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Secondary and Tertiary Methods in Soviet Oil Production

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A Research Paper

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A Research Paper

This paper was prepared by [redacted] of the Office of Soviet Analysis, with technical support by [redacted] Comments and queries are welcome and may be addressed to the Chief, Soviet Economy Division, SOVA, [redacted]

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Preface

Soviet oil production is encountering interrelated problems in exploration, drilling, production, field processing, and transportation. Crude oil production operations are concentrated in West Siberia's Tyumen' oblast, which in 1983 was assigned a quota of 362 million tons—almost 60 percent of the 619 million tons planned for the USSR as a whole. At one point, Tyumen' production reached the record rate of 1 million tons per day, but the industry could not maintain it, and the total for 1983 was 359 million tons.

The Soviets may no longer be able to cope with their mounting production problems. In 1983 one-third of the Tyumen' wells were reaching the end of their producing life, and drillers were putting into operation only half as many new wells as would be needed to replace them. Reporting often mentions idle wells, as well as inefficiency in well operation due to lack of maintenance.

The Soviet press has commented that, with Tyumen's inadequate infrastructure, any weak link in production, processing, or transportation weakens the entire operation. This paper discusses one of those links—the industry's trouble in applying secondary and tertiary oil recovery techniques, at a time when declining well flows and rising water-cuts call for their more intensive application.

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Secondary and Tertiary Methods in Soviet Oil Production 25X1

Summary

Information available as of 7 March 1984 was used in this report.

Soviet application of secondary and tertiary methods of oil production is becoming increasingly critical to sustaining oil output at a high level. In primary production, the flow of oil depends on natural reservoir pressure, which drops as oil is removed. Secondary methods (waterflooding, artificial lift) and tertiary methods (flooding with steam or chemicals) can prolong the flow. They demand substantially more investment, manpower, and technology than natural well flow but promise higher oil recovery. 25X1

Secondary production methods are widely used in the USSR. Waterflooding to maintain pressure in a well is initiated soon after the onset of primary production; as larger volumes of water are injected into the oil reservoir, more artificial-lift equipment (pumps and gas lift) is required to stabilize the flow of oil. In 1982, 85 to 90 percent of total Soviet oil output came from fields that had been waterflooded. 25X1

In the new areas being developed, the reservoirs are likely to be smaller and well-flow rates lower than at currently operating fields; the application of secondary production methods will be costly in investment, labor, and maintenance. The 1981-85 plan calls for the number of oil wells on artificial lift to increase by more than 60 percent. To produce the 630 million tons of oil planned for 1985, the Soviets must lift 2.1 billion tons of fluid (oil plus water)—over 40 percent more than in 1980. More than 1.4 billion tons of this would be lifted by pumps. Beyond 1985 the requirements for artificial lift will be even greater. 25X1

Soviet industry probably will not be able to satisfy these massive needs. During the past several years, it has failed to meet its goals for artificial-lift equipment by 15 to 20 percent annually. Moreover, the domestic equipment is poorer in quality than that available in the West. US-made electric submersible pumps have been important in Soviet secondary recovery since the 1970s, when some 1,200 units were imported. The Soviets wish to buy more of these pumps, as well as spare parts, but US licensing policy has had the effect of delaying purchases. 25X1

Equipment shortages contribute to the wells' increasing downtime for mechanical repairs. The magnitude of the maintenance task was illustrated in 1978, when about 250,000 well repairs were performed, 216,000 of which involved artificial-lift equipment. By the late 1980s the oilfields could require more than 500,000 repairs annually, and an even greater share could involve artificial-lift equipment. 25X1

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In one plan for the 1980s, the Soviets calculated that the use of Western equipment in secondary recovery would provide significant savings. Planning (unrealistically) to put some 40,000 oil wells on gas lift and 8,000 wells on new hydraulic pumps during 1981-90, they estimated that by using Western equipment they could do the job with thousands fewer pumps and workover rigs, save 1 million well repairs over the decade, and cut their maintenance force by 25,000 workers. The combined savings were calculated at perhaps 9.0-9.5 billion rubles. 25X1

In recent years the USSR has undertaken a program of *tertiary production methods* to recover more oil from old reservoirs, but the commercial results have been insignificant. In 1981 the Soviets obtained only about 3 million tons of oil from these enhanced oil recovery (EOR) techniques, or about 0.5 percent of total Soviet oil production. They appear to have conducted laboratory and pilot tests on almost all of the EOR processes known in the West, but commercial application is hampered by shortages of equipment, chemicals, and trained personnel. 25X1

Published plans call for EOR to yield oil output of 17 million tons in 1985 and 36 million tons in 1990. These plans appear to be extremely ambitious, in view of the limited domestic capacity to supply the equipment. The Soviet Union currently depends on Western assistance in these complex and costly operations. Even if they give EOR an all-out priority, we doubt that the Soviets could meet these goals. We estimate that oil production from EOR methods could reach some 4 million tons in 1985 and no more than 10 million tons in 1990. 25X1

In the West, the slack market for crude oil has slowed the use of EOR, which not only is capital intensive but also requires long leadtimes before oil is produced. Oil production by EOR methods in the United States has remained nearly constant since 1980, although some indications suggest a significant rise in application of EOR techniques in the coming decade. 25X1

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Background

The techniques for extracting crude oil from petroleum reservoirs are commonly classified as primary, secondary, and tertiary. *Primary* production entails drilling a production well into a crude oil reservoir. There oil, gas, and connate water[1] are trapped in the small pores of the reservoir rock beneath a sealing layer of cap rock and are subject to considerable pressure from the overlying rock and from the hydrostatic force of the underlying ground water. At this pressure, a large share of the gas present in the reservoir is usually dissolved in the oil. Once the impermeable cap rock is pierced by the drill, the compressed connate water, the oil, and the gas in solution expand and move into the wellbore and upward. As this natural reservoir energy declines, so does the rate of oil production from a flowing well.

To sustain pressure in the reservoir and to maintain oil flows at an efficient rate over a longer period, *secondary* production methods are normally initiated soon after the onset of natural production. These methods involve injecting a medium into the oil reservoir (figure 1). The medium is usually treated water or gas, depending on reservoir conditions. Water is most often employed early in the cycle of Soviet field development. Over time this causes an increase in the water-cut (the proportion of water in the mixture of oil and water produced from an oil well). Water is heavier than oil, and water-cuts of 30 percent or more necessitate the extensive use of artificial-lift (pumping and gas lift) equipment to stabilize the flow of oil as increasing volumes of water must be produced together with the oil.

Even after a successful waterflood, substantial quantities of oil remain in the reservoir. If it is considered worthwhile, *tertiary* production methods (thermal and/or chemical treatment) may be employed to increase the oil recovery still further (though at a lower rate of output) by altering the natural forces that hold the oil-in-place in the pores of the reservoir rock. Tertiary methods, usually referred to as enhanced oil recovery (EOR), are technically more complex and considerably more expensive than secondary methods of production.[2] In addition, they themselves consume substantial amounts of energy—to generate heat for steam or to manufacture the necessary petroleum-based solvents and other chemicals. Soviet attempts to apply EOR have been hindered by the need:

- For tailoring the EOR applications precisely to the local conditions at each oilfield—often, indeed, at each well.
- For large amounts of geological data on the reservoir.
- For a high degree of specialized expertise on the part of technicians at the production site.

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Secondary Methods

Waterflooding—Pro and Con

As natural reservoir pressure declines, the flow of oil slows and eventually stops. However, both the oil-production rate and the amount of oil ultimately obtained from a deposit can be increased by appropriately engineered waterflood pressure-maintenance operations. The waterflood process involves pumping water into the oil-bearing reservoir through wells drilled at its flanks and base to force the oil to flow toward the production wells. As a rule, water can raise reservoir pressure quickly because of its higher density, relatively efficient displacement characteristics,

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[1] Connate water is the water present in a petroleum reservoir in the same zone occupied by oil or natural gas. It is a film of water around each grain of sand in granular reservoir rock and is held in place by capillary attraction

[2] The terms *enhanced*, *secondary*, and *tertiary* recovery are variously defined in oil industry and legal circles. Some experts employ *enhanced* recovery as a generic category to include all of the techniques subsumed in *secondary* and *tertiary* recovery; others use the term as a synonym for *tertiary recovery* only. We use *enhanced oil recovery* (EOR) in the latter sense and define the other terms functionally with respect to Soviet conditions.

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and nearly incompressible nature. By prolonging the economic life of a producing oil well, waterflooding can substantially reduce the requirement for drilling and can hold down the cost of producing additional oil.

Waterflooding leaves behind significant amounts of oil, however, for two reasons. First, as the water moves through the reservoir rock, it does not flush all the oil from the pore spaces. Because oil and water do not mix, oil is left behind in the form of droplets and pools held within the smaller pores; these can add up to more than 50 percent of the oil originally in a reservoir. This problem may be alleviated somewhat by the use of additives. Second, as the water "front" advances, it tends to follow the larger channels and sometimes bypasses significant portions of the reservoir because of changing lithology or microgeological conditions. Thus, the waterflood may not sweep all areas as efficiently as planned and may leave much of the oil behind.

Soviet Waterflooding Practices

Since World War II, waterflooding has been employed in most new Soviet oilfields soon after the start of production and has been continued throughout the life of these fields. Water-injected fields accounted for more than half of the oil produced in the USSR as early as 1955 and for 85 to 90 percent in 1982.

By providing higher initial output per well than would be possible under natural drive alone, waterflooding has enabled the Soviets for more than two decades to minimize their initial oilfield investment by holding down the number of wells and pumps required.[3]

Although waterflooding results in high production rates in the early years of an oilfield's life, it can produce complications:

- In some fields, the Soviets carried the practice to extremes, raising pressures beyond the original level enough to rupture the reservoir seals and cap rock. Before 1977 this malpractice was reported at many Volga-Urals fields and at several large West Siberian fields, including Samotlor.

- Ideally, the injected water moves through the oil-bearing formation in a broad front, from the injection well to the producing well; however, if a "finger" of water under pressure breaks through to the producing wells, the rest of the water will follow this easier path. When this "coning" happens, additional wells must be drilled (infill drilling) to locate the bypassed pockets of oil, and more of the expensive pumps or gas-lift equipment must be installed.

The productivity of artificial-lift equipment and the maintenance burden associated with its use are often affected by unwanted consequences of waterflooding. In the Middle Ob' producing region of West Siberia, for example, the underground aquifers have insufficient volume to supply all the region's water injection needs. Therefore, the Soviets added untreated surface water from lakes and rivers to the aquifer water and recycled water. Untreated water in some Soviet waterflood projects has created problems in the reservoirs:

- Oil recovery was reduced by the lowering of bottom-hole temperatures when cold surface water was injected into the highly paraffinic Uzen-Zhetibay reservoirs of the Mangyshlak Peninsula. The same problem occurred at Samotlor and Ust'-Balyk in West Siberia.

- Injection of untreated water has led to excessive salt formations in well bores and downhole pumping equipment at Samotlor and in West Siberian fields.

- Organic material and dissolved gases in untreated surface waters injected into hot oil reservoirs have also caused prolific bacterial growth, reducing rock permeability and porosity.

- Many West Siberian reservoirs consist of sands and montmorillonite clays, which when flooded tend to swell and lower the formation's permeability and porosity.

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[3] In the United States, primary natural drive production was used exclusively in the 1950s because of the fragmented ownership of oilfield minerals. It took years of negotiation to get a majority of the owners to agree to "pooling" and "unitization" of all rights, so that pressure maintenance operations could begin. In the USSR, however, the state owns the minerals, so there are no legal obstacles to early waterflooding.

Figure 1
Oil Well Pressure Maintenance

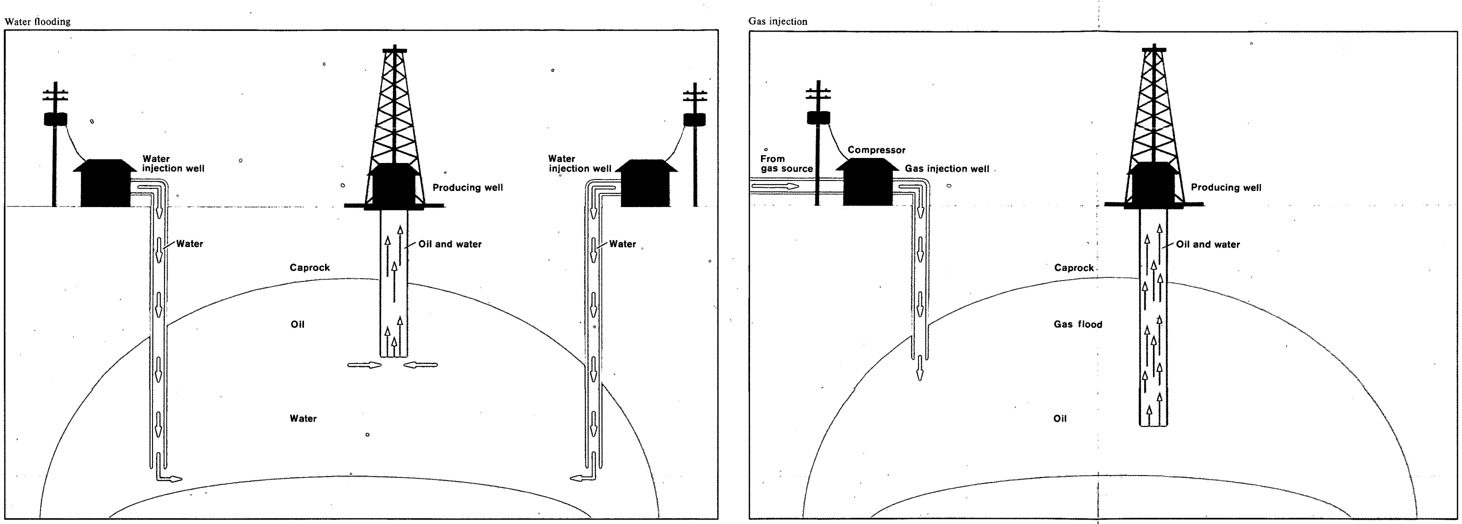

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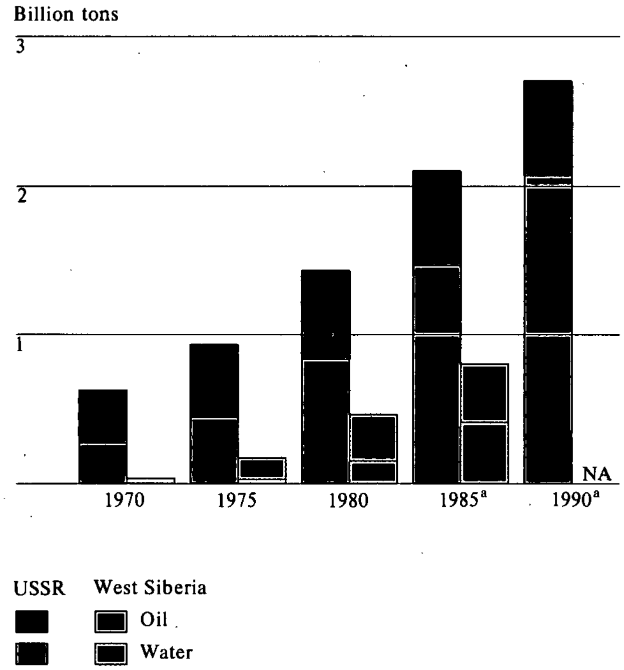
Figure 2
USSR: Oil Well Fluid Production, 1970-90



[a] Estimated.

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Increasing Requirements for Artificial Lift
With increasing numbers of new wells being drilled and old wells "watering out" rapidly because of waterflooding, the Soviet oil industry's requirements for artificial lift of fluid will escalate rapidly. Its ability to meet these requirements will be critical to oil-production prospects during the remainder of the 1980s. The burgeoning proportion of water in oil well field production is illustrated in figure 2. Many fields—including most of the largest and best—have passed their prime. Stabilization of oil output (that is, its maintenance at a planned level) at the large fields will require conversion of a large number of flowing wells to artificial-lift operation (major types of artificial-lift equipment are shown in figure 3). It will also require continued development by infill drilling. The increasing dependence of oil output on development of numerous small new fields is an additional factor bearing on the need for pumping equipment.

Although the Soviets plan to employ large gas-lift systems in some key fields, the sharply rising fluid-lift requirements point to an urgent near-term need for many high-quality pumps of appropriate size to cope with increasing volumes of water and oil. The Soviets have recently placed a large order for submersible pumps with a US firm (see discussion in the section on pumping requirements in 1981-90). 25X1

Pumps can be installed faster and with less capital cost than gas lift, but are more costly to maintain and are down more often for repairs. The impact on the oil industry of large-scale use of pumps and the concommitant maintenance burden is already serious. On the basis of information from Soviet technical journals, we estimate that at any one time about one-third of West Siberia's 20,000 active wells are idle because of equipment failures. Around Samotlor, for example, pump breakdowns are occurring with increasing frequency—the average time between breakdowns has decreased in recent years from about 130 days to 80 days. 25X1

The importance of submersible pumps in Soviet oil production is illustrated by production data of 1980. In that year approximately 20 percent of the active wells in the USSR were exploited by submersible pumps, which accounted for: 25X1
- About 40 percent of the total oil produced.
- More than half of the total fluid produced.
- About 66 percent of the oil produced by artificial-lift methods.

By 1980 the USSR had imported some 1,200 high-volume, US-made submersible pumps with a combined annual capacity of about 150-175 million tons of fluid—enough to recover roughly 30 percent of the oil produced by all submersible pumps in the USSR. 25X1

By 1980 the USSR had also imported Western gas-lift equipment for another 2,500 to 3,000 oil wells; but in 1980 only 10 to 20 percent of this equipment was estimated to be in operation. In 1980 the combined capacity of the Western gas-lift equipment in Soviet oilfields was probably around 15-20 million tons of fluid per year, and it produced about 11 million tons

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of oil. This was nearly half of the total amount produced by all gas-lift equipment, Soviet and Western—but only about 2 percent of total crude oil output in that year.

The role of artificial lift is graphically illustrated by the experience in the Volga-Urals fields. Between 1970 and 1980 the average water-cut in the oilfields of the Bashkir ASSR rose from 63 percent to over 80 percent. This meant that for every ton of oil recovered, the producers had to lift 3 tons of water in 1970 and 4 tons in 1980. Only special high-volume pumping equipment can cope with such increases in the amount of fluid, and the equipment most commonly chosen is the submersible pump.

Impact of Aging

As oil wells age, operating problems intensify. After an initial five- to seven-year period of rising oil production, fields reach a period of "maturity," characterized by almost flat, or stable, production; this lasts from five to 10 years. Thereafter, output gradually declines to a point where production at that field is no longer economical.

It is technically impossible to stabilize oil production for more than about 10 years. During the years when it is feasible, stabilization requires constant infusions of new capital, labor, and other resources for new installations at the mature fields. In addition to these expenses, conversion of flowing wells to artificial-lift operation usually leads to a sharp rise in maintenance requirements due to breakdowns of pumps and gas-lift equipment and to well-casing leaks. The magnitude of such conversion and maintenance requirements facing the Soviet oil industry is evident from the rapid increase in the percentage of fluid to be produced by artificial lift (figure 4).

In Soviet practice, pumps are usually installed at the producing well once the water-cut exceeds 30 percent of a well's total fluid output. The volume of fluid that must be lifted is, of course, substantially increased when waterflooding is used. Nearly all of the largest oilfields in the USSR are more than 12 years old, and in 1982 the nationwide average water-cut was over 62 percent (it was 44 percent in 1970). Trends in water injection, fluid production, and water-cut are shown in table 1. In 1983 the Tyumen' oilfields were expected to produce 362 million tons of oil (with a water-cut of 47 percent). About 140 million tons were to come from Samotlor, where the water-cut is 54 percent and production is in the early stage of decline. By 1985 the nationwide water-cut will approach 70 percent. 25X1

Major Types of Oilfield Pumps

The rod-and-beam (sucker-rod) pumps used extensively in oil well service employ a relatively primitive technology. A cylindrical working barrel attached to the lower end of tubing is suspended from the wellhead inside the casing. A power-actuated walking beam at the surface raises and lowers (by means of a column of "sucker" rods) a plunger set below the fluid level inside the working barrel. Oil trapped by valves in the working barrel is lifted through the tubing with each upward stroke. 25X1 25X1

The electric centrifugal submersible pumps used in high-volume artificial-lift operations involve more sophisticated technology in both materials and fabrication. Their three parts—an electric motor, a protective chamber, and a pump unit—are encased in seamless steel tubing with watertight joints. The entire assembly is suspended in the well on tubing through which the fluid is pumped to the surface. Electric current is transmitted from the surface to the downhole pump motor by an armored cable clamped at intervals to the outside of the discharge tubing. 25X1 25X1 25X1

The one-year and five-year plans for oil industry operations ought ideally to be geared to total fluid recovery—that is, the goal for oil production in a given year contains an implicit assumption of what the water-cut will be in that year, and this assumption ought to be realistic. Estimates of the volume of water that must be coped with in a given year are always subject to a variety of factors. Achieving the target for oil production depends on there being enough pumps of the right size (or, for some fields, gas-lift equipment). But in the USSR the supply of equipment 25X1

Figure 3
Artificial Lift Equipment

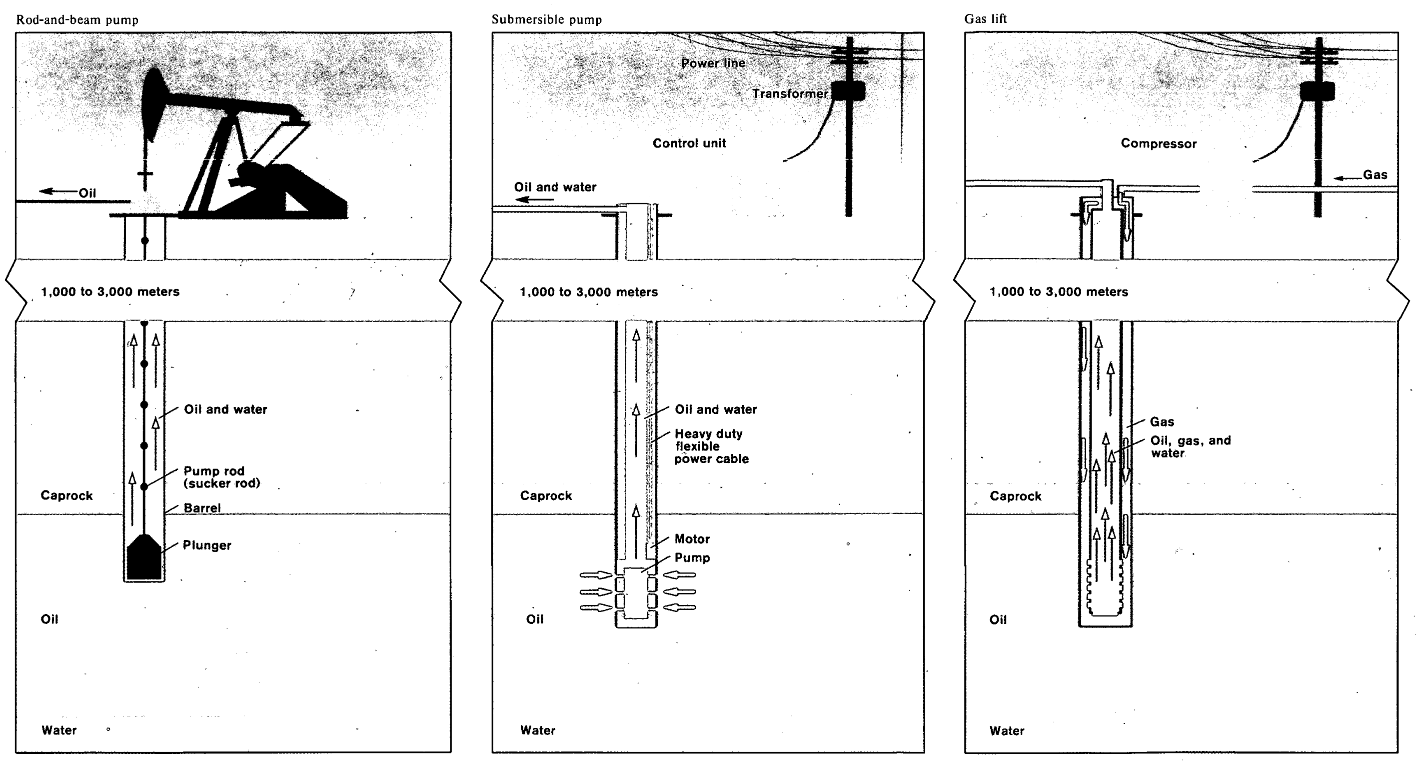

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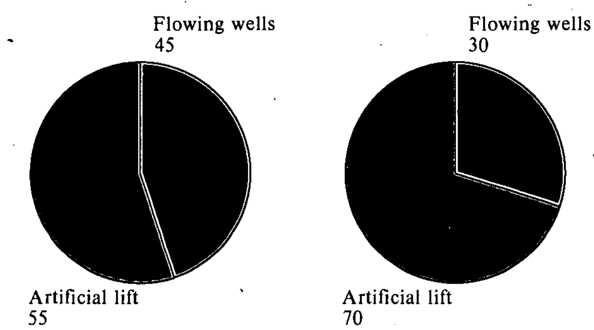
Figure 4
USSR: Increase in Percent of Fluid Being Produced by Artificial Lift

Percent

1975 **1985 Plan**



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is undependable, unpredictable, and almost always less than total requirements. Operational planning is forced to proceed on a day-by-day basis, largely because of the scarcity of artificial-lift equipment. Consequently, oil-production targets frequently are scaled down later in a plan period to levels more realistic than those originally set. [redacted]

Soviet Plans and Performance

During the mid-1970s, Soviet planners clearly recognized that their drilling and pumping problems were escalating. They had discussed the possibility of a rapid rise in pumping requirements in the late 1960s, when requirements for the 1970s were being examined. Up to 1970, however, pumping was not a significant problem because of the relatively large number of high-yield "flowing" wells (those that did not require artificial lift), the wide spacing of wells, and the youth of the big fields being exploited. After 1970, however, the average space between wells was reduced steadily as infill drilling programs gained momentum at Romashkino, Tyumazy, Bavly, Arlan, and other large Volga-Urals fields. At older producing fields, the tighter well spacing means that each new well has a shorter period of water-free oil production and old wells have greater requirements for pumps as their water-cut increases. [redacted] 25X1

During discussions of the plan for 1976-80, oil industry officials noted the sharply declining share of total oil production yielded by flowing wells (nearly all of which were under pressure maintenance by waterflooding) and the rise in the share yielded by artificial lift. We estimate that fluid production from flowing wells had fallen from about 55 percent of the total fluid produced in 1970 to 45 percent in 1975.[4] [redacted] 25X1

Oil Ministry officials clearly realized that pumps would be crucial for efficient exploitation of the oilfields, but even so the plans they issued for 1980 included only about 80 percent of the pumps that the period would require. Thus, during the late 1970s (in the optimum "window"—when the water-cuts were only 30 to 50 percent and pumps would be lifting more oil than water), the Soviets failed to install enough pumping equipment. This led to lower than planned oil production in 1980, to a more rapid "watering out" of wells, and to some reduction in the ultimate potential oil recovery. As a consequence of that shortage of pumps in the 1970s, the task of maintaining the level of national oil production in the 1980s entails a greater drilling effort than it should—and, consequently, a greater resource drain on the economy. [redacted] 25X1

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[redacted] the Soviets were preoccupied with pumping requirements for the 1980s and that efforts to expand pump production were deemed most urgent. Planned production of domestic gas-lift equipment, submersible pumps, and rod-and-beam pump units was to be

[4] This percentage has continued to fall and is likely to reach 30 percent in 1985. More significant was the fact that the nationwide water-cut passed 50 percent in 1977 and 62 percent in 1982. By 1985, both the water-cut and the total fluid produced by artificial lift will be approaching 70 percent. [redacted] 25X1

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Table 1
USSR: Water Injection, Fluid Production, and Water-Cut

Million metric tons

Year	Water Injected	Total Fluid Production [a]	Oil Production	Average Water-Cut as Percent of Total Fluid
USSR overall				
1960	189	NA	148	NA
1965	329	443	243	45
1970	559	625	353	44
1975	985	935	491	47
1980	1,560	1,435	603	58 plan
1985 plan	1,900-2,100 plan	2,100 plan	630 plan	70 estimate
West Siberia only				
1970	45	33	31	5
1975	259	173	148	14
1980	650 plan	465 estimate	313	33 estimate
1985 plan	1,035 plan	800-1,000 estimate	385-395 plan	52-60 estimate

[a] We estimate total fluid production on the basis of water-cut data and plans reported in Soviet publications.

Note: Figures show actual production reported by the USSR except where indicated; *plan* means official Soviet production plans, and *estimate* indicates a CIA estimate.

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boosted sharply—just to stabilize crude oil production.[5] [redacted] at least 40,000 submersible pumps, 20,000 gas-lift units, and 21,000 more rod-and-beam pump units would be required over the 1980s. [redacted]

Production of such pumps trailed far behind the need, and the effect of the shortage is evident in the statistics on oil production by primary (natural flow) and secondary methods. For example, a Soviet oil industry journal reported that in 1979 only 49 percent of oil production came from wells on artificial lift, instead of the 60 percent or so that had been planned. In 1980, artificial lift probably accounted for no more than 53 percent of oil output. This means that oil output by natural flow from old watered-out wells and from newly drilled infill wells, even though it was declining, still accounted for a greater share of total production than had been planned (47 percent instead of the planned 37 percent) because of the lack of pumping equipment for artificial lift. [redacted] 25X1 25X1 25X1

Between April 1978 and February 1981, the planners revised sharply upward their estimates of total fluid (oil plus water) output in 1985, from about 1.7 billion tons to 2.1 billion tons. This called for a hefty increase over 1980's record of 1.4 billion tons (table 2). If the planned 2.1 billion tons were a firm commitment, the plans for pump production by 1985 would also have had to be revised sharply upward. If pump production is rising as the plans require, these trends suggest that total fluid output could hit 2.7 billion tons in 1990. [redacted] 25X1

The water-cut is rising faster than the Soviets had expected. We anticipate that the nationwide average water-cut will increase from 58 percent in 1980 to

[5] It is noteworthy that in 1979 the Soviet planners foresaw that crude oil production would remain flat at 580 million tons from 1980 to 1990. This view reflected their projections that the nationwide average water-cut would reach 63 percent in 1985 and 68 percent by 1990. Total oil production includes small amounts of crude oil production by the Gas Ministry, as well as condensate from natural gas produced. [redacted] 25X1

Table 2
USSR: Total Fluid Production

	1970	1975	1980	1985	1990
Water injected in wells *(million tons)*	559	985	1,560	1,900-2,1000 p	2,700-3,000 e
Number of active wells (yearend)	53,400	63,600	82,500	129,000 p	175,000 e
Flowing wells	8,600	8,600	11,430 p	13,000 p	20,000 e
Artificial-lift wells	44,800	55,000	71,070 p	116,000 p	155,000 e
Equipped with:					
Electric submersible pumps	5,400	9,900	17,200 p	36,500 e	40,000 p
Gas lift	900	2,200	2,300 p	6,500 e	12,000 e
Rod-and-beam pumps	38,500	42,900	51,570	73,000 e	103,000 e
Total fluid recovered *(million tons)*	625	935	1,435	2,100 p	2,500-2,750 e
Percent of fluid produced by artificial lift	45	55	63 e	70 e	75 e
Fluid produced by artificial lift *(million tons)*	280	515	905	1,470 e	1,875-2,065 e
Tons of fluid per day per unit	17	26	35	35 e	33-37 e
Average water-cut (*percent*)	44	47	58 p	70 e	78 e
Oil production (*million tons*)	353	491	603	630 p	550-600 e

Note: p = Soviet five-year plan figures, and e = CIA estimates based on review of Soviet publications. Derivative calculations in the table are approximate because of rounding and inconsistency in available data.

[redacted] 25X1

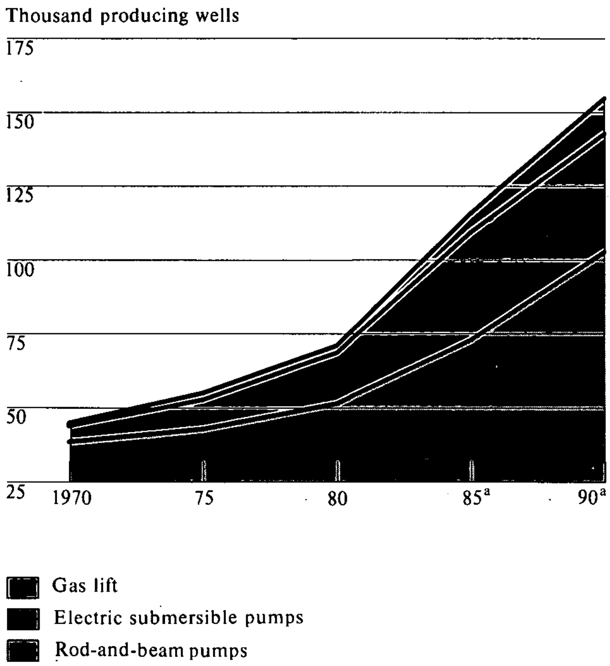
about 70 percent in 1985—well above the 63 percent earlier projected by Soviet planners. Our estimate takes into account the 62-percent nationwide water-cut reported for 1982 and the Soviet projections of a 47-percent water-cut in Tyumen' and a 54-percent water-cut at Samotlor in 1983. [redacted] 25X1

The substantial impact of each 1-percent change in water-cut on total fluid-lift requirements may be illustrated by reference to the Soviet oil industry's experience in 1980, as shown in table 2. If the average water-cut had been 57 percent, as originally planned, the 603 million tons of oil output would have implied a total fluid production of 1,402 million tons. With the 58-percent water-cut in the revised plan, however, the implied production of total fluid for the year amounted to 1,435 million tons. A 1-percent change in water-cut implies the lifting of an additional 33 million tons of fluid. [redacted] 25X1

Pumping Requirements in 1981-90

In late 1982, in an article discussing requirements for the coming decade, the Oil Minister stated that in 1985 and 1990 only 10 percent of the active wells are expected to flow (either with natural reservoir pressure or with pressure maintenance from water or gas injection). This low proportion of flowing wells, combined with the rapidly rising water-cut, implies a tremendous need for more and better pumps of the proper capacity if the Soviets are to avert a decline in total oil production in the mid-1980s. The sharp increases in requirements for artificial-lift equipment estimated for 1985 and 1990 are illustrated in figure 5. [redacted] 25X1

Figure 5
USSR: Utilization of Artificial Lift, by Type



[redacted]
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Since 1978, growth in Soviet oil production has slowed to a crawl. A critical need for large amounts of Western fluid-lift technology and equipment already exists. This need should intensify as more of the giant and supergiant fields age, become depleted, and begin to produce mostly water. If adequate artificial-lift equipment is not made available, Soviet oil output will almost certainly decline sooner and more rapidly. The oil-production history of the Tatar ASSR provides an example of the requirement for artificial lift as water-cuts increase. Tatar oil production reached a maximum of 104 million tons in 1974, when the average water-cut for the region passed 40 percent. By 1980 the water-cut exceeded 60 percent, 98 percent of the region's 14,000 active wells were on artificial lift, and submersible pumps produced 75 percent of the 82 million tons of oil recovered [redacted] 25X1

The Soviets expected water-cut in the Tyumen' fields of West Siberia to reach 47 percent in 1983, and the conversion of roughly 20,000 flowing wells to pumps should be well under way. The timing and rate of decline of the older fields in Tyumen' will not be easy to offset or moderate by infill drilling because new-well productivities there are declining. Thus, artificial lift will be a major factor determining West Siberian oil production. Nearly two-thirds of the wells on artificial lift in West Siberia are already equipped with submersible pumps, according to a Soviet oil industry journal. [redacted] 25X1

To meet their current crude oil production plans for 1985, the Soviets have estimated that they must cope with a 50-percent increase in total production of fluid (oil and water) from oil wells. This is a planned increase from about 1.4 billion tons in 1980 to about 2.1 billion tons in 1985. The task will call for expanding the number of producing wells on artificial lift very rapidly—from over 71,000 to some 116,000 within five years. They expect to achieve much of the planned increment in oil production from wells on artificial lift by equipping about 19,000 more oil wells with submersible pumps and 4,000 more with gas lift.
[redacted] 25X1

In early 1984 the USSR took initial steps to obtain better pumps from the West, concluding a contract 25X1
with a US firm for the sale of 400 high-performance submersible pumps [redacted] Their combined annual capacity will be about 150 million tons of fluid. Delivery and installation of all 400 pumps will probably take 18 months and come too late to have much impact on Soviet oil output in the current five-year plan. These pumps will, however, help stem decline in the 12th plan. Follow-on orders may be included in future Soviet plans. [redacted] 25X1 25X1

We believe that a failure to meet the massive needs for artificial-lift equipment (which could stem in part from constraints on investment and manpower allocations) would be a powerful force for decline in Soviet oil production in the late 1980s. With respect to artificial lift alone, equipment supply in recent years—under far less ambitious programs than will be called for in the second half of the 1980s—has trailed demand by about 15 to 20 percent annually.

Equipment and Maintenance Requirements

The USSR's oil output targets imply the need for a sharp increase in the supply of artificial-lift equipment. As water-cuts climb, so do the requirements for high-volume submersible pumps. Providing them will be a burdensome task for an economic system that in 1976-80 could supply no more than 82 percent of the oil industry's pumping needs. It also implies a substantial additional task of providing the increase in manpower and industrial supplies necessary for performing maintenance tasks. Both will be difficult to achieve.

Soviet industry has made little progress in developing improved high-volume pumps since the need for these items was first recognized in the 1970s. A plant was activated at Al'met'yevsk in 1981, but in late 1982 its serial production of these pumps still failed to meet standards for quality and quantity. The Soviets have made some advances by using their existing equipment more efficiently, but significant technological breakthroughs cannot be expected before 1990 unless they improve their capabilities in metallurgy and precision manufacturing.

Soviet plans for development of new oil reserves deal with deposits much smaller in size than the giant fields now being exploited. Thinner reservoirs and, in some cases, higher viscosity crude oil will certainly lower the well productivities and increase the need for artificial lift. The heavier crude oil, in addition to being more difficult to pump, usually contains more corrosives and contaminants. The increase in average viscosity, coming at a time when the Soviets will have to pump over 3 tons of water for each ton of oil, will greatly complicate their artificial-lift operations.

Both factors—many more active oil wells and much more artificial-lift equipment—could create a shortage in well-maintenance services. In 1978, for example, about 250,000 well-repair jobs (workovers) were performed in the oil industry, ranging in difficulty from cleaning the wellbore through repairing the casing and pumps to reperforating the casing to permit freer flow of oil into the wellbore. Some 216,000 of these repair jobs involved artificial-lift equipment—submersible pumps, gas-lift units, and rod-and-beam pumps. Workovers that require pulling the equipment up to the surface occur three to four times as often in the USSR as in the United States, according to Soviet data. 25X1

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The magnitude of the maintenance task is highlighted by the following Soviet forecast of the approximate number of oil wells that would have to be equipped with artificial lift in 1985 and 1990 under the production assumptions (in number of oil wells) underlying the estimates shown in table 2:

25X1

	1985	1990
Electric submersible pumps	36,500	40,000
Gas-lift units	6,500	12,000
Rod-and-beam pumps	73,000	103,000

Unless marked improvements in Soviet equipment and technology reduce the time between repairs, the requirement for well-repair jobs in the late 1980s could top 500,000 a year. 25X1

Rod-and-Beam Pumps. Soviet rod-and-beam pumps have an average service life of about 100 days between repairs (in the United States the equivalent figure is 350 days). Most mechanical breakdowns are caused by: (1) breakage of pump rods (currently, nearly 16,000 per year because of their low tensile strength), (2) poor sleeve bearings, and (3) sleeve misalignments. Soviet oil wells using this type of pump are deeper on average than those in the United States, a factor contributing to the relatively greater incidence of pump-rod failures. 25X1

25X1

For exploiting high-volume wells, rod-and-beam pumps are less efficient than submersible pumps and gas-lift equipment. 25X1

Submersible Pumps. Increased use of high-quality, high-volume submersible pumps from the United States—to date the only proven supplier—could reduce substantially Soviet manpower and maintenance 25X1 requirements for oilfield operations and probably permit higher oil output. Soviet and US electric submersible pumps are of the same general design; indeed, Soviet design standards are based on published US pump specifications. However, the lack of appropriate metallurgy and machining prevents Soviet pumps from matching US standards for fluid output and service life.

Submersible pumps have been installed at one time or another in most oilfields with high-productivity wells—Samotlor, Romashkino, Fedorovo, Arlan, Nebit Dag, Uzen-Zhetibay, and many other Volga-Urals and West Siberian deposits. Depending on pump size and well conditions, US units can lift 200 to 3,000 tons of fluid per day. Soviet pumps average less than 100 tons of fluid daily, with only a few units lifting more than 165 tons. (Soviet prototype units of 500- to 700-ton-per-day capacity are being tested.)

The Soviets have concluded—after many years of experience in the same oilfields with domestic submersible pumps and with US Reda (TRW) and B-J (Byron-Jackson) units—that the US pumps are about twice as efficient as their own. Breakdowns are fewer and average service life is longer—520 days between major overhauls for US imports and some 240 days for Soviet pumps—because of the more corrosion-resistant metals and the far greater precision used in the manufacture of US units.

Moreover, for pumps immersed in hot, corrosive fluids, the Western-made electric-power cable is much better than Soviet cable. The cost of any cable for this purpose is high (usually exceeding the cost of a pump at depths greater than 1,000 meters), but the extra original cost of Western cable can provide overall economies by reducing the incidence of short circuits and burned-out pump motors

Gas-Lift Units. Gas-lift equipment requires less maintenance than either rod-and-beam or submersible pumps. It includes "downhole retrievable" packers, valves, and mandrels, all of which can be operated from the surface by wireline tools. The related wireline tools (which are lowered into the well by small-diameter steel cable) and special workover rigs permit rapid workovers and minimum downtime for repairs, but these advantages are largely offset by the much greater initial capital costs of gas lift: the gas must be brought to the oilfield and compressed before it can be used. (If this initial cost is included, the US-made submersible pumps are economically as efficient as gas lift over the life of the well, despite their more frequent repairs.) 25X1

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In 1980 there were only about 2,300 gas-lift wells in the USSR, but this number would at least double and might increase tenfold by 1990 if the Soviets could acquire (or copy) and assimilate more of the better US gas-lift equipment and technology. In this event, the Soviet need for high-capacity submersible pumps could be lowered by about 50 percent, with considerable savings in maintenance manpower. This scenario is unlikely, however: gas lift requires longer leadtimes, associated with supplying and installing the necessary compressors, downhole equipment, and gas supply pipelines. 25X1

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Currently, the huge 1,800-well Samotlor gas-lift project is at least two or three years behind schedule. The smaller 600-well Federovo project is nearing completion, but it was also delayed. Both projects were supplied with critical US gas-lift equipment through a US affiliate in Ireland. Other fields slated for gas-lift operations include Barsa Gelmes, Kotur Tepe, Uzen-Zhetibay, and several offshore fields in the Caspian Sea. 25X1

25X1

Hydraulic Pumps. Hydraulic (rodless) pumps are installed downhole, as are electric submersible pumps, but they are operated by a fluid pumped at high pressure from the surface instead of by electric motors. Hydraulic pumps are being tested in the USSR, and oil industry planners have indicated an interest in obtaining as many as 8,000 by 1990. 25X1

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Workover Rigs, Self-Propelled Units, and Other Equipment. During the 1970s the Soviet Union made no substantial progress in well-repair engineering or the manufacture of repair equipment. The number of wells that need to be worked over each year increases steadily, however, and now exceeds Soviet repair capabilities. New workover rigs capable of lifting 100 to 125 tons of pipe and of moving over snow and swampy terrain are needed to service deep wells. Better snubbing devices (small blowout preventers) are required for raising and lowering tubing in high-pressure wells. Development of new and improved equipment is slow. For example, Soviet output of most types of oilfield equipment lagged behind demand by 20 to 30 percent during 1971-79. Pump rods and workover rigs were in especially short supply, and the industry delivered only 58 percent of the dewaxing equipment needed for cleaning deep wells, 46 percent of the centrifugal pumps for water injection, and 73 percent of the wellbore compressors for gas-lift wells.

Soviet oil industry managers recognize the efficiency of Western equipment. Evidence of this is a plan of 1978 that—unrealistically—contemplated putting some 40,000 oil wells on gas lift and 8,000 wells on new hydraulic pumps during 1981-90. the use of Western equipment for these installations over the decade could yield the following savings:

- 32,300 rod-and-beam pumps and 2,200 workover rigs.
- 1 million well repairs.
- 25,000 maintenance workers (they planned to reduce the maintenance force by this amount).
- Combined savings of perhaps 9.0-9.5 billion rubles.

Tertiary Methods

The term *enhanced oil recovery* refers to a spectrum of methods and techniques increasing the ultimate recovery of oil from a reservoir beyond that attainable by primary methods (natural reservoir energy) and secondary methods (artificial maintenance of reservoir energy and artificial lift). EOR extends oil production by altering the forces that hold the oil in place.

The major categories of EOR are thermal and chemical. Thermal methods, aimed at reducing the viscosity of the oil by heating, include:

- Cyclic steam injection (steam soaking).
- Steam drive (steam flooding).
- In situ combustion (fireflooding).

Chemical methods (also called miscible flooding) are aimed a reducing the surface-tension forces between the oil and the driving fluid. They include:

- Hydrocarbon miscible flooding.
- Carbon dioxide miscible flooding.
- Polymer-augmented waterflooding.
- Micellar-polymer flooding.
- Alkaline flooding.

A basic description of EOR methods and their application is provided in the appendix, and three commonly employed methods are illustrated in figure 6. 25X1

25X1 The success of an EOR operation is critically dependent on the composition and consequent behavior of the injected fluids, the accuracy of the reservoir engineering and modeling, and the process technology employed. Each reservoir presents a different set of technical problems, and the complex technology is not directly transferable from one geologic formation to another. Each oilfield requires at least one pilot test, 25X1 lasting up to five years. Once a pilot test is successful, 25X1 many new injection wells have to be drilled to bring the project up to commercial size. After these wells are drilled and injection of heat or chemicals has begun, it may take as long as two years for additional oil to appear at the original producing wells. Consequently, EOR can be up to 10 times as labor intensive as conventional oil production. 25X1

EOR offers high potential benefits. Its use can permit 25X1 the ultimate recovery of as much as 90 percent of the original oil in place (under ideal conditions), whereas waterflooding can be expected to recover 30 to 40 percent. EOR also entails high cost and high risks. Large expenditures for chemicals, equipment, manpower, and capital must be made before it can be known whether application of the process in an oilfield is a success or a very expensive failure. 25X1

Western oil companies' application of major technical advances in EOR has been slowed temporarily by the 25X1 worldwide surplus of crude oil that has depressed price levels, increased the risk element, and made

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EOR activities uneconomic. Company budgets are now emphasizing projects with short payback periods, and EOR is not only capital intensive but also slow to pay off.

Development of the Soviet EOR Program

Soviet petroleum specialists have recognized the need to increase oil recovery from existing oilfields since the early 1960s, but an EOR program was not given high priority until 1976. In February of that year the 25th Congress of the Communist Party of the Soviet Union stressed the importance of providing the economy with an adequate supply of fuels and energy and noted that the task would require a substantial improvement in the technology for exploiting oil deposits.

In September 1976 the deputy chairman of Gosplan, A. Lalayants, announced a high-priority plan designed to increase oil recovery from existing oilfields. It called for:

- Setting timetables for adopting new recovery methods.
- Establishing a special association within the Ministry of the Petroleum Industry for enhanced oil recovery techniques.
- Creating a special fund to help cover costs incurred by oil-production enterprises adopting the new technology.
- Building new plants to produce large quantities of specialized chemicals.
- Producing large amounts of special equipment.
- Training workers.

The Committee on Science and Technology of the Council of Ministers was to be responsible for coordinating the EOR program. The planners hoped that by the early 1980s they would be recovering an additional 10 to 15 percent of the original oil in place.

Soviet petroleum officials have continued to emphasize the importance of EOR endeavors. In September 1977 the Minister of the Petroleum Industry, N. A. Mal'tsev, indicated that a long-term comprehensive program had been formulated for commercial use of new EOR methods—especially those employing surface-active agents (surfactants), polymers, and carbon dioxide—that would facilitate an increase in oil production equivalent to the opening of several large oilfields. 25X1

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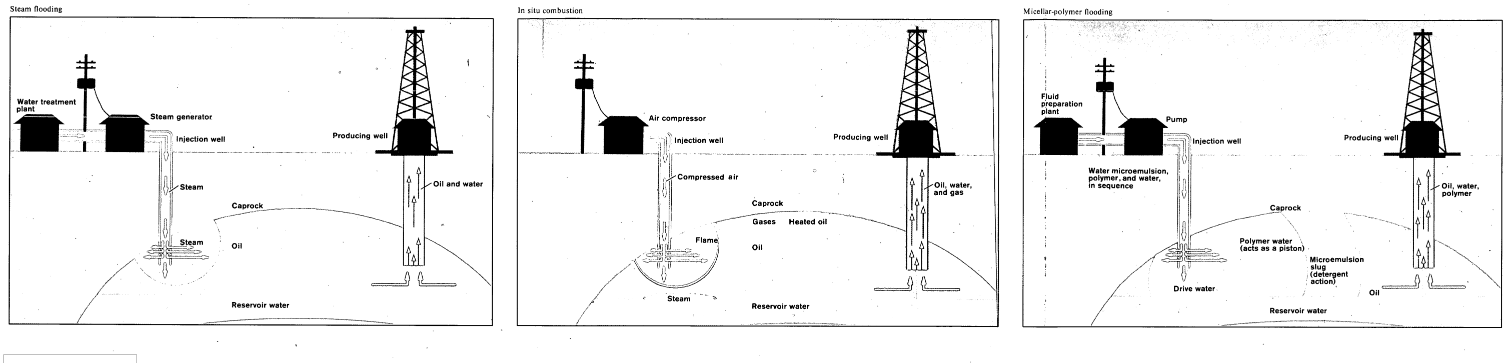
In January 1978 the Ministry of the Petroleum Industry established a scientific-industrial association for thermal oil recovery techniques, called Soyuztermneft. This organization, centered at the Krasnodar Scientific Research and Planning Institute for the Petroleum Industry, is responsible for developing and applying thermal oil extraction processes, designing the machinery and equipment for these processes, and supervising the operations at oilfields where these processes are applied. N. K. Baybakov, Chairman of Gosplan (and a former Minister of the Petroleum Industry), has voiced a strong belief that EOR methods 25X1 could make a significant contribution to improving the USSR's oil situation by increasing the amount of recoverable reserves. 25X1

Despite these optimistic plans and expressions of confidence, the program is still in low gear. Commercial production of oil via EOR techniques is only about 60,000 barrels per day (3 million tons per year), or approximately 0.5 percent of total Soviet oil production. thermal 25X1 methods—injection of steam and hot water and in situ combustion—account for about 70 percent of the increased yield being achieved by use of EOR methods. 25X1

Although EOR technology will probably account for only a low total yield of oil in the USSR during the next 10 years, the Soviets will continue to use it in existing fields into the 1990s and beyond. This is because EOR offers the possibility of producing additional oil from existing fields, where the infrastructure is already in place. Therefore, despite its costliness, 25X1 EOR is claimed to be cheaper than the exploration and development of small West Siberian deposits and potential new fields in East Siberia and offshore in the Arctic seas. And the Soviets can expect oil recovery to increase with improvements in technology and equipment—much of it to be acquired from the West. 25X1

Figure 6
Selected Methods of Enhanced Oil Recovery



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Soviet EOR efforts have been hampered by shortages of equipment and chemicals. In 1979 the Soviet press reported that domestic industry had delivered only 2 percent of the equipment for that year's planned EOR work and that much of what it delivered was of inferior quality. The inadequacies of domestic steam generators were especially noted, as was a shortage of chemicals. Two years later the first deputy minister of the petroleum industry in charge of EOR work, E. M. Khalimov, indicated that Soviet machine-building plants had not fulfilled their plans for the manufacture of equipment and spare parts for thermal operations and that the chemical industry had not produced nearly enough chemical agents. The results of the Soviet EOR program during the past 15 years are summarized in table 3.

Table 3
Oil Produced by Enhanced Oil Recovery Methods

Thousand metric tons

	1966-70	1971-75	1976-80
Total	**1,616**	**8,598**	**Over 10,000**
Thermal methods	1,421	5,922	About 7,000
Chemical methods	195	2,676	About 3,000

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Soviet Application of EOR

Since the mid-1960s, Soviet specialists have conducted laboratory and pilot tests on various thermal and miscible flooding processes, with varying success. They appear to be aware of every EOR process that has been tried in Western fields and laboratories, and they are pioneers in the thermal mining of extremely viscous deposits and the nuclear stimulation of oil deposits. A summary of the major EOR projects conducted or planned is shown in table 4. EOR techniques applied or planned at major oilfields include chemical (polymer) flood at Arlan, miscible flood at Romashkino, thermal methods at Baku, and thermal mining at Yarega.

Arlan. The giant Arlan field is a major producer of heavy, viscous oil. Output has been declining steadily since peak production was reached in the early 1970s. The nature of the reservoirs at Arlan is such that polymer flooding is the only technique that offers promise for increased oil recovery, and the Soviets have been experimenting with it there since 1966. They are still in the experimental stage. Polymer injection on the large scale required at Arlan has never been employed before; its effectiveness is uncertain, and the cost and risk would be very high. In any case, the Soviet chemical industry cannot currently supply polymers in the amounts needed for a full-scale polymer flood at Arlan.

Romashkino. This mature supergiant oilfield has dominated oil production in the Tatar ASSR since the early 1950s; until 1977 it was the largest oilfield in the USSR, in terms of both production and reserves. 25X1
It still ranks second only to the Samotlor field as a major producer, though its output has been declining after reaching a peak of 80 million tons in the early 1970s. 25X1

The Soviets consider the carbon dioxide method of EOR the most suitable for conditions at Romashkino and have announced elaborate plans for its use there. Because of the complex nature of the producing formations (already damaged by the way in which waterflooding was applied earlier in their exploitation), the Soviets probably cannot use CO_2 in more than 10 of the field's 23 producing areas. Even so, however, this project would need 10 times as much 25X1
CO_2 as may be available from a chemical plant built near Tol'yatti by a West German firm. 25X1

Even if sufficient CO_2 were available, the Soviets probably would recover no more than 130-200 million tons of additional oil over a 20-year period. This would be a very modest return at a very high cost. The Soviets appear to be having second thoughts about the project—they recently delayed indefinitely the construction of the pipeline that was to deliver the CO_2 to the Romashkino area. 25X1

Baku Area. Production at Baku, the oldest producing oil region of the USSR, has been declining despite efforts to explore and develop new fields in the 25X1
offshore areas of the Caspian Sea. Since the 1970s,

25X1

Table 4
Major Soviet Enhanced Oil Recovery Projects

Project	Field (Location)	Comments
Chemical flood		
Surfactant	Kura flood plain fields (Azerbaijan SSR) Tatar fields (Tatar ASSR)	Pilot projects in operation.
Polymer	Arlan (Bashkir ASSR)	Major pilot project has increased oil yields.
Alkaline	Arlan (Bashkir ASSR)	Projects are under way in heavy oil deposits.
Acid	Tatar fields (Tatar ASSR)	Pilot tests have been under way for some years.
Miscible flood		
Enriched gas	Bashkir fields (Bashkir ASSR)	Tests have used hexane, methane, and propane.
Carbon dioxide	Romashkino (Tatar ASSR)	Major project is planned, but delayed because of uncertain CO_2 supplies and shortage of hard currency for Western equipment.
Thermal		
Steam drive	Baku (Azerbaijan SSR)	Produced 40,000 tons of additional oil at three deposits during 1976-80.
Cyclic steam flooding	Karazhanbas (Kazakh SSR)	Test project is under way.
In situ combustion	Khorosany and Balakhany (Azerbaijan SSR)	Incremental output of 100,000 tons produced during 1976-80.
Other		
Thermal mining	Yarega (Komi ASSR)	Process has been in commercial use since 1972.
Nuclear stimulation	Grachevka (Bashkir ASSR), Osa (Bashkir ASSR), Salym (West Siberia)	No details are available on increases in oil yields at these fields over time.

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EOR methods have been applied in several oilfields in the region and have provided small additional yields of oil. During the five-year period 1976-80, application of surfactants to oilfields in the Kura flood plain facilitated the output of an additional 140,000 tons of oil, steam injection in old deposits near Khorosany produced an additional 40,000 tons of oil, and in situ combustion at old oilfields near Ramaninskoye and at the Artem Islands produced an additional 100,000 tons.

Shortcomings abound in EOR work in the area, however. Open Soviet sources describe producers as reluctant to experiment as long as there is no prospect of an immediate payoff, equipment shortages persist, and much of the available equipment is of poor quality.

Yarega. The field at Yarega contains a highly viscous crude that is not recoverable by conventional means. To exploit it, the Soviets developed a thermal mining method that has been in commercial use since 1972; they claim that it permits recovery of 50 percent of the original oil in place.

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In the thermal process, two mine shafts are sunk to a level above the pay zone, and horizontal passages are drilled and blasted to form galleries for underground drilling and production operations. From these galleries shallow production wells—either slanted or horizontal—are drilled into the reservoir. Steam is injected, and the resulting flow of oil and water is

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channeled into a sump. Oil is separated from the water and pumped to a central collecting point, where it is heated and pumped to storage tanks on the surface. [redacted]

Dependence on Western Equipment and Technology

As the Soviets seek to increase the application of EOR technology, their reliance on Western equipment and know-how will continue until they can train their own personnel and develop their own manufacturing capabilities. Since 1978 the Soviet Union has entered into negotiations and signed contracts with US, Japanese, and West European firms for the supply of EOR equipment, chemicals, and plants to produce carbon dioxide and surfactants. [redacted]

In the fall of 1977 an Italian firm, Pressindustria, was awarded a $24.5 million contract to build a plant for the annual production of 250,000 tons of surfactants for tertiary oil recovery. It was to have been completed in 1979, but no reports of its operational status are yet available. Two carbon dioxide liquefaction plants (together valued at $38 million) were ordered in 1978 from a West German company, Borsig, to support miscible flooding operations. One of these, with a capacity of 1 million tons per year, was built near Tol'yatti for a miscible flood project at the Romashkino deposits. The second, with a capacity of 400,000 tons per year, was to have been installed at Kemerovo in Siberia; information on its status is not available. [redacted]

The Tol'yatti plant will take the CO_2 produced as a byproduct at nearby ammonia synthesis plants and liquefy it. To use the liquid for EOR projects, the Soviets will have to build a 300-km pipeline to the Romashkino fields, plus pumping stations, CO_2 handling equipment, and CO_2 injection facilities. In about 1980, they began negotiating with US, French, and Japanese firms for assistance in this CO_2 flood project, but in 1981 they downplayed it for various reasons. In April 1981 they claimed that it was delayed indefinitely because of uncertainty about CO_2 supplies from the ammonia plants and disagreement on whether the CO_2 should be piped in gaseous or liquid form. In March 1982 the project was reported to be "on the shelf" because other projects had higher priority. [redacted]

For thermal EOR work, the USSR purchased 15 high-capacity steam generators from a US firm in March 1978 for use in pilot projects in five old oil-producing areas. None was placed in operation before mid-1980, because of the lack of competent Soviet personnel. The Soviets apparently had appropriated $81 million in 1981 for purchase of US steam injection equipment to increase oil production in the Baku region by 5.5 million tons per year and at the Uzen' oilfield in Mangyshlak by 6.25 million tons per year. After the US embargo on sales of oilfield equipment to the USSR was imposed in that year, the Soviets began trying to obtain Western-built steam generators [redacted] but no additional units have been acquired to date. [redacted]

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In early 1982, Soviet officials stated that efforts to obtain Western steam generators and EOR technology had been suspended indefinitely for lack of hard currency. [redacted] however, any future purchases of steam generators would have to include a turnkey package because Soviet petroleum engineers and technicians cannot properly use the equipment already obtained. Without Western equipment and technology, the Soviet EOR program probably will remain insignificant. [redacted]

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Plans and Prospects for the 1980s

The Soviet enhanced oil recovery program is unlikely to achieve significant increases in oil production during the 1980s and probably will never reach the goal (set in 1976) of recovering an additional 10 to 15 percent of the original oil in place. The evidence shows ambitious plans repeatedly being downgraded as the realities of the task strike home. [redacted]

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In 1980 a deputy minister of the petroleum industry revealed that the USSR wanted to obtain an additional 125 million tons per year of oil from EOR operations by 1985, but he admitted that this timetable could not be met because of serious technical and bureaucratic problems. A few months later he acknowledged that this goal was to be attained "eventually." [redacted] oil recovery from EOR methods would reach

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17.1 million tons in 1985 and 35.7 million tons in 1990. Announcements in 1981 revealed that the amount of oil to be obtained from EOR techniques during 1981-85 would be double the more than 10 million tons produced during 1976-80. But in October 1981, First Deputy Minister E. M. Khalimov, the director of EOR efforts in the Oil Ministry, was dismissed for falsifying data and wasting materials—casting further doubt about the realism of the Soviet EOR goals. 25X1

Enhanced recovery operations are often viewed by Soviet specialists as a straightforward development and application of new technologies. But, when new techniques (developed and tested under laboratory or pilot project conditions) are applied in the field to heterogeneous oilfield reservoir structures and permeabilities, unforeseen difficulties can crop up. Efforts to cope with these difficulties are very expensive—requiring careful management and control, large quantities of specialized chemicals and equipment, and considerable time. On the basis of the revised plans and Soviet performance thus far, we judge that oil production from EOR methods will reach only about 4 million tons in 1985 and no more than 10 million tons in 1990. 25X1

Appendix

Enhanced Oil Recovery Techniques

Enhanced oil recovery (EOR) methods are generally categorized as thermal and miscible. Thermal methods are considered to be the most advanced, and large-scale applications are under way in several countries. Field tests of the miscible flooding processes are under way, as well as some commercial applications.

Thermal Methods

Thermal methods are aimed at reducing the viscosity of the oil by heating and, in some cases, changing the characteristics of the oil. These methods are most widely used for highly viscous, low-gravity crude oils occurring at shallow depths.

Cyclic Steam Injection (Steam Soak). High-pressure steam generated at the surface is injected into a producing well for several weeks. Then the well is capped and allowed to "soak." After four to 10 weeks, the well is placed back on production and the accumulated oil and water are allowed to backflood to the surface. As the pressure in the well decreases, some of the water that had condensed under pressure from the injected steam vaporizes and drives heated oil toward the producing well. Oil production is highest when the well is first reopened and declines as steam is consumed. When it has declined to a predetermined level, the entire cycle can be repeated, but the process gradually becomes less efficient. Because of its cyclic nature, the process is often called the huff-and-puff method of oil recovery.

The value of cyclic steam injection lies not so much in improving ultimate recovery as in increasing the oil-production rate. The average rate when the well is reopened is 10 to 30 times the pretreatment rate. The major inefficiency of the process is the loss of heat. It is not useful in strata of oil-bearing sands thinner than 20 feet, because too much heat escapes to the rocks above and below.

Steam Drive (Steamflooding). This process involves the continuous injection of steam or hot water, or a mixture, into a group of outlying wells to push oil toward producing wells. It creates a series of temperature zones in the reservoir: nearest the injection wells is a steam zone, pushing a zone of hot water, which pushes a zone of hot water plus oil. The steam and hot water heat the oil, removing it from the deposit and forcing it to the producing wells.

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Steam drive is likely to be the technique most widely applicable. It recovers an additional 35 to 50 percent of the original reservoir oil in place, depending on oil and reservoir characteristics.[8] The success of a steaming project depends on the rapid, continued growth of a steam zone with resulting high rates of oil displacement. Heat losses must be minimized. The major practical problems are isolating the geologic zone to be steamed, injecting steam into selected wells, pumping the hot wells, handling the excess associated water production, controlling the sand produced (to avoid sand-plugging of the well or of lines at the surface), and coping with the weakening effect of high temperatures on the equipment.

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In Situ Combustion (Fireflood). This is another method of heating the oil in the reservoir to reduce its viscosity. Air is injected into the reservoir, providing oxygen so that some of the trapped oil will burn. Combustion may be spontaneous when the injected airflow is large enough to cause gas saturation, or a heater may be lowered to initiate combustion. Heat from the burning oil thins the remaining oil, partially vaporizing it, and the steam, hot water, and hot gas

25X1

[8] Raising the recovery rate from 33 percent of oil in place (OIP) to 45 percent actually recovers only 12 percent of OIP. This is the practical limit for projects of this nature.

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produced by the fire push this more fluid oil toward the producing wells. Usually air is injected through one set of interlocking wells, and oil is produced from another set.

The three basic types of in situ processes are: conventional, or forward combustion; wet combustion, a combination of forward combustion and waterflood; and reverse combustion. In forward combustion, a fire is started in the formation at the bottom of an injection well. In wet combustion, a similar fire is started, then water is injected alternately with air to transfer heat (in the form of water vapor) from the burned region through and ahead of the combustion front. In reverse combustion, the reservoir oil is ignited at the production wells rather than at the injection wells.

In situ combustion is the most difficult of the tertiary processes to model and predict. Most of the operating problems arise from the high temperatures involved. Thermal stresses on cement, pumping equipment, and tubing increase the frequency of their failure, and the composition of the combustion gases, together with high temperatures, accelerates corrosion problems. Sand production causes clogging and severe wear (abrasion) in pumping equipment.

Miscible Methods
Miscible methods of enhancing oil production are aimed at reducing the surface-tension forces that bind the oil to rock. These include the use of hydrocarbons and carbon dioxide and the chemically augmented methods (polymer, micellar, and alkaline flooding).

Hydrocarbon Miscible Flooding. Light-to-intermediate-weight hydrocarbons—such as dry gas, propane, butane, and liquefied petroleum gas (LPG)—are injected to mix with the reservoir oil, forming a bank of oil and driving it toward producing wells. This technique requires high pressures and is limited to fairly deep fields, where the threat of rupturing the cap rock is small. It is also energy intensive, not only because the miscible slug is a hydrocarbon derivative (that is, it uses oil to produce oil) but also because compression is required.

Carbon Dioxide Miscible Flooding. Injected CO_2 dissolves in crude oil, reduces its viscosity, and increases its permeability and bulk. The swelling increases reservoir pressure, while the reduced viscosity lets the oil flow more readily toward the production wells. A slug of water injected after the slug of CO_2 drives the gas away from the injection well. When CO_2 appears at the producing well, it is recovered, cleaned of impurities, compressed, and reinjected.

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Carbon dioxide flooding appears to be the most promising of the miscible methods. However, its use probably will be limited to fields of light oils that are relatively close to sources of CO_2, because the compression and transport of the gas is expensive and energy intensive. The effectiveness of this EOR method depends greatly on reservoir homogeneity, and at best it can probably recover no more than 10 to 15 percent of the oil remaining after waterflood.

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Polymer-Augmented (Enhanced) Waterflooding. Chemicals with high molecular weights (polymers) can be added to injected water to increase its effective viscosity and its efficiency as a front to drive oil toward producing wells. The increased viscosity reduces the flow of water in the reservoir formation and improves its ability to sweep out the oil. The use of polymers reduces the ratio of water to oil and thus reduces overall operating costs.

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Enhanced waterflood can potentially recover more of the original oil in place than can a plain waterflood. However, the rate of oil recovery with either method is the same during the first few years of operation. Moreover, enhanced waterflooding poses formidable engineering problems, and there are no well-defined measuring techniques to optimize the process

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Micellar-Polymer Flooding (Surfactant Flooding). This category of EOR includes a number of processes based on the injection of detergent solutions. Chemicals are employed to wash the reservoir rock, much as laundry detergent washes away greasy stains. In a

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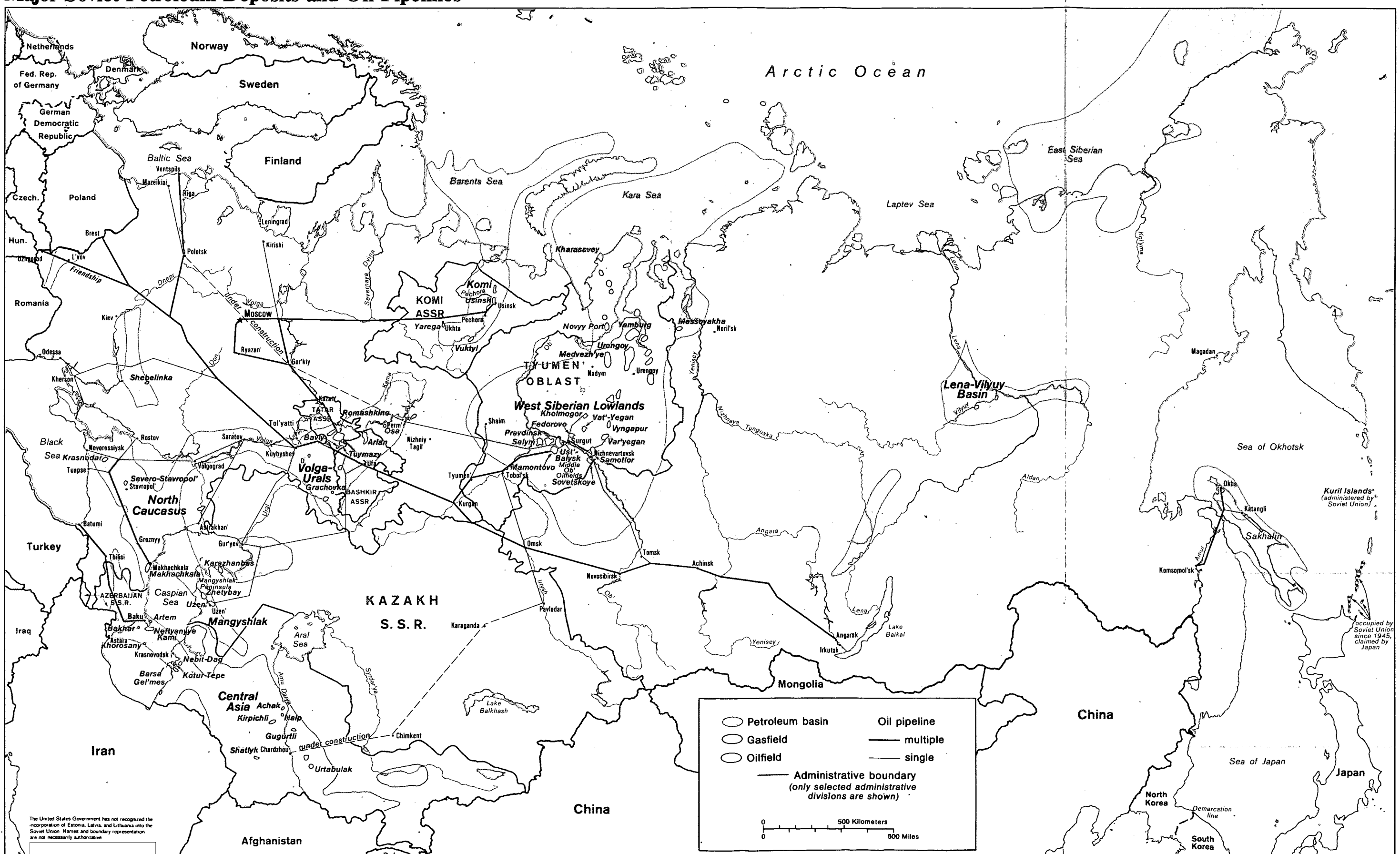
micellar flood, a water slug containing a small amount of surfactant is injected into the reservoir. The solution is called micellar because its concentration causes the surfactant molecules to cling together in clusters called micelles. Because the microemulsion formed is miscible with oil, it dissolves the oil in the formation. At the same time, the emulsion reduces interfacial tension between the oil and water, permitting the oil to flow freely out of the rock pores. 25X1

As is the case with most EOR processes, each surfactant flood must be precisely designed for the specific reservoir. The concentrations and types of chemicals used will depend on the crude oil composition, the reservoir temperature and clay content, and the ion concentrations in the reservoir water. The surfactant injection must be carefully designed for minimum absorption by the porous media in the reservoir and maximum sweep efficiency. 25X1

Alkaline Flooding. Caustic chemicals like sodium hydroxide or sodium silicate reduce the interfacial tension between the injected fluids and the reservoir oil. Added to injection water, they form surfactants within the reservoir by neutralizing the petroleum acids. Alkaline flooding processes are still in a testing stage. Their success depends on the chemical and physical properties of the reservoir materials, the composition of the crude oil, and the effectiveness of surfactants formed when the caustic chemicals react with different acidic compounds in the reservoir. 25X1

Major Soviet Petroleum Deposits and Oil Pipelines



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