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SCHOONEBEEK OIL FIELD: THE RW-2E STEAM INJECTION PROJECT[1]

P. J. P. M. TROOST[2]

ABSTRACT

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The Dutch Schoonebeek oil field initially contained 170 x 10^6 m^3 of 25° API crude. Primary recovery is low mainly due to the high viscosity of the oil. It varies between 6% of stock tank oil initially in place (STOIIP) in the west (solution gasdrive) to 18% in the east (waterdrive). Research on enhanced recovery began in 1950 and concentrated on thermal processes. As a result hot water injection has been applied on a large scale increasing the recovery of oil by 8% of STOIIP.

The performance of hot water injection projects is declining and a gradual switch is being made towards steam injection. Steam injection was applied already in 1960 in a depleted part of the field. In 1972 a pilot project was started to test the feasibility of steam injection in the much larger waterdrive part where pressures are kept at the hydrostatic level of 85 bar by aquifer water influx. This project indicated that steam injection under waterdrive conditions is a very effective recovery process and that a recovery increase of 14% of STOIIP can be obtained at an extra-oil/steam ratio exceeding 0.6 m^3/ton.

On the basis of the pilot results a large scale project was designed, the RW-2E steam injection project. It consists of 14 steam injection wells, 43 producers and 14 water disposal wells. Steam will be injected at a total rate of about 3000 tons/day for a period of 6 years. Additional oil recovery of the RW-2E project is estimated at 4 x 10^6 m^3. The maximum additional oil production rate is estimated at 1500 m^3/day. During the design and construction of the RW-2E project extreme care was taken to minimise the impact of the project on the environment. The project started in January 1981. Total project life is estimated at 15 years.

INTRODUCTION

The Schoonebeek oil field, discovered in 1943, is large. With an initial oil in place of 170 x 10^6 m^3 it is the largest onshore oil accumulation in Western Europe. However, the recoverable fraction of the oil in place is small. This is mainly due to the high viscosity of the crude.

Research on improved recovery methods started in 1950. As a result field tests were carried out on hot water injection (1957), steam injection (1960) and in-situ combustion (1960). Both hot water and steam injection gave promising results. The in-situ combustion test failed and was discontinued in an early stage.

As a follow-up to the successful hot water injection pilot project seven full scale field projects have been implemented. Their performance is now declining.

Steam injection started in 1960 in an area of the field where reservoir pressures had been depleted to very low values. Encouraged by the success of this test a pilot steam injection project began in 1972 in the waterdrive part of the field where the reservoir pressure is kept at about the original hydrostatic level.

When in 1976 the steam injection process was proven to be successful also under waterdrive conditions, the design of a large scale extension began: the RW-2E project. During 1980 drilling and construction for this project were finalised and injection started in January 1981.

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[2] Nederlandse Aardolie Maatschappij B.V.
Postbus 28, 9400 AA Assen, The Netherlands.

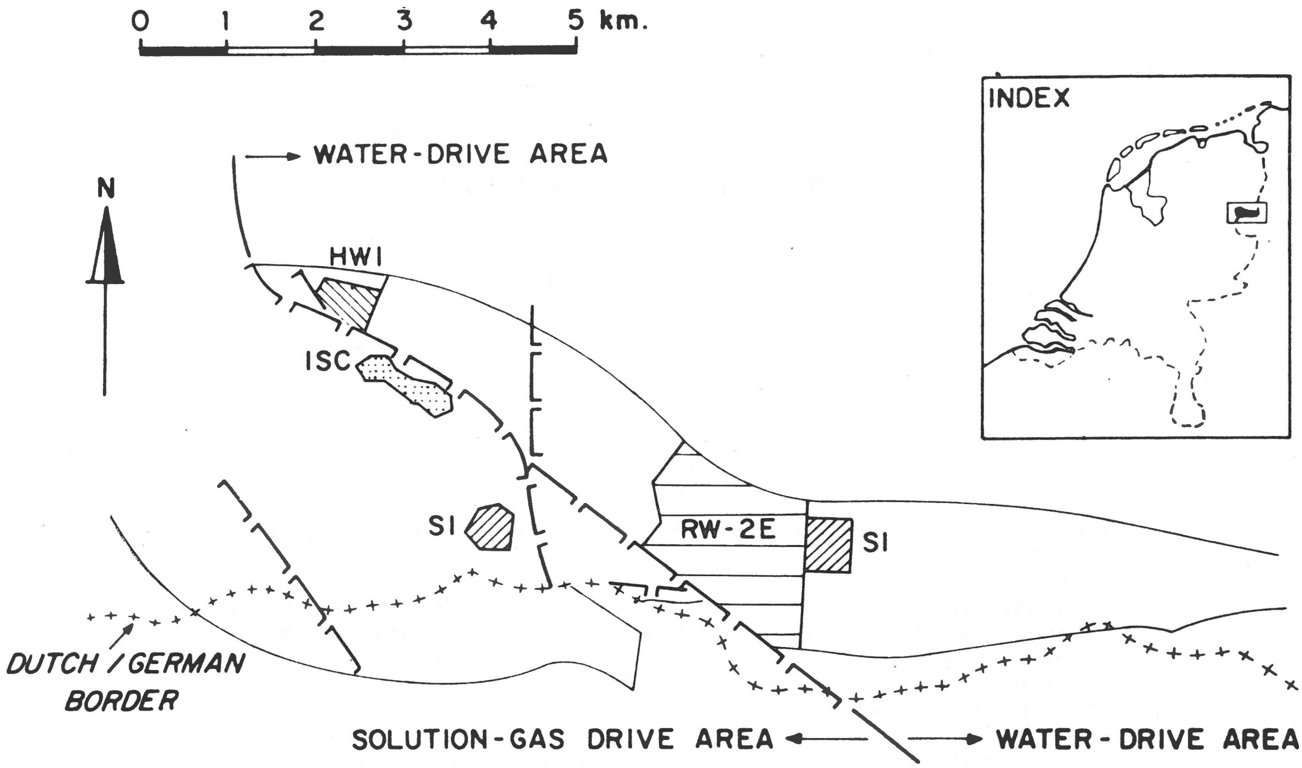

Fig. 1
Schoonebeek oil field with thermal pilot projects and RW-2E. HWI = hot water injection; SI = steam injection; ISC = in situ combustion

RESERVOIR DESCRIPTION

Geology

The Schoonebeek oil field (Fig. 1) is located in the Netherlands, in the southeastern corner of the province of Drenthe. The reservoir consists of the Bentheim sandstone, which is a Lower Cretaceous regressive coastal barrier sequence. The east-west trending anticlinal structure is oilbearing at a depth between 700 and 900 m and consists of three sandbodies:

- The Upper Sand is a shaly, low permeable (1 μm^2)* sand with a maximum thickness of 10 m. This sand unit is present in the eastern part of the field.
- The Middle Sand covers the central and eastern part of the field and is much better developed than the Upper Sand. The maximum sand thickness is 10 m and the permeability increases from less than 1 μm^2 in the centre to 10 μm^2 in the east.
- The Lower Sand, by far the best developed of the three sandbodies, is present throughout the field. The maximum thickness is about 35 m in the centre of the field. Permeabilities vary from 0.1 μm^2 along the bottom to 10 μm^2 (locally even 20 μm^2) near the top of the sand. Towards the west the thickness of the sand decreases. There the most permeable upper part has been eroded away.

One major sealing fault system is present in Schoonebeek separating the downthrown south-western from the upthrown north-eastern part.

Reservoir and Fluid Characteristics

The porosity of the unconsolidated and well sorted reservoir sand is 32%. Original oil saturations as high as 95% have been measured at least in the Lower Sand unit.

The volumetrically calculated STOIIP amounts to 170 x 10^6 m^3. One third of this oil is located in the downtrown block, two thirds in the upthrown block.

Production mechanisms are different for the two blocks: The upthrown north-eastern part of the field is connected to an aquifer of medium size. Water influx from this aquifer, together with re-injection of produced formation water maintained the reservoir pressure fairly well at the original hydrostatic level of about 85 bar. Aquifer pressures near the oil water contact never dropped more than 25 bar below the initial pressure. The downthrown block is a typical depletion

* $1 \mu m^2$ = 1,0133 Darcy

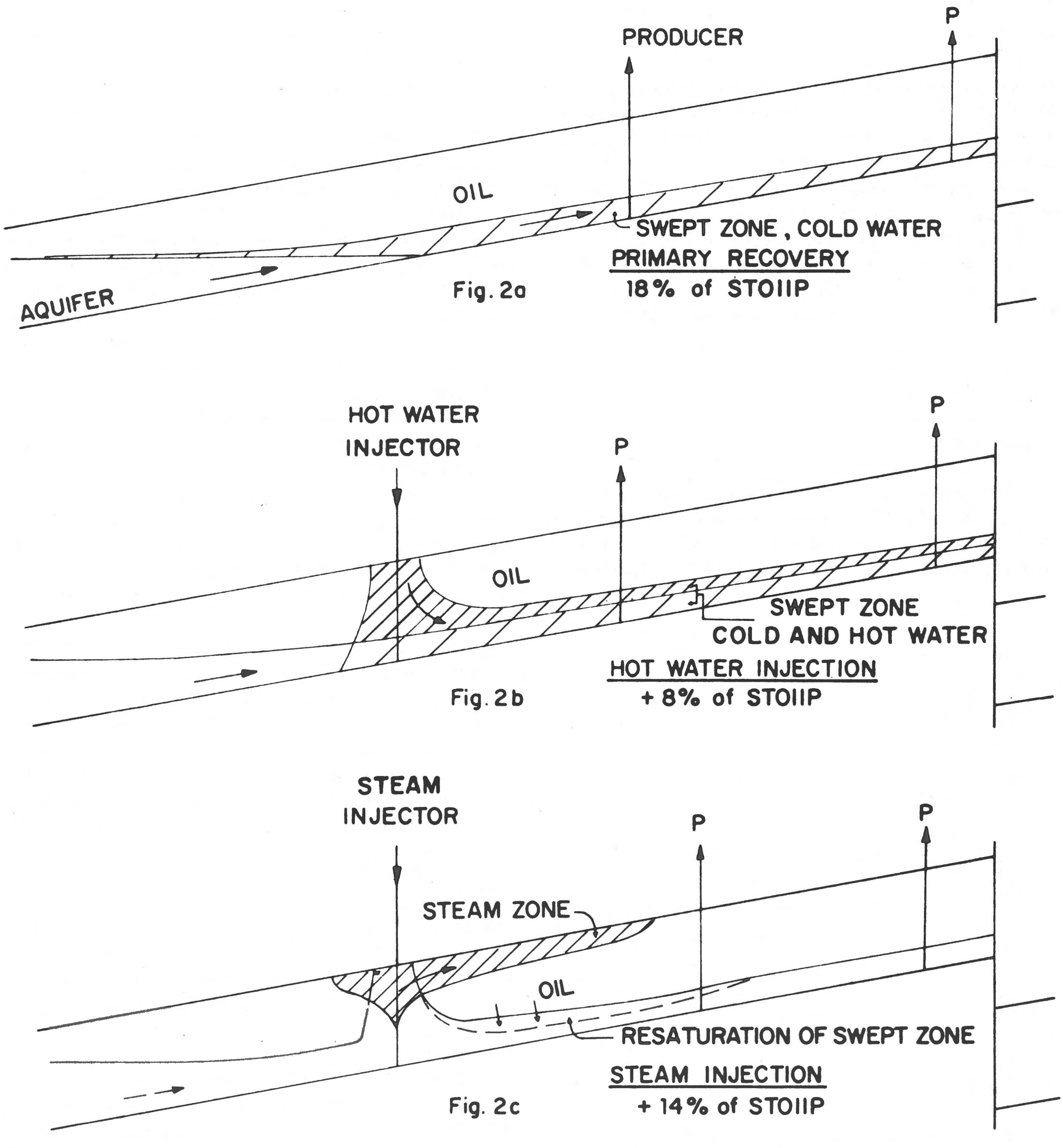

Fig. 2
Recovery mechanisms.

type reservoir with a small contribution of solution gasdrive.

The main problem for the recovery of the paraffinic, 25° API-crude is the high viscosity (160 - 180 mPa s at the prevailing reservoir temperature of 40°C). As a result well productivities are low and the water/oil mobility ratio is unfavourably high (100 - 200). Consequently, water, when present, is produced preferentially. The average water cut during 1980 was as high as 93%.

RECOVERY MECHANISMS AND ULTIMATE RECOVERIES

A few years after the start of production in 1945 breakthrough of water occurred in all wells in the northeastern part of the field, called Main Water Drive Area (MWDA). Simultaneously rapid pressure depletion was observed in the southwestern part, called Solution Gas Drive Area (SGDA). These events indicated the need for secondary and tertiary oil recovery projects already in a very early stage in the production life of the field.

Main Water Drive Area

Primary production (Fig. 2a) — Primary production in the MWDA is governed by pressure maintenance due to aquifer water influx, assisted by re-injection of produced water just downdip of the oil/water contact.

At the very unfavourable water/oil mobility ratio of 100-200 preferential flow of water takes place. Gravity segregation causes the water to flow along the bottom of the reservoir. As a result, after more than 30 years of production, a bottom water layer has developed all over the waterdrive part of the field. The thickness of the water layer is 10 - 15 m with oil saturations ranging from 30 - 80% (original oil saturation exceeds 90%). Consequently, large volumes of water are being produced along with the oil. Watercuts exceed 99% in several wells. Primary ultimate recovery in the MWDA is estimated at 18% of STOIIP.

Hot water Injection (Fig. 2b) — Research on supplementary recovery started in 1950, aiming at thermal processes in view of the viscous nature of the oil. Initial research for the MWDA concentrated on hot water injection in view of the reservoir pressures, which were considered high for steam injection. The outcome of experimental studies on hot water injection for Schoonebeek conditions was favourable and a field test started in 1957 (HWI-I, DIETZ, 1967, SCHÄFER, 1974). This field test confirmed the research results and was followed-up by 7 full scale field projects since 1963. In total these projects cover about 60% of the total field STOIIP, or 81% of the STOIIP of the MWDA.

The principle of the HWI-process is to inject hot water at about 200°C in downdip wells. This water flows along the bottom through the existing cold water layer to the producers. As a result the temperature of the overlying oil will increase, the water/oil mobility ratio decreases and the recovery of oil will improve. The temperature dependancy of the oil viscosity and water/oil viscosity ratio are presented in figure 3.

A second effect of hot water injection is a reduction of the residual oil saturation in the bottom layer, which has been swept already by cold water.

The two effects together are expected to improve the ultimate recovery by 8% of STOIIP. The energy efficiency of the HWI process is 1:3, i.e. for every 3 m^3 of extra oil produced 1 m^3 is used as fuel to heat the injection water. At present the performance of the HWI-projects is declining.

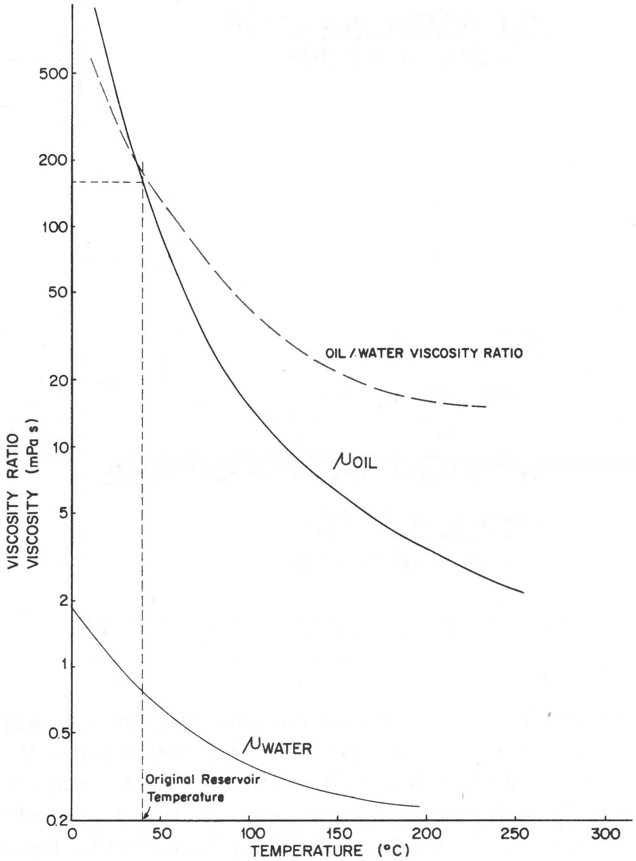

Fig. 3
Oil and water viscosity vs. temperature.

Steam Injection (Fig. 2c) — Steam injection in the MWDA takes place since 1972. Then, encouraged by research results a pilot project was started. Steam, when injected into the oilsand, will flow up into the top of the sand due to gravity segregation. There it will displace oil and create a hot reservoir layer. When steam injection is discontinued and the steam zone collapses, cold oil will be pushed upwards into the hot top zone by water influx via the bottom water layer. The temperature of the cold oil will increase, using the heat stored in the sand grains, and the viscosity will decrease.

In the steam injection process the heat injected is used very efficiently. In contrast with the HWI process, where a large fraction of the injected heat is lost in the cold bottom water, steam takes the heat into the top of the sand where only oil is present. The energy efficiency of the SI-process is 1:8 or, of every 8 m^3 of extra oil produced, 1 m^3 is used as fuel for steam generation.

When in 1976 the feasibility of this process was confirmed by the field-pilot project (HARMSEN, 1979), planning for a large scale follow-up began: the RW-2E steam injection project.

The ultimate recovery increase by steam injection is estimated at 14% of STOIIP.

Solution Gas Drive Area

Primary Production — The primary recovery mechanism in the SGDA is pressure depletion assisted by solution gas drive. Contribution of solution gas drive is minor at the small amount of the gas dissolved in the oil (initial Gas-Oil Ratio (GOR): 12 m^3/m^3). Ultimate recovery is estimated at 6% of STOIIP.

Steam Injection — For the SGDA efforts concentrated on steam injection with the dual purpose of oil viscosity reduction by heat and repressurisation of the depleted reservoir by the expanding steam zone. Favourable results of laboratory experiments led to the start of a steam drive project in 1960, consisting of four 5-spots each with a steam injector in the centre. Reservoir pressure at the start of the project had dropped from the initial 85 bar to below the bubble point of 34 bar. The project was very successful (VAN DIJK, 1968). In 1967 an extension took place from 4 to 10 five-spots. Between 1969 and 1974 steam injection was gradually terminated. It was followed by cold water injection for pressure maintenance and to scavenge the remaining heat stored in the reservoir. In 1975 a follow-up project was started in an adjacent part of the SGDA.

The increase in ultimate recovery by steam injection (incl. cold water follow-up) is estimated at 26% of STOIIP. This figure is much higher than in the MWDA because oil saturations at start steam injection were higher in the SGDA (primary production only) and because condensed steam, flowing along the bottom of the sand, is acting as a hot waterdrive.

STEAM INJECTION IN THE MWDA

The Pilot Project

Stimulated by the success of the field project in the SGDA and in view of the large amount of oil present in the MWDA, research concentrated on steam injection in the waterdrive area. Laboratory experiments (HARMSEN, 1979) were carried out to investigate the effect of the high pressure levels and active edgewater influx prevailing in the MWDA on the steam injection process. Encouraging results led to a proposal for a pilot project, which was carried out from 1972 to 1976.

The pilot project was located in the centre of the field. The reservoir is about 40 m thick of which the lower 15 m had been flushed to residual oil saturation (35%) by aquifer water. Oil saturations in the upper part of the sands were at original conditions (> 90%). The vertical permeability profile consists of a top part of 0.5 μm^2 (Middle Sand, about 5 m thick) and a bottom part with a linear permeability distribution from 10 μm^2 at the top to 1 μm^2 at the bottom (Lower Sand, 30 m thick). The Lower and Middle Sand bodies are in direct contact with each other. The reservoir dip is 6°.

Two down-dip steam injection wells were drilled. As the extension of the steam zone is dominated by gravity forces, the main area of influence will be updip of the injectors. Here the producers, 3 first row wells per injector, are located.

Steam injection started early in 1972 at a rate of 400 tons/day per well. Mechanical problems limited steam injection in one well (SCH-451) and led to early abandonment. Injection into the second well, SCH-450, continued for about four years and was terminated because of steam breakthrough in a producer.

The overall project response was favourable. The main pilot results are:

— The steam injection process is very effective in the MWDA. The extra-oil/steam ratio exceeds 0.7 m^3 of oil per ton of steam injected.

— Steam injection initially results in a re-saturation of the bottom water layer by oil and reduces edge-water influx. Consequently more oil is produced at lower watercuts during this 'cold oil bank' period (i.e. long before temperature effects are observed in the producers). The cold oil bank period is followed by increased production temperatures and the corresponding favourable effect of improved oil mobility on the production rate.

— Steam breakthrough occurs about 4 years after start injection in the well at a distance of 300 m updip of the injector.

— A complicating aspect of steam injection is the in-situ generation of CO_2 and H_2S, which, when produced with the associated gas, severely increase the complexity and cost of surface equipment.

Full details on the pilot project are presented by HARMSEN (1979).

The RW-2E Steam Injection Project

In 1976, after four years of experience with the pilot project, the decision was taken to apply the steam injection process in a large project.

The area adjacent to the pilot project (RW-2E, Fig. 1) has been selected mainly because the reservoir characteristics are similar to those of the pilot project. The area of the project is roughly 2.5 x 10^6 m^2. The northern boundary is formed by the Oil-Water Contact (OWC), the southern boundary by sealing faults. The reservoir dips from the crest towards the north at 6° and to the south (southeastern corner) at about 3°.

Current oil saturations above the 870 m contour (OWC at 890 m) are considered suitable for steam injection. This has been confirmed by a well, drilled in 1976 on the 870 contour, which found original oil saturations in the upper 12 m of the Bentheim sandstone.

In the main part of the project area a bottom water layer of 10 - 15 m thickness is present as a result of previous aquifer water influx, replacing oil produced. Total sand thickness averages 35 m.

Project history — In 1967, after a 20 year period of primary production, six existing producers at the 830 m contour were converted to hot water injection. In view of the unfavourable economic situation the drilling of new wells was not considered feasible. Because of the large distance along strike between the injectors, the areal coverage of the project by heat was poor. Due to offtake, updip of the row of injectors, the hot water flowed towards the crest. At present the majority of the first row of producers has reacted to Hot Water Injection (HWI). For a proper continuation of HWI the number of injectors would have to be doubled and the injectors would have to be moved updip. However, in view of the start of the more prospective steam injection project in RW-2E, HWI has been discontinued in this area in 1980.

Reserves — The oil initially in place in the RW-2E project amounted to 23 x 10^6 m^3, of which 4 x 10^6 m^3 (17%) has been produced as per 1.1.1981. The ultimate recovery after steam injection is estimated at 9 x 10^6 m^3 on the basis of the pilot performance. This is to be compared with 5 x 10^6 m^3 expected from continuation of the existing hot water injection project. Thus, an extra amount of 4 x 10^6 m^3 of oil is expected to be produced by steam injection.

Well configuration — The flow of steam in the Schoonebeek oil field is governed by gravity forces. As a result steam enters the top of the oilsand only. Furthermore it would at the prevailing high permeability of 10 μm^2 and a dip of 6° flow updip, sweeping a very narrow part of the reservoir only. However, in the pilot project and also in the down-dip half of RW-2E, the lateral (along strike) movement of steam relative to the vertical (updip) movement is improved due to the presence of a top layer, the Middle Sand, with a permeability lower than 1 μm^2. Because of the low permeability top layer, viscous forces on the flow of steam increase and become of the same order of magnitude as the gravity forces.

In the crestal part of RW-2E the low permeability top layer is not present. However, the fact that in this area the structure is flat or has a small dip angle reduces gravity-forced updip flow and compensates for the missing low permeable top layer. Thus, both in the crestal and in the down-dip parts of the RW-2E the areal coverage by heat through steam injection is expected to be satisfactory. This has been confirmed by the pilot project for the down-dip area.

The producing wells are positioned updip of the injector to make optimum use of the heat. Each pattern consists of one

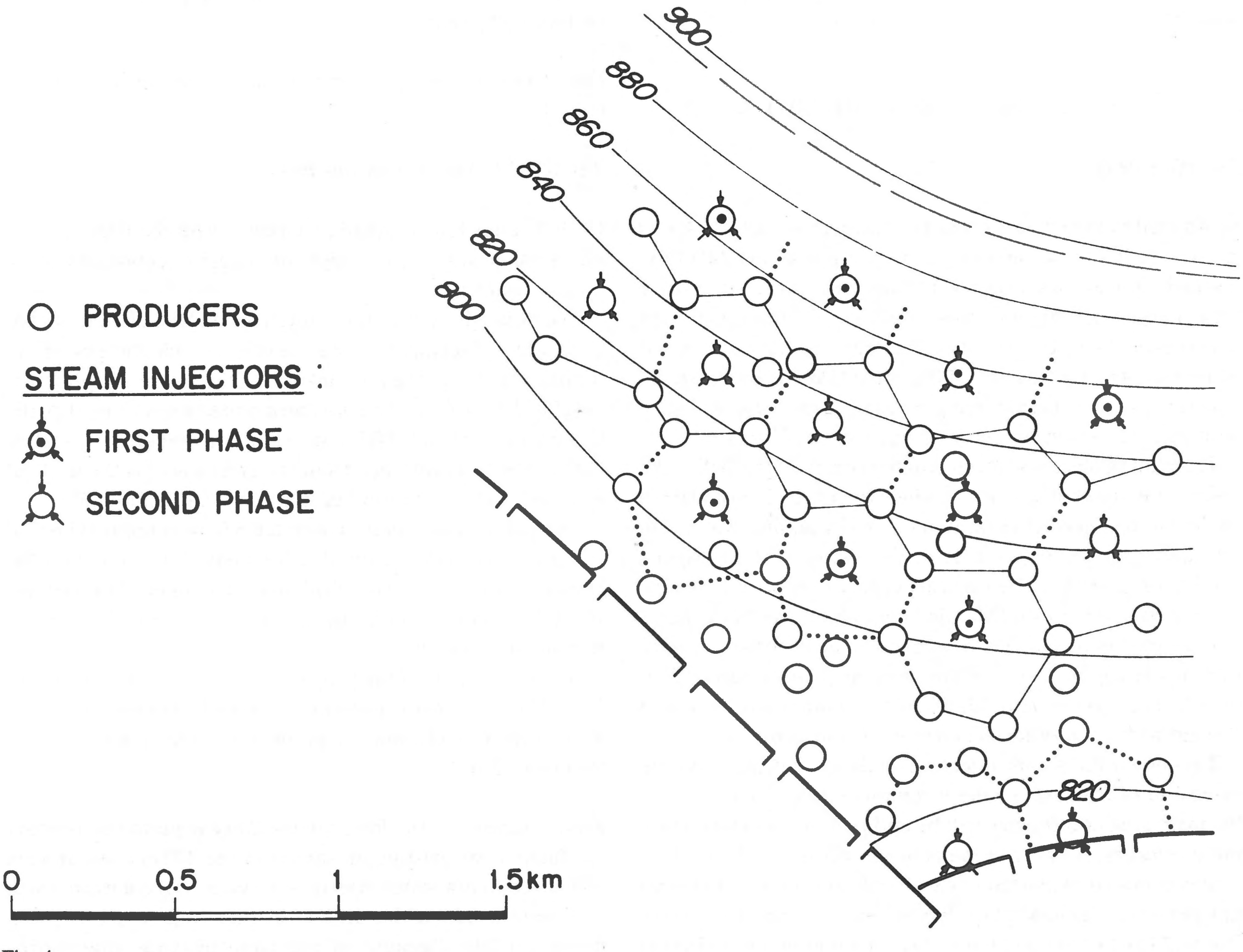

Fig. 4.
RW-2E Steam injection project.

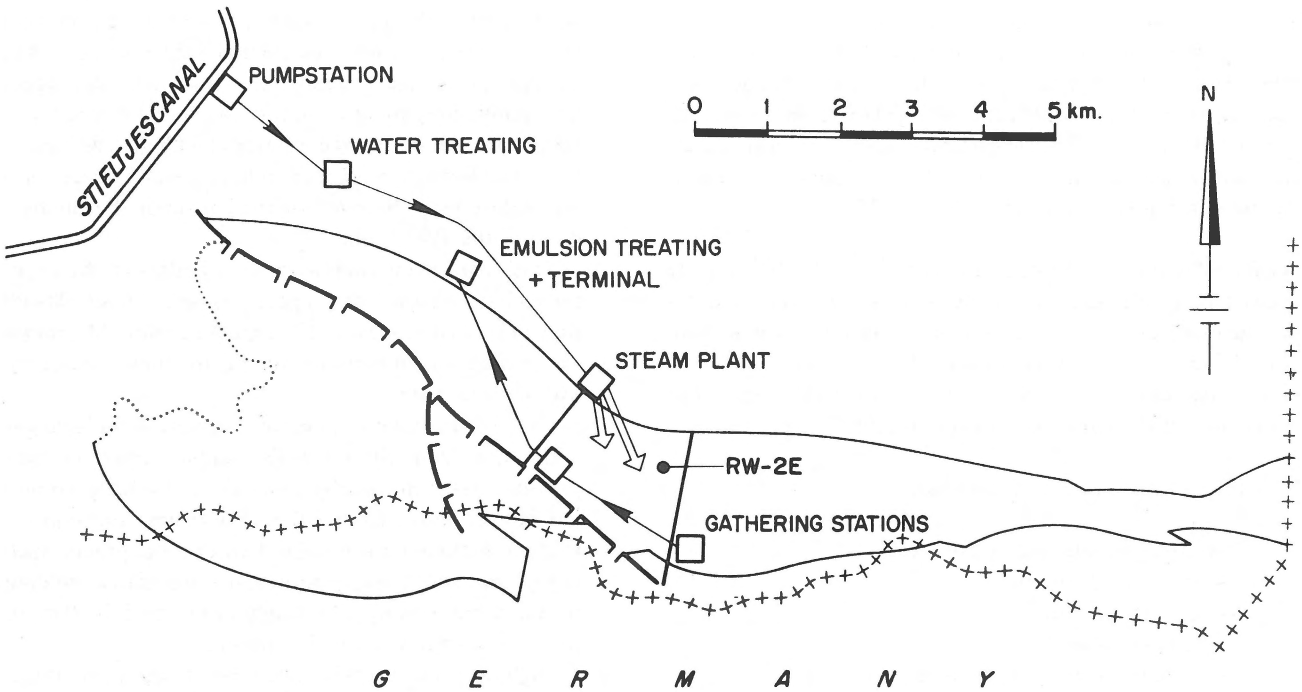

Fig. 5
Schoonebeek oil field: RW-2E facilities.

injector and three producers at a distance of 250 to 300 m. At the planned injection rate of 400 tons/day of dry steam per injector, steam breakthrough in the producers will occur 3 years after start injection.

This pattern has been repeated 14 times in the RW-2E project (Fig. 4). Injection has started in 4 wells along the 870 m contour line and in 3 injectors on the 810 m contour line. The distance between the rows of injection wells in the dip direction is 750 m which eliminates interference between the areas of influence of each injector. After 3 years, injection will be transferred to 5 mid-dip wells on the 830 m contour line and 2 on the southern flank for another 3 years of steam injection.

In view of the severe operating conditions during steam injection (325°C, 120 bar) the majority of the existing old wells had to be abandoned before the start of the project for safety reasons. Only 17 existing wells could be maintained, nine of which after extensive repairs.

In total 54 new wells have been drilled for the project, consisting of 26 producers, 14 steam injectors and 14 water injection wells to dispose of additional water produced with the oil. The total number of wells in the project is 71.

Surface well-locations — The impact from a large project on the environment is considerable. To avoid disturbance as much as possible wells have been grouped on cluster locations and deviated to the subsurface targets. The 71 wells in the project have been drilled from about 30 locations. Maximum deviation was 300 m at a depth of 800 m.

The additional complications of a non-vertical thermal well were recognised, but accepted. The main potential problem is the expansion/contraction of casings and tubing at extreme temperature variations between 40°C and 325°C (SCHÄFER, 1974).

Production Performance Prediction — The expected reaction to steam injection of individual wells is based on observations in the SCH-450 pilot project and has the following characteristics:

— About one year after start injection the resaturation process of the bottom water layer is influencing the producers. Consequently watercut and gross production decrease and the net oil production increases. Simultaneously the arrival of condensed steam is expected causing a drop in the salinity of the produced water. Formation water salinity is about 95 g/l.

— About three years after start injection full breakthrough of fresh water occurs. At the same time the temperature of the produced fluids rises rapidly. Oil production will increase again due to the improved mobility of the oil.

— At the first signs of steam breakthrough the injection of steam is terminated. Production of hot oil continues at increased rates. Watercuts gradually rise again.

The insight in the process has been improved considerably by the application of numerical thermal simulators in which the physics of the flow of fluids and of heat are combined.

Total project production performance has been derived by adding forecasts for the individual wells. These in turn are directly based on observed performances of the pilot wells. The extra oil recovery of 4 x 10^6 m^3 will be obtained at a cumulative extra-oil/steam ratio (EOSR) of about 0.6 m^3/ton. The EOSR of the pilot project exceeds 0.7 m^3/ton, but to account for possible interference effects in the large project, planning is based on the lower figure of 0.6.

Surface Facilities — Surface facilities for RW-2E (Fig. 5) consist of equipment for the generation of steam and for production, gathering, treating and transportation of produced fluids. The required steam volume is about 3100 tons/day. Maximum extra oil rate is estimated at 1500 m^3/day. The main project data are summarized in table I.

Steam generation and distribution

The steam equipment consists of:
— fresh water supply
— a water treating plant
— a steam plant
— a steam distribution system

Fresh water required for steam generation can be obtained from several sources:
a. surface water
b. shallow fresh groundwater reservoirs
c. drinking water
d. produced formation water

Treatment of produced formation water is complicated and very expensive in view of its high salinity (up to 95 g/l). Withdrawal of large volumes from shallow reservoirs could interfere with drinking water systems, which take water from the same source. Volumes were also considered too large to be available from existing drinking water-systems. Surface water is abundantly available from the nearby canal (Stieltjescanal). Eventually, the latter source was selected in spite of the poor quality of the canal-water. Permits for withdrawal of water were obtained. Two pumps have been installed in the canal, each of which can supply about 4000 m^3/day of water to the watertreating plant located at a distance of about one kilometer from the canal.

In the watertreating plant the canal-water is brought up to the extremely high boiler feed water specifications. Organic and inorganic materials are removed by the use of chemicals (flocculation process). Subsequently the water passes through sand filters and ion-exchangers (water-softeners). For operational convenience it was strongly preferred to build water treatment and steam generation equipment close together at the boundary of the project. However, the treating plant had to be built in the industrial area of the Schoonebeek village, 4.5 kilometers away, to minimise the impact on the environment in the RW-2 area.

The steam plant consists of four boilers of the once-through type, each with a capacity range of about 100-800 tons of saturated steam (2% water) per day. Maximum steam pressure and temperature at the boiler outlet are 140 bar and 360°C.

Fuel for the boilers is the low pressure associated gas and liftgas from the oil wells, supplemented by high pressure gas from nearby gasfields. A building around the bottom part of the boilers containing the burners forms a shield to reduce noise. Periferal equipment, such as high pressure booster pumps, is situated in a building for the same reasons. The height of the stack is 20 m, to meet air pollution control requirements.

High pressure steam is transported to the steam injection wells through carbon steel pipelines. These heavily insulated lines are mounted in concrete culverts. The total length of these lines is about 3.5 kilometer. A number of expansion loops in the line takes care of thermal expansion, which reaches values of over 10 m for the total length of 3.5 km.

The steam injection wells are specially designed (SCHÄFER, 1974) to meet the extreme requirements of temperatures up to 325° C and pressures up to 120 bar at wellhead. Expansion of the injection string is in general taken up by a telescopic expansion joint at the bottom of the well.

Oil production

Production wells will be equipped with beam pumps or with gaslift systems to meet the specific requirements at the various phases of reaction to steam. In principle, highly productive wells will be produced by means of gaslift. During the intermediate 'oil bank' period, when highly viscous cold oil is produced at low watercuts, beam pumping could be a better method. Air coolers at the well site reduce fluid temperatures to below 80°C. Oil production from the RW-2E project is collected in two gathering stations (MS-4 and 5), which, in view of the

Table 1: RW-ZE Project Data

Wells:		Steam:		Oil:	
Steam injection	14	Plant capacity	3100 tons/day	Maximum oil rate	1500 m^3/day
Production	43	Injection rate per well	440 tons/day	Extra-oil production	4 x 10^6 m^3
Water disposal	14	Steam quality	> 90%	Extra-oil/steam ratio	0.6 m^3/ton
	—	Injection time per well	3 years		
Total	71	Cumulative steam inj.	6.7 x 10^6 tons		

presence of H_2S and CO_2 in the produced fluids, have been constructed mainly from corrosion resistant stainless steel.

In these gathering stations free water is separated from the oil, treated and injected into the aquifer to the north of the oil/water contact. The remaining emulsion is pumped to the central emulsion treating station where, by means of fresh water injection, the salinity of the crude is reduced. Addition of emulsion breaking chemicals and subsequent separation in large settling tanks reduce the water content until refinery specifications are met.

The oil is transported to the Shell and Exxon refineries by train. During the peak production period when the total field production amounts to about 4000 m^3/d 19 trains per week with 27 wagons each are required.

Environmental aspects — Projects of this size have to be planned carefully to reduce the planological and environmental impact as much as possible. NAM has requested a governmental landscaping institution to investigate the incorporation of the project into the existing situation.

A team of 10 researchers spent a half year in the field to inventarise the environment (watersystems, soil, vegetation, water life, birds etc.). This study resulted in:
— an advise for selection of well and plant locations,
— indications for size of locations and height of equipment,
— a proposal for measures to be taken to minimise the influence of equipment and buildings on the landscape.

An advisory committee has been implemented in which all authorities involved in environmental aspects of the area were represented. NAM's plans were discussed in this committee, to arrive at the best solution both from the environmental and from the technical point of view.

Future plans

The location of the steam plant is at the borderline between RW-2E and a similar project area, RW-2W. After termination of the RW-2E project and depending on the outcome of this project the equipment will be used in RW-2W. A pilot project will be implemented shortly in this area.

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