SUBSURFACE DISPOSAL OF MINE WATER

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Introduction

The concept of disposing of liquid industrial wastes by deep-well injection is not a new one. During the past ten years, a variety of industries have resorted to subsurface disposal, some of the details of which are given elsewhere[1,2]. The list reveals wide variations in injection rate, pumping pressure, cost, and waste disposition. Enactment of more restrictive clean water legislation in Pennsylvania recently had a great impact on the coal industry. When a feasibility study of deep-well disposal was proposed to the Pennsylvania Department of Mines and Mineral Industries, the Coal Research Board approved it. To evaluate the potential of deep-well disposal, geologic studies were undertaken.

Contiguous with the bituminous producing areas of Western Pennsylvania are a great number of formations containing petroleum and natural gas. This was a mixed blessing: providing important information from numerous drill holes but presenting a serious legal problem of water disposal. With the aid of hundreds of driller's logs, four cross-sections were constructed through southwestern Pennsylvania to determine potential water disposal strata. From the cross-sections and all other available geologic data it appeared that the Homewood sandstone and Connoquenissing sandstone, referred to collectively as the "Salt Sands" by most drillers, were very promising disposal formations because: they underly all coal seams; no commercially producible minerals are present in the formations; the formations contained brine under nearly hydrostatic pressure; driller's logs indicated high porosity and permeability and adequate thickness over a large area; the Salt Sands are bordered by impermeable rocks; and the formations were at a shallow depth of about 1500 ft.

After viewing the feasibility report[2], the Bethlehem Mines Corporation, a subsidiary of the Bethlehem Steel Corporation, agreed to cooperate in developing a test disposal well at its No. 58 Mine. Subsurface contour maps indicated that the Salt Sands were approximately 130 feet thick at the proposed well site and were covered by 1400 feet of overburden. The exact position of the well was chosen between the mine discharge point and a 1,500,000 gallon emergency storage pond on the surface that coincided with the location of a rectangular pillar in the mine, Fig. 1. This selection would permit an underground installation of the pumping unit if the disposal technique proved feasible. It also was a good surface choice allowing adequate sludge pond construction, proximity to acid water discharge and a supply of fresh water for preliminary testing. Bethlehem offered to finance completely the development, completion, testing, equipping and operation of the well. Ownership and supervision of the well were to remain Bethlehem's responsibility, but the information obtained from the well was to be released to the general public through the Coal Research Board. The Department of Mining at Penn State was to act as the agent of the Coal Research Board for this project, and also was to assist Bethlehem in an engineering capacity

Experimental Well Development

Appropriate surface arrangements were made and cable tool drilling began. A 20-inch bit was used to penetrate the 25 feet of unconsolidated material between the surface and bedrock, and a 16-inch conductor pipe was set to prevent spalling of loose material into the hole, Fig. 2. Drilling continued to a depth of 535 feet with a 13 3/8-inch bit, penetrating the Pittsburgh coal seam between the depths of 497 and 502 feet. Drill cuttings were removed by bailing out the hole with a conventional "dart" bailer. Representative samples of these cuttings were dried and visually examined to determine the rock types penetrated. In addition, the drill rig operator kept a "driller's log" of the subsurface units encountered. This latter record was based primarily on relative drilling rates. Ten-inch H40 steel casing was set from a depth of 532 feet to the surface and was cemented in place with circulated cement in accordance with the Oil and Gas Laws of the Commonwealth.

Cable tool drilling continued below the 535-foot depth using a ten-inch bit to a depth of 1302 feet. Cutting samples were also collected during this phase of drilling, and the driller's log similarly was recorded. Examination of these two records indicated that considerable disagreement existed in the indentification of the stratigraphic sequence encountered. Both logs showed, however, that the strata encountered were beds of sandstone, shale, limestone, claystone and coal of varying thickness and order of deposition, and both logs showed the presence of at least 30 feet of shale cap rock above the 1302-foot level. After Caliper and formation density logs were performed on the uncased portion of the well between 532 feet and 1302 feet, a seven-inch J55 steel casing was cemented throughout the entire hole. Diamond core drilling which followed in the interval from 1302 to 1588 feet provided 2 5/16-inch diameter cores, after which the cored zone was enlarged to a diameter of 6 1/2 inches by reaming the well to the 1565-foot depth. Examination of the cores disclosed that much less sandstone existed in this zone than had been expected. Although the lithology of this zone was quite complex, it could be approximated and is presented in Table 1.

Table 1

General Lithology of Cored Interval of Disposal Well

Depth From Surface (Feet)	Rock Description
1302 - 1314	Shale
1314 - 1365	First Salt Sand *
1365 - 1428	Shale and Siltstone
1428 - 1518	Second Salt Sand **
1518 - 1547	Shale with Minor Coal
1547 - 1565	Maxton Sand ***
1565 - 1588	Shale and Claystone

* Interbedded shale, siltstone, claystone and minor sandstone (16 feet).

** Approximately 64 feet of sandstone with minor shale and siltstone.

*** Entire interval sandstone.

The combined thickness of sandstone in the Salt Sands was 80 feet, considerably less than the 130 feet predicted by the isopach map of these units. The Maxton sand furnished an additional 18 feet of sandstone to make the total of 98 feet of uncased sandstone in the well. Strata encountered in the proposed disposal zone were quite different than those recorded for three nearby gas wells.

Density, Guard and Nuclear Logs were run to determine porosity and water saturation of the formations penetrated by the well. A 3-Dimensional Velocity

Log was performed to determine the quality of the bond between the cement and the seven-inch casing. The well was bailed dry following the logging program. Subsequent bailings revealed that water from the uncased interval was entering the well at rates between 8.5 and 10 gallons per hour. This was considered an exceptionally low influx of water for the Salt Sands.

Several aspects of the well were not as favorable as had been expected prior to well development. The main potential problems were the relative thinness of the sandstone units in the proposed disposal zone and the low porosity of these units. A low influx of formation water in the well also was a point of concern. A washout of claystone beds in the uncased part of the well also presented a potential problem in the maintenance of the well under injection. Nevertheless, since the well represented an investment of $40,000 at this stage, a decision was made to proceed with fresh water injection tests on the disposal well.

Water Injection Tests

Treated and filtered municipal water was injected through the seven-inch casing into the entire uncased portion of the well below the 1302-foot depth. No flow occurred until a pumping pressure of 1550 psig was reached, at which point water began to enter the well at the approximate rate of 84 gallons per minute (gpm). This phase of the test was continued a little over 2 hours; the flow rate increasing to 150 gpm with a pumping pressure in the range of 1700-1800 psig. A radioactive tracer log was run simultaneously with the initial injection test to determine which zones in the well were taking fluid. The log chart indicated that most of the injected fluid initially was leaving the well between the depths of 1472 and 1485 feet. As the injection rate was increased, other zones in the well began to take water, specifically the interval from 1496 to 1508 feet and the caved zone between 1340 and 1350 feet.

Fresh water injection was resumed and continued for an additional period of approximately 4 1/2 hours. Flow rates varied from 93 to 218 gpm and the pressure fluctuated from 1475 to 1940 psig. A total of 48,654 gallons of fresh water was injected during this nearly 7-hour period with no apparent change in the hydrological properties of the disposal zone. There was concern for the magnitude of the pumping pressures. At disposal capacity of 150 gpm, the pressures recorded during the injection test varied from 1650 to 1940 psig as opposed to a calculated theoretical well head pumping pressure of approximately 600 psig. As a result of the high injection pressure encountered during this first test, a decision was made to hydraulically fracture the uncased part of the well. Radioactive material was injected during the fracture treatment to indicate the location of the fracture. Approximately 30,000 gallons of fresh water and 34,000 pounds of 20-40 mesh sand were used in the treatment. Radioactive beads were added to the injected sand during the tailing-in period of the operation. Although the highest pressure recorded during the fracture treatment was 2200 psig, flow rates during the treatment were as high as 1500 gpm in the pressure range of 1500-1600 psig. This large flow was largely due to the fact that four large pumping trucks were used.

The well was allowed to back flow following the fracture treatment to release the pressure build-up in the disposal zone. A radioactive tracer log was run on the well to attempt to locate the fracture and to determine its orientation. The log chart indicated a high radioactivity level at a depth of 1508 feet which was interpreted to result from radioactive beads mixed with sand holding an induced fracture open. This fracture was thought to be oriented horizontally, as the radioactive peak was confined to a small vertical interval. According to this interpretation, the well had been fractured at one of the most porous and permeable zones. A second fresh water injection test was run to determine if the fracture had improved the flow characteristics of the well. The test began at an injection rate of 147 gpm at a well head pressure of 600-800 psig. A flow rate was maintained at 150 ± 10 gpm for the duration of the test. The injection pressure gradually rose to 1800 psig during the first 1 1/2 hours and leveled off at this value. The test was stopped one-half hour later after 15,942 gallons of water had been pumped into the well because it was assumed that the high pumping pressure may have been caused by fine particles in the well plugging the pores of the sandstone beds. Thus the well was allowed to back flow in the hope that the flow of water out of the disposal zone would remove any loose particles in contact with these formations. Flow of water from the well continued for about four hours when the well was shut in.

Attempts to bail down the well three days later revealed that frequent bridging, or plugging, of the hole was occurring below the 1350-foot level. This bridging could be knocked free by running the drill bit down the well. Pebble to cobble sized pieces of claystone, similar in color to silt observed in the back flow after the second injection test, were removed from the bailer. This rock was identified as claystone from the spalled zone between the depths of 1340 and 1351 feet. This development implicated two threats to the future of the well. One, fine clay particles from these zones could permanently plug the pores of the sand face. The second possibility was that a continuation of spalling of this clay zone could initiate large scale caving, resulting in the loss of the well. Therefore, a bridge plug was set at a depth of 1370 feet, about 20 feet below the caved area, and cement was introduced into the well from the bridge plug upward to a depth of 1205 feet. After the cement had set for four days, it was drilled out with a 6 1/2-inch bit, hopefully leaving an irregular "doughnut-shaped" plug of cement in each of the caved areas. The bridge plug also was drilled out at this time. A caliper log was run on the uncased portion of the well to determine the effectiveness of the cementing operation. A comparison of this log with the previous caliper log indicated that the cement had blocked off at least part of the lower clay seam, but gave inconclusive evidence regarding the upper seam.

A third injection test was then performed to determine if the partial sealing of the caved area would result in lower pumping pressures. Approximately 46,000 gallons of fresh water were pumped into the disposal zone at injection rates from 105 to 250 gpm. Very little pressure change was recorded for the various flow rates used, the pressure remaining in the range of 1800 to 2000 psi through the five-hour test. Therefore, a decision was made to hydraulically fracture an isolated zone in the well. Examination of the core records showed that the interval from 1480 to 1520 feet had the highest porosity and permeability and should be most receptive to a fracture treatment. Therefore, it was decided to isolate this zone, notch and fracture it, and conduct another injection test. The zone was isolated from the lower part of the well by filling the well with a cement mixture of Calseal and Hydromite below the 1520-foot level. A retrievable packer was set at a depth of 1482 feet on 3 1/2-inch casing that ran from the packer to the surface. The setting of this packer completed the isolation of the zone to be fractured. Notching pipe was run into the zone through the 3 1/2-inch casing and the zone was hydraulically notched at 1491, 1492 and 1493 feet. The notches were cut in an attempt to create a locus for fracture initiation.

The fracture treatment was designed to rupture the sandstone and then place 40,000 pounds of sand, suspended in 30,000 gallons of water, in the fractures as a propping agent. Formation breakdown pressure for this treatment was 3000 psig. Water and sand were pumped into the well at a flow rate of about 850 gpm at 2500 psig until the treatment was about 75 per cent completed. At this time water was observed flowing out of the top of the well from the annulus between the seven-inch casing and the three and one-half-inch tubing. This flow was continuous and increased in volume. The fracture treatment was concluded after 34,000 pounds of sand and 26,000 gallons of water had been pumped into the well as the benefits to be derived from further pumping were dubious. This leak indicated that water was entering the formation, by-passing the packer, re-entering the well bore and flowing to the surface, Fig. 2. An induced vertical fracture, which bridged the packer, would cause this type of flow pattern. The possibility of a wash-out around the packer seemed unlikely, as the rock at this depth appeared competent enough to withstand rapid erosion.

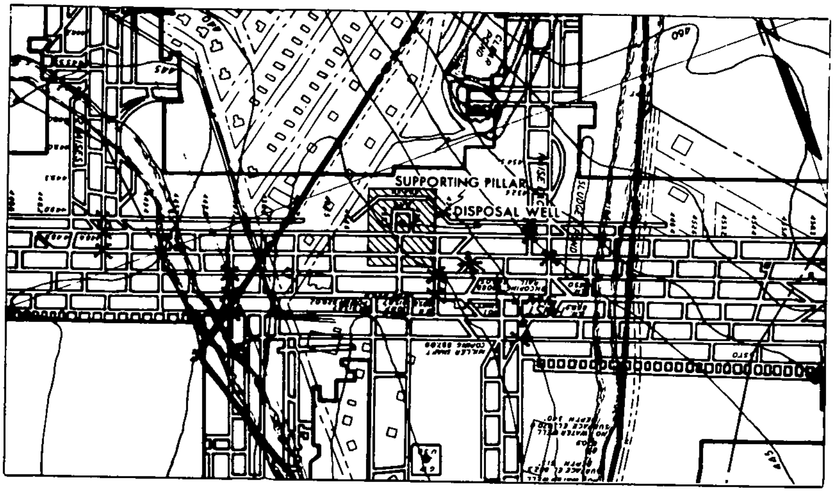
After the pressure had been bled off the well, the packer was unseated and reset at the depth of 1480 feet in an attempt to isolate the entire fracture. Fresh water injection was resumed after the packer had been reset. The flow rate varied from 145 to 160 gpm and the pressure ranged from 1600 to 1700 psig. After 12,700 gallons of water had been injected, water again began to flow out of the annulus at the top of the well. Injection was halted and the packer was raised and reset at the depth of 1472 feet. Injection into the well began again at the rate of 150 gpm. The pumping pressure ranged from 1600 to 1800 psig. After the injection of 18,400 gallons of water, the leak recurred and the injection test was stopped. No further attempt to relocate the packer at a higher elevation was made, as the caliper log indicated the upper well bore was unsuitable for this purpose.

Geologic sections revealed two other potential disposal zones in this area. The first was the Buffalo and Mahoning sandstone (Dunkard Sand) formations approximately 600 feet above the Salt Sands and the Burgoon Sandstone (Big Injun Sand) located at approximately 400 feet below. However, experimental work for steam injection oil recovery was contemplated for the former in this area, and the latter was a gas producer. Therefore, permission could not be obtained for disposing in these formations and all work ceased.

Discussion

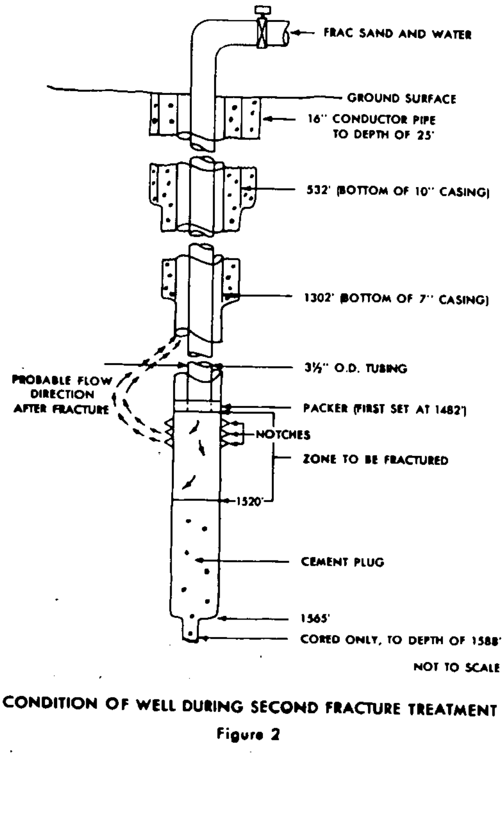
The decision to halt work on the disposal well was brought about by the high pumping pressure of about 2000 psi required to inject 150 gallons of acid mine water per minute into the well and the development of a more economical water treatment process at this mine. The high pumping pressures indicated higher operating and capital costs than originally anticipated. A total of $57,080 had been spent by Bethlehem Mines Corporation on the development and testing of this disposal well, this sum being broken down elsewhere[3]. This phase of the project was well within the expected cost range. Despite thorough planning, careful execution and exhaustive remedial measures, the disposal well did not approach expected performance. The pumping pressure ranged from 1500 to 2000 psig for a flow rate from 84 to 250 gpm. Furthermore, during the flush stage of the first fracture treatment, water was injected into the well at a rate of 1430 gpm with a pressure of 1600 - 1650 psig. Any benefits gained from the first hydraulic fracture treatment were not evident. For a given flow rate, the pumping pressure after the fracture treatment should be less than the pressure prior to treating. Strangely enough, most of the post-fracture pressures were higher than the pre-fracture pressures for comparable flow rates.

The phenomena described above indicate clearly that the particular region of the Salt Sands penetrated by this well was not a good disposal zone. The Homewood and Conoquenessing sandstones, which comprise the Salt Sands, are members of the Pottsville Series of Carboniferous rocks. One of the main reasons



WELL LOCATION

Figure 1



CONDITION OF WELL DURING SECOND FRACTURE TREATMENT

Figure 2