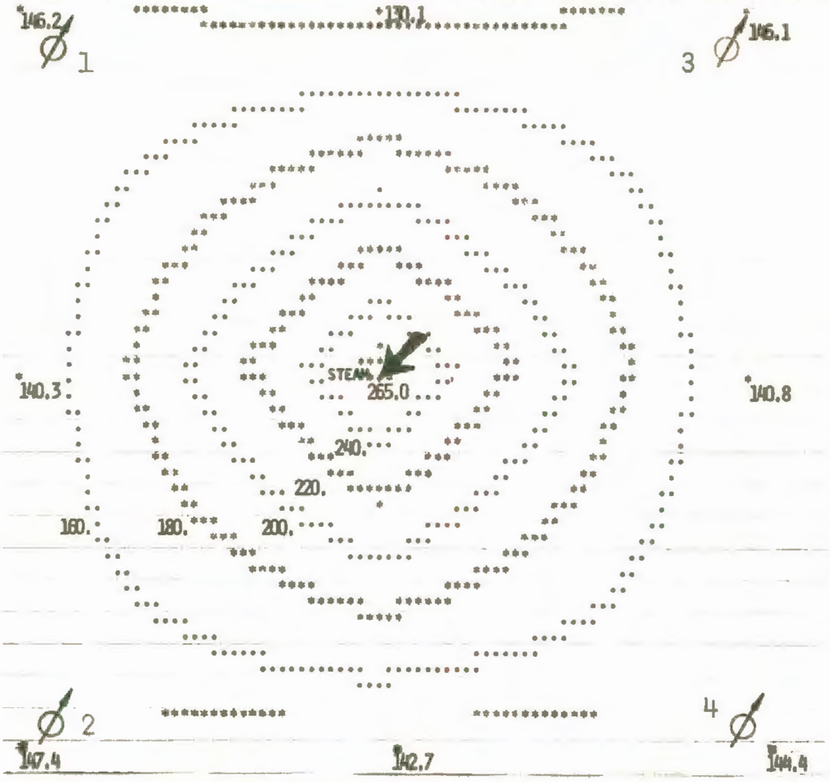


Figure 119 Temperature Profiles for Run 22.

PLANE EFGH(3"FROM THE BASE),TEMP.PROFILE AFTER 09.5 HRS OF STEAM INJ.,P = 30.PSIG., TEMP. IN DEG. F.



PLANE EFGH(3"FROM THE BASE),TEMP. PROFILE AFTER 12 HRS,P = 35. PSIG,TEMP. IN DEG. F.

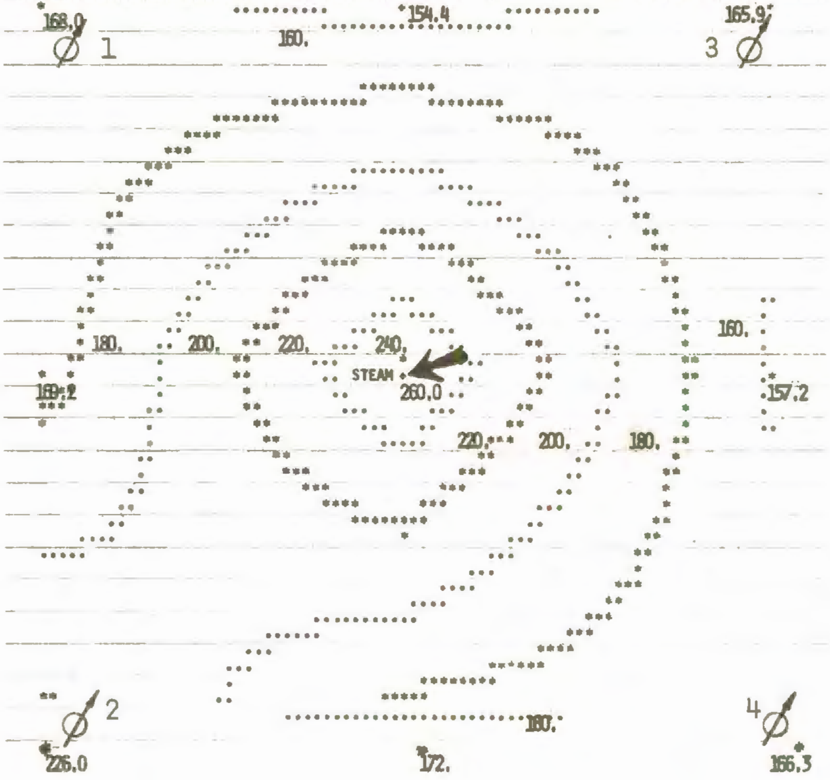
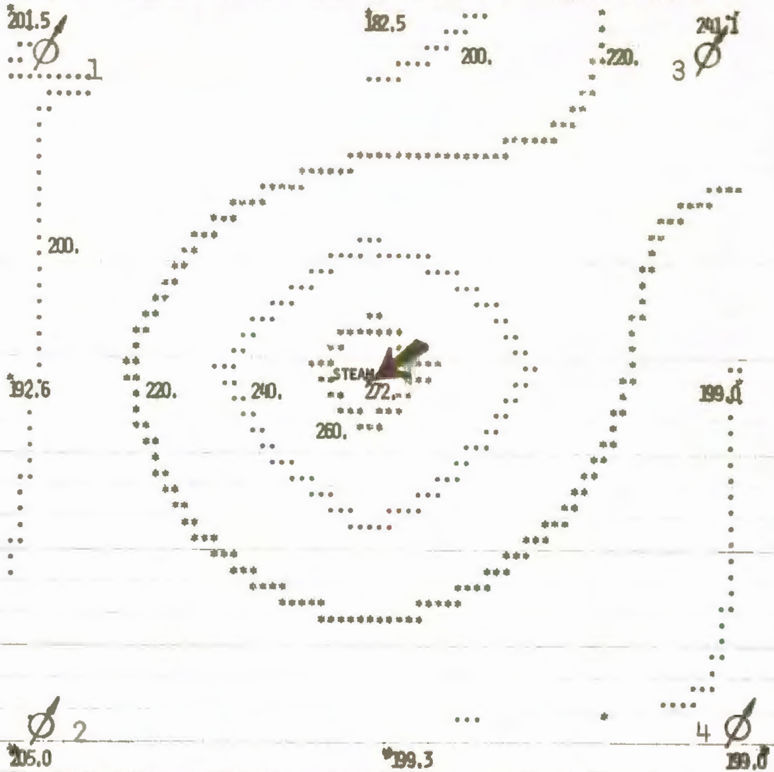


Figure 120 Temperature Profiles for Run 22.

PLANE EFGH(3"FROM THE BASE),TEMP. PROFILE AFTER 16.25 HRS,P=30. PSIG,TEMP. IN DEG. F.



PLANE EFGH(3"FROM THE BASE),TEMP.PROFILE AFTER 19 HRS ,P=30.PSIG,TEMP. IN DEG F.

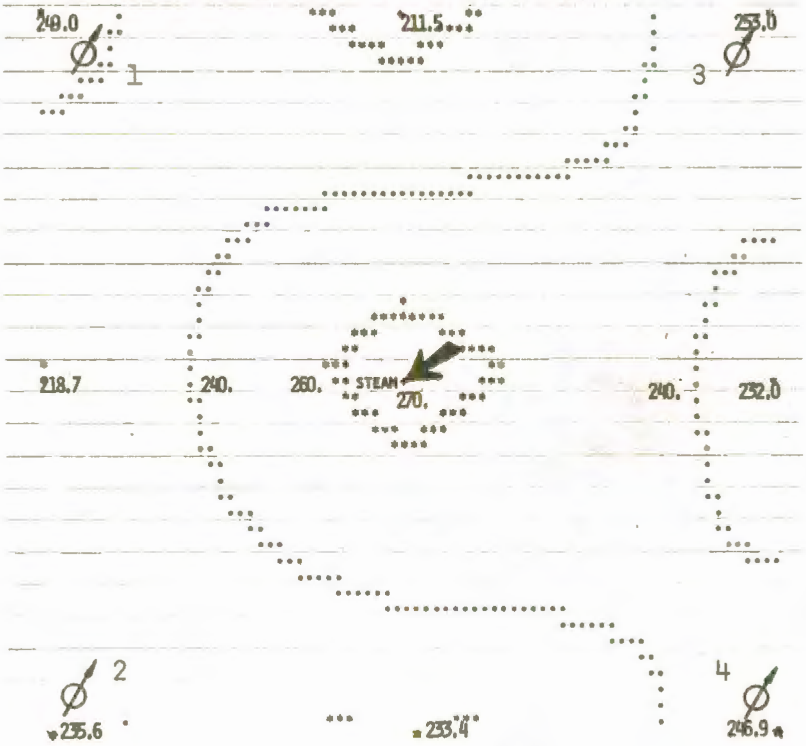


Figure 121 Temperature Profile for Run 22.

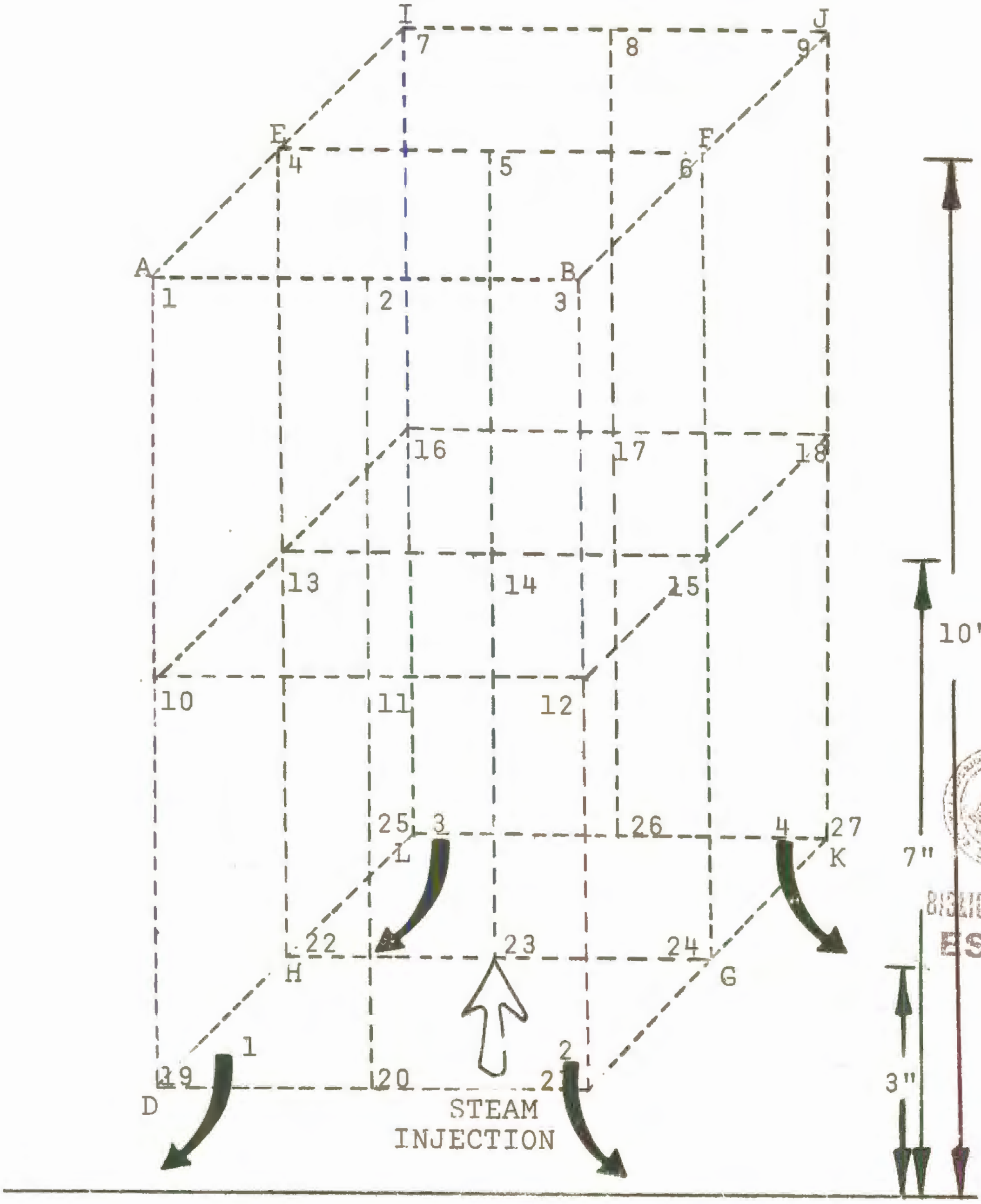
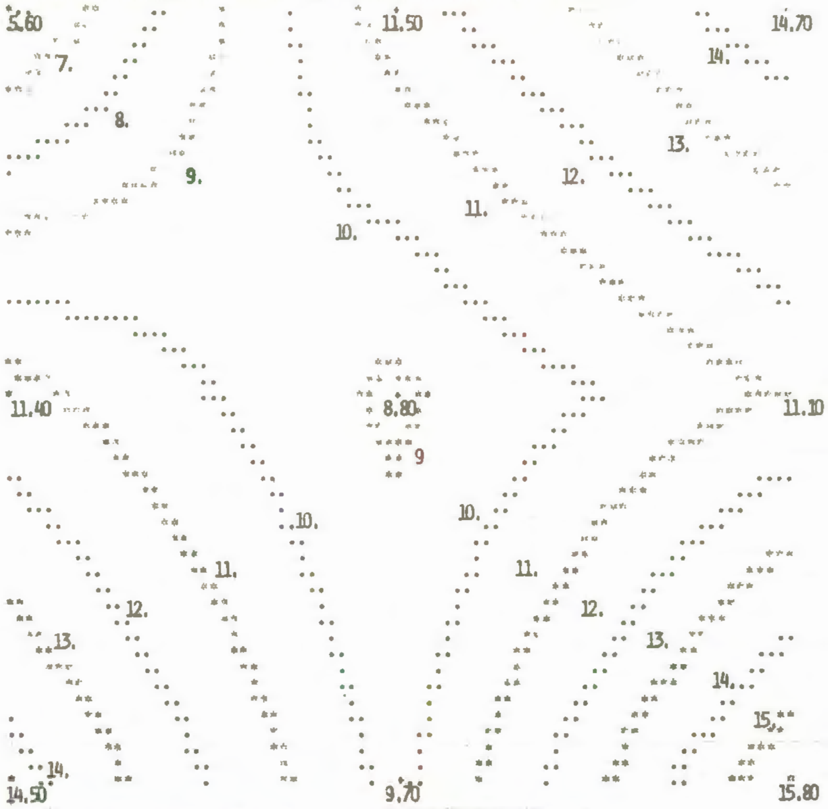


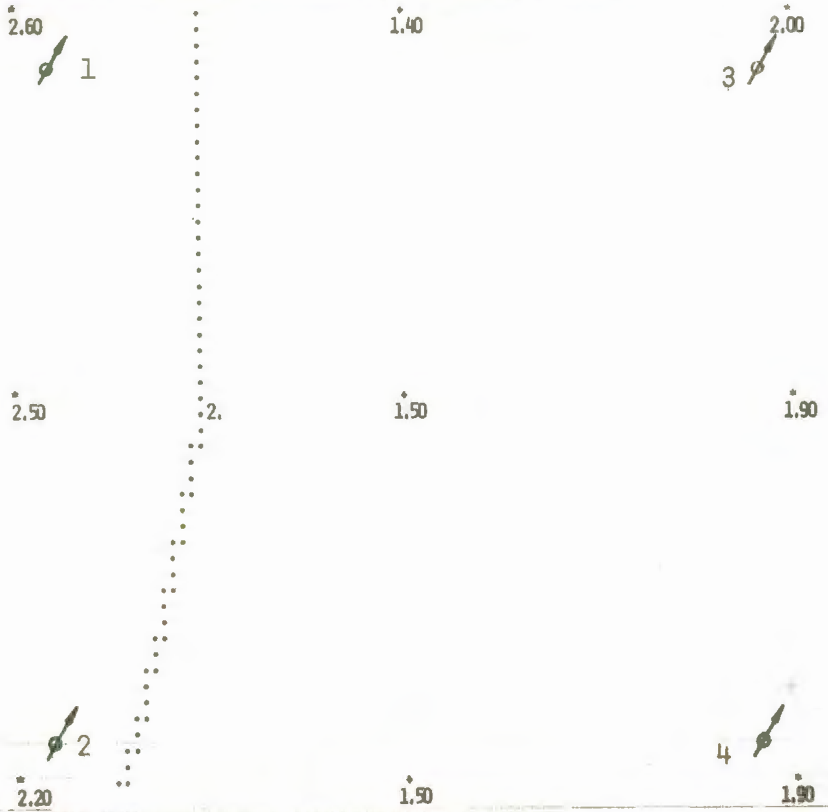
Figure 122 Sampling Intervals of Run 22.

HORIZONTAL PLANE 1,(10"FROM THE BASE),INITIAL BITUMENSATURATION = 16.52(WT.%)



HORIZONTAL PLANE 2,(7"FROM THE BASE),INITIAL BITUMEN SATURATION = 16.52(WT.%)

Figure 123 Residual Saturation Contours for Run 22.


HORIZONTAL PLANE 3,(5"FROM THE BASE),INITIAL BITUMEN SATURATION = 16.52(WT.%)

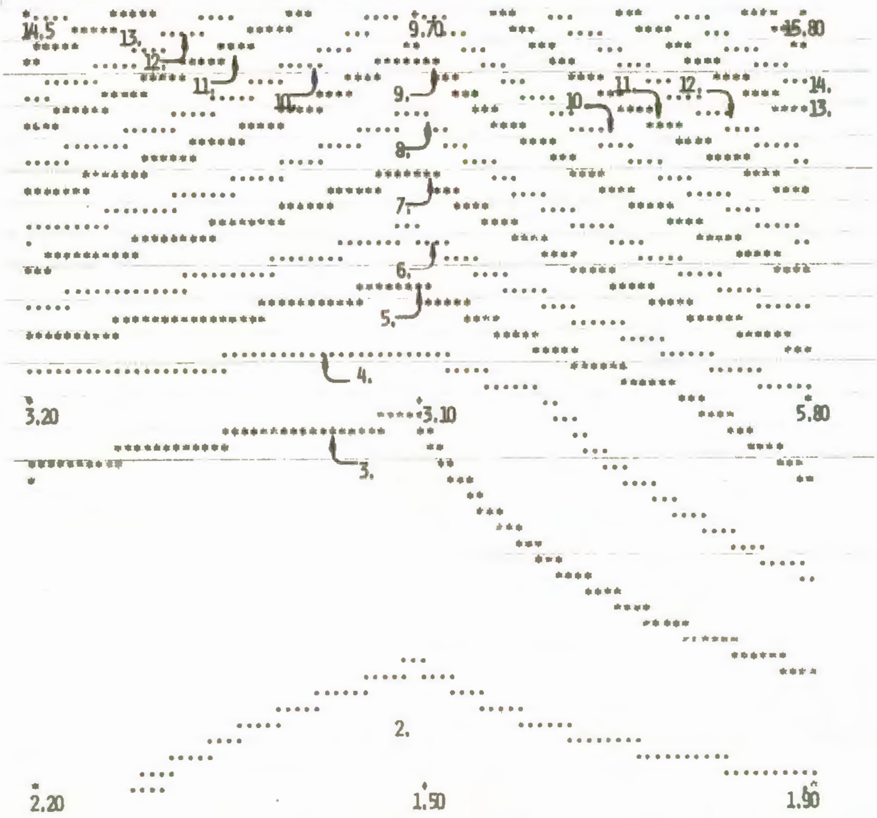
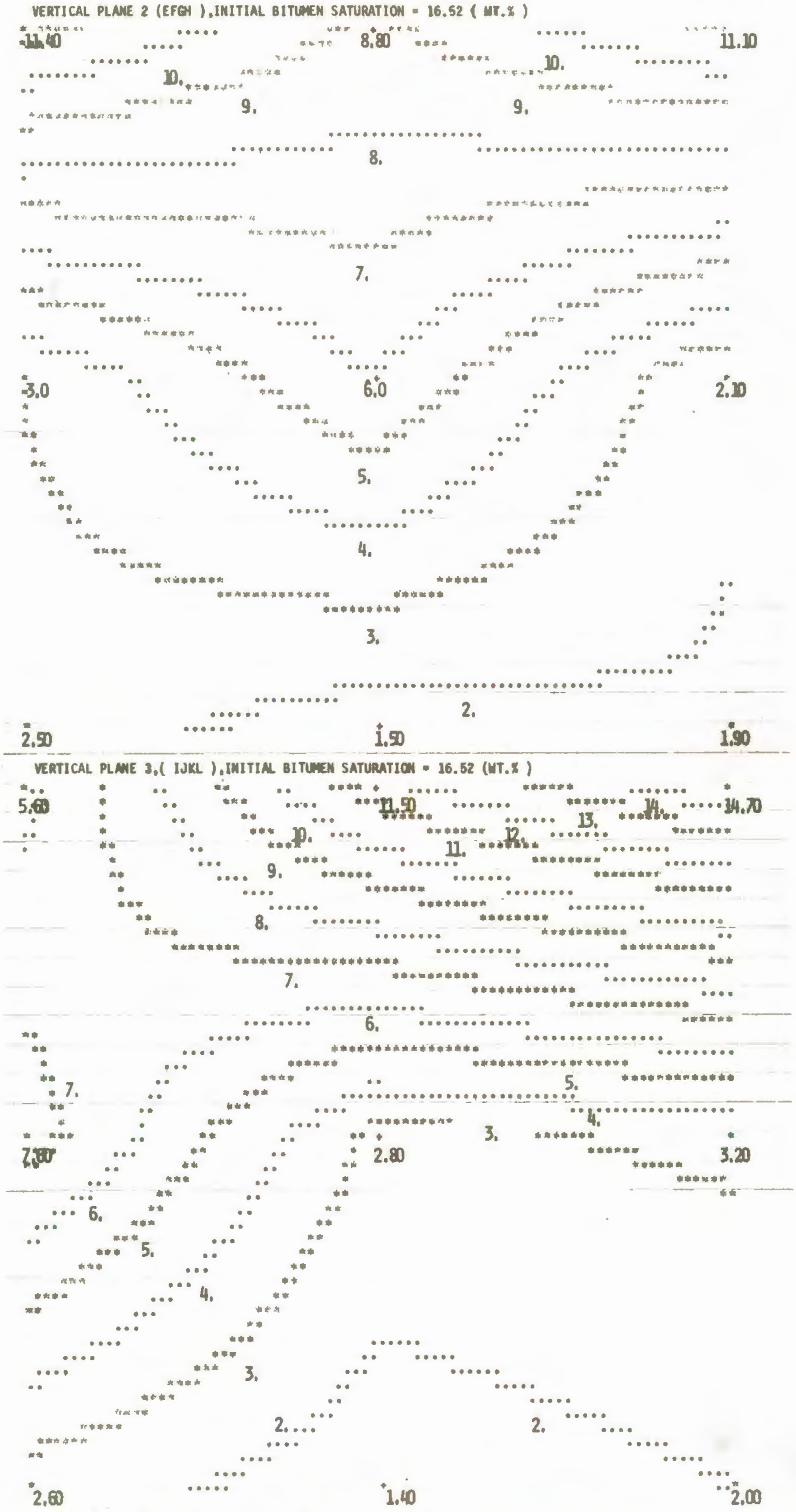

VERTICAL PLANE 1,(ABCD),INITIAL BITUMEN SATURATION = 16.52 (WT.%)

Figure 124 Residual Saturation Contours for Run 22.



VERTICAL PLANE 2 (EFGH),INITIAL BITUMEN SATURATION = 16.52 (WT.%)

VERTICAL PLANE 3,(IJKL),INITIAL BITUMEN SATURATION = 16.52 (WT.%)

Figure 125 Residual Saturation Contours for Run 22.

VIII. SUMMARY AND CONCLUSIONS

This study is a continuation of a series of investigations conduced at The Pennsylvania State University by Snyder (32) and Hernandez (21). The present study was concerned with the recovery of bitumen from Athabasca Tar Sands in a two-dimensional vertical model with restricted fluid entry, and in a three-dimensional model. Three different solvents (GCOS synthetic crude, Mobil Solvent and naphtha) were used to investigate recovery from the models by miscible displacements. Thermal-miscible displacement effectiveness of different slug sizes (45% PV, 20% PV and 10% PV), and solvents (GCOS synthetic crude and naphtha) was studied for both tar sand packs saturated with bitumen and air and tar sand packs saturated with bitumen and water.

The effect of changing the placement of the slug from the steam injection well to the production well for the three GCOS synthetic crude slugs (45% PV, 20% PV and 10% PV) was also investigated.

Finally, two GCOS synthetic crude slugs (45% PV and 10% PV), followed by steam were placed in the neighborhood of the production wells of the three-dimensional model to investigate bitumen recovery from a 5-spot system under the action of a 75 psig overburden pressure. Miscible and thermal-miscible displacement were studied in the three-dimensional model. Within the limitations of the present study, the following conclusions may be drawn:

Miscible Displacements

1. Recovery of bitumen by miscible displacement is not feasible considering the large volumes of solvent used to recover relatively low amounts of bitumen. Of the three solvents used, Mobil solvent yielded the highest recovery (32.2%), naphtha was next (21.35%), followed by GCOS synthetic crude (16.6%).
2. When the sand pack is saturated with bitumen and air, the solvent injected does not create a channel but instead tends to saturated all the empty spaces and pores left after packing the model. It was necessary to inject a volume of solvent close to the void space in the model before obtaining effluent breakthrough.
3. Mobil solvent was the solvent that swept the tar sand efficiently. When GCOS synthetic crude and naphtha were injected, the amount of solvent retained by the pack was the volume injected before effluent breakthrough. The tar sand samples recovered always showed decreasing bitumen concentration. It is therefore, concluded that the new portions of the tar sand pack contacted by these two solvents after effluent breakthrough were of a small extent. When the Mobil solvent was injected, the amount of solvent retained by the

pack was twice the volume of the solvent injected before effluent breakthrough. As a consequence, bitumen recovery was higher for this solvent, because a fresh portion of the pack were contacted and swept.

4. Pressurizing the model and recirculation of effluent did not improve bitumen recovery.
5. Capillarity in bitumen-solvent-air-sand systems was found to be a strong force which helped to distribute the solvent over the tar sand pack.
6. Wall effect is to be expected in such experiments because it is practically impossible to achieve perfect contact between the tar sand and the walls of the steel box.
7. Asphaltene flocculation was not observed for any of the solvents at the experimental conditions.

Thermal-Miscible Displacements

Naphtha-Steam Combinations

1. Naphtha-steam combinations proved to be an efficient way of recovering bitumen from the Athabasca Tar Sands.
2. Non-continuous steam injection yielded higher bitumen recoveries than continuous injection for similar conditions of slug size and steam injection pressure, but the water requirements and steam injection time were also higher for the non-continuous steam injection case.

3. Solvent-temperature combination caused asphaltene flocculation (for 45 and 20% PV slug size, and temperatures up to 210°F)
4. Recovery of bitumen was directly, proportional to any slug size.
5. Bitumen recovery was found to depend upon the steam injection rate, being higher at medium[1] injection rates.
6. Residual saturations of solvent were negligible for naphtha.
7. Injection of slugs of light solvents such as naphtha is not desirable, because due to the low boiling point of these solvents most of the solvent is produced in the first stages of steam injection.

<u>GCOS Synthetic-Steam Combinations</u>

i) Tar Sand Pack Saturated with Bitumen and Air

   1. GCOS synthetic crude-steam combinations were found to be more efficient than naphtha-steam combinations in the recovery of bitumen, especially for cases where a 45% PV slug was injected. For 20% PV slugs, recovery was the same for both solvents, but the water

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[1] The following classification was used for the steam injection rates; low (0-4.75 cc/min.), medium (4.75-10 cc/min) and high (10 cc/min. and up).

requirement of the naphtha-steam runs was higher.

2. Bitumen recovery was a direct function of the size of the slug injected, being higher for larger slugs.
3. GCOS synthetic crude-steam combinations did not cause plugging by asphaltene flocculation for any of the conditions studied.
4. Residual saturation of solvent ranged from 47 to 16% of the original volume of the solvent injected.
5. Medium steam injection rates were more effective in the recovery of bitumen of all the slug sizes used.
6. Water-bitumen ratios were usually lower for GCOS synthetic crude-steam combinations than for naphtha-steam combinations.

ii) Tar Sand Pack Saturated with Bitumen and Water

1. When water, and subsequently, solvent are injected through the same side of the pack (steam injection point) the volume of water displaced from the pack is equal to the volume of solvent injected and there is no difference in the general behavior of the experiments with regard to those experiments where the pack was saturated with bitumen and air.

2. Low steam injection rates proved to be undesirable for bitumen recovery.
3. When solvent injection was changed from the side of the steam injection well to the side of the effluent production well, recovery of bitumen increased for all the slug sizes used and recovery was no longer dependent upon slug size.
4. Changing the placement of the slug reduced the volume of solvent required to have effluent breakthrough from 900 cc (when solvent was injected through the steam injection well) to 200-300 cc. In this case, the solvent opened a channel in the pack and a definite path was created between the injection and the producing wells.
5. Becuase of the presence of water saturating the empty spaces of the tar sand pack the flow of solvent was confined to small sections of the pack, and the miscible displacement was more efficient.
6. Recovery of bitumen was higher for medium steam injection rates than for high steam injection rates
7. When solvent was injected in the neighborhood of the production well, residual saturations of solvent were negligible.

8. Water-bitumen ratios were lower when the slug was placed in the neighborhood of the production well.
9. The characteristics of the experiment did not change when the three-dimensional model was used, and the conclusions obtained for the two-dimensional model are valid for the three-dimensional model as well. The only difference was the absence of the wall effect and the overriding effect of the steam observed in the two-dimensional model.
10. The presence of the overburden pressure helped in confining the solvent flow to a definite section of the model, improving communication between wells and lowering the volume of solvent required to open a channel in the sand pack.
11. Compaction of the tar sand packs is to be expected when the production of bitumen is large. It should be remembered that the cementing material in this unconsolidated sand is bitumen, and when this is produced the sand grains are left with a larger void space inbetween, if to this is added the action of the steam flow as well as the overburden pressure large compaction is to be expected. (This conclusion is limited

only to experiments where the tar sand is manually packed, because in actual tar sands the contact is grain-to-grain and compaction is negligible.)

IX. LIMITATIONS OF THE EXPERIMENTS, AND EXPERIMENTAL DIFFICULTIES

Limitations of the Experiments

Even though the experiments conducted provided information on the mechanics of miscible and thermal-miscible displacements, a number of factors, limit the validity of the results obtained.

Even when the model was carefully packed, it was impossible not to have a void space in the model which gives some degree of communication between wells. It is known that the Athabasca Tar Sand in its original state has zero permeability, then the characteristics of flow could change in a system like that.

The porous media studied were homogeneous tar sand packs, where all the clay and rock were removed before packing. But the tar sand formations have a variable bitumen saturation which changes from one point to another in the formation.

The small thickness of model 1 caused strong steam override of the sand pack which was the reason for early steam breakthrough and the consequent decrease in recovery.

The compaction observed in the models shows that the models did not have grain-to-grain contact.

Both models were insulated with fiberglass which helped to maintain the models without too much heat losses. A thermometer placed on top of the fiberglass insulation never exceeded 150°F, while inside the model the temperature many times was above 250°F allowing a uniform temperature distribution.

The effluent samples recovered where centrifuged to separate any water that stayed in suspension but it is still possible that some readings may be affected because of this. (It must be remembered that the samples were analyzed in an infrared spectrophotometer and the samples are suppose to be made up only of two components, bitumen and solvent.)

Experimental Difficulties

Considering 14.5 (wt.%) as an average value for bitumen content of the tar sand samples used in the experiments, to obtain 1000 cc of bitumen necessary for the viscosity measurements experiments, it was necessary to extract 15 pounds of tar sand using large amounts of solvent. Later it was necessary to separate the solvent from the bitumen by distillation using a glass column. These processes are very time consuming and difficult, especially because of the sulfurous gases liberated from the bitumen.

Bitumen must be handled at high temperatures, because at room temperature it is solid, and cannot be transferred from one beaker to another.

The experimental runs were lengthy and difficult. Sometimes it took more than 30 hours to have steam breakthrough, and steam injection had to be continuous. Handling of the models was complicated because it was necessary to pack the models carefully in each run and packing was done manually. Model 2, in particular, was extremely difficult to operate. Its weight was more than 350 pounds once the steel box was packed. Finally, when steam was injected it was necessary to record temperature and steam pressure every hour. As mentioned before, many runs took over 30 hours. Collection of effluent was also troublesome because of the large volumes of water produced, and because emulsification of the water in the viscous bitumen produced occurred several times.

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