Chapter 5
Oilfield Waste Disposal Control

A.K. Wojtanowicz

1 Introduction

Environmental control of waste generation in the oilfield processes, discussed in Chaps. 2 and 4, may pro-actively reduce the waste volume and toxicity but cannot eliminate the waste altogether. Typically, in offshore operations the waste would be either disposed of on-site by discharging to the sea – as discussed in another section of this book, or reinjected to disposal wells – as discussed in this chapter, below. In the onshore operations, the waste fluids would be temporarily stored in earthen pits (on-site or off-site) before its ultimate disposal to the land or subsurface.

Land disposal of oilfield waste, known also as "pit closure by land treatment" may be performed using landspreading or landfarming. Lanspreading involves spreading the waste over the surface of the ground and tilling it into the soil. After this initial tilling, no further action is needed. In land farming, the soil is commonly processed for several seasons after the initial application of the waste. This additional processing may include adding fertilizers and tilling repeatedly to increase oxygen uptake in the soil.

There are two potential problems with waste disposal to land that may limit future applications. First, land treatment provides little control over migration of the mobile (leachable) fractions that may eventually enter the food chain of animals or humans. Second, spreading of oily wastes results in emissions of volatile organic compounds resulting in violation of some local laws and regulations controlling air pollution.

Injection to subsurface is the most widely used method for the disposal of most petroleum industry wastes. Liquids are usually injected to permeable formations through injection wells. Solids are grinded and slurrified before being injected into the petroleum well's annulus or to a designated slurry injection well. During the

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injection, the disposal strata would be fractured with the slurry. Then, the solids would be filtered out at the fracture face and permanently stored inside the fracture.

2 Oilfield Waste Disposal to Land

On-site oilfield pits are surface impoundments usually excavated directly adjacent to the site of operation so that they can be used for temporary storage of waste generated from field operations prior to its final disposal. In the past, oilfield pits were typically used for both the temporary storage and final disposal. Such practices often resulted in surface damage due to excessive concentrations of buried hydrocarbons or permanent disposal of produced brines in pits. Modern technology of pit closure involves partial removal of waste from the pit, separation of liquids from solids and different treatment of these two phases prior to their final disposal on-site.

The petroleum industry has been using on-site pits in several different applications so the pits can be classified according to type of waste or function as follows [1]:

- *Drilling reserve pits* are used to accumulate, store and, to a large extent, dispose of spent drilling fluids, cuttings and associated drill site wastes generated during drilling and completion operations.
- *Workover pits* typically contain workover fluids and are open only for the duration of workover operations. Workover fluids may contain total dissolved solids (TDS) in excess of 3000 ppm (approximately 4 mmho/cm conductivity) in addition to hydrocarbons or potentially toxic additives or compounds.
- *Produced water* (*collecting*) *pits* are used for storage of produced water prior to disposal to sea at a coastal (tidal) disposal facility or for storage of produced water or other oil and gas wastes prior to disposal at a fluid injection well.
- *Basic sediment pits*, also called burn pits, are used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank.
- *Blowdown/emergency pits* are used for storage of produced water for limited periods of time. They are not used for storage or disposal. Fluids diverted to emergency pits are removed as quickly as practical. After pit closure, contaminated soil should be remediated.
- *Skimming pits* are used for skimming oil off produced water prior to disposal of the water at a tidal disposal facility, disposal well or fluid injection well.
- *Percolation pits* allow liquid contents to drain or seep through the bottom and sides of the pit into surrounding soils. Percolation pits are unlined.
- *Evaporation pits*, defined as surface impoundments that are lined with clay or synthetics, are used in areas where small volumes of wastewaters are generated. Disposal of wastewater by evaporation results in the concentration of salts and residual hydrocarbons in the pit.

2.1 Impact of Oilfield Pit Contaminants

Typical contaminants in oilfield pits are heavy metals, chloride salts and organics. Studies showed that soluble chloride salts and excess exchangeable sodium cause harmful effects on soil and plant growth [2, 3]. High levels of soluble salt lower the amount of water in the soil available to plants and reduce plant uptake of required nutrients [4, 5]. High levels of exchangeable sodium cause loss of soil structure, resulting in low water and air infiltration and excessive compaction of soil.

Heavy metals in soil can become incorporated and accumulated in the food chain or contaminate local sources of drinking water if leaching and migration occur from oilfield pits. Migration of metal ions from a pit site is usually limited by their attenuation in clay minerals and the formation of insoluble complexes in the soil. For drilling reserve pits, for example, researchers found little or no migration of metal ions from drilling muds because of clay attenuation and complexing [6, 7]. Attenuation and migration are affected by the type of soil; it is more extensive in porous soils than in clayey soils [4].

Incorporation of metals from oilfield pits into the food chain takes place through several possible pathways of exposure from soil to an individual. Research indicated that the exposure pathway may be different for each metal [8, 9]. In this research, a maximum soil concentration (MSC) (soil loading factor) was calculated using a so-called soil ingestion rate, i.e. the estimated amount of soil ingested by the individual per day. It was found out that of 14 possible exposure pathways for sewage sludge, four pathways have been identified as most likely to apply to oilfield pits. Maximum loading factors for 12 metals of concern in soils associated with oilfield pits are listed in Table 5.1. The table also shows the most likely exposure pathway for each metal and its maximum concentration detected in oilfield waste.

The presence of organics in soil, typically measured as oil and grease (O&G) concentration, may severely limit revegetation efforts after oilfield pit closure (usually, the revegetation should be accomplished in one season). It has been established that, for most soils, an O&G concentration of 1 % is an acceptable maximum [10, 11]. Surveys of oilfield pit content have indicated that 92.6 % of the pits had organics concentrations below the soil loading level [12]. The remaining 7.4 % of the pits required some dilution mixing of the waste with soil to reduce the O&G concentration to 1 % by weight.

Table 5.1 gives a comparison of soil loading factors recommended by the API guidelines with those from Louisiana State Wide Order 29-B and Canadian Interim Soil Remediation Criteria for Agriculture [13]. The Louisiana 29-B criteria were developed primarily from early work on metals in sewage sludge (before 1980) (these early studies were later superseded by the research supporting the API guidelines). The Canadian Agriculture values for maximum loading have been adopted by the Canadian Council of Ministers for the Environment (CCME) from values that were currently in use in various jurisdictions across Canada. The API guidance criteria have resulted from a quantitative risk assessment, in combination

Table 5.1 Maximum soil loading for oilfield pit metals[a, b]

Metal	Exposure pathway	API guidance	Louisiana 29-B[c]	Canadian agriculture	Maximum concentrations detected[d]
Arsenic	1	41	10	20	29/27.9/140
Barium[c]	1	180,000	20,000	750	56,200
			40,000		24,500
			100,000		10,700
Boron	3	2 mg/l	–	2 mg/l	290/73.6
Cadmium	4	26	10	3	14/1.5/3
Chromium	3	1500	500	750	368/145/54
Copper	3	750	–	150	82/124/210
Lead	1	300	500	375	446/302/970
Mercury	1	17	10	0.8	2.1/1.1/1.4
Molybdenum	2	–	–	5	16/9
Nickel	3	210	–	150	61/40.6/100
Selenium	1	–	10	2	3/0.6/1.4
Zinc	3	1400	500	600	823/413/400

[a]After Ref. [9]
[b]All concentrations in mg/kg unless otherwise specified
[c]Louisiana 29-B barium values for wetlands, uplands and commercial landfarming facilities, respectively [10]
[d]Independent evaluations by American Petroleum Institute and US Environmental Protection Agency in 1987 and 1995

with the best available data, which provided less conservative guidelines than those proposed by CCME.

2.2 *Oilfield Pit Sampling and Evaluation*

The design of pit closure depends upon the degree of pit contamination. Oilfield pit samples must fully represent the concentration of pollutants in the pit waste material. Recent publications provide methodologies for representative sampling using grid networks and composite samples [14]. For example, sampling can be performed at the 50 × 50 ft (15 × 15 m) grid basis with subsamples collected over 2 ft (60 cm) intervals and the lowermost sample taken below the waste bottom. Then, at each of the sampling points (not necessarily a grid point), the subsamples are combined into a single composite for this point. Detailed testing procedures have been developed for environmental analysis of oilfield waste [10]. Particularly important in these procedures are the measurements of true total barium [15] and hot water-soluble boron [16].

Optimization of the sampling plan is an important issue because, theoretically, the cost of taking and analyzing samples at each grid point, multiplied by the number of grid points, is prohibitive. Usually, the number of sampling points can be much smaller than the number of grid points. An analytical method for determining a minimum required number of pit samples was developed using the variability of metals in the oilfield reserve pits [17].

In addition to oilfield pit content, sampling of the background soils is necessary on locations designated for pit closure by on-site land treatment.

The land treatment area should be well drained and out of floodplains and wetlands. Background soil samples should be collected from the A soil horizon or upper 1 ft (30 cm), and composited from a number of nearby locations. Details for designing and executing a soil sampling plan can be found in the relevant literature [14, 18, 19].

2.3 Oilfield Pit Closure: Liquid Phase

Oilfield pits are closed by segregating the liquid phase from the solid phase and disposing of each phase separately. The liquid phase can be broadly defined as an aqueous layer usually containing some suspended solids and situated above settled solids. The solid phase comprises the settled solids and significant amounts of liquids remaining in the pit after pumping the liquid phase out. Usually, the pumping continues until the remaining mixture becomes non-pumpable.

Three options for on-site disposal of the liquid phase are disposal to surface waters, land spreading or subsurface injection (annular injection or injection well). Disposal to surface waters requires dewatering the oilfield pit. The dewatering process can be accomplished *in situ* by chemical flocculation and settling or by using a portable process of chemically enhanced decanting [20, 21]. The principles of dewatering have been described earlier in this chapter. After dewatering, the pit liquid phase is practically solids free and may qualify for surface water disposal if it meets permit requirements for such disposal. An example requirement for disposal of oilfield pit liquids to surface waters is shown in Table 5.2.

If the liquid phase cannot meet requirements for surface water disposal, the only two options for disposal are subsurface injection or land spreading. The decision in this case is solely based upon electrical conductivity (EC) of pit liquids [22]. For an EC greater than 4 mmho/cm (4 Si/cm), liquids should be injected underground.

The design of land spreading of pit liquids requires calculation of the minimum land area for liquid application. Typically, water infiltration rates are used to determine the minimum required land spreading area that would not cause liquid phase run-off. Alternatively, the minimum land area can be calculated using the required values of ESP = 15 % after the pit liquid phase infiltrates the soil to an assumed depth, usually 15 cm [22].

Table 5.2 Effluent limitations (MAC) for reserve pit water discharge for Gulf of Mexico coast states[a]

Analysis[b]	Texas	Louisiana	Mississippi
Ph	6–9	6–9	6–9
O&G (mg/l)	15.0	15.0	–
Chloride (mg/l)	500 (inland) 1000 (coast)	500	500
EC (μmho/cm)	–	–	1000
Total solids (mg/l)	–	–	–
TSS (mg/l)	50.0	50.0	100
TDS (mg/l)	3000	–	–
COD (mg/l)	200	125	250
TOC (mg/l)	–	–	–
Metals (mg/l):			
Arsenic	0.1	–	–
Barium	1.0	–	–
Cadmium	0.05	–	–
Chromium	0.5	0.5	0.5
Copper	0.5	–	–
Iron	–	–	–
Lead	0.5	–	–
Mercury	0.005	–	–
Nickel	1.0	–	–
Selenium	0.05	–	–
Zinc	1.0	5.0	5.0
Phenol (ppm)	–	–	0.1

[a]*MAC* maximum allowable concentration for effluent discharge
[b]*COD* chemical oxygen demand, *TOC* total organic carbon, *TSS* total suspended solids, *TDS* total dissolved solids

2.4 Oilfield Pit Closure: Solid Phase

The oldest and cheapest technique for pit closure is backfilling. This technique involves pushing the pit berm into the pit on top of waste, letting pit fluids spread over the adjacent well and compacting the closure surface area. A potential environmental risk of this technique stems from the fact that waste is buried inside the pit in concentrated form, so it may become subject to leaching from periodic rainfalls. Also, hydrocarbon-contaminated waste may be buried too deep for biodegradation of organics due to insufficient supply of oxygen. In Louisiana, for example, the method of backfilling would meet regulatory approval only if the concentration of contaminants was below certain levels that would make the waste harmless without dilutions [10]. Otherwise, land treatment techniques should be used for oilfield pit closure.

Land treatment is another method for rendering the waste pit material harmless through soil incorporation. The method employs dilution, chemical alteration and biodegradation mechanisms to reduce the concentrations of pollutants to acceptable levels consistent with intended land use [14]. The technique combines the treatment with final disposal of salts, petroleum hydrocarbons and metals. Land treatment of pit solids can be performed using techniques of land spreading, dilution burial (trenching or landfill) or solidification and burial. Laboratory analysis of waste composition must be made for each pit in order to evaluate levels of contamination [23]. Then, these levels are compared with their limiting values [loading factors or limiting constituents (LC)] to decide on the type of pit closure technique needed for successful land treatment design. Table 5.3 shows limiting constituents required for oilfield pit closures related to on-site disposal options in Louisiana [10].

The technique of land spreading involves addition of pit waste solids to the receiving soil, disking these solids to an appropriate depth such that the final waste–soil mixture meets the limiting constituent criteria.

The dilution burial technique involves both the mixing of soil with waste solids to reduce concentrations below LC values followed by burial of the mixture in trenches. The mixture is buried with at least 5 ft of soil cover above it and with at least 5 ft of undisturbed soil between the mixture and the highest level of groundwater table below. Management of waste in dilution burial is based on mechanisms of dilution and chemical alteration with little effect from the biodegradation mechanism due to lack of oxygen.

The technique of solidification and burial involves mixing solidifying agents, such as commercial cement, flash and lime kiln dust, with pit sediments to produce a relatively insoluble concrete matrix. Then, the solidified concrete is buried in the pit using the levee material, or in trenches using a protective liner. Solidification is a viable disposal option but is more expensive than land spreading or dilution burial. However, for highly contaminated waste or a small area of available background soil for mixing, operators may find this option more cost effective than off-site disposal. Also, the operator must demonstrate integrity and strength of the waste material, as shown in Table 5.3 (compressibility, wet–dry cycling, permeability and leachate test).

3 Subsurface Waste Disposal to Wells

Technically, the term ‘waste slurries’ includes suspensions in fluids having various concentrations of solids, from less than 1 % to over 20 % by volume. All waste liquids from oilfield pits, contaminated produced water, drilling muds and slurrified (fluidized) drill cuttings fall into the category of oilfield waste slurries. Also, subsurface injection includes injection through the annular space between two strings of oilfield casing (annular injection) and injection well technology (tubular injection).

Table 5.3 Limits for oilfield pit closure and on-site disposal

Parameter (for waste material)	Units	Land treatment: Uplands (waste- soil mixtures)	Land treatment: Freshwater wetland (waste-soil mixtures)	Burial or trenching (waste-soil mixtures)	Solidification and burial (solidified material)
pH		6–9	6–9	6–9	6–12
EC (electrical conductivity)	mmho/cm	<8 mmho/cm sol. phase[a]	<4 mmho/cm sol. phase[a]	<12 mmho/cm sol. phase[a]	
SAR (sodium adsorption ratio)	Ratio	<14 solution phase[a]	<12 solutionphase[a]	–	–
ESP (Exchangeable sodium percentage)	%	<25 % solidphase[a]	<15 % solid phase[a]	–	–
CEC (cation-exchange capacity)	millieq. v/100 g				
	Soil	–[b]	–[b]	–[b]	–[b]
O&G (oil and grease)		<1 % by weight[a]	<1 % by weight[a]	<3 % by weight[a]	<10 mg/l[c]
Metals:	%dry weight				
As (arsenic)	ppm (or mg/l)	<10 ppm[a]	<10 ppm[a]	<10 ppm[a]	<0.5 mg/l[c]
Ba (barium)					<10 mg/l[c]
Elevated wetlands			<20,000 ppm[d]	<20,000 ppm[d]	<10 mg/l[c]
Uplands		<40,000 ppm[d]		<40,000 ppm[d]	
Cd (cadmium)		<10 ppm[a]	<10 ppm[a]	<10 ppm[a]	<0.1 mg/l[c]
Cr (chromium)		<500 ppm[a]	<500 ppm[a]	<500 ppm[a]	<0.5 mg/l[c]
Pb (lead)		<500 ppm[a]	<500 ppm[a]	<500 ppm[a]	<0.5 mg/l[c]
Hg (mercury)		<10 ppm[a]	<10 ppm[a]	<10 ppm[a]	<0.2 mg/l[c]
Se (selenium)		<10 ppm[a]	<10 ppm[a]	<10 ppm[a]	<0.1 mg/l[c]
Ag (sliver)		<200 ppm[a]	<200 ppm[a]	<200 ppm[a]	<0.5 mg/l[c]
Zn (zinc)		<500 ppm[a]	<500 ppm[a]	<500 ppm[a]	<5.0 mg/l[c]

Soluble anions:					
Cl (chlorides)	ppm (or mg/l)	–	–	–	<500 mg/l[a]
Ratioisotopes:					
Coastal areas after 20 Oct. 90		–[b]	–[b]	–[b]	–[b]
Other requirements					
Moisture content	% by weight	–	–	<50 % by weight	–
Top of buried mixture	ft	–	–	<5 ft below ground level	10 < 5 ft below ground level
				w/5 ft soil on top	w/5 ft soil on top
Bottom of burial cell	ft	–	–	<5 ft above high water	<5 ft above high water
				Table	Table
Qu (unconfined compressive strength)					
	Ib/in^2 (psi)	–	–	–	<20 psi[e]
Permeability	cm/s	–	–	–	$<1 \times 10^{-6}$ cm/s[e]
Wet/dry durability	cycles to failure	–	–	–	>10 cycles to failure

[a]Analyzed using 'standard soil' testing procedures [23]
[b]Mentioned as a parameter to analyze for, but no limitations are given
[c]Analyzed using 'leachate' testing procedures [23]
[d]Analyzed using 'true total' testing procedures [23]
[e]Testing must be done according to ASTM
GL Ground level

Subsurface disposal of solid waste has evolved from downhole injection of solids-free liquids combined with the well stimulation technique of hydraulic fracturing to the new technology of subsurface injection of slurrified solids. Conventional injection of solids-free liquids such as water flooding or deep well disposal of the cleaned produced water is based upon mechanisms of flow and displacement in continuous porous media. On the other hand, injection of the waste slurry implies fracturing of the disposal zones, even for cases when these zones display very high permeabilities of the order of several darcies ($1\ \mathrm{D} = 0.9868 \times 10^{12}\ \mathrm{m}^2$), and low pore pressures. In high permeability zones, fracturing may still occur during the injection as a result of plugging off the disposal zone adjacent to the wellbore. For the purpose of this chapter, we shall call this technology high-permeability slurry injection in contrast to slurry fracture injection, the technology of slurry disposal in artificial fractures that have been created in impermeable rocks. The technology of high-permeability slurry injection has been also termed, *slurry subfracture injection* – as the injection is performed at pressure lower than formation fracturing pressure [24]. Recently, the high-permeability slurry injection technique has also been applied to dispose of municipal sanitation wastes [25]. In this application, the natural geothermal heat present in the deep subsurface would biodegrade the organic waste, converting it into carbon dioxide and methane. The carbon dioxide is preferentially dissolved and sequestered in the native formation fluids, while methane in relatively pure form collects for potential recovery as a source of renewable energy.

In the early 1980s, high-permeability annular injection of small volumes of drill cuttings became an environmentally sound alternative for on-site disposal of drilling waste, particularly in the Gulf Coast area [26–29]. Later, slurry fracture injection technology was developed for disposal of drill cuttings from oil-based muds in Alaska and the North Sea [30–32], and for NORM (Naturally Occurring Radioactive Materials) disposal [33]. In the mid-1990s, the first large commercial facility with dedicated injection wells began operation [34, 35]. This was followed by large-scale injection operations in Alaska [36] and Gulf of Mexico [37–39].

Since the early 2000s, annular injection has become available for routine use offshore, with several different service companies providing a range of operations and engineering support [40]. An example of continuing evolution of the technology was documented in a study on commingled drill cuttings and produced water injection [41]. Also, slurry fracture injection has been used for disposal of oilfield wastes other than drilling mud and cuttings such as produced sand, sediment from tank bottoms, unset cement and unused fracture sand [42–44]. However, the most common sources of waste injected are from ongoing drilling operations and from mud and cuttings stockpiled in tanks or stored in earthen pits.

Volumes of cuttings from drilling operations could be very large. In the US Gulf of Mexico, for example, over 1000 wells were drilled in 1998. Each well would generate at least 1500 barrels of cuttings or about 5000 barrels of slurry. On the North Slope of Alaska, cuttings from wells drilled in the 1970s and 1980s had been stored in reserve pits at numerous drill sites. By 1993, the volume had grown to about 5 million cubic yards of mud and cuttings, or about 15 billion pounds of solid cuttings.

There is a tremendous range in the capacity of surface processing systems used for injection. In contrast to offshore cuttings injection units having batch mixing capacity of 200 bbl, a large-scale onshore waste disposal facility in South Texas has the capacity to process 20,000 bbl of cuttings slurry and there are two other facilities within a few miles of this one. Each of these facilities has several injection wells available at any time [34, 35]. Between 1994 and 2001, these facilities injected over 7 million barrels of NORM slurry and over 10 million barrels of NOW (Non-Hazardous Oilfield Waste) slurry.

3.1 Description of Slurry Injection Process of Muds and Cuttings

Virtually, all slurry injection operations are batch processed, where drill cuttings are mixed with waste mud and water in the mixing/processing tanks, sent to a holding tank and then injected downhole. In offshore applications, the mixing is done in skid-mounted units on the platforms. Drill solids are mixed with seawater. The mixture is circulated through centrifugal pumps that grind the solids to a desired size. The slurry is then sent to a holding tank and injected downhole with a triplex pump. The offshore units are designed to keep up with the rig drilling rate and the volume of batch is typically about 200 barrels.

The two typical wellbore configurations for injection are annular injection and tubing and packer injection. Shown in Fig. 5.1 is a typical wellbore schematic of a tubing and packer completion, where the slurry is injected down the tubing and into the formation through perforations. This type of completion has been more typical for longer or permanent injection operations onshore. As tubing has lower frictional losses than the annulus, injection rates are much higher than those for the annular injection (1–6 bbl/min) and can be up to 5–25 bbl/min. In some locations, existing producing wells could be recompleted as injection wells while in other places new injection wells must be drilled for the purpose. Reportedly, dedicated injection wells are frequently in service for several years and total slurry volumes can be greater than 2 million barrels per well [40].

In the past, the annular disposal of waste fluids from drilling mud reserve pits has been practiced only in onshore drilling operations [26]. Later, annular injection became more common offshore with the cuttings injected either into the upper annulus of the same well or into an annulus of a nearby well. As shown in Fig. 5.2, annular injection is the injection of fluids between the annulus created by the space between the surface and intermediate casings or between the surface and production casings. The surface casing is cemented all the way to the surface to protect fresh waters, and its setting depth may range from approximately 300 to 2000 ft. The intermediate casing is cemented below the depth at which the surface casing is set

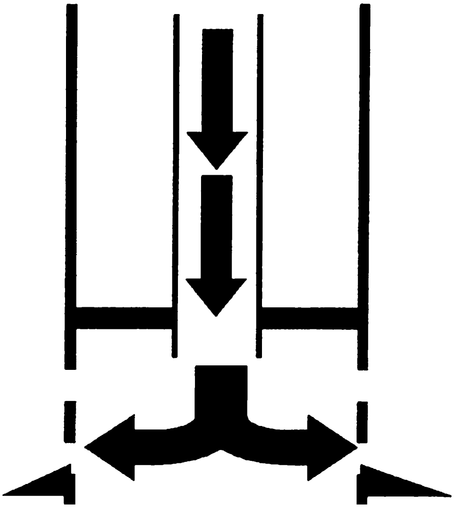

Fig. 5.1 Tubing and packer injection wellbore schematic [40]

so there is an open hole annulus below the surface casing shoe. The annular space that has an open hole exposure enables the fluids to go down between the surface casing and the intermediate casing and out into the permeable formation. In wells with no intermediate casing strings, the fluid will go down below the surface casing and above the top of the cement on the production casing and out into the zones of least resistance. Usually, these zones of least resistance are low- pressure non-productive sands.

In the mid-1980s, the typical application of annular injection followed a fairly routine procedure [26]. The pit fluid injection contractor would connect the injection pump discharge line to the valve at the wellhead that led to the annulus. Then, the waste drilling mud from the pit was pumped into the annulus to fill it up. (Some void space in the annulus, which was caused by settling of the mud, sometimes occurred.) Next, the pumping pressure was increased to 'break the formation down'. This breakdown pressure was usually higher than the average pumping pressure by 200–500 psi (~1360–3400 kPa). The process of formation breakdown is believed to have been in fact a fracturing treatment because gelled and thick mud was pushed out of the annulus and into the permeable rock.

After pumping for a few minutes, the pumping pressures were returned to normal. In most cases, the pumping was begun with water and was gradually changed from water to pit slurry, often with a corresponding increase in pressure. Most contractors injected the entire contents of the pit; therefore, at the end of injection, the pit was usually almost empty. Crowding (pushing) the pit levee with dozers ensured that most of the slurry was removed from the pit.

By the time the pumping was finished, the dozers would have covered and closed the pit, grading the surface back to its original elevation. During the reserve pit injection, the wellhead pressure typically ranged from 500 to 1000 psi in most areas. For shallow wells, such as those in the Canadian counties of McClain or

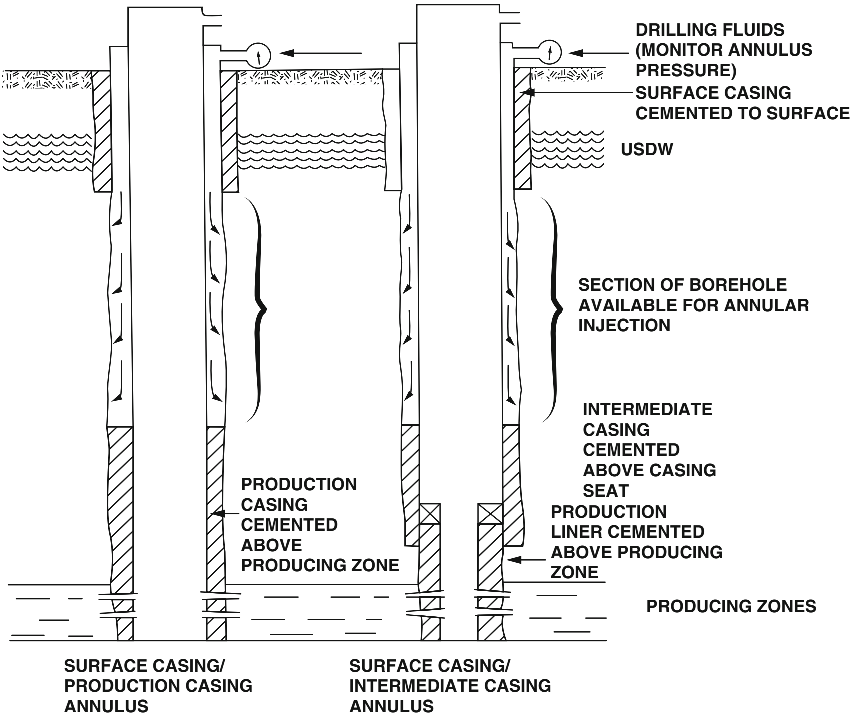

Fig. 5.2 Well configurations for annular injection. *USDW* underground source of drinking water

Kingfisher, for example, the average injection pressure ranged from 500 to 700 psi. In the Anadarko Basin, on the other hand, the deep-drilled wells usually required injection pressures ranging from 1000 to 5000 psi. The waste volume injected from a well depended upon the well's depth and pit volume and ranged from 15,000 to 60,000 barrels. The rates of injection, from two to ten barrels per minute, varied depending on the contractor's equipment. The equipment used in this technology was a type of centrifugal pump, known as a 'trash' pump, which homogenized the contents of the pit by circulating and stirring the pit and mixing the mud, cuttings and water together.

Specific for early applications of slurry injection technology was a lack of concern for hydraulic fracturing of the disposal zones. The injection zones were shallow (3600–4600 ft) unconsolidated sand strata with extremely high permeability due to the presence of shell deposits. Table 5.4 shows properties of the rock strata in the disposal zone. The high permeability of these formations allowed successful disposal of materials such as slurrified, drilled-out cement, shredded paper waste (mud sacks and cardboard boxes), shredded industrial plastic foil and ground wood with plastics (shredded wooden pallets and crates) [28]. Lack of concern for fracturing was based on the assumption that in highly permeable rocks fractures cannot be propagated far because most of the liquid phase of the

Table 5.4 Description of subsurface disposal zone: Gulf of Mexico

Depth range (ft)	Rock	Per cent	Description
3810–3960	Sand	40–90	Clear, white, translucent, loose, very fine grained, well sorted
	Shale	10–50	Light gray, soft (occasionally firm), flaky, sticky, calcareous
	Shells	10	Loose fragments, macro fossils, microfossils
3960–4080	Sand	70–90	Clear, white, moderately well consolidated, fine grained, well sorted, calcareous cement
	Shale	0–10	Gray, moderately firm, blocky, platy
	Shells	0–20	As above
4080–4280	Sand	30–70	Clear, translucent, unconsolidated, fine grained, moderately sorted, spherical
	Shale	10	Firm, blocky, platy, calcareous
	Shells	20–60	As above

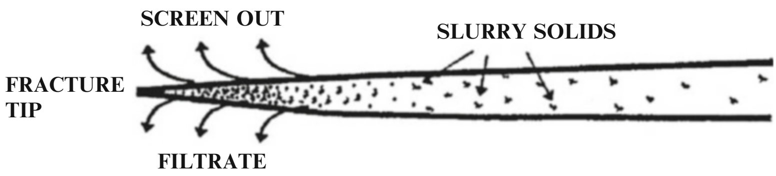

Fig. 5.3 Fracture screen-out during high-permeability injection of slurrified solid waste

injected slurry is lost from the fracture into the rock structure due to the 'screen out' effect.

As shown in Fig. 5.3, screen-out can occur when the fluid phase of a solid–liquid mixture is lost into the fractured formation. As the liquid phase fraction diminishes, the solids fraction can increase in the fracture tip until there is no longer enough liquid phase to continue conveying the solids. Cuttings slurries typically have a high potential for rapid screen-out across fracture walls since they tend to exhibit excessive fluid loss properties. However, data from various cuttings injection operations show that a drill cuttings' slurry can be successfully injected into formations with high permeability [29].

Figure 5.4 is a schematic diagram of the basic surface slurrification equipment and the downhole cuttings injection process. Cuttings generated by drilling operations are removed from the drilling fluid using conventional solids control equipment and then transported to the cuttings slurrification system using conveying equipment. When the cuttings reach the system, they are transformed into pumpable slurry by mixing water with the drilled cuttings at approximately a 3:1 ratio. Once the cuttings and water are blended into a homogeneous mixture, the cuttings are reduced to an acceptable particle size distribution by shearing them with specially modified centrifugal pumps and/or by grinding them using mechanical grinding equipment. Injection pumps are modified to enhance cavitation. Also, the pump impellers are hard faced so that erosion of the blades is minimized.

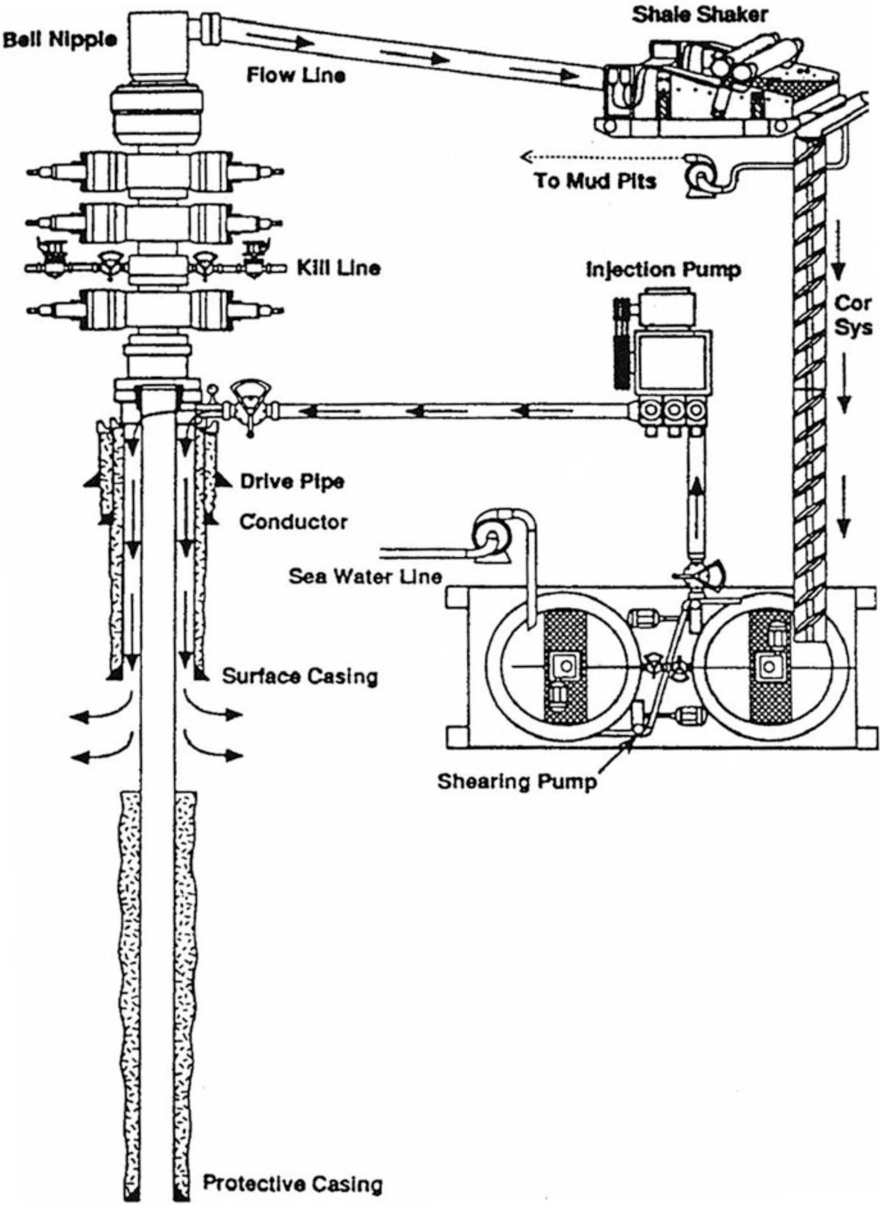

Fig. 5.4 Schematics of slurrification and annular injection process for OBM cuttings in the Gulf of Mexico [27]

Table 5.5 Properties of slurrified drill cuttings injected in Gulf of Mexico[a]

Property	Minimum	Maximum
Density (lb/gal)	9.9	12.7
Funnel viscosity (s/qt)	41	92
Retort solids (vol %)	4	25
Retort water (vol %):	64	85
Retort water (vol %)	4	24

[a]After Ref. [27]

In the Gulf of Mexico area, drilled cuttings are so soft that the dispersion of the cuttings and the preparation of the slurry generally require only one pass through the centrifugal pump. Then, a small triplex pump takes the slurry from the slurrification pods and pumps it down the well's annulus. The slurry is kept at an optimum viscosity by adding sea water, dispersant, caustic or gel and is pumped at a specified rate. Typical properties of the slurry are shown in Table 5.5. When the pressure increase resulting from the pumping operation exceeds the strength of the exposed formation, the rock fractures and the cuttings slurry flow into the created fissure.

The pumping operation continues until all slurry is injected into the formation. Table 5.6 gives the maximum injection parameters for four wells in the Gulf of Mexico. Maximum pumping pressures evidently exceeded the fracturing pressures of the disposal zones at times.

The high-permeability annular injection process has not yet been standardized. However, some basic guidelines have been developed from experience gained mostly in the Gulf of Mexico [29]. In the presence of a high permeability disposal zone overlaid by a continuous sealing shale formation, the surface casing should be set and cemented at the bottom of the sealing zone. It has been proved by radioactive tracer surveys that the injected slurry would enter the high-permeability zone immediately below the surface casing shoe. Hydraulic fractures initiated in these zones are short and wide and do not propagate very far. Also modeling studies indicate that the amount of open hole below the surface casing shoe and the top of the cement controls the direction of fracture propagation [29]. As the length of the open hole section increases, the propagating fracture will tend to grow in the downward direction.

Since fracturing is not of much concern in the high-permeability injection, the limiting factors for injection pressure and rate design are casing resistance to collapse, burst and erosion. Typically, operational practices call for the maximum injection pressure limits based on 70 % of the burst rating for surface casing and 50 % of the collapse pressure for intermediate casing string. Protection from erosion involves installation of a steel collar that deflects the stream of slurry entering the casing head and protects the intermediate casing hanger from exposure to the stream.

Table 5.6 Injection parameters for four wells in the Gulf of Mexico[a]

	Surface casing		Intermediate casing			Maximum injection parameters		
Well location	TVD[b](ft)	Size (in)	Size (in)	TOC[c] (ft)	Leak-off test equivalent mud weight (lb/gal)	Volume (bbl)	Rate (bbl/min)	Pressure (psi)
East Cameron	4724	10.750	7.625	5230	14.4	1270	0.5	1500
Matagorda Island	4490	13.375	9.625	5800	14.3	9560	4.0	1800
Galveston	3566	13.375	9.625	5200	14.1	19,579	2.0	2000
Galveston	3495	13.375	9.625	5890	14.3	9990	3.5	1200

[a]After Ref. [27]
[b]*TVD* true vertical depth
[c]*TOC* top of cement

3.2 Slurry Fracture Injection of Muds and Cuttings

The technology of disposal to artificial fractures has been developed in drilling areas that lack low-pressure/high-permeability disposal zones typical for the Gulf of Mexico or other areas with naturally fractured formations. In the North Sea, for example, permeable shallow sands having a porosity of 35 % and permeability in the range of a few darcies are underlain by massive Tertiary mudstones, as shown in Fig. 5.5. Two options for annular disposal can be considered theoretically:

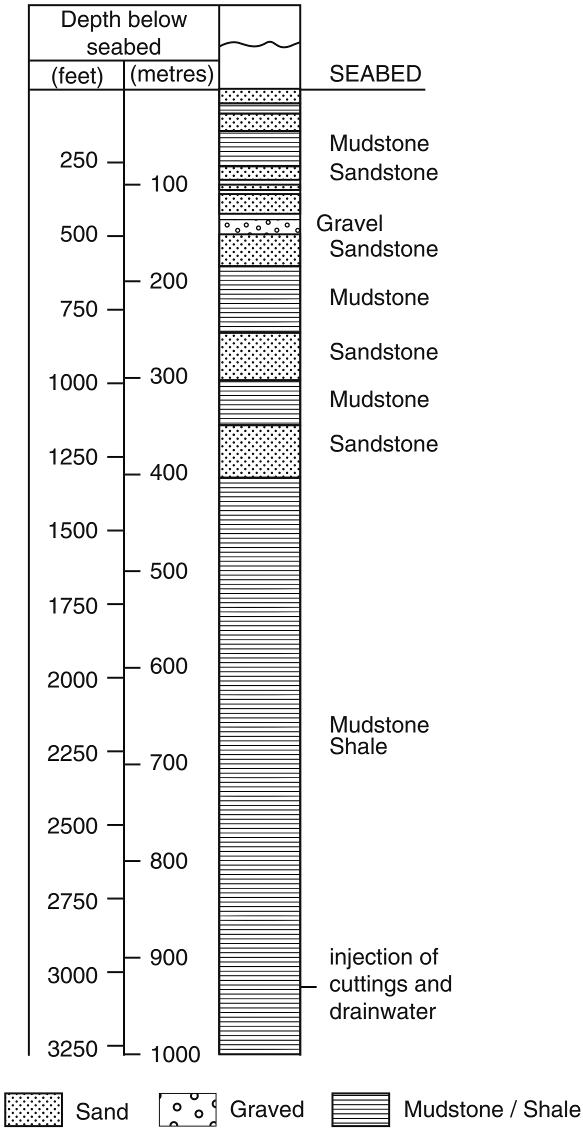

Fig. 5.5 Example of shallow subsea stratigraphy in the North Sea area

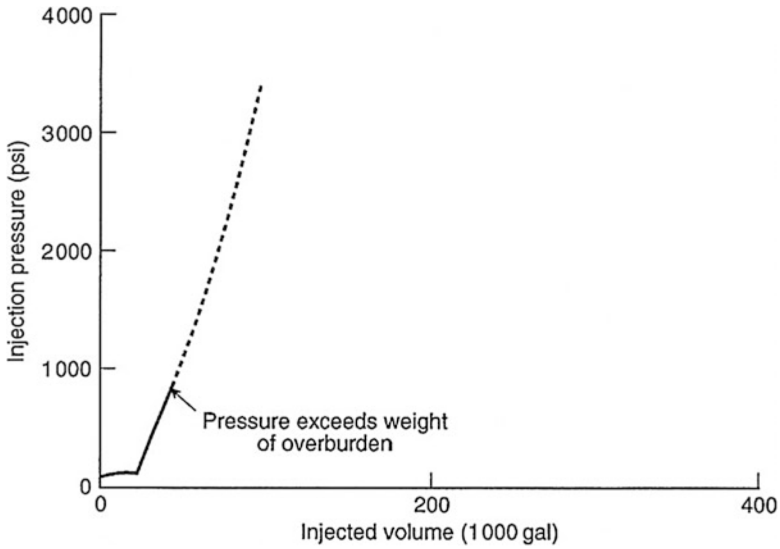

Fig. 5.6 Computer-simulated trend of injection pressure during high-permeability injection to single fracture with early slurry screen-out [32]

high-permeability injection to the lowermost sandstone formation or slurry fracture injection into the mudstone.

A numerical simulation study of high-permeabily injection showed that the disposal fracture in sandstone would be shorter owing to slurry dehydration and would tend to propagate upwards into the overlying (impermeable) shales and siltstones [32]. Also, the calculations showed a rapid increase in injection pressure due to early screen-out (dewatering) of the slurry, as shown in Fig. 5.6. High permeability injection was concluded to result in smaller disposal volumes, a rapid increase in injection pressure for any new fracture created and a tendency of the fracture to propagate upwards into the sealing zone.

The other alternative, slurry fracture injection into a massive mudstone overlaid by permeable sandstone, proved superior to the high-permeability injection in the North Sea area. The conclusion was initially based upon theoretical simulation studies of fracture initiation, propagation, fracture shape and slurry screen-out [32, 45]. Fractures made in practically impermeable rocks were concluded to have a favorable, circular shape, i.e. they will propagate uniformly in vertical and horizontal directions. This process is shown in Fig. 5.7. Initially the vertical fracture expands as a radial fracture until its top reaches the permeable sand. Then, the cuttings laden slurry would start to dehydrate, plugging the portion of the fracture that is in contact with the sand. Additional lateral fracturing would then occur (probably at a slightly higher pressure), as illustrated by fracture '2', until again the fracture could grow vertically up into the permeable formation, where it would again screenout, etc. Hence this mechanism of fracture propagation could

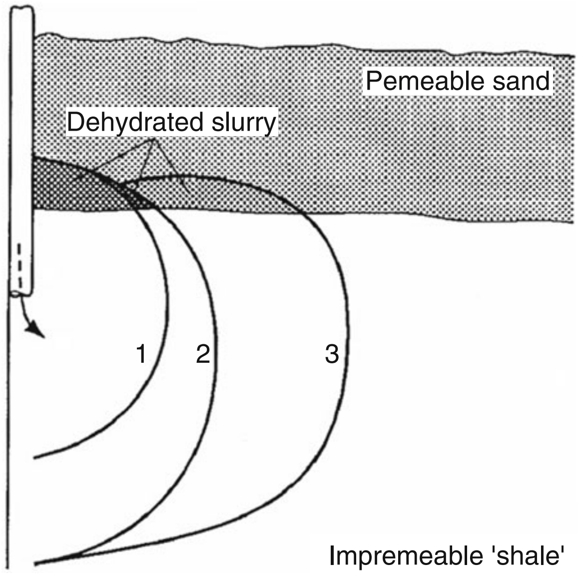

Fig. 5.7 Propagation of disposal fracture during slurry fracture injection process [32]

conceivably allow significantly larger quantities of injection than might be possible for injection directly into a permeable formation.

Cuttings injection could be used in a wide range of geologic formations. In the North Sea, injection is typically into shales, with overlying sandstones used to dissipate pressures and contain waste migration. In Alaska and California, injection is into sandstone, with shales used to contain fracture propagation. In the large waste disposal facility in South Texas injection is into a naturally fractured formation [34, 35]. All of these completion schemes have injected large quantities of waste.

As we start injecting into a formation that is not naturally fractured, the pressure will rise as the formation accepts fluid under matrix injection, as shown in Fig. 5.8. At this point, the pressure will exceed the breakdown pressure of the formation and a hydraulic fracture will initiate and begin to propagate. Fracturing is essential for solids placement because without fracturing the slurry would screen-out at the surface of the open hole and solids would fill-out the well.

The slurry fracture injection process for OBM cuttings has been fully implemented in the Gyda field [31, 46–49]. The BP Norway's Gyda was the first platform in the North Sea to dispose of all its drilling waste by downhole injection. The process is shown in Fig. 5.9 [49]. The oil-based mud is used to drill the three lower sections of 12¼, 8½ and 6 in holes.

Approximately 500, 13 and 15 tonnes of rock and 35, 20 and 2 tonnes of oil were typically discharged from each of the respective hole sizes per well. As shown in Fig. 5.9 the surface installation for slurry fracture injection was very similar to the high-permeability injection process used in the Gulf of Mexico. A simple centrifugal pump shearing system was used to grind and mix drill cuttings with sea water

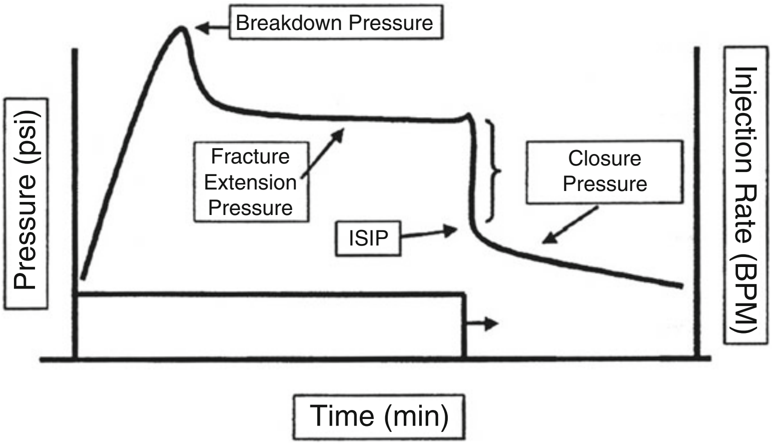

Fig. 5.8 Slurry fracture injection process [41]

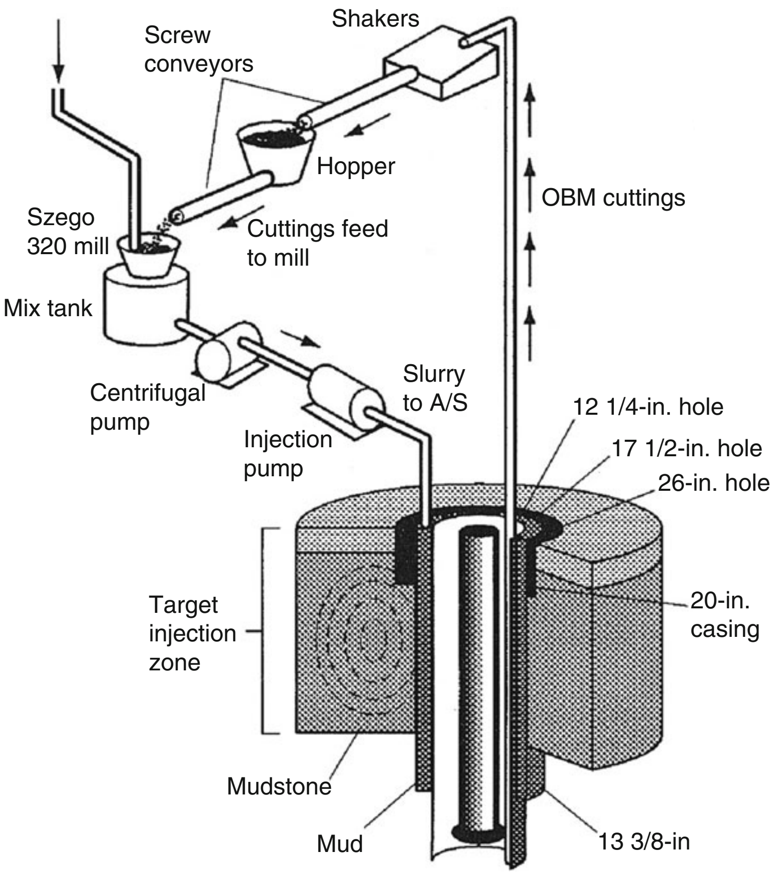

Fig. 5.9 Slurry fracture injection process [49]

Table 5.7 Parameters of slurry fracture injection at Gyda[a]

	Well numbers: injection/drilled							
Parameter	A-23/ A-09	A-09/ A-22	A-22/ A-16	A-16/ A-19	A-19/ A-27	A-27/ A-15	A-15/ A-26	A-26/A-24
Start injection	30/7/91	12/9/91	5/11/92	18/1/92	1/5/92	2/7/92	11/8/92	29/9/92
Duration (days)	42	31	47	41	42	21	30	Ongoing
Volume (bbl)	13,500	27,000	27,000	16,245	15,037	13,111	16,033	11,615
Injection rate (bbl/min)	8	3.8	7	7	7	7	9	11
Injection pressure (psi)	900	1000	1200	1100	1200	1400	1600	1450
Initial shut-in pressure (psi)	900	1100	700	NR[b]	NR	NR	NR	NR
Shut-in pressure (psi) (01/02/92)	700	150	700	NR	NR	NR	NR	NR
Shut-in presssure (psi) (10/10/92)	900	900	700	1100	1000	900	1100	950

[a]After Refs. [45] and [49]. Data as of 10 October 1992
[b]*NR* not recorded

to produce pumpable slurry. The slurry was pumped through the casing spool wing valve into the $9^5/_8 \times 13^3/_8$ in casing annulus to fracture the massive Tertiary mudstones below the $13^3/_8$ in casing shoe, which is about 900 m below the seabed (Fig. 5.5). Several sand intervals with interbedded shales between 250 and 400 m below the seabed provide excellent geological barriers against fracture propagation and fluid migration to the seabed.

At Gyda, sequential annular injection, whereby cuttings from the well being drilled are injected into the annulus of the most recently completed well, has been adopted. On average, about 15,000 bbl of slurry per well were injected, including wash water and other watery drain-off wastes, with a maximum volume of 33,000 bbl in one well.

Performance of the fracture injection process is documented in Table 5.6 for the Gyda platform [45]. Note a sequential annular injection procedure in which cuttings from the well being drilled are injected into the annulus of the most recently completed well, etc. Also note in Table 5.7 that the annular shut-in pressure has not dropped over 1 year period, which may become an environmentally significant fact regarding fracture disposal technology. This and other environmental considerations are discussed below.

The fracture injection process from Gyda platform was designed using hydraulic fracturing models to estimate maximum volume injected. In the design, they assumed zero leak-off in any of the formations above the injection zone and modeled multiple batch injections as a single batch. The analysis showed that 90,000 barrels of slurry could be injected before a fracture grew to the seabed. Then, they allowed leak-off into the various sandstone layers and noted that 52,000 barrels could be injected before the fracture grew into the deepest of these layers. The sandstone layers would contained the fracture from any additional growth uphole. Since the typical Gyda injection volume was only 15,000 barrels, there was a built-in safety factor in the analysis.

In 1993, ARCO performed a field demonstration of fracturing for solid waste disposal in an unconsolidated formation in Southeast Texas [50–52]. This project was designed to mimic a long-term large-scale solid waste disposal operation, not a small batch cuttings injection operation. A volume of 50,000 barrels of bentonite mud with 100-mesh sand was pumped in four batches over a 5 day period.

The real-time microseismic monitoring project showed the fractures were contained in the 200-ft thick injection zone and grew to roughly 1200 ft in half-length. In the first three stages, the fractures systematically grew out to about 1200-ft half-length in fairly planar growth. During the last injection cycle, the microseismic events grew out 90° off the original fracture plane. Subsequent geophysical analysis confirmed these off-planar events indicating the onset of multiple fracture evolution as a result of batch injection, even in unconsolidated formations.

In 1994, a commercial injection of cuttings began in a dedicated disposal well started in the Wilmington Field in Long Beach, California [52]. The injection well was an old producer and was scheduled for plugging and abandonment. The injection stratum consists of several shale-sand sequences, all of them below groundwater and bounding shale. The injection started in the deepest sand and has moved uphole as zones gained pressure over time. The injection permit allowed the packer to be set above all these injection zones, which allowed inexpensive through-tubing re-completions to set plugs, perforate and establish injection into a new disposal zone. In the late 2000, over 1.3 million barrels of slurry and 26,000 cubic yards of solids have been injected into this well [52].

The Prudhoe Bay Unit Grind and Inject program began in early 1995 with a surface processing capacity of 24,000 bbl/day. The injection interval is a poorly-consolidated sandstone with large aerial extent. Over 8 million barrels of slurry were injected into one well over 3 year time, but the operation was temporarily stopped in 1997 due to a surface breach suspected to be caused by the slurry breaking into not cemented annulus of another well. Three new wells were drilled in 1998 and, by 2002, over 35 million barrels of slurry has been injected in these three wells. The fact that so much fluid and solids was injected with no sustained pressure increase led to considerable debate about the downhole mechanics of solids injection and the concept of multiple fracturing – discussed later in this chapter.

3.3 Properties of Injected Slurries

Cutting slurry injection is similar to fracture stimulation technology in that both technologies inject liquids and solids into a fracture and both technologies rely on the ability to continue fracture propagation until the entire volume of materials has been injected. Still, there are differences between these two technologies, primarily because cuttings slurries exhibit fluid properties very different from those of fracture stimulation fluids.

During conventional fracture stimulation operations, a low-solids fluid with very low fluid loss properties is injected ahead of solids-laden (proppant) phase. This low fluid loss pad is essential to maximizing fracture propagation and to minimizing the chance of fracture screen-out. As shown above, screen-out can occur when the fluid phase of a solid–liquid mixture is lost into the fractured formation. As the liquid phase fraction filters out, the solids fraction can increase in the fracture tip until there is no longer enough liquid phase to continue conveying the solids.

In slurry injection technology the particle size distribution of solids in the slurry can be designed such that it controls the rate of the screen-out. If the selected injection zone is impermeable, the particle size of solids in the slurry should be increased to cause rapid fracture screen-out when the fracture propagates into a permeable formation. On the other hand, for high-permeability injection, the particle size of solids in the slurry should be reduced to minimize the rate of fracture screen-out and to maintain fracture propagation into the permeable injection zone.

The size of particles in a slurrified suspension results from the type of grinding device used. These devices include a hard-faced centrifugal pump for weak cuttings (Gulf of Mexico), a vibrating ball-mill (Alaska [30]), an autogenous wet-crushing mill or a Szego ball-mill (North Sea [29, 32]). An example of the size distribution of solids in the slurry injected in the North Sea area is $d_{10} = 3$, $d_{50} = 9$ and $d_{90} = 120$ μm [44, 45]. With 50 % of the particles smaller than 9 μm, the viscosity of the suspension is sufficient to prevent settling of larger solids in the fracture.

Rheological properties of injected slurries reported in the literature are plastic viscosity = 15 cP, yield point = 60 dyn/cm^2, flow behavior index = 0.26, consistency index = 0.148 lbf/ft^2/s$^{0.26}$, solids content ≈ 30 % by volume and specific gravity = 1.68. Also reported was the use of polymeric viscosifiers with biocides [32], as well as thinners, bentonite and caustic, to control the rheology and biodegradation of the slurries [27].

The filtration properties of injected slurries follow the theoretical mechanism of cake (or 'static') filtration, with filtrate volume directly proportional to the square root of time and with a proportionality constant equal to 0.004 ft/min$^{0.5}$ [32].

3.4 Environmental Implications of Subsurface Slurry Injection

The most important environmental concern for all injection operations is the protection of the groundwater. In the liquid or solid injection wells, groundwater protection is accomplished through both the internal mechanical integrity of the casing/tubing system and external integrity of the annulus isolation with cement – discussed in Chap. 4. For solid injection into geologic zones that are not highly naturally fractured, there is an added concern of hydraulic fracturing height growth and its safe containment below the groundwater zone.

The most important technical parameters in the fracture slurry injection are vertical propagation of the disposal fractures, loss of annular integrity of wellbore and the ultimate fate of the injected slurry. Typically, the risk of vertical propagation of fractures has been evaluated through mathematical modeling with the use of 3-D fracturing simulators. The simulator inputs include minimum *in situ* stresses, pore pressure gradients, Young's modulus and Poisson's ratio variations, slurry filtration (screen-out) and rheological properties, depth of injection and injection rate. The calculations typically show a relationship between the cumulative volume injected and the vertical height of the fracture for a given geological profile of sediments above the injection point. For example, simulation studies for the Gyda platform showed that, in the absence of any high-permeability sands above the massive mudstone (disposal zone), 90,000 bbl of slurry would be needed to propagate the fracture of the seabed [45]. This study also showed that any shallow sand strata would become a barrier for fracture propagation. Similar studies were also reported for the Clyde platform in the North Sea [31].

In Alaska, field measurements of surface deformation were used to assess the potential for vertical propagation of disposal fractures under the permafrost in Prudhoe Bay field [42]. The fractures were initiated under the permafrost at 2000 ft. Then, a total of 2 million barrels of oilfield waste fluids were injected into three wells with injection rates averaging 1–2 bbl/min. Surface deformation of the permafrost was measured with an array of tiltmeters installed 25 ft into the permafrost. Analysis of the surface deformation was combined with transient pressure testing (step-rate and fall-off tests) of the injection wells. The analysis revealed the presence of horizontal fractures without discernible vertical fracturing.

Propagation of vertical disposal fractures in the highly permeable and thick (155 ft) Frio Sand at 4500 ft was effectively stopped by a 130 ft thick layer of shale overlaying the sand. This finding was documented by a recent field study involving computer simulation combined with a new method of realtime passive seismic monitoring and analysis [46].

Loss of external annular integrity of the borehole involves channeling outside the outer casing of the injection annulus and the flow of injected waste slurry to shallow aquifers or breaching the slurry to the surface. Verification of external integrity involves periodic additions of radioactive tracers to the slurry injected to the well's annulus while drilling the lower sections of the well. Typically, different types of short half-life tracers such as antimony, iridium and scandium are injected at the beginning, during and at the end of the annular injection process (upon reaching the total drilling depth). Upon completion of all drilling operations, a multiple isotope tracer log is run to determine actual injection points and flow behind the casing [28].

A long-term environmental risk results from the ultimate fate of injected slurry. When injecting wholly into shales, fluid screen-out is minimal. Here the fate of the solid waste slurry is dependent on chemical reaction with the surrounding shale. The hypothesis has been proposed that, since shales are usually reactive with water-based fluids, over time the sea water carrying the fluid reacts with the swelling clays to form increasingly viscous, dehydrated slurry within the fracture, which will eventually seal the fracture over a long time period. The softened zone adjacent to the fracture would be relatively localized (a few feet at most, by virtue of the low permeability), thus posing little threat to subsequent well drilling, which may pass through the sealed fracture plane. In this new well the fracture will manifest itself as a localized tight-spot within the open hole without abnormally high-pressure trapped in the fracture. Moreover, even if the pressure has been trapped, the high viscosity and gel strength of the remnant of dehydrated slurry preclude taking an unexpected kick. The above theory has never been verified experimentally. To date, field data indicate the continuing presence of pressurized fractures with no observed release of pressure in time, as shown in Table 5.6.

Significant fluid migration is also believed to be impossible, even in permeable strata. When disposal fractures intersect an unconsolidated sand of considerable thickness (10 m or so is usually sufficient), a rapid leak-off of the filtrate (screen-out), resulting in dehydration of the slurry, takes place. The dehydration assures permanent disposal of the solid particles, which remain trapped at the fracture–sand contact surface. Only the smallest clay particles may enter the sand formation. Also, the dehydrated solid cake will in time reduce the intrusion of the liquid phase into the sand. As the pore volume of these laterally extensive shallow sands is large and because of their compressible nature, substantial volumes of slurry could be injected without the risk of over-pressuring either the fracture or the sand formation.

3.5 Periodic Injection to Multiple Fractures

A new concept of multiple fracturing due periodic injection has been derived from the observation that for periodic injections, there is a repetitive pattern of initial increase of injection pressure followed by pressure decrease and final stabilization [53]. Also, the stabilized pressure level at the end of each injection tends to increase with the number of injections. This behavior contradicts the propagation of a single fracture, which would require a smaller propagation pressure due to the fracture size increase. This observation led to the conclusion that periodic injections may create multiple fractures in the same region of the formation around the injection borehole (disposal domain).

The mechanism of inducing disposal domain of multiple fractures due periodic injection begins with creation of a single planar fracture after the first batch injection [40] – as shown in Fig. 5.10. After the injection stops, slurry liquid will leak-off into the rock, and the fracture will close on the solids, trapping the mud filter cake and cuttings. The trapped material will slightly increase *in situ* stress in the direction normal to the fracture face. Also, the pore pressure around the fracture will be increased by the liquid leak-off (filtration). Finally, the conductivity of the closed fracture (controlled by the very low permeability of waste solids) will be

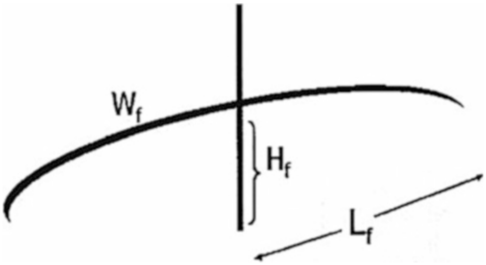

Fig. 5.10 A single two-wing planar fracture [40]

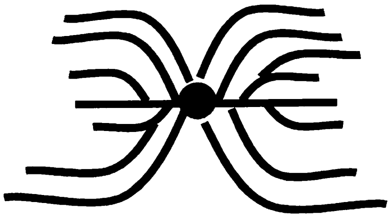

Fig. 5.11 Multi-fractured "disposal domain" [53]

very low comparing to a conventional fracture filled with breakers and proppant. In fact, the permeability will be lower than that of the formation matrix.

The next batch injections may still re-open the existing fracture and extend its height, length or width. However, as the number of batches increase, the combined effects of low fracture conductivity and increasing stresses due to growing fracture width would favor the creation of a new fracture. These new fractures will be branching off the original fracture. As we inject more batches, these multiple fractures become numerous thus creating a network of interconnected fractures – a disposal domain, as shown in Fig. 5.11.

For soft, unconsolidated rocks with low compressive strengths – typical of the Gulf of Mexico and shallow formations on the North Slope of Alaska, liquefaction (disaggregation) may also take place [54]. In addition to creation of multiple fractures, each injection may induce enough shear stress to overcome the minimal grain-to-grain cementing. This in turn would increase the *in situ* porosity and yield a tremendous storage capacity of the formation. The disaggregation concept is shown in Fig. 5.12.

The theoretical concept of multiple fractures was verified experimentally by a drilling Engineering Association consortium DEA-81 funded by the petroleum industry (Amoco, Arco BP, Chevron, Exxon, Shell, and Statoil) [52]. In the project, a series of laboratory experiment were conducted using blocks of shale, hard sandstone, soft sandstone and synthetic rocks placed under confining stresses and pore pressures. The blocks ranged in size from about one cubic foot to one cubic meter. The hard rocks were from quarries and the weak rocks were made in the lab. Each test involved multiple batch injections of slurries of mud and simulated cuttings with each injection followed by a long shut-in time to allow fractures to close.

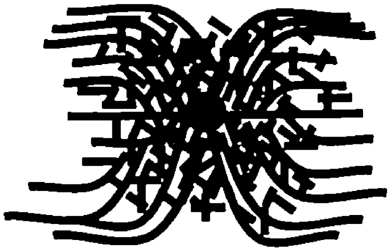

Fig. 5.12 Schematic of "disaggregation" concept [54]

The most important result from the DEA-81 project was that multiple fractures are indeed created with multiple batch slurry injections. It was found out that, in most cases, each new batch injection created a new fracture. In hard rocks, the multiple fractures tended to be parallel to one another and very closely spaced.

Multiple fracturing in soft rock samples also involved multiple parallel fractures but some of the fractures were wider than others with blunted tips and solids invasion ahead of the fracture tip. Some of the tests also showed solids invasion across the fracture face, suggesting liquefaction (disaggregation) of the rock.

One of the important parameters of periodic injection process is the incremental volume of storage resulting from large number of fractures having limited size (storage domain). The number of multiple fractures in the disposal domain has been initially modeled using analogy with fractures induced by thermo-elastic effect [55]. The solution scaled the number of fractures with the fracture height, yielding:

$$\begin{array}{l} N_f = \pi R/4H_f \\ \text{for} R > 4H_f/\pi \end{array} \tag{5.1}$$

where:

N_f = number of fractures; R = radius of single fracture; H_f = fracture height.

For example, for a fracture height of 100 ft, with fracture domain radius 1000 ft, the number of fractures is rounded up to eight fractures. This simply means that the storage volume of the domain is eightfold larger than that for a single fracture.

The results of the DEA-81 project did not confirm the above concept, however. It suggested that the number of multiple fractures would scale with the fracture width rather than height. That would mean – by a very rough approximation [56], that formula (5.1) should read:

$$N_f = \pi R/4W_f \tag{5.2}$$

where:

W_f = width of fractures.

Thus, for the same radius of the domain and fracture width of 0.5 ft., the number of fractures becomes 19,625. Even for a radius of 50 ft, with a width of 0.1 ft., the number is almost 500. Notwithstanding accuracy, the examples show tremendous storage volume of this disposal method.

The periodic injection method has been also verified in field experiments. In 1998, the Mounds Drill Cuttings Injection project was funded jointly by petroleum industry and Gas Research Institute and the US Department of Energy [57–59]. The project involved drilling three wells in Mounds, Oklahoma. One well was the injection well and the other two were monitoring wells for microseismic and downhole tiltmeter measurements. Surface tiltmeters were also used. In addition, four sidetrack core runs were conducted after the injection to confirm the location of the created fractures and injected waste.

There were two target intervals for slurry injection: the Wilcox Sand at 2600–2800 ft, and Atoka Shale at 1950 ft. Both formations have large elastic modulus typical of this mid-continent US geologic setting. In the Wilcox, a total of 22 batches were injected of which 17 were slurry batches. There were 23 injections to Atoka, of which 20 were slurry batches. The batches ranged in size from 50 to 100 barrels.

The coring results integrated with the fracture diagnostics provided indisputable proof that multiple fractures can be created in the field as a result of batch slurry injection. The conclusion was later independently confirmed in the data assessment study [59].

The apparent environmental advantage of periodic fracturing is minimization of risk due to better containment of a large volume of waste in a small disposal domain comprising multiple fractures of controlled extent.

The new process has been also evaluated from the standpoint of design methodology using mathematical modeling of the disposal domain. In a project involving large-volume slurry injection, a comprehensive approach was used for injection design, operations, and data interpretation [39, 60]. The conclusion was that simulation models of hydraulic fractures did not adequately describe nonlinear fractures and dilation behavior of soft formations. The existing models could be only used for qualitative evaluation of formation response to the injection process. The findings suggest that there is a need for improved modeling capability.

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