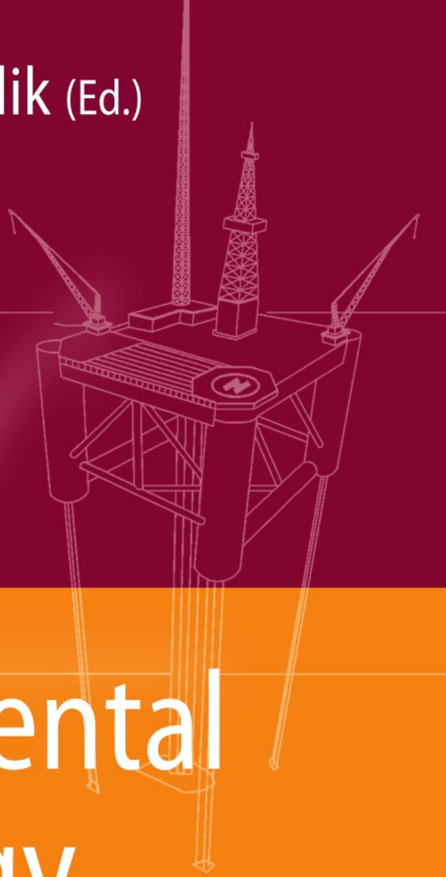
Stefan T. Orszulik (Ed.)



Environmental Technology in the Oil Industry

2nd Edition

Springer

Environmental Technology in the Oil Industry

Environmental Technology in the Oil Industry

2nd Edition

Edited by

Stefan T. Orszulik

Oxoid Ltd,
Hampshire, U.K.

Springer

Stefan T. Orszulik
Oxoid Ltd,
Hampshire, U.K.

ISBN 978-1-4020-5471-6 e-ISBN 978-1-4020-5472-3

Library of Congress Control Number: 2007940833

Printed on acid-free paper.

9 8 7 6 5 4 3 2 1

springer.com

Contents

Chapter 1
General Introduction

A. Ahnell[1] and H. O'Leary[1]

1 Environmental technology

Perhaps the place to start this book is with definitions of the two key words [1]:

- **Technology** – the scientific study and practical application of the industrial arts, applied sciences, etc., or the method for handling a specific technical problem.
- **Environmental** – all the conditions, circumstances and influences surrounding and affecting the development of an organism or group of organisms.

Environmental technology is the scientific study or the application of methods to understand and handle problems which influence our surroundings and, in the case of this book, the surroundings around oil industry facilities and where oil products are used. Traditionally the phrase has meant the application of additional treatment processes added on to industrial processes to treat air, water and waste before discharge to the environment. Increasingly the phrase has a new meaning where the concept is to create cleaner process technology and move towards sustainability.

2 The beginning

As we begin our discussion of environmental technology, it is important to take a few moments to remember how we became so involved with this substance, oil. Regardless of our opinions about its use, oil is, and has been, the key resource in the twentieth century. From humble beginnings as a medicine and a lamp oil, oil has become the energy of choice for transport and many other applications and the feedstock for a major class of the material used today, plastic.

It is in some ways ironic that oil, initially the cheap fuel for lighting that improved many peoples' lives, next the enabler of affordable motorized personal transport and later the solution to the air pollution problems caused by coal, has become one of the chief environmental concerns of the early

[1] *BP International Ltd, Chertsey Road, Sunbury-on-Thames, Middlesex TW16 7LN, UK*

twenty-first century. Often the fuel of choice because of price and convenience, oil was once also the 'environmentally friendly' choice. Long before the 1950s, London suffered from 'pea souper' fogs caused by stagnant air patterns and emissions from open coal fires which resulted in serious respiratory problems. These fogs caused hospitals to fill with sufferers of respiratory ailments. As a result, 'smokeless zones' were enacted and coal gas and then oil became the heating fuels of choice.

It can truly now be said we exist in a Hydrocarbon Society [2], the paradox being that we want the mobility and convenient energy that oil provides, but we also want a clean environment. In recognizing the need for oil, we also need to ensure that the environment is respected.

3 The environmental effects of the oil industry

What kind of impact does the oil industry have? One way to begin to assess this aspect is to look at the emissions, in terms of both their effect and the quantity. Although emissions data for industry worldwide are not available, some companies are now publishing their data. The data in this chapter is from BP's *Sustainability Report 2004*, which is published as part of a policy to improve communication of the company's HSE performance [3].

3.1 Air emissions

As an example of oil industry emissions and how they change over time, BP's total emissions to air (aggregating all monitored pollutants excluding carbon dioxide) fell significantly in 2004 – a decrease of 5% from 2003 (988 to 936 kilo-tonnes). This 2003 emissions total is 37% lower than the 1,500 kilo-tonnes reported in 1999, see Figure 1.1.

Of BP's total mass of emissions to air (excluding carbon dioxide) in 2004, 56% came from the exploration and production (E&P) stream and 20% from refining and marketing. The remaining operations combined contributed 24% of the total mass of emissions to air, see Figure 1.2.

3.1.1 Methane

Methane is a hydrocarbon. Its main impact is as a greenhouse gas, with 21 times greater global warming potential than carbon dioxide. Emissions of methane represented 28% of BP's total emissions to air (*excluding carbon dioxide) during 2004 and were 258 kilo-tonnes. In BP's case, methane results primarily from exploration and production businesses, which emitted 90% of the total methane in 2004 (some 231 kilo-tonnes).

3.1.2 Non-methane hydrocarbon emissions

Many of petroleum industry products are volatile. When exposed to air, some components of crude oil, gasoline, other fuels and many chemicals can

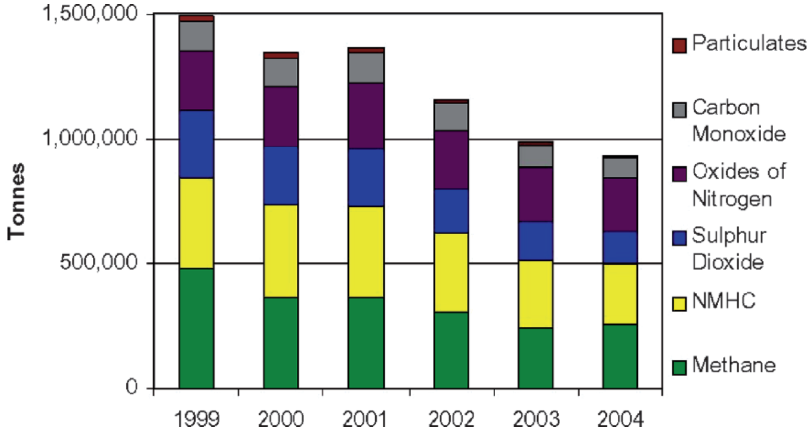


FIGURE 1.1. BP group annual total air emissions by pollutant 1999–2004 (*See Color Plates*).

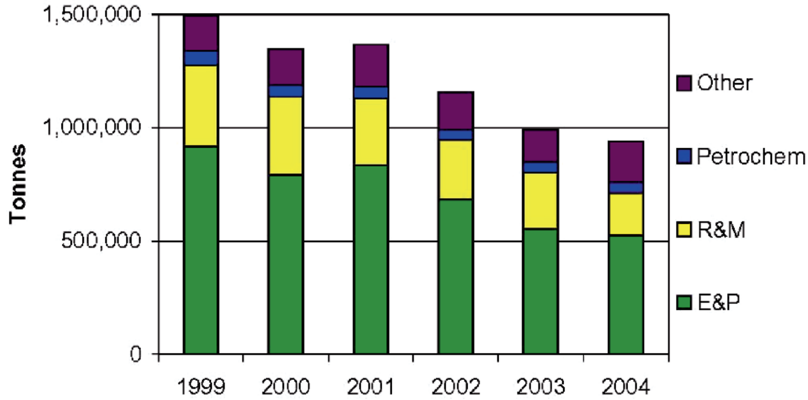


FIGURE 1.2. BP group annual total air emissions* by business 1999–2004 (*See Color Plates*).

evaporate. In addition, gas can be released from operations through controlled process vents for safety protection. Further safety devices, such as flares, are used to burn excess hydrocarbons in the industry, but can allow a small proportion of hydrocarbon into the atmosphere without being burnt. Industry contains and controls these emissions wherever possible to minimize any loss of hydrocarbon.

Hydrocarbon vapours, often described as volatile organic compounds or VOCs, are potentially harmful air pollutants, which can result in local health impacts as well as local or regional contributions to the formation of low-level ozone; which in turn, may also impact human health. Controlling hydrocarbon loss helps prevent impact on air quality and is also economically beneficial.

In 2004, BP emitted 245 kilo-tonnes of non-methane hydrocarbons to air, a decrease of 24 kilo-tonnes (9%) compared with 2003. The largest proportion of these emissions came from the exploration and production businesses (44%), followed by refining and marketing (R&M) (35%).

Combining methane and non-methane hydrocarbon totals provides a better idea of where most of the hydrocarbon emissions come from within the industry sectors. In BP's case, the exploration and production activities account for 67% of the total volume of such hydrocarbons emitted to air in 2004.

One example of controlling emissions is through the use of vapour recovery systems. This technology captures and condenses the volatile hydrocarbons, sending the recovered fuel back into the product storage tanks. One example of improvement is in the BP exploration and production business where vapour recovery systems were recently installed at large crude oil tanker-loading facilities in Alaska and Scotland. BP's refining and marketing operations have installed vapour recovery systems at many gasoline distribution terminals. Additional benefit can be gained from vapour recovery installation on retail car refuelling sites reducing VOC emissions during car refuelling by up to 90%.

3.1.3 Sulphur dioxide

Sulphur is a component of most crude oils and many gases and a significant percentage of emissions. In the BP case, 14% of our total emissions to air (*excluding carbon dioxide) are sulphur oxides, primarily sulphur dioxide, which forms whenever fuels containing sulphur are burned. Sulphur dioxide pollution can have local health and vegetation impacts as well as contributing to regional acid rain impact.

BP emissions of sulphur oxides to air fell from 151 kilo-tonnes in 2003 to 126 kilo-tonnes in 2004 – a 25 kilo-tonnes decrease (16%). The largest percentage of sulphur oxide emissions usually come from refining and marketing businesses (48%). Shipping of products contributed 37% of the BP's total sulphur emissions.

3.1.4 Nitrogen oxides

Nitrogen oxides are produced whenever fossil fuels are burned. When emitted, they result in nitrogen dioxide pollution. This can have both local health and vegetation impacts, as well as contributing to regional acid rain impacts and low-level ozone formation. Nitrogen oxides can be reduced through the installation of modern low NO_x burners in processing plants. Reviewing the BP data as an indicator, the total nitrogen oxide emission of 215 kilo-tonnes in 2004 is slightly lower than the 220 kilo-tonnes reported in 2003 representing a 2% decrease.

3.1.5 Emissions to air from exploration and production operations

Total reported air emissions (excluding carbon dioxide) from exploration and production activities decreased from 554 kilo-tonnes in 2003 to 524 kilo-tonnes in 2004 (5% lower). Because the level of activity in exploration and production activities can vary, it is also relevant to examine emissions in terms of the total oil and gas production.

In terms of emissions per unit production, BP emitted on average 330 tonnes of air emissions (excluding carbon dioxide) for every million barrels of oil equivalent (Mboe) in 2003, compared to 353 tonnes per Mboe in 2004. This equates to a 7% increase in emissions per unit production. However, BP's exploration and production sulphur dioxide emissions decreased by 23%, from 14 kilo-tonnes in 2003 to 10 kilo-tonnes in 2004.

3.1.6 Gas flaring from exploration and production operations

In BP 1,342 kilo-tonnes of hydrocarbon gas were flared during exploration and production activities in 2004; the same amount that was flared in 2003. Overall, BP reduced the annual amount of flared gas by 54% between 1998 and 2004. These reductions have also benefited greenhouse gas emissions related to climate change. Flaring per unit production in BP exploration and production was 905 tonnes of gas on average for every Mboe exported in 2004.

3.1.7 Emissions to air from other operations

Total emissions to air (excluding carbon dioxide) from BP refining and marketing operations continued to fall in 2004 – from 249 kilo-tonnes in 2003 to 189 kilo-tonnes (a 24% decrease). Emissions have shown a steady decline since 1998. However, this has been affected by changes in the refining portfolio as well as emissions reductions at retained refineries.

Total emissions to air (excluding carbon dioxide and other inorganics) from BP chemicals operations in 2004 was 43 kilo-tonnes down slightly from the 44 kilo-tonnes in 2003.

The total emissions to air (excluding carbon dioxide) from BP gas, power and renewables businesses increased to 47 kilo-tonnes in 2004 from 34 kilo-tonnes in 2003. Mostly driven by an increase in the LNG operations internally transferred from BP exploration and production activities into BP gas, power and renewables activities last year.

BP emissions to air from shipping operations increased from 107 kilo-tonnes in 2003 to 133 kilo-tonnes in 2004 and relates to the operated BP fleet having grown from 36 ships in 2003 to 42 ships by December 2004.

3.2 Water management

It may be surprising but in many cases the petroleum industry manages a great deal of water. In BP's case, it manages large volumes of all types of water and handles more water than oil.

The petroleum industry uses fresh water in every part of the business: sometimes as a raw material; frequently in the processes employed; and almost everywhere for drinking, catering and sanitation, see Figure 1.3. BP's 2004 fresh water extraction was nearly 500 million cubic metres (m^3). The industry

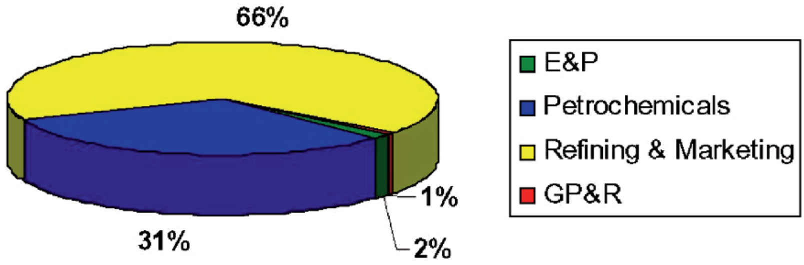


FIGURE 1.3. Fresh water withdrawal by BP business in 2004 (as volume percent of BP group total) (*See Color Plates*).

gets fresh water from many sources, including lakes, rivers, reservoirs, wells and aquifers. Also potable (drinking) water can come from municipal supplies. After cleaning, the water is returned to the environment. Typically discharge of the water is back to its source, although cooling towers can evaporate fresh water into the air.

Discharges to water come from many different activities: from drilling; from separating produced water extracted with oil from reservoirs; as a by-product of the refining and manufacturing process; from cooling water; from ships' ballast; and from rain water run-off. For example in 2004, the treated waste water discharges from BP exploration and production (E&P) and refining operations totalled nearly 260 m^3 a minute.

The petroleum industry discharges to water in several ways:

- Rock fragments in drilling muds, usually disposed of overboard from platforms into the sea
- Produced water is extracted with oil from reservoirs. It contains small quantities of hydrocarbons and process chemicals needed for efficient oil handling, typically disposed to sea
- Cooling water at raised temperature and containing residual traces of chemical inhibitors added to prevent fouling, scaling and corrosion, discharged into rivers, lakes or the sea
- Waste water from manufacturing and processing containing small amounts of hydrocarbons and petrochemicals, discharged into rivers, lakes or the sea
- Ballast water from product shipping. Ballast water could have an impact through the transfer of harmful aquatic organisms

Industry waste waters are treated and monitored as necessary in order to meet any relevant legislation before discharge and complex treatment plants exist at many major installations. These remove the hydrocarbons, chemicals and solids that are present in the process waste water streams. In 2004, BP total fresh water withdrawal was 493 million m^3. This is a decrease of 5% from 2003, fresh water use is mainly of concern at the local level. In 2004, the breakdown of BP fresh water withdrawals was: potable 15.3%; fresh 83.3%; and reclaimed 1.4%.

3.2.1 Drilling discharges

In 2004, BP total discharges to water decreased slightly from the 2003 level to 57,000 tonnes, see Figure 1.4. Levels over the last two years are very similar to 2000, but 23% higher than in 1999. The impact of these discharges is mainly upon the local receiving waters. The major changes in BP group level reported discharges to water in recent years have typically resulted from increases or decreases in E&P drilling activity as exploration for new energy resources occurs.

As part of oil and gas drilling activities rock cuttings and drilling muds are discharged. Water based drilling muds are the least damaging to the environment, when compared to oil- or synthetic-based alternatives. The industry is generally phasing out the discharge of oil-based drilling muds to water. BP E&P operational discharges of oil and chemicals in produced water both increased slightly last year, rising around 13% in 2004 compared to 2003 levels. Many E&P sites reinject their produced water to maintain oil field pressure suggesting reuse of a great deal of produced water.

3.3 Waste management

The extraction of raw materials and the many manufacturing uses to which they are put all generate waste. The careful use and conservation of these materials, and the products they result in, is one of the most effective ways to address the waste issue. However carefully we use raw materials and the products derived from them, some waste is inevitable at present. Waste is generally disposed of either by burying in a landfill, or by incineration. Landfill sites can affect groundwater should hazardous materials seep out. Decomposing landfill waste can also produce methane, which is a greenhouse gas. There is now also a growing shortage of suitable landfill sites.

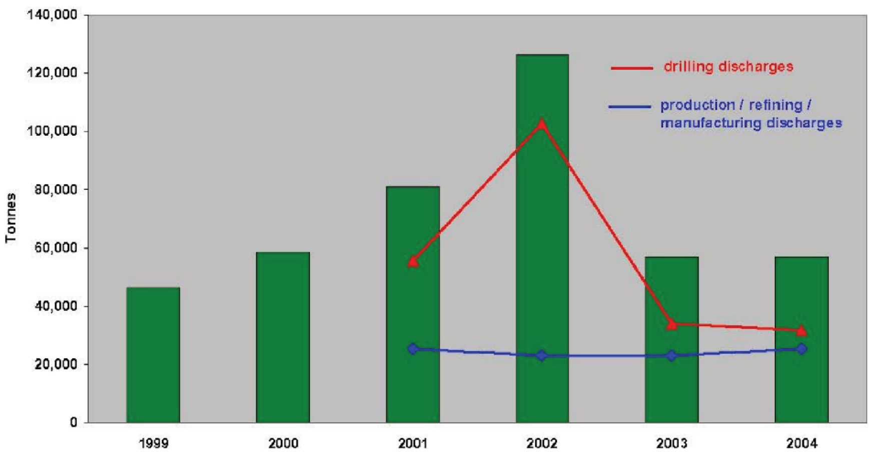


FIGURE 1.4. BP group discharges to water 1999–2004 (*See Color Plates*).

Concerns about the heavy metals and dioxins that incineration can produce make this a controversial process in many countries. Such emissions can be reduced or eliminated with special filters, and the heat produced by incineration may be recovered for direct use, or employed to generate electricity.

3.3.1 The waste disposal hierarchy

Government and industry employ many different waste disposal strategies, but there is broad agreement that the following options, listed in order of acceptability, constitute the waste disposal hierarchy:

- reduce waste at source through improved design – less packaging, for instance;
- reuse materials wherever possible;
- recycle materials wherever possible;
- incinerate with energy recovery;
- incinerate without energy recovery;
- landfill.

Businesses, including BP, along with other organizations, and individuals can all make an impact on waste. Long-term solutions depend on policies that promote and support the conservation and recovery of materials. Creative strategies for resource efficiency in homes and businesses also have a part to play.

3.3.2 Industry impacts

Waste is generated by many different industry operations: apart from hydrocarbon and petrochemical raw materials associated with our products it can include wood, metal, glass, process chemicals, catalysts and drilling cuttings, plastics, packaging and food.

Beyond hydrocarbons, a main concern is liquid or solid wastes classified as hazardous (under local or national regulations) and requiring special treatment. Other waste materials that have to be disposed of are classified as non-hazardous. Where solid waste is produced on offshore facilities, there's the added pressure of limited storage space and the need to transport it back to land for treatment and disposal. Minimizing waste production is thus particularly critical.

3.3.3 Industry approach

Waste is a local issue: it presents different risks and potential consequences depending on where it is generated. Typical significance is assessed locally, and local waste management plans are developed to reduce impacts.

3.3.4 Hazardous waste

The total amount of hazardous waste disposed of by BP in 2004 was 245,000 tonnes, with almost three-quarters (73%) of this volume coming from refining and marketing segment and over one-fifth (21%) from petrochemicals plants. This total represents a slight increase of 3% (6,800 tonnes) compared with the

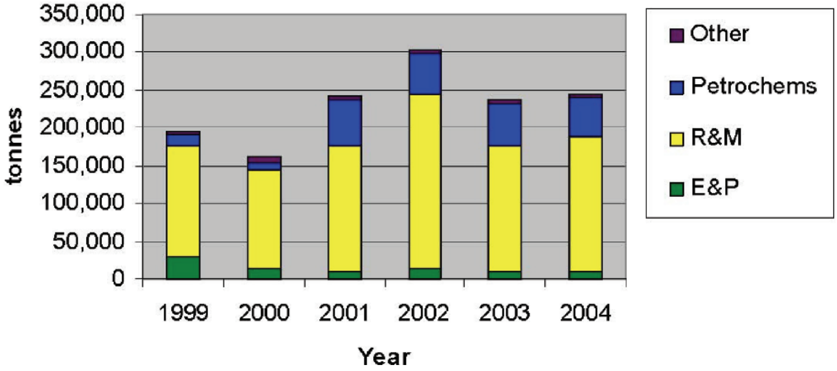


FIGURE 1.5. BP total hazardous waste 1999–2004 (*See Color Plates*).

figures reported for 2003, see Figure 1.5. However, hazardous waste disposals increased annually due to changes in facility portfolio, intermittent refinery shutdowns, and changing regulatory definitions.

3.3.5 Exploration and production

The BP exploration and production business (E&P) reduced the amount of hazardous waste generated in 2004 to 9,800 tonnes a 7% reduction compared to 2003. This continues a downward trend from the 28% reduction achieved in 2003 compared with 2002. However, increases and decreases in waste generation often result from increased drilling operations.

3.3.6 Refining and marketing

Refining and marketing (R&M) business usually generates the largest volume (179,000 tonnes for BP) of hazardous waste within the petroleum industry. At BP, R&M waste volumes increased by 14,000 tonnes (+9%) compared with 2003 figures, generally resulting from major turnarounds or project work at several facilities. Almost 80% of the R&M amount was generated by the refineries, whose waste increased 27% over 2003. Hazardous waste from the petroleum retail business comprised 18% of the R&M total in BP.

3.3.7 Petrochemicals

In 2004, the BP petrochemicals business disposed of 51,000 tonnes of hazardous waste; a reduction of 9% compared with the 56,000 tonnes disposed in 2003. This amount of waste (excluding deepwell) makes up 21% of the group total in 2004.

3.3.8 Non-hazardous waste

BP reported amount for 2004 of 237,000 tonnes represented an 18% decrease from volumes reported in 2003. In contrast to hazardous waste the reported

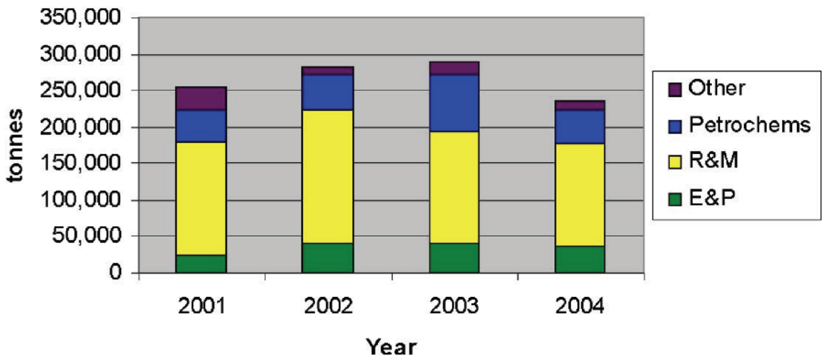


FIGURE 1.6. General solid waste disposal 2001–2004 (*See Color Plates*).

amount of general solid waste disposed during 2004 was lower than in the previous three years, see Figure 1.6.

Of the 2004 group total, BP attributed 60% to R&M operations, 19% to petrochemicals plants, 15% to E&P and the remaining 6% to GP&R and other businesses. As with hazardous wastes, increases in non-hazardous waste generation resulted from changes in production unit turnaround and construction activities. Industry continuously looks for ways to improve waste management and reduce waste disposed.

4 Technology used in the oil industry

Pollution can be seen as a waste product and environmental management has become a major part of the oil industry. Historically, environmental management has been predominantly 'end-of-pipe' pollution control but over the last 10 years the focus has been shifting towards pollution prevention. Obviously in this introduction it is only possible to skim the surface of these areas and subsequent chapters will go into much greater detail. All pollution control techniques are very dependent on plant and process specifics.

4.1 Pollution control

4.1.1 Production

Produced water. Historically, efforts have been concentrated on the separation of oil and water and the key technologies are separators, hydrocyclones and increasingly produced water reinjection.

Drilling mud. Traditionally, oil-based muds have been used. The main types of pollution control technologies are substitution by biodegradable synthetic muds and water-based muds, treatment of drill cuttings, e.g. solvent extraction and thermal treatment process, and reinjection of the ground-up cuttings into an impermeable formation. Also, ship to shore for waste treatment and disposal is increasingly used as an option.

Air. Reduction of venting and flaring together with improved operational procedures and leakage minimization are some of the most cost-effective technologies applied in production. Purge substitution or management, flare gas recovery, compression and reuse are other control measures.

4.1.2 Refining

Waste water. The main pollution controls are source segregation and effluent treatment facilities. Treatment facilities can include gravity separation, e.g. APIs, plate interceptors; advanced treatment, e.g. flocculation, filtration; and biological treatment, e.g. biofilters, activated sludge. About 90% of refineries in Western Europe apply all these methods [4].

Air. The two major groups of air pollutants are VOCs and combustion products. Fugitive emissions which are responsible for the majority of VOC emissions can be reduced by improved maintenance and inspection regimes, by effective operating procedures, by improved seals on tanks and valves and by implementing vapour recovery systems. Combustion products can be reduced by improving energy efficiency, by process modifications such as low NO_x burners or dry low NO_x systems, and end-of-pipe systems such as flue gas desulphurization, e.g. Claus plants.

Waste. Sludge handling, waste minimization, recycling, management systems and regeneration (e.g. catalysts) are involved. Disposal methods include recycling, reuse and alternative fuel use, incineration (with or without energy recovery), landfill and land farming, see Figure 1.7 [5].

4.1.3 Marketing

Air. The key control systems are reduction of vapour pressure of the fuel, on-board vehicle carbon canisters, specially designed filling nozzles, hoses and lines to transfer vapour from vehicle tanks to service station tanks.

Groundwater. The main forms of pollution control are overfill protection, e.g. high-level alarms, and inventory control for surface water run-off, a three chamber interceptor being used. For new, installations, pollution control may include secondary containment where required, e.g. double-bottomed tanks and second sleeves on piping, corrosion-resistant tanks and piping, fibre-glass underground storage tanks and closed drainage systems.

4.1.4 Transport

Spill prevention. On sea-going tankers, double-skin vessels are being used and commissioned and procedures are continually improving. Also, ballast is segregated to avoid discharge of oily ballast water. On road tankers, bottom

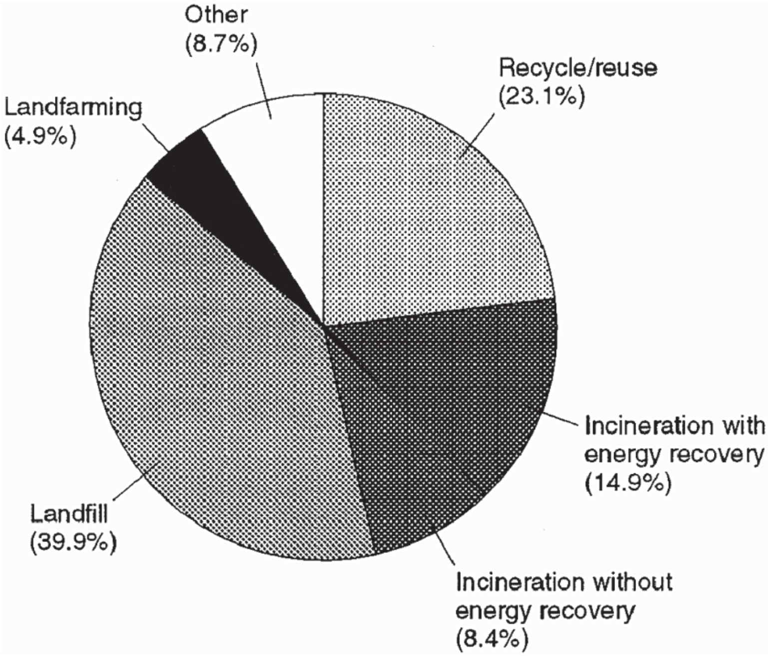


FIGURE 1.7. Refinery waste disposal methods [4].

loading has been implemented. In loading and unloading areas, impermeable surfaces are used to prevent spills reaching underlying groundwater.

Vapour recovery. Some of the main sources of VOCs come from tanker loading and unloading; the major control technologies are closed-loop systems and vapour recovery units, liquid absorption (usually kerosine), liquefaction by refrigerated cooling and membrane systems.

4.2 Pollution prevention

Pollution is a wasted resource, incurring raw material costs, disposal costs, expensive treatment and increased liability from environmental risk. The oil industry has been aware for many years that it makes both environmental and commercial sense to prevent and minimize pollution wherever possible.

The basic concepts of pollution prevention or waste minimization are to identify all sources of waste (where waste includes all pollutant emissions: atmospheric, aqueous and solid discharges to all media), quantify these losses and evaluate opportunities to reduce the waste such as reduce at source, reuse or recycle (see Figure 1.8) [4]. Examples of where these concepts have been applied are shown in Table 1.1.

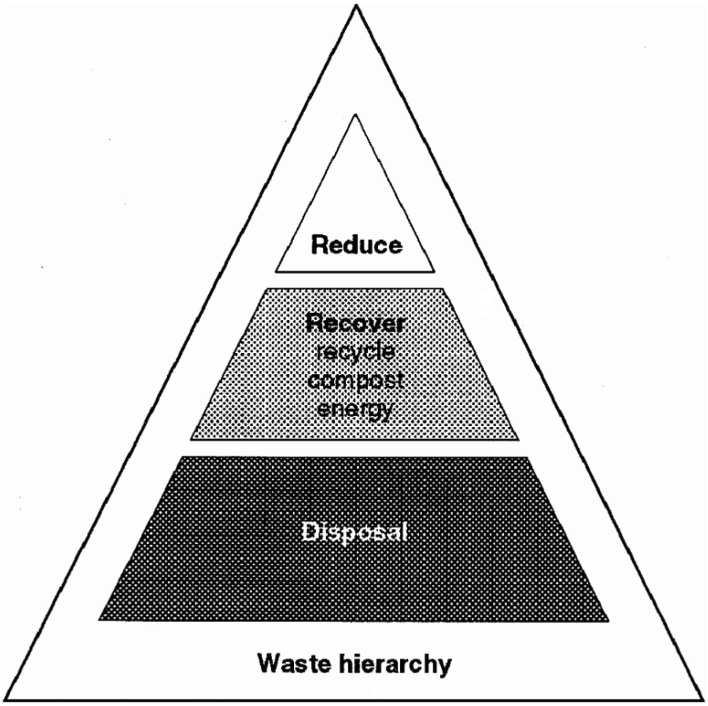


FIGURE 1.8. Waste hierarchy.

5 Oil industry future: design for the environment

The most effective way forward for environmental technology is to design in environmental considerations, in much the same way as mechanical strength and solvent and catalyst characteristics are. There are two ways for the industry to design for the environment, that is, within facility design and within the product specification.

5.1 Design out the production problems

A new drilling technique – extended reach drilling (ERD), sometimes called 'horizontal drilling' – has allowed the development of reservoirs in environmentally sensitive areas, by keeping the drilling and production facilities away from the most sensitive locations, such as at Poole Harbour in Dorset, UK. This type of drilling also allows greater production from minimum facilities, which is both cost effective and environmentally beneficial.

Operators in Alaska, BP and Arco, have moved away from using surface reserve pits for muds and cuttings (a large-volume but low-toxicity waste stream) and have developed downhole injection techniques for the disposal

TABLE 1.1. Pollution prevention

Reduced emissions	Zero discharge to sea of drilling waste by annular reinjection
	Drilling wastes are the combination of drilling muds and cuttings from wells. By grinding and injecting these wastes into the impermeable layers of rock formation where they came from there is: • no contamination of the environment; • energy efficiency – no transportation of waste; • cost saving in transportation and disposal charges.
Reduced waste	Minimization of liquid effluent Surveys of refineries have been able to identify an average of 30% reduction in effluent flow and to reduce future capital expenditure on end-of-pipe treatment
Reduced emissions	Flare reduction scheme Flaring from BP's North Sea operations have been reduced by over 20% without additional cost by target setting, reporting, optimization and improving awareness and cooperation between onshore and offshore expertise to ensure the best solutions
Substitution	Lubricant substitution Replacement of a listed toxic catalyst lubricant with limestone, which is non-toxic, has resulted in: • zero toxic emissions from this source; • savings in raw material costs; • reduced particulate emissions.
Recycling	Recycling refinery oily waste By reducing the water content of the solid waste and blending with fuel to use as cement kiln fuel, it was possible to: • reduce solid waste to landfill; • save disposal costs; • remove existing waste handling treatment; • obtain approval from regulatory agencies and local community.

of waste muds and cuttings to eliminate the need for surface discharge into reserve pits. In addition to the benefit of zero discharge of drilling wastes, the surface area of a well pad can be significantly reduced by as much as 70%.

In continental Europe service stations now are built to improve groundwater protection. Designs in Germany and other countries now use technology such a suction pumps at the dispenser, double skinned containment with pressurized and monitored interstitial space, and leak proof forecourt pavement. All being done to ensure fuel never reached the ground or groundwater.

6 Summary

Oil is integral to our society and is likely to continue to be so. The oil industry does produce emissions to the environment but these emissions are continually being minimized by the application of improved ‘end-of-pipe’ technology and improved design of facilities. Further chapters in this book will deal with all these issues in much more detail.

References

1. Nuefeldt, V. (ed.) (1988) *Webster’s New World Dictionary*, 3rd College edn., Simon and Schuster, New York.
2. Yergin, D. (1991) *The Prize*, Simon and Schuster, New York.
3. *BP’s Sustainability Report 2004* (2005), British Petroleum, London.
4. Concawe (2004) *Trends in Oil Discharged with Aqueous Effluents from Oil Refineries in Europe, 2000 Survey*, CONCAWE Report No. 4/04.
5. Concawe (1995) *Oil Refineries Waste Survey – Disposal Methods, Quantities and Costs, 1993 Survey*, CONCAWE Report No. 1/95.

Chapter 2
Environmental Control Technology for Oilfield Processes

A.K. Wojtanowicz

1 Introduction

For over 100 years, oilfield science and technology have been continually improving. The oil industry has evolved from one that was interested mainly in inventing tools and equipment to one that is not only economically, but also environmentally, conscious. In the 1980s, low oil prices forced oilfield technology to focus on economic efficiency and productivity. Simultaneously, environmental regulatory pressure added a new factor to petroleum engineering economics: the cost of working within the constraints of an environmental issue. In the 1990s, the industry has absorbed this cost and made a considerable progress in pollution control. The progress has been demonstrated by various indicators as follows [1–3]:

Since 1970, emissions of six principal pollutants (nitrogen dioxide, ozone, sulfur dioxide, particulates, carbon monoxide, and lead) decreased by 25%. At the same time, U.S. Gross Domestic Product (GDP) increased 161%, energy consumption grew 42%, and vehicle miles traveled rose 149%.

- Since the early 1990s, emissions of air toxics decreased by almost 24%.
- The rate of annual wetland losses decreased from almost 500,000 acres per year three decades ago to less than 100,000 acres per year, on average, since 1986.
- Between 1991 and 1997, volumes of the 17 most toxic chemicals in hazardous waste fell 44%.
- In the North Sea, total discharges have declined by 3,000 tons annually since 1996; despite the fact that produced-water discharges have increased by 15%.
- Industry spending on environmental activities averaged $9 billion per year in the last decade, more than it spent on exploration, and more than EPA's entire budget.

Department of Petroleum Engineering, Louisiana State University, Baton Rouge, LA 70803-6417, USA

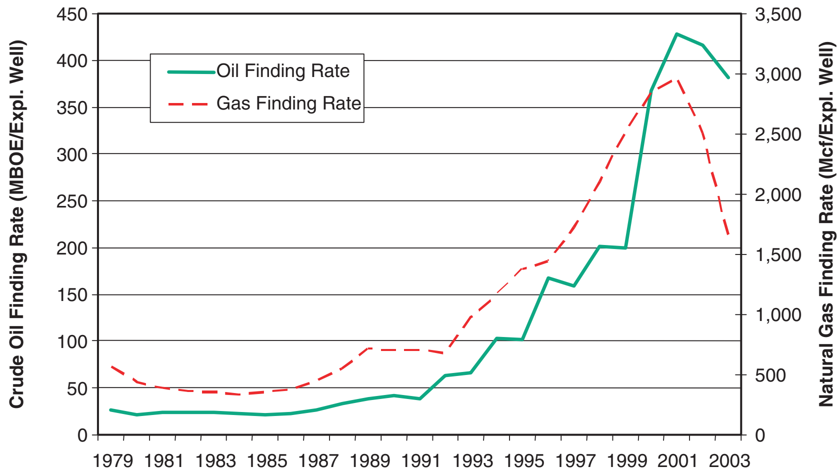


FIGURE 2.1. U.S. oil and gas finding rates; 3-year moving average [1].

Behind these and other general indicators of environmental performance lies the technology progress – various modifications and improvements of the oilfield process.

Some of the new technologies have directly addressed pollution control. Most of the technological progress, however, has been made primarily for productivity enhancement, but – indirectly – it also improved environmental performance. The technological progress made in the 1990s increased sevenfold the average new discovery of oil and gas reserves comparing to that in the late 1980s [4]. Also, the oil and gas finding rates, on average, have increased over fourfold, as shown in Figure 2.1. Moreover, the exploration drilling success rates have increased from 27% in the 1980s to over 42% in the 2000–2003.

These technological advances have indirectly produced environmental benefits by [4, 5]:

- Drilling fewer wells to add the same reserves; today, the U.S. industry adds two to four times as much oil and gas to the domestic reserve base per well than in the 1980s.
- Generating lower drilling waste volumes; today, the same level of reserve additions is achieved with 35% of the generated waste.
- Leaving smaller footprints; the average well site footprint today is 30% of the size it was in 1970, and through the use of extended reach drilling, an average well can now contact over 60 times more subsurface area.

The above observations show that environmental performance can be interrelated with productivity improvements and the overall technological progress so it does not have to be considered a separate and expensive undertaking with no economic returns on investments. Hence, it is feasible to develop technologies that increase productivity while protecting environment.

Traditionally, industry activities focused on environmental protection, was felt not to contribute to corporate profitability. Increasingly, however, environmental performance is being considered as a potentially important contributor to the bottom line. Consequently, the oil and gas industry is responding to a market increasingly driven, at least in part, by desires for simultaneously improved environmental performance and growth and profitability. More and more companies are reporting progress on environmental performance with a comparable level of rigor and sophistication as that exhibited in their financial reports.

Environmental performance is also being considered an important factor impacting corporate image. Petroleum industry is particularly vulnerable to public image because, on one hand it must seek public approval for accessing geographical areas and developing natural reserves, while – on the other hand – its image can be easily damaged by highly visible accidents of oil spills or well blowouts. For example, in March 2001, Petrobras's P-36 platform in the Roncador field in the Campos Basin off the coast of Brazil sank after three explosions left 11 workers dead. The world's largest semisubmersible at the time had been producing 84,000 barrels per day of oil and 1.3 million cubic meters per day of natural gas. The operator's report concluded that a gas leak had escaped into the sea where the blasts took place [6]. Another example is the highly publicized oil spill from the Prestige tanker that sank off the coast of Spain in November 2002 [7–9]. The tanker was carrying 20 million gallons of fuel oil – nearly twice the amount of oil as the *Exxon Valdez*. Although much of the fuel remained in the tanker after it sank, substantial volumes of spilled fuel washed up on beaches over a large area of Northern Spain and Southern France, damaging prime fishing areas.

The petroleum industry involved in these and other visible accidents learned that public perception might often play a larger role in influencing a course of action than facts. They learned that compliance with existing laws and regulations is not sufficient to convince the public but there must be evidence of improvement of technology to receive approval for continuing operation. Moreover, a company's environmental performance is becoming an important factor in corporate assessments by the investment community, not just as a factor considered as part of the 'watchdog' function of environmental organizations. In fact, a company's environmental performance is increasingly becoming a factor in investor evaluations of future potential [10].

Petroleum industry is expected to perform concurrently in three areas, productivity, environmental and social. This 'triple bottom line' concept operates on the principle that better performance of one of the three pillars – representing economic, environmental and social considerations – cannot be considered substitutable for underperformance in another [11]. Therefore, a successful technological progress must address a technology that combines productivity advantage with environmental protection and – as such – make the operator accountable to the public.

2 Environmental control technology

Environmental control technology (ECT) is a process-integrated pollution prevention technology. Within the broader scope of environmental technology that includes assessment of environmental impact, remediation and prevention, ECT relates mostly to prevention and risk assessment. Historically, developments in preventive techniques came after analytical and remediation measures, which have been found to be inadequately reactive and progressively expensive.

Reactive techniques focus on impacts and risk. With reactive pollution control, the positive action is entirely linked to the environmental objective. History provides ample evidence that reactive strategies do little more than transfer waste and pollution from one medium to another. *Preventive* action seeks root causes of pollution generation. It often requires modification of technology that has no apparent linkage to an environmental objective and is intrinsically more comprehensive than reactive strategies [12].

In principle, ECT is a process-engineering approach to the prevention of environmental damage resulting from industrial (oilfield) operations. The approach draws on the modern theory of 'clean production', a term coined by the United Nations Environmental Program's Industry and Environmental Office (UNEP/IEO) in 1989 [13].

The clean production theory, in its broadest sense, delineates an approach to industrial development that is no longer in conflict with the health and stability of the environment, a kind of development that is sustainable. In the narrowest sense of the theory, clean production signifies a preventive approach to design and management of 'environmentally controlled' industrial processes. The approach seeks to reduce 'downstream' or end-of-pipe solutions to environmental problems by looking 'upstream' for reformulation and redesign of the processes or products. It also involves a broader, integrated, systematic approach to waste management.

Within the parameters of clean production, then, oilfield environmental control technology allows an examination of drilling, well completion and production as environmentally constrained processes containing inherent mechanisms of environmental impact. These mechanisms include the generation of waste, induction of toxicity or creation of pathways for pollutant migration. Identification and practical evaluation of these mechanisms constitute two parts of the ECT scope. A third part involves the development (at minimum cost) of new methods and techniques to meet environmental compliance requirements without hindering productivity.

Naturally, ECT tackles a large spectrum of oilfield technologies, such as closed-loop drilling systems, subsurface injection, borehole integrity, toxicity control in petroleum fluids, downhole reduction of produced water and use of land for on-site storage and disposal of oilfield waste. In this chapter, basic concepts of the ECT approach are presented first. Then, the ECT approach is used to analyze oilfield processes of drilling and production and to describe developments of environmental control components in these technologies.

3 Evolution of environmentally controlled oilfield processes

Conceptually, the perception of environmental problems and solutions is an evolutionary process of shifting paradigms of waste management as depicted in Figure 2.2. Over time, concepts regarding what is the best strategy for waste management have changed from 'disposing at will' (followed by remediation), to dilution/dispersion of waste below the assimilative capacity of the environment, to controlling the rate or concentration of pollutants at the waste discharge ('end-of-pipe' treatment), to developing truly preventive technologies.

In the petroleum industry this shift of paradigms is described as a transition from a PCD (produce–consume–dispose) approach to a WMT (waste management technology) approach and, finally, to a preventive ECT approach [14]. The large quantities of waste fluids and slurries (drilling muds and produced waters), and their associated wastes that are created during everyday oilfield activities have been conventionally perceived as unavoidable. This perception is typical of the PCD approach. Not only does this approach assume a proportional relationship between the production stream rate (oil/gas) and the volume of waste, but it also assumes that the flow of materials is open so that the waste must be discharged from the process into the environment. Such an attitude has prevailed for most of the modern history of petroleum engineering.

In the early 1980s, evidence of health and environmental hazards in the oilfield was accumulated and made public, which triggered serious public concerns and resulted in regulatory pressures [15–19]. Public opinion has

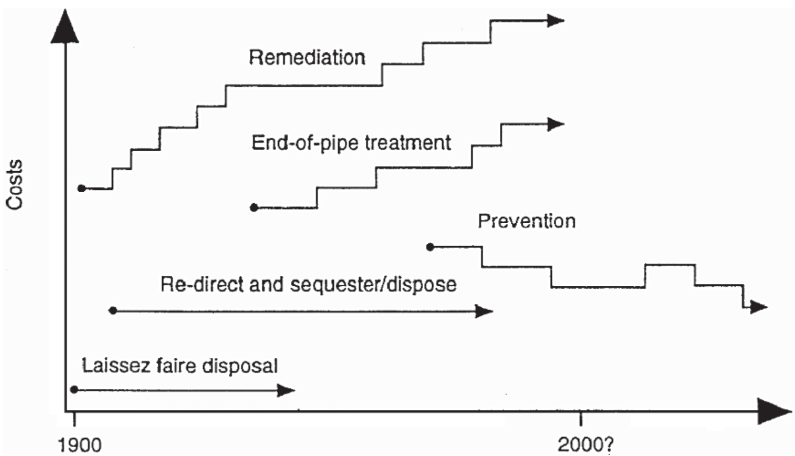


FIGURE 2.2. Waste management strategy paradigm shift [12].

been documented in several surveys. Growing public pressures (and private lawsuits) prompted regulatory activities. Since the late-1980s and early 1990s in the USA, for example, oilfield waste has been identified, its volume and toxicity evaluated and its disposal methods scrutinized [20, 21, 25]. This scrutiny, together with the industry's PCD-dominated environmental paradigm, resulted in the rapid development of waste management programs (the WMT approach). Indeed, at the time, clean-ups were prioritized over preventive measures in an effort to employ the existing waste disposal industry rather than to rethink the whole oilfield process again and identify environmental control techniques.

This seemingly logical paradigm was founded on three fundamental arguments: (1) waste must be managed because there is no other way to protect the environment; (2) waste has no value so its management is the most efficient solution; and (3) waste is external to the oilfield process. In fact, all these arguments lack substance:

(1) The environment can be efficiently protected by reducing waste volume and/or its toxicity (source reduction and source separation); for example, downhole oil/water separation (DOWS) could revolutionize the industry by dramatically reducing the amount of water brought up the wellbore [22]. These technologies can minimize the possibility of groundwater contamination from tubing and casing leaks, and can help minimize spillage of produced water onto the soil because less water is handled at the surface. Produced-water lifting, treatment, and disposal costs are large components of operating costs; reducing the amount of water brought to the surface can help to substantially reduce these costs.
(2) Oilfield waste does sometimes have value; for example, in California, production sludge is processed to recover crude, and in Alaska the drilled cuttings gravel is used for road construction [26]. A study by Shell examined alternatives for recycling spent drill cuttings. From an initial list of over 100 options, the most viable alternatives for application in the U.K. were determined to be used in cement manufacture, road pavement, bitumen and asphalt; as low-grade fuel, and for cement blocks and ready mix concrete [23].
(3) Waste becomes external only if it is released from the process; for instance, the annular injection of spent drilling mud leaves no drilling waste. Another example is taking carbon dioxide emitted from the coal gasification in southeastern Saskatchewan and injecting it in the Weyburn field to enhance recovery [24].

Within the petroleum industry, a change in the environmental paradigm from the PCD syndrome to the preventive approach of environmental control has recently emerged as a result of high disposal costs. The cost of waste management has grown steadily in response to increasing volumes of oilfield waste. Interestingly, the amount of regulated waste has grown much faster than oil and gas production because regulated waste volume has been driven mainly by regulations rather than by production rates.

In principle, the environmental control paradigm in petroleum engineering involves three concepts: (1) the fundamental purpose of petroleum engineering is not to protect the environment but to maximize production while preventing environmental impact; (2) compliance problems can be eliminated when environmental constraints are introduced into the production procedures; and (3) any stream of material is off-limits to regulatory scrutiny and can be controlled by oilfield personnel as long as it remains within the oilfield process. In practice, this attitude requires an understanding of environmental impact mechanisms and the willingness to redesign the process.

The environmental control paradigm presented above is a philosophical concept which needs a practical methodology. Such a methodology would give a designer some guidelines regarding how to analyze an industrial process and where to put efforts to make the process 'cleaner' (or 'greener', as some put it).

3.1 Scope and characteristics of oilfield ECT

This overview of ECT methodology includes a definition, objectives and characteristic features, general ECT methods and a description of basic steps needed to develop a specific technology. ECT is defined as a technical component of an industrial process that is functionally related to the interaction between the process and environment. Such interaction involves pollution and other adverse effects (impacts) on environmental quality. The objective ECT is to prevent this interaction by controlling the impact mechanisms. The three important features of ECT are integration with the process, specific design and association with productivity.

These three features make ECT different from the technologies of waste management. The difference requires further discussion in relation to oilfield applications. First, however, we must recognize the difference between waste and the process material stream. This difference draws on two facts: (1) where the material is with respect to the process; and (2) what the material's market value is. This concept assumes that no waste exists inside the process – just material streams. On leaving the process (i.e. crossing the process boundary) a stream of material becomes either a product (including by-products) or waste. The difference stems from the market value of the material. Having a positive market value, the material becomes a product. Material with zero value becomes waste. When the value is negative, the material becomes regulated waste (regulated waste requires expenditures for proper disposal).

In view of the above, WMT becomes extraneous to the process because it operates outside the process boundaries and within the environment. WMT involves processing and disposing of the waste as it is discharged from a well site or production plant. Expertise in waste management technologies lies mostly outside the petroleum engineering field. Over the last 10 years, the oil industry has been offered several waste management technologies, providing considerable understanding of the available services. Examples of alternative WMT for production operations are land farming, incineration, road spreading, commercial waste injection facilities and brine demineralization plants. The WMT for drilling operations, other than those for production, include offshore hauling of drilling fluids and cuttings for onshore disposal. These techniques abate pollution without interfering with oilfield procedures; therefore, they provide no incentive for process improvement. Also, the implementation of WMT requires no expertise in petroleum engineering and does nothing to prevent waste generation.

In contrast to WMT, ECT is an integral part of petroleum engineering. It addresses all of the mechanism and control techniques that relate to adverse environmental effects, such as generation of the waste volume and its toxicity, subsurface migration of toxicants and damage to the land surface. The objective of ECT is to minimize, through process improvements, interactions between oilfield processes and the environment. Therefore, the ECT concepts draw exclusively from petroleum engineering expertise. However, development of specific techniques may require expertise outside of petroleum engineering, such as solid–liquid and liquid–liquid separation, environmental science and environmental law, risk analysis and economics.

The use of outside expertise to develop ECT for petroleum engineering includes, of course, some waste management techniques. Indeed, both technologies are bound to draw from the same pool of science. This may sometimes create an impression that ECT is merely a part of WMT. There is, however, a distinct difference between the two. For example, dewatering of abandoned oilfield waste pit slurries, highly diluted with rainfall/run-off water, is a WMT and does not require any oilfield expertise. However, the inclusion of the dewatering component within the closed-loop mud system is an ECT. In this application, dewatering becomes intrinsic to the drilling process; it requires an in-depth knowledge of mud engineering. It also poses a research challenge since drilling fluids, unlike waste water, contain high concentrations of surface active solids.

ECT overlaps with WMT in the area of subsurface injection, which has long been perceived as a waste disposal option in various industries. In this case, however, the petroleum engineering expertise in borehole technology has merely been extended to other applications. Further, when subsurface injection is used in the oilfield for recycling produced water or annular injection of drilling fluids, the method is (1) intrinsic to the oilfield process and (2) requires oilfield expertise to perform, thus making it an ECT.

There is a strong affiliation between ECT and process-control measures. Similar to process-control projects, ECT requires a considerable knowledge of oilfield processes in order to identify the chain reactions that lead to the environmental impact. As an example, let us consider the cause-and-effect relationship between the seemingly unrelated phenomena of drilling mud inhibition and the environmental discharge of drilling waste from the well site. In fact, there is a strong functional relationship between the degree of drilled cuttings dispersion in mud and the waste mud volume. There is also a close analogy between ECT and process-control methods when solving design problems. In process-control design one must prioritize objective function and consider constraints imposed on the design. Similarly, any practical design of ECT must consider the environmental regulations as constraints, while also prioritizing productivity measures (such as daily production or cost per foot).

In this chapter, the term 'environmental control' is preferred over 'pollution prevention' because it implies broader objectives and suggests the process-control-related means to accomplish these objectives. Oilfield operations create the potential for ecological damage that can hardly be viewed as 'pollution', though this damage may set the scene for pollution. Examples of such ecological impact include land subsidence or damage to subsurface zonal isolation resulting from a poor annular seal or from fracturing a confining zone. Characteristically, the destruction of interzonal isolation will not result in pollution if there is no sufficient pressure differential across confining zones.

In summary, any WMT may become ECT if it becomes integrated with the oilfield process. Such integration requires (1) containing the process within clearly defined environmental boundaries and (2) placing the WMT within these boundaries.

3.2 Methodology of ECT design

A conceptual schematic diagram of an environmentally controlled industrial process is shown in Figure 2.3. Any process including oilfield operations can be visualized as such an entity having both market and environmental boundaries. Of course, manufacturing processes are best fitted to this schematic because their boundaries are visible and clearly defined. Nevertheless, petroleum drilling and production can also be visualized using the material flowpath in Figure 2.3. In contrast to manufacturing, oilfield processes do not have readily perceived environmental boundaries, particularly in the subsurface environment. However, they may generate subsurface pollution, which implies a flow of pollutants across a subsurface environmental boundary. The presence of such a boundary is implicit in the issues of borehole integrity and migration across confining (sealing) zones into underground sources of drinking water. Oilfield technologies related to these issues are discussed later.

Although ECT must be specifically designed for each industrial process, its methodology includes general techniques such as source reduction, source separation, recycling, confinement, beneficial use (reuse), environment risk analysis and life-cycle assessment. Figure 2.2 depicts the concepts that underlie these methods.

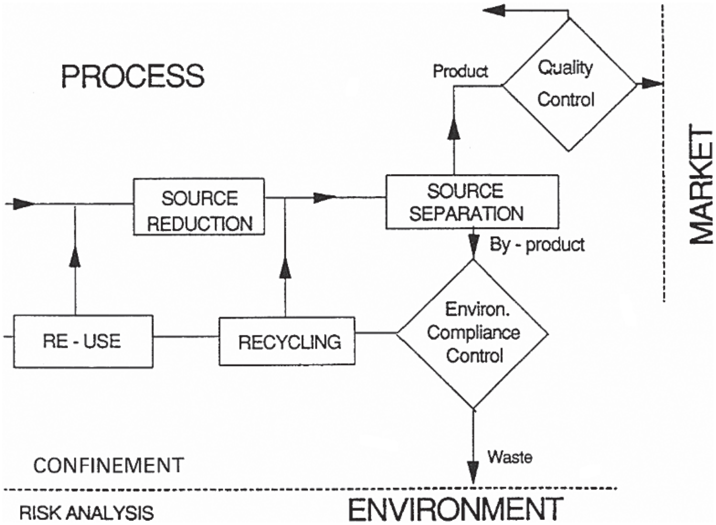


FIGURE 2.3. Conceptual flowpath of environmentally controlled process.

Source reduction involves restricting the influx of pollutants into the process or inhibiting reactions that produce toxicants within the process (examples: slim-hole drilling; subsurface water 'shut-off'; low-toxicity substitution).

Source separation means the removal of pollutants from the process material stream before the stream leaves the process across the environmental boundary and becomes a waste (examples: surface or downhole separators of petroleum and water; segregated production of oil and water; reserve-pit dewatering).

Internal recycling involves closing the loop of a material stream within the process (examples: drill solids-control systems; annular injection of cuttings; downhole separation and disposal of produced brines).

Internal reuse involves employing potential waste within the process (examples: mud-to-cement technology; reservoir pressure maintenance through produced-water reinjection; water flooding with produced brines).

Containment means prevention of an uncontrolled transfer across the environmental boundary caused by leaking, leaching, breaching or cratering (examples: mechanical integrity tests; shallow well shut-in procedures; anti-gas migration cements; annular pressure monitoring during subsurface injection).

Environmental risk analysis (ERA) consists of analytical methods for predicting localized environmental impact (endpoint) for a given variant of process design (emission point). Generally, these are mathematical models (and software) of flow, transport, mixing and dispersion. ERA for oilfield operations involves simulation models of flow across leaking confining zones, channeling outside unsealed boreholes and disposal fracture propagation.

Life-cycle assessment (LCA) is another analysis method for economic production strategies that considers concurrently the productivity and pollution aspects of the production process. In petroleum production the LCA approach qualifies for macro-analysis of petroleum development projects in environmentally sensitive areas, economic impact analysis of environmental regulations or, on a smaller scale, for designing environmental management of a single drilling well or production site [27].

Conceptually, process modification through additions of the environmental control components requires a systematic approach that can be summarized in the following steps:

- define environmental boundary of the process;
- identify inherent mechanisms of environmental impact;
- consider ECT methods and create options for process modification;
- evaluate technical performance (upstream and downstream) of each ECT option;
- calculate net ECT cost;
- decide on process modification.

The difficulty in defining subsurface environmental boundaries for oilfield drilling and production has been discussed above. The surface boundary is somewhat easier to define, but the decision is still based upon subjective judgement rather than scientific definition. In drilling operations, for example, reserve pits were initially included in the drilling fluid circulation systems (hence the name 'reserve') and considered part of the drilling process. Later, the pits were often used as a waste dump that belonged to the environment. After well completion, reserve pits were either abandoned [15] or opened and spread on the surrounding land. Today, on modern rigsites, reserve pits during drilling are carefully isolated from the surrounding environment and are closed promptly after well completion using various environmental techniques described in Chapter 5. In this modern approach, reserve pits are considered part of the drilling process rather than as part of the environment; they reside within the environmental boundary that surrounds the whole rigsite and underlays the bottoms of the pits.

Being an integral part of the process, each ECT component not only improves environmental compliance (downstream performance), but also affects the process productivity (upstream performance). Thus, evaluation of ECT performance should include both the upstream and downstream effects. The most typical example here is the screening of various oilfield chemicals in search of those chemicals that give a combination of the highest performances both upstream and downstream. In one such study [28], five different biocides used to prevent microbically induced corrosion, souring (generation of hydrogen sulphide) or fouling (plugging) of petroleum production installations were evaluated. The evaluation method involved assessment of upstream performance, i.e. the effectiveness of these chemicals in reducing production of H_2S or soluble sulfides (by-product of bacterial growth). Downstream performance was evaluated by modelling transport and the fate of these chemicals for five scenarios of their possible emissions from the production process to the environment.

The net cost of an ECT component is the sum of the ECT cost, value of lost (or gained) production due to ECT and savings in compliance costs due to ECT. Typically, the use of ECT would result in some productivity losses. In drilling, for example, the use of water-based, low-toxicity mud substitute for an oil-based mud would result in a slower rate of drilling. However, some ECT components show potential for improvement of both productivity and environmental compliance. One example here is the new production technique of *in situ* water drainage, described later. Potentially, this method may increase petroleum production while reducing both the amount and contamination level of produced water.

4 ECT analysis of drilling process

A fundamental notion in the ECT approach is that petroleum production, being a process of extraction of minerals from the environment, comprises inherent mechanisms of environmental impact that result from disruption of the ecological balance. The objective of this chapter is to identify these mechanisms and discuss the present level of understanding.

The disruption of the ecological balance (environmental impact) through drilling operations (excluding the well site preparation work) occurs in two ways: (1) surface discharge of pollutants from an active mud system; and (2) subsurface rupture of confining zones (that hydrodynamically isolate other permeable strata) to provide a potential conduit for vertical transport of pollutants.

The regulatory definition of pollutant (in contrast to the popular perception based on health hazards) includes seemingly non-toxic elements such as total suspended solids (TSS), biological oxygen demand (BOD), pH and oil and grease (O&G) (the list of conventional pollutants in the USA includes TSS, BOD, pH, fecal coliform and O&G).

4.1 Mechanisms of drilling waste discharge

Volume and toxicity are two environmental risk criteria for evaluating drilling waste discharge. The flowpath of the drilling process and its environmental discharge mechanisms is shown in Figure 2.4. The process material stream comprises two recycling loops, the solids-control (drilling mud) loop and the volume-control (water) loop. Conventional drilling operations employ only the solids-control loop. Theoretically, the solids-control loop could be ‘closed’ so that all drill cuttings may be removed in their native state, and the mud may be recycled in the system. In reality, however, some cuttings are retained in the mud system and some drilling fluid is lost across the separators so that

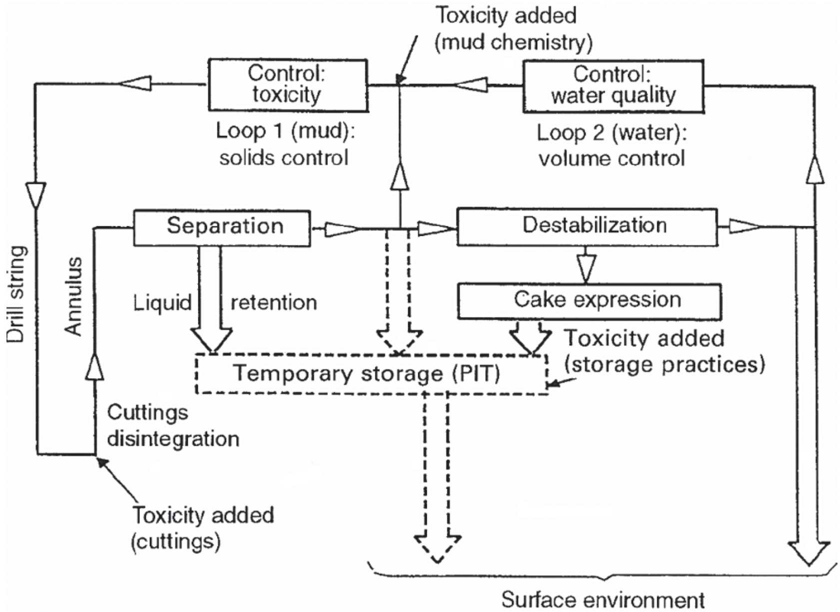


FIGURE 2.4. Flowpath of drilling process in relation to environmental discharge.

the loop is always open, thus contributing to surface discharge. The excessive build-up of drilling mud from loop 1 passes over to the second stage process depicted as the water loop 2 in Figure 2.4 [29]. The objective of the water loop process is to reduce the volume and recover the water phase of drilling mud. The process has been developed from the principles of industrial sludge dewatering and it employs two mechanisms of mud dewaterability: soil destabilization and cake expression. Dewatering is discussed in more detail later.

The largest volume of drilling-related wastes is spent drilling fluids or muds. The composition of modern drilling fluids or muds can be complex and vary widely, not only from one geographical area to another, but also from one depth to another in a particular well as it is drilled. Muds fall into two general categories: water-based muds, which can be made with fresh or saline water and are used for most types of drilling, and oil-based muds, which can be used when water-sensitive formations are drilled, when high temperatures are encountered, when pipe sticking occurs or when it is necessary to protect against severe drill string corrosion. Recently, there has been a rapid development of a third category of drilling fluids, synthetic muds. These muds are formulated with synthetic organic compounds instead of mineral or diesel oil and are less toxic than oil-based muds.

Drilling muds contain four essential parts: (1) liquids, either water or oil or both; (2) active solids, the viscosity/filtration building part of the system, typically bentonite clays; (3) inert solids, the density-building part of the system, such as barite; and (4) additives to control the chemical, physical and biological properties of the mud.

Drill cuttings consist of inert rock fragments and other solids materials produced from geological formations encountered during the drilling process and must be managed as part of the content of the waste drilling mud. Other materials, such as sodium chloride, are soluble in freshwater and must be taken into account during disposal of drilling muds and cuttings.

The most general classification of drilling waste includes primary waste and an associated waste. The classification considers the origin and volume of generated waste. Drilling wastes with low toxicity constitute primary waste. The category of primary drilling waste comprises drilling muds and drill cuttings. Associated drilling waste may include rigwash, service company wastes such as empty drums, drum rancid, spilled chemicals, workover, swabbing, unloading, completion fluids and spent acids.

Large volumes of primary drilling waste are generated during the drilling process as a result of volumetric increase in the mud system. The volumetric increase of the active drilling fluid (loop 1 in Figure 2.4) is inherent in the drilling process. The volume build-up mechanism is a chain reaction shown in Figure 2.5 [29]. The chain reaction begins with the dispersion of reactive cuttings into the drilling fluid environment. The dispersion results in the decrease of cuttings size from their initial size to the few-microns size range. Most currently used separators do not work efficiently with small solids, i.e. they remove only a small fraction (or none) of these solids. The resulting build-up of fine solids affects the ability of the drilling fluid to perform its functions, which, in turn, hinders drilling process performance (low drilling rate, hole problems).

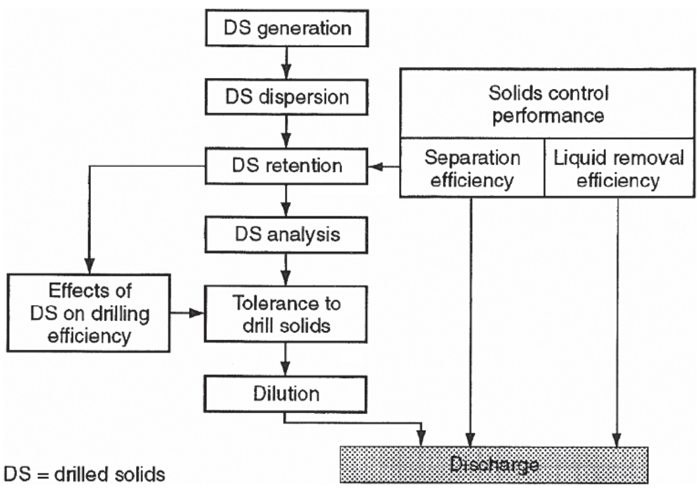


FIGURE 2.5. Chain of causality in generation of primary drilling waste [29].

The minimum acceptable drilling performance relates to a certain maximum concentration of solids or solids tolerance. Solids tolerance varies for different mud systems and densities. Low-solids/polymer systems display the lowest level of solids tolerance (4%), whereas the dispersed systems display the highest (15%). Also, the increase in mud density reduces its tolerance to solids. (Specific values of solids tolerance for various muds have been compiled in various empirical nomograms.) Dilution with fresh mud (or water) is used to keep the solids concentration below the solids tolerance level. The dilution results in a steady build-up in the mud system volume and a subsequent overflow of loop 1 in Figure 2.5. In conventional drilling operations, the overflow of loop 1 becomes a waste discharge stream. Its volume may exceed by several-fold the actual borehole volume. Table 2.1 shows the estimated discharge volumes of waste mud per barrel of the drilled hole [30]. It is evident that the volume build-up mechanism is most active for dispersed lignosulfonate systems. Characteristically, these systems are the most tolerant to solids.

Disintegration of drilled solids takes place during annular transport from the drilling bit to the flowline. As a result, cuttings become smaller. This size reduction of cuttings is the first factor contributing to cuttings retention in the mud system. The size of cuttings depends upon (1) the initial size resulting from the bit action, (2) bottomhole cleaning efficiency, and (3) the mechanical strength of cuttings in the mud environment. Besides a qualitative understanding of the effects of bit type and pressure differential across the rock face, very little is known about the initial size of cuttings. An example of the actual initial size of cuttings generated by various types of cone bits is shown in Table 2.2 [31]. Data

TABLE 2.1. Mud used per hole drilled[a]

Mud type	Mud/hole (v/v)
Lignosulfonate	6–12
Polymer	4–8
Potassium (KOH)/lime	3–6
Oil-base	2–4

[a]After Ref. 30.

TABLE 2.2. Effect of roller cone insert bit type on initial size of cuttings[a]

Bit type	Chip volume) (mm^3)	Height[b] (mm)	Diameter[c](mm)	R/R_2[d]	T/T_2[e]
Very soft	825	5	26	2.5	2
Soft[f]	504	4	22	1	1
Soft[g]	495	3	26	2	2

[a]After Ref. 31.
[b]Minimum measured.
[c]Calculated for cylindrical chip.
[d]Relative drilling rate, related to bit No. 2.
[e]Relative bit life, related to bit No. 2.
[f]Slim, wedge-shaped inserts.
[g]Thick, short, scoop-shaped chisels.

support the common knowledge that the harder is the bit type, the smaller are the cuttings. However, there is no predictive model based on drilling mechanics that would relate initial cuttings size to bit geometry and rock strength. A preliminary study in this area determined the relationship between the specific energy of rock destruction, total mechanical energy of a bit and cuttings size [32].

The effect of bottomhole cleaning on the initial size of cuttings can be inferred from the experimentally verified response of the drilling rate to the bottomhole hydraulic energy generated by bit nozzles. It is generally assumed that in soft rock drilling, the bit flounder point represents an offset of poor cuttings removal from under the bit [33]. The remaining cuttings undergo additional grinding, which results in size reduction. The flounder point can be determined experimentally using the drill-off test. Further cuttings destruction can be prevented by adjustment of the mechanical energy to the hydraulic energy at the bottom of the hole.

Size reduction of cuttings is caused by loss of cohesion due to hydration of their rock matrix. Cuttings originating from non-swelling rocks (sand, limestone) are unlikely to lose their initial cohesion on their way up the borehole annulus. It has been proved, however, that even these inert solids undergo disintegration under conditions of shear, as shown in Table 2.3 [34].

The major mechanism controlling cuttings disintegration stems from the hydration energy of their source rock, usually shale. The disintegration has been correlated with several variables measured in various tests of cuttings hydration rate, such as (1) the swelling test (measured: linear expansion); (2) capillary suction time test, CST (measured: time of water sorption); (3) cation-exchange capacity test, CEC (measured: dye adsorption); (4) activity test (measured: electrical resistance of water vapor); and (5) rolling test (measured: weight loss of drill cuttings of a certain size) [35–38]. The drawback of these tests is that they do not provide a direct measurement of drill cuttings properties (strength, size). However, they do determine other variables that correlate with these properties.

The proposed single property of shale cuttings representing their strength is the storage modulus of viscoelasticity [39]. The storage modulus is a measure of the energy stored and recovered under conditions of oscillating stresses. It can be measured using an oscillatory viscometer and a compacted ‘drill cutting’ platelet after various exposure times of a cutting to drilling mud. Figure 2.6 shows the strength of a shale cutting after 18 h of exposure to various concentrations of salts (KCl) and polymer in the drilling fluid.

TABLE 2.3. Shear disintegration of inert solids in mud[a]

	Particles smaller than 2 μm (volume fraction)						
Shear treatment	Barite A (green)	Barite B (orange)	Barite C (orange)	Barite D (buff)	Barite E (orange)	Itabarite	Ilmenite
None	6.6	8.0	5.3	8.8	12.6	4.3	0.3
Ultrasound (1 min)	13.3	13.2	12.1	16.9	12.8	15.7	0.6

[a]After Ref. 34.

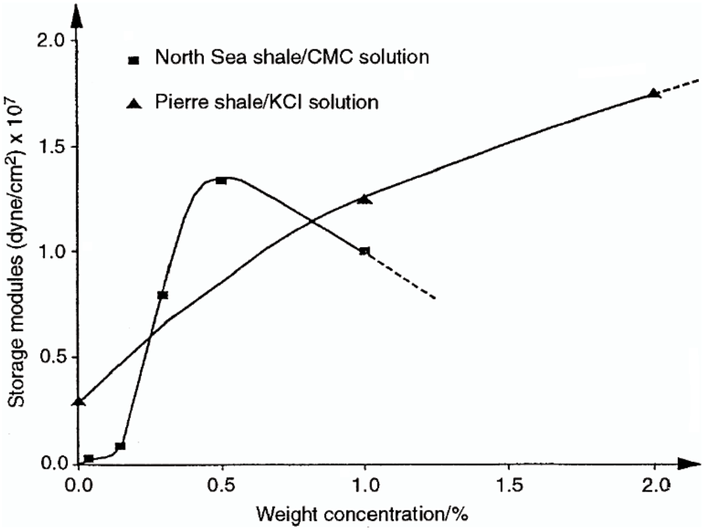


FIGURE 2.6. Strength of shale cutting in various mud environments (1 dyne = 10^{-5} N) [39].

The initial strength of cuttings and their tendency to become hydrated can be inferred from the mineralogy of shales with respect to depth. The disintegration rate of shale cuttings results from the mineralogical composition of the shale and can be directly related to geological structures in the drilling area. For example, Figure 2.7 shows the drilled-depth correlations of the illite concentration (low-reactivity clay) and shale water content for the offshore Louisiana Gulf Coast [40].

The depth-related reactivity of shales can also be observed in the size of cuttings coming from the well. An analysis of the size distribution of solids at the flowline versus drilling depth shows different rates of cuttings disintegration during their annular transport, as evidenced by Figure 2.8 [41]. Also shown in Figure 2.8 is a correlation between size of mud solids at the flowline and at the pump suction (i.e. upstream and downstream of solids-control system). Such correlations are more useful than measurements of the rock hydration rate because they not only identify well sections with water-sensitive rocks but also provide data that can be used to evaluate solids-control systems.

The separation efficiency of a solids-control system is limited by the size of the solids in the drilling mud entering the separators. This limitation is the next factor contributing to solids retention in the mud system. The plots in Figure 2.8 show a comparison of solids size in drilling mud samples taken from the flowline and the suction tank. In the three sections of the well (2300–2800, 5000–5600 and 6150–7215 ft; 1 ft = 0.3048 m), the efficiency of cuttings removal was evidently almost zero. The most likely reason is that the size of the solids was below the removal range of the surface separators. Thus, the

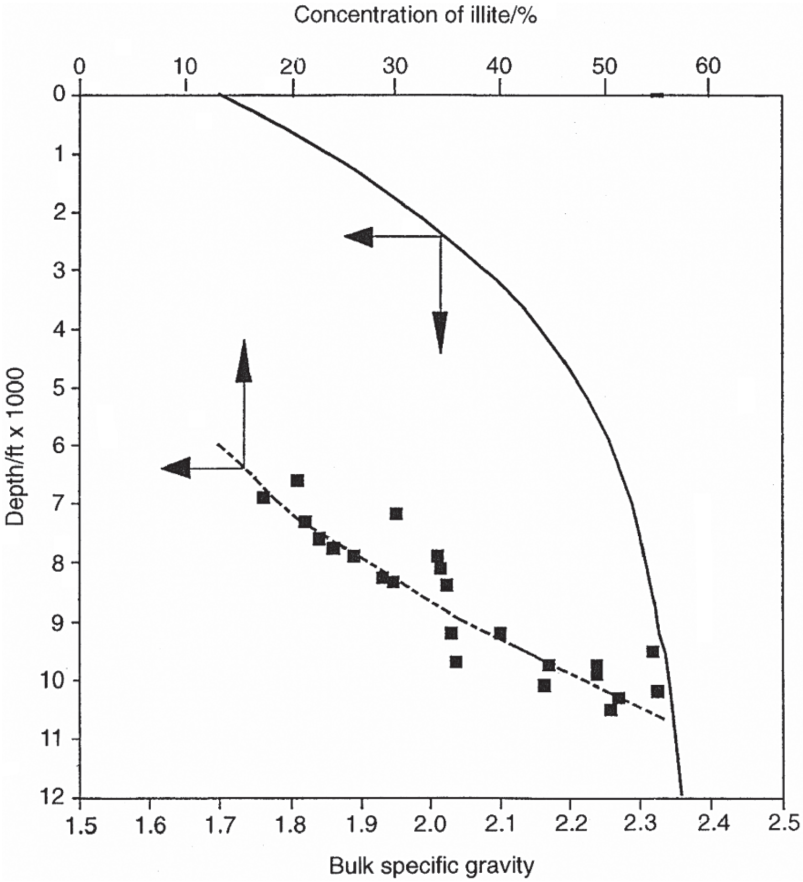


FIGURE 2.7. Shale reactivity indicators versus depth for Louisiana Gulf Coast [35].

drilling fluid loop in these sections was 'wide open' because the only way to control mud solids was to dilute the mud system and generate an excessive volume.

There is an important misconception about the performance of solids-control separators. The widely recognized concept of the subsequent size exclusion of solids holds that the shale shaker removes cuttings > 120 μm, desander 50 μm, desilter 15 μm and a centrifuge 3 μm. However, the actual performance is not only lower than the theoretical one, but it is also affected by the feed mud rheology and operational parameters of a separator. As an example, Figure 2.9 shows the theoretical and actual grade separation curves for a 4 in (10 cm) hydrocyclone [34, 41, 42]. Both the laboratory and the field data indicated poor performance of hydrocyclones with weighted mud systems; this raised some questions regarding the applicability of mud

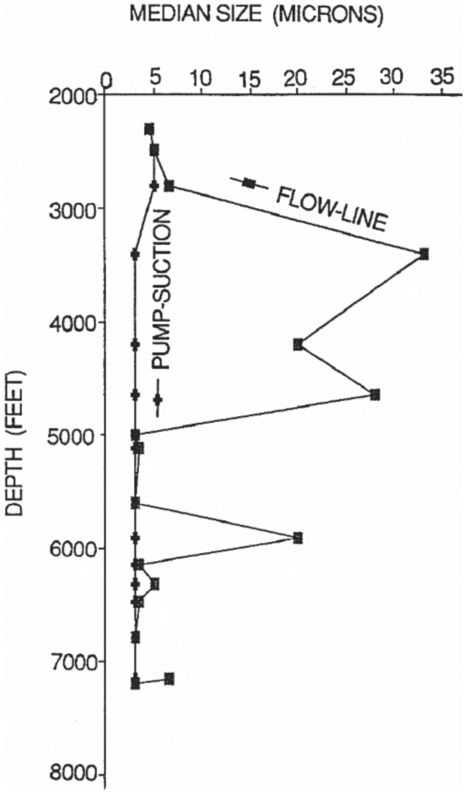


FIGURE 2.8. Depth-related size of cuttings upstream (flowline) and downstream (pump suction) from solids-control separators [34].

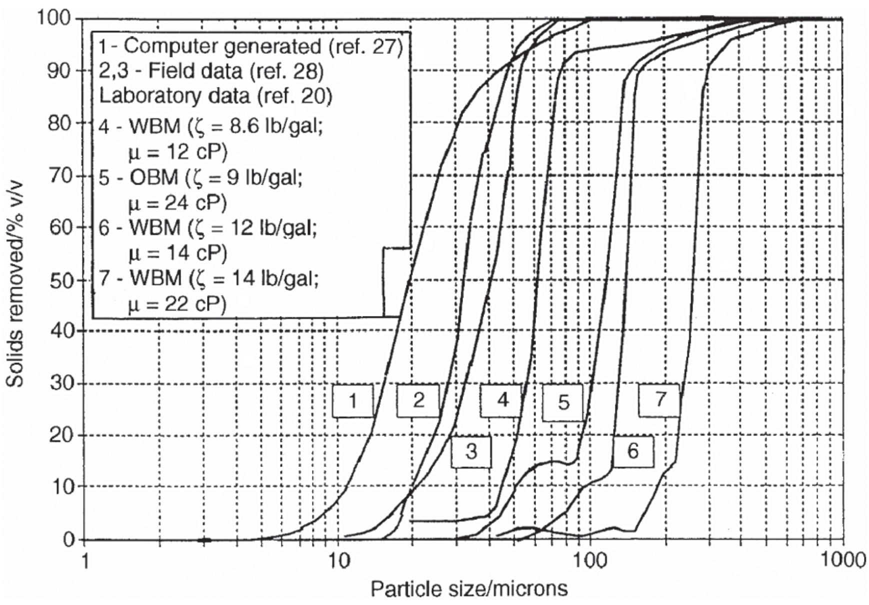


FIGURE 2.9. Theoretical and actual performances of 4 in hydrocyclones: effects of mud and type and rheology (1 lb = 0.454 kg; 1 gal = 3.785 dm^3; 1 cP = 10^{-3} N s/m^2).

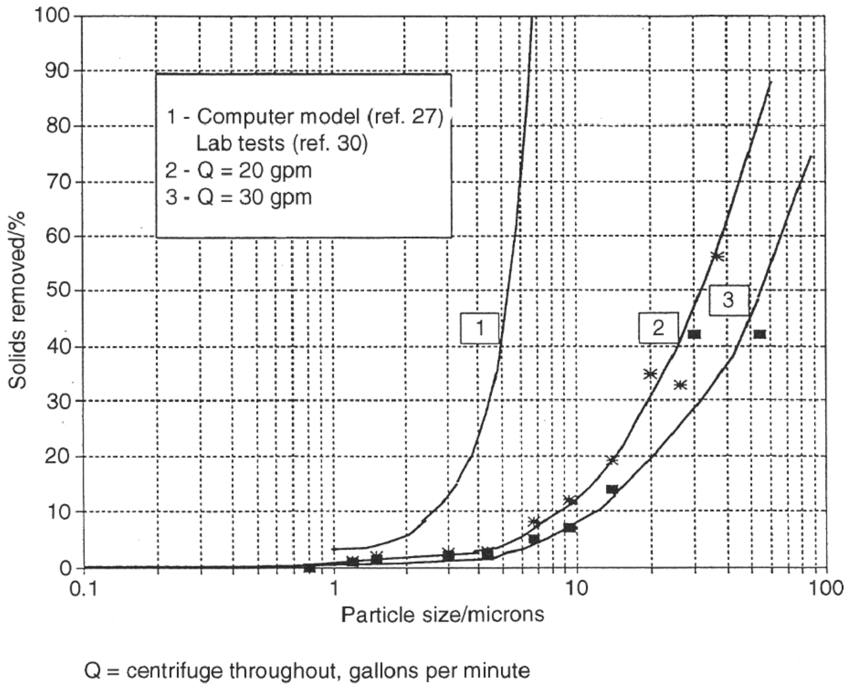


FIGURE 2.10. Theoretical (inert solids) and actual (active solids) performance of decanting centrifuge.

cleaners. Reportedly, the 50% cut made by the 100-mesh screen was smaller than the cut for the 4 in hydrocyclone [42]. Note however, that when comparing separators, the grade efficiency should be considered together with the load capacity. The liquid conductance of vibrating screens has been proved to decrease rapidly with increasing mesh size and mud viscosity [43]. In contrast, the operator can increase the volume processed by the hydrocyclones simply by adding more cones.

The separation efficiency of centrifuges is highly dependent upon the type of separated solids. The theoretical values of 50% cut, 3–4 μm, claimed by manufacturers are relevant only for the barite-recovery application of centrifuges. Much poorer separation is obtained for low-gravity (reactive) solids, as shown in Figure 2.10 [44]. The inability of the decanting centrifuge to control fine solids in the mud system during the double-stage centrifuging was observed in both field [42] and full-scale laboratory tests [44].

4.2 *Sources of drilling waste toxicity*

There are three contributing factors of toxicity in drilling waste: the chemistry of the mud formulation, inefficient separation of toxic and non-toxic components and the drilled rock. Typically, the first mechanism is known best because it includes products deliberately added to the system to build and maintain the rheology and stability of drilling fluids. The technology of mud mixing and treatment is recognized as a source of pollutants such as barium (from barite), mercury and cadmium (from barite impurities), lead (from pipe dope), chromium (from viscosity reducers and corrosion inhibitors), diesel [from lubricants, spotting fluids, and oil-based mud (OBM) cuttings] and arsenic and formaldehyde (from biocides).

Inefficient separation of toxic components from the drilling waste discharge stream becomes another source of toxicity through retention of the liquid phase on OBM cuttings, use of spotting pills or indiscriminate practices of on-site storage. Removal of the liquid phase from cuttings separated by the solids-control equipment becomes particularly important while using diesel-based drilling fluids (DOBM). Field data show that the total oil-based mud discharge rate jointly for the mud cleaner and centrifuge is 10 bbl/h [28]. Also, the OBM removal performance is different for various separators as shown in Table 2.4 (the highest for mud cleaners, and lowest for centrifuges) [42, 45, 46].

Research revealed that the OBM retention on cuttings is smaller for the mineral oil-based than for diesel-based OBMs, as evidenced by field data in Table 2.5 [47, 50]. The hypothetical mechanisms of oil retention on solids have been attributed to adhesive forces, capillary forces and oil adsorption and were identified as the amount of oil removed from OBM cuttings using centrifugal filtration, *n*-pentane extraction and thermal vaporization, respectively. The conclusion has been forwarded that 50% of the oil–solids bond could be attributed to adhesive/capillary forces, 29% to weak adsorption and 20% to strong adsorption, i.e. 20% of oil on cuttings could not have been removed with *n*-pentane extraction. The adhesive mechanism was also explained using

TABLE 2.4. Liquid discharge and oil retention on cuttings from oil-based muds (OBM) for various separators

	Oil content (% w/w)/OBM discharge rate (gal/min)[a]		
Reported data	Shale shaker	Mud cleaner	Centrifuge
Ref. 32	12.3/NR	14.1/NR	8.4/NR
Ref. 28	NR/NR	NR/4.2	NR/0.7
Ref. 31	11.1–16.5/NR	NR/NR	3–10.2/NR

[a]NR = not reported.

TABLE 2.5. Oil retention on OBM cuttings[a] vs type of oil[b]

	Well			
Drilling fluid	**1**	**2**	**3**	**4**
Diesel OBM	20.0	13–16	9.8	10.8
Mineral OBM	7.9	10.3	NR	NR

[a]Per cent by dry weight of discharge from shale shaker.
[b]Compiled from Refs. [47–50].

TABLE 2.6. Toxicity difference between active and waste drilling fluids[a]

Toxicant	Active mud	Detection rate (%)	Reserve pit	Detection rate (%)
Benzene	No	–	Yes	39
Lead	No	–	Yes	100
Barium	Yes	100	Yes	100
Arsenic	No	–	Yes	52
Fluoride	No	–	Yes	100

[a]Based on Ref. 20.

the wettability preference of drilled rock. The preference was evaluated by measuring the adhesion tension of thin-cut plates of quartz and shales immersed in OBM. The results showed that the rocks immersed in diesel OBM became strongly oil-wet, whereas for the mineral OBM, the initially oil-wet surfaces tended to reverse their wettability and became water-wet.

Indiscriminate storage/disposal practices using drilling mud reserve pits can contribute toxicity to the spent drilling fluid, as shown in Table 2.6. The data in Table 2.6 are from the U.S. EPA survey of the most important toxicants in spent drilling fluids. In the survey, sample taken from active drilling mud in the circulating system were compared with samples of spent drilling mud in the reserve pit [20]. The data show that the storage/disposal practices were a source of the benzene, lead, arsenic and fluoride toxicities in the reserve pits because these components had not been detected in the active mud systems.

The third source of toxicity in the drilling process discharges is the type of drilled rocks. A recent study of 36 core samples collected from three areas (Gulf of Mexico, California and Oklahoma) at drilling depths ranging from 3,000 to 18,000 ft revealed that the total concentration of cadmium in drilled rocks was more than five times greater than the cadmium concentration in commercial barites [51]. With a theoretical well discharge volume in a 10,000 ft well model, 74.9% of all cadmium in drilling waste was estimated to be contributed by cuttings, whereas only 25.1% originate from the barite and the pipe dope.

4.3 Waste generation mechanisms in petroleum production

Petroleum production involves the extraction of hazardous substances, crude oil and natural gas, from the subsurface environment. Therefore, by its very nature, production technology involves pumping and processing pollutants. Any material used in conjunction with the production process and exposed to petroleum becomes contaminated. In essence, there are two mechanisms of pollution in the production process: generation of contaminated waste and leakage of material streams from the process to the environment. All non-petroleum materials entering the production process are either naturally occurring subsurface substances, such as formation waters and produced sand, or deliberately added chemicals facilitating production operations.

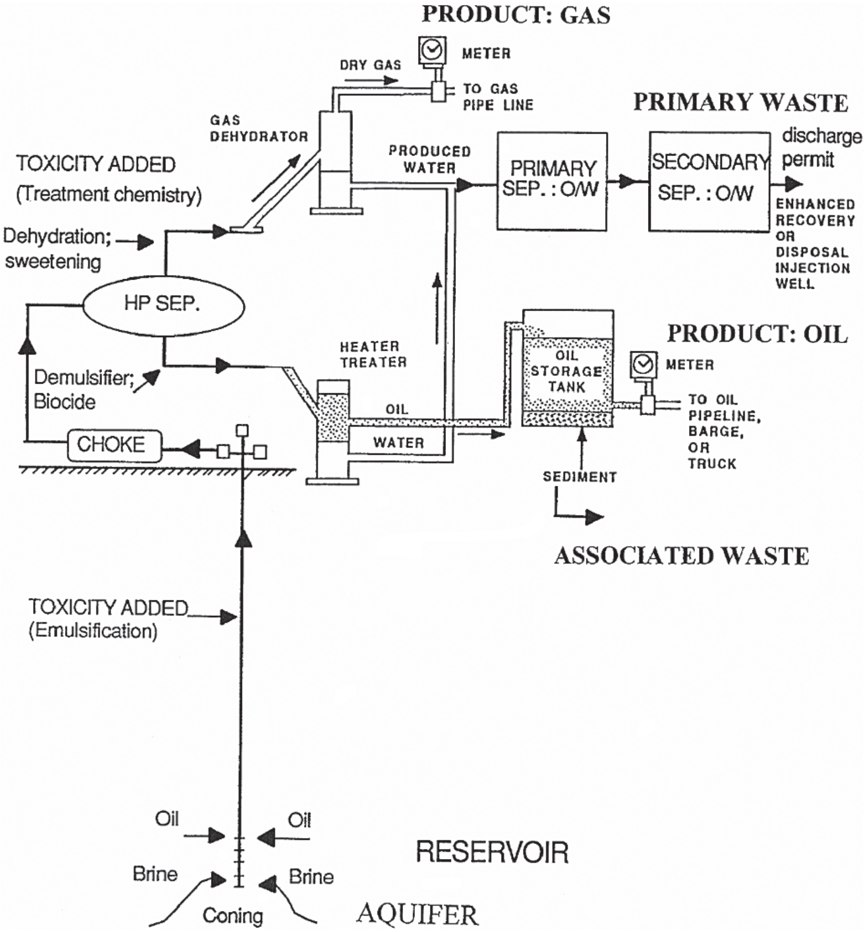


FIGURE 2.11. Waste generation mechanisms in petroleum production process.

Inside the process, these materials are mixed into the stream of petroleum, then separated into three final streams at the process output: marketable oil or gas products, produced water and associated waste. This simplified analysis is depicted in Figure 2.11 and discussed below.

The mechanisms of waste generation are related to production operations. *Downhole production operations* include primary, secondary and tertiary recovery methods, well workovers and well stimulations. Primary recovery refers to the initial production of oil or gas from a reservoir using only natural pressure to bring the product out of the formation and to the surface. Most reservoirs are capable of producing oil and gas by primary recovery methods alone, but this ability declines over the life of the well.

Eventually, virtually all wells must employ some form of secondary recovery. This phase of recovery is at least partially dependent on artificial lift methods, such as surface and subsurface pumps and gas lift, but typically also involves injection of gas or liquid into the reservoir to maintain pressure within the producing formation. Water flooding is the most frequently employed secondary recovery method. It involves injecting treated freshwater, seawater or produced water into the formation through a separate well or wells.

Tertiary recovery refers to the recovery of the last portion of the oil that can be economically produced. Chemical, physical and thermal methods are available and may be used in combination. Chemical methods involve injection of fluids containing substances such as surfactants and polymers. Miscible oil recovery involves injection of gases, such as carbon dioxide and natural gas, which combine with the oil.

When oil eventually reaches a production well, injected fluids from secondary and tertiary recovery operations may be dissolved in formation oil or water or simply mixed with them. The removal of these fluids is discussed below in conjunction with surface production operations.

Workovers and stimulations are another aspect of downhole production operations. Workovers are designed to restore or increase production from wells whose flows are inhibited by downhole mechanical failures or blockages, such as those caused by sand or paraffin deposits. Fluids circulated into the well for this purpose must be compatible with the formation and not adversely affect permeability. Stimulations are designed to enhance the wells productivity through fracturing or acidizing. Fluids injected during these operations may be very toxic (hydrochloric acid, for example) and may be produced partially back to the surface after petroleum production is resumed. Other chemicals may be periodically or continuously pumped down a production well to inhibit corrosion, reduce friction or simply keep the well flowing. For example, methanol may be pumped down a gas well to keep it from becoming plugged with ice.

Surface production operations generally include gathering the produced fluids (oil, gas, gas liquids and water) from a well or group of wells and separating and treating the fluids.

During production operations, pressure differentials tend to cause water from adjoining formations to flow into the producing formation (water breakthrough or water coning). The result is that, in time, production water/oil ratios may increase steeply. New wells may produce little, if any, water; mature wells may produce more than 100 barrels of water for every barrel of oil. Virtually all of this water must be removed before the product can be transferred to a pipeline (the maximum water content permitted is generally less than 1%). The oil may also contain completion or workover fluids, stimulation fluids or other chemicals (biocides, fungicides) used as an adjunct to production. These, too, must be removed. Some oil–water mixtures may be easy to separate, but others may exist as fine emulsions that do not separate by gravity settling. Conventionally, gravity settling has been performed in a series of large or small tanks (free water knock-outs, gun barrels, skim tanks), the large tanks affording longer residence time to increase separation efficiency (API separators). When emulsions are difficult to break, heat is usually applied in so-called 'heater treaters'. Whichever method is used, crude oil flows from the final separator to stock tanks. The solids and liquids that settle out of the oil at the tank bottoms ('produced' sand) must be collected and discarded along with the separated water.

Natural gas requires different techniques to separate out crude oil, gas liquids, entrained solids and other impurities. These separation processes can occur in the field, in a gas processing plant, or both. Crude oil, gas liquids, some free water and entrained solids can be removed in simple separation vessels. Low-temperature separators remove additional gas liquids. More water may be removed by any of several dehydration processes, frequently through the use of glycol, a liquid desiccant or various solid desiccants. Although these separation media can generally be regenerated and used again, they eventually lose their effectiveness and must be discarded.

Both crude oil and natural gas can contain the highly toxic gas hydrogen sulfide (200 ppm in air is lethal to humans). At plants where hydrogen sulfide is removed from natural gas, sulfur dioxide (SO_2) release may result. Sulfur is often recovered from the SO_2 as a commercial by-product. Hydrogen sulfide (H_2S) dissolved in crude oil does not pose any danger, but, when it is produced at the wellhead in gaseous form, it poses serious occupational risks through possible leaks or blowouts. These risks are also present later in the production process when the H_2S is separated out in various 'sweetening' processes. The amine, iron sponge and selexol processes are three examples of commercial processes for removing acid gases from natural gas. Each H_2S removal process results in spent iron sponge or separation media that must be disposed of.

Production waste is broadly classified as either primary or associated waste. Most of the materials used and discarded from production operations fall into the associated waste category. A listing of associated waste is shown in Table 2.7. This waste is characterized as having low volume and high toxicity. Produced water is a primary production waste having a very large volume and relatively low toxicity compared with associated waste. In 1989, the daily average discharge of produced water from all North Sea production operations

Table 2.7. Associated production waste

Associated production waste
Oily wastes: tank bottoms, separator sludges, pig trap solids
Used lubrication or hydraulic oils
Oily debris, filter media and contaminated soils
Untreatable emulsions
Produced sand
Spent iron sponge
Dehydration and sweetening wastes (including glycol amine wastes)
Workover, swabbing, unloading, completion fluids and spent acids
Used solvents and cleaners, including caustics
Filter backwash and water softener regeneration brines

was 355,000 m^3/day, with oil and gas production rates of 535,000 m^3/day and 267×10^6 m^3/day, respectively [52]. During 1990, Gulf of Mexico oilfield operations produced 866.5 million barrels of water [53], while the total U.S. production of water from oil and gas operations was 14 billion barrels [54]. Because of these large volumes, produced water is the major production waste stream with potential for environmental impact.

The system analysis of the production process in Figure 2.11 clearly shows that formation water enters the process downhole through the petroleum producing perforations, where it begins to mix with hydrocarbons. The water may flow into the hydrocarbon formation through processes of coning or fingering. The process kinetics of mixing oil and water under conditions of variable temperature and pressure during the two-phase flow in the well have not yet been investigated. In this process, formation water becomes contaminated by dispersed oil and soluble organics. The time required to reach an equilibrium concentration of fatty acids and other polar, water-soluble components of crude oil in produced brine is expected to be significantly shorter than the time of the two-phase flow [55]. Thus, a maximum level of contamination is reached before the brine is separated from oil. In addition to hydrocarbons, all treating chemicals used in surface operations are mixed into the water, thus adding to the final toxicity of produced-water discharge. Characteristically, most of the recent research regarding composition and toxicity of produced water has focused solely on the endpoint product of the above mixing mechanism while disregarding subsequent stages of water contamination on its way from the aquifer to the environmental discharge point.

4.4 Sources of toxicity in produced water

As discussed above and depicted in Figure 2.11, toxicity of produced water results from two factors: properties of formation water in its natural state and toxicity contributed by the very process of production. Sources of produced-water toxicity that has been added to the water during the production process include hydrocarbons and treating chemicals. Water toxicity has been shown to increase along its flowpath across the production process [20]. Table 2.8 compares toxic components in a typical oilfield production waste stream at the midpoint and at the endpoint of the production process. As can

TABLE 2.8. Toxicity increase of produced water across production process[a]

Pollutant	Midpoint	Detection rate (%)	Endpoint	Detection rate (%)
pH	6.4, 6.6, 8.0	–	2.7, 7.6, 8.1	–
Benzene	Yes[b]	60	Yes[b]	76
Phenanthrene	No	–	Yes[b]	24
Barium	No	–	Yes	87
Arsenic	No	–	Yes	37

[a]Based on Ref. 20.

[b]Detected concentration was 1,000 times greater than that hazardous to humans.

be seen, the hazard of benzene and pH toxicity increases along the process flowpath. Also, three additional toxicants, phenanthrene, barium and arsenic, are detectable at the endpoint but are absent in the midpoint samples.

Prior to production, formation waters may display some level of toxicity which is usually unknown. Unlike toxicity of produced water, the *in situ* toxicity of oilfield brines has not been investigated. The most likely sources of toxicity in formation water prior to production are salt and radionuclides.

The lack of hydrocarbon contamination of the formation water column underlying the oil column was recently evidenced in a pilot study in which water was produced separately from, and concurrently with, oil using a dually completed well [56, 57]. No polyaromatic hydrocarbons (PAHs) or oil and grease were detected in that water. Therefore, conventional concurrent production of petroleum and water was concluded to be the sole source of hydrocarbon contamination of produced water, at least in water-drive reservoirs where the oil column is separated from the water column. The contamination may take two forms: dispersed oil and soluble oil (mostly non-hydrocarbon organic material).

Dispersed oil consists of small droplets of oil suspended in the water. As a droplet moves through chokes, valves, pumps or other constrictions in the flowpath, the droplet can be torn into smaller droplets by the pressure differential across the devices. This is especially true of flow viscosity oils and condensates. Precipitation of oil from solution results in a water fraction with smaller droplets. These small droplets can be stabilized in the water by low interfacial tension between the oil and the produced water. Small droplets can also be formed by the improper use of production chemicals. Thus, the addition of excess production chemicals (such as surfactants) can further reduce the interfacial tension so that coalescence and separation of small droplets becomes extremely difficult.

Oilfield deoiling technology, discussed later in this chapter, is designed to remove dispersed oil. Failure to remove small oil droplets results in the presence of dispersed oil in produced-water discharges. (The total maximum concentration of oil and grease, O&G, in these discharges varies in different areas. In the USA, for example, the daily maximum O&G concentration is 42 mg/l, while under the Paris Convention the maximum dispersed oil concentration is 40 mg/l.)

Soluble oil includes organic materials such as aliphatic hydrocarbons, phenols, carboxylic acids and low molecular weight aromatic compounds. The concentration of dissolved oil in produced water depends upon the type of oil. However, it is also related to technological factors, such as the type of artificial lift techniques (mixing energy of petroleum in water) and stage of production (encroachment of formation water into petroleum-saturated zone).

The concentration of dissolved organics may in some cases reach the maximum regulatory limit for offshore discharge (O&G 29 mg/l monthly average), as shown in Figure 2.12 [58]. Most of the contribution to these concentrations comes from phenols and volatile aromatics, as shown in Table 2.9 [59].

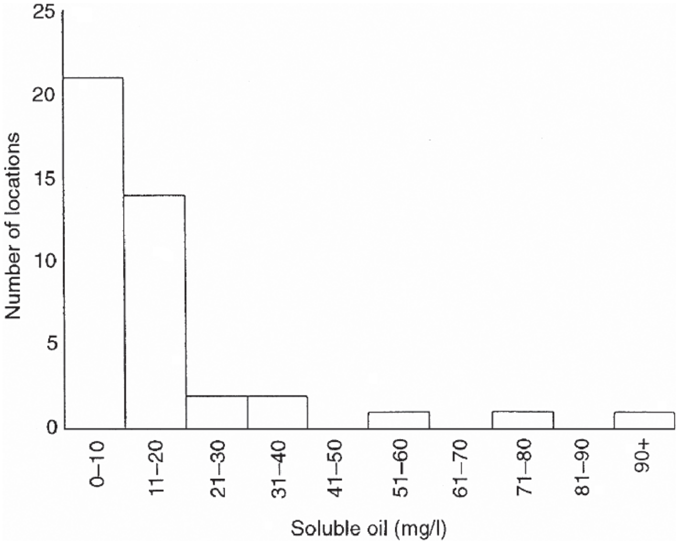


FIGURE 2.12. Concentration of soluble oil in produced water [58].

TABLE 2.9. Phenols and volatile aromatics in produced water[a]

		Toxicant			
Production	Concentration (μg/l)	Phenols	Benzene	Toluene	C_2–Benzene
Gas	Average	4,743	5,771	5,190	700
	Standard deviation	5,986	4,694	4,850	1,133
	Maximum	21,522	12,150	19,800	3,700
	Minimum	150	683	1,010	51
Oil	Average	1,049	1,318	1,065	221
	Standard deviation	889	1,468	896	754
	Maximum	3,660	8,722	4,902	6,010
	Minimum	0	2	60	6

[a]From Ref. 59.

At least one study has shown that the toxicity of soluble oil is not significant. The soluble oil fractions of two different produced waters were tested for toxicity and found to have acute toxicities of 15.8 and 4.8% [59, 60]. One of the reported characteristics of these components is that they are easily biodegraded. Therefore, low levels of dissolved organic materials are easily assimilated by the receiving ambient water. In addition to locally increasing BOD, the components of soluble oil each have a different fate in the environment [60].

Heavy metals in produced waters may be either present in formation water or added through the production process. Metals that may contribute to toxicity include barium, cadmium, chromium, copper, lead, mercury, nickel, silver and zinc. Typically, their concentrations in produced water may be in the range of thousands of μg/l while their concentration in seawater varies from trace to tens of μg/l. Heavy metals have been reported to pose little harm in the marine environment [60, 61]. They may settle out in marine sediments, thus increasing the sediment metal concentrations. However, they are tightly adsorbed to other solids and have much lower bioavailability to marine animals than do the metal ions in solution.

Radionuclides found in produced waters are often referred to as naturally occurring radioactive material (NORM). The source of the radioactivity in scale deposits from produced water comes from the radioactive ions, primarily radium, that coprecipitate from produced water along with other types of scale. The most common scale for this coprecipitation is barium sulfate, although radium has also been found in calcium sulfate and calcium carbonate scales.

Studies of soluble radionuclides in produced water have been summarized recently [59]. Early studies of wells in Oklahoma, the Texas panhandle and the Gulf of Mexico coastal area showed ^{226}Ra levels ranging from 0.1 to 1620 pCi/l (1 Ci = 3.7×10^{10} Bq) and ^{228}Ra levels ranging from 8.3 to 1507 pCi/l. Recent studies conducted by the State of Louisiana, Offshore Operators Committee and the U.S. Environmental Protection Agency showed ^{226}Ra level ranges of 0–930, 4–584 and 4–218 pCi/l, respectively, and ^{228}Ra level ranges of 0–928, 18–586 and 0–68 pCi/l, respectively. These levels are considerably lower than those from early findings. Also, reported research provides no evidence of the impact of radionuclides on fish or human cancers exceeding that resulting from a background concentration of radium.

Treating chemicals used in production operations can be classified according to types of production operations and the purpose of the treatment, as production liquid treating chemicals, gas processing chemicals and stimulation or workover chemicals. The production liquid treating chemicals are those routinely added to the produced oil and water (including waters used for water flooding). Chemically, these compounds are complex mixtures manufactured from impure raw materials. However, when looked upon as a source of toxicity in produced water these chemicals can be broadly analyzed according to their function, initial toxicity, solubility in water and treatment concentration. Obviously, all the above factors will control individual contribution of these chemicals to the final toxicity of produced-water discharge. For the purpose of reference, Table 2.10 shows the general grading of toxicity using lethal

TABLE 2.10. Classification of toxicity grades[a]

Classification	LC_{50} value (ppm)
Practically non-toxic	>10,000
Slightly toxic	1,000–10,000
Moderately toxic	100–1,000
Toxic	1–10
Very toxic	<1

[a]From Ref. 61.

concentration values representing the 50% mortality rate (LC_{50}) [61]. The following analysis summarizes findings regarding production chemical use and toxicity [62].

Biocides control bacterial growth, particularly sulfate-reducing bacteria that cause corrosion or fouling. Aldehydes, quaternary ammonium salts and amine acetate salts are the most commonly used biocides. All the biocides are highly water soluble. Intermittent slug treatments at 50–200 ppm of formulation are used to obtain good control with a minimum total biocide usage. The LC_{50} values for biocides may vary from less than 1 to above 1,000 ppm.

Scale inhibitors control deposition of common oilfield scales of calcium carbonate, calcium sulfate, strontium sulfate and barium sulfate. Three generic chemical types – phosphonates, phosphate esters and acrylic-type polymers – comprise 95% or more of the chemical being used. All formulations are highly water soluble. A minimum concentration, typically 3–10 ppm, must be present at all times to prevent scale deposition. After squeeze treatments (relatively uncommon) the concentration of compound in the produced water may be as high as 5000 ppm for a few days. The LC_{50} values for scale inhibitors fall within the range 1,000–11,000 ppm.

Corrosion inhibitors include compounds of the amide/imidazoline, amine or amine salt, quaternary amine and heterocyclic amine types. Oil-soluble inhibitors generally are preferred for oil production because of their great effectiveness. Continuous treatment with 10–20 ppm may be used in oil wells or pipelines. The initial LC_{50} values for corrosion inhibitors may be below 1 ppm. Most typical values, however, are from 1.2 to less than 10 ppm.

Emulsion breakers improve the separation of oil from water. The most common compounds are oxyalkylated alkylphenol–formaldehyde resins, polyglycol esters and alkylaryl sulfonates. Almost all formulations contain more than one of these generic types, as well as a surfactant. Virtually all components of these formulations are very insoluble in water and distribute into the oil phase. Typical use concentrations are about 25–100 ppm based on oil, with perhaps only 0.4–4 ppm distributing into the produced water. Initial LC_{50} values for emulsion breakers range from 3.8 to 80 ppm.

Reverse breakers are used to help remove droplets of oil from the produced water before discharge into the ocean. The two most common generic types are low molecular weight (2,000–5,000) polyamines and polyamine quaternary ammonium compounds. Both types are highly water soluble. Some formulations also include moderately high concentrations of aluminium, iron or zinc chlorides. Dosages of 5–25 ppm may be required, with perhaps half distributing into the discharged water. Minimum initial values of LC_{50} for reverse breakers can be below 1 ppm. Coagulants and flocculants are used to enhance the oil–water separation process. They are polymers similar to reverse breakers, but have a wider range of molecular weights, from 0.5 to 20 million. They are water soluble and used in concentrations from 5 to 10 ppm. Their LC_{50} values in the salt water environment are from 2 to 14,800 ppm. They are, however, more toxic to freshwater organisms.

Surfactants are used for cleaning equipment, tanks and decks. The two most common types are the alkylaryl sulfonates and the ethoxylated alkylphenols, both of which are widely used in other industrial and household applications. Oil-soluble versions are available for maintenance of tank and vessel internals. The LC_{50} values for surfactants may be as low as 0.5 ppm.

Paraffin inhibitors prevent solid hydrocarbons from forming or sticking to the walls of the system, thereby controlling accumulations of solid hydrocarbons in the system. Vinyl polymers, sulfonate salts and mixtures of alkyl polyethers and aryl polyethers are the most common compounds. Paraffin solvents are used to remove accumulations of deposits. The solvents are usually refinery cuts and may be primarily aliphatic or aromatic, depending on the nature of the deposits. Inhibitors are usually added in the 50–300 ppm range, while the solvents may range from a few percent in a stream to near 100% in cleaning out a vessel. All these materials are far more soluble in the oil than in the produced water. The LC_{50} values range from 1.5 to 42 ppm.

Gas treating chemicals include hydrate inhibitors and dehydration agents. A typical hydrate inhibitor is methanol, which has LC_{50} values from 8,000 to 28,000 ppm. Also, glycol dehydration is a closed-loop process that may produce leaks. However, glycol toxicity is low, with LC_{50} values from 5,000 to 50,000 ppm.

Stimulation and workover chemicals include hydrochloric acid (HCl) and workover brines. If properly used, these fluids should not contaminate produced water. Acids should be caught separately and neutralized, while toxic brines (e.g. zinc bromide) should be collected and reconditioned for reuse.

The potential effect of treating chemicals on produced-water toxicity is summarized in Table 2.11 [62]. The 'discharge concentration' is an estimated

TABLE 2.11. Toxicity of treatment chemicals and their potential concentration in produced water[a]

Function type	Use concentration (ppm)	Discharge concentration (ppm)	LC_{50} concentration (ppm)
Scale inhibitor	3–10 normal	3–10	1,200–>12,000, 90% >3,000
	5,000 squeeze[b]	50–500	
Biocides	10–50 normal	10–50	0.2–>1,000, 90% >5
	100–200 slug	100–200	
Reverse breakers	1–25 normal	0.5–12	0.2–15,000, 90% >5
Surfactant cleaners	Not measured	Not measured	0.5–429, 90% >5
Corrosion inhibitor	10–20 water[b]	5–15	0.2–5, 90% >1
	10–20 oil[b]	2–5	2–1,000, 90% >5
	5,000 squeeze[b]	25–100	
Emulsion breakers	50 oil	0.4–4	4–40, 90% >5
Paraffin inhibitor	50–300	0.5–3	1.5–44, 90% >3

[a]After Ref. 62.

[b]Water indicates solution of a water-soluble inhibitor; oil means that the inhibitor is mostly oil soluble; squeeze is the maximum concentration of inhibitor in returns from the well after squeeze or batch treatment.

concentration range in the discharge pipe. The top four chemicals are all water soluble and expected to be primarily in the water phase. The biocides are the only type in which the discharge concentration is likely to be above the LC_{50} values, and then only for periodic, short durations. The corrosion inhibitors are the most complex type, as compounds and formulations are made to be water soluble, oil soluble or mixed soluble/dispersible. The water-soluble compounds are most likely to resemble biocides chemically but are most commonly added to injection water or gas pipelines and are not discharged to the ocean continuously. The oil-soluble corrosion inhibitors are at or below the LC_{50} value, except possibly for short periods after squeeze or batch treatments.

The *salinity* of produced water can vary from very low to saturation, depending on geology and the production process. It is believed that the impact of discharging fresh or brackish produced water into the ocean would be the same as for rain [59]. This view is supported by observations from platforms that discharge produced water with very high salt contents show that there is a lively aquatic life community present. Also, dilution of a 200,000 mg/l salt water solution, such as produced water, in a 35,000 mg/l ocean occurs very quickly. Therefore, the concentration of salt in produced water discharged offshore has little potential to cause a harmful impact on aquatic life.

References

1. Environmental Protection Agency, EPA's Draft Report on the Environment 2003, July 2, 2003.
2. Garland, Emmanuel (2003) Discharge of Produced Water: New Challenges in Europe, SPE Paper No. 80585 presented at the 2003 Exploration and Production Environmental Conference, San Antonio, Texas, March 10–12.
3. American Petroleum Institute, U.S. Oil and Natural Gas Industry's Environmental Expenditures: 1993–2002, January 28, 2004.
4. Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2003 Annual Report, DOE/EIA-0216 (2003) Advanced Summary, September 2004.
5. American Petroleum Institute, Overview of Exploration and Production Waste Volumes and Waste Management Practices in the United States, May 2000.
6. Final Report of the Inquiry Commission P-36 Accident, June 22, 2001, Rio de Janeiro, Brazil; also, World awaits Roncador disaster report, Offshore Engineer, April 2001, p. 12.
7. Tanker Sinks Near Spain: Millions of Gallons of Fuel Oil Could Pose Ecological Disaster, Washington Post, November 20, 2002, p. A-18.
8. Stricken Tanker Splits, Sinks off Spanish Coast, Oil and Gas Journal Online, November 20, 2002.
9. Rusting of Prestige to Worsen Oil Spill Disaster, Reuters Online, January 28, 2003.
10. Duncan Austin and Amanda Sauer (2002) *Changing Oil: Emerging Environmental Risks and Shareholder Value in the Oil and Gas Industry*, World Resources Institute.

11. Whitaker, Marvin (1999) Emerging 'triple bottom line' model for industry weighs environmental, economic, and social considerations, *Oil and Gas Journal*, December 20.
12. Hirschhoth, J., Jackson, T. and Bass, L. (1993) Towards prevention – the emerging environmental management paradigm, in *Clean Production Strategies* (ed. T. Jackson), Stockholm Environmental Institute, Lewis, Chelsea, MI, pp. 130–3.
13. Baas, L.W. and Dieleman, H. (1990) Cleaner technology and the River Rhine: a systematic approach, in *Industrial Risk Management and Clean Technology* (eds. S. Maltezou, A. Metry and W. Irwin), Verlag Orac, Vienna, p. 139.
14. Wojtanowicz, A.K. (1993) Oilfield environmental control technology: a synopsis. *Journal of Petroleum Technology*, February, pp. 166–72.
15. Oil legacy in Louisiana, *The Wall Street Journal*, October 23, 1984.
16. Wasicek, J.J. (1983) Federal underground control regulations and their impact on the oil industry. *Journal of Petroleum Technology*, August, 1409–11.
17. State moves to regulate wastes to hit industry with added costs. *Oil and Gas Journal*, June 24, 1985.
18. Modesitt, L.E., Jr. (1987) Environmental regulations: leading the way towards restructuring the petroleum industry. *Journal of Petroleum Technology*, September, pp. 1113–8.
19. Sullivan, J.N. (1990) Excellence and the environment. *Journal of Petroleum Technology*, February, pp. 130–3.
20. EPA (1987) *Report to Congress: Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas and Geothermal Energy – Volume 1: Oil and Gas*. U.S. Environmental Protection Agency, Washington, DC, pp. 11.1–11.26 and 111.5–111.29.
21. API (1995) Characterization of exploration and production associated wastes. *Production Issue Group – API Report*. American Petroleum Institute.
22. Veil, John (2003) An Overview of Applications of Downhole Oil/Water Separation Systems, paper presented at the Produced Water Workshop, Aberdeen, Scotland, March 26–27.
23. Page, P.W. *et al*. (2003) Options for the Recycling of Drill Cuttings, SPE Paper No. 80583 presented at the 2003 Exploration and Production Environmental Conference, San Antonio, Texas, 10–12 March.
24. U.S. Department of Energy, DOE Oil Field Takes Pioneering Role, *Fossil Energy Techline*, October 20, 2003.
25. Lawrence, A.W. and Miller, J.A. (1995) *A Regional Assessment of Produced Water Treatment and Disposal Practices and Research Needs*. GRI-95/0301, Gas Research Institute.
26. Schumaker, J.P. *et al*. (1991) Development of an Alaskan north slope soils database for drill cuttings reclamation. SPE 22094, *Proc. International Arctic Technology Conference*, Anchorage, AK 29–30 May, pp. 321–2.
27. Ohara, S. and Wojtanowicz, A.K. (1995) A drilling mud management strategy using computer-aided life-cycle analysis. *Proc. Fourth International Conference on Application of Mathematics in Science and Technology*, Krakow, Poland, June, pp. 200–21.
28. Brandon, D.M., Fillo, J.P., Morris, A.E. *et al*. (1995) Biocide and corrosion inhibition use in the oil and gas industry: effectiveness and potential environmental impacts. SPE 29735, *Proc. SPE/EPA E&P Environmental Conference*, Houston, Texas, 27–29 March, pp. 431–44.
29. Wojtanowicz, A.K. (1991) Environmental control potential of drilling engineering: an overview of existing technologies. SPE/IADC 21954, *Proc. 1991 SPE/IADC Drilling Conference*, Amsterdam, 11–12 March, pp. 499–516.

30. Walker, T.O. and Simpson, Y.P. (1989) Drilling mud selection for offshore operation, Part 3. *Ocean Industry*, October, pp. 43–6.
31. Hou, J. and Luo, Z. (1986) The effect of rock cutting structure on rock breaking efficiency. SPE 14868, *SPE 1986 International Meeting on Petroleum Engineering*.
32. Hayatadavoudi, A. *et al*. (1987) Prediction of average cutting size while drilling shales. *Proc. SPE/IADC Drilling Conf*., New Orleans, LA, 15–18 March.
33. Fullerton, H.B., Jr. (1973) *Constant-Energy Drilling System for Well Programming*, Smith Tool, Division of Smith International.
34. Mohnot, S.M. (1985) Characterization and control of fine particles involved in drilling. *Journal of Petroleum Technology*, September.
35. Chenevert, M.E. and Ossisanya, S.O. (1989) Shale/mud inhibition defined with rig-site methods. *SPE Drilling Engineering Journal*, September.
36. Ritter, A.J. and Gerant, R. (1985) New optimization drilling fluid program for reactive shale formations. SPE 14247, *Proc. 60th Annual Technical Conference and Exhibition of SPE*, Las Vegas, NV, 22–25 September.
37. Bol, G.M. (1986) The effect of various polymers and salts on borehole and cutting stability in water-base shale drilling fluids. IADC/SPE 14802, *Proc. 1986 IADC/SPE Drilling Conference*, Dallas, TX, 10–12 February.
38. Bourgoyne, A.T. *et al*. (1986) *Applied Drilling Engineering*, SPE, Richardson, TX, p. 78.
39. Lu, C.F. (1985) A new technique for evaluation of shale stability in the presence of polymeric drilling fluid. SPE 14249, *Proc. 60th Annual Technical Conference and Exhibition of SPE*, Las Vegas, NV, 22–25 September.
40. Baroid (1979) *Manual of Drilling Fluid Technology; Borehole Instability*, NL Baroid Industries, p. 4.
41. Lal, M. (1988) Economic and performance analysis models for solids control. SPE 18037, *Proc. 63rd Annual Conference and Exhibition of SPE*, Houston, TX, 2–5 October.
42. Rodt, G. (1987) Drilling contractor proposes new methods for mud solids control optimization on the rig. SPE 16527/1, *Proc. Offshore Europe 87*, Aberdeen, 8–11 September.
43. Hoberock, L.L. (1991) Fluid conductance and separation characteristics of oilfield screen cloths, in *Advances in Filtration and Separation Technology, Volume 3: Pollution Control Technology for Oil and Gas Drilling and Production Operations*, American Filtration Society, Houston, TX.
44. Wojtanowicz, A.K. *et al*. (1987) Comparison study of solid/liquid separation techniques for oil pit closure. *Journal of Petroleum Technology*, July.
45. Thoresen, K.M. and Hinds, A.A. (1983) A review of the environmental acceptability and the toxicity of diesel oil substitutes in drilling fluid systems. IADC/SPE 11401, *Proc. IADC/SPE 1983 Drilling Conference*, New Orleans, LA, 20–23 February.
46. Jackson, S.A. and Kwan, J.T. (1984) Evaluation of a centrifuge drill-cuttings disposal system with a mineral oil-based fluid on Gulf Coast offshore drilling vessels. SPE 14157, *Proc. SPE Annual Technical Conference and Exhibition*. Houston, TX, 16–19 September.
47. Bennett, R.B. (1983) New drilling fluid technology – mineral oil mud. IADC/SPE 11355, *Proc. 1983 Drilling Conference*, New Orleans, LA, 20–23 February.
48. Boyd, P.A. *et al*. (1983) New base oil used in low-toxicity oil muds. SPE 12119, *Proc. 58th Annual Technical Conference and Exhibition*, San Francisco, CA, 5–8 October.

49. Hoiland, H. *et al*. (1986) The nature of bonding of oil to drill cuttings, in *Oil-Based Drilling Fluids*, Norwegian State Pollution Control Authority, Trondheim, pp. 24–6.
50. Cline, J.T. *et al*. (1989) Wettability preferences of minerals used in oil-based drilling fluids. SPE 188476, *Proc. SPE Int. Symp. on Oilfield Chemistry*, Houston, TX, 8–10 February.
51. Candler, J. *et al*. (1992) Sources of mercury and cadmium in offshore drilling discharges. *SPE Drilling Engineering*, December, pp. 279–83.
52. Jacobs, R.P.W.M. *et al*. (1992) The composition of produced water from Shell operated oil and gas production in the North Sea, in *Produced Water* (ed. J.P. Ray), Plenum Press, New York, pp. 13–21.
53. Reilly, W.K., O'Farrell, T. and Rubin, M.R. (1991) *Development Document for 1991 Proposed Effluent Limitation Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category*. U.S. Environmental Protection Agency, Washington, DC.
54. Daly, D.J. and Mesing, G. (1993) *Gas Industry-Related Produced-Water Management Demographics*, Gas Research Institute, GRI Contract No. 5090–253–1988 and 5090–253–1930 (Draft Report).
55. Matovitch, M.A. (1978) *The Existence of Effects of Water Soluble Organic Components in Produced Brine*, Report to EPA Region IV, Shell, 26 May.
56. Swisher, M.D. and Wojtanowicz, A.K. (1995) *In situ*-segregated production of oil and water – a production method with environmental merit: field application. SPE 29693, *Proc. SPE/EPA Exploration & Production Environmental Conference*, Houston, TX, 27–29 March.
57. Swisher, M.D. and Wojtanowicz, A.K. (1995) New dual completion method eliminates bottom water coning. SPE 30697, *Proc. SPE Annual Technical Conference and Exhibition, Volume: Production*, Dallas, TX, 22–25 October, pp. 549–55.
58. Otto, G.H. (1990) *Oil and Grease Discharge Characteristics of Methods 413.1 and 503E (42 Platform Study)*, Report to Offshore Operators Committee, University of Houston, Houston, TX.
59. Stephenson, M.T. (1992) A survey of produced water studies, in *Produced Water* (eds. J.P. Ray and F.R. Engelhart), Plenum Press, New York, pp. 1–11.
60. Brown, J.S., Neff, J.M. and Williams, J.W. (1990) *The Chemical and Toxicological Characterization of Freon Extracts of Produced Water*, Report to Offshore Operators Committee, Battelle Memorial Institute, Duxbury, MA.
61. Ayers, R.C., Sauer, T.C. and Anderson, P.W. (1985) The generic mud concept for NPDES permitting of offshore drilling discharges. *Journal of Petroleum Technology*, March, 475.
62. Hudgins, C.M. Jr (1992) Chemical treatment and usage in offshore oil and gas production systems. *Journal of Petroleum Technology*, May, pp. 604–11.

Chapter 3
Environmental Control of Well Integrity

A.K. Wojtanowicz

1 Introduction

Productivity performance requires petroleum wells to provide a sealed high-pressure conduit for reservoir fluids production to the surface. The installation typically includes well completion, production casing, packer and tubing string. Absence of possible leaks in the installation is often referred to as "internal integrity" of the wells.

Environmental performance requires petroleum wells to maintain "external integrity" to prevent pollution. Figure 3.1 shows the pollution mechanism due to the loss of external integrity of injection or production wells resulting in upwards migration of fluids outside cemented wellbores. Pollution of air, surface waters or groundwater aquifers may result from the migration of produced petroleum hydrocarbons, injected brines or other toxic waste fluids. The migration takes place in the annular space between the well casing string and borehole walls. This phenomenon has long been known in petroleum terminology as "flow behind cement", "gas migration", "flow after cementing" or "annular migration", or – more recently, "sustained casinghead pressure". Most of these terms refer to the failure of well cements.

2 Mechanism of cement seal failures

In theory, well construction requires that the subsurface isolation of aquifers and other strata be restored with annular seals (cement, grout, resin mixtures). Failure of these seals would provide conduits for vertical transport of pollutants. The pollutants may originate from either wellbore fluids (drilling mud or injected wastewater) or formation fluids (oil, gas, or brine).

Department of Petroleum Engineering, Louisiana State University, Baton Rouge, LA 70803-6417, USA

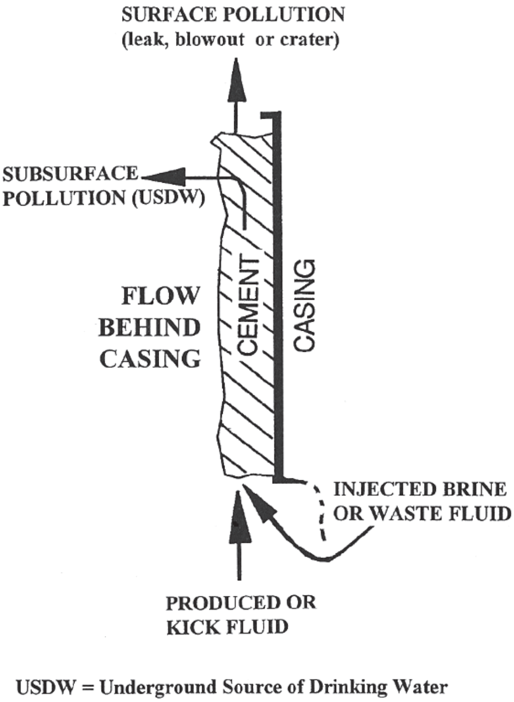


FIGURE 3.1. Pollution caused by lack of well integrity.

Typically, cement design specifications are based on the compressive strength of set cement; its tensile strength is assumed to be about 12 times smaller than the compressive strength. These properties have little effect on the quality of the annular seal. The failure of annular seals has been shown to be caused by poor bonding of cement or by the development of channeling during the cement setting process. The ability of set cement to isolate subsurface zones has been conventionally attributed to bonding of hardened cement to the pipe and borehole wall. Two magnitudes have been used to measure the quality of cement bond to the pipe (bond strength): shear bonding and hydraulic bonding. Shear bonding represents the force required to move pipe in a cement sheath [1]; hydraulic bonding represents the pressure required to initialize a leak between cement and pipe for liquid or gas [2]. Bond strength testing has been performed in laboratories for various pipe surfaces (rusty, sandblasted, resin–sand coated). This testing gave some basis for the actual design of cementing operations. The understanding of the cement-formation bond mechanism has been limited to the qualitative observations regarding the role of a mud cake and formation permeability [3] and the effect of mud displacement practices [4].

Channeling or development of secondary permeabilities in the cemented well annulus can be caused by either the annular gas migration during the cement thickening process [5, 6] or the sagging phenomenon (i.e. formation of water channels in inclined wellbores caused by solids–water separation) [7].

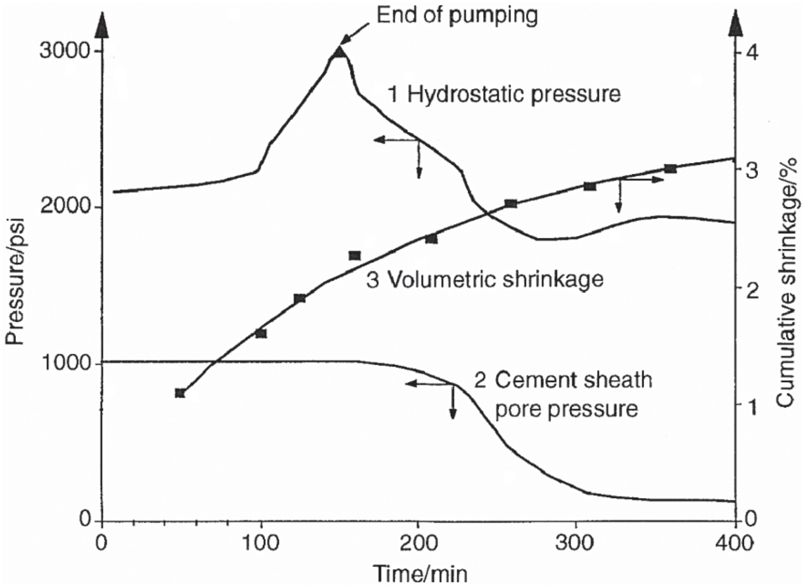


FIGURE 3.2. Loss of bottomhole pressure and shrinkage of cement slurry after cementing. (1) Field data at 4034 ft. (After Ref. 12.) (2) Laboratory gas flow simulator (pressure = 1000 psi). (After Ref. 6.) (3) Laboratory shrinkage cell at 250°F (121°C). (After Ref. 10.)

Two causes of annular gas migration are the loss of hydrostatic pressure in the cement column and volumetric changes in the annulus. Annular pressure loss occurs during the transition of the cement slurry from the fluid state to the solid state due to fluid loss and development of static gel strength [8]. Simultaneously with the hydrostatic pressure, the pore pressure is reduced. The pore pressure loss mechanism results from the development of a matrix stress in the thickening cement so that the water pore pressure responds to the volumetric shrinkage, caused by dehydration of the matrix. The hydrostatic and pore pressure changes in cement are shown in Figure 3.2.

Volumetric changes in the cemented well annulus may result from either a pressure drop inside the casing or volumetric shrinkage of the cement sheath. The casing pressure drop may create a microannulus between the casing and cement while cement shrinkage may cause the development of a microannulus between the formation and cement. Though the casing–cement microannulus is, by itself, too small to allow substantial flow, it is believed to be capable of initializing development of a flow channel and therefore must be prevented [9].

Shrinkage of cement, which is believed to be 3–4% by volume, is related to the concentration of calcium silicate crystals (which form during hardening) and the amount of available water during hardening [10]. An observation has also been made that 95% of volume shrinkage (up by 7% by volume)

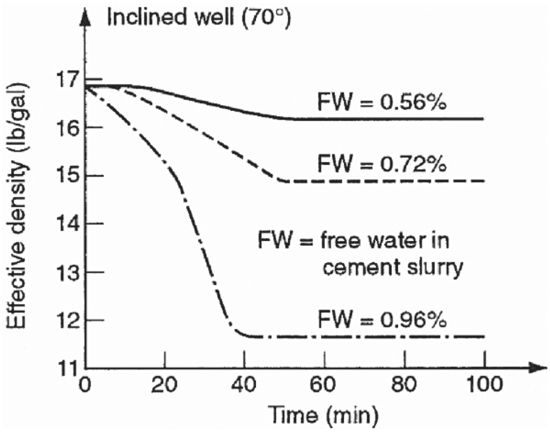


FIGURE 3.3. Loss of equivalent density in cement slurry column after cementing. (After Ref. 7.)

takes place after cement is in the solid state; therefore, the development of gas channeling through the bulk cement sheath when it is in a plastic state (transition state) is very unlikely [10, 11].

Sagging of cement slurries is an important mechanism of channeling in deviated wells. Settling of cement solids along the lower portion of the inclined well has been documented in well tests [12]. Also, the formation of a water channel along the upper portion of an inclined well, together with the resulting loss of the effective density, was observed in pilot-scale laboratory tests, as shown in Figure 3.3 [13].

3 Improved cementing for annular integrity

Annular seal integrity has been achieved through improvements in well cementing technology in three main areas: (1) steel–cement bonding techniques; (2) mud displacement practices; and (3) cement slurry design to prevent fluids from migrating after placement. The control of the steel–cement bond and mud displacement practices have long been incorporated into cementing technology [3, 4]. The most recent techniques have been developed to prevent the formation of channels due to gas migration in annuli after cementing [5, 9, 13–15].

Understanding the role of static gel strength in the mechanism of hydrostatic pressure loss has led to the development of delayed gel strength technology for oilwell cements. The technology was successfully demonstrated in the field when an addition of 0.4% of the delayed gel strength additive effectively stopped annular flow problems that had been traditionally experienced in the area [13].

Another control measure, foam cementing technology, was derived from observation of the pore pressure drop in the annular cement column caused by shrinkage of the solids matrix and low compressibility of the matrix–water system. In typical applications of foam cements, gas is either added to the slurry at the surface or is generated by chemical reaction downhole. A recent improvement in this technology is to use foaming surfactants in cement slurry [5]. This new system employs a formation gas (invading the cement) to generate the foam.

A new laboratory procedure has been proposed to find an optimal composition of cement slurry for particular wellbore conditions. In this procedure, a sample of cement slurry is exposed to the expected gas invasion pressure in the gas flow cell simulating the downhole environment of the wellbore [14].

A more fundamental approach has been used in the slurry response number (SRN) method [161]. In principle, SRN is a ratio of static gel strength development rate to the fluid loss rate at a critical time. This critical time corresponds to the onset of a rapid increase in static gel strength. Fluid loss represents volumetric reduction of the slurry. The rate of fluid loss declines over time. At the critical time, the rate of fluid loss should be very small (high values of SRN). Otherwise, pressure at the bottom of the cement slurry could rapidly decline, causing gas migration.

SRN can be evaluated graphically from laboratory measurements of static gel strength and fluid loss versus time for a given cementing system. The optimal cement slurry selected is the one with the largest value of SRN. Recently, the SRN method was correlated with a conventional measure of gas migration tendency, i.e. gas flow potential (GFP) [15]. The analytical correlations, SRN versus GFP, in the form of two equations, constitute the first quantitative model of the annular seal integrity for a well.

4 Cement pulsation after placement

In 1982, a landmark field experiment performed by Exxon revealed hydrostatic pressure loss in the annuli after primary cementing in wells [16]. Since then, hydrostatic pressure loss after cement placement has been considered a primary reason for loss of well's external integrity due gas migration in the un-set cement. As the annular cement – still in liquid state – loses hydrostatic pressure, the well becomes under-balanced and formation gas invades the slurry and finds its way upwards resulting in the loss of well's integrity.

Cement slurry vibration using a low-frequency cyclic pulsation is used by the construction industry for improving quality of cement in terms of better compaction, compressive strength, and fill-up. (Cement gelation or transmission of hydrostatic pressure is not a concern in these applications.)

In the oil industry, the idea of keeping cement slurry in motion after placement has been postulated a promising method for prolonging slurry fluidity in order to sustain hydrostatic pressure and prevent entry of gas into the well's annulus. The idea was based upon experimental observations that cement slurries in continuous motion remained liquidous for a prolonged period of time [17, 18].

Manipulating the casing string would move the cement slurry. Thus, early concepts considered keeping cement slurry in motion through casing rotation or reciprocation [19–21]. The motion should improve displacement of drilling mud and placement of cement slurry in the annulus.

The concept of using forced casing vibrations for gas flow prevention prompted several inventions in the 1970s, 80s and 90s [22–27]. For example, "enhanced filling of annulus with cement slurry without rotating or reciprocating the casing" was considered the main advantage of the first casing vibration method with mechanical vibrator placed at the bottom of the casing string [22]. All these methods have been already experimentally studied and patented. However, none of them have been used commercially because of difficulty involved in manipulating the entire casing string. Apparently, heavy equipment and installation needed to vibrate a long and heavy string of casing makes these methods not feasible, even onshore.

In 1995, Texaco patented a technique based on pulsation of the cement top [28, 29]. In this method, low frequency and small-amplitude pressure pulses are applied at the top of the cement by cyclic pumping of water or air to the wellhead. The treatment continues for sufficiently long time to keep cement in liquid state, reduce transition time, and maintain hydrostatic pressure overbalance.

Texaco field-tested a number of shallow (up to 4700 ft) wells in the Concho (Queen) field of the Permian basin, Texas. The tests demonstrated that pulses could be transmitted through the slurry in the lab and that the bond logs of pulsed wells were superior to those that were not pulsed.

In 2001–2002, the Coiled Tubing Engineering Services, and the Louisiana State University jointly further developed the cement pulsation technology in a project sponsored by the Gas Technology Institute [30]. Field testing of instrumented wells (with downhole pressure gauges) demonstrated that annular pulses could be transmitted to a significant depth in excess of 9000 ft and that hydrostatic pressure in the annulus was maintained by pulsing the slurry [31, 32]. Full-scale laboratory pulsation experiments with thixotropic slurry in an LSU well showed how small pressure pulses would progressively break gel structure and deliver pressure to the well's bottom [33, 34]. They also revealed that pulsation should have an additional advantage versus application of a constant pressure [34]. Another laboratory study showed that pulsation did not reduce final compressive strength or shear bond of cement [35].

The process of top cement pulsation works as follows. After cement placement, the well annulus is intermittently pressurized–depressurized by cyclically pumping water from the cement pulsation unit to the wellhead. A portable cement pulsation unit consists of an air compressor, water tank, hoses to connect to the well, instrumentation, and a recording system. Pulses are applied to the annulus by water that is pressurized by the air compressor. After charging

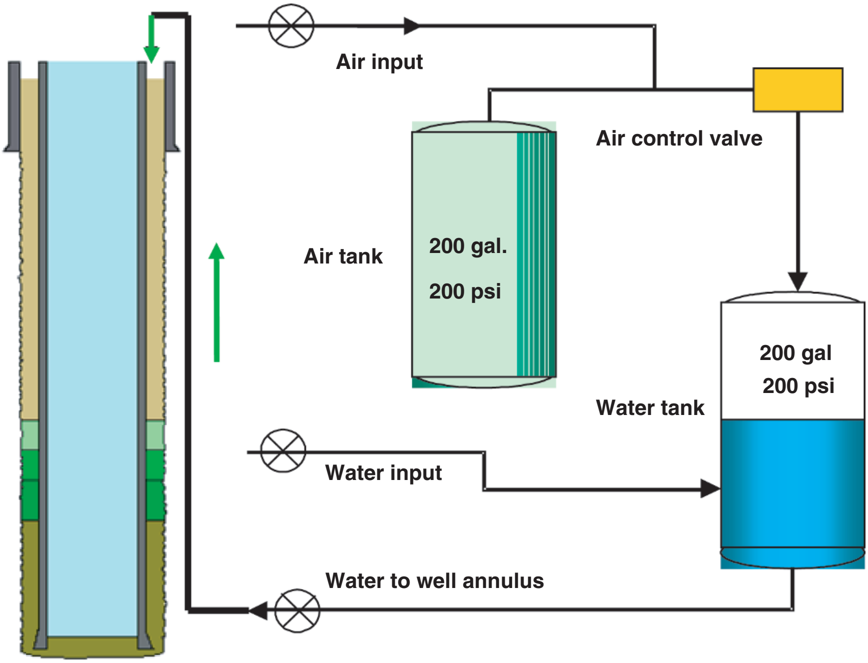


FIGURE 3.4. Principle of top cement pulsation method. (After Ref. 30.) (*See Color Plates*)

the well, the water is bled back to the tank. The system schematic is shown in Figure 3.4.

The air compressor continuously pressurizes an air tank. To pressurize the annulus, the control system opens a valve between the air tank and a water tank. The air pressure forces the water into and pressurizes the casing annulus. To release the pressure, the control system closes the pressurization valve and opens the exhaust valve. As the pressure is released, water returns from the casing annulus to the water tank. Once the pressure is fully released, water is added to the water tank if needed, to keep the water tank full.

The volume of water displaced to the well for each pulse is determined by measuring the water level in the tank. From this measurement a "compressible volume" is derived using a data-smoothing algorithm with corrections for water loss in the well and compressibility of surface installation [41]. As the cement slurry thickens, the compressible volume of the casing annulus decreases. When the cement sets, the compressible volume becomes constant and pulsation is stopped.

Frequency of pressure pulses is quite low, with built-in delays. Each pressure pulse is applied and held for up to 10–25 s (design parameter). After pressure is released, there is a dormant period of up to 10–25 s (design parameter). Thus, the pulsation frequency is of the order of 1–2 cycle/min (design parameter).

Field	Probability of Gas Flow P (GF), %	Wells Treated with Cement Pulsation			
		CP Jobs #	Wells w/o GF, #	Wells with GF, #	CP Performance, %
Tangleflags	10.5	24	24	0.0	100.0
Wildmere	25.0	20	18	10.0	60.0
Abbey	80.0	8	6	25.0	69.0
Other	75.0	28	28	0.0	100.0
All	44.0	80	76	4.0	91.0

$$\text{Performance} = \frac{\text{P(GF)-P(GF)cp}}{\text{P(GF)}}$$

P(GF) = probability of gas flow after cementing w/a pulsation
P(GF)cp = probability of gas flow after cementing with pulsation

FIGURE 3.5. Performance of top cement pulsation method.

Development and commercialization of the technology required a method for designing the treatment. Mathematical modeling, performed at LSU, provided theoretical basis for the treatment design and diagnostic analysis methods and software [18, 33, 36–38]. Industrial use of the technology has been carried out by two companies in three oilfields of Eastern Alberta, Canada [39, 40]. As depicted in Figure 3.5 the top pulsation method showed a 91% success rate in preventing gas flow after cementing [30, 39, 40].

5 Integrity of injection wells

The problem of hydraulic integrity of well annular seals has been addressed through both regulatory and technological measures. The two areas of regulatory initiatives to control annular integrity are drilling permit regulations and injection permit regulations. Drilling regulations focus mostly on the integrity of the surface casing. Typically, drilling permits require the surface pipe to be entirely cemented to protect freshwater sands from oil and gas zones. In addition, typical drilling regulations may specify minimum footage for surface pipe, minimum waiting-on-cement (WOC) time, minimum volume of cement slurry to be used, minimum length of cement sheath above the top producing zone and at the salt–fresh groundwater interfaces and the minimum testing requirements after completion [pressure test or cement-bond log tests (CBL)]. At present, no quantitative requirements exist to verify a potential annular flow between well casing and formations. For production casing, drilling permits are not very specific about the verification of annular integrity even though this integrity is most important in effectively isolating upper zones from produced hydrocarbons and brines.

Subsurface injection permits require an operator to provide evidence of the hydrodynamic integrity of the well's annular seal. However, no direct standardized tests for such integrity exist [13]. Usually, permit decisions are based upon indirect evidence of the well's integrity, such as CBL, electric logs, the driller's log and geological crossplots, which indicate to the regulatory agency that no unusual environmental risk is involved [42]. Typical generic criteria for wells injecting oilfield brines address the following issues: (1) the length of casing; (2) the mechanical integrity (pressure) test procedure (wellhead pressure, test duration, maximum pressure drop) and its frequency (usually before the operation, then every 5 years); and (3) the minimum distance to any abandoned well (usually 0.4–0.8 km). A permit is also required for the annular injection of solid drilling waste, the common method of on-site disposal during drilling operations (as discussed in the previous section).

In the area of subsurface brine injection, the permitting issue revolves around reliable techniques to prevent the stream of brine from migrating freely into the environment. The three main criteria are the "internal" mechanical integrity of the borehole installation (IMI), the "external" integrity of annular seals (EMI) and the integrity of the confining layer. The IMI practices of pressure testing casing as well as monitoring the annular pressure during injection are the most typical field technologies. However, since there are no standard procedures for IMI test analyses, the results of these tests are often left to the judgment of the permitting agency [43]. In addition, several factors may affect the result of pressure tests, such as the length and type of gas blanket, gas solubility in the annular liquid, temperature, and the tubing–annulus pressure changes [44]. These effects should be included in quantitative interpretations of the tests.

A simple system to control continuously the internal integrity of an injection well has been developed by the chemical industry [45]. As shown in Figure 3.6, the system does not use a packer at the bottom of the injection tubing or a surface pressurization system. Instead, it relies upon the laws of hydrostatics to separate the annular fluid from the injected fluid. A continuously recorded pressure differential between the injection and annular pressure is considered to be a sensitive indicator of tubing splits or casing leaks. Unlike the conventional "packed" annular configuration, this system is believed to be insensitive to injection pressure variations and is unaffected by the packer leaks. Also, it has the unique ability to locate a point at which the mechanical integrity of a well is lost. Recently, the static fluid seal design was criticized for lack of precision, which is caused both by slow mixing at the interface between the annular and the injected fluids and by the sensitivity of the design to injection fluid density/flow rate variations [46]. Therefore, unless the interface-mixing problem is solved (by placing a viscoelastic spacer, for example), conventional completions with packers will probably remain the accepted field practice.

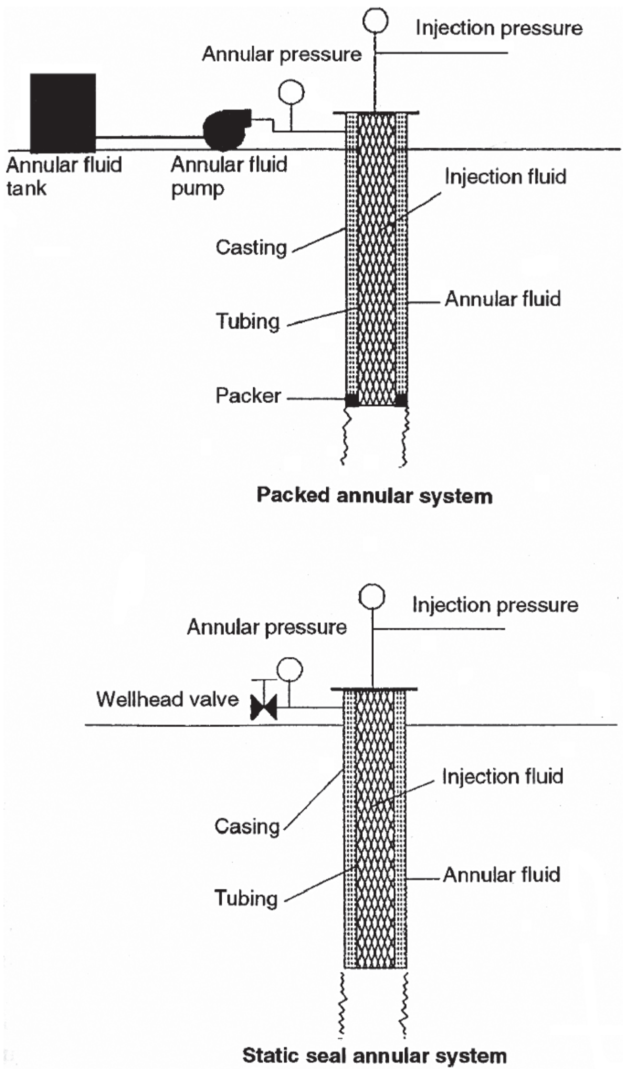


FIGURE 3.6. Two methods for continuous control of well integrity during subsurface injection. (After Ref. 45.)

Verification of the external (annular) mechanical integrity (EMI) of injection wells includes two groups of techniques: EMI tests and continuous monitoring systems. The most promising methods of EMI testing are radioactive tracer surveys [47], helium leak tests [48] and oxygen activation logging [also known as behind-casing water flow (BCWF)] or neutron activation technique (NAT) [48–51]. None of the techniques, however, has been yet adopted as a single tool to demonstrate well integrity [52]. For hazardous waste injection wells, EMI is performed in a two-stage procedure using a combination of EMI tests. The first stage involves a demonstration of the absence of interzonal flow using noise, temperature or oxygen activation logs. In the second stage, the path of injected fluid as it exists in the wellbore is monitored, using the radioactive tracer survey to determine whether it is confined to the permitted injection zone. However, in the USA, for example, the use of the above procedure is not a required EMI test for oilfield brine injection but is considered the best achievable practice for oilfield injection wells [52]. In fact, the actually practiced requirements for EMI involve only reviews of cementing records; radioactive tracer surveys or temperature surveys are required infrequently [53–55].

NAT seems to be a particularly promising tool to detect flow in channels within annular seals. The wireline tool consists of a generator of neutrons and two gamma-ray detectors that are installed above and below the generator for detecting the upward and downward flow, respectively. The flowing water in the channel is irradiated with neutrons emitted by the generator. These neutrons interact with oxygen nuclei in the water to produce ^{16}N, which decays with a half-life of 7.13 seconds, emitting gamma radiation. Radiation energy and intensity is recorded by detectors and is used for computation of flow.

A concept of an on-line monitoring system installed in a single injection well is shown in Figure 3.7. The suggested completion procedure would involve the following steps: (1) set a monitoring casing in the confining layer that overlays the injection zone and cement the monitoring casing inside the surface casing; (2) drill the well to the injection zone; (3) set a cement bridge plug and mill a short window in the monitoring casing opposite the permeable formation that is above the confining layer; (4) run the casing with a sophisticated packer (cement retainer) equipped with two (upper and lower) packing elements connected with two short tubing sections, one of which has been perforated; (5) install monitoring tubing in the annulus of the injection casing and land the monitoring tubing in the perforated section of the cement retainer; (6) cement the injection casing below and above the cement retainer; and (7) complete the well with injection tubing and a packer inside the injection casing [56].

During the injection operation, any change in pressure in the monitoring tubing becomes a sensitive indicator of fluid migration across the confining layer. Although theoretically sound, the system requires a complex well completion procedure, and its practical implementation still remains to be seen.

6 Measurements of well integrity

In the early 1980s, a systematic study was conducted in the USA to determine the state-of-the-art in EMI testing [57]. The first phase of the study was a survey of methods available for determining the mechanical integrity of oilfield brine injection wells. The second and third phases of the project

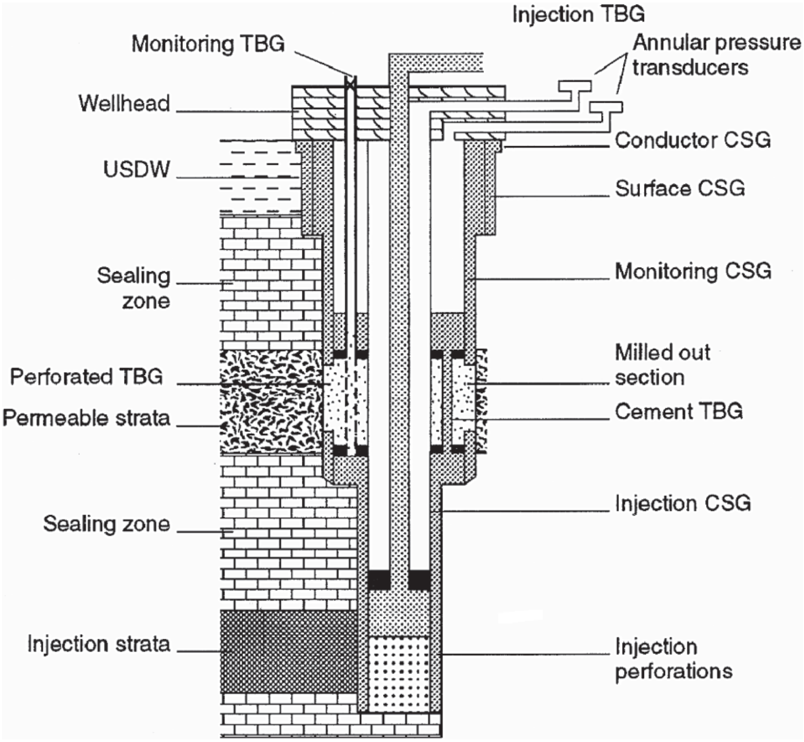


FIGURE 3.7. Dual completion for continuous monitoring of injection wells. (After Ref. 56.)

involved experimental work using three research wells. The first two wells were used to evaluate the performance of CBL tools to detect channels in the cement sheaths behind the steel and fiberglass casings. The purpose of the third well was to evaluate the capability of various downhole tools to detect fluid movement behind the casing. The tested tools included an acoustic CBL tool, a noise logging tool and a neutron activation technique (NAT). In addition to the research well experiments, a "real world" test was conducted in an abandoned 10,600 ft gas well using the NAT method. A known 100 ft long channel in the annular cement sheath of the well had been identified using a radioactive tracer survey.

The results of this study showed that most present commercial techniques do not provide sufficient information to determine the mechanical integrity of a well. With the acoustic CBL technique, the flow in channels behind the casing could only be detected when cement was not present. The noise logging tool proved to be very sensitive to extraneous sources of sound that resulted in poor quality of the noise log. Moreover, when the logging tool was placed either in the casing or within the tubing, only the NAT method showed good detection of flow in the annular channel. In conclusion, there seems to be a trend in the permit regulations to verify external integrity by a test rather than the review of cementing records. NAT has great potential for testing EMI. Particularly, NAT seems to be an excellent method for detecting flow in a channeled annular seal. Also, since the cost of periodic EMI tests may be excessive, it seems possible that the oil industry might develop a new well completion system for injection wells that would allow a continuous monitoring of pressures across confining zones.

7 Sustained casinghead pressure

One of the most typical problems caused by the lack of well integrity is "sustained casinghead pressure". Sustained casing (or casinghead) pressure (SCP) originates from late gas migration in one of the well's annuli and manifests itself at the wellhead as irreducible casing pressure. In the United States, the federal statistics have shown that the problem in the Gulf of Mexico (GOM) is massive, as 11,498 casing strings in 8,122 wells exhibit SCP [58]. In the offshore operations, sustained casing pressure represents a potential loss of hydrocarbon reserves, risk of harm to or loss of human lives and physical facilities, possible damage to the marine and coastal environments, and air pollution. Although 90% of sustained casing pressures are small and could be contained by casing strength, it is still potentially risky to produce or more importantly, to abandon such wells without elimination of the pressure.

Risks associated with SCP depend upon the type of affected casing annulus and the source of migrating gas. Most serious problems have resulted from tubing leaks. A tubing leak would exhibit SCP at the production casing. A failure of the production casing may result in an underground blowout that, in turn, can cause damage to the offshore platform, loss of production and/or widespread pollution. Catastrophic outcomes of SCP on production casing have been documented in several case histories [59]. Consequences of SCP on casings other than the production casing are less dramatic but equally serious. SCP on these casings usually represents gas migration originating from an unknown gas formation. As the gas migration continues, casing pressure may increase to the point when either the casing or casing shoe fails so the migrating gas will leak into the annulus of the next (and weaker) casing string. As a result, the gas would not be contained by any of the well's casings and would come to the surface outside the well. Eventually, the process could potentially result in destabilization of the seafloor around the well, loss of the platform, and pollution of the water column and surrounding area.

In the US, most of regulatory attention has been focused on the SCP problem in the Gulf of Mexico. However, the "surface casing vent leakage" problem with gas wells in Alberta has essentially the same downhole causes. It has received substantial attention via regulation by the Alberta Energy and Utilities Board and prevention and remediation efforts by the industry [60, 61]. Serious problems resulting from unintended pressure on casing–casing annuli have also been reported in the San Juan Basin of New Mexico, in South Louisiana, in India, and in Tunisia. Hydrocarbon intrusion into drinking water aquifers has occurred in the San Juan Basin and in Alberta, and its potential for occurrence should be a major concern in any onshore producing areas.

The US regulations for the Gulf of Mexico require that an operator may continue production (i.e. be self approved) if:

- casing pressure remains at less than 20% of internal yield rating of casing; and
- casing pressure bleeds to zero during diagnostic tests.

If casing pressures are greater than 20% of internal yield, a departure from the regulations may be applied for. The granting of a departure allows the well to continue *producing without elimination of SCP*.

Normally, departures are granted for producing wells with casing pressures that bleed to zero and demonstrate a relatively slow subsequent 24-h build-up rate. However, for wells that are temporarily or permanently abandoned, the casing pressures must remain at zero which means *elimination of SCP is mandatory*.

Furthermore, recent regulations further reduce operator eligibility for being granted a departure. They allow only a one-year, fixed-term, departures for some producing wells, eliminate departures for non-producing wells, and require operators to remove SCP on temporarily abandoned wells. Also, the proposed regulation requires operators to document their plans for SCP removal thus making operators actively responsible and prepared for future removal of SCP in all wells. In conclusion, there is an undeniable trend in the regulatory strategy to require remedial treatments of SCP rather than tolerate the SCP problem.

The petroleum industry, through American Petroleum Institute (API), and Offshore Operators Committee (OOC) is presently working on an industry-developed Recommended Practice on SCP [62]. This new API RP would address the monitoring, diagnostics, and remedial actions that should be taken when SCP occurs. Thus, the RP is to summarize and standardize all the industry knows about dealing with SCP problem in a set of performance-based procedures.

Remedial treatments of wells with SCP are inherently difficult because of the lack of provisions to access the affected annuli. Since there is no rig at the typical producing well, the costs and logistics involved in removal of SCP are frequently equivalent to a conventional workover. Moreover, there may be multiple casing strings between the accessible wellbore and the affected annulus. Methods for SCP removal can be divided into two categories: rig and rig-less methods.

7.1 Rig methods for SCP isolation

The rig methods involve moving in a drilling rig, workover rig or, in some cases, a coiled tubing unit and performing either routine well repair, such as replacing the tubing and/or packer, some kind of plug back to isolate the productive zone, or perforate/cut-and-squeeze operations in the well. The rig methods are inherently expensive due to the moving and daily rig costs [58]. When SCP affects the production casing string, the tubing repair or plug back operations are generally successful. When the SCP affects outer casing strings, the rig method usually involves squeezing cement. These procedures involve perforating or cutting the affected, inner casing string and injection of cement to plug the channel or microannulus in the cement outside the inner string. Both block and circulation squeezes have been attempted. The success rate of this type of operations is low (less than 50%) due to the difficulty in establishing injection from the wellbore to the annular space of the casing with SCP and getting complete circumferential coverage by the cement. In the 1990s, the SCP workover programs concentrated on squeezing cement into the affected casing annuli of wells. Initially, deep cement squeezes were attempted where logs indicated poor bond. Annular pressures were not successfully reduced until large cement volumes were squeezed at intermediate shoes. The early workover programs succeeded in reducing annular pressures but did not bring them to zero.

Recently, the rig methods have been significantly improved by adding more drastic techniques for pressure isolation [63]. Two main approaches to accessing and alleviating sustained casing pressure have been adopted: casing termination and window milling. The first method involves terminating the affected casing string as deeply as possible inside the outer casing without extending below the casing shoe. By terminating the casing as deeply as possible, it maximizes the room available for possible future intervention as well as gaining the hydrostatic advantage of the longer fluid column.

Shown in Figure 3.8 is an example of a typical "cut and pull" operation of the 7"; casing inside the 10¾"; casing. "Upon gaining access to the wellbore, the mud was circulated out with the kill heavy brine. A trip in the hole with the workstring and a mechanical cutter was made to cut the 7" casing in an attempt to circulate kill weight fluid down the casing and into the annulus if possible. The pumps were rigged up and tested to circulate in the 11.6-ppg brine into the 7" casing. Upon making both the deep cut and the cut immediately below the hanger, the well was verified to be dead before continuing rigging down the pumps and pulling out of the hole with the workstring.

A spear and grapple set to catch the 7" casing was then picked up on 4½" workstring and tripped into the hole to spear into the 7" casing. An attempt to establish circulation was not made until there was casing movement in order to avoid packing mud or sediment in the annulus. Once the pipe was moving, it was reciprocated while circulating mud in the hole. The casing was picked up and pulled out of the hole to recover the casing to the deeper cut" [63].

The second method involves milling a long window and isolating both the lower stub and upper stub with cement plugs. This method is used in cases

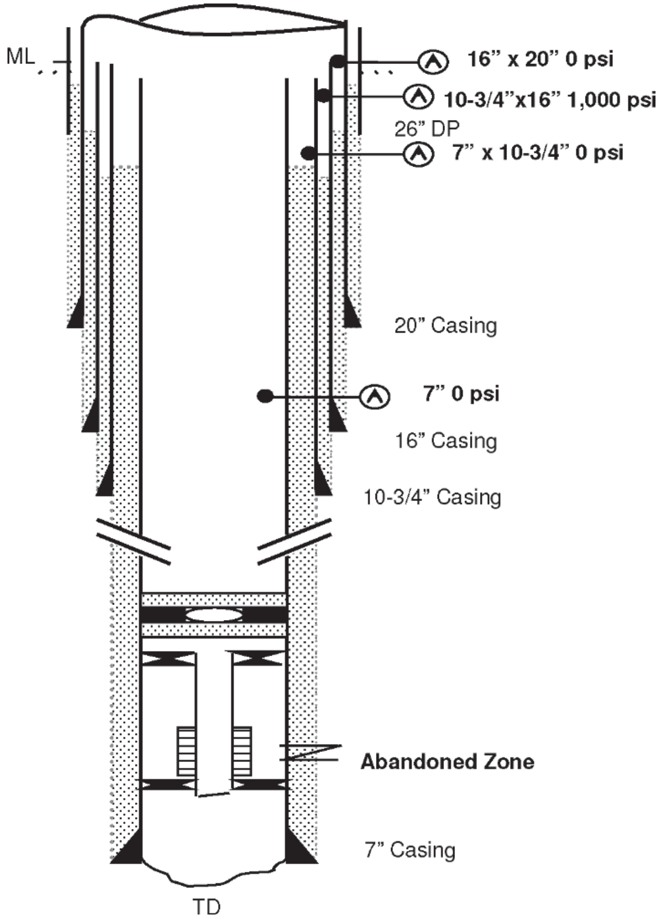


FIGURE 3.8. Cut-and pull-casing method for SCP removal. (After Ref. 63.)

where the inner casing string could not be economically or feasibly removed to a necessary minimum depth to isolate annular pressure. For instance, if drilling reports indicates the inner casing was cemented in place with cement to surface or if a cement bond log indicates too shallow depth of the cement's top, a window milling procedure is applicable.

7.2 Rig-less technology for SCP isolation

The rig-less technology involves external treatment of the casing annulus usually involving a combination of bleeding-off pressure and injecting a sealing/killing fluid either at the wellhead (bleed-and-lube method) or at depth through flexible tubing inserted into the annulus (Casing Annulus Remediation System, CARS).

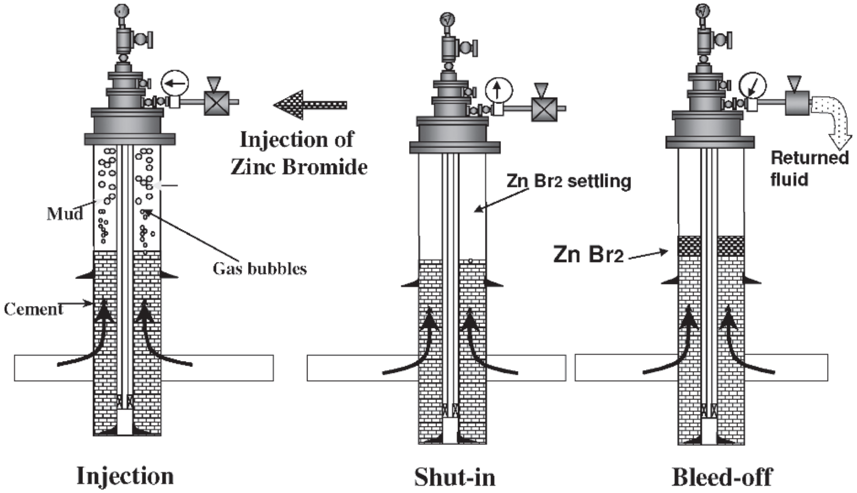


FIGURE 3.9. Principle of the lube-and-bleed method for SCP removal.

The concept of the lube-and-bleed method is to replace the gas and liquids produced during the pressure bleed-off process with high-density brine such as zinc bromide. It is, then, expected that the hydrostatic pressure in the annulus can gradually be increased using this technique. The procedure – shown in Figure 3.9 – involves lubricating (injecting) zinc bromide brine into the wells's annulus, holding the pressure to allow settling of the brine to the bottom, and bleeding small amounts of lightweight gas and fluid from the annulus over several treatment cycles.

Limited number of case histories reported the lube-and-bleed method as partially successful. In one of these cases, SCP in the 13–3/8" casing was reduced from 4500 psi to 3000 psi. The operation took over a year with numerous cyclic injections during which 118 bbls of 19.2 ppg Zinc Bromide brine replaced 152 bbls of the annular fluid (a gas-cut water-based mud having density of 7.4–9.5 ppg) [64]. Other operators also observed incomplete reduction in surface casing pressures from this method. A study of the lube-and-bleed method demonstrated dramatic effect of the interaction between the lubricated and annular fluids on the method's performance [65]. The study showed that injection of Zinc Bromide into the annulus filled with conventional water-based mud is ineffective because of flocculation-plugging effect. Compatibility of the two interacting fluids entirely controlled the method's performance. Others also observed in the field that pressures can increase while applying this method [58]. They also hypothesized that this occurs when a new "gas bubble" migrates to the surface. In all, after trying the lube-and-bleed method for several years in several wells, the field results have not been as promising as first indicated.

In 1997, Shell Oil and ABB Vetco Gray designed a system called CARS (Casing Annulus Remediation System) [66, 67]. This system is similar to the "lube-and-bleed" process in that it is designed to place heavy fluids into the casing annulus without the use of workover rig or perforating. This is done by running a thin flexible hose into the casing annulus through the casing valve. After placing the hose at certain depth, heavy fluids can be circulated through the hose, as opposed to the "lube-and-bleed" process in which fluids are squeezed into the closed annulus system from the top of the annulus.

The CARS equipment has been designed and successfully tested in the lab at maximum surface pressures of approximately 200 psi. The system has been also upgraded for surface pressures up to 1000 psi. Shown in Figure 3.10 is the CARS system schematics [66]. There are several options for CARS equipment arrangement, depending on the casing pressure conditions. The arrangement shown in Figure 3.10 is for casing pressure that would not bleed to zero, i.e. the CARS hose must be run under pressure. The system comprises the following items counting from the wellhead to the right:

1. Shear valve flanged directly onto the wellhead. The valve is used in cases when it becomes necessary to cut the hose
2. A 5000-psi BOP, for containment of pressure on outside of the hose during hose cutting or crimping operations
3. Injector head used to "grip" the hose and force into the well
4. CARS hose reel
5. A pump connected to the tank filled with displacing fluid

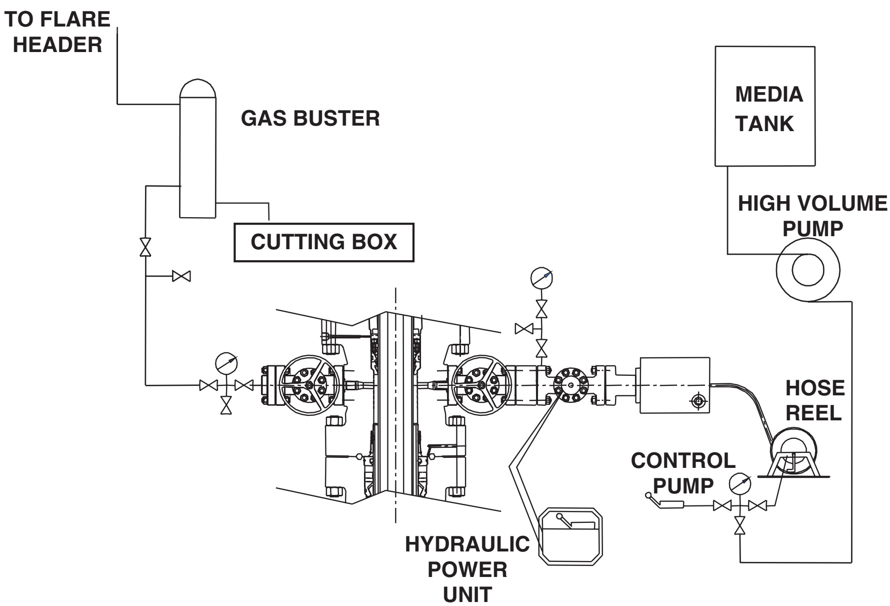


FIGURE 3.10. Schematics of CARS installation. (After Ref. 66.)

On the opposite (left) side of the wellhead there is a discharge manifold, gas buster, and a cutting box. This installation's function is bleeding off the casing, monitoring casing pressure, and taking fluid samples. In cases when the casing pressure bleeds to zero, the 5000-psi BOP may be removed. Depending on the severity of the casing pressure and its bleed-down/build-up characteristics, the shear valve and/or the injector head may be removed and replaced with a casing valve and a pack-off. In principle, the procedure of CARS operation is as follows [66]:

- Connect one annulus outlet to test facilities and bleed down
- Install VR plug in opposite annulus and install shearing valve
- Rig up CARS packoff, driver, and pumping system
- Run in hole until desired depth is achieved
- Displace annular volume with selected fluid
- Bleed off all lines and verify pressure is reduced to zero
- Disconnect CARS system and install terminal fitting
- Rig down and secure well

The major problem encountered with CARS, to date, has been the inability to get the hose to a depth that would allow circulation of a significant volume of Zinc Bromide. Because the hose depths are so shallow, the Zinc Bromide brine must be pumped in stages, the volumes of which are equal to the annular displacement to the depth of the hose. In some cases, these volumes were as small as one barrel. Thus, the fluid must be pumped over several one-barrel cycles separated by shut-in periods when the brine would gravitate down the annulus.

Recently, a new technique for isolation of SCP has been patented and tested experimentally [68, 69]. The method involves placing palletized alloy–metal into the well's annulus, heating the alloy–metal above its melting point, and then allowing the alloy–metal to cool. When the alloy–metal cools, it expands slightly and seals the annulus. The method was tested on large-scale models of the 5½" by 8½" pipe-open hole annulus and the 10¾" by 13⅜" casing–casing annulus by applying 100 psi pressure. The testing proved the concept that the alloy metal pellet could be placed in an annulus through a static column if drilling mud but the seal quality needs improvements.

References

1. Carter, L.G. and Evans, G.W. (1964) A study of cement–pipe bonding. *Journal of Petroleum Technology*, Vol. XVI, No. 2, February.
2. Becker, H. and Peterson, G. (1963) Bond of cement composition for cementing wells. *Proc. 6th World Petroleum Congress*, Frankfurt, 19–26 June.
3. Smith, K.D. (1976) *Cementing*. SPE Monograph, Vol. 4, Society of Petroleum Engineers, New York, Dallas.
4. Hartog, J.J. et al. (1983) An integrated approach for successful primary cementation. *Journal of Petroleum Technology*, Vol. 35, No. 9, September.

5. Stewart, R.B. (1986) Gas invasion and migration in cemented annuli: causes and cures. IADC/SPE 14779, *Proc. 1986 Drilling Conference*, Dallas, TX, 10–12 February.
6. Cheung, P.R. (1982) Gas flow in cements. SPE 11207, *Proc. 57th Annual Fall Technical Conference and Exhibition of SPE*, New Orleans, LA, 26–29 September.
7. Webster, W.W. and Eikerts, J.V. (1979) Flow after cementing – a field and laboratory study. SPE 8259, *Proc. 54th Annual Technical Conference and Exhibition*, Las Vegas, NV, 23–26 September.
8. Sutton, D.L. and Sabins, F.L. (1990) Interrelationship between critical cement properties and volume changes during cement setting. SPE 20451, *Proc. 65th Annual Technical Conference and Exhibition of SPE*, New Orleans, LA, 23–26 September.
9. Sutton, D.L. and Ravi, K.M. (1989) New method for determining downhole properties that affect gas migration and annular sealing. SPE 19520, *Proc. 64th Annual Technical Conference and Exhibition of SPE*, San Antonio, TX, 8–11 October.
10. Chenevert, M.E. and Shrestha, B. (1987) Shrinkage properties of cement. SPE 16654, *Proc. 62nd Annual Technical Conference and Exhibition of SPE*, Dallas, TX, 27–30 September.
11. Sabins, F.L. (1990) An investigation of factors contributing to the deposition of cement sheaths in casing under highly deviated well conditions. IADC/SPE 29934, *Proc. 1990 IADC/SPE Drilling Conference*, Houston, TX, 27 February–2 March.
12. Cooke, C.J. Jr. et al. (1982) Field measurements of annular pressure and temperature during primary cementing. SPE 11206, *Proc. 57th Annual Fall Technical Conference and Exhibition of SPE*, New Orleans, LA, 26–29 September.
13. Sykes, R.L. and Logan, J.L. (1987) New technology in gas migration control. SPE 16653, *Proc. 62nd Annual Technical Conference and Exhibition of SPE*, Dallas, TX, 27–30 September.
14. Beirute, R.M. and Cheung, P.R. (1989) A scale-down laboratory test procedure for tailoring to specific well conditions: the selection of cement recipes to control formation fluids migration after cementing. SPE 19522, *Proc. 64th Annual Technical Conference and Exhibition of SPE*, San Antonio, TX, 8–11 October.
15. Harris, K.L. et al. (1990) Verification of slurry response number evaluation method for gas migration control. SPE 20450, *Proc. 65th Annual Technical Conference and Exhibition of SPE*, New Orleans, LA, 23–26 September.
16.Cooke, C.E. Jr., Kluck, M.P., and Medrano, R. (1982) Field Measurements of Annular Pressure and Temperature During Primary Cementing. SPE Paper 11206.
17. Cooke, C.E., Gonzalez, O.J., and Broussard, D.J. (1988) Primary Cementing Improvement by Casing Vibration During Cementing Casing Time. SPE 14199.
18. Wojtanowicz, A.K. and Manowski, W. (1999) Pressure pulsation of cement for improved well integrity – Field method and theoretical model. *Proc. 10th International Scientific & Technical Conference: New Methods and Technologies in Petroleum Geology, Drilling and Reservoir Engineering,* Krakow, Poland, 24–25 June, Vol. 2, 421–436.
19. Carter, G. and Slagle, K. (1970) A Study of Completion Pratices to Minimize Gas Communication. SPE 3164, *Central Plains Regional Meeting of the Society of Petroleum Engineers of AIME*, Amarillo, TX, 16–17 November.
20. Carter, G., Cook, C., and Snelson, L. (1973) Cementing Research in Directional Gas Well Completions. SPE 4313, *2nd Annual European Meeting of the Society of Petroleum Engineers of AIME*, London, England, 2–3 April.1.

21. Christian, W.W., Chatterji, J., and Ostroot, G. (1975) Gas Leakage in Primary Cementing – A Field Study and Laboratory Investigation. SPE 5517, *50th Annual Fall Meeting of the Society of Petroleum Engineers of AIME*, Dallas, TX, September 28–October 1.
22. Solum, K.W. et al. (1971) Method and Apparatus for Vibrating and Cementing a Well Casing. U.S. Patent 3,557,875, 26 January.
23. Cooke, C.E. Jr. (1983) Method for Preventing Annular Fluid Flow. U.S. Patent 4,407,365, 4 October.
24. Keller, S.R. (1985) Oscillatory Flow Method for Improved Well Cementing. U.S. Patent 4,548,271, 22 October.
25. Bodine, A.G. and Gregory, Y.N. (1987) Sonic Cementing. U.S. Patent 4,640,360, 3 February.
26. Rankin, R.E. and Rankin, K.T. (1992) Apparatus and Method for Vibrating a Casing String During Cementing. U.S. Patent 5,152,342, 6 October.
27. Winbow, G.A. (1994) Method for Preventing Annular Fluid Flow Using Tube Waves. U.S. Patent 5,361,837, 8 November.
28. Haberman, J.P., Delestatius, D.M., and Brace, D.G. (1995) Method and Apparatus to Improve the Displacement of Drilling Fluid by Cement Slurries During Primary and Remedial Cementing Operations, to Improve Cement Bond Logs and to Reduce or Eliminate Gas Migration Problems. U.S. Patent 6,645,661.
29. Haberman, J.P. and Wolhart, S.L. (1997) Reciprocating Cement Slurries After Placement by Applying Pressure Pulses in the Annulus, SPE/IADC 37619, March.
30. Wojtanowicz, A.K. et al. (2002) Cement pulsation treatment in wells. SPE 77752, *Proc. Annual Technical Conference and Exhibition of SPE*, San Antonio, Texas, 29 September–2 October.
31. Newman, K., Wojtanowicz, A.K., and Gahan, B.C. (2001) Improving Gas Well Cement Jobs with Cement Pulsation. *Gas Tips*, Fall, pp. 29–33.
32. Newman, K., Wojtanowicz, A.K., and Gahan, B.C. (2001) Cement Pulsation Improves Gas Well Cementing. *World Oil*, July, pp. 89–94.
33. Chimmalgi, V.S. and Wojtanowicz, A.K. (2005) Design of cement pulsation treatment in gas wells – model and field validation.*Journal of Canadian Petroleum Technology*, Vol. 44, No. 6, 36–45.
34. Martin, J.N., Smith J.R., and Wojtanowicz, A.K. (2001) Experimental Assessment of Methods to Maintain Bottomhole Pressure After Cement Placement. ETCE'01-17133, *ASME Engineering Technology Conference on Energy*, ETCE 2001, 5–7 February, Houston, TX.
35. (2001) Shear Bond/Compressive Strength Testing. CSI Final Report on Pulsation Project submitted to CTES, Houston, TX.
36. Manowski, W.M. and Wojtanowicz, A.K. (1998) Oilwell cement pulsing to maintain hydrostatic pressure: a search for design model. *Journal of Energy Resource Technology – Transactions of the ASME*, December, Vol. 120, 250–255.
37. Kunju, M.R. and Wojtanowicz, A.K. (2001) Well Cementing Diagnosis from Top Cement Pulsation Record. SPE 71387, *SPE Annual Technical Conference and Exhibition*, New Orleans, LA, 30 September–3 October.
38. Novakovic, D., Wojtanowicz, A.K, and Chimmalgi, V.S. (2001) Cement Pulsation Design Software. LSU Final Report submitted to GTI, August, 42.
39. Dusterhoft, D. and Wilson, G. (2001) Field Study of the Use of Cement Pulsation to Control Gas Migration. Paper 2001–01 presented at the *C ADE/CAODC Drilling Conference*, Calgary, Alberta, Canada, 23–24 October.

40. Dusterhoft, D., Wilson, G., and Newman, K. (2002) Field Study of the Use of Cement Pulsation to Control Gas Migration. SPE 75689, *SPE Gas Technology Symposium*, Calgary, Alberta, Canada, 30 April—2 May.
41. Kunju, M.R. (2001) Post-treatment Diagnosis of Cement Pulsation in Wells. MS Thesis, Chapter 4, Louisiana State University, May, 33.
42. Thornhill, J.P. and Benefield, B.G. (1986) Mechanical integrity research. *Proc. International Symposium on Subsurface Injection of Liquid Wastes*, New Orleans, LA, 3–5 March.
43. Kamath, K.I. (1989) Testing injection wells for casing leaks: theory, practice and regulatory requirements. *Proc. International Symposium on Class I and II Injection Well Technology*, Underground Injection Practices Council, Dallas, TX, 8–11 May, pp. 505–519.
44. Langlinais, J.L. (1981) Waste Disposal Well Integrity Testing and Formation Pressure Buildup Study. Report for Louisiana Department of Natural Resources, September.
45. McKay, J.E. et al. (1989) Static fluid sealed injection wells – an acceptable alternative. *Proc. International Symposium on Class I and II Injection Well Technology*, Underground Injection Practices Council, Dallas, TX, 8–11 May, pp. 141–149.
46. Kamath, K.I. (1988) Significance of regulatory constraints on the operation of packerless waste injection well. *Journal of Petroleum Technology*, Vol. 40, No. 11, November, pp. 1501–1505.
47. UIPC (1986) Radioactive tracer surveys. *Mechanical Integrity Testing Seminar*, Underground Injection Practices Council, Oklahoma City, OK, pp. 113–157.
48. Dewan, J.P. (1983) Mechanical Integrity Tests – Class II Wells: Review and Recommendations, Report for Environmental Protection Agency Regions II and III.
49. Williams, T.M. (1987) Measuring behind casing water flow. *Proc. International Symposium on Subsurface Injection of Oilfield Brines*. Underground Injection Practices Council, New Orleans, LA, 4–6 May, pp. 467–484.
50. DeRossett, W.H. (1986) Examples of detection of water flow by oxygen activation on pulsed neutron logs. *Proc. SPWLA 27th Annual Logging Symposium*, 9–13 June.
51. Wieseneck, J.B. (1989) Practical experience with oxygen activation logging in South Mississippi. *Proc. International Symposium on Class I and II Injection Well Technology*, Underground Injection Practices Council, Dallas, TX, 8–11 May, pp. 7–24.
52. Lyle, R. (1989) Demonstration of mechanical integrity utilizing radioactive tracer surveys. *Proc. International Symposium on Class II Injection Well Technology*, Underground Injection Practices Council, Dallas, TX, 8–11 May, pp. 65–73.
53. UIPC (1989) The Texas Railroad Commission, Oil and Gas Division UIC Program: a Peer Review, Report of Underground Injection Practices Council, pp. 24–27.
54. UIPC (1989) The Louisiana Department of Natural Resources, Office of Conservation, Injection and Mining Division UIC Program: a Peer Review, Report of Underground Injection Practices Council, pp. 19–22.
55. Gould, L.A. and Landry, D.A. (1987) Status of mechanical integrity testing in Mississippi. *Proc. International Symposium on Subsurface Injection of Oilfield Brines*, Underground Injection Practices Council, New Orleans, LA, 4–6 May, pp. 435–437.

56. Poimboeuf, W.W. (1989) Injection well with monitoring system installed in a single wellbore. *Proc. International Symposium on Class I and II Injection Well Technology*, Underground Injection Practices Council, Dallas, TX, 8–11 May, pp. 461–488.
57. Tornhill, J.T. and Kerr, R.S. (1990) *Injection Well Mechanical Integrity*. EPA/625/9–89/007, US Environmental Protection Agency, Washington, DC.
58. Bourgoyne, A. T. Jr., Scott, S.L. and Manowski, W. (2000) A Review of Sustained Casing Pressure Occurring on the OCS.LSU Final Report submitted to MMS, Baton Rouge, LA.
59. Bourgoyne, A.T. Jr., Scott, S.L., and Regg, J.B., (1999) Sustained casing pressure in offshore producing wells, OTC 11029, *Proc. Offshore Technology Conference*, Houston, TX, May 3–6.
60. (2003) Alberta Energy and Utilities Board, Interim Directive ID 2003–01, Calgary, 30 January.
61. (2003) Alberta Energy and Utilities Board, EUB Guide 20: Well Abandonment Guide, Calgary, August.
62. Don Howard (2004) MMS Workshop on Development of Recommended Practice for Annular Casing Pressure Management for Offshore, 17–18 August, Houston, Texas.
63. Soter, K., Medine, F., and Wojtanowicz, A.K. (2003) Improved techniques to alleviate sustained casing pressure in a mature gulf of Mexico field. SPE 84556; *Proc. SPE Annual Technical Conference and Exhibition*, Denver, Colorado, 5–8 October.
64. Hemrick, R. and Landry, C. (1996) Case History: 13–3/8 Casing stair step casing pressure elimination project, *Proc. LSU/MMS Well Control Workshop*, Louisiana State University, Baton Rouge, LA, 19–20 November.
65. Nishikawa, S., Wojtanowicz, A.K., and Smith, J.R. (2001) Experimental Assessment of the Bleed-and-Lube Method for Removal of Sustained Casing Pressure. *Petroleum Society, Canadian International Petroleum Conference*, Calgary, AB, 12–14 June.
66. Monjure, N.A. (1998) Casing annulus remediation system (CARS), *Proc. LSU/MMS Well Control Workshop*, Louisiana State University, Baton Rouge, LA, 1 April.
67. Ditta, F. (1999) Update on casing annulus remediation system, *Proc. LSU/MMS/IADC Well Control Workshop*, Louisiana State University, Baton Rouge, LA, 24–25 March.
68. (2005) Remediation Treatment of Sustained Casing Pressures (SCP) in Wells with Top Down Surface Injection of Fluids and Additives, U.S. Patent 6,959,767 B2, 1 November.
69. Carpenter, R.B. et al. (2002) Alloy annular plugs effective for casing annular gas flow remediation, *Offshore*, March, pp. 72–74.

Chapter 4
Environmental Control of Drilling Fluids and Produced Water

A.K. Wojtanowicz

1 Control of drilling fluid volume

This section presents technology for environmental control of waste generation from the drilling process. Spent drilling fluid is the primary waste stream from the process. Thus, by the preventive nature of ECT, discussed in Chapter 2, new waste reduction components have been built into the mud engineering technology.

A steady increase of the mud system volume, as shown in Chapter 2, is inherent in the drilling process and results from both disintegration of cuttings during their transport to the surface and limited efficiency of cuttings removal by the solids-control separators. For water-based muds, this mechanism can be controlled by adding a second (dewatering) loop to the mud processing system so that the mud's water phase can be recycled and the volume of drilling waste minimized. Ultimately, disposal of this waste depends upon the toxicity of mud systems used to drill the well. Therefore, the properties of mud systems that are directly related to pollution are dispersibility, dewaterability, and toxicity. In a 'clean' drilling process these properties must be controlled. Also, such a process requires improvements in mud solids-removal efficiency.

1.1 Control of mud dispersibility

In mud engineering, several conventional methods can be used to inhibit swelling of shales. These methods have been developed primarily to combat the borehole instability problems. In addition, these methods usually prevent disintegration of cuttings, thus providing a basis for development of dispersibility control systems. Most of known inhibitive muds, however, are too toxic to be environmentally acceptable. Table 4.1 lists the inhibitive drilling fluids together with values of their toxicities, as reported by various sources. The

Department of Petroleum Engineering, Louisiana State University, Baton Rouge, LA 70803-6417, USA

TABLE 4.1. Drilling mud dispersibility vs toxicity [2]

Mud type	Mysid shrimp LC_{50} (ppm)
PHPA (9.6 lb/gal)	>1,000,000
PHPA (14.3 lb/gal)	>1,000,000
PHPA/salt water (20% NaCl, 14.5 lb/gal)	140,000
PHPA/sea water (13.5 lb/gal)	>1,000,000
Sea-water lignosulfonate (generic no. 2)[a]	621,000
Freshwater lignosulfonate (generic no. 8)[a]	300,000
Lime base (generic no. 3)[a]	203,000
KCl/polymer (generic no. 1)[a]	33,000
Cationic mud system	>1,000,000
Freshwater CLS – chromium lignosulfonate (2% diesel)	5,970
Freshwater CLS (2% mineral oil, 15% aromatics)	4,740
Freshwater CLS (2% mineral oil, 0% aromatics)	22,500
Mineral oil-based mud (MOBM)[b]	1,80,000

[a]Generic muds [1, 3].
[b]After Ref. 4.

data indicate a general trend, suggesting that the stronger the inhibitive properties are, the more toxic the mud becomes.

Potassium/polymer muds have traditionally been the best water-based system with the lowest dispersibility. Unfortunately, in the USA, the toxicity limitation of a minimum LC_{50} value of 30,000 ppm essentially eliminated potassium from use in the Gulf of Mexico and other offshore areas of the outer continental shelf [3, 5]. High-salt (NaCl) polymer muds, instead of the more effective potassium systems, are now being used in the Gulf of Mexico. However, potassium muds are being used in the North Sea and elsewhere where regulations are not biased against addition of potassium to sea water. To reduce the dispersibility characteristics of potassium muds in the North Sea, a variety of additives based on glycol and glycerol chemistry have been developed and are being used successfully [6–8].

One feature of polymer mud systems is that they typically operate at low pH levels relative to lignosulfonate muds that are highly dispersive. Lignosulfonate requires an alkaline additive for activation, such as sodium hydroxide (caustic soda), and the pH ranges from 9 to 11.5. The lower pH of polymer muds appears to be an important feature that helps reduce cuttings disintegration when cuttings are circulated to the surface. However, a number of high-pH lime muds are being used to take advantage of low dispersibility arising from the presence of insoluble lime [$Ca(OH)_2$] [9–11].

An example of non-dispersive polymer mud concept is the 'cationic' system [12–14]. The cationic mud is designed to have low dispersibility and toxicity. These mud systems were usually formulated using non-reactive sepiolite or attapulgite clay, cationic polymeric extender, and cationic inhibitors so that the solids in suspension are positively charged. Negatively charged reactive cuttings are encapsulated by adsorption of the cationic inhibitor on their surfaces, thus preventing their disintegration. Another formulation of the cationic mud system employs a solids-free combination of pregelatinized starch and hydroxyethylcellulose (HEC) for viscosity and fluid loss with cationic polymer and 10% KCl for dispersibility control. Because the system is solids free, it has been developed exclusively for slim-hole drilling with high rotating speeds and annular transport velocities.

A non-toxic claim has been made on the inhibitive mud system known as the *mixed metal-layered hydroxide compound* MMLHC (or MMH) fluid [15–17]. In fact, the system formulation clearly implies lack of toxicity. It is built using low concentration of bentonite clay (10 lb/bbl) and an inorganic MMLHC (<1 lb/bbl). Microscopically, the MMLHC compound contains discrete layers of metal ions surrounded by hydroxide ions. The layers are positively charged and are smaller than clay platelets. The clay inhibition is based on an ion-exchange mechanism (similar to that of KCl systems) with the MMLHC exchange capacity being more than three times greater than that of sodium bentonite. However, not only are the particles of bentonite inhibited from swelling through the exchange of sodium ions for the metal ion hydroxide platelets, but they are also aggregated around MMLHC particles owing to their excess of positive charge. The practical result of this interparticle association is the development of gel structure and excellent solid suspension ability. Field applications confirmed the non-dispersive behavior of MMH drilling fluids through the following observations: (1) no washouts; (2) no viscosity increase; (3) clean borehole; (4) small volume of clean shaker cuttings; and (5) low MBT values. Also, the retention of simulated cuttings on a 6-mesh screen was over 80% by weight.

The most promising group of the water-based muds that has been successfully developed, field tested and commercialized has been based on synthetic organic compounds. The concept gave rise to the new type of mud – Synthetic Base Muds, discussed in the following sections. One of such early systems was based on highly concentrated solutions of methyl glucoside (30–70% by weight). Laboratory studies indicated that this fluid may indeed have possessed the low dispersibility property achievable by oil muds [18].

1.2 Improved solids-control–closed-loop systems

The overall efficiency of cuttings removal by the solids-control system, E_s, can be expressed as

$$E_s = E_1 f_1 + (1 - E_1) E_2 f_2 + (1 - E_2) E_3 f_3 + (1 - E_3) E_4 f_4 \tag{4.1}$$

where E_1–E_4 are solids-removal efficiencies (by volume) of the shale shaker, desander, desilter, and centrifuge, respectively, and $f_1 - f_4$ are volume fractions of mud processed by these separators. The equation has little practical use because the efficiencies $E_1 - E_4$ are dependent upon separators' inputs, which in turn depend on the variable content of the flowline mud. However, Equation (4.1) is useful for the design of a new system configuration, and also for the evaluation of solids-control separators at work. In the latter case, the efficiency of each separator should be determined using API procedures [19]; then the overall efficiency should be calculated from Equation (4.1).

There are a few direct methods available at the well site to determine the overall efficiency of cuttings removal. The methods are based either on density measurements or water dilution records. Calculation of the overall separation efficiency using mud density measurements at the suction pit usually takes a long time (a day) and requires several cycles of mud circulation. The other method, measurement of the density difference between flowline mud and suction pit mud, does not give enough accuracy with the use of a mud balance. Alternatively, determination of reactive cuttings in the mud using the retort and the Methylene Blue tests does not have the precision required to detect the increase of clay concentration before it affects the mud rheology. An interesting method has been presented to determine a solids-control index (SCI) from the monitored water dilutions required to control drilled solids [19, 20]. (SCI can be converted to the separation efficiency through the equation $E_s = 1 - \text{SCI}$.) Although very practical, the method requires monitored water usage for dilutions and cannot be used for weighted mud systems.

Several attempts have been made to develop a mathematical computerized model of cuttings removal [21–25]. All of these attempts use the steady-state material balance approach with known and constant values of separation efficiencies of system components. They do not consider the relationship between the separation efficiency and particle size distribution, solids throughput and liquid-phase properties of the processed mud stream. Also, practical verification of the models is limited because no solids-control instrumentation is available on drilling rigs. More successful efforts have been made to develop experimental models of single separators: hydrocyclones [26, 27], shale shakers [28, 29], and centrifuges [30], together with the analytical and field-deployable techniques for evaluation of the separators' performances [31–33].

Emphasizing the efficiency of solids-removal may lead to the generation of excessive volumes of drilling waste. For any separator, whether shale shaker, hydrocyclone or centrifuge, a strong correlation exists between solids separation efficiency and volume removal of the associated mud liquid phase. Hydrocyclones, for example, when operated at 0.6 solids separation efficiency, may remove up to nine times more liquids than solids, as shown in Figure 4.1 [27, 34]. Generally, any increase in E_s would result in increasing values for liquid removal, represented by the liquid removal ratio, R (the ratio of the volume of removed liquid to the volume of removed solids). The correlation between E and R is unique for solids-control equipment and drilling mud used in the well. Theoretical calculations indicate that maximizing the efficiency of solids separation may result in up to a 50% increase of drilling waste volume [34]. Hence, there is an optimum value of E_s that gives a minimum volume of waste.

In the late 1980s and over the 1990s, a considerable improvement was made in solids-control separators [35, 36]. One significant improvement was in shale shakers and screens. Drilling rigs are now equipped with two or more linear-motion shale shakers. Some rigs may have as many as ten shakers, several of

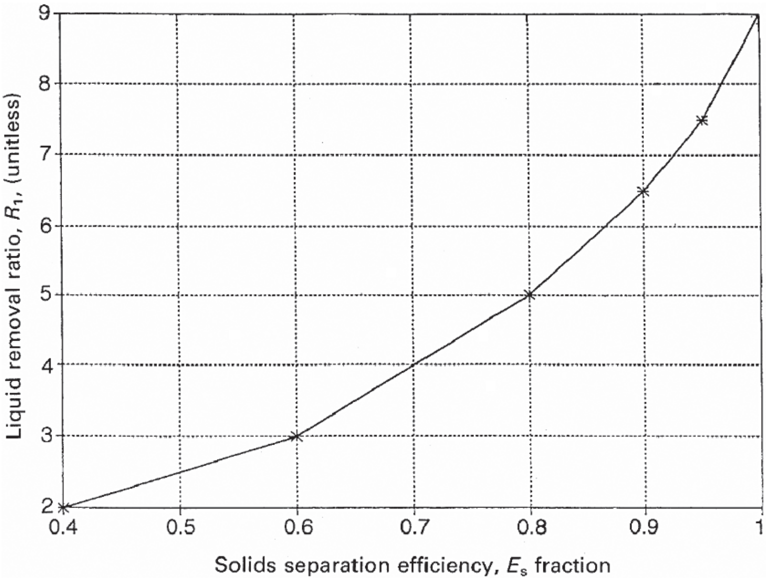


FIGURE 4.1. Typical relation between efficiency of solids removal and liquid removal ratio for hydrocyclones.

which are used as scalping shakers upstream of the fine-screen linear-motion shakers. The linear-motion shakers are often fitted with screens having an equivalent mesh size of 150 or more, which results in the removal of fine particles. The dramatic reduction in the size of the particles that can be screened from the drilling fluid has led to improved drilling-fluid performance and to a reduction in the volume of fluid required for drilling a well and discharged at the end of drilling the well. In addition to shale shakers and screens, the importance of the entire mechanical solids-removal system in reducing waste volumes from drilling operations has become better understood, which has resulted in the development of closed-loop drilling systems [37, 38].

The closed-loop system approach requires that the drilling waste should be disposed of at the drilling site and not taken out of the loop for off-site disposal [38]. From the standpoint of ECT methodology, closed-loop system technology integrates on-site disposal techniques with the drilling process (the environmental boundary is drawn around the drillsite, reserve pits and land treatment area). The drilling mud loop is partially closed through improved efficiency of the solids-control separators. The loop is finally closed through ultimate disposal on-site within the process boundaries. Table 4.2 shows the improvement in cuttings separation (hole removal) efficiency and economics resulting from the closed-loop system approach [38]. Closed-loop technology employs high-quality solids-control separators in various configurations. Sometimes these systems are provided as skid-mounted tandems known as unitized solids-control systems. Two types of unitized systems are

TABLE 4.2. Development and performance of closed-loop drilling systems[a]

Performance measure	1983	1984–85	1986	Closed-loop condition
Surface hole removal efficiency (%)	15	46	68	81
Production hole removal efficiency (%)	20	67	80	89
Surface hole mud and disposal costs ($)	10,200	7,800	6,300	4,500
Production hole mud and disposal costs ($)	25,600	14,300	8,300	4,800
Total costs ($)	35,800	22,100	14,600	9,300

[a]After Ref. 38.

available: one built by the solids-control equipment vendors and the other custom designed and built by operators.

1.3 Dewatering of drilling fluids: 'dry' drilling location

An ECT alternative to closed-loop systems is a zero-discharge, or 'dry', drilling location at which no disposal on-site is permitted. A dry drilling location requires advanced technology for mud processing to minimize the volume and cost of on-site storage and off-site disposal [34]. One such technology is mud dewatering [39]. The dewatering component incorporates technology for separating water from water-based muds for reuse in the mud system. It also significantly reduces the volume of liquid waste that is destined for ultimate disposal.

A schematic diagram of the mud processing system with the dewatering component is shown in Figure 4.2. After flowing out of the well, drilling mud is initially processed by solids-control separators (classification) and recycled back to the well. Since cuttings removal is not complete, a continuous increase of mud contamination by solids occurs. The contamination is controlled through additions of freshly mixed mud so that the mud system is steadily replaced with the new one. The rate of mud replacement is directly proportional to the rate of contamination of the system with fine cuttings. As a result, the rheological and filtration properties of drilling fluids are constant. Also unchanged is the mud system chemistry, which is closely maintained to its original formulation. In order to maintain a constant volume of the surface mud, the rate of mud replacement must be balanced with the mud discharge rate. Therefore, part of the mud stream, after being processed by the solids-control system, is diverted and treated by the dewatering component. First, the weighting material (barite) is removed and recycled back to the mud system. Second, the diverted mud is diluted with water to improve the chemical treatment which follows. Third, the diluted mud is treated with chemicals. The treatment transforms the mud from a stable suspension into a mixture of water-soaked flocculates and free water. The flocculates readily release water under a squeeze. The last stage of dewatering involves centrifugation of flocculates, resulting in a dense, solid cake (underflow) and solids-free water (overflow). The volume of underflow is significantly smaller than the feed

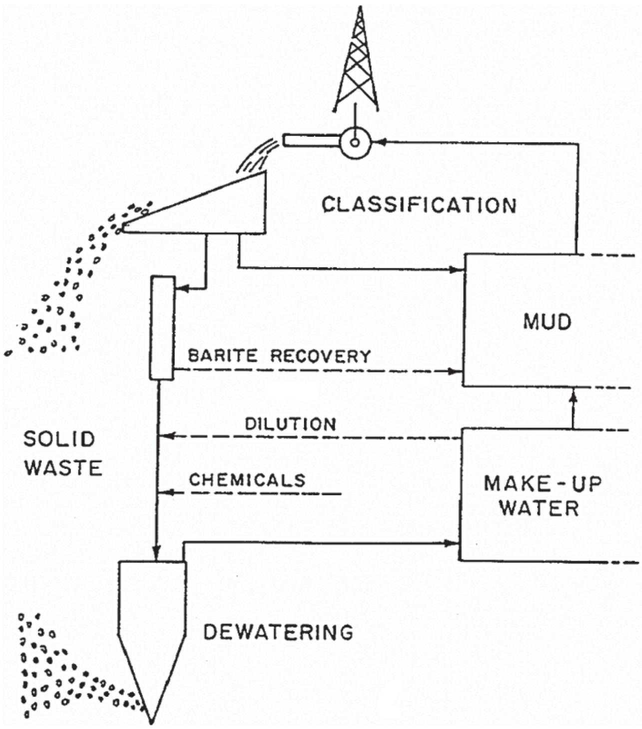


FIGURE 4.2. Principles of drilling mud dewatering.

mud volume. Also, returning the overflow water to the mud dilutions reduces water consumption and saves on chemicals dissolved in the mud–water phase.

Dewaterability involves the ability of drilling fluid suspensions to destabilize and release their water phase. The treatment consists of two stages: (1) chemical destabilization, in which a uniform liquid suspension is converted to two phases, free water and wet structure of solids (flocculates); and (2) mechanical expression, in which additional water is released by squeezing the solid structure. Like other properties of drilling fluid (e.g. water loss, viscosity, and gel strength) dewaterability embodies complex physical mechanisms. However, it can be determined simply by measuring relative volume reduction due mechanical expression [40, 41].

Dewaterability values for various drilling fluids are presented in Table 4.3 [42]. The data indicate that, theoretically, the volume of waste drilling mud can be reduced by 1.4–4.8-fold. On the other hand, the data show that the presence of inert solids (barite) may distort the dewatering performance. For example, high solids content in the dewatered salt/polymer mud may create the illusion of high performance and 'dry cake'. However, the actual performance is low, a mere 1.34-fold volume reduction. Therefore, in field applications, barite should be separated from drilling fluid prior to dewatering.

TABLE 4.3. Dewaterability of drilling fluids[a]

Mud system	Density (lb/gal)	Water removal (% v/v)	Cake solids (% v/v)	Volume reduction (% v/v)
Spud	9.2	65	43	72
Salt/polymer	13.5	65	66	28
Lime	9.6	63	47	62
CLS/unweighted	9.1	59	49	79
KCl/polymer	11.6	48	53	30

[a]After Ref. 42.

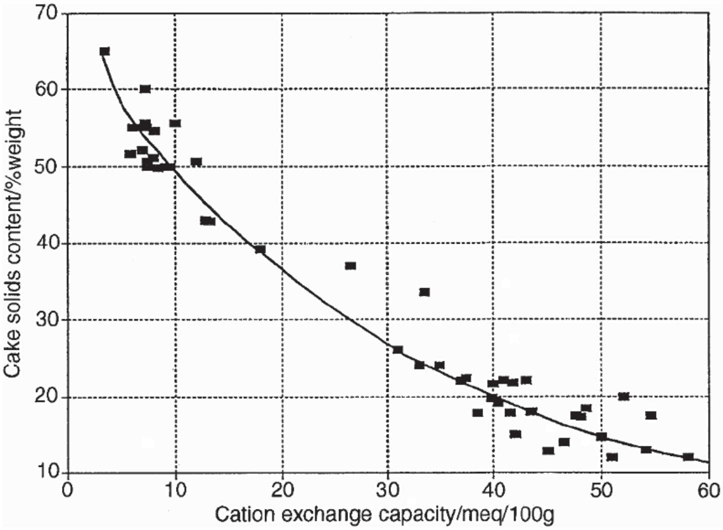


FIGURE 4.3. Effect of drilling mud solids reactivity on dewatering cake dryness [114].

The inverse effect of reactive solids on dewaterability was observed in laboratory tests [43] and documented in field tests as shown in Figure 4.3 [44]. Evidence shows that mud solids with a high cation-exchange capacity (CEC) produce moist cakes. However, the data do not show the simultaneous effects of mud inhibition and cuttings CEC on the cake's moisture. Moreover, the high moisture level in dewatering cakes has been often misinterpreted for low dewatering efficiency. In fact, the volume reduction ratio R_{vr} for unweighted mud is a function of both the cake moisture M and the fraction of water phase in the dewatering mud, f_w, as

$$R_{vr} = \frac{1-M}{1+M(SG_m-1)-f_w} \tag{4.2}$$

where SG_m is the specific gravity of the mud. Equation 4.2 indicates that a significant volume reduction can be obtained even with wet cakes (large M) for the low-solids mud systems (large f_w). For example, if the dewatering of a mud with 4% cuttings (and 10 lb/bbl commercial solids) produces a solid cake having only 30% solids by weight (14% solids by volume), the volume reduction is still a significant 2.5-fold.

Selection of the best chemical treatment for a drilling mud has been repeatedly reported as a difficult design problem. Typically, the only selection method is the tedious trial-and-error approach. A solution to this problem has been developed using the theory of multiple factorial experiments [40]. In this method, the number of experiments required to find the best treatment (dilution, coagulant, flocculent, error) is reduced to nine points (nine-point test). In principle, the nine-point test is a simultaneous optimization of three variables of chemical treatment.

The second stage of the dewatering process, cake expression, is critical for reducing the volume of waste mud because it generates almost all of the water recovered in the process. Characteristically, for drilling fluids, the content of water in the flocculated structure of solids is greater than that in untreated drilling mud.

The cost of mud dewatering has been considered a key factor of the process design and control in all reported applications [39, 44–46]. The decision regarding whether or not to use the mud dewatering process should be based upon calculations of economics because (1) the dewatering process may be non-economical for a well, when traditional solids-control system is efficient enough, or when savings due to volume reduction with the dewatering process cannot offset its cost and (2) at certain stages of well drilling, the dewatering component should be disconnected because its cost breaks even with the off-site disposal cost.

2 Control of drilling fluid toxicity

A remarkable progress was made during the 1980s and early 1990s in the development of technical measures to control the toxicity of environmental discharges from drilling operations. The methodology of toxicity control includes testing methods, low-toxicity substitutes and source separation techniques.

2.1 Drilling fluid toxicity testing

Toxicity testing of drilling fluids is currently required in the USA, North Sea and other offshore drilling areas. Various tests have been adopted from conventional bioassays, measurements involving living organisms, for marine, freshwater or sediment toxicities. Organisms used in marine toxicity testing are oysters, shrimp (white, brown, grass, or Mysid), crabs, fish, and clams. Freshwater assays involve fish such as sheepshead minnows, bluegill, rainbow trout, and daphnia. Typically, bioassays are conducted in licensed laboratories under controlled environmental conditions (light–dark cycles, temperature, salinity, pH, etc.), over time periods from a day to a week, and use organism populations carefully grown to meet sensitivity standards. Because of these reasons, the laboratory tests, rather than field-based toxicity tests, have been incorporated into environmental discharge regulations.

For example, the 96 h Mysid shrimp bioassay for drilling fluids was adapted from the US Army Corps of Engineers procedure for measuring the toxicity of dredged materials in compliance with ocean dumping criteria [1]. The test has been included in general permits for offshore dumping of drilling waste to the waters of the US Outer Continental Shelf (OCS) since the early 1980s. The Mysid shrimp LC_{50} value of 30,000 ppm has been set as the limiting toxicity to maintain the general permit for drilling mud discharge offshore, together with 'no sheen' and 'no free oil' requirements, and concentration limits for mercury (1.0 mg/l) and cadmium (3.0 mg/l) in barite. Companies that discharge mud with LC_{50} value smaller than 30,000 ppm are subject to penalty because acute toxicity increases as the LC_{50} decreases.

The Mysid shrimp bioassay has been criticized for its imprecision and inconvenience in practical applications [2, 5, 47, 48]. The test's turnaround time may be as long as 2–3 weeks, which is comparable with the well's drilling time. Major problems for operators in using the 96 h LC_{50} test is just how to comply because results are not known for days or weeks following a mud or cuttings discharge. Operators currently comply with the regulations by setting an internal margin of safety based on LC_{50} tests run previously on the mud type they are using. This safety level may be set 60,000 ppm higher than the regulatory limit of 30,000 ppm or even higher, reflecting the fact that LC_{50} test results are highly variable and that some cushion is needed for unexpected events [49].

A considerable effort has been made to develop a new field-deployable test of toxicity, a rapid bioassay [50–54]. The three basic requirements for such test are a short (few hours) completion time, feasibility for use at well sites and correlation with the Mysid shrimp bioassay. The Microtox toxicity test is a promising alternative for rapid bioassay. One concept was to use the test as a statistical tool to predict on the offshore drilling platform whether the mud's Mysid shrimp toxicity would exceed (or not) its limiting value of 30,000 ppm (with a probability level of 98–100%) [52]. Drilling mud passing such a test can be discharged overboard. The method could probably be further refined by introducing an element of calculated environmental (and economic) risks.

Another rapid toxicity test, cumulative bioluminescence, showed promise for further developments [54]. The test measures the total cumulative flux of light generated by a stirred suspension of algae plants in a controlled solution of drilling mud. The preliminary research results showed sensitivity of the test to progressive changes of mud toxicity. Also observed was a drastic improvement in the correlation with the Mysid test for higher mud toxicities (below the Mysid LC_{50} value of 300,000 ppm). However, neither of the rapid toxicity tests have been approved by the regulators and adopted for commercial use.

To avoid long waiting time for the test results, several useful methods are currently used for quickly checking a mud for compliance before discharge. A computer program is also available for estimating the LC_{50} based on mud composition [55]. However, from the compliance viewpoint, quick checks and computer estimates cannot be substituted for a full 96 h LC_{50} test.

2.2 *Low-toxicity substitutes*

Low-toxicity substitutes include either completely new mud systems, or replacement of individual mud treatment chemicals with low-toxicity alternatives. The low-toxicity substitutions have been used to solve the metal toxicity problem in drilling muds. Chromium lignosulfonate contains 2–4% by weight of trivalent chromium. Because it is considered a heavy metal, chromium presents an environmental problem. Even though toxicity tests have usually not indicated an adverse effect caused by the presence of chromium in lignosulfonate, considerable effort has been made to reduce the chromium content or replace the chromium with another cation. Chromium lignosulfonates have been replaced with modified sulfonates of the less toxic metals, such as iron, manganese, calcium, potassium, titanium, and zirconium. Most of these substitutes have shown certain deficiencies in performance when compared with chromium-based thinners, particularly in the thermal gelation after hot oven rolling. One of these new products, based on titanium lignosulfonate, has been reported as not showing any increase in gel strength, yield point and plastic viscosity when the weighted freshwater muds are heat-aged [56]. Also, the reported field applications indicated that the viscosity control performance with this new thinner (measured by the treatment dosage, lb/bbl, required to maintain a low value of yield point) was equivalent to the conventional chromium lignosulfonate performance.

Spotting fluids used for freeing stuck drillstrings have been traditionally based on diesel or mineral oil and are notorious for adding toxicity to the mud systems. Starting in the late 1980s, suppliers and chemical companies began to develop spotting fluids formulated without diesel or mineral oil [57]. Effective low-toxicity, water-based spotting fluids are now available that, after freeing a pipe, can be incorporated into the water-based mud system without causing a significant change in the toxicity so that overboard discharges of mud and cuttings can be continued [58]. Other low-toxicity substitutes for miscellaneous drilling chemicals, such as biocides, lubricants, defoamers, and corrosion inhibitors, have also been developed recently.

A dramatic progress has been made in developing low-toxicity substitution for oil-base muds. The idea of replacing diesel OBM with mineral oil-based mud (MOBM) was initially derived from toxicity measurements made in the UK. These measurements showed that the toxicity of mineral oil is five times lower than that of diesel oil [4]. Other comparisons of mineral and diesel oil toxicities in sea-water emulsions showed mineral oil to be at least 14 times lower in toxicity [59]. The difference has been attributed to reduced content and different types of aromatic hydrocarbons in mineral oils. Aromatics are particularly toxic because of their rapid bioaccumulation rates. Toxic effects of monocyclic and polynuclear aromatics are dependent upon their water solubility [60]. Mononuclear and dinuclear aromatics are the most toxic. Other polynuclear aromatics (with higher molecular weight) contribute little to toxicity because their solubility in water is low. Because mineral oils do not contain volatile monocyclic aromatics, their main toxic component is dinuclear aromatics.

Currently available mineral oils with no aromatics may be almost non-toxic with the Mysid shrimp LC_{50} value over one million ppm. However, some presence of aromatics is necessary for stability of invert emulsions. Therefore, a toxicity trade-off is needed for the MOBM formulations. The reported toxicities of MOBM are different, as shown in Table 4.1. The LC_{50} value of 180,000 ppm does not compare well with the values of 22,500 and 4,740 ppm reported for two freshwater muds having 2% mineral oil with 0% and 15% aromatics, respectively. One explanation might be a different concentration of aromatics in the base mineral oils. Also, higher toxicities of MOBMs than their base mineral oils may result from the toxic nature of primary and secondary emulsifiers used in these muds.

2.3 Synthetic base drilling fluids

A whole new class of non-toxic drilling fluids has been developed in the last two decades. These muds are formulated with a variety of synthetic organic base fluids. The resulting so-called synthetic-based mud possess most of the performance properties of oil-based muds but avoid most of the environmental problems of diesel and mineral oil muds [61–63]. (An environmentally-acceptable substitute for the mineral oil drilling fluids was first noticed with the use of a mud made from an ester in the Norwegian sector of the North Sea in 1990).

The chemistry of the synthetic-based fluids that are currently commercially available includes an ester derived from palm kernel oil, a diether, a food-grade paraffin, and a Poly-Alpha-Olefin (PAO) [64]. The ether-based SBM was used offshore Norway in 1990. The first PAO mud was used in 1991. Other synthetic base fluids were introduced to the industry in the following order: Linear Alkybenzene (LAB), acetal, Linear Alpha Olefins (LAO), Internal Olefins (IO), and linear Paraffins (LP) [65]. The chemistry of the components of the synthetic-based muds, other than the base fluid, is usually different from those in mineral-oil muds. These compounds may be found in petroleum and other sources, but they should not be called synthetic base fluids unless they are synthesized or manufactured. The use of feedstocks and strict control of the manufacturing process assure that SBM will not contain trace amounts of priority pollutants as even the purest highly refined and processed liquids do [66]. As synthetic fluids used for SBM are synthesized by the reaction of purified compounds, they are typically free of polycyclic aromatic hydrocarbons (PAHs).

The general definition of synthetic material requires production process be chemical synthesis. The compounds used SBM formulations must meet two ECT criteria for drilling fluids delineating the environmental and productivity performance. To be environmentally acceptable, they must meet local standards and regulations for the discharge of drill cuttings into the sea. (If the cuttings have to be collected and transported to land, then there is no advantage in using SBM rather than oil-base mud other than health and safety.) From the productivity standpoint, the synthetic material must be the base fluid for a stable mud systems with inhibitive properties of an invert emulsion oil-base mud.

Synthetic-based muds proved little or no toxic. Initially, as they passed the LC-50 Mysid toxicity test required for offshore discharges, cuttings from SBM systems were discharged on the interim basis within the context of water-base mud discharge limitations. Problems have been reported, however, in passing the US-based sheen test for these muds as they had been viewed by the regulators as another family of oil-based muds. At the time when SBM were introduced, regulations were developed only for water and oil-based muds and the testing and regulatory structure in place for these fluids did not fit with synthetics. To allow industry to continue discharging SBM cuttings, a new toxicity testing methods – specific to SBM – had to be developed.

Presently, the SBM cuttings discharge to sea is controlled by limiting concentration of synthetic fluid on cuttings to about 7% (dependent upon the type of base fluid) by using advanced solids-control equipment with cuttings dryers (centrifuges) that could reduce the concentration to 3% by weight. Regulators believe that reducing fluid content on cuttings also controls the amount of SBM discharged to ocean, enhances the biodegradation rate, and controls development of cuttings beds that damage the seafloor. In the US, in 2001, Environmental Protection Agency published final regulations that established technology-based effluent limitation guidelines and standards for controlled discharge of SBM cuttings anywhere offshore beyond 3 miles. The agency also revised general permit under the National Pollutant Discharge Elimination System allowing operators in the western Gulf of Mexico to discharge SBM cuttings under the new regulation specific for SBM. The permit requires toxicity testing and best management practices [67].

Biodegradation test discriminates the base fluids so they can be ranked for the use in SBM. The base fluid is the primary organic constituent that dominates biodegradation of mud system. The test has been adopted from an anaerobic test developed in the UK for sewage sludge [68]. The test runs for 275 days and costs about $2000. The regulatory stock limitations for SBM cuttings discharge specify that the base fluid's biodegradation ratio must be less than or equal to one. The ratio is computed by dividing the percent degradation of C_{16}–C_{18} internal olefin reference fluid by the percent degradation of the stock fluid used in SBM.

The LC_{50} toxicity of SBM is different to the LC_{50} Mysid test for water-based muds performed on suspended particulate phase (SPP). It is a 10-day bentitic toxicity test using organisms from the specie of amphipods (Leptocheirus plumulosus) that lives in the sediments at the sea floor. (As SBM are water insoluble they bond to solids and settle quickly at the bottom of water column. Consequently, there is little of suspended particulate phase.) It has taken over 7 years for the industry to develop the test. The regulatory stock limitations for SBM cuttings specify that the base fluid's toxicity rate ratio must be less than or equal to unity. Again, the ratio is computed by dividing the value of the 10-day LC_{50} for the C_{16}–C_{18} internal olefin reference fluid by the LC_{50} value of the stock fluid used in SBM [69].

The disadvantage of the synthetic-based muds is their high cost, typically several hundred dollars per barrel. However, this high cost is offset by cost reductions arising from the use of a high-performance, high-penetration-rate fluid and the ability to handle cuttings disposal on-site without special equipment. The main technical uncertainty associated with these fluids is the threat of lost circulation. Losses can be extremely expensive because lost fluid cannot be returned to the service company at the end of the well for credit, reconditioning and reuse [5].

2.4 Source separation – drill cuttings deoiling

The ECT method of pollution source separation – discussed in Chapter 3 – has been used to reduce oil-related toxicities of offshore drilling discharges. The most typical applications include removal of oil from drill cuttings and separation of diesel spots from water-based muds. Table 4.4 gives a summary of the maximum oil retention values for OBM cuttings using various separation techniques. Considerable controversy exists regarding the performance of centrifuges, with the lowest and highest values of oil retention being 3% and 10.25%, respectively (the typical reported values fall within the

TABLE 4.4. Separation techniques for oil removal from OBM cuttings[a]

Separation method		Oil retention (%w/w)
Shale shaker[b]		11.1–16.5
Mechanical cuttings washer[c]		9.4
Centrifuge[d]		3.0–10.25
Incinerator		0.0005–3
Solvent extraction		0.2
Vacuum distillation		0.01–0.05
	Diesel washed	3–5
Ultrasonic cleaning[e]		
	Unwashed mineral oil	8–15
	Screw type unit	1.0
Thermal desorption[f]		
	Hammermill	0.1
Liquefied gas extraction[g]		0.5–4.0

[a]After Ref. 70. [b]After Ref. 60. [c]After Ref. 71. [d]After Ref. 72.
[e]After Ref. 73. [f]After Ref. 77. [g]After Ref. 78.

range 5–8%). The best-performing separation technique, vacuum distillation, has been commercially applied in the oilfield. Three vacuum distillation plants for OBM cuttings have been reported as working efficiently in the North Sea [74].

Characteristically, most of the research and development work regarding OBM cuttings cleaning methods has been done in Europe for North Sea applications [71, 73, 75, 76]. In the past, European regulations specified the maximum oil content on OBM cuttings with different values for different types of oils: 3% and 10% in Norway and 5% and 15% in the UK for diesel oil and mineral oil, respectively. In the USA, however, the general permit regulations placed a ban on the overboard discharge of OBM cuttings, regardless of whether they came from diesel OBM or MOBMs, or SBM. The situation has changed with the development of SBM – once the regulators accepted these fluids as different to OBM as discussed above. Presently, in the Gulf of Mexico the discharge of cuttings with oil levels (measured as TPH) of either 6.9% or 9.4% by weight, depending on the synthetic oil selected, is allowed if the toxicity and biodegradation standards are met. These levels of oil on cuttings can be reached with centrifugal 'cuttings dryers'.

As the regulations have become more stringent the technology for removal of oil from cuttings has changed. Presently in Europe and South America, the processed cuttings typically measure less than 1% by weight of Total Petroleum Hydrocarbons (TPH) before disposal to in landfills. For offshore discharge of cuttings in the UK sector of the North Sea, an oil content of less than 1% is also required. Generally, oil-based cuttings generated offshore in the North Sea have been taken to land for treatment and disposal because, until recently, no method for reducing the oil content to less than 1% was available at offshore platforms. This situation has changed with development of thermal desorption technology for offshore locations.

Until recently, thermal desorption units were fixed facilities to which cuttings had to be transported. Now however, a unit has been successfully developed for use offshore [77, 78]. Use of desorption units offshore has required significant changes in the configuration and technology. Thermal process evaporates the oil and water from cuttings. The evaporation removes free oil and emulsified oil because the heat required for evaporation of the oil and water provides enough energy to remove and separate emulsified oil. However, removal of interstitial oil is more difficult as the oil is trapped in the rock interstices by molecular forces and surface tension. A higher level of heat is needed to overcome these forces, hence the removal of the last fraction of oil from cuttings – usually less than 1% – requires additional energy.

Hammermill desorption units have been specifically developed for offshore work and approved by regulators for use in the North Sea [79]. Principle of its operation is shown in Figure 4.4.

In the unit, a Hammermill grinder is used to pulverize the cuttings to a very fine powder comprising 60% particles smaller than 50 μm. The grinding generates friction and heat in the process. Typical temperature of products produced

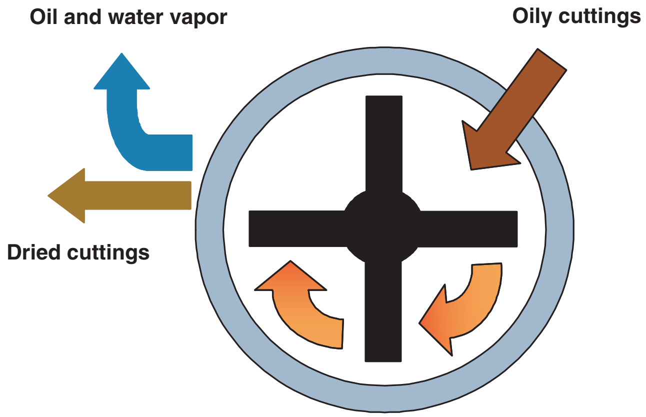


FIGURE 4.4. Principles of Hammermill thermal desorption unit (*See Color Plates*).

in the unit is 460°F (240°C–260°C), but can be as high as 570°F (300°C). This temperature range is more than adequate to remove oil with water.

Vapors are drawn off with a slight vacuum and dust is removed in a cyclone. After the dust removal a two-stage condenser removes oil and water. The Hammermill unit is very compact and relatively light. It has been used offshore in the North Sea where the dried cuttings having TPH lesser than 0.1%w/w are directly discharged to the sea. The low level of TPH indicates that the interstitial oil has been removed by reducing the particle size. Interstices are physically removed or destroyed as the rock particles fracture along their surfaces.

The technology of liquefied gas extraction of oil from cuttings has been developed as an alternative to thermal desorption [78]. The drawback of thermal desorption is the high energy consumption excessive frictional wear and associated cost. In addition, some base fluids for SBM may contain a high concentration of esters. The esters enhance drilling performance of SBM and impart properties of low toxicity and high biodegradation. However, they cannot be recovered thermally because their thermal stability is lower than that of other oils commonly used.

In principle, liquefied gas extraction is identical to supercritical carbon dioxide extraction. However, it employs as a solvent a hydrocarbon gas instead of carbon dioxide. Hydrocarbon gas can be liquefied at pressures much lower than carbon dioxide (40–100 psi). Presently, the technology is in the development stage; pilot scale testing showed that liquefied gas extraction can be used with SBM drilling fluids containing variety of base fluids and that low (below 1%) retention on cuttings can be achieved. Also, high-cost synthetic oils, including the ester-base fluids not recoverable by thermal desorption, can all be recovered with very low consumption of energy.

The ECT concept of pollution source separation has been also used for handling discharges of water-base muds contaminated with toxic spotting fluids. After a stuck pipe has been freed, the spotting fluid is circulated out of the hole and – in principle – should be separated from the drilling fluid. A separation technique for diesel-based spotting fluids was pilot-tested in the USA under the 1 year diesel pill monitoring program (DPMP) [80]. The program allowed participating operators to use a diesel pill that had been separated from the remaining mud by 50 bbl buffers on each side. After the diesel spot had been used in the well, the pill and the buffers were separated from the mud and sent ashore for toxicity testing, while the remaining mud was allowed to be discharged overboard regardless of diesel content. The purpose of DPMP was to create a database to determine toxicity limitations for diesel oil.

The results of DPMP showed that only about 70% of the spot was actually separated; the rest was incorporated into the drilling fluid. The remaining 30% has been proven to increase the toxicity of the water-based mud to the extent that it cannot be discharged even if a mineral-oil spot has been used. DPMP generated data that disqualified this separation technique and resulted in the ban on dumping mud after using diesel-based spotting fluids. Although this separation technique may still work for mineral oil-based spots, operators frequently haul all of the mud and cuttings to the shore instead of taking the risk of non-compliance following use of mineral-based spotting fluids [3].

3 Control of produced water volume

Recently, new technologies for subsurface management of produced water have been developed, as shown in Figure 4.5. These technologies represent attempts either to eliminate surface production of formation waters through injection *in situ* (downhole water separation – water unloading, downhole water sink/injection – water drainage/injection), or to reduce the water inflow into the wellbore (water 'shut-off'), or to eliminate hydrocarbon contamination of the water by segregating inflows of petroleum and water (downhole water sink/production – water drainage/production).

Several of these technologies improve the deliverability of petroleum wells and have been primarily developed as productivity measures having some environmental merit. For example, horizontal well completions are used for combating water coning problems in thin petroleum strata underlaid by strong aquifers. The environmental implication of this technology is that produced water to be disposed of is reduced. This implication has never been a main reason for the development of horizontal drilling. On the other hand, the technology of *in situ* injection of formation water has been solely developed for environmental reasons, but it also enhances well productivity by eliminating water coning (water sink). Thus, in the ECT terminology discussed in Chapter 3, each of these technologies shows both the upstream (productivity) and downstream (environmental) performances to some degree.

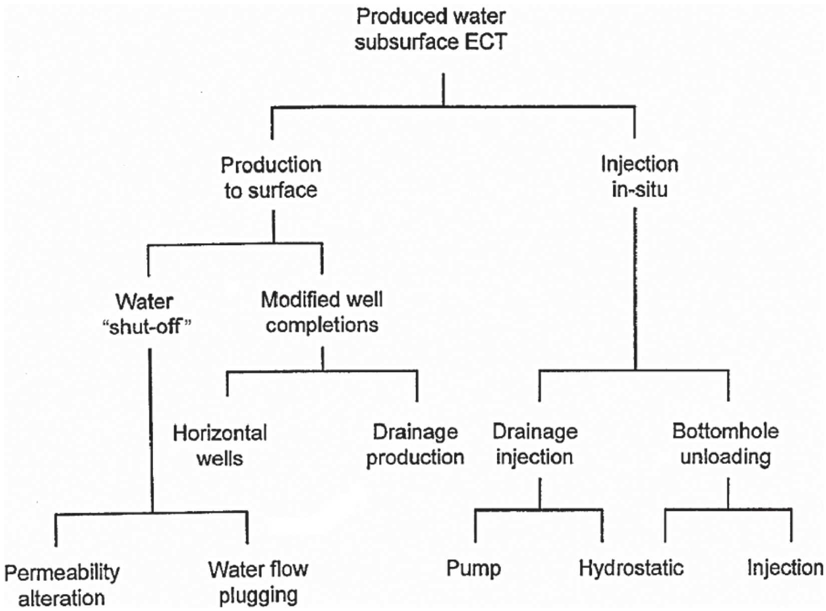


FIGURE 4.5. Subsurface environment-control technologies for produced water.

3.1 *Source reduction – water shut-off technology*

Methods of water shut-off include techniques based on alteration of permeabilities or rock plugging. Alteration of relative permeability involves injection of a low-concentration polymer into the pay zone producing oil and water to create a selective near-well barrier with reduced permeability to water and unchanged permeability to oil. The selective effect has been evidenced in laboratory experiments with sandpacks [81] and rock cores [82, 83], as well as in field tests [84, 85]. The physical mechanism of this method is not very well known. Most researchers agree that the water permeability reduction is attributed to surface adsorption of the polymer and that the effect works only in small size pores. The effect is based on either selectively plugging the water-flowing pores [84] or, according to the other theory, altering the flow pattern in the two-phase flowing pores so that the annular flow of water is hindered while the central core flow of oil remains essentially unaffected [82].

The method of rock plugging is used to reduce brine flow when water and hydrocarbon flowpaths are clearly separated. This method requires selective placement of a reversible barrier into the water flowpath by injecting a gel slug. When the water flowpath consists of a system of high-conductivity fractures producing mostly water, the effect on oil production is small while the water flow is greatly reduced.

Three basic mechanisms of *in situ* gelation of the injected slug are polymer crosslinking, reversible gelation and sol stabilization. Crosslinking is accomplished with inorganic multivalent salts such as magnesium chloride, aluminum sulfate, aluminum nitrate, or aluminum citrate [86]. These salts attract reactive sites on anionic polymer molecules so that they become larger and more rigid. At present, polyacrylamides crosslinked with solutions of inorganic Cr^{3+} are the most widely used gels. Their advantage stems from the ability to control the gelation time by selecting process parameters such as polymer and metal ion concentrations [87]. Also, crosslinking cationic polyacrylamide with organic crosslinking agents has recently been reported [85].

The biopolymer used in the reversible gelation process has the ability to change from the solution to the gel state by reducing the pH. This process has been proven to be reversible through an increase in pH. The proposed field procedure for this method, based upon laboratory tests [88], involves placing a biopolymer slug in the water zone and then displacing it with a solution of hydrochloric acid, which would create a barrier. To remove the barrier, an injection of sodium hydroxide would reverse the process and restore the initial permeability of the barrier zone.

The most environmentally attractive mechanisms of formation plugging, sol stabilization, is based on the gelling properties of colloidal silica suspensions. These suspensions are stable in fresh water, and their stability is sensitive to changes in pH and salinity. When destabilized, the suspensions form an impermeable gel structure. The time of destabilization and gelation can be controlled by pH and salinity changes. The field procedure involves pre-flushing the treated zone with fresh water to displace the *in situ* brine, followed by controlled on-line mixing and injection of the freshwater suspension of silica gel with a controlled volume of NaCl brine. The process has been field-tested with varying success and is considered a new alternative to polymer treatments [89].

A typical field example of successful gel treatments is shown in Table 4.5. Although the method reportedly works in the field, an actual outcome of the treatment is difficult to predict in the laboratory. Recent analysis of 57 field treatments with polymers and colloidal dispersion gels in water flood projects showed that 89% of these treatments were successful, despite laboratory predictions of a maximum 58% success rate [90]. The laboratory assessment of

Table 4.5. Example field performance of water 'shut-off'[a]

		Oil production rate (bbl/day)		Water production rate (bbl/day)	
Well No.	Area	Before treatment	After treatment	Before treatment	After treatment
1	Kansas	6	23	634	183
10	Kansas	7	10	384	96
4	Louisiana	33	12	440	0
7	Offshore Louisiana	30	30	720	370

[a] After Ref. 85.

crosslinked gels' ability to build structure and resist shear rates in reservoir conditions was concluded to be inadequate, primarily owing to uncertainties regarding downhole flow variables. Another treatment design problem arises because the mechanism that triggers the disproportionate reduction in water permeability compared with oil permeability is poorly understood. Recent studies of this mechanism have suggested that segregation of oil and water pathways throughout a porous medium, which results in selective plugging of water flowing pores, may be a dominant effect of gel treatment [91]. The conclusion was based on observations that the water-based gel reduced water permeability more than oil permeability, whereas the oil-based gel reduced oil permeability more than water permeability.

3.2 Source separation–downhole oil/gas/water separation

As shown in Figure 4.6, the techniques for bottomhole unloading and re-injection of water fall within the scope of technologies for *in situ* disposal of formation brines that eliminate water production to the surface. The technique is also called downhole oil/gas water separation (DHOWS or

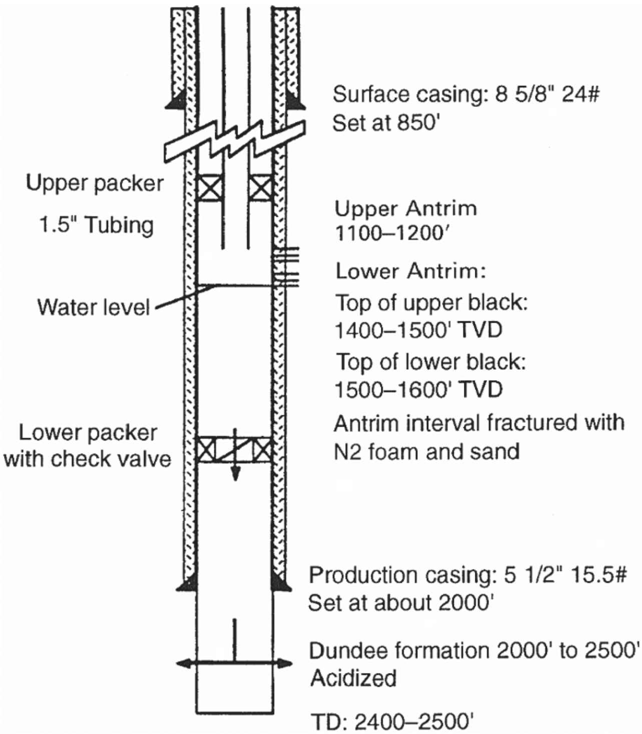


FIGURE 4.6. Schematic of 'waterless' completion in Antrim shales (1″= 2.54 cm; 1′ = 0.3048 m) [92].

DHGWS) as it involves moving the separation equipment from the surface to the bottom of the well. Moreover, the downhole – separated brine is disposed of by injection to the bottom (tail) section of the same well. DHOWS can be accomplished either by using a gravity segregation mechanism for gas wells or by adding a liquid–liquid separator to the downhole completion installation for oil wells. Downhole brine disposal involves either hydrostatic drainage to a low-pressure disposal zone or *in situ* injection using a downhole pump and isolating packer.

Because of spontaneous and rapid separation of gas and water, these techniques were first used in producing natural gas, which requires unloading excessive water. For example, dewatering coalbed methane gas formations has been successfully applied in field operations to stimulate gas production. The Fruitland coal gas wells in the San Juan Basin in southwestern Colorado require artificial lift for dewatering. Most Fruitland wells produce 150–250 Mcf/day of gas, with flow rates improving gradually as dewatering continues. Dewatering is performed in this area using conventional plunger pumps that produce water concurrently with gas production. Similarly to the San Juan Basin, removing water from the Antrim shale gas reservoir in northern Michigan is necessary for efficient gas production in the area. Conventionally, the wells require continual dewatering to reduce the head of water. Therefore, several operators installed submersible pumps as a means of lowering the flowing pressure of the bottomhole water. In this application, water is pumped up through the tubing, and gas is produced from the annulus.

Although the concurrent water removal from the San Juan Basin coal seams and Antrim shales increases gas production rates, water pumping consumes energy, and the problem of brine disposal arises. In the Antrim shale wells a recent solution to this problem has been the waterless completion technique that employs downhole dumping of produced water to the Dundee limestone located about 1000 ft below the Antrim shale formations [92]. The completion is shown in Figure 4.6. In this technique, the same well is used as both a production and disposal well. Its upper part, at about the gas–water contact (GWC), produces gas; the bottom part provides a conduit for the Antrim water downwards to the low-pressure Dundee limestone. Since the water drainage is hydrostatic due only to the formation pressure difference between Antrim and Dundee, the water removal rate is limited and cannot be controlled. Despite this problem, the waterless completion has been successfully field tested and approved by both the US Environmental Protection Agency (EPA) and the Michigan Department of Natural Resources as a waste injection method [93, 94].

Another technique of downhole water disposal using hydrostatic drainage is to build a hydrostatic head of water inside the well to overcome the injection pressure of the disposal zone [95]. In this technique, the well is dually completed both in the gas reservoir and the deeper disposal zone. These two completions are separated by a packer. A mixed gas–water stream enters the well through the upper completion, where gravity separation takes place above the packer. The accumulated water is then picked up by a downhole pump and lifted inside the string of tubing, while the gas is produced to the surface through the tubing–casing annulus. When the hydrostatic head of water in the tubing exceeds the pressure in the disposal zone, the water flows down the tubing, bypassed the pump (through the seating nipple bypass valve) to the well section below the packer, moves to the bottom completion and then goes to the disposal zone. Because the underground injection is entirely controlled by the hydrostatic head of brine, this method can only be used in a specific geological area. Also, the disposal zone's pore pressure gradient must be substantially lower than its normal value. In addition, the permeability must be high enough to assure the minimum required injectivity index so that the water injection rate will match its inflow rate. In pilot tests conducted in southwestern Kansas and the Oklahoma panhandle, the required injection rates were from 50 to 300 bbl/day per well, with average inflow rates of 134 bbl/day of water and 105,000 scf/day of natural gas per well. One of the two reported failures of this method (out of the seven total wells tested) was attributed to the low injectivity of the disposal zone.

Development studies using mechanical downhole separators for oil and water have been reported in Canada and Norway [96, 97]. A downhole separation system developed in Canada is shown in Figure 4.7. The system uses a dual-stream pump/hydrocyclone system to separate mechanically the produced water and oil. The bulk of the water is separated downhole (near the production zone) and re-injected into a disposal zone, while the oil-rich stream is pumped to the surface. The system includes a liquid–liquid hydrocyclone unit from Vortoil Separation Systems and standard artificial lift equipment modified to operate with the downhole separator. Systems have been tested in two separate field trials, the first with a Reda dual-stream electric submersible pump in a light crude application and the second with a progressive cavity pump in medium crude. In both cases, water production was reduced by 80–90% with no detrimental impact on oil production.

A prototype downhole separation system (DHS) developed in Norway has not yet been field tested [97]. The system is run on production tubing and temporarily connected with a polished bore receptacle to the permanent lower section of the tubing installed inside a 7 in. liner string. The liner string goes all the way down through the oil reservoir, into the water disposal zone and is perforated in the oil zone. A packer at the top of the liner holds the lower tubing, while the second packer below the oil zone isolates the oil from the disposal zone below. A mixture of oil and water can enter the liner–tubing annulus and flow upwards, across and above the dual-bore top packer. Then, the mixture is segregated and oil is produced to the surface through the upper section of production tubing, while the separated water is pumped with the electrical submersible pump down the lower tubing and into the disposal zone. The DHS separation system consists of an integrated string with a bulk hydrocyclone, a dewatering hydrocyclone and a produced water hydrocyclone in series. This arrangement enables the oil to be dewatered down to 1% bottom sediment and water (BS&W) and the produced water to be deoiled down to 40 ppm.

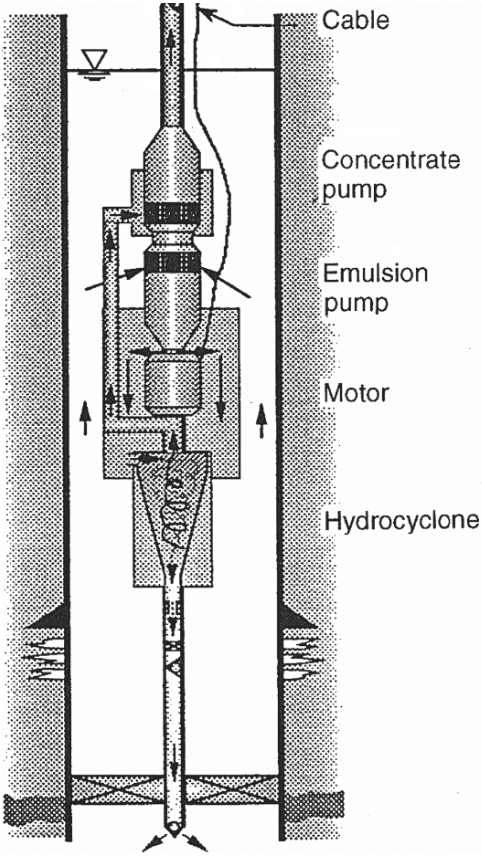


FIGURE 4.7. Downhole separation–disposal system [96].

3.3 Source reduction with downhole water sink

The source reduction technique of downhole water sink (DWS) involves drainage of the formation water *in situ* – from the water layer underlying the oil layer. The concept draws on a hydrodynamic theory of water coning control and it employs dual well completion and segregated inflows of oil and water into the well [98–103].

As shown in Figure 4.8, the DWS technique of coning control can be coupled with downhole injection of the drained water in the same well into a deeper disposal zone. Ideally, the disposal zone should be isolated from the drainage zone by an impermeable stratum. Alternatively, when no outside isolating stratum exists between the disposal and drainage zones, the water will be drained from and pumped into the same aquifer, thus constituting a downhole water loop. The DWS drainage-disposal technology has not yet been used in petroleum wells. In gas wells, applications of this technology are often mistaken for DHGWS techniques. However, the difference between

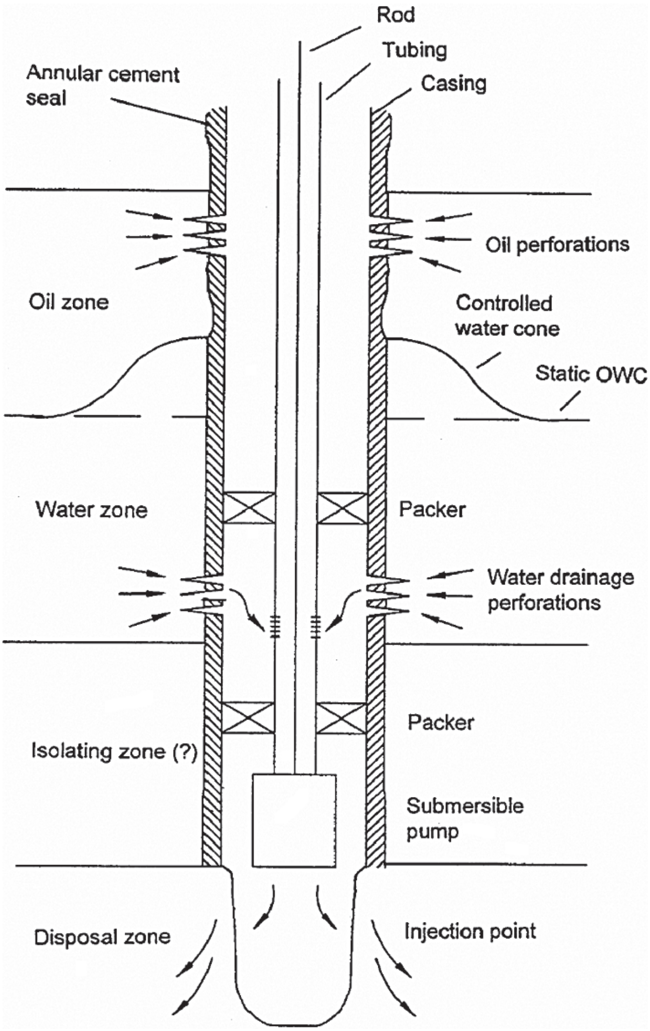


FIGURE 4.8. Downhole water drainage-disposal system [105].

the two is that DHGWS does not control water coning, whereas the DWS drainage-disposal technique does.

For oil wells, the feasibility and design of DWS drainage-disposal systems were theoretically investigated in the simulation studies [104–106]. Also, downhole installation for drainage injection was tested in the field [107]. In the field test, the pumping system was installed in an existing water flood well with one packer placed above the water drainage perforations and a second packer placed between these perforations and the injection perforations below (see Figure 4.9). During the test, a sucker rod-driven, progressive cavity pump

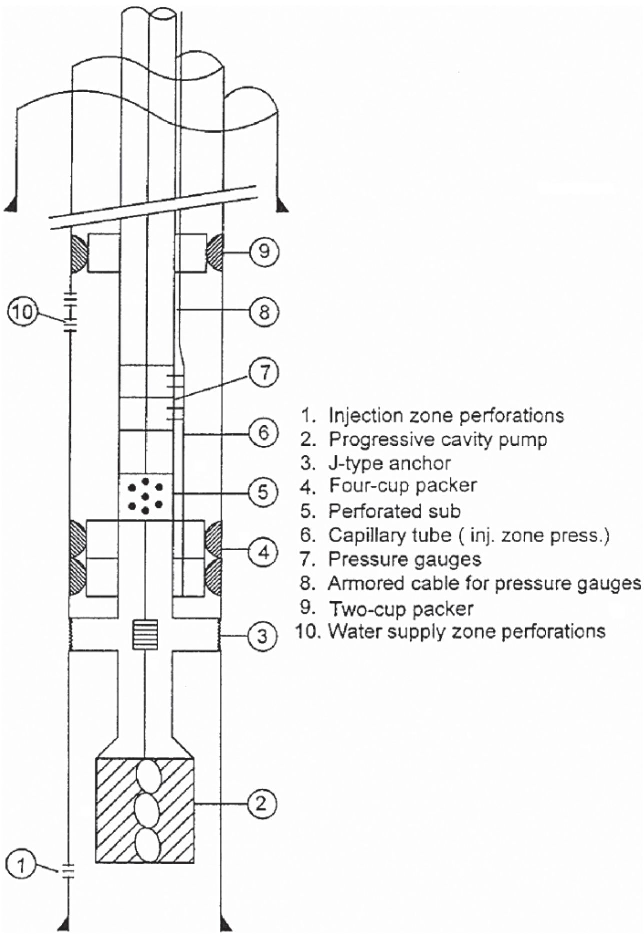


FIGURE 4.9. Field-tested downhole water loop [107].

drained formation water from the upper water supply zone and pumped it into the injection perforations. The injection rate, measured with a downhole recording flow meter, was from 130 to 180 bbl/day at the differential pressure between the pump suction and discharge of 175 psi. The test proved that the drainage-disposal system was functional. Also, the study resolved engineering problems regarding packing-off the system components inside the production casing and installing pressure gauges and a flow meter downhole. However, the test provided no information on annular isolation of the drainage and injection zones because its objectives were limited to the installation and operation of the downhole tools inside the casing.

A single potential problem in using DWS drainage-disposal systems is hydraulic isolation of the system components. This problem is likely to be commonplace in practical applications and may be caused either by geological conditions or by installation failures. For example, the configuration of geological strata below the pay zone may lack an isolating zone between the aquifer and the water disposal strata. Also, some degree of leaking across the well's annular seal may develop as a result of the well completion operations. Therefore, actual field systems are likely to operate under conditions of partial hydraulic communication between their components.

An analytical tool and computer program were developed and used to model dual well completions (DWS) with downhole injection in a multi-layered reservoir with crossflows and annular leaks [104, 106]. The analytical tool generates dynamic profiles of oil–water/gas–water contacts for a given geology, completions fluids and production/drainage injection rates. An example of a dynamic oil–water contact for a well with a deviated disposal section is shown in Figure 4.10. It shows the effect of lateral departure of the disposal completions (x) on water coning reversal. It is clear that the lateral departure of 300 ft is sufficient for reversing the cone. In fact, it has also been proved that the disposal section does not have to be placed in a deviated section of the well – just in the lower section of the same vertical well [104]. For injecting the water into the same aquifer (downhole water loop), the only requirement is to drill an adequate vertical rat hole and complete disposal section deep enough so injection completion will have no effect upon the water cone.

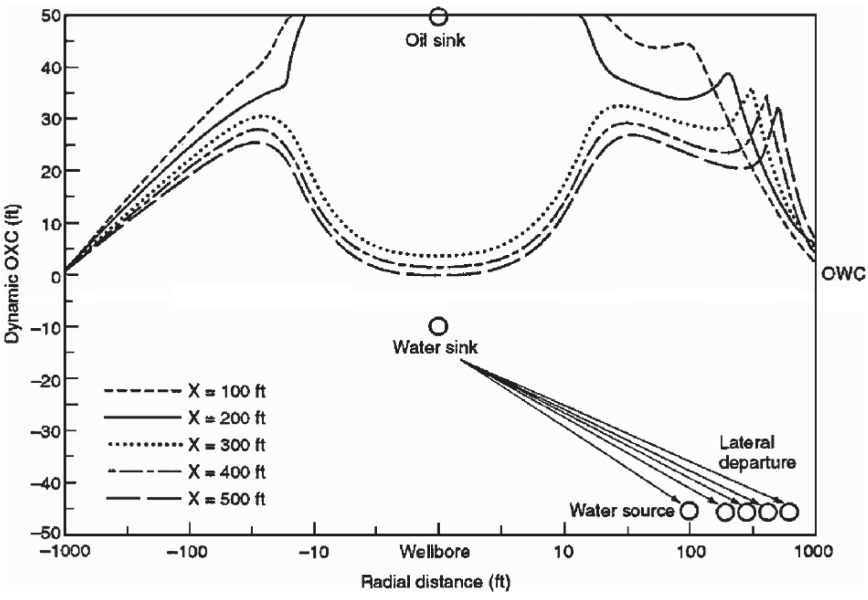


FIGURE 4.10. Dynamic oil–water contact (OWC) profiles for water drainage-disposal systems with deviated rat holes [104, 106].

The DWS drainage-injection systems have also been proven to be effectively operated with a leaking annulus outside the well.

When an annular leak develops around a well completed in isolated water zones, the amount of leaking water becomes proportional to the total water pumping rate. Therefore, a reduction in the system's performance caused by a leak depends only on the leak's conductivity. The reduced performance can be estimated using the predicted rate of leakage and the performance window plot. Thus, the performance window without the leak can be modified and used to predict the reduced performance with the leak.

4 Control of produced water pollutants

This section presents a brief overview of the source separation technology for removing pollutants from oilfield produced waters to comply with environmental discharge limitations. The technology is categorized according to the type of pollutant as control of oil – deoiling, removal of organics and demineralization. Deoiling involves separation of free oil suspended in the continuous water phase. The objective of organic treatment is to remove dissolved oil. The demineralization process is designed for removing salinity from produced water.

Limitations regarding the discharge of produced water to surface waters vary considerably in different countries. For land production operations the most restrictive limitation is prohibition of discharge. In this case, the only two alternatives for final disposal are either subsurface injection or evaporation to dryness followed by disposal of the solid material in permitted landfills. However, in arid areas having little surface water, discharge of produced water may be allowed under limitations on salinity (within a few thousand ppm of chlorides) and O&G (below 30 mg/l). In this case, the discharged water is used for beneficial purposes, such as crop irrigation or livestock watering.

In offshore production, a simple approach to regulating overboard discharge may address only maximum O&G concentrations in the discharge with little consideration given to other pollutants. In fact, such an approach has been typical for early regulatory initiatives in many countries. In this approach, the objective was to lower the O&G concentration in produced water and was subject to the discretion of regional authorities. For example, the O&G discharge limits would vary for geographical areas within the following values: 48 mg/l for the Gulf of Mexico, 40 mg/kg for the UK/North Sea, 30 mg/l for Australia and 15 ppm for the Red Sea and the Mediterrranean Sea [108–110].

Produced water discharge limitations have undergone, and are continuing to undergo, steady evolution. A conventional regulatory approach to the produced water effluent guidelines has been changed from one based solely upon the total O&G concentration to one which discriminates between the limiting constituents and specifies maximum concentrations for each constituent separately.

Table 4.6. Produced water discharge limitations to saline waters of Louisiana[a]

Pollutant	Discharge limitation
Benzene	0.0125 mg/l (daily maximum)
Ethylbenzene	4.380 mg/l (daily maximum)
Toluene	0.475 mg/l (daily maximum)
Oil and grease	15 mg/l (daily maximum)
Total organic carbon	50 mg/l (daily maximum)
pH	6–9 standard units
Total suspended solids	45 mg/l (daily maximum)
Chlorides	Dilution required at a ratio of 10:1 (ambient water: produced water). All other prescribed parametersmust be within acceptable limits prior to dilution
Dissolved oxygen	4.0 mg/l (daily minimum)
Toxicity (acute and chronic)	1 toxicity unit[b]
Soluble radium	60 pCi/l (2.2 Bq/l)
Visible sheen	No presence

[a]After Ref. 111.
[b]Toxicity unit is defined as the ratio of discharged effluent concentration to concentrations producing either lethality (acute toxicity) or no observable effects (chronic toxicity).

For example, Table 4.6 shows effluent limitations for discharging produced water to the saline inland, coastal and offshore state waters of Louisiana [111].

If this regulatory trend continues, more sophisticated (and expensive) technology for water cleaning will be needed. Some believe that the costs associated with such development may result in the technology shift from the source separation approach to subsurface injection (recycling-containment) or subsurface reduction (source reduction) of produced water. These methods are discussed later in this chapter.

4.1 Oil-free water from DWS drainage-production systems

This Downhole Water Sink (DWS) completion theory postulates that, as petroleum and water are naturally segregated *in situ* in the reservoir rock, the water would not be contaminated with hydrocarbons if it was produced separately and independently from petroleum [98, 112]. The principle of the DWS drainage-production technique is shown in Figure 4.11. The well is dually completed so that the lower perforations are placed in the water zone, and water can be produced both concurrently with, and independently of, oil production. These two producing streams are separated by a packer to prevent water from mixing with oil. Coning control is performed by adjusting the water production rate to the oil production rate so that the water cone does not break through the oil and enter the oil perforations. Physically, the water sink (water perforations) alters the flow potential field around the well so that the water cone is suppressed. Flow into the water sink generates a downward viscous force, which reduces the upwards viscous force that is generated by the

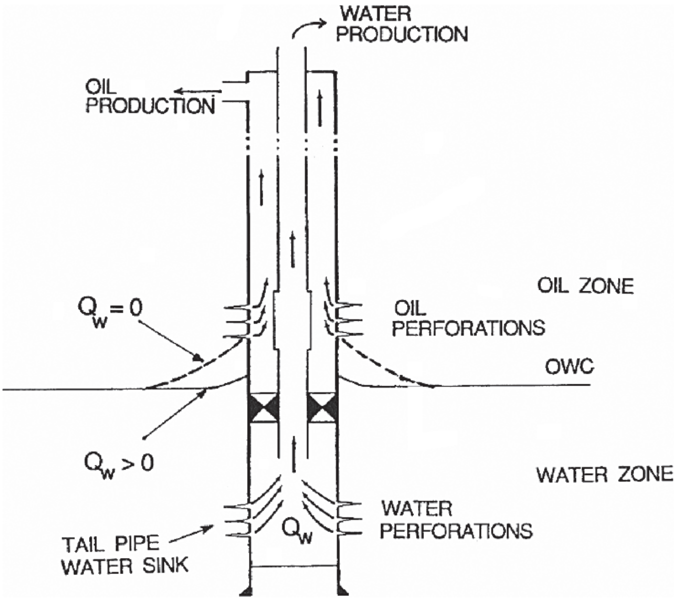


FIGURE 4.11. Schematics of water drainage-production system: tailpipe water sink [112].

flow into the upper (oil) perforations. At equilibrium, a stable water cone is 'held down' around and below the oil-producing perforations.

The segregated production method has several potential advantages:

- Oil production rate increases without water breakthrough.
- Well life extends beyond its value without coning control.
- Oil recovery per well (and for the whole reservoir) increases due to these mechanisms: (a) production can be continued with high levels of static OWC (caused by the bottom water-drive invasion), even when this level reaches the oil perforations and (b) well productivity remains high because the near-well zone permeability to oil is not reduced by water encroachment.
- Produced water is not contaminated with crude oil; there is no need for using de-mulsifiers or other agents so the discharge is more likely to meet effluent discharge limitations.
- Water cut of the produced oil is minimized.

Theoretical simulation studies of *in situ* water drainage revealed that, for each completion, a unique relationship exists between the oil production and water drainage rates, a performance window [104]. The window envelops the area of all possible combinations of oil and water rates that would provide stable operation of the drainage system. The window can be developed theoretically using data regarding reservoir and fluid properties in addition to well completion design. Also, the window can provide input for the economic analysis of the production project at hand.

Recently, the technique of water drainage-production has been used in the Wilcox sand oil reservoir of the Nebo Hemphil field in North Louisiana to resolve the problem of excessive water cuts experienced in conventional wells and to find out how clean the drainage water could be [113, 114]. Typically, for a conventional well in this area, a water problem would develop 60–90 days after the beginning of oil production. The excessive water cut would cause a reduction of the oil rate from 35 bbl/day initially to 12 bbl/day, with a 97% water cut.

This application was used in a new well that was drilled through the oil and water columns and dually completed in both zones. The water drainage completion (gravel packed) was isolated from the oil completion with a packer and 3½ in. tubing. A downhole progressive cavity pump lifted the water in the tubing, while the formation pressure drove the water-free oil up the annulus between the tubing and 7 in. casing.

The reported performance of drainage-production after 17 months of production was 57 bbl/day of almost water-free oil (0.2% BS&W), compared with 15 bbl/day using conventional completions [43]. The produced water/oil ratios were almost the same for both the new and conventional completions. However, the drainage water was free of hydrocarbons, as shown in Table 4.7 [42].

The analysis provided in Table 3.23 shows no detectable O&G contamination of the drainage water (below 2 mg/1). From a regulatory standpoint, this water would not require any clean-up to remove contamination with hydrocarbons before discharge or reuse. Also, additional analysis was made to compare concentrations of polyaromatic hydrocarbons (PAHs), the most toxic components of oil pollution in water.

Table 4.7 shows the results of the high-performance liquid chromatographic determination of PAHs in the drainage and conventional completion waters. These results clearly indicate that the drainage water is very clean relative to the conventionally produced water samples. Only 12 out of the total 55 PAHs determined this test were above the detection level of 0.005 ppb. Also, only a few of the most soluble aromatics, such as naphthalene and a few of its alkylated analogs, were detected, and these were found at very low levels. The total content of aromatics in the drainage water is approximately 11 ppb, almost one-fiftieth

Table 4.7. Hydrocarbon contamination of water produced from water drainage and conventional completions[a]

Contaminant	Conventional completion	Drainage production
Total dissolved solids (mg/l)	69,100	63,300
Oil and grease (mg/l)	484	UDL (2.0)[b]
PAHs (ppb)	592.6	ND[c]

[a]After Ref. 113.
[b]UDL (2.0) = under detection limit of 2 mg/l.
[c]ND = not detected.

of that in water samples from conventional completions. The results of this test showed that, in view of present environmental regulations regarding hydrocarbon limits in produced water discharges, the drainage water does not need any treatment for hydrocarbon contamination prior to discharge.

4.2 Deoiling of produced water

In the early 1980s, the conventional systems of produced water treatment were exclusively designed for oil removal and employed a two-stage configuration. In these systems, the primary stage would incorporate either a gravity settler (skim tank, gun barrel) or a coalescer (parallel/corrugated plates, serpentine path), and the second stage would employ a flotation unit.

All gravity settlers are settling tanks designed to provide sufficiently quiescent flow conditions so that free oil rises to the water surface and coalesces into a separate oil layer to be mechanically removed. In addition, particulates coated with heavy oil may settle to the bottom and are removed as a sludge or underflow. Chemicals such as de-emulsifiers and/or coagulents may be added to improve separation.

Serpentine-path coalescers convert small oil droplets to larger ones. The process of oil coalescence can be realized by forcing the oil–water mixture to flow through a permeable pack of a granular or fibrous material. The idea is attractive, but there are a number of practical difficulties (one of which is the occurrence of both droplet coalescence and droplet fragmentation in the permeable pack). In practice, this technique is not often used for reduction of the oil concentration in produced water.

A plate coalescer consists of an assembly of parallel plates, through which the oil-in-water emulsions flow. The presence of the plates leads to a reduction in the settling distance of the oil droplets and to coalescence on the plates' surfaces. To enhance the removal of the collected oil, the plates are inclined and corrugated. The main advantages of plate coalescers are their simplicity, low maintenance and lack of moving parts. Their limitation is that oil droplets below a minimum size, reportedly around 8 μm, cannot be separated. However, also reported was a practically achievable minimum size of oil droplets in the range 20–30 μm [115].

The induced gas flotation process disperses fine gas bubbles into a reaction chamber to suspend particles that ultimately rise to the surface and form a froth layer. Oil droplets and oil-coated solids, which are suspended in the water, attach to these bubbles as they rise to the surface, are trapped in the resulting foam and are removed when the foam is skimmed from the surface. Flotation cells for deoiling produced water utilize two different methods to induce gas into the produced water. The most common method is mechanical and uses a rotating impeller positioned inside a stator at the base of a draft tube. The rotation of the impeller creates a vacuum which draws gas down the draft tube. The gas is then ejected from the impeller through the stator, which disperses the gas in the form of fine bubbles. The second type of gas induction uses hydraulic ejectors to aspirate gas into the produced water. This requires recirculation of a portion of the treated water for use as the motive force to aspirate the gas.

The oil removal performance of conventional water treatment systems has been evaluated in field [116–118] and laboratory studies [119–120]. The results provided a general assessment of this technology: (1) there was no removal of dissolved organic fractions; (2) the minimum oil concentration at the output of gravity settlers was 113 mg/l; (3) the mean oil concentrations in effluents from over 50% of the flotation units tested were above the regulatory limit of 48 mg/l; and (4) the design of a system should incorporate an actual brine and crude produced from a reservoir.

The field survey data [117] were further analyzed [121]. The objective was to determine a relationship among the system variables, such as water flow rate, the oil content in the feed water and the oil content in the effluents from primary and secondary separators. A multiple regression analysis was used to model the simultaneous changes of the recorded variables. The results indicated a lack of any statistically meaningful correlation between the variables. The oil-separation performance, measured as the effluent oil concentration, appeared insensitive to varying input rates and oil contents. Several factors explain this insensitivity. First, the system was operated at a fraction of its nominal throughput (insensitivity to the flow rate). Second, the separation efficiency was a possible maximum (insensitivity to the influent oil content). Additionally, the mean value of the effluent oil content was below the compliance level of 48 mg/l (monthly average) for only five out of ten systems, and the daily values fluctuated closely to the compliance limit of 72 mg/l (daily maximum). Further reduction of oil content at the process end-point was concluded to be accomplished only by adding an efficient separator downstream from the flotation unit.

Also, the statistical analysis provided an interesting insight into the performance of the primary separation devices. The study revealed that, during most of the test, the primary separation was redundant. As shown in Figure 4.9, the flotation units were capable of reducing the oil content in produced water to levels of 10–60 mg/l for influents containing less than 800 mg/l oil. This performance was not significantly dependent either on the feed oil content or the flow rate. The plot in Figure 4.12 also indicates that, for the same range of the input oil, the primary-stage separator effluents had oil content levels well above those for flotation units. Moreover, the field data used in this analysis show that system input oil contents smaller than 800 mg/l were very common (93% of all input samples contained less than 800 mg/l oil). Therefore, the actual use of gravity settlers and coalescers was minimal.

The logical steps in the future development of deoiling systems for the oilfield production process appear to be: (1) the improved control of effluents from heater treaters using API separators to stabilize oil concentration below 500 mg/l; (2) design of the first-stage separation (e.g. flotation unit) to reduce the oil content to a range of 10–50 mg/l; and (3) addition of a new, high-quality separator to the second stage of the process.

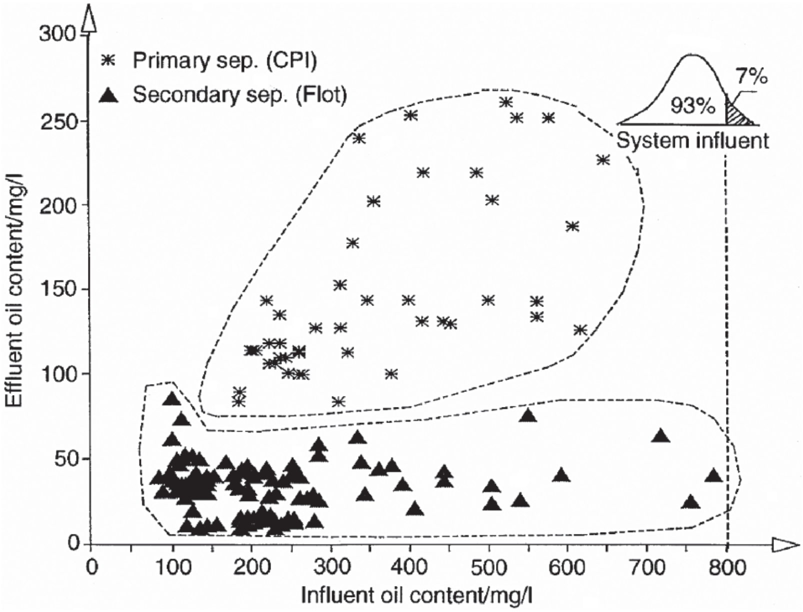


FIGURE 4.12. Redundance (93%) of primary treatment of produced water [121].

Several new technologies show promise for the oilfield surface process application. A list of these technologies, together with their tested efficiencies of oil removal, is presented in Table 4.8 [109, 110, 122–128]. This table has been compiled using information from various sources, ranging from rigorous scientific laboratory projects [110] to commercial publications [123]. Therefore, the data in Table 4.8 should be viewed as the best estimates of the performances for each method. In addition, the oilfield applicability of the methods either has not been fully analyzed or is controversial. For example, the use of hydrocyclones requires a stable input pressure and a constant feed rate, both of which cannot be easily achieved at the output of free water knock-outs (FWKO) [129]. There is an ongoing discussion among oilfield service companies on the superiority of various modern deoiling technologies; hydrocyclones, centrifuges, membrane filters, diffusion-barrier filters, etc. [130].

Cost performance of the deoiling technology is shown in Figure 4.13 [131]. Unit cost curves are presented for five options of deoiling technology versus water production rate: deep bed filter; gas flotation; hydrocyclone; and API separator, with and without chemical conditioning. The unit costs presented in Figure 4.13 have been calculated using the following assumptions regarding removal efficiency: 5 mg/l O&G concentration in effluents from induced gas flotation or API separator, 98% removal efficiency for deep bed filtration and 80% removal efficiency for hydrocyclones. These assumptions are not universal but represent average performances of these technologies.

From Figure 4.13, the least-cost deoiling treatment is apparently the API separator, followed by the hydrocyclone, deep bed filter, induced gas flotation

TABLE 4.8. Environmental performance of modern techniques for deoiling produced waters

Technology	Influent oil (mg/l)	Effluent oil (mg/l)
Vortoil hydrocyclone [109][a]:		
35 mm	43	11
60 mm	408	16
Colman–Thew hydrocyclone [110][b]	100	12
	1000	100
Rotary hydrocyclone [122][c]	100	15
	1000	35
Disk-stack centrifuge [123][d]	<1000	5
Crossflow microfiltration [124, 125][e]	28–583	5
High-gradient magnetic separation [126][f]	190–240	23
Electrolytic treatment:		
[127][g]	1000–2000	3–11
[128][h]	500–5000	TR[i]

[a]Field tests offshore; flow rate up to 11 gpm/cone.
[b]Laboratory tests; constant size of oil droplet in influent, d_{50} = 35 μm; flow-rate range 21.5–37.4 gpm/cone.
[c]Prototype test offshore (mean value of results from two platforms); flow rate 26–36 gpm/cone; rotary speed 1900 rpm.
[d]Commercial data for oily water only; flow rate 29 gpm; rotary speed 5000 rpm.
[e]Offshore field test; permeate flux 850 gpd/ft^2; flow rate 3 gpm per two units in series.
[f]API separators effluent tests.
[g]Bench- and pilot-scale experiments; wastewater from manufacturing plant.
[h]Bench-scale experiments; Nigerian light crude + sea-water emulsion.
[i]TR = no residual turbidity; 100% removal claimed.

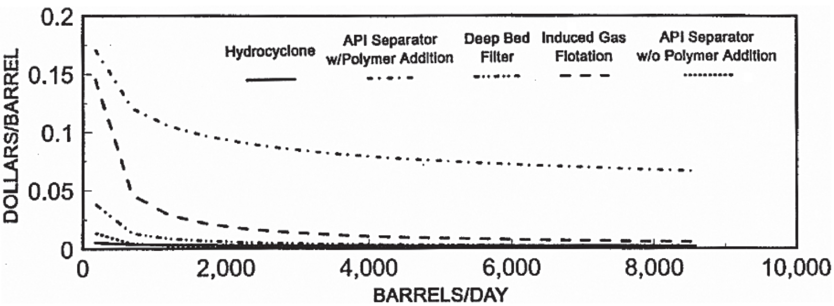


FIGURE 4.13. Cost of deoiling technologies for produced water (1994 dollars; 20 year project life; 5% discount rate) [131].

and the API separator with chemical polymer addition. The higher cost for the API separator with chemical conditioning results from the use of the chemicals. However, the selection of a deoiling technology should be based on technical performance as well as cost. Technical performance determines the lower limit of O&G concentration that each treatment technology can attain and is dependent on the removal efficiency and influent O&G concentration. Moreover, these two factors, removal efficiency and influent quality, are inter-related. Therefore, selection of the specific deoiling treatment process would require consideration of the upstream quality of the process influents and the downstram quality of the effluents. The effluent O&G concentration may be either subject to discharge permits or determined by downstream pretreatment requirements.

4.3 Removal of dissolved organics from produced water

Two technologies, bio-oxidation and granular carbon adsorption, have been recently selected as the most promising options for removal of organic material dissolved in produced waters. These technologies have been included in the computer-aided engineering model for calculation of the cost of different produced water treatments for the natural gas industry [132].

The bio-oxidation process for produced water has been adapted from the biological fluidized bed reactor (FBR) process for treatment of municipal wastewater. FBR for produced water is an aerobic reactor employing aerobic bacteria to biodegrade dissolved organics. The process consists of passing the produced water to be treated upwards through a bed of finegrained media, such as sand, granular activated carbon or ion-exchange resins, at a velocity sufficient to impart motion to, or 'fluidize', the media. This occurs when the drag forces caused by the liquid moving past the individual media particles are equal to the net downward force exerted by gravity (buoyant weight of the media). This is referred to as the point of incipient fluidization (defined either as the point at which fluidization occurs or the maximum bed porosity achievable prior to fluidization occurring). Greater fluid upflow velocities (flux rates) cause the bed of media to expand beyond the point of incipient fluidization.

Fluidization of fine-grained media allows the entire surface of each individual particle to be colonized by bacteria in the form of a biofilm. Surface areas of the order of 300 m^2/m^3 of bed are common in FBR systems. This results in accumulation of biomass concentrations of 5–50,000 mg of volatile suspended solids (VSS) per liter of fluidized bed, which is an order of magnitude greater than that obtained in most other biological processes. Manipulating the volume of media added to a system, the fluidization velocity and the point in the reactor at which the bed height is controlled allows the average biofilm thickness and mean cell retention time to be designed for maximum performance.

The granular activated carbon (GAC) adsorption process employs a fixed-bed column that is used as a means of contacting the produced water with the carbon media. Produced water with dissolved organic compounds enters the inlet to the granular activated carbon container. Soluble organics are adsorbed on the surface of the carbon and the treated produced water exits the GAC container. The GAC must be reactivated when it can no longer absorb organics. The carbon can be reactivated in the canister or removed and reactivated off-site.

Figure 4.14 is a plot of the unit cost curves for dissolved organic treatment using bio-oxidation (GAC–FBR), GAC–FBR with a sand filter and GAC

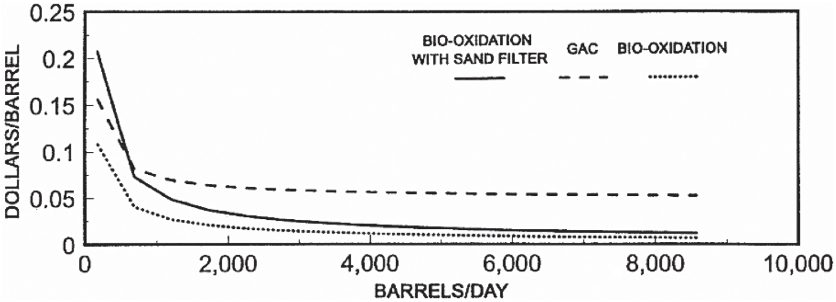


FIGURE 4.14. Cost of various techniques for removal of dissolved organics from produced water (1994 dollars; 20 year project life; 5% discount rate) [131].

alone [131]. The GAC–FBR unit cost curve is a function of the flow rate and an influent chemical oxygen demand (COD) concentration of 34 mg/l. The GAC unit cost curve is a function of the flow rate and influent organic concentrations of 12 mg/l benzene, 1 mg/l naphthalene and 1 mg/l phenol. A sand filter would be needed to remove biosolids in certain situations, such as when total suspended solids (TSS) would be above permit limits or prior to electrodialysis, reverse osmosis or vapor compression, forced evaporation and solar evaporation. It is also shown that the addition of a sand filter does not significantly affect the unit cost of using a GAC–FBR. The cost for removing dissolved organics ranges from less than \$0.01 to \$0.25/bbl of produced water, depending on the process selected.

4.4 Produced water salinity reduction

Demineralization technologies are electrodialysis, reverse osmosis, vapor compression, forced evaporation, and solar evaporation. A brief description of each of these processes is given below [131].

Electrodialysis accomplishes a selective separation of ionic compounds from produced water using semi-permeable, ion-selective membranes and electricity. Application of an electric potential between two electrodes causes cations to move toward the negative electrode and anions toward the positive electrode. Alternate spacing of cationic- and anionic-permeable membranes results in the formation of diluted (product) and concentrated (reject brine) salt solutions between the alternate membranes.

Reverse osmosis is a process in which produced water is partially demineralized by being forced through a semi-permeable membrane at a pressure greater than the osmotic pressure caused by the dissolved salts in the produced water. A partially demineralized water stream and a concentrated brine solution are produced.

Vapor compression is a process in which steam is used to heat the produced water above the boiling point. The vaporized produced water is compressed and

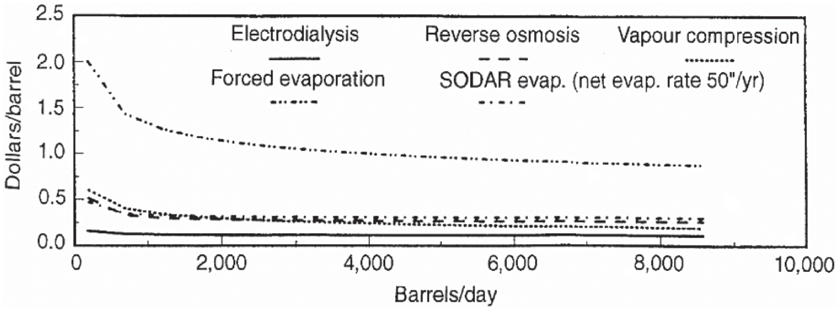


FIGURE 4.15. Cost of demineralization technologies for produced water (1994 dollars; 20 year project life; 5% discount rate) (50″ = 1.27 m) [131].

also used to heat the incoming produced water in a heat exchanger. The condensate from the heat exchanger is the treated, demineralized, produced water.

Forced evaporation uses a spray dryer into which the produced water is flashed at temperatures above boiling point, resulting in the production of steam and solid salt. The steam is then emitted to the atmosphere or recondensed.

Solar evaporation is accomplished in ponds and can be used in arid regions. Produced water evaporates from the surface of the pond, resulting in the build-up of solid salt in the pond.

Figure 4.15 is a plot of the unit cost curves for the five demineralization treatment options discussed above [131]. The cost ranges from \$0.10 to \$2.00/bbl of produced water. These unit costs are related to flow rate and have been calculated assuming an influent TDS concentration of 50,000 mg/l and an effluent TDS concentration of 500 mg/l. Electrodialysis is the least expensive technology for partial demineralization of produced water and ranges from \$0.11 to \$0.16 over a produced water flow rate range of 8570–170 bbl, respectively. Disposal cost of the rejected stream has not been included in the given unit costs. Forced evaporation is the most expensive technology for managing inorganic salts in produced water. The unit cost ranges from \$0.88 to \$2.00 over a produced water flow rate range of 8570–170 bbl, respectively. These unit costs do not include solids disposal or recovery of water. The solar pond unit costs were based on a 50 in./year net evaporation rate.

References

1. Ayers, R.C., Sauer, T.C., and Anderson, P.W. (1985) The generic mud concept for NPDES permitting of offshore drilling discharges. *Journal of Petroleum Technology*, March, 475.
2. Dunn, H.E. and Beardmore, D.H. (1989) Status report: Gulf of Mexico, mud toxicity limitations. *Petroleum Engineer International*, October.
3. Clark, R.K. (1994) Impact of environmental regulations on drilling-fluid technology. *Journal of Petroleum Technology*, September, 804–9.

4. Jones, R.D. et al. (1983) The development and performance of a nontoxic oil mud. *Drilling*, April.
5. Clark, R.K. et al. (1976) Polyacrylamide/potassium chloride mud for drilling water-sensitive shales. *Journal of Petroleum Technology*, June, 719; also in *Transactions AIME*, 261.
6. Steiger, R.P. (1982) Fundamentals and use of potassium/polymer drilling fluids to minimize drilling and completion problems associated with hydratable clays. *Journal of Petroleum Technology*, August, 1661.
7. Reid, P.I. et al. (1993) Reduced environmental impact and improved drilling performance with water-base muds containing glycols. SPE 25989, *Proc. 1993 SPE/EPA E&P Environmental Conference*, San Antonio, TX, 7–10 March.
8. Downs, J.D. et al. (1993) TAMME: a new concept in water-base drilling fluids for shales. SPE 26699, *Proc. 1993 SPE Offshore European Conference*, Aberdeen, UK, 7–10 September.
9. Reid, P.I., Minton, R.C., and Twynam, A. (1992) Field evaluation of a novel inhibitive water-based drilling fluid for Tertiary shales. SPE 24979, *Proc. 1992 SPE European Petroleum Conference*, Cannes, France, 16–18 November.
10. Elsen, J.M. et al. (1991) Application of a lime-based drilling fluid in a high-temperature/high-pressure environment. *SPE Drilling Engineering*, March, 51.
11. Hale, A.H. and Mody, F.K. (1993) Mechanism for wellbore stabilization with lime-based muds. SPE 25706, *Proc. 1993 SPE/IADC Drilling Conference*, Amsterdam, Netherlands, 23–25 February.
12. Beihoffer, T.W. et al. (1992) Field testing of a cationic polymer/brine drilling fluid in the North Sea. SPE 24588, *Proc. 1992 SPE Annual Technical Conference and Exhibition*, Washington, DC, 4–7 October.
13. Hemphill, T. et al. (1992) Cationic drilling fluid improves ROP in reactive formations. *Oil and Gas Journal*, 8 June, 60.
14. Welch, O. and Lee, L. (1992) Cationic polymer mud solves gumbo problems in North Sea. *Oil and Gas Journal*, 13 July, 53.
15. Burba, J.L. et al. (1988) Laboratory and field evaluation of novel inorganic drilling fluid additive. IADC/SPE 17198, *Proc. 1988 IADC/SPE Drilling Conference*, Dallas, TX, 28 February–2 March.
16. Burba, J.L. et al. (1990) Field evaluations confirm superior benefits of MMLHC fluid system on hole cleaning borehole stability, and rate of penetration. IADC/SPE 19956, *Proc. 1990 IADC/SPE Drilling Conference*, Houston, TX, 27 February–2 March.
17. IDF (1990) Visplex system. *Technical Bulletin*, International Drilling Fluids, Houston, TX.
18. Simpson, J.P., Walker, T.O., and Jiang, G.Z. (1994) Environmentally acceptable water-base mud can prevent shale hydration and maintain borehole stability. SPE 27496, *Proc. 1994 IADC/SPE Drilling Conference*, Dallas, TX, 15–18 February.
19. API (1994) Drilling fluids processing equipment. *API Bulletin*, 13C.
20. Goldsmith, R. and Hare, M. (1982) Solids analysis improves mud cost control. *World Oil*, June.
21. Dearing, H.L. (1990) Material balance concepts aid in solids control and mud system evaluation. IADC/SPE 19957, *Proc. 1990 IADC/SPE Drilling Conference*, Houston, TX, 27 February–2 March.
22. Beasley, R.D. and Dear, S.F., III (1989) A process engineering approach to drilling fluids management. SPE 19532, *Proc. 64th Annual Technical Conference and Exhibition of SPE*, San Antonio, TX, 8–11 October.

23. Lal, M. (1988) Economic and performance analysis models for solids control. SPE 18037, *Proc. 63rd Annual Conference and Exhibition of SPE*, Houston, TX, 2–5 October.
24. Sharples, V.M. and Nance, G.W. (1979) New computerized model optimizes solids control. SPE 8227, *Proc. 54th Annual Conference and Exhibition of SPE/AIME*, Las Vegas, NV, 23–26 September.
25. Ardrey, W.E. et al. (1986) Automation of solids control system. IADC/SPE 14751, *Proc. 1986 IADC/SPE Drilling Conference*, Dallas, TX, 10–12 February.
26. Sharma, S.P. (1984) Experimental investigation of the performance characteristics of hydrocyclones. SPE 13209, *Proc. 59th Annual Technical Conference and Exhibition of SPE*, Houston, TX, 16–19 September.
27. Young, G.A. (1987) An experimental investigation of the performance of a 3-in. hydrocyclone. SPE/IADC 16175, *Proc. 1987 SPE/IADC Drilling Conference*, New Orleans, 15–18 March.
28. Hoberock, L.L. (1980) A study of vibratory screening of drilling fluids. *Journal of Petroleum Technology*, November.
29. Hoberock, L.L. (1990) Fluid conductance and separation characteristics of oilfield screen cloths. *Proc. Fall Meeting of American Filtration Society*, Baton Rouge, LA, 29–30 October.
30. Thurber, N.E. (1988) Decanting centrifuge performance study. MS Thesis, Univ. of Tulsa, OK.
31. Field, J. and Anderson, B. (1972) An analytical approach to removing mud solids. *Journal of Petroleum Technology*, June.
32. Patel, J. and Steinhauser, J. (1979) A material balance method to evaluate drill-fluid solids removal equipment. *Petroleum Engineer International*, March.
33. Froment, T.D. et al. (1986) A drilling contractor tests solids control equipment. IADC/ SPE 14753, *Proc. IADC/SPE Drilling Conference*, Dallas, TX, 10–12 February.
34. Wojtanowicz, A.K. (1993) Dry drilling location: an ultimate source reduction challenge: theory, design and economics. SPE 26013, *Proc. SPE/EPA Exploration and Production Environmental Conference*, San Antonio, TX, 7–10 March.
35. Mongomery, M.S. and Love, W.W. (1993) Improve your solids control. *World Oil*, October, 59.
36. American Association of Drilling Engineers (1999) *Shale Shakers and Drilling Fluid Systems – Techniques and Technology for Improving Solids Control Management*, Gulf Publishing Company, Houston, Texas.
37. Thurber, N.E. (1992) Waste minimization for land-based drilling operations. *Journal of Petroleum Technology*, May, 542.
38. Lal, M. and Thurber, N. (1989) Drilling wastes management and closed-loop systems, in *Drilling Wastes* (eds. F.R. Englehardt, J.P. Ray, and A.H. Gillam), Elsevier, London, pp. 213–28.
39. Halliday, W.S. et al. (1993) Closed-loop operation with alternative dewatering technology. *SPE Drilling and Completion*, March, 45.
40. Wojtanowicz, A.K. (1994) Optimization of drilling mud conditioning for chemically-enhanced centifuging. *Proc. 45th Annual Technical Meeting of CIM*, Calgary, Canada, 12–15 June, pp. 18.1–18.12.
41. Wojtanowicz, A.K. (1994) Testing protocol and economic analysis of mud dewatering for closed-loop drilling systems. *Proc. 45th Annual Technical Meeting of CIM*, Calgary, Canada, 12–15 June, pp.19.1–19.21.

42. Wojtanowicz, A.K. (1988) Modern solids control: a centrifuge dewatering process study. *SPE Drilling Engineering*, September, 315–23.
43. Wojtanowicz, A.K. et al. (1987) Comparison study of solid/liquid separation techniques for oilfield pit closures. *Journal of Petroleum Technology*, July, 845–56.
44. Malachosky, E. et al. (1989) The impact of the use of dewatering technology on the cost of drilling waste disposal. SPE 19528, *Proc. 64th Annual Technical Conference and Exhibition of SPE*, San Antonio, TX, 8–11 October.
45. Sanders, J.M. (1989) Minimized hauloff while drilling in a zero-discharge area. SPE 19529, *Proc. 64th Annual Technical Conference and Exhibition of SPE*, San Antonio, TX, 8–11 October.
46. Wojtanowicz, A.K. and Griffin, J.M. (1990) Drilling fluids dewatering: application survey and case history economics, in *Advances in Filtration and Separation Technology: Volume 1: Filtration and Separation in Oil and Gas Drilling and Production Operations*, American Filtration Society, Houston, TX.
47. Sirgo, M.A. Jr. (1986) Regulatory changes impacting drilling and producing operations. *Journal of Petroleum Technology*, September.
48. (1989) How to choose a bioassay laboratory. *Offshore*, April.
49. Ray, J.P. et al. (1989) Drilling fluid toxicity test: variability in US commercial laboratories, in *Drilling Wastes* (eds. F.R. Englelhardt, J.P. Ray, and A.H. Gillam), Elsevier, London, pp. 731–55.
50. Bland, R.G. et al. (1987) Toxicity of drilling fluids using photobacteria and Mysid shrimp bioassays. SPE 16689, *Proc. 62nd Annual Technical Conference and Exhibition of SPE*, Dallas, TX, 27–30 September.
51. API (1989) *Rapid Bioassay Procedures for Drilling Fluids*, Publication No. 4481, API.
52. Dorn, P.B. et al. (1990) Rapid methods for predicting compliance to drilling mud toxicity tests with Mysids for offshore NPDES general permits. *Environmental Auditor*, **1**, 221–7.
53. Hoskin, S.J. and Strohl, A.W. (1993) On-site monitoring of drilling fluids toxicity. SPE 26005, *Proc. 1993 SPE/EPA E&P Environmental Conference*, San Antonio, TX, 7–10 March.
54. Wojtanowicz, A.K. et al. (1991) Cumulative bioluminescence – a potential rapid test of drilling fluid toxicity: development study. SPE/IADC 21938, *Proc. 1991 SPE/IADC Drilling Conference*, Amsterdam, The Netherlands, 11–14 March.
55. Jones, F.V. and Jardiolin, R.A. (1991) Field evaluation of toxicity of drilling fluids using computer applications. *Proc. 1991 Petro-Safe Conference*, Houston, TX, 6 February.
56. Park, L.S. (1988) A new chrome-free lignosulfonate thinner performance without environmental concerns. *SPE Drilling Engineering*, September.
57. Halliday, W.S. and Clapper, D.K. (1989) Toxicity and performance testing of non-oil spotting fluid for differentially stuck pipe. SPE 18684, *Proc. 1989 SPE/IADC Drilling Conference*, New Orleans, LA, 28 February–3 March.
58. Clark, R.K. and Almquist, S.G. (1992) Evaluation of spotting fluids in a full-scale differential-pressure sticking apparatus. *SPE Drilling Engineering*, June, 121.
59. Boyd, P.A. et al. (1983) New base oil used in low-toxicity oil muds. SPE 12119, *Proc. 58th Annual Technical Conference and Exhibition*, San Francisco, CA, 5–8 October.
60. Thoresen, K.M. and Hinds, A.A. (1983) A review of the environmental acceptability and the toxicity of diesel oil substitutes in drilling fluid systems. IADC/SPE 11401, *Proc. IADC/SPE 1983 Drilling Conference*, New Orleans. LA, 20–23 February.

61. James, R.W. and Helland, B. (1992) The Greater Ekofisk area: addressing drilling fluid challenges with environmental justifications. SPE 25044, *Proc. 1992 SPE European Petroleum Conference*, Cannes, November.
62. Park, S., Cullum, D., and McLean, A.D. (1993) The success of synthetic-based fluids offshore Gulf of Mexico: a field comparison to conventional systems. SPE 26354, *Proc. 1993 SPE Annual Technical Conference and Exhibition*, Houston, TX, 3–6 October.
63. Hinds, A.A., Carlson, T., and Peresich, R. (1991) Industry searching for alternative to transport of drill cuttings: biodegradable esters substitute for oil in drilling performance. *Offshore*, October, 30.
64. Growcock, F.B. and Frederick, T.P. (1994) Operational limits of synthetic drilling fluids. SPE 29071, *Proc. 1994 Offshore Technology Conference*, Houston, TX, 2–5 May.
65. Friedheim, J.E. and Conn H.L. (1996) Second generation synthetic fluids in the North Sea: are they better? SPE 35061, *Proc. IADC/SPE Drilling Conference*, New Orleans, 12–15 March.
66. MI Drilling Fluids Manual (1998) *Synthetic systems*. Houston, Texas.
67. Hall, J. (2002) The new Gulf of Mexico National Pollutant Discharge Elimination System Permit: how does it shape-up, SPE 77391, *Proc. SPE Annual Conference*, San Antonio, Texas, 29 September–2 October.
68. Candler, J. et al. (2000) Modification of standardized anaerobic biodegradation test to discriminate performance of various non-aqueous base fluids, SPE 61203, *Proc. SPE Intl. Conference on Health, Safety, and the Environment*, Stavanger, Norway, 26–28 June.
69. Sumrow, M. (2002) Synthetic-based muds reduce pollution discharge, improve drilling. *Oil and Gas Journal*, 23 December.
70. Jones, M. and Evangelist, R. (1986) A review of drill cuttings discharge technology and regulations. *Proc. National Conference on Drilling Muds*, EGWI, Norman, OK, 29–30 May, pp.188–211.
71. Davies, S. (1986) An assessment of the development of cuttings cleaning systems within the context of North Sea offshore drilling. *Conference Proceedings, Oil Based Drilling Fluids*, Norwegian State Pollution Control Authority, Trondheim, 24–26 February, pp. 71–8.
72. Jackson, S.A. and Kwan, J.T. (1984) Evaluation of a centrifuge drill-cuttings disposal system with a mineral oil-based fluid on Gulf Coast offshore drilling vessels. SPE 14157, *Proc. SPE Annual Technical Conference and Exhibition*. Houston, TX, 16–19 September.
73. Kristensen, A. et al. (1986) Ultrasonic cleaning of oil rock particles. *Conference Proceedings, Oil Based Drilling Fluids*, Norwegian State Pollution Control Authority, Trondheim, 24–26 February, pp. 63–70.
74. (1982) Hughes creates environmentally safe mud cleaning unit. *Offshore*, April, 147.
75. Warnheim, T. and Sjoblom, J. (1986) A theoretical study of surfactant and surfactant systems suitable for washing of drill cuttings contaminated by oily mud. *Conference Proceedings, Oil Based Drilling Fluids*, Norwegian State Pollution Control Authority, Trondheim, 24–26 February, pp.47–54.
76. Wiig, P.O. (1986) Cleaning of drilling cuttings in seawater/surfactant wash systems. *Conference Proceedings, Oil Based Drilling Fluids*, Norwegian State Pollution Control Authority, Trondheim, 24–26 February, pp. 55–62.

77. Stephenson, R.L. et al. (2004) Thermal desorption of oil from oil-based drilling fluids cuttings: processes and technologies, SPE 88486, *Proc. SPE Asia Pacific Oil and Gas Conference and Exhibition*, Perth, Australia, 18–20 October.
78. Seaton, S. and Hall, J. (2005) Recovery of oil from drilled cuttings by liquefied gas extraction, SPE 92963, *Proc. SPE International Symposium on Oilfield Chemistry*, Houston, Texas, 2–4 February.
79. Paulson, J.E. et al. (2003) Drill cuttings disposal balancing zero discharge and use of best available technique, SPE/IADC 85296, *Proc. SPEIADC Middle East Drilling Technology Conference and Exhibition*, Abu Dhabi, UAE, 20–22 October.
80. Ayers, R.C. et al. (1989) The EPA/API diesel pill monitoring program, in *Drilling Wastes* (eds. F.R. Englelhardt, J.P. Ray, and A.H. Gillam), Elsevier, London, pp. 757–72.
81. Sparlin, D.D. (1976) An evaluation of polyacrylamides for reducing water production. *Journal of Petroleum Technology*, August, 906–13.
82. Zaitoun, A. and Kohler, N. (1989) Improved polyacrylamide treatments for water control in producing wells. SPE 18501, *Proc. SPE International Symposium on Oilfield Chemistry*, Houston, TX, 8–10 February, pp. 379–88.
83. Kohler, N. and Zaitoun, A. (1991) Polymer treatment for water control in high-temperature production wells. SPE 21000, *Proc. SPE International Symposium on Oilfield Chemistry*, Anaheim, CA, 20–22 February, pp. 37–48.
84. White, J.L. et al. (1973) Use of polymers to control water production in oil wells. *Journal of Petroleum Technology*, February, 143–50.
85. Avery, M.R. (1988) Field evaluation of a new gelant for water control in production wells. SPE 18201, *Proc. 63rd Annual Technical Conference and Exhibition of the Society of Petroleum Engineers*, Houston, TX, 2–5 October, pp. 203–14.
86. Needham, R.B. et al. (1974) Control of water mobility using polymers and multivalent cations. SPE 4747, *Proc. Third Symposium on Improved Oil Recovery*, Tulsa, OK, 22–24 April.
87. Terry, R.E. et al. (1981) Correlation of gelation times for polymer solutions used on mobility control agents. *Society of Petroleum Engineers Journal*, April, 229–35.
88. Vossoughi, S. and Putz, A. (1991) Reversible in-situ gelation by the change of pH within the rock. SPE 20997, *Proc. SPE International Symposium on Oilfield Chemistry*, Anaheim, CA, 20–22 February, pp. 7–12.
89. Jurinak, J.J. et al. (1989) Oilfield application of colloidal silica gel. SPE 18505, *Proc. SPE International Symposium on Oilfield Chemistry*, Houston, TX, 8–10 February, pp. 425–54.
90. Smith, J.E. (1994) Closing the lab-field gap: a look at near-wellbore flow regimes and performance of 57 field projects. SPE 27774, *Proc. SPE/DOE Ninth Symposium on Improved Oil Recovery*, Tulsa, OK, 17–20 April, pp. 445–59.
91. Liang, L., Sun, H., and Seright, R.S. (1995) *Why Do Gels Reduce Water Pearmability More Than Oil Permeability*? SPE 27829 (peer reviewed).
92. Lang, K.R., Oliver, S.J., and Scheper, R.J. (1991) Optimization of gas production in the Antrim shale. SPE 21694, *Proc. SPE Production Operation Symposium*, Oklahoma City, OK, 7–9 April.
93. EPA reclassifies waterless Antrim wells. Texas inventor holds patent on use of pump. *Michigan's Oil and Gas News*, **96**(45), 9 November, 1990.
94. Lintemuth, R. (1990) Antrim play proves strong catalyst in boosting Michigan drilling permit totals. *Michigan's Oil and Gas News*, **96**(51–52), 21 December.

95. Grubb, A.D. and Duball, D.K. (1992) Disposal tool technology extends gas well life and enhances profits. SPE 24796, *Proc. 67th Annual Technical Conference and Exhibition of SPE*, Washington, DC, pp.309–16.
96. Bell, S. (1995) Downhole separation technology tested. *Hart's Show Daily, Suppl. to Petroleum Engineer International*, 23 October, 3.
97. Kjos, T. et al. (1995) Downhole water–oil separation and water reinjection through well branches. SPE 030518, *Proc. 1995 SPE Annual Technical Conference and Exhibition, Volume: Drilling*, Dallas, TX, 22–25 October, pp.689–701.
98. Wojtanowicz, A.K. et al. (1991) Oil well coning control using dual completion and tailpipe winter sink. SPE 21654, *Proc. SPE Production Operations Symposium*, Oklahoma City, OK, 7–9 April.
99. Wojtanowicz, A. K. and Armenta, M. (2004) Assessment of downhole water sink technology for controlling water inflow at petroleum wells. *Journal of Energy Resources Technology-Transactions ASME*, **126**, December, 334–41.
100. Wojtanowicz, A. K. and Shirman, E. I. (2005) Water Cone Reversal in Oil Wells – An Analytical and Experimental Study., *Mining Archives – Transactions of Polish Academy of Sciences,* **50**(1)3–16.
101. Shirman, E. I. and Wojtanowicz, A. K. (2004) Reversal of water coning in wells with downhole water sink completion – Experimental analysis. *Mining Archives – Transactions of Polish Academy of Sciences*, **49**(4), 437–52.
102. Wojtanowicz, A.K. and Shirman, E.I. (2000) More oil using downhole water sink technology: a feasibility study. *SPE Production and Facilities*, 15(4), November, 234–240
103. Wojtanowicz, A.K. and Shirman, E.I. (2002) Inflow performance and pressure interference in dual-completed wells with water coning control. *Journal of Energy Resources Technology-Transactions ASME*, **124**, December.
104. Wojtanowicz, A.K. and Shirman, E.I. (1996) An in-situ method for downhole drainage-injection of formation brine in a single oil producing well, in *Deep Injection Disposal of Hazardous and Industrial Waste* (eds. J.A. Apps and C. Tsang), Academic Press, New York, pp. 403–20.
105. Wojtanowicz, A.K. and Xu, H. (1992) A new in-situ method to minimize oilwell production watercut using downhole water loop. CIM 92-13, *Proc. 43rd Annual Technical Meeting of CIM*, Calgary, Canada, 7–10 June.
106. Wojtanowicz, A.K. and Xu, H. (1995) Downhole water loop – a new completion method to minimize oilwell production watercut in bottom-water-drive reservoirs. *Journal of Canadian Petroleum Technology*, **3**(8), October, pp. 56–62.
107. Klein, S.T. and Thompson, S. (1992) Field study: utilizing a progressive cavity pump for a closed-loop downhole injection system. SPE 24795, *Proc. 67th Annual Technical Conference of SPE*, Washington, DC, pp. 301–8.
108. Cornitius, T. (1988) Advances in water treating solving production problems. *Offshore*, March.
109. Meldrum, N. (1988) Hydrocyclones: a solution to produced-water treatment. *SPE Production Engineering*, November, 669–76.
110. Yong, G.A. et al. (1991) Oil–water separation using hydrocyclones – an experimental search for optimum dimensions in environmental-control technology in petroleum engineering. *Journal of Petroleum Science and Engineering*, Special Issue (ed. A.K. Wojtanowicz), **11**(1), April, 37–50; *Advances in Filtration and Separation Technology*, Volume 3, American Filtration Society, Gulf, pp. 102–23.

111. LADEQ (1994) *Water Quality Regulations*, 3rd edn, LAC 33:IX.708. Louisiana Department of Environmental Quality, Baton Rouge, LA.
112. Wojtanowicz, A.K., Xu, H., and Bassiouni, Z. (1994) Segregated production method for oil wells with active water coning. *Journal of Petroleum Science and Engineering, Special Issue: Environmental Control Technology in Petroleum Engineering*, **11**(1), April.
113. Swisher, M.D. and Wojtanowicz, A.K. (1995) In situ-segregated production of oil and water – a production method with environmental merit: field application. SPE 29693, *Proc. SPE/EPA Exploration & Production Environmental Conference*, Houston, TX, 27–29 March.
114. Swisher, M.D. and Wojtanowicz, A.K. (1995) New dual completion method eliminates bottom water coning. SPE 30697, *Proc. SPE Annual Technical Conference and Exhibition, Volume: Production*, Dallas, TX, 22–25 October, pp. 549–55.
115. Broek, W.M.G.T. and Plat, R. (1991) Characteristics and possibilities of some techniques for deoiling of production water. SPE 23315, *Proc. First International Conference on Health and Safety and Environment*, The Hague, The Netherlands, 10–14 November, pp. 47–54.
116. Brown and Root Inc. (1974) *Determination of Best Practicable Control Technology Currently Available to Remove Oil from Water Produced with Oil and Gas*, Report prepared for the Offshore Operations Committee, Sheen Subcommittee, New Orleans, LA.
117. EPA (1981) *Oil Content in Produced Brine on Ten Louisiana Production Platforms*, EPA-600/2-81-209. EPA, Cincinnati, OH.
118. Jackson, G.F. and Humes, E.E. (1983) Oil content in produced brine on 10 production platforms. SPE 12195, *Proc. 58th Annual Technical Conference and Exhibition*, San Francisco, CA, 5–8 October.
119. Strickland, W.T., Jr. (1980) Laboratory results of cleaning produced water by gas flotation. *Society of Petroleum Engineers Journal*, June, 175–90.
120. Leech, C.A. et al. (1978) Performance evaluation of induced gas flotation (IGF) machine through math modeling, OTC 3342, *Proc. 10th Annual Offshore Technology Conference*, Houston, TX, 8–11 May, pp. 2513–22.
121 Wojtanowicz, A.K. (1993) Oilfield environmental control technology: a synopsis. *Journal of Petroleum Technology*, February, 166–72.
122. Gay, J.C. et al. (1987) Rotary cyclone will improve oily water treatment and reduce space/weight requirement on offshore platforms. SPE 16571, *Proc. Offshore Europe '87*, Aberdeen, UK, 8–11 September.
123. Alfa-Laval Industry (1989) *Oily Water Treatment in Oilfield Industry*, Alfa Laval, Maarssen, The Netherlands.
124. Chen, A.S.C. et al. (1990) Removal of oil, grease, and suspended solids from produced water using ceramic crossflow microfiltration, in *Advances in Filtration and Separation Technology, Volume 3: Pollution Control Technology for Oil and Gas Drilling and Production Operations*, American Filtration Society, Kingwood, TX, 292–317.
125. Hagen, R.D. and Lorne, C.G. (1988) Membralox crossflow microfiltration of heavy oil produced water. *Proc. Quarterly Meeting of Canadian Heavy Oil Association*, Calgary, Alberta, 25 October.
126. Petrakis, L. and Ahner, P.F. (1976) Use of high-gradient magnetic separation techniques for the removal of oil and solids from water effluents. *IEEE Transactions on Magnetics*, **MAG-12**(5), September, 486–8.

127. Weintraub, M.H. et al. (1983) Development of electrolytic treatment of oily wastewater. *Environmental Progress*, **2**(1), February, 32–7.
128. Balmer, L.M. and Foulds, A.W. (1986) Separating oil from oil-in-water emulsions by electroflocculation/electroflotation. *Filtration and Separation*, November/December, 366–70.
129. Burke, R.G. (1985) Cleanup of oily water poses a challenge. *Offshore*, September, 100–6.
130. Clean water, clear choices. *Journal of Petroleum Technology*, January 1994, 24–6.
131. GRI (1995) *A Regional Assessment of Produced Water Treatment and Disposal Practices and Research Needs*. GRI-95/0301, Gas Research Institute, Chicago.
132. GRI (1995) *GRI-Pro W Calc*™, *Gas Research Institute – Produced Water Calculation Cost Model User's Manual*. GRI-95/0302, Gas Research Institute, Chicago.

Chapter 5
Oilfield Waste Disposal Control

A.K. Wojtanowicz

1 Introduction

Environmental control of waste generation in the oilfield processes, discussed in Chapters 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 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.

Department of Petroleum Engineering, Louisiana State University, Baton Rouge, LA 70803-6417, USA

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

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	1,500	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	1,400	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 [11].
[d]Independent evaluations by American Petroleum Institute and US Environmental Protection Agency in 1987 and 1995.

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 [11]. 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].

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

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)	500	500
	1000 (coast)		
EC (μmho/cm)	–	–	1000
Total solids (mg/l)	–	–	–
TSS (mg/l)	50.0	50.0	100
TDS (mg/l)	3,000	–	–
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.

of oxygen. At present, the method of backfilling meets regulatory approval only if the concentration of contaminants has been found to be below certain levels that render the waste harmless without dilutions [11]. Otherwise, land treatment techniques should be used for oilfield pit closure.

Land treatment technology which renders waste pit material harmless through soil incorporation employs dilution, chemical alteration and biodegradation mechanisms to reduce the concentrations of pollutants to acceptable levels consistent with intended land use [14]. The technique provides both treatment and 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 [11].

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 and a small areas of available background soil for mixing, operators may find this option more cost effective than off-site disposal. Also, using the final solidified product the operator must demonstrate the integrity and strength of the product, 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).

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

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]	
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 (silver)		<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 w/5 ft soil on top	10<5 ft below ground level w/5 ft soil on top
Bottom of burial cell	ft	–	–	<5 ft above high water Table	<5 ft above high water Table
Qu (unconfined compressive strength)					
	lb/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].
GL = Ground level.
[d]Analyzed using 'true total' testing procedures [23].
[e]Testing must be done according to ASTM.

several darcies (1 D = 0.9868×10^{12} m^2), and low pore pressures. In high-permeability zones, fracturing may occur at later stages of 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 injection in contrast to slurry fracture injection, the technology of slurry disposal in artificial fractures that have been created in impermeable rocks. In the recent report, the technology of high-permeability injection has been also termed, *slurry subfracture injection* – as the injection is performed at pressure lower than formation fracturing pressure [24].

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 [25–28]. Later, slurry fracture injection technology was developed for disposal of drill cuttings from oil-based muds in Alaska and the North Sea [29–31], and for NORM (Naturally Occurring Radioactive Materials) disposal [32]. In the mid-1990s, the first large commercial facility with dedicated injection wells began operation [33, 34]. This was followed by large-scale injection operations in Alaska [35] and Gulf of Mexico [36–38].

At present, annular injection is available for routine use offshore, with several different service companies providing a range of operations and engineering support [39]. An example of continuing evolution of the technology was documented in a study on commingled drill cuttings and produced water injection [40]. 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 [41–43]. 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 [33, 34]. 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 Figure 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 completion is presently more typical for longer or permanent injection operations and is more common 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 are recompleted as injection wells, in other places new injection wells are drilled for the purpose. These dedicated injection wells are frequently in service for several years and total slurry volumes can be greater than 2 million barrels per well [39].

In the past, the annular disposal of waste fluids from drilling mud reserve pits has been practiced for onshore drilling operations [25]. (Presently, annular injection is more common offshore, where the cuttings are injected into either an uphole annulus of the well being drilled or into an annulus of a nearby

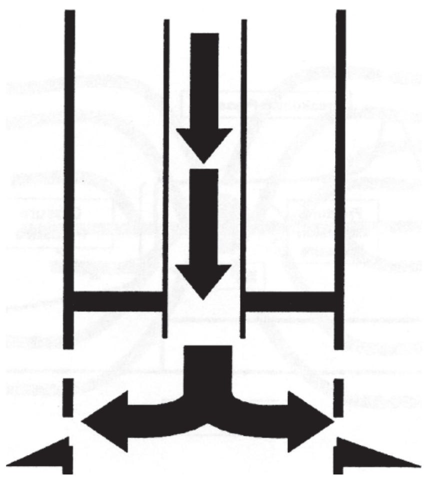


FIGURE 5.1. Tubing and packer injection wellbore schematic [39].

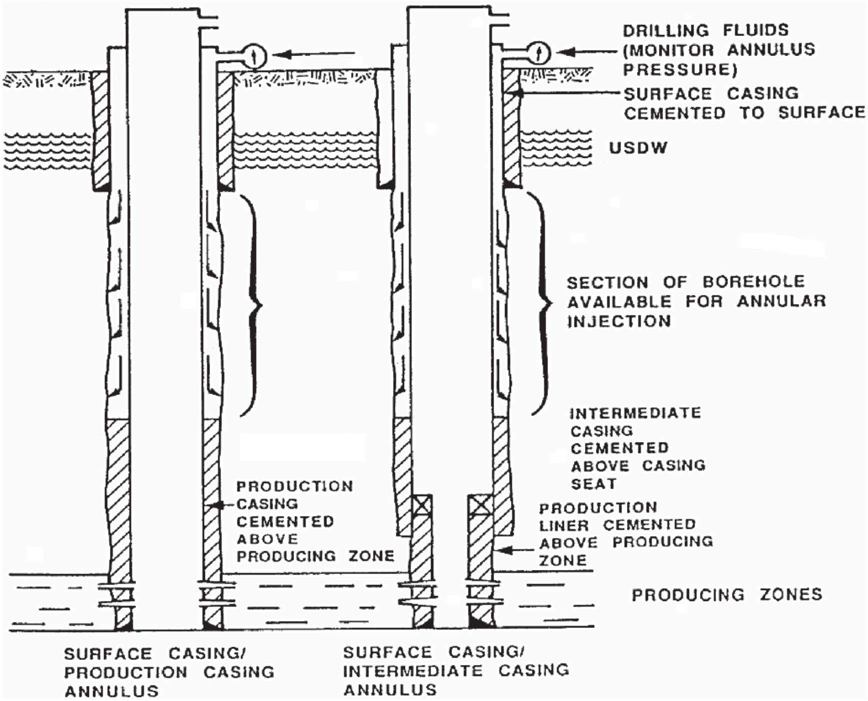


FIGURE 5.2. Well configurations for annular injection. USDW = underground source of drinking water.

well.) As shown in Figure 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 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 [25]. 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 1,000 psi in most areas. For shallow wells, such as those in the Canadian counties of McClain or 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 1,000 to 5,000 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 permeabilities due to the presence of shell deposits. Table 5.4 shows an example of the rock strata in the disposal zone. The high permeability of these

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

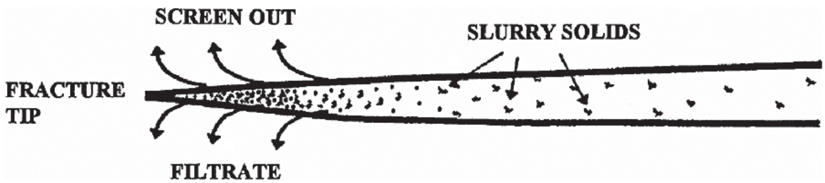


FIGURE 5.3. Fracture screen-out during high-permeability injection of slurrified solid waste.

formations allowed successful disposal of materials such as slurrified, drilled-out cement, shredded paper waste (mud sacks and carboard boxes), shredded industrial plastic foil and ground wood with plastics (shredded wooden pallets and crates) [27]. 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 injected slurry is lost from the fracture into the rock structure due to the 'screen out' effect.

As shown in Figure 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 [28].

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.

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.

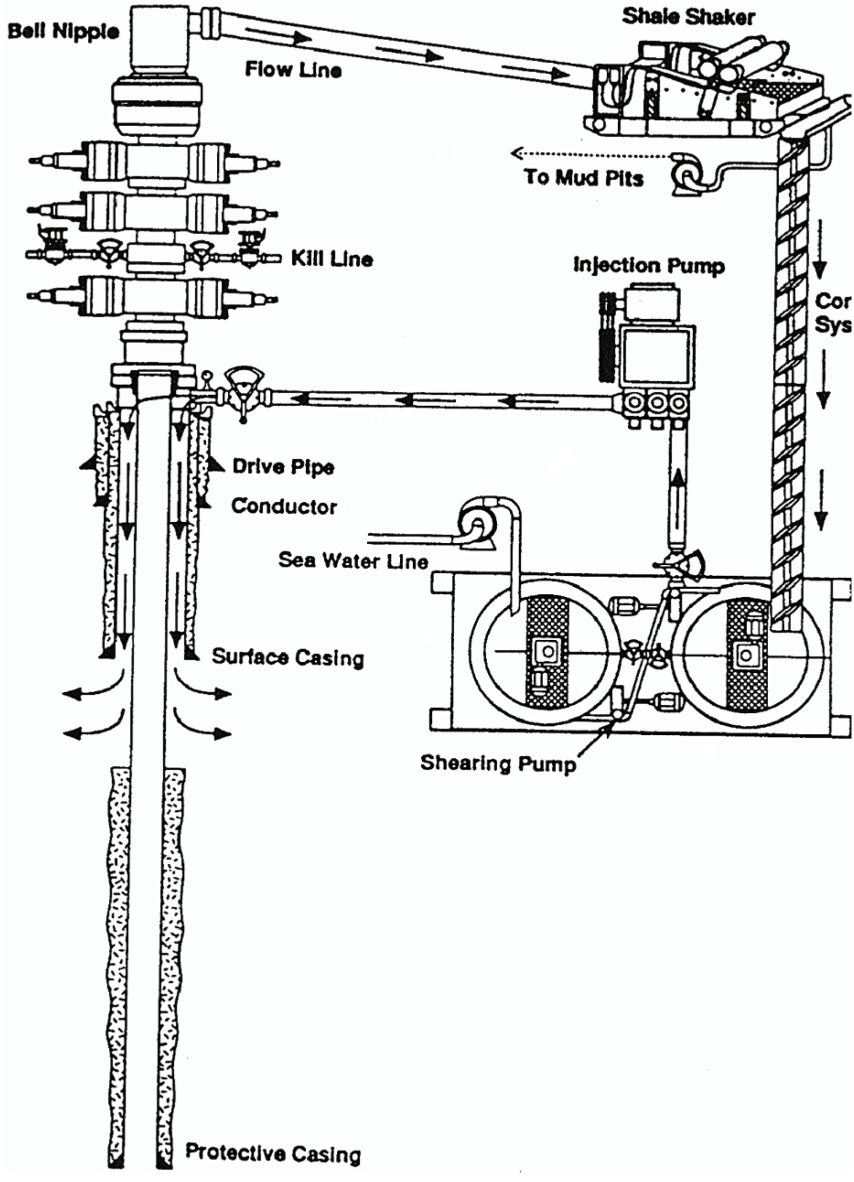


FIGURE 5.4. Schematics of slurrification and annular injection process for OBM cuttings in the Gulf of Mexico [26].

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.

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. 26.

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	4,724	10.750	7.625	5,230	14.4	1,270	0.5	1,500
Matagorda Island	4,490	13.375	9.625	5,800	14.3	9,560	4.0	1,800
Galveston	3,566	13.375	9.625	5,200	14.1	19,579	2.0	2,000
Galveston	3,495	13.375	9.625	5,890	14.3	9,990	3.5	1,200

[a]After Ref. 26.
[b]TVD = True vertical depth.
[c]TOC = Top of cement.

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 [28]. 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 [28]. 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.

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 Figure 5.5. Two options for annular disposal can be considered theoretically: high-permeability injection to the lowermost sandstone formation or slurry fracture injection into the mudstone. A numerical simulation study showed that the disposal fracture in the

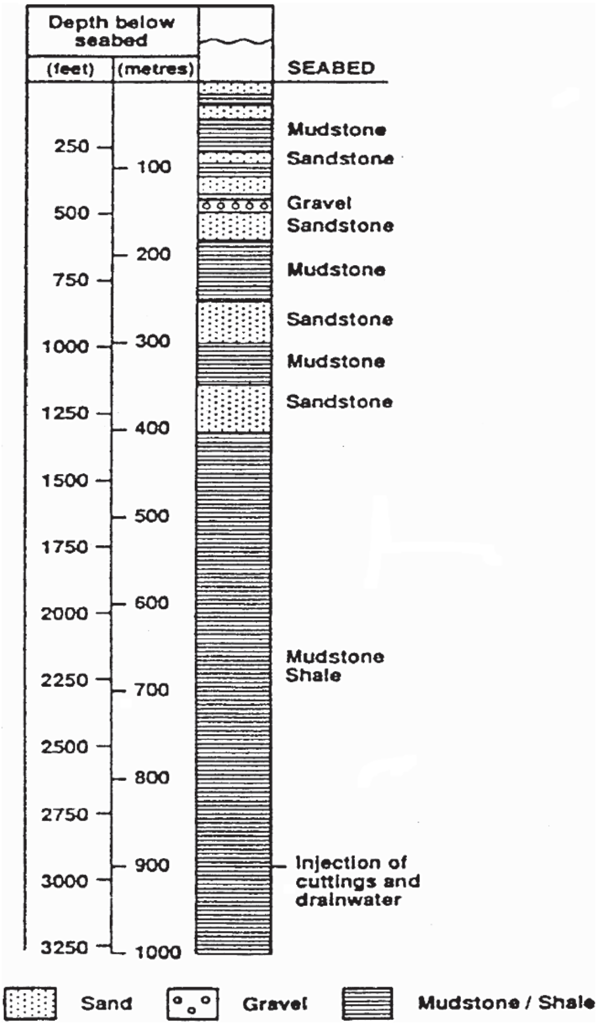


FIGURE 5.5. Example of shallow subsea stratigraphy in the North Sea area.

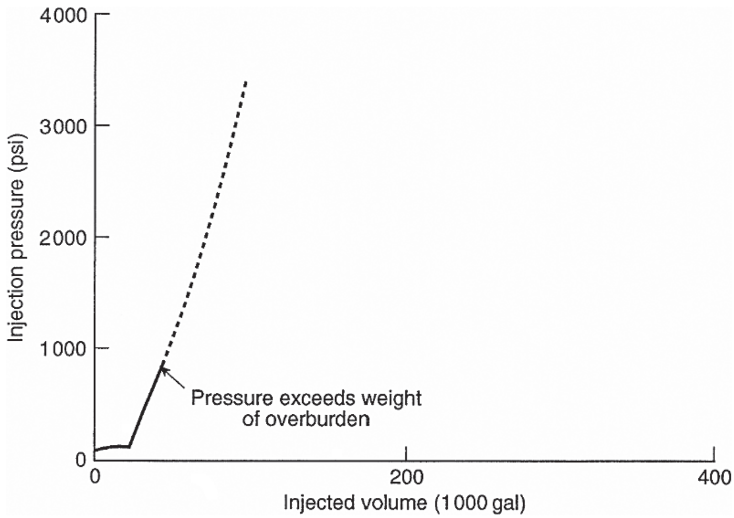


FIGURE 5.6. Computer-simulated trend of injection pressure during high-permeability injection to single fracture with early slurry screen-out [31].

sandstone would be shorter owing to slurry dehydration and would tend to propagate upwards into the overlying (impermeable) shales and siltstones [31]. Also, the calculations showed a rapid increase in injection pressure due to early screen-out (dewatering) of the slurry, as shown in Figure 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 [31, 44]. 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 Figure 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 screen-out, etc. Hence this mechanism of fracture propagation could 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

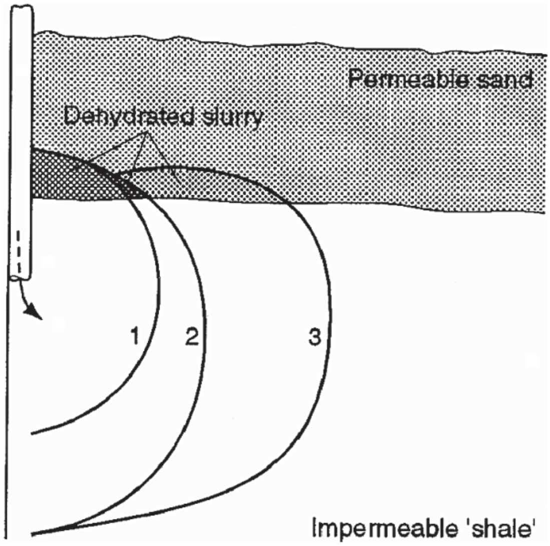


FIGURE 5.7. Propagation of disposal fracture during slurry fracture injection process [31].

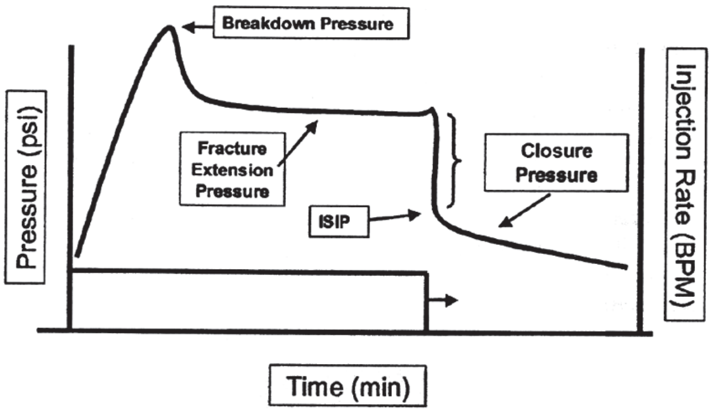


FIGURE 5.8. Slurry fracture injection process [40].

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 [33, 34]. 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 Figure 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 [30, 45–48]. 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 Figure 5.9 [48]. The oil-based mud is used to drill the three lower sections of 12¼, 8½ and 6 in holes.

Approximately 500, 13 and 15 tones of rock and 35, 20 and 2 tones of oil were typically discharged from each of the respective hole sizes per well. As shown in Figure 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 to produce pumpable slurry. The slurry was pumped through the casing spool wing valve into the 9⅝ × 13⅜

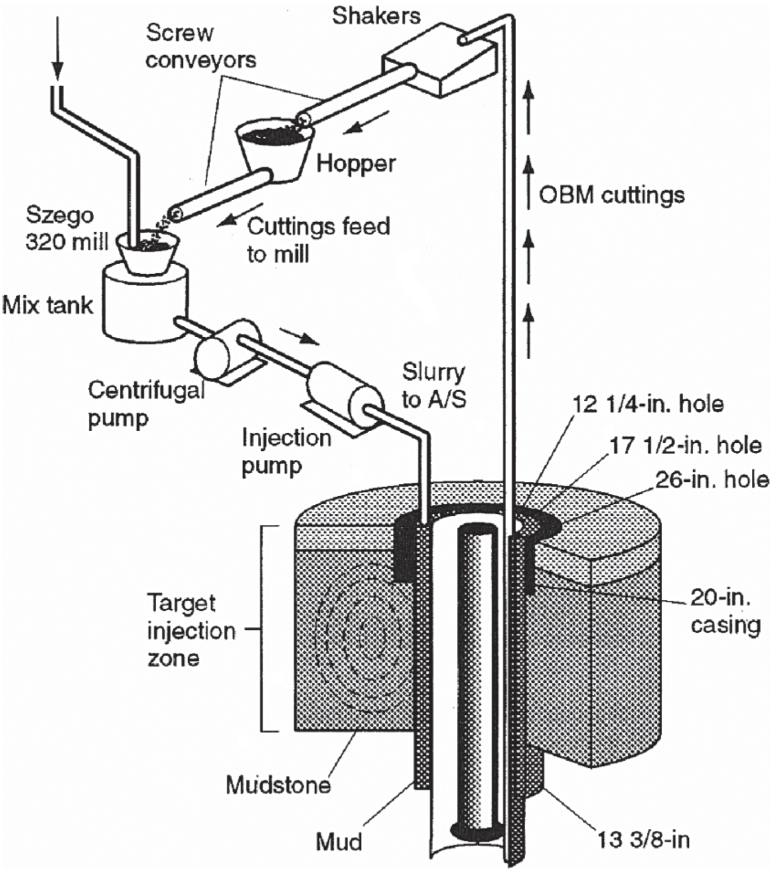


FIGURE 5.9. Slurry fracture injection process [48].

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 (Figure 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 [44]. 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 one 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

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	1,000	1,200	1,100	1,200	1400	1600	1450
Initial shut-in pressure (psi)	900	1,100	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	1,100	1,000	900	1100	950

[a]After Refs. 44 and 48. Data as of 10 October 1992.
[b]NR = not recorded.

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 [49–51]. 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 five 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 [51]. 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 [51].

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 three 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 [29]), an autogenous wet-crushing mill or a Szego ball-mill (North Sea [28, 31]). 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 [149, 150]. 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 dyne/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 [31], as well as thinners, bentonite and caustic, to control the rheology and biodegration of the slurries [26].

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$^{0.5}$ [31].

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 Chapter 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 [44]. 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 [30].

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 [41]. 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 real-time passive seismic monitoring and analysis [45].

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 [27].

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 longtime 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 [52]. 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 [39] – as shown in Figure 5.10. After the injection stops, slurry liquid will leak-off into the rock, and the fracture will close on the

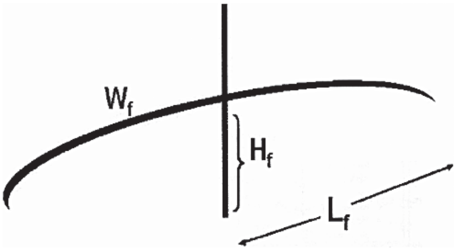


FIGURE 5.10. A single two-wing planar fracture [39].

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 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 Figure 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 [53]. 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 Figure 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) [51]. 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.

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.

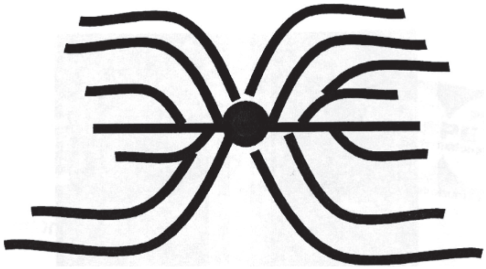


FIGURE 5.11. Multi-fractured "disposal domain" [52].

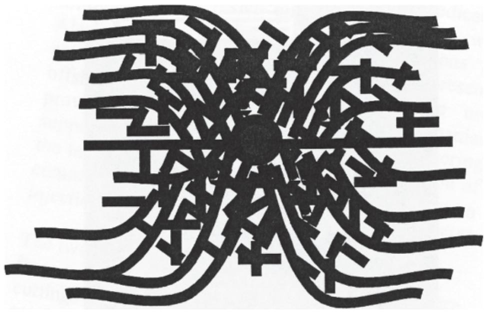


FIGURE 5.12. Schematic of "disaggregation" concept [53].

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 [54]. The solution scaled the number of fractures with the fracture height, yielding:

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

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 [55], 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 [56–58]. 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 [58].

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 [38, 59]. 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.

References

1. Wojtanowicz, A.K. (1999) Oilfield pit management, Chapter 8 in *Environmental Engineering for Exploration and Production Activities*, SPE Monograph (Eds. M.J. Wilson, and J.D. Frederick), Vol. 18, Society of Petroleum Engineers, Richardson, TX.
2. Moseley, H.R. (1983) Summary and analysis of API onshore drilling mud and produced water environmental studies. *American Petroleum Institute Bulletin D19*.
3. Miller, R.W. and Honarvar, S. (1975) Effect of drilling fluid component mixtures on plants and soil. EPA 560/1-75-004. *Conf. Proc. Environmental Aspects of Chemical Use in Well Drilling Operations*, Houston, TX, May, 125–43.
4. Murphy, E.C. and Kehew, A.E. (1984) The effect of oil and gas well drilling fluids on shallow groundwater in Western North Dakota. *Report No. 82*, North Dakota Geological Survey.
5. Miller, R.W., Honarvar, S. and Hunsaker, B. (1980) Effects of drilling fluids on soils and plants: 1. Individual fluid components. *Journal of Environmental Quality*, 547–52.
6. Whitmore, J. (1982) Water base drilling mud land spreading and use as a site reclamation and revegetation medium. *Fosgren-Perkins Engineering Report*, API Production Department, Dallas, TX.
7. Henderson, G. (1982) Analysis of hydrologic and environmental effects of drilling mud pits and produced water impoundments. *Dames and Moore Report*, API Production Department, Dallas, TX.
8. EPA (1993) *Standards for the Use or Disposal of Sewage Sludge*, 40 Code Federal Register, Parts 257, 403 and 503, US Environmental Protection Agency, Washington, DC.
9. API (1995) *Metals Criteria for Land Management of Exploration and Production Wastes: Technical Support Document for API Recommended Guidance Values*. Publication 4600, American Petroleum Institute, Washington, DC.
10. Pal, D and Overcash, M.R. (1978) Plant oil assimilation capacity for oils. *Proc. 85th National Meeting of American Institute of Chemical Engineers*, Philadelphia, PA.
11. LADNR (1990) *Amendment to Statewide Order No. 29-B*. Office of Conservation, Louisiana Department of Natural Resources, Baton Rouge, LA.
12. Freeman, B.D. and Deuel, L.E. (1984) Guidelines for closing drilling waste fluid pits in wetland and upland areas. *Proc. 7th Annual Energy Source Technology Conference and Exhibition*, Petroleum Division of ASME, New Orleans, 12–16 February.
13. API (1995) *Criteria for pH in Onshore Solid Waste Management in Exploration and Production Operations*. Publication 4595, American Petroleum Institute, Washington, DC.
14. Deuel, L.E. Jr. and Holliday, G.E. (1994) *Soil Remediation for the Petroleum Extraction Industry*, Pennwell, Tulsa, OK.
15. Deuel, L.E., Jr. and Freeman, B.D. (1989) Amendment to Louisiana statewide order 29–B: suggested modifications for barium criteria. *Proc. SPE/IADC Drilling Conference*, New Orleans, LA, 28 February–3 March, 481–86.
16. Carter, M.R. (1993) *Soil Sampling and Methods of Analysis*. Lewis, Boca Raton, FL, 91–3.
17. Wojtanowicz, A.K., Field, S.D., Krilov, Z. and Spencer, F.L. Jr. (1989) Statistical assessment and sampling of drilling fluid reserve pits. *SPE Drilling Engineering*, June.
18. Peterson, R.G. and Calvin, L.D. (1986) Sampling, in *Methods of Soil Analysis, Part 1: Physical and Mineralogical Methods* (Eds. A. Klute et al.), American Society of Agronomy Monograph, **9** (1), 33–50.

19. Crepin, J. and Johnson, R.L. (1993) Soil sampling for environmental assessment, in *Soil Sampling and Methods for Analysis* (Ed. M.R. Carter), Canadian Society of Soil Science, Lewis, Ann Arbor, MI.
20. Wojtanowicz, A.K. et al. (1987) Comparison study of solid/liquid separation techniques for oilfield pit closures. *Journal of Petroleum Technology*, July, 845–56.
21. Osterman, M.C., Wojtanowicz, A.K. and Field, S.D. (1987) The development study of a centrifuging technique for oilfield production pit closure. *Transactions of the ASME, Energy Resources Technology*, December.
22. API (1993) *Evaluation of Limiting Constituents Suggested for the Land Disposal of Exploration and Production Wastes*, Publication 4527, American Petroleum Institute, Washington, DC.
23. LADNR (1989) *Laboratory Procedures for Analysis of Oilfield Waste*, Office of Conservation, Louisiana Department of Natural Resources, Baton Rouge, LA.
24. Veil J.A., and Dusseault M.B. (2003) Evaluation of slurry injection technology for management of drilling waste. Final Report, *DOE Contract W-31-109-ENG-38*, May.
25. McCaskill, C. (1985) Well annulus disposal of drilling waste. *Proc. National Conference on Disposal of Drilling Waste*, University of Oklahoma, Environmental and Ground–water Institute, Norman, OK, 30–31 May, 28–34.
26. Malachosky, E., Shannon, B.E. and Jackson, J.E. (1993) Offshore disposal of oil-based drilling fluid waste: an environmentally acceptable solution. SPE 23373, *Proc. First International Conference on Health Safety and Environment*, The Hague, The Netherlands, 10–14 November, 465–73; also *SPE Drilling and Completion*, December, 283–87.
27. Louviere, R.J. and Reddoch, J.A. (1993) Onsite disposal of rig-generated waste via slurrification and annular injection. SPE/IADC 25755, *Proc. 1993 SPE/IADC Drilling Conference*, Amsterdam, The Netherlands, 23–25 February, 737–51.
28. Anderson, E.E., Louviere, R.J. and Witt, D.E. (1993) Guidelines for designing safe, environmentally acceptable downhole injection operations. SPE 25964, *Proc. SPE/EPA Exploration and Production Environmental Conference*, San Antonio, TX, 7–10 March, 279–86.
29. Smith, R.I. (1991) The cuttings grinder. SPE 22092, *Proc. SPE International Arctic Technology Conference*, Anchorage, AL, 28–31 May.
30. Minton, R.C. (1992) Annular reinjection of drilling waste. SPE 25042, *Proc. European Petroleum Conference*, Cannes, France, 16–18 November, 247–53.
31. Sirevag, G. and Bale, A. (1993). An improved method for grinding and reinjecting of drill cuttings. SPE/IADC 25758, *Proc. 1993 SPE/IADC Drilling Conference*, Amsterdam, The Netherlands, 23–25 February, 773–88.
32. Gardiner, N.H. (1994) NORM Scale safely disposed of by fracturing well. *Oil and Gas Journal*, 23 March, 68–71.
33. Marinello, S.A. et al. (1996) NORM waste disposal methods: technology, risk, liability. SPE 36642, *Proc. SPE Annual technical Conference and Exhibition*, Denver, CO, October, 6–9.
34. Marinello, S.A. et al. (1996) Nonhazardous oil filed waste disposal into subpressured zones. *Environmental Geoscience*, Vol. 3, No. 4, 199–203.
35. Schmidt et al. (1999) Large-scale injection of North Slope drilling cuttings. SPE 52738, *Proc. 1999 SPE/EPA/DOE Exploration and Production Environmental Conference*, Austin, TX, 28 February–3 March.

36. Baker, B. et al. (1999) Large-scale NOW/NORM disposal through slurry waste injection. SPE 53821, *Proc. SPE Latin America and Caribbean Petroleum Engineering Conference*, Caracas, 21–23 April.
37. Baker, B, et al. (1999) Large-scale NOW/NORM disposal through slurry waste injection: data analysis and modeling. SPE 56491, *Proc. SPE Annual Technical Conference and Exhibition*, Houston, TX, 3–6 October.
38. Reed, A.C. et al. (2001) Safe disposal of one million barrels of NORM in Louisiana through slurry fracture injection. SPE 71434, *Proc. SPE Annual Technical Conference and Exhibition*, New Orleans, LA, 30 September–3 October.
39. Keck, R.G. (2002) Drill cuttings injection: a review of major operations and technical issues. SPE 77553, *Proc. SPE Annual technical Conference and Exhibition*, San Antonio, TX, 29 September–2 October.
40. Hagan, J.T. et al. (2002) Engineering and operational issues associated with commingled drill cuttings and produced water re-injection schemes. SPE 73918, *Proc. SPE International Conference on health, Safety, and the Environment*, Kuala Lumpur, Malaysia, 20–22 March.
41. Abou-Sayed, A.S., Andrews, D.E. and Buhidma, I.M. (1989) Evaluation of oily waste injection below the permafrost in Prudhoe Bay field. SPE 18757, *Proc. SPE California Regional Meeting*, Bakersfield, CA, 5–7 April, 129–42.
42. Bruno, M.S. et al. (1995) Economic disposal of solid oilfield wastes through slurry fracture injection. SPE 29646, *Proc. 1995 SPE Western Regional Meeting*, Bakersfield, CA, 8–10 March.
43. Bruno, M.S. and Qian, H.X. (1995) Economic disposal of solid oilfield wastes, *Journal of Petroleum Technology*, September, 775.
44. Willson, S.M., Rylance, M. and Last, N.C. (1993) Fracture mechanics issues relating to cuttings reinjection at shallow depth. SPE/IADC 25756, *Proc. 1993 SPE/IADC Drilling Conference*, Amsterdam, The Netherlands, 23–25 February, 753–62.
45. Kech, R.G. and Withers, R.J. (1994) A field demonstration of hydraulic fracturing for solids waste injection with real-time passive seismic monitoring. SPE 28495, *Proc. SPE 69th Annual Technical Conference and Exhibition*, New Orleans, LA, 28–28 September, 319–34.
46. Minton, R.C. (1994) Downhole injection of OBM cuttings economical in North Sea, *Oil and Gas Journal*, 30 May.
47. Minton, R.C. (1993) Annular reinjection of drilling wastes, *Journal of Petroleum Technology*, November.
48. Minton, R.C., Meader, A. and Willson, S.M. (1992) Downhole cuttings injection allows use of oil-base muds. *World Oil*, 47–52.
49. Truby, L.S. et al. (1994) Data gathering for comprehensive hydraulic fracturingdiagnostic project: a case study. IADC/SPE 27506, *Proc. 1994 IADC/SPE Drilling Conference, Dallas*, TX, February, 15–18.
50. Weng, X. et al. (1997) A filed demonstration of hydraulic fracturing for solid waste disposal: injection pressure analysis. *Proc. North American Rock Mechanics Symposium*, New York, NY, June.
51. Hainey, B.W. et al. (1999) On-site fracturing disposal of oilfiled wasre solids in Wilmongton field, Lon Beach unit, Calofornia. SPE 56070, also, *SPE Production and Facilities*, Vol. 14, No. 2, May.
52. Moschovidis, Z.A. et al. (1994) Disposal of oily cuttings by downhole periodic fracturing injections, Valhall, North Sea: case study and modelling concepts. *SPE Drilling and Completion*, December, 256–62.

53. Schmidt, J.H. et al. (1995) Slurry injection into disaggregated earth formations. *US Patent 5387737*, 7 February.
54. Perkins, T.K. (1994) Disposal of waste solids in hydraulic fractures. *Proc. International Symposium on Computer Methods and Advances in Geomechanics*, Morgiontown, WV, 23–28 May.
55. Willson, S.M. et al. (1999) Laboratory investigation of drill cuttings disposal by downhole injection. *Proc. 37th US Rock mechanics Symposium*, Vail, CO.
56. Moschovidis, Z.A. et al. (2001) The mounds drill cuttings experiment; determining placement of drill cuttings by hydraulic fracturing injection. SPE 48987, *Proc. SPE Annual Technical Conference and Exhibition*, New Orleans, LA, 30 September–3 October.
57. Moschovidis, Z.A. et al. (2000) The mounds drill cuttings injection field experiment: final results and conclusions. IADC/SPE 59115, *Proc. IADC/SPE Drilling Conference,* New Orleans, LA, 23–25 February.
58. Peterson, R.E. et al. (2001) Assessment of the mounds drill cuttings injection disposal domain. SPE 71378, *Proc. SPE Annual Technical Conference and Exhibition*, New Orleans, LA, 30 September–3 October.
59. Bruno, M.S. et al. (2000) Environmental management, cost management, and asset management for high-volume oilfiled waste injection projects. IADC/SPE 59119, *Proc. IADC/SPE Drilling Conference,* New Orleans, LA, 23–25 February.

Chapter 6
Drilling and Production Discharges in the Marine Environment

A.B. Doyle[1], S.S.R. Pappworth[1], and D.D. Caudle[2]

1 Introduction

The exploration and development of offshore oil and gas fields is a relatively recent activity. For example, exploration first started in the United States' Gulf of Mexico in the early 1950s. Gas was not produced from the British sector of the southern North Sea until 1967 and the large North Sea oilfields were developed in the 1970s. At first the environmental impact of offshore operations was unknown and so there were few regulations or standards in place to control discharges. However, soon after offshore operations began, concerns arose about the potential environmental impact of exploration and production activities. The first regulations were therefore developed to control discharges. Over the years treaties, laws and regulations have been promulgated so that now drilling and production discharges are strictly controlled by a complex system of limits. A complicating factor in the early stages of offshore environmental standards was that their development coincided with rapid changes in the technology used in offshore operations. However, the objective of the rules and regulations has always been, and still is, to allow offshore exploration and production to occur while minimizing any associated environmental impacts.

In order to develop effective regulations and the technology required to ensure that the discharges meet the limits, it is necessary to understand both the nature and volumes of the discharges and the sensitivities of the receiving environment. Offshore operations may be in international waters, national waters or in waters under local jurisdiction. In some cases this can mean that more than one regulatory body may be involved.

The characteristics of the water bodies receiving discharged wastes vary widely. Some of the important factors in determining sensitivity to the impact of discharges are:

[1]*Sound Environmental Solutions Inc., 11111 Katy Freeway, Houston TX, USA*
[2]*Sound Environmental Solutions Inc., 6002 Morton Road, Katy, TX, USA*

- The chemical and physical characteristics of the waste
- Water depth
- Distance from shore
- Typical wind and wave forces in the area
- The presence of sensitive marine communities

The nature of wastes discharged is affected by several factors including:

- Regulations
- Operator policies and practices
- Limits imposed by financial institutions
- Public interest groups

The wastes generated by oil and gas exploration and production operations fall into two broad categories: those from the oil and gas operations themselves and those due to the support activities. The major wastes, by volume, from drilling and production operations include:

- Produced water
- Excess water based drilling muds
- Drill cuttings
- Wastes that require handling during site abandonment

The discharge of major wastes may be either allowed or prohibited depending on the characteristics of the waste, the receiving environment, and the specific regulatory limits.

Minor wastes include:

- Deck drainage
- Tank bottoms
- Produced sand
- Excess chemicals and chemical containers
- Household wastes

Most minor wastes are taken to land for treatment and disposal.

In addition to permitted discharges, accidental releases can result from a number of situations, including tank or pipeline ruptures, ship or boat accidents, and well blowouts. The material spilled can include crude oil, fuel oil, diesel, or bulk chemicals. Most major accidental discharges of crude oil are associated with shipping rather than oil and gas exploration and production.

At the end of the development of an offshore oil or gas field, the platform and associated equipment (e.g. wellheads) must be removed. In some areas any accumulated piles of drilling cuttings must also be taken away and disposed of when the field is abandoned. It is very costly to remove fixed platforms and so over the years a number of alternative structures have been developed, for example tension leg platforms (TLP) and moored spars, that can be moved, refurbished and reused to develop another field.

Although governments develop environmental regulations, the regulations are strongly affected by the limitations of technology, the need to support industry and the influence of public opinion. Over time, regulatory systems have been developed through the interaction of the forces listed above.

2 Nature of offshore discharges

2.1 Produced water

Produced water is the water generated from the oil and gas extraction process. It includes: the water native to the producing formation, water injected into the formation to increase reservoir pressure and to sweep oil from the formation, and various well treatment solutions and chemicals added during production and the oil/water separation process. The volume of produced water varies over the life cycle of an oilfield, typically increasing over time.

Formation water, which initially comprises the bulk of the produced water, is found in the same rock formation as the crude oil and gas, or in an adjoining level of the same formation (e.g. below the oil/gas cap). Formation water is classified as meteoric, connate or mixed. Meteoric water comes from rainwater that percolates through bedding planes and permeable layers. Connate water (seawater in which marine sediments were originally deposited) contains chlorides, mainly sodium chloride ($NaC1$), and dissolved solids in concentrations many times greater than common seawater. Mixed water is characterized by both a high chloride and sulfate–carbonate–bicarbonate content, which suggests multiple origins.

Besides its ionic constituents, produced water may also contain dissolved and dispersed organic compounds, including hydrocarbons (both aliphatic and aromatic), oxygen, nitrogen and sulfur containing compounds, e.g. carbon dioxide, hydrogen sulfide, ammonia, and small concentrations of heavy metals. Normally formation water is low in sulfate ion and may contain significant quantities of calcium, barium and/or strontium ions. Produced water is usually in a chemically reduced state and it may have both a significant chemical oxygen demand (COD) and biological oxygen demand (BOD). It will react with air and changes in pressure and may release carbon dioxide or hydrogen sulfide, which can also cause chemical reactions in the water.

Treating chemicals are added to produced water and may significantly affect its environmental impact. Treating chemicals are used to accomplish several functions. The following is a listing of some of the most common uses:

- Breaking emulsions to aid in the separation of oil and water
- Preventing the formation of water-formed scales
- Controlling the growth of bacteria in the producing wells and production system
- Aiding in the treating of water to remove oil

The industry magazine, World Oil, annually publishes a list of chemicals currently used in production treating applications. Specific information on the properties of these materials can be obtained from their suppliers from their Material Safety Data Sheets (MSDS).

In summary, produced water is a complex mixture of inorganic and organic materials in water. Its salinity is usually higher than most surface waters and its composition varies with time. In addition, the volume of produced water varies over the life cycle of an oilfield.

2.2 Drilling waste

Drilling wastes include drilling fluids (or muds) and the formation fragments (known as cuttings) removed in the drilling process. Drilling fluids are suspensions of solids and other materials in a liquid base. The composition and properties of drilling fluids are determined by their functions.

Three of the primary functions that drilling muds perform are:

- Lubricating and cooling the drilling bit
- Maintaining downhole hydrostatic pressure
- Cleaning out the hole by bringing cuttings to the surface

In order to work, muds must have a high density, a high viscosity and lubricity. To meet these requirements the muds contain weighting agents such as barium sulfate (Barite) or iron (III) oxide to increase the density of the mud, clays (bentonite, etc.) or polymers to adjust viscosity and chemicals to increase lubricity. Usually several minor additives are used to more precisely control the mud properties. The industry magazine, World Oil, annually publishes a list of chemicals used in the formulation of drilling muds. Information on the properties of these materials can be obtained from their suppliers from their MSDS. In recent years, great emphasis has been given to selecting mud components that both perform well and are environmentally friendly.

Drilling fluids fall into one of the three classes based on the fluid comprising the mud:

- Water based muds
- Oil based muds
- Synthetic based muds

More than one type of mud may be used in a single well depending on the conditions encountered.

A water based drilling fluid or mud is one in which water is the continuous phase and the suspending medium for solids and other liquids, whether or not oil is present (EPA, 1993). Water based drilling muds are relatively inexpensive. Modern formulations are generally non-toxic to marine fauna. Discharged cuttings will disperse in the water column.

The water in water based muds can be fresh or salt water. Clays or organic polymers are added to achieve the proper viscosity. Barite is added to achieve the correct mud weight (density), and other components are added to mud systems to create the desired characteristics. The United States Environmental

Protection Agency (EPA) recognizes eight generic water based mud types (OCS Guidelines).

Oil based drilling fluids are ones in which the continuous phase is oil: diesel, mineral or some other oil (EPA, 1993). Simplistically they can be viewed as water based muds dispersed in oil. One important difference from water based muds is that viscosity is achieved by emulsification of water in oil as well as through the use of clay. They are also more expensive to use than water based muds.

Oil based drilling fluids are used to solve drilling problems that water based muds cannot handle efficiently or at all. Conditions warranting the use of oil based muds include: required thermal stability when drilling high-temperature wells, required specific lubricating characteristics when drilling deviated wells, the ability to reduce stuck pipe or hole wash-out problems when drilling thick, water-sensitive formations and drilling through water soluble formations such as salt. Most offshore wells fall into one or more of these classes. Currently oil based muds are standard for the lower portions of most offshore wells.

Concerns over the potential toxicity of oil based drilling fluids lead to the development of synthetic based drilling muds (SBMs). Synthetic based muds are drilling fluids that use synthetic organic chemicals, principally containing carbon, hydrogen and oxygen, as base fluids. Synthetic based muds are more expensive than oil based muds, however, they have the same desirable properties of the oil based fluids, but are more environmentally benign. SBMs have low toxicity because of the elimination of the polynuclear aromatic hydrocarbons (PAHs). They were also designed to have faster biodegradability, lower bioaccumulation potential and, in some instances, less drilling waste volume. This means that the discharge of SBM cuttings may be permitted. Like oil based drilling fluids, synthetic based fluids are hauled to shore after use to be reprocessed and reused.

Cuttings are small pieces of formation rock that are generated by the crushing action of the drill bit. Drill cuttings are carried out of the borehole by the drilling fluids. Drill cuttings themselves are inert solids from the formation. However, drill cuttings discharges also contain drilling fluids that adhere to the cuttings. The volume of the mud that adheres to the cuttings can vary considerably depending on the formation being drilled and the cutting's particle size distribution (EPA, 1993). A general rule of thumb is that five percent mud, by volume, is associated with the cuttings (Ray, 1979). In the case of some water based drilling fluids, the formation materials drilled up will become part of the mud solids and chemical adjustments have to be made to accommodate them. This results in an increase in mud volume that is not needed in the drilling process. Some drilling mud then becomes a waste and must be disposed of. Therefore, drilling mud itself becomes a waste material in two ways: as a coating on cuttings and as excess mud.

Drilling fluids are designed to have the required characteristics to aid in the drilling of the well, while at the same time limiting their potential environmental impact. Their potential for environmental impact is partially determined by where they end up in the environment as well as their intrinsic properties. Water based mud and cuttings tend to disperse into the water column on discharge. The dispersion is broken and the solid components slowly settle to the sediment layer at the bottom of the sea. Because the cuttings are rapidly dispersed and their liquid components diluted, their potential impact should be less than that of oil based, or synthetic muds but spread over a much wider area.

Cuttings from oil based mud drilling have oil on their outer surfaces and do not tend to disperse in the water column. The solid components tend to settle rapidly to the bottom and collect in piles under the platforms of drilling rigs. Free oil on the cuttings tends to rise to the surface of the water and spread over the surface of the water. The environmental impact of the cuttings tends to be highly localized initially and persist over a long time in the sediment and water column immediately above it.

The offshore oil and gas industry uses a number of water based fluids. These include:

- Completion fluids
- Packer fluids
- Workover fluids

Completion fluids are typically solutions of salts in water. They are used to clean out wells after drilling is complete and aid in the setting of downhole equipment. Packer fluids are concentrated salt solutions placed between the tubing and the casing of a well. Their purpose is to hold pressure on the formation in case the packer fails. They must have a high density in order to be heavy enough to exert sufficient pressure on the producing formation. Workover fluids are used in cleaning, repairing, and stimulating wells. Typical operations include washing sand from the tubing or wellbore, fracturing formations to increase oil flow from them, and acidifying wells to remove water-formed scales and corrosion products. The salts used to make these fluids include the cations sodium, potassium, calcium, barium, and zinc, and the anions chloride, bromide and sulfate. Hydrochloric acid is the one most frequently used for treating wells.

Completion fluids can be transported offshore as water solutions or the solid salt can be taken offshore and the solution prepared on-site. Spills could result from broken flowlines on the platform or on boats or from tank failures. When large volumes of completion fluids are needed they are generally transported on work boats. In the event that the vessel has an accident, the completion fluids could be released.

2.3 Magnitude of waste discharges

The volume of drilling and production discharges varies over time due to two factors:

- The level of drilling and production activity
- The fraction of wastes discharged to the environment

The American Petroleum Institute (API) estimated that in 1985 in the United States the oil and gas industry (both onshore and offshore) generated 361 million barrels of drilling wastes (1.5% of the total) and 20.9 billion barrels of produced water (98% of the total). Another 118 million barrels of associated wastes (0.5%) were generated for a total of 21.4 billion barrels (Freeman and Wakin, 1988). From this it is clear that the majority of waste generated by oil and gas operations is in the form of produced water. In 1995, the API web site's waste prevention data showed that the total volume of wastes generated declined to 18.1 billion barrels, a reduction of 3.3 billion barrels. This included an increase of 9% in produced water discharges and a decrease in drilling discharges of 53%.

Produced water volumes are much greater for structures producing oil or a combination of both oil and gas as compared to gas-only platforms. Although the gas-only platforms generate less produced water, the concentration of the chemical constituents of the water is considerably higher than those from oil producing platforms (op ten Noort et al., 1994). The volume of produced water at a given platform is site-specific. For example, in some instances, no formation water is encountered whilst in others there is an excessive amount of formation water encountered at the start of production.

According to Walk, Haydel and Associates (1984), the average produced water discharge rate from an offshore platform off the United States is usually less than 1,800 barrels per day (bpd), whereas discharges from large treatment facilities handling water from many platforms may be as high as 157,000 bpd.

In the North Sea, the method of reporting of waste discharge volumes has changed over the years. Initially reports were made on the volume of waste such as produced water and drill cuttings. For example, the International Association of Oil and Gas Producers (OGP), formerly known as E&P forum, have estimated that in 1991, oil and gas platforms in the northern North Sea discharged 160 million cubic meters (1 billion barrels) of produced water, with about 5% of the total volume coming from gas platforms (E&P Forum, 1994). Recently the practice is to report only oil in the waste. For example, the Oslo Paris Commission (OSPAR) reports that the total oil discharged (including oil in produced water and displacement waters and accidental spills) in the maritime area of OSPAR was 9,053 tonnes in 1999, 9,420 tonnes in 2000 and 9,317 tonnes in 2001. This did not include oil from oil based mud use since discharges of cuttings generated when using these muds are prohibited.

Whatever method is used to account for waste generation, oilfield operations anywhere in the world will generate comparable amounts of waste. However, countries have different regulatory schemes that may prohibit certain discharges. Regulations controlling the types and quantities of wastes that can be discharged are discussed later in this chapter.

2.4 *Accidental discharges*

Materials that might be accidentally discharged to the sea include:

- Crude oil and tanker fuel oil from tankers
- Crude oil from well blowouts

- Crude oil from tank ruptures on offshore installations
- Crude oil from pipeline and gathering line ruptures
- Fuel and chemicals from storage vessel ruptures on offshore installations and supply boat accidents
- Drilling fluids
- Completion fluids
- Packer fluids
- Workover fluids

Oil spilled at sea will disperse into the receiving environment. This is a result of a number of chemical and physical processes that occur to "weather" the oil. The exact nature of the weathering depends on the type of oil that is involved. Part of the weathering process, for example, the natural dispersion of the oil into the water, results in some of the oil leaving the sea surface, whereas others, such as evaporation or the formation of water in oil emulsions, result in oil components that stay on the surface becoming more persistent.

How spilled oil reacts depends largely on how persistent the oil is. Light products such as condensate tend to evaporate and dissipate quickly and naturally, and are classed as non-persistent oils. They do not usually require any extensive cleanup or response actions. Alternatively, in the case of persistent oils, like most crude, the oil is much slower to disperse and evaporate and so response actions are required. In addition to the chemical changes, the oil's physical properties including density, viscosity and pour point all affect behavior.

The oil does not immediately disperse. The time required depends on a series of factors, including: the amount and type of oil spilled; the weather conditions; and whether the oil stays in the marine environment or is washed ashore. The whole process can move quickly or slowly depending on the oil involved and the conditions. For example, dispersion will be quicker in rough seas than in shallow, sheltered, calm waters.

There are generally eight main processes that cause oil to weather. The first of these is spreading. Any oil that is spilled will immediately spread out over the sea surface. The viscosity of the oil generally dictates how quickly the oil spreads. The lower the viscosity, the quicker the spreading. However, even high viscosity oils still spread relatively quickly. Typically the slick that forms will vary in thickness. Due to the action of the wind, waves and water turbulence, over the next few hours the initial slick will begin to break up and form narrow windrows parallel to the wind direction. The water and air temperatures, currents and wind speeds also have an effect on how quickly windrows are formed. Obviously, the rougher the conditions, the quicker that the windrows will form.

The second process is evaporation of the lighter components of the oil. The volatility of the oil, that is the amount of light and volatile components in the oil, governs the volume of oil that will evaporate and how quickly this will happen. For example, aviation fluid and condensate will evaporate almost completely in a few days. On the other hand, heavier crude and heavy fuel oil will hardly evaporate. Evaporation tends to increase as the oil spreads out, and in rougher seas and higher temperatures.

The third process is dispersion. Wave action and turbulence on the sea surface will break up the oil slick into separate slicks and individual oil droplets. The droplets become mixed into the upper part of the water column. Some of the smaller droplets will remain suspended in the water column. Larger droplets will rise to the surface and will either attach onto other droplets and make a new slick or, alternatively, will spread out on the surface to form a very thin oil film. The oil droplets that remain in the water column have a larger surface area, which makes it easier for biodegradation and sedimentation to occur. The sea conditions and the viscosity of the oil are the principle factors in determining how quickly an oil will disperse. The use of chemical dispersants can accelerate the process.

Emulsification is the fourth process. An emulsion is formed when two liquids combine, with one ending up suspended in the other. Emulsification of crude oils refers to the process whereby seawater droplets become suspended in the oil. This occurs by physical mixing promoted by turbulence at the sea surface. The emulsion that is formed is usually very viscous and more persistent than the original oil and is often referred to as chocolate mousse because of its appearance. Apart from increasing the persistence of the oil, the formation of an emulsion increases the volume of material that has to be recovered by three to four times. The higher the asphaltene content of the oil, the more likely it is that an emulsion will be formed. Typically, oils with asphaltene contents greater than 0.5% form stable emulsions. It is possible for emulsions to separate out into oil and water if the emulsion is in calm seas or on shore and the material is heated by sunlight.

Dissolution is the fifth process. Water soluble compounds in an oil may dissolve into the surrounding water. This depends on the composition and state of the oil, and occurs most quickly when the oil is finely dispersed in the water column. Components that are most soluble in seawater are the light aromatic hydrocarbon compounds such as benzene and toluene. However, these compounds are also those first to be lost through evaporation, a process which is 10–100 times faster than dissolution. Oil contains only small amounts of these compounds making dissolution one of the less important processes.

The sixth process is oxidation. Oils react chemically with oxygen. In the reaction the oil either forms a persistent "tar" or breaks down into soluble products. The rate and extent of oxidation is generally dependent upon the type of oil involved and sunlight. Oxidation is an extremely slow process and, even in favorable conditions, will only break down 0.1% per day. Tar balls are formed when the oxidation process forms a protective layer of heavy compounds around a less weathered, soft center. The outer layer makes the tar balls very persistent.

Sedimentation or sinking is the seventh process. In the case of heavy crude oils or refined products with densities greater than one, the oil will sink in fresh or brackish water. There are very few crude oils or refined products with a greater density than the 1.025 for seawater, and so the material will typically not sink when spilled at sea. However, as the oil adheres to particles, flora, fauna or other organic material, it may sink. Oil that impacts a beach or shoreline may become mixed with sands and other sediments. If this material is washed out to sea, it may then sink. The residue from spilled oil that has caught fire, or been burned, can also be sufficiently dense to sink.

The eighth process is biodegradation. There are naturally occurring microorganisms that live in the marine environment that can degrade oil to water soluble compounds and even eventually to carbon dioxide and water. Not all oils are equally susceptible to biodegradation. The amount of nitrogen and phosphorous in the water, the temperature and the oxygen concentration all affect the ability of the microbes to degrade the oil. The degradation can only take place in an anaerobic environment and so the degradation is usually limited to the oil–water interface. Converting the oil into droplets, both through natural processes or by the use of chemical dispersants, increases the surface area available to the microbes and hence raises the rate of biodegradation.

In the early stages of a spill, spreading, evaporation, dispersion, emulsification and dissolution are the most prevalent processes. Oxidation, biodegradation and sedimentation become much more important later in the spill and tend to determine the eventual fate of the oil.

Accidental discharges fall naturally into two classes: those that can be recovered and those that cannot. Oil spills can be recovered, assuming that equipment and manpower is available to recover the oil before it reaches the shoreline, evaporates into the air or sinks. Sometimes bad weather or other conditions can interfere with recovery. Water based fluids usually cannot be recovered. Since they are miscible with water they rapidly dilute on reaching the sea and some undergo chemical reactions with seawater constituents.

2.5 Wastes that require handling during site abandonment

Although platform disposal is discussed in Chapter 5, site abandonment has the potential for discharging materials to the sea. Platforms having large integral storage vessels might have residual oil or chemicals in the vessels; the presence of the platform or its residue modifies the local environmental habitat by its very presence. For example, most of the northern Gulf of Mexico is a mud bottomed body with few coral reefs or other bottom relief. Abandoned platforms will tend to act as artificial reefs and attract fish species that live around reefs.

Abandoned platforms could be a hazard to shipping or fishing boats. This would be especially troublesome if they were not visible from the surface.

In the North Sea there is the additional problem of old cuttings piles beneath some of the older platforms. These piles resulted from drilling with oil based muds during the period when discharge of such cuttings was allowed. The interior of these piles may be wet with oil and contain no continuous water. Degradation of these cuttings is dependent on wind and wave action and bacterial degradation of any oil. Wind and wave action does not normally reach the bottom of the northern North Sea and with little water content the piles will not rapidly bacterially degrade. Removing a platform without removing the cuttings piles would leave them as a hazard to trawling and other activities for periods estimated to be up to 100 years.

3 Potential impacts on the environment

3.1 Introduction

The term “environmental impact” covers a variety of effects that discharges might have on the receiving environment. These effects can range from very minor variations in the chemical composition of water to complex changes in the chemical, physical and biological nature of water columns, sediments, flora and fauna. Even if an environmental effect is defined, it may be very difficult to identify or quantify it in an actual environment. Therefore, in this document, “environmental impact” will be interpreted as any issue that raises concerns in public or regulatory bodies, whether or not actual lasting effects have been proven to occur.

Toxicity is a concern both in the water column and on the sediment. Toxicity is a measure of the power to interfere with the life processes of an organism. This concern is for both immediate lethal toxicity (acute) and sub-lethal (chronic) effects. Acute toxicity is a measure of immediate danger of poisoning while chronic toxicity is a measure of sub-lethal impacts. These affect such things as growth and reproduction. Toxic impacts are measured by:

- A minimum concentration
- A minimum exposure time
- The time to recover after exposure

Organic materials are removed from the aquatic environment through either aerobic or anaerobic biodegradation. Organic materials in both the water column and sediment are consumed by bacteria and converted into simpler material and ultimately into carbon dioxide and water. Aerobic biodegradation requires an oxygen source in the affected environment. The oxygen necessary for biodegradation is termed the biochemical oxygen demand (BOD). Neither the water column nor the sediment contains much oxygen, and a high concentration of organic materials will consume available oxygen rapidly making that environment unable to support life. Oxygen is easily replaced in the water column because wind, waves and currents act to replace the oxygen at a rate higher than most degradation depletes it. On the other hand, oxygen in the sediment is easily depleted by biodegradation. In anoxic (oxygen free) sediments anaerobic (non-oxygen) biodegradation takes place.

The persistence of the contaminant in the environment also plays a role in determining the overall impact to the environment. Persistence is the ability to remain in the environment in a detrimental form and not be broken down into more innocuous materials. The only materials that might persist in the aquatic environment are highly stable, complex aromatic compounds that degrade very slowly. The materials that would persist in the environment are generally present in very low concentrations and the threat of build up is low.

3.2 Potential impacts from produced water

The chemical composition of produced water can change the ionic strength of the receiving waters. The individual constituents of produced water can potentially have toxic effects on the flora and fauna in the water column and the sediments. Chemical reactions with seawater can produce solids that can change the nature of sediments both chemically and physically. All these effects can result in significant impacts on the biological communities living in the water and sediments. The organic constituents of produced water can also deplete oxygen in the receiving water body and the sediments under it due both to chemical and biological reactions.

Laboratory tests have demonstrated that produced water has an intrinsically low toxicity level (E&P Forum, 1994). Therefore, acute toxicity should not be a significant issue for produced water. However, toxicity limits are imposed on produced water by some regulatory authorities.

In the early development of the offshore oil industry it was feared that both the inorganic and organic constituents of produced water would result in:

- Bioaccumulation and fish tainting
- Biochemical oxygen demand (BOD)
- Persistence in the environment
- Contamination of sediments

Many years of intensive investigations and studies have shown that most of these fears have not proven to be a significant threat to the environment.

However, salinity has been shown to have a serious impact on shallow receiving waters such as bays and estuaries. Consequently the discharge of produced water to these areas has been banned in many places including the United States.

On the other hand, a large study done jointly in the Gulf of Mexico by various industry groups and government agencies found no bioaccumulation of heavy metals from produced water (Continental Shelf Associates, 1997).

The biodegradation of organic compounds in produced water is known to deplete oxygen in limited water bodies such as ponds, streams and shallow bays. Oxygen recharge from wind and wave action minimizes oxygen depletion in the open sea. The oxidation of inorganic compounds does not create significant oxygen demand (E&P Forum, 1994).

3.3 Potential impacts from drilling waste

Potential impacts to the marine environment from drilling waste generated by oil and gas operations include:

- Toxicity
- Bioaccumulation and fish tainting
- Disturbance to the physical environment
- Biochemical oxygen demand (BOD)
- Persistence

Both organic and inorganic components in drilling mud can cause impacts. Oil is one of the organic components of drilling muds. Even water based muds can contain some amounts of oil from solvents for other components or the oil from the formation. Inorganic components consist mainly of inorganic salts, with trace metals and nutrients.

Toxicity is a concern both in the water column and on the sediment. The chemical components of the drilling fluids have the most obvious potential for toxicity. However, the effect of the chemicals in drilling mud can be significantly impacted by reactions within the mud itself and with the constituents of seawater.

Mud toxicity can occur in both the water column and in sediments. Exposure to a toxic concentration in the water column can be due to dissolved chemicals and dispersed solids and droplets. Exposure to a toxic concentration in the sediments is due to the accumulation of the solid portion of the mud and cuttings. Regulations in most areas ensure that toxicity is not a serious problem.

When solid containing wastes such as cuttings are discharged, the solid portion will eventually end up in the sediment layer. For water based muds the area of sediment covered might be very large because many of the solids tend to disperse into the water column and settle slowly over a long period of time. Furthermore, in shallow waters such as the continental shelf of the Gulf of Mexico hurricanes regularly stir up sediments and effectively dilute accumulated cuttings. For oil based muds the cuttings are oil encapsulated particles which are heavy enough that they settle very near the discharge point. The result, after drilling several wells from the same platform, is a large pile of oily material. Since the oil in this pile is not exposed to water containing bacteria it might last a century or more. The environmental concern is that these piles will be a fishing and navigation hazard when the platform is removed and oil escaping from them can affect the environment. In both cases modification to the sediment layer is deemed undesirable.

Since drill cuttings usually end up on the sediment, if they have an oxygen demand impact it is in the sediment, not in the water column (Davies et al., 1988). However, it should be noted that the floor of the ocean in deep water, such as the northern North Sea, is sparsely populated, and so the impact is small and the aerial extent limited. This concern is recognized and addressed by most regulatory bodies.

3.4 Potential impacts from treating chemicals

Chemicals are used in all phases of offshore oil and gas production. Many of these chemicals have either surface active properties, toxicity, or react chemically with the constituents of seawater. Potential effects include toxicity, oxygen demand and physical fouling of sediments and structures. The oil industry publication, World Oil, publishes lists of all types of treating chemicals annually. These lists provide information on the composition and properties of these materials.

The solubility of treating chemicals can determine where they end up and whether or not they are discharged. For example, many chemicals are water soluble and will end up in the produced water that is discharged. Others are preferentially oil soluble and will end up in the oil stream and will not be discharged. Chemicals used in drilling muds will be in the mud discharged but may have reacted with other chemicals prior to discharge.

To understand the environmental impact of chemicals one must consider:

- The amount used
- Its properties
- Any reactions it undergoes
- Whether it is discharged

These factors influence the limits that are established in the regulations.

3.5 Potential impacts from accidental discharges

Almost all accidental discharges are of liquid materials. It is important to understand where these liquids will end up when they are accidentally discharged. Some crude oils are relatively volatile and if spilled most of the spilled liquid will evaporate into the air. Other crude oils have components that have low volatility. These oils will spread on the surface of the water initially and if not recovered will ultimately end up on the sea floor due to emulsification and absorption of solids. When oil spills reach shorelines and sediments they can physically and chemically impact biological communities as well as physically impact beaches.

The amount of material spilled is an important factor in determining any potential impacts. The size of the release can vary from a few milliliters from a dripping hose connection to thousands of tonnes in the event of a major tanker grounding. Water based accidental discharges typically release a much smaller volume than oil spills. They also have a different pathway in the environment. For example, water based fluids such as completion fluids will disperse in the water column and be diluted.

Accidental discharges differ from waste discharges in that they are generally one time, instantaneous events. The maximum volume discharged can be significantly more than routine waste discharges. In addition, there is little control over where and when the material is released. Consequently, the discharge may occur in, or close to, very sensitive areas that cannot easily tolerate the discharged material; for example, a tanker spill that impacts a mangrove. In the case of a tanker spill, the response equipment and containment and cleanup crews have to be mobilized. Equipment and crews may be stationed significant distances away from the spill site. This potentially allows the spilled material to impact sensitive areas before the spill response equipment arrives. Fortunately however, large tanker spills are extremely rare and represent a very small percentage of the hydrocarbons that enter the environment.

Most accidental discharges into the marine environment are of crude oil or refined petroleum products. Although the environmental impacts of crude oil might be assumed to be similar to the impacts from drilling fluids, they are in fact very different. The highest concerns are for:

- Fouling of beaches and shorelines including manmade structures
- Fouling of birds and sea mammals
- Fouling of sediments
- Impact on breeding habitats

Some of the factors affecting environmental impact include:

- Speed and effectiveness of recovery of the spill and cleanup of the environment, which in turn can be influenced by cleanup liability issues
- Remediation of fouling of birds, mammals and habitats

In the early stages of a spill, spreading, evaporation, dispersion, emulsification and dissolution are the most prevalent processes. Oxidation, biodegradation and sedimentation become much more important later in the spill and tend to determine the eventual fate of the oil.

Recovery and cleanup operations are most effective when performed immediately, or soon after, the spill has occurred. Recovery operations are often made harder when the oil starts to emulsify. Emulsification starts soon after discharge and is exacerbated by wind and wave forces. Emulsified oil does more damage to beaches and habitats than free oil.

If the spill reaches the shoreline, part of the recovery will be decontaminating birds and mammals as well as the beaches and sediments. The sooner remediation starts the higher the effectiveness of the recovery.

With the advent of the use of supertankers in the 1960s the potential for large releases of hydrocarbons was created. The tanker, Torrey Canyon, was the first major spill from a super tanker. It grounded on the southwest coast of England in 1967 and 860,000 barrels of oil leaked into the sea. Much of the south coast of England was affected when oil coated rocky coastlines. The damage was compounded when laundry detergent was applied in an attempt to de-oil rocks, beaches and wildlife and when the carrier for the oil dispersant was kerosene that was highly toxic to marine fauna. The effects of these efforts retarded the development of non-toxic dispersants for treating oil spills for years.

In 1978, the Amoco Cadiz was grounded off the coast of France and approximately 1,635,715 barrels of crude oil was spilled. Bad weather slowed response to the spill and rapidly emulsified the oil. Much of this oil ended up on sandy beaches. The removal of a large amount of oiled sand severely impacted the beaches.

In 1989, the Exxon Valdez ran aground on a reef in Prince William Sound offshore the State of Alaska. This area is biologically rich and large numbers of sea birds, ducks and sea otters and other animals were coated with oil and had to be rescued and cleaned. There have been extensive industry, government and privately funded studies to determine the impact of the spill. These studies have come to a variety of conclusions ranging from there being no long-term impact to significant impacts on the flora and fauna in the area.

The UK Royal Commission (1981), after reviewing a substantial body of information on the environmental effects of actual oil spills, concluded that there is no evidence to substantiate claims for long-term irreversible impact to the marine environment. On the other hand, the short-term consequences in relation to amenity loss, interruption of fishing activities, and impact on individual sea birds (although not on bird populations) are sufficiently serious to justify efforts to develop and implement effective means of oil spill cleanup.

4 Regulatory approaches

4.1 Regulations for waste discharges

It is important to balance the development of natural resources with protection of the environment. Oil and gas exploration and production activities generate wastes that must be properly handled and disposed of. As previously discussed, some of these, for example produced water, are high volume, low toxicity waste streams that would be very expensive to transport to shore for disposal. Other wastes, such as oil based fluids, have the potential to cause significant environmental impacts. Regulations addressing offshore waste discharges were developed to ensure that the environment is protected while still allowing disposal offshore where possible. A key ingredient in developing the appropriate balance between the costs associated with waste disposal and protecting the environment has been obtaining input from the regulatory authority, industry and environmental groups. Each group has brought data, information and perspective on the issues. The steps in regulatory development include:

- Identifying wastes
- Determining their volumes, properties, potential impacts
- Assessing the sensitivity of the receiving environment
- Determining control strategies
- Implementing systems for monitoring and control

Regional, national and local government authorities are responsible for gathering this information. Industry groups, various industry organizations and environmental groups help identify concerns and supplement the available data.

There are a number of different schemes that are used to regulate waste discharges. In some areas the impact of discharges is controlled by limiting the chemicals that are used in systems that will ultimately be discharged. Other regions apply "end of the pipe" controls. That is they put a limit on the volume and content of the effluent. Generally, there are three major regulatory systems that are used:

- Those for the waters of the United States
- Those for the waters around northern Europe
- Those for Russia and former Soviet Republic waters

There are other additional regional and national regulatory systems. Most of these are modeled on the United States and European systems with local modifications. The following provides an overview of the three different regulatory schemes.

4.2 OSPAR agreements and national regulations for the OSPAR area

The regulations for the North Sea, the Baltic Ocean and the northeast Atlantic Ocean are the result of a treaty organization, the OSPAR Commission, between 15 countries bordering these waters and the European Union. The OSPAR commission identifies issues, investigates impacts and sets goals for controlling pollution of the seas from several sources including offshore oil and gas waste discharges. The member countries through national regulations then implement these goals. For example, the department of Trade and Industry in the United Kingdom issues regulations and limits for the United Kingdom waters.

Information on the types of waste controlled and the limits set on them is available from the OSPAR Commission. The issues covered include, abandoned platforms and pipelines, the discharge of treating chemicals and oil in produced water and the discharge of drilling wastes among others. The approach used is primarily to control waste at the source. For example, treating chemicals are controlled by limiting the chemicals and the amounts used in the oil industry processes. Both drilling chemicals and production treating chemicals are classified according to their potential impacts into several classes. These classes range from materials too hazardous to discharge down to those considered having very little impact on the environment. The first class cannot be discharged and no limits are placed on the discharge of the group that has minimal impacts. Few limits are placed on monitoring the waste discharged. Limitations on oil in produced water are an exception. Since oil originates in the underground formation the concentrations in the waste discharge stream are limited.

Discharges are of interest to groups other than regulators. Industry members and organizations and environmental organizations also give input to regulations. For the OSPAR areas organizations industry groups such as the Oil and Gas Producers (OGP), the United Kingdom Offshore Operators Association (UKOOA), the Netherlands Oil and Gas Exploration and Production Association (NOGEPA), and others input industry views and data. The OGP is an international organization whose members are oil and gas companies around the world. They respond to regulations and develop environmental standards for oil companies to use where no definitive standards exist locally. UKOOA and NOGEPA are associations of oil and gas operators in the United Kingdom and the Netherlands. The other member countries of the OSPAR also have national associations of operators. In addition, suppliers to the oil industry provide information on environmental impacts. The European Oilfield Speciality Chemicals Association's (EOSCA) members supply chemicals to the North Sea offshore oil industry. The Environmental groups such as Green Peace and Friends of the Earth are active in lobbying for strong environmental regulations and have an impact on regulatory development. Information and data is available from all these organizations on environmental impacts and regulations.

Over time the limits placed on the chemical use and discharge of oil have evolved and changed. Initially oil concentration in produced water was subject to a concentration limit. Now the emphasis has changed to reducing the total amount of oil permitted to be discharged annually. OSPAR publishes data on volumes of produced water and amounts of oil discharged annually.

Drilling waste concerns have focused on the oil used to make the oil based drilling muds commonly used offshore. Initially there were no limits on what type of oil was used and diesel oil muds were common. Concerns over the toxicity of diesel oils led to a ban on them and muds were prepared using refined mineral oils, which did not contain aromatic compounds and other more toxic components. Later, all refined oils were banned from discharge and manufactured oils with a controlled composition were used until finally the discharge of drill cuttings containing more than 1% oil were banned. Current information on discharge regulations for areas controlled by the OSPAR Commission can be obtained from their offices in London or from their web site. Many of the same groups mentioned above for produced water also provide information and lobbying for drilling waste issues. In addition supply groups such as the International Association of Drilling Contractors (IADC) are active on behalf of drilling suppliers.

4.3 United States regulations

The EPA develops regulations for the discharge of oil industry wastes to United States waters. All waters of the United States are regulated. The environmental impacts of principle concern are toxicity and oxygen depletion.

In the United States discharges are separated into subcategories by potential impact. The subcategories include:

- Onshore waters (ponds, lakes, streams, and rivers)
- Beneficial use waters
- Stripper well discharges
- Coastal waters
- The territorial seas
- The outer continental shelf (OCS)

The national office of the EPA identifies and classifies waste discharges and develops guidelines for issuing permits to operators wishing to discharge to these waters. Discharges are not allowed in some of these categories and are very restricted in others. For example, no discharge is permitted in the onshore subcategory because produced water and cuttings are biotreated in the aquatic environment and this process uses up the oxygen in the water faster than it can be replenished. There is also concern about the impact of hazardous substances that might be present in the waste.

In two of these subcategories, beneficial use and stripper wells, discharge volumes are very minor. In some dry areas of the United States, produced water is very low in salinity and can be used for watering livestock and for irrigation. These types of produced water discharges are in the beneficial use subcategory. In one older area of the United States, very old gas wells producing very small amounts of water (stripper wells) are allowed to discharge to rivers as they have done for many years prior to the implementation of regulations. If discharge were not allowed, the wells would be uneconomical.

The coastal subcategory is that area inside the recognized coastline and outside the brine line, the distance inland that is covered in brackish or salty water. The territorial seas are that area outside the recognized coast line to a distance of usually three miles. These waters are deemed to be part of a state. The OCS is that area outside the three mile limit and is controlled by the federal government and not an individual state. In these three subcategories discharge of waste to the waters was the traditional method of disposal. Over time it was shown that in the coastal areas oxygen depletion and increased salinity were affecting the local environment and discharges to the coastal subcategory are now banned. In the territorial seas and the outer continental shelf waste discharge is allowed under a permit issued by the EPA.

For regulatory purposes the EPA divides the United States into ten regions. The identification of wastes and the determination of their potential impacts are done by the national office of the EPA. These findings are published as guidelines for the preparation of permits. The regional offices can then develop and issue permits to discharge for each industry category based on the applicable guidelines. Originally all permits were developed and issued by an EPA Region. Now individual states can apply to the EPA for the right (called primacy) to issue permits to discharge. These permits are based on EPA guidelines and are subject to the approval of the applicable EPA Regional Office. In the case of the offshore oil and gas industry, discharges were deemed to be similar for all operators in a given EPA region and a system of general permits was developed. For each regional subcategory one permit is issued and all oil and gas operators in that area can apply to be covered by that permit.

Environmental concerns for oil industry discharges to United States waters are similar to those in the OSPAR countries. In both produced water discharges and drilling discharges toxic impacts, oil and oxygen depletion are the major issues. Where discharge of produced water is allowed the discharges have a toxicity limit and a limit on oil in produced water. Drilling waste discharges depend on the type of mud used. For water based muds, cuttings and excess mud can be discharged if a toxicity limit is met and the discharge does not produce a sheen on the water. For non-water based muds, discharges are forbidden for all mud bases except synthetic oils. The characteristics of these synthetic oils are specified in EPA guidelines. These discharges are limited to an average of 6% oil on the cuttings over the discharge portion for the well being drilled. One additional limit on drilling discharges is that the barite used for weighting the mud must meet limits on the trace amounts of cadmium and mercury.

In addition to the major waste streams several minor discharge streams are also limited. These include treated cooling water, deck drainage from platforms, pipeline pressure test water, sewage from platforms and others. Each general permit for a regulated subcategory in a specific EPA region lists the waste streams discharged and the limits placed on them.

4.4 Comparing and contrasting OSPAR and United States EPA regulations

OSPAR tends to control what goes into the exploration and production processes. The chemicals used are limited by the amount or concentration allowed. All treating chemicals and additives are placed in one of a number of specific classes. Each class is assigned a maximum amount to be used. Chemicals in the most toxic class may not be used at all. The theory behind this approach is that controlling chemicals that might have an adverse impact will control the potential impact. In contrast, the philosophy of the United States EPA is that how oil and gas operators conduct their business is for them to determine. However, the operator's actions must not impact the environment. Control is exerted through so-called end of pipe limits. In this approach control is accomplished by measuring the composition or toxicity of the discharge not specific additives used in operations. The major exception in United States EPA regulations is the ban on oil in drill cuttings discharged. A minor exception is the limits on cadmium and mercury in barite.

OSPAR regulations do set limits on oil discharged, but the emphasis is on controlling the total amount going into a particular water body not the concentration of individual discharges. In addition to the overall controls, there are also limits on individual discharges. The United States EPA limits oil in produced water as an indicator of toxic pollutants, not for the potential harm caused by the oil itself. This is in contrast to the OSPAR regulations, which assume that the oil itself might harm the environment. This ignores the fact that along the edge of the continental shelf all over the world natural seeps leak tonnes of oil into the marine environment every day.

4.5 Russian and former Soviet Republics regulations

In Russia and many of the former Soviet Republic States, there is a general prohibition on the discharge of effluents into the marine environment. Then, on a case-by-case basis, approval is obtained to discharge certain materials. The process involves testing the chemicals that will be used in the process to determine their toxicity and potential impact. Those chemicals that pass are given specific limits to control the impact of the discharge. Then discharge of the materials is allowed if a compensation payment is made. The monies are not in reality payment for damage but rather a usage fee.

4.6 Other regulatory systems

Countries outside Europe and the United States tend to base their regulatory systems on features from both the OSPAR system and the United States EPA system. For example, the Arabian Gulf countries have developed a regional organization similar to OSPAR but have included some United States features. The body is called the Regional Organization for the Protection of the Marine Environment (ROPME), and is comprised of Bahrain, Iran, Iraq, Kuwait, Oman, Qatar, Saudi Arabia, and United Arab Emirates. In addition almost all countries where the offshore oil industry is active have national regulations. There have been a number of attempts to summarize the regulatory limits for all the countries of the World (Jones et al., 2000) but in a rapidly changing world these efforts can only be considered to provide preliminary guidance and specific, current information would be needed to get an accurate understanding of discharge limits for a particular country.

4.7 Accidental discharges

Accidental discharges differ from waste discharges in several ways. Waste discharges are necessary and intentional. They are expected and always occur at a specific site. The impact on the receiving environment has been considered and is controlled by the conditions of the discharge permit. Accidental discharges are unplanned; occur randomly at unexpected locations; and discharge volumes are sometimes large in comparison to waste discharges. For waste discharges the regulatory emphasis is on controlling the discharge composition and rate. In addition, equipment should always be in place to maintain the permitted conditions for discharge.

The goal of waste discharge regulations is to control the treatment of waste, the rate of discharge and the potential impact on the environment. In contrast, the aims of accidental discharge regulations are:

- Prevention of releases
- Recovery of the discharge where possible
- Remediation of any damage that occurs
- Determining compensation for damages caused by the discharge

4.7.1 Summary of accidental discharge regulatory history

Much of the regulatory emphasis has been on reducing and responding to accidental releases from transportation-related incidents. As production of oil and gas has expanded throughout much of the world, a concerted effort to address how to respond to accidental releases has been made. The initial steps in this direction tended to come as a direct response to a specific incident.

The first such incident to attract massive public attention was the grounding of the Torrey Canyon off the southwest coast of England in April 1967, which resulted in pollution of the English and French beaches. As a result of the Torrey Canyon, a number of individual governments began to urgently study the situation and look for remedies. However, they quickly realized that oil spills do not recognize or respect international boundaries and, as such, unilateral action would be of very little use. It was clear that there was a need to handle these issues internationally, and so the governments went to what was then called the Intergovernmental Maritime Consultative Organization (IMCO) – a specialized organization of the United Nations – and asked for help. IMCO has since changed its name to the International Maritime Organization (IMO) but it continues to this day to take the lead in this area.

In the meantime during the late 1960s, while IMCO began its work, the tanker and oil industries decided to move ahead with their own plans to address the problem of accidental releases. The objective of the work was to develop a scheme that would ensure that governments and people adversely impacted by oil spills anywhere in the world would be promptly and fairly compensated for any damage that they had suffered. Industry also endeavored to come up with a scheme that would help ensure that cargo and tanker owners would take immediate steps to prevent or mitigate any environmental damage.

In order to meet their objectives, the tanker and oil industries entered into two voluntary agreements:

- The Tanker Owners Voluntary Agreement Concerning Liability for Oil Pollution (TOVALOP)
- The Contract Regarding an Interim Supplement to Tanker Liability for Oil Pollution (CRISTAL)

Both these agreements terminated on February 20, 1997 when they were superseded by international spill compensation conventions.

In November 1969, IMCO convened the International Legal Conference on Marine Pollution in Brussels. The majority of the Governments attending signed the Civil Liability for Oil Pollution Damage Convention (CLC), which closely matched TOVALOP. On November 29, 1969, the CLC was adopted to ensure that anyone who suffered damage as a result of a spill from an oil carrying vessel would be compensated.

In December 1971, the Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage (FUND) was signed. The Fund Convention is in addition to CLC and was adopted with the purpose of providing additional compensation to those who could not obtain full and adequate compensation for oil pollution damage under the CLC. The Fund Convention set up the International Oil Pollution Compensation Fund (IOPC Fund) an intergovernmental organization, to administer the Fund. Companies who receive crude oil and heavy fuel oil in member states, after transport by sea finance the Fund. The Fund Convention came into force in October 1978, at which time the IOPC Fund was established.

The CLC entered into force on June 19, 1975. Under the convention the liability for the damage rests solely with the owner of the ship. There are a number of exceptions to this strict liability (for example an accident as a result of an act of war). It is the responsibility of the ship owner to prove that one of the exceptions applies. The owner can, however, limit liability per incident to 133 Special Drawing Rights (SDR) (which is currently around $18 million) unless the owner has been guilty of actual fault.

The CLC applies to all seagoing vessels that carry a cargo of oil. The owner of any vessels covered by the CLC must also maintain insurance or some other financial security in an amount equal to the total liability for a release, although only ships that carry a cargo of over 2000 tonnes of oil are required to carry oil pollution insurance. The CLC does not apply to warships. However, vessels in commercial service that are owned by a participating State are covered by the CLC. The State owned vessels are not required to carry pollution insurance but must instead carry a certificate from the appropriate authority of the State in which the vessel is registered certifying that the ship's liability under the CLC is covered. The CLC covers pollution damage that results from a spill of oil in the territory, including the territorial seas of a State that is a Party to the Convention. It applies only to vessels that are carrying bulk oil as a cargo (for example, laden tankers). It does not cover spills of ballast or oil that is used as fuel by the ship. Nor, ironically, is it possible to recover any costs for the response to the incident if the actions result in no actual release of oil.

There have been a number of protocols adopted over the years in an ongoing effort to improve the Convention and help make it more manageable. The 1976 Protocol came into force on April 8, 1981. The original CLC had used the "Poincaré franc" which was based on the "official" value of gold as the unit in the compensation fund. It was very difficult to convert the gold franc into national currencies and so an alternative unit was found. The alternative was based on the Special Drawing Rights (SDR) as used by the International

Monetary Fund (IMF). However, in cases where a member State was not a member of the IMF and it was against the law of the country to use SDR, a mechanism was put in place to use an alternative monetary unit based on the value of gold. The daily conversion rates for the SDR can be found on the IMF web site (http://www.imf.org).

The 1984 Protocol was adopted on May 25, 1984 and was to enter into force 12 months after being accepted by 10 States, including six with tanker fleets of at least 1 million gross tonnes. The Protocol was developed to address the fact that by the mid-1980s it was generally accepted that with the prevalence of the super tankers, the limits of liability in the original CLC were not high enough to adequately respond to a large incident. However, it never came into force and was eventually superseded by the 1992 Protocol. This was largely because the United States did not want to accept the Protocol. The USA preferred a system that did not limit liability, much more like the Oil Pollution Act of 1990 (OPA) that was passed by the USA largely in response to the Exxon Valdez spill. Therefore, the 1992 Protocol was written in such a way that the ratification of the USA was not needed in order for the Protocol to be ratified.

The Protocol of 1992 was adopted on November 27, 1992 and entered into force on May 30, 1996. The Protocol changed the entry into force requirements so that only 4 States with tanker fleets of at least 1 million gross tonnes were needed to ratify the Protocol. The compensation limits were the same as those adopted in the 1984 Protocol. In addition to raising the compensation limits from the CLC, the 1992 Protocol included exclusive economic zones (EEZs) of a State in coverage by the CLC. It also included spills from seagoing vessels that were built or adapted to carry bulk oil cargo and so included spills of bunker oils from such ships. The 1992 Protocol added that a ship owner cannot limit liability if it is shown that the owner's act or omission caused the spill. An added quirk is that Parties to the 1992 Protocol on May 16, 1998 ceased to be Parties to the 1969 CLC as a result of a provision in the 1992 Protocol that resulted in the compulsory denunciation of the "old" regime. The two regimes are currently co-existing, because there are a number of States that are Party to the 1969 CLC, but have not yet ratified the 1992 Protocol as it establishes higher levels of liability. The 1992 Protocol permits States that are Party to the 1992 Protocol to issue certificates to ships that are registered in States that are not Party to the 1992 Protocol. This allows an owner to obtain certificates to both 1969 and 1992 CLC even if the vessel is registered in a State that is not Party to the 1992 Protocol. This is important because a vessel registered in a 1969 CLC State, may not be able to do business in a country that is a Party to the 1992 Protocol without the appropriate 1992 Protocol certificate, as higher limits of liability are established in the 1992 Protocol.

The 2000 Amendments were adopted on October 18, 2000 and entered into force, by tacit acceptance, on November 1, 2003. The amendments raised the compensation limits by 50% over those established in the 1992 Protocol. The liability limit for a ship of less than 5,000 gross tonnage is 4.51 million SDRs, or approximately $5.78 million at the exchange rates in 2005. For a ship of 5,000–140,000 gross tonnage the liability limit is 4.51 million SDRs plus 420 SDRs ($537.6) for each additional gross tonne. For vessels over 140,000 gross tonnage the limit is 89.77 million SDRs ($76.5 million).

Finally, the 2003 Protocol establishing an International Oil Pollution Compensation Supplementary Fund entered into force on March 3, 2005. The purpose of the supplementary fund is to supplement the compensation available under the 1992 CLC and Fund Convention with an additional third tier of compensation. Participation in the fund is optional, but is open to all States that are Party to the 1992 Fund Convention. The total amount of compensation that is payable for an incident will be limited to 750 million SDRs (just over $1,152 million at 2005 exchange rates). The purpose of the supplementary fund is to ensure that victims of oil pollution damage will be fully compensated. It is expected that increasing the liability limit will end the practice of pro-rating payment of claims that exceeded the old limit. This practice, although unavoidable, has led to criticism of the 1992 Fund.

An International Convention on Civil Liability for Bunker Oil Pollution Damage, 2001, was adopted on March 23, 2001. The Convention was adopted to ensure that adequate, prompt and effective compensation is available to those affected by a release of oil that was carried as fuel in the ship's bunkers. As of April 30, 2005, the Convention had not yet entered into force. It will enter into force 12 months following the date on which 18 States, including 5 States each with ships whose combined gross tonnage is not less than 1 million gross tonnage have either signed it without reservation as to ratification, acceptance or approval, or have deposited instruments of ratification, acceptance, approval or accession with the IMO Secretary-General. So far there are seven Contracting States.

4.7.2 International Conventions on prevention of pollution

In addition to developing International Conventions that address liability and compensation issues associated with accidental discharges, there are also a number of International Conventions that address pollution prevention. The first international convention on the prevention of oil pollution at sea, the International Convention for the Prevention of Pollution of the Sea by Oil (OILPOL 1954) was signed in 1954. It specifically controlled oily water discharges from general shipping and oil tanker transportation operations. OILPOL has now been largely superseded by "MARPOL 73/78", the International Convention for the Prevention of Pollution from Ships 1973, as Modified by the Protocol of 1978. MARPOL 73/78 defines a ship to include "floating craft and fixed or floating platforms" and as such oil production platforms are covered by the Convention. This means, for example, that drainage discharges must not exceed 15 ppm, and so, in the UK, offshore installations are required to maintain an oil record book of all such discharges. Over the years MARPOL has been expanded and now addresses such issues as the phasing out of single hull tankers. For example, the December 2003 amendments to MARPOL 73/78 revising regulation 13G of Annex I of MARPOL, bring forward to April 5, 2005 from 2007 the final phasing out of Category 1 single hull tankers for ships delivered on April 5, 1982 or earlier and Category 2 ships delivered on, or before, April 5, 1977. The amendments also banned the carriage of heavy grade oil in single hull tankers after April 5, 2005. The October 2004 amendments to MARPOL will come into force on January 1, 2007. They include additional construction and equipment provisions designed to help prevent accidental discharges. The amendments also establish the Oman Sea as a special area. Existing special areas under Annex I of MARPOL are the Baltic Sea, Black Sea, Red Sea, "Gulfs" Area, Gulf of Aden, Antarctic and North West European Waters. There are stricter controls in the special areas.

The latest convention concerning oil pollution at sea is the International Convention on Oil Pollution Preparedness, Response and Cooperation 1990 (OPRC). It was adopted in November 1990, and entered into force on May 13, 1995. The objective of OPRC is to improve the level of preparation and preparedness to respond to an oil pollution incident, and to increase and promote international cooperation. OPRC seeks to build on the regional agreements (such as the Bonn Agreement for the North Sea area) to establish an interlocking series of plans that will ensure that all affected countries can adequately respond to any oil pollution incident in a coordinated, effective and rapid manner.

The impetus for the development of the OPRC was the much publicized Exxon Valdez spill in Prince William Sound, Alaska. The incident pointed out that to some extent governments and industry, having developed spill prevention and response plans, had become complacent, and some of the plans had become merely paperwork exercises to meet a regulatory requirement, rather than working documents. The Oil Pollution Act of 1990 (OPA 90) was passed in the United States largely in response to the same incident.

4.7.3 Government and industry initiatives to help prevent accidental releases

The previous section addressed the conventions and agreements that govern the response to an accidental release. This section will discuss some of the initiatives that have been taken to prevent accidental releases, and to minimize the impact of any releases that might still occur. Obviously, as stated elsewhere, the best method of avoiding environmental damage from an accidental release of oil is to prevent the release from ever occurring. To this end, industry groups and governments have developed voluntary and regulatory requirements to ensure that plans are in place with the objective of prevention, control and cleanup of any release. The plans range from individual facility prevention and response plans to regional intergovernmental and industry plans, as oil spills do not recognize or respect international boundaries.

To be effective, spill prevention planning needs to be done on a site-specific, local and regional basis. This is because successful planning has to start with prevention at the source, but then must address the potential regional impact of a spill, and how best to respond quickly and decisively to minimize any potential negative impact.

The first generation of facility spill plans was fairly rudimentary. They covered a description of the facilities involved, discussed the possible type and size of releases that could occur, identified appropriate control measures that would be employed to prevent a release, addressed what to do in the event of a release, and listed both the internal and external notifications that must be made in the event of a reportable spill, as well as some of the contractors who could help in a cleanup. A good example of such a plan is the Spill Prevention, Control and Countermeasure (SPCC) Plan that is required in the US under the Clean Water Act. The regulations also require that all personnel be adequately trained to respond appropriately in the event of a release.

Although the SPCC type of plans were an excellent start to good spill prevention planning, over the years they have had the tendency to become merely paperwork exercises. This was graphically illustrated with the Exxon Valdez spill in Prince William Sound, Alaska. The contingency planning that had been done, when tested, did not perform as had been anticipated. Consequently the new breed of spill planning requires not only extensive reviews of the potential impact of any release, but also requires detailed planning that ensures that responders will know exactly how to respond to all types of releases. Equipment has to be either on-site, or available on-site within specified time limits. In order to do this, operators have to enter into binding contracts with equipment providers who will guarantee a certain level of response within a specific time. The equipment has to be regularly inspected for operability, and the equipment has to be actually used in drills or actual responses on a specified schedule. Company and agency personnel who would be responsible for responding to a release have to receive regularly scheduled training that must include classroom and field segments. A good example of this type of plan is the Facility Response Plan required under the Oil Pollution Act of 1990 (OPA 90) in the United States.

On a regional basis, industry groups and governments have recognized the need for a cooperative effort to pool resources so that spill response can be as quick and effective as possible. The initial thrust came from industry that formed regional equipment cooperatives, which allowed each company to have access to a stockpile of equipment usually stored at strategic locations. Examples of these cooperatives include the United Kingdom Offshore Operators Association (UKOOA) equipment stockpiles and those of Clean Gulf and Clean Seas in the United States. On a worldwide basis, groups, such as the Marine Spill Response Corporation (MSRC), stockpile equipment at strategic locations throughout the world.

Again, in response to a series of usually tanker spills, although there were also a few exploration and production releases (Ixtoc blowout, Ekofisk and the Santa Barbara release), individual governments began to set up their own response groups. Each country has established a program that meets its individual needs, and as such they vary from country to country.

As the programs are developed to meet specific needs, there is a wide variation in the nature and type of system that is established and how it operates. However, their objective is to be as prepared as possible to respond to any oil pollution incident.

For example, in the United Kingdom, the Coastguard Agency's Marine Pollution Control Unit (MPCU) was formed in 1967 following the Torrey Canyon incident, to provide a command and control structure for decision making and response following a shipping incident that causes, or threatens to cause, pollution in UK waters. This replaced the previous non-dedicated central government organization for dealing with oil and chemical pollution at sea, with a small dedicated unit. This change came about as a result of the work done by the United Kingdom Royal Commission on Environmental Pollution which, amongst other things, stated that they considered it essential that the response to a major spill should be a single coordinated operation overseeing the response at sea, inshore and on the land, hence the MPCU. MPCU was then restructured during the merger between Marine Safety Agency and The Coastguard Agency in 1998 to become the Counter Pollution and Response (CPR) Branch of the MCA. MCA's CPR is now based on a regional response with central operational, technical and scientific support. A Counter Pollution & Salvage Officer (CPSO) is based in each region, supported by scientists, a mariner, a cost recovery specialist and logistics support specialists in the MCA's headquarters in Southampton.

The "National Contingency Plan for Marine Pollution from Shipping and Offshore Installations" (NCP), was published in 2000, but has since been under review. The 2000 Plan sets out revised command and control procedures for incident response following Lord Donaldson's Review of Salvage and Intervention and their Command and Control. These procedures have built-in thresholds to allow for flexibility of response to different degrees of incident.

The UK has studied carefully the short- and long-term impacts an accidental release could have on the environment and leisure activities, and established its resources within financial limits set by the level of impact anticipated. Generally, the UK endeavors to achieve maximum response through the pooling of resources, for example having government owned, strategically located stockpiles of equipment, coordinating the government owned stockpiles with the industry cooperative stockpiles, and the Bonn signatory government ones.

The MCA's CPR manages a series of framework agreements with technical experts to assist the MCA during incidents. Computer programs are used to model the fate and trajectory of both oil and hazardous substance spills. This information assists MCA decision making, to determine the appropriate response level for all types of threat to the UK interests

In addition to the MCA, there are a number of other organizations in the UK that have a responsibility to respond to accidental releases. For example, offshore oil and gas facilities have the statutory responsibility to be able to respond to and clean up any release associate with their activities. Local authorities, or the Environment and Heritage Service (in Northern Ireland) have the non-statutory responsibility for shoreline cleanup.

The MCA runs and participates in many spill drills and also runs a series of training courses for local authorities to prepare their personnel to respond to shoreline pollution. CPR also runs courses in Oil Spill Response, aimed at local authority Beachmasters, which are hosted by local authorities. Both courses are accredited by the Nautical Institute. In addition, MCA runs Decision Making in Oil Spill Response Courses to prepare the statutory nature conservation agencies, the environmental regulators and the Government fisheries departments for their role in the Environment Group set up in response to a maritime incident. Counter Pollution & Response works closely with international colleagues. This includes the Anglo French Accident Technical Group (AFATG), the recently formed European Marine Safety Agency (EMSA) and the Bonn Agreement, which it currently chairs.

In contrast to the UK, which is a well established program that has developed over many years, China has taken a different approach, which more closely meets its specific needs. Unlike the UK, China is a vast country, which did not open up to oil exploration and production until the 1990s. The initial program was based on requiring the operator to do the spill contingency planning and to maintain any equipment necessary to provide an initial response until the international spill response community could get equipment and expertise into the area, if needed. The China National Offshore Oil Company (CNOC) was charged with reviewing the contingency planning and equipment to ensure that it is adequate. Subsequently, the Chinese Government instituted the State "Emergency Plan for Oil Pollution Management on the High Seas" and formed an emergency response team for pollution in port areas. It has also begun formulating an emergency response plan for spills from ships. China is now acting in cooperation with adjacent countries to mitigate the impact of accidental spills. As part of this process the government established the Maritime Safety Agency as the responsible authority for oil spill contingency planning and spill response.

The law requires that an environmental impact statement must be completed, submitted and approved by the National Environmental Protection Agency prior to a company being able to begin exploration and production activities. The information collected in the environmental impact statement is used in the contingency planning phase. The contingency plan must include at a minimum the following elements: a general description of the project; the environmental conditions of the area, including the oceanography, meteorology, and the sensitive environmental zones; risk analysis; response organization and responsibilities; oil spill response procedures; and how spilled oil will be handled (in particular taking into account that most of the offshore discoveries have been of high density, high pour point, waxy crudes, which means that standard skimmers and dispersants might not be effective).

The Ivory Coast, West Africa, has developed a coordinated approach to responding to oil spills. In the early 1990s, the government teamed with the Danish International Development Agency (DANDIA) who sponsored a study to determine the current situation and to propose and implement any needed changes, and to purchase any necessary equipment. The Centre Ivoirien Antipollution (CIAPOL) under the Ministry of Environment is the organization that deals with marine pollution problems. CIAPOL has three divisions: an administrative division; a division that deals with combating oil and chemical spills at sea, known as the Centre Ivoirien de lutte contre les Pollution Marines et Lagunaires (CIPOMAR); and the Central Laboratory for the Environment (LCE) which carries out most types of water analyses, including analyses for total and individual hydrocarbons.

The national oil spill plan, Plan Pollumar, was originally developed in the early 1980s, and has now been completely revised. The government has decided that CIAPOL will act as the national responsible authority, and so is responsible for all matters related to marine oil and chemical spill contingency planning in the Ivory Coast. The day-to-day running of the program, and the implementation of Plan Pollumar have been delegated to the CIPOMAR division. CIPOMAR has been organized into three sections, namely Operations, Maintenance and Administration. The Operation Section has set up a national communications center, which receives the reports of spills in the Ivory Coast response area, as well as pollution reports from neighboring countries within the West and Central Africa region. The duty officer at the communications center evaluates the report, and decides on the appropriate response, including, for example, enacting Plan Pollumar. The Maintenance Section is responsible for maintaining the spill response equipment. The Administrative Section is responsible for the financial, accounting and personnel functions. In the event that Plan Pollumar is enacted, the Administrative Section is responsible for creating all the documentation that will be used for the claim and compensation procedures. Employees from all three sections have been trained to perform the functions of the Incident Commander and On-Scene Coordinators.

However, a country organizes its Spill Contingency Planning, all countries have recognized the importance of conducting regular drills. In some cases the drills are self contained within the country. In other cases combined drills are held with neighboring States.

5 Should the release be re-mediated?

Since the first oil spill and resultant cleanup, the question has been raised as to how clean is clean? Over the years considerable effort and resources have been expended to determine not only the impact of spilled crude oil on the environment, but also the impact of the cleanup. In the early days the cure was often worse than the original incident. For example, as previously mentioned, the dispersants used on the Torrey Canyon Spill were several orders of magnitude more toxic than the oil that they were trying to disperse. Eventually the recommendations arising from the results of the scientific studies began to be implemented by both individual companies and by the agencies responsible for a Country's response planning. It began to be an accepted credo that the net impact on the environment should be an important factor in deciding on the appropriate response to an accidental release.

However, it is important to remember that the political reality will not always allow the responders to a spill to base their decisions solely on what is best for the environment. For example, natural biodegradation, and bioremediation of a beach may be the best ecological solution, however, the company responsible for the spill, and cleanup, and the agency overseeing the response may have to attempt to clean the area in order to be seen as responsive.

In spite of political pressures, it is important to try and always make the minimum net environmental impact the objective of a response plan. Exactly how to do this will depend on the nature of the crude oil spilled, the location of the oil, and the systems that are, or may be, impacted. For example, it is now generally accepted that crude oil spilled in a salt marsh is best left to degrade naturally, as any attempt to mechanically remove the oil will result in a much greater negative impact on the biosystem.

Another critical component of the "how clean is clean" debate is the importance of the stakeholders coming to an agreement on the appropriate end point, beyond which the cost of remediation far exceeds the net benefit to the environment.

6 Sources of data on discharges to the marine environment

Much of the information on oil industry discharges to the sea is not reported in scientific studies but in industry technical documents or legal documents. At the present time the best sources of such information on discharges to the sea from oil industry operations are the web sites of the various regulatory and industry bodies. These organizations include:

- Regulatory bodies
- Industry associations
- Technical societies
- Industry support groups and suppliers
- Environmental activist organizations

Some of the important regulatory bodies are:

- The Oslo Paris Commission (OSPAR)
- The United States Environmental Protection Agency (USEPA)
- The United Kingdom Department of Trade and Industry (DTI)
- The Regional Organization for the Protection of the Marine Environment – Kuwait (ROPME)
- International Maritime Organization (IMO)

Some of the important industry associations are:

- The International Association of Oil and Gas Producers (Formerly the E&P Forum) (OGP)
- The American Petroleum Institute (API)
- The United Kingdom Offshore Operators Association (UKOOA)
- The Society of Petroleum Engineers International (SPEI)

Some important industry support groups and suppliers associations are:

- European Oilfield Specialty Chemicals Association, (EOSCA)
- International Association of Drilling Contractors, (IADC)

Some important environmental groups are:

- Friends of the Earth
- The Natural Resources Defense Council (NRDC)

These organizations can be accessed on the Internet by entering their names or acronyms into a search engine. Much of the information in this chapter was verified using these web sites.

References

Continental Shelf Associates (1997) Metals and Organic Chemicals Technical Report prepared for the Gulf of Mexico Offshore Operators Committee as a part of the Gulf of Mexico Bioaccumulation Study.

Davies, J.M., Bedborough, D.R., Blackman, R.A.A., Addy, J.M., Appelbee, Grogan, W.C., Parker, J.G. and Whitehead, A. (1988) Environmental Effect of Oil Based Mud Drilling in the North Sea. Proceedings, 1988 International Conference on Drilling Wastes, Calgary, Canada, April 5–8, 1988.

E&P Forum (1994) North Sea Produced Water: Fate and Effects in the Marine Environment. E&P Forum Report No. 2.62/204. May 1994.

EPA (1993) Development Document For Effluent Limitation Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, Final. EPA 821-R-93-003, U.S. Environmental Protection Agency, Washington, D.C., January 1993.

Freeman, B.D. and Wakin, P.G. (1988) API Survey Results on 1985 Onshore Wastes Volumes and Disposal Practices within The U.S. Petroleum Extraction Industry, in *Drilling Wastes* (ed. Engelhardt), Elsevier Applied Science.

Jones, F.V. et al. (2002) Discharge Practices and Standards for Offshore Operations Around the World, Proceedings, The Seventh International Petroleum Environmental Conference, Albuquerque, New Mexico.

op ten Noort, F.J., Marquenie, J.M., Cofino, W.P., van Hattum, B (1994) Environmental Aspects of Produced Water From Offshore platforms on the Dutch Continental Shelf. Proceedings, The Second International Conference on Health, Safety and Environment in Oil and Gas Exploration and production, Jakarta, Indonesia, 1994, 391–398 (vol 1).

Ray, J.P. (1979) Offshore Discharges of Drilling Cuttings, Proceedings, Outer Continental Shelf Frontier Technology, National Academy of Sciences, December 6, 1979 (Offshore Rulemaking Record Volume 18).

Chapter 7
Decommissioning of Offshore Oil and Gas Installations

M.D. Day

1 Introduction

The offshore oil and gas industry had its beginnings in the Gulf of Mexico in 1947. The first offshore development used a multipiled steel jacket to support the topside production facilities, a design which has since been used extensively. Now there are more than 7000 drilling and production platforms located on the Continental Shelves of 53 countries [1]. Some of these structures have been installed in areas of deep water and treacherous climates, and consequently structure designs have adapted to withstand the environmental conditions of these areas. Some typical designs are shown in Figures 7.1 through 7.5. In the North Sea, which is an area that experiences some extreme environmental conditions, more than 200 structures have been installed, about 25% of which are in water depths greater than 75 m and can be exposed to maximum storm wave heights of 30 m. This combination of deep waters and extreme storm forces dictates large structures, some with component weights that exceed 50,000 tonnes [6]. One of the world's largest gravity base structures (GBS) was installed off the coast of Canada. It was designed to withstand impacts by icebergs and weighs approximately 1.5 million tonnes including ballast [7]. Now, as oil and gas fields begin to deplete their reserves, the concern has turned to the removal and disposal of these structures at the end of their producing lives. Estimates indicate that the cost of some removals may exceed the cost of the original installation. The structures located on the Norwegian Continental Shelf contain only 1% of the world's offshore structures, but will account for nearly 20% of the worldwide removal costs [4]. Innovative removal and disposal techniques must be developed to limit costs and minimize the impact on the environment.

The Gulf of Mexico, the western and central coasts of Africa, the Persian Gulf, the bulk of the Pacific region and the Mediterranean Sea are all

---

Devon Energy Corporation, 1200 Smith Street, Houston, TX 77002

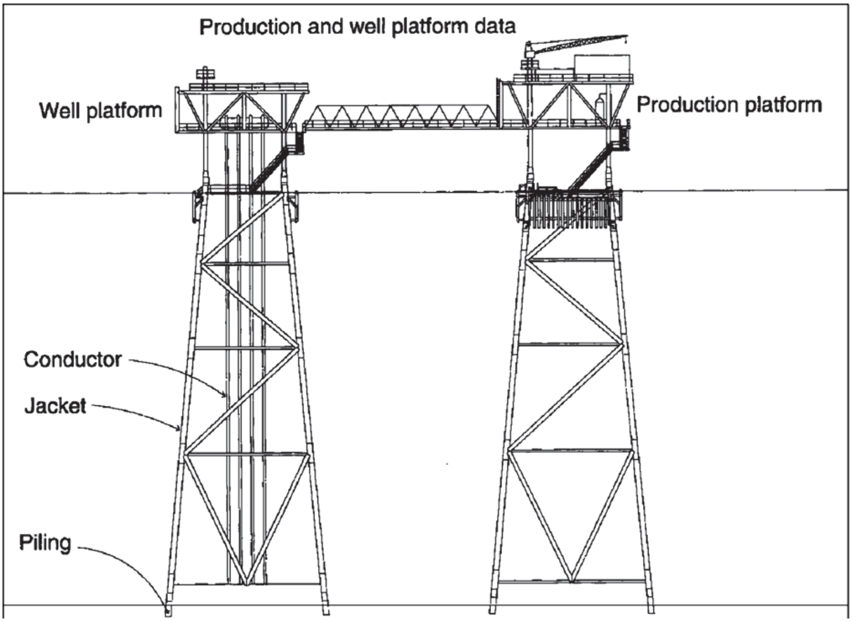


FIGURE 7.1. Steel-jacketed structure [2].

examples of areas with more moderate environments. The majority of structures in these areas are in water depths from 3 to 300 m with maximum storm wave heights of 12 m. With a few exceptions, platforms in these areas will probably be totally removed at the end of their producing lives. The major implication with total removal is in choosing the method to dislodge the structure from the sea-bed and an issue in remote areas of the world is the availability of support equipment to perform the removals.

2 Legal framework of platform decommissioning

International law provides the basic foundation of the legal requirements for the removal and disposal of offshore structures. The removal of installations was addressed by the 1958 Geneva Convention on the Continental Shelf, which stated that any installations which are abandoned or disused must be entirely removed. However, several parties to the Convention were soon adopting some form of local standards to allow for partial or non-removal. The more widely accepted statement of international law is contained in the United Nations Convention on the Law of the Sea (UNCLOS), which allows for partial removal and has been widely accepted as it appears to represent customary international law in relation to abandonment [8]. The International Maritime Organization (IMO) guidelines were issued using UNCLOS as

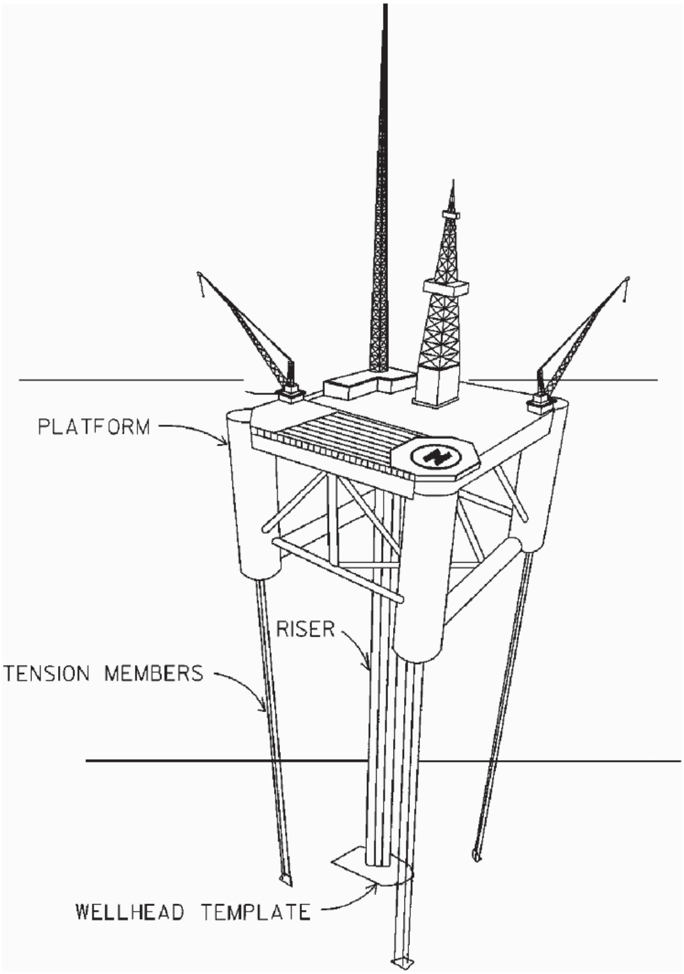


FIGURE 7.2. Tension leg platform [3].

a basis. These guidelines state that if the structure exists in less than 75 m of water and weighs less than 4000 tonnes, it must be totally removed [8]. Structures installed after January 1988 will have a water depth criterion of 100 m, forcing the owner to plan for the eventual abandonment in the initial design. If the removal is done partially, the installation must maintain a 55 m clear water column. There are exceptions in the guideline that allow for non-removal, e.g. if the structure can serve a new use after hydrocarbon production including enhancement of a living resource, if the structure can be left without causing undue interference with other uses of the sea or where removal is technically not feasible or an unacceptable risk to the environment or personnel [8]. If the installation is to remain in place, it must be adequately maintained to prevent structural failure.

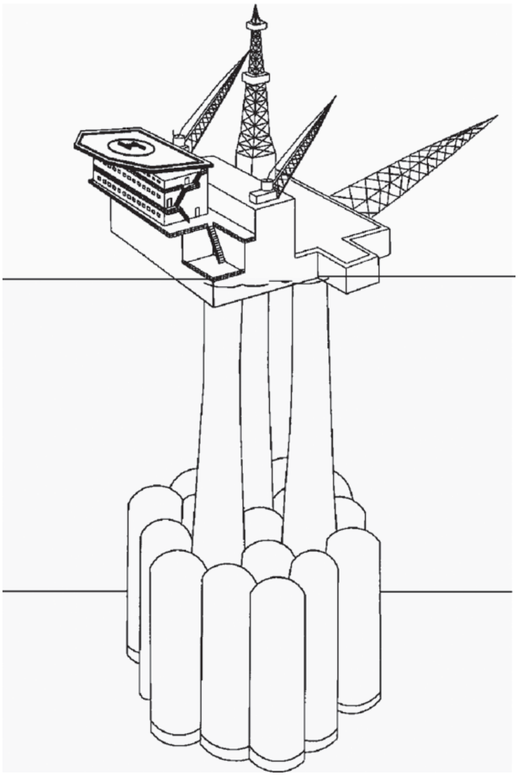


FIGURE 7.3. Concrete gravity base structure [3].

Basic disposal stipulations can be traced to international dumping conventions. The Oslo Convention of 1972 for the Prevention of Marine Pollution by Dumping from Ships and Aircraft provides some guidelines.

However, it is not clear if this Convention applies to dumping of platforms in place. The London Convention of 1972 on the Prevention of Marine Pollution by Dumping of Wastes and other Matter also supplies guidelines for deliberate disposal of platforms or other artificial structures at sea. UNCLOS deals with dumping, and states that 'dumping within the territorial sea and the exclusive zone or onto their continental shelf will not be carried out without the express prior approval of the coastal state ...' [8].

The Convention for the Protection of the Marine Environment of the North East Atlantic (Paris, 1992) is relevant. It provides that 'no disused structures ... be dumped and no disused offshore installation shall be left wholly or partly in place in the Maritime area without a permit issued by the appropriate competent authority of the contracting party on a case-by-case basis', and that 'dumping does not include the leaving wholly or partly in place of a disused installation ... provided that such operation takes place in accordance with any relevant Convention and with relevant international law' [8].

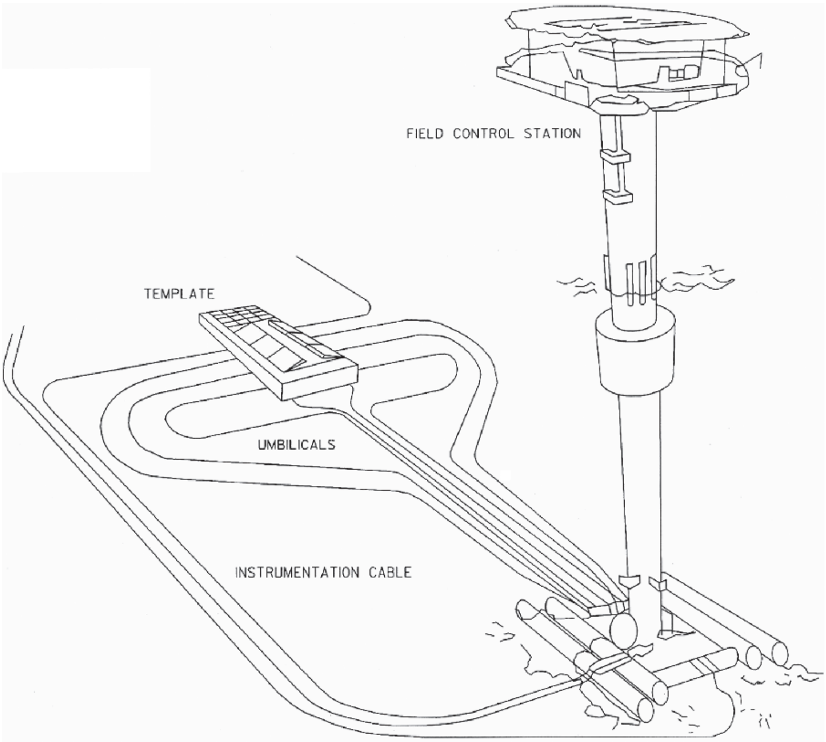


FIGURE 7.4. Floating production system [4].

The body established by the 1991 Oslo Convention, the Oslo Commission, adopted guidelines on a trial basis to exercise overall supervision over the implementation of the Convention. These guidelines are complementary to the IMO guidelines and aim to minimize pollution to the sea by hazardous residues left in parts of installations disposed of at sea [8].

While all of the above are basic guidelines to removal and disposal, they do not account for all of the issues involved with the abandonment or disposal of offshore structures. Thus, local states are left to decipher the issues, and to generate legislation to cover loopholes in international law in accordance with their priorities. By 1992, 15 United Nations Environment Programme (UNEP) regional conventions had been held (Figure 7.6). Here, local states have adopted varying degrees of guidelines for potential legal concerns such as determination of the party responsible for removal, responsibility and methods of payment, responsibility of owners in default situations, owner designation upon non-use, maintenance responsibility and liability for items left in place and such site-specific issues as bottom debris removal and moratoriums for marine migrations.

The complexity of issues has stymied most countries from adopting specific guidelines and standards for platform removal, but most do require

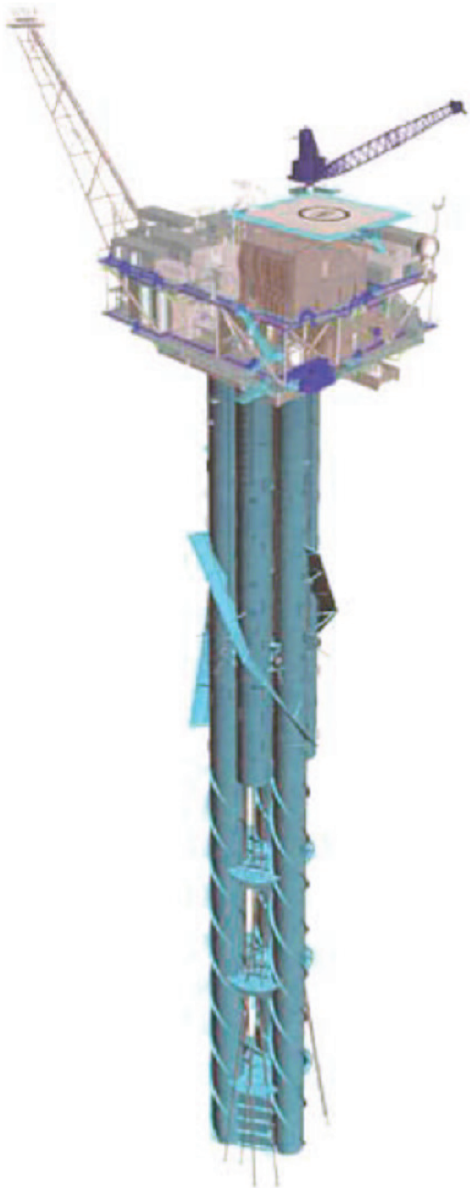


FIGURE 7.5. Cell Spar (*See Color Plates*).

abandonment procedures to be submitted to designated regulatory agencies for approval on a case-by-case basis. Some countries, depending on their experience with removals, are fairly mature in their regulatory standards for abandonment, whereas others still have great strides to make in enacting requirements for removals within their coastal waters.

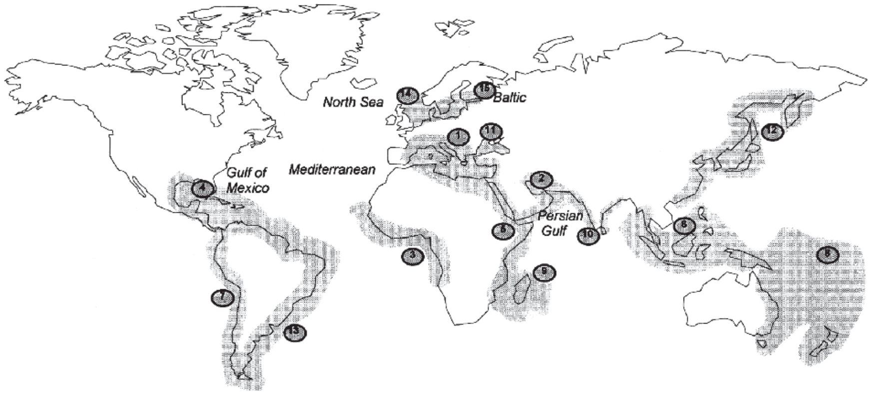


FIGURE 7.6. UNEP regional seas program and other conventions.

3 Planning

The most critical and time-consuming task of the abandonment process is the planning phase. This phase should be initiated years in advance when depletion plans for a field are recommended. The planning phase can be effectively organized with the aid of commercially available computer software. A software package which allows for input of schedules, tasks, resources and contingencies is recommended. This will be beneficial in establishing the critical path of the project and will help keep the project on schedule for the available construction weather window. A project management software package will enable the project engineer to maintain accurate cost accounting and to keep the project organized, on schedule and within budget.

4 Abandonment phases

The entire abandonment process can be broken down into seven discrete activities [9]:

1. *Well abandonment*: the permanent plugging and abandonment of nonproductive well bores.
2. *Preabandonment surveys/data gathering*: information-gathering phase to gain knowledge about the existing platform and its condition. Governing ministries or standards organizations should be contacted to determine permit and environmental requirements.
3. *Engineering*: development of an abandonment plan based on information gathered during preabandonment surveys.
4. *Decommissioning*: the shutdown of all process equipment and facilities, removal of waste streams and associated activities to ready the platform for a safe and environmentally sound demolition.

5. *Structure removal*: removal of the deck or floating production facility from the site, followed by removal of the jacket, bottom tether structures or gravity base.
6. *Disposal*: the disposal, recycle, or reuse of platform components onshore or offshore.
7. *Site clearance*: final clean-up of sea-floor debris.

The following is a brief discussion of the sequence of processes involved with structure decommissioning.

4.1 Well abandonment

The exact timing of cessation of production can be difficult to predict. However, a close working relationship between the reservoir, downhole and salvage engineers should be developed to establish the timing of a well and platform abandonment project. Before abandonment can begin, the salvage engineer must confirm that all wells on the platform are abandoned. The wells should be permanently abandoned according to the recommended procedures of the governing body. Generally this means isolating productive zones of the well with cement, removing some or all of the production tubing and setting a surface cement plug in the well with the top of the plug approximately 30–50 m below the mudline. The inner casing string should be checked to ensure that adequate diameter and depths are available for the lowering of explosives or cutting tools. If the well plug and abandonment are not performed properly, removal of the conductor by explosive or mechanical means becomes unsafe and much more expensive.

To ensure no delays in structure removal, all well plug and abandonments should be completed several months prior to commencement of offshore decommissioning. After well plug and abandonment responsibility and schedules have been established, the next step is an information-gathering phase.

4.2 Preabandonment surveys/data gathering

Critical to a successful abandonment program is planning. Proper planning requires that as much as possible about the platform be known. Information must be gathered on the topside deck and support structure design, fabrication and installation as well as any structural modifications that may have occurred since installation. The preabandonment survey should assess the condition of the platform facilities and structure prior to beginning the abandonment. The survey should include the following:

(a) File surveys. All available documentation concerning the platform design, fabrication, installation, commissioning, start-up and continuing operations should be investigated. The file survey will familiarize the project engineer with the other appurtenances to the platform facility such as living quarters, process equipment, piping, flare system and pipelines and

any additions/deletions or structural repairs to the jacket or the topside since the original installation. The project engineer must remain aware that platform records may be incomplete or unreliable. After an extensive search of all available files, the engineer should be able to define the abandonment scope of work and the objectives of subsequent surveys.

(b) *Geophysical survey*. Depending on the results of the file survey, the engineer may choose to have additional data gathered by means of side-scan sonar. This survey will indicate the amount of debris on the seafloor. In the case of deep-sea disposal, the sonar can determine if there are any obstructions at the dump site. Proximity of an available dump site or 'rigs to reef' site, water depths and obstructions along the tow route should be investigated as part of the geophysical survey.

(c) *Environmental survey*. This consists of an environmental audit of the offshore platform to identify waste streams or other government controlled materials. At this time items such as naturally occurring radioactive materials (NORM), asbestos, PCBs, sludges, slop oils and hazardous/toxic wastes should be identified and quantified. The problem of dealing with these waste streams should be addressed in the scope of work for handling during the decommissioning phase of the project. The project engineer should determine what permits or operating parameters are required by the host government or international standards.

(d) *Structural survey*. A structural engineer can use observation and non-destructive ultrasonic testing techniques to evaluate the structural integrity. Items inspected will include condition and accessibility of lifting eyes, obstructions on the deck which may require removal and interfaces between production modules/deck and deck/jacket which may require cutting for disassembly. Discrepancies between actual conditions and as-built information identified in the files should be noted during this phase. The platform legs should be checked for damage that may obstruct explosives or cutting tools from accessing the proper cutting depth. If obstruction from damage is anticipated or found, smaller diameter charges or cutting tools should be provided by the removal contractor as a contingency. Information concerning the underwater condition of the structure should be available from previous underwater inspections. If not available, consideration should be given for gathering this information by divers or remote-operated vehicles (ROVs).

4.3 Engineering

Upon completion of preabandonment surveys, a strategy for decommissioning and abandonment can be developed. The engineering phase takes all of the data previously gathered and pieces it together to form a logical, planned approach to a safe abandonment. Of major concern during the development of this strategy is the safety of the operations. As with all offshore operations, there exists a high potential for accidents involving bodily injury or loss of life and the accidental discharge of oil and flammable, corrosive or toxic material into the environment.

A risk analysis for all phases of the decommissioning should be performed. The results of this risk analysis are used to develop a decommissioning safety plan. Safety targets can be set and achieved provided the appropriate attention is devoted to the elements of the decommissioning plan. These procedural elements include the following items:

- regularly scheduled safety meetings;
- identification of safe work areas;
- safety equipment and training for emergency situations;
- working at high elevations and over water;
- safe operations of cutting tools and explosives;
- safe demolition to maintain structural integrity;
- proper use of rescue and evacuation equipment;
- diving and ROV operations;
- testing for and monitoring of toxic/explosive gases;
- pollution controls and containment;
- methods for handling and disposal of oil wastes, corrosive, NORM, or toxic materials;
- weather monitoring/night watch procedures;

Addressing each of the above-mentioned elements will help in the development of a safe decommissioning and salvage plan. After all the safety and environmental aspects of the project have been considered, details of the salvage process need to be identified. The sequence of process equipment and structure decommissioning and the salvage and disposal methods need to be determined. Any required government permits should be submitted for approval.

A major determination for an effective and efficient abandonment program is proper selection of the salvage equipment. Equipment selection for lifting purposes is determined by maximum weights of components to be lifted. Oceangoing derrick barges or Heavy Lift Vessels (HLV) currently available to the industry range from approximately 135 to 7000 tonnes (Figure 7.7). Other lower capacity, less expensive lift spreads can be used if the lift weights can be broken down through equipment removal or by cutting the components into smaller lifts.

Cost comparisons must be made between the time savings afforded by heavier lift, more expensive equipment and time-consuming, lighter lift, less expensive equipment. In addition to costs, the project engineer must assess the safety and environmental risks associated with sectional removal. Sectional removal will require significant time at the site for dismemberment and removal of production piping and equipment prior to cutting the topside deck into pieces. Additional hazardous tasks involved with decommissioning, lifting and rigging operations need to be performed offshore in a sectional removal, thus the time during which personnel will be exposed to increased

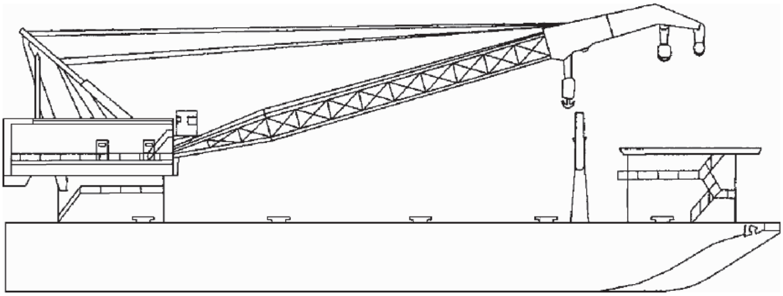


FIGURE 7.7. Derrick barge.

workplace hazards will be increased. More details pertaining to sectional removal will be addressed in Section 4.5.

Once the sizing of equipment is complete, a qualified list of contractors can be generated based on equipment availability and the area of the world in which the salvage is to take place. Awarding of the job based on the list of qualified contractors can be carried out in many ways. Two often used methods are bidding out the job for award to the lowest bidder or by negotiating a contract with the contractor who is most capable of performing the work. The job scope could include all aspects of the abandonment from the well abandonment to the final site clearance. Another method might be to award each portion of the abandonment and salvage as individual components similar to the breakdown of the seven phases of abandonment.

4.4 Decommissioning

A primary objective during the decommissioning is to protect the marine environment and the ecosystem by proper collection, control, transport and disposal of various waste streams. Decommissioning is a dangerous phase of the abandonment operation and creates the possibility of environmental pollution. Decommissioning and removal or abandonment in place should be carried out by personnel who have specific knowledge and experience in safety, process flows, platform operations, marine transportation, structural systems and pipeline operations. All contractors involved with the decommissioning should be brought in early in the planning stage to further assure a smooth decommissioning project.

The sequence of decommissioning the process system, utilities, power supplies and life support systems is important. The platform's power, communications and life support systems should be maintained for as long as practicable to support the decommissioning effort.

Process systems throughout the platform will have to be flushed, purged and degassed in order to remove any trapped hydrocarbons. Safe lock-out, tag-out, hot work and vessel entry procedures must be in place to ensure safety. Procedures must outline all duties of the standby/rescue teams including the use of breathing apparatus, air purging and lighting and caution must be exercised in removing all amounts of gases, oils and solids which may still remain in valves, production headers, filter housings, vessels and pipework that could present hazards to the crew.

Platform decommissioning will result in large amounts of waste liquids and solids. Where possible, waste liquids can be dealt with most cost effectively by placing them in existing pipelines and sending them to existing operating facilities. If no ongoing operations are available, then the waste streams will have to be pumped into storage containers and transported onshore for disposal or recycling. The constituents of the waste stream will dictate the cost of disposal. Solid wastes such as discarded batteries, glycol filters and absorbent rags will also have to be handled onshore according to acceptable disposal practices. Many platforms will have chemical treatment additives as well as possible toxic/hazardous materials such as methanol, biocides, antifoams, oxygen scavengers, corrosion inhibitors, paints and solvents, some of which may cause damage to the marine environment if accidentally discharged. Therefore, the procedures for handling and containing should be followed. The presence of radioactive scale, NORM, PCBs, hydrogen sulfide, etc., should have been detected during the environmental survey and a disposal plan developed. Disposal will generally mean transporting this material in drums to disposal wells or approved landfills.

Prior to removal, a detailed plan on how each material will be disposed of should be developed. The plan should identify recyclable materials such as steel, rubber and aluminum and the recycling centers that will take delivery of these materials. For those items not to be recycled, the abandonment plan should include the environmental impact that disposal will have on the dump site.

After the process piping and vessels have been cleaned and it has been determined that there is no future utility for the pipelines, pipeline decommissioning should commence. Pipelines departing the platform will either board another platform or commingle with another pipeline via a sub-sea tie-in. A surface to surface decommissioning is the least costly to perform. This requires pigging the line to vacate any residual hydrocarbons followed by flushing with one line volume of detergent water followed by final rinsing with one line volume of sea water. Upon completion of the pipeline purging operation, pipeline ends should be cut, plugs inserted and the ends buried below the sea-bed. In the case of a sub-sea tie-in, details of the sub-sea tap will have to be obtained so that pipeline decommissioning plans can be developed. The flowline can be pigged, flushed and disconnected if the receiving platform can accept the fluids, otherwise the pipeline segment will have to be isolated from the adjoining trunkline and then decommissioned. This will generally involve a boat capable of mooring over the sub-sea tie-in, connecting flexible piping to the tie-in using divers or ROVs, then pumping pigs, detergent water and rinsing water toward the platform for handling.

Decommissioning involves a variety of waste streams, disposal handling methods and specialty contractors. This phase more than any other will determine the success of the abandonment and salvage.

4.5 *Structure removal*

The method of a structure removal will be determined by the structure design, availability of removal equipment, method of disposal and the legal requirements governing the jurisdiction in which the abandonment is to take place. The legal requirements will usually be based on the social, economic, environmental and safety concerns of the local governing bodies. All of these issues are interrelated and will have a direct effect on the overall cost of the removal operation. The economics of the removal are of prime importance to the party responsible for the removal, whether it is a contractor, local government or producer. Each structure consists primarily of the topsides or deck above the water line and the jacket below the waterline.

4.5.1 Deck removal

Topsides removal is essentially the reverse sequence of the installation. Any piece of equipment obstructing the deck lifting eyes must be removed prior to the lift. The deck section is removed by cutting the welded connection between the piles and the deck legs. Slings are attached to the deck lifting eyes and the crane hook on the HLV. The HLV's crane lifts the deck section from the jacket. The deck is then placed on the cargo barge and readied for transportation to a land based facility for offloading [10].

4.5.2 Jacket removal

The jacket portion of the platform consists of the steel template which resides in the water column. Prior to removing the jacket, the piles must be cut to dislodge the jacket from the seafloor. The majority of structures in moderate environments will be totally removed. Most regulatory bodies throughout the world require that the structure be removed anywhere from the mudline to 5 m below. The chief consideration when developing a removal procedure is to determine if the piles or well bores will be severed using explosive or non-explosive methods.

(a) Removals using explosives. Severing platform piles and well bores with explosives is relatively effective compared with using non-explosive methods, as multiple cuts can be made in a short period of time. This limits the amount of time that removal support equipment must be on the site and limits personnel exposure to unsafe working conditions. Generally, explosives are the least expensive and the method of choice for structure removal. However, when explosives are used, more stringent regulations may become effective, including consultations with the local fishery or natural resource agencies. A project plan should allow lead time for consultations and permit approval

from these agencies. Explosives emit high-energy shock waves that can be harmful to habitat fisheries immediately adjacent to a removal site and some endangered species, such as marine turtles or mammals, in close proximity to the detonations may be mortally affected by these shock waves. Local regulations should be researched to determine limits to the amount and size of charges allowed and to determine if moratorium periods exist during marine migration periods.

In some areas, a condition for approval requires that observers from the local regulatory agencies and/or resource groups be present at the removal site prior to detonations, to observe that permit requirements are being met and to ensure that no harm is done to endangered species that may be in the area. Other conditions that may be imposed to limit the effects of explosives on habitat fisheries are predetonation aerial surveys, daylight-only working hours and staggered detonations.

Numerous studies are ongoing to reduce the harmful effects on local fish populations during detonations. Focus or shaped charges concentrate the detonation energy to the target, requiring less explosive weight with the same cut efficiency. The disadvantage of focus charges is that they need to be properly set in the well bore or pile and corrosion scale or damage in the piles can inhibit the charge from applying its full energy to the target.

A technique to reduce the effects of explosives on habitat fisheries is to evacuate the platform piles of all water. This reduces the resistance of the shock wave from the charge to the target. Also, special shock-attenuating blankets can be placed at the mudline to limit the energy emitted from the seafloor. Another technique may be to deter fish from entering the blast area. Small, preset charges set off prior to the detonation of the severing charges, known as scare charges, have been used. However, there are risks that scare charges may actually draw some species of curious fish toward the blast site. The use of strobe lights similar to those used to keep fish away from dam intakes may be effective.

(b) Non-explosive removals. An option for the project engineer is to eliminate the use of explosives in the removal. Use of non-explosive removal techniques eliminates the impact due to shock waves. Consequently, costs and time associated with observers and additional permit conditions may be eliminated. However, salvages using non-explosive methods can be more costly since only one pile or well bore can in practice be severed at one time. Each non-explosive cut will typically take several hours to perform. The additional time and cost can be minimized depending on the scope of work and with proper project planning. The project engineer should perform a precise cost estimate, evaluating the costs and risks between using explosive and non-explosive methods of severing. The following is a discussion of some non-explosive severing techniques.

High-pressure water/abrasive cutters. This system uses a high-pressure water jet operating at anywhere from 200 to 4000 bar to perform the cut. In some systems, sand, garnet or other type of abrasive is injected into the water stream to aid in the cutting process. The nozzle is lowered into the hole attached to an umbilical hose line or a hard pipe supply line. The nozzle is rotated 360° inside of the pile or well bore until the cut comes back on itself. One of the advantages to the system is its effective cutting ability. The casing strings do not have to be concentric in the well bore. The wall thickness of the platform piles is typically not a concern. The reaction of the water spray and the returns of the water give the operator an indication that the cut is actually being made. Some disadvantages are the tendency for system breakdowns due to the high working pressures, electrical and mechanical complexities, the delicate characteristics of the abrasive injection and wear and tear on the nozzle. Interrupting the cutting operation requires that the tool be placed in the exact location of the cut to avoid incomplete cuts. The effectiveness of these cuts is reduced at deeper cutting depths owing to the hydrostatic head that the water jet needs to overcome. As with all cutters, the tool must be centered in the pipe to maximize cutting efficiency. This can be difficult in heavily scaled pipes or in battered piles. Topside instrumentation can be used to monitor the position of the cutting tool during the cut. Camera technology has been used to inspect visually the status and effectiveness of a cut.

Mechanical cutters. Mechanical cutters use tungsten bit cutters that are extended from a housing tool with hydraulic rams. The tool is rotated continuously using friction to perform the cut. Disadvantages include frequent breakdowns of the tool due to frictional wear and tear, high labor intensity in handling heavy and bulky tools, the need for a work platform around the piling/well bore to be cut and poor cutting performance on non-concentric casing strings. Also, it can be difficult for the operator to determine if a cut is complete. Shifting of the well strings or platform piles downward can jam the tool into the kerf of the cut.

Diver cut. Internal or external pile or well bore cuts can be made with divers using underwater burning equipment. This type of cut can be made internally if there is access for the diver into a large-diameter casing or piling. If there is no internal access and the cut must be made below the mudline, a trench must be excavated to afford the diver access to the area to be severed. In some soils, keeping a trench open to the required 5 m depth may be impractical and may put the diver at undue risk from trench collapse. If the cut must be made below the mudline, the local regulatory agencies should be consulted as to the required depth of the cut. This may require obtaining a waiver to reduce the required cutting depth due to local soil characteristics and safety concerns for the diver personnel. Another concern to the diver's safety is oxygen entrapment in the soil near the cut or on the backside of the pipe being cut. Oxygen build-up can lead to an explosion if contacted with a flammable source such as a burning rod.

Cryogenics. Cryogenics is a little used technology that consists of freezing the platform pile in the area of a cut with CO_2. A relatively small explosive charge is then placed at the elevation to be cut and detonated. The brittle behavior of the frozen steel theoretically requires little energy to sever the pile. To use cryogenics, water must be completely evacuated from the pile, which can be a time-consuming operation. Also, the cutting efficiency is hindered by the freezing of the mud on the exterior of the pile to be severed.

Plasma arc cutting. Plasma arc cutting is achieved by an extremely high-velocity plasma gas jet formed by an arc and an inert gas flowing from a small-diameter orifice [11]. The arc energy is concentrated on a small area of metal, thus forcing the molten metal through the kerf and out of the backside of the pipe. Water can be used as a shielding agent to cool and constrict the arc [11]. The process requires a high arc voltage provided by specialized power sources. This method has not been used often, and is therefore not highly developed. For it to be effective, the tool must be set properly in the cut pipe. It is difficult to determine if a cut is being made unless camera technology is used.

Whether using explosives or non-explosive methods of severing, obstructions in the pile can hinder the proper placement of charges or cutting tools in the well bore or pile. Examples of obstructions include scale build-up, damaged piling, mud or pile stabbing guides. The removal of mud from the pile is generally accomplished with the use of a combination of a water jet and air lifting tools. When properly designed, these work well. This task is traditionally performed after the topside deck has been removed by the heavy lift contractor. A more cost-effective technique is the use of a submersible pump to excavate mud from the platform pile prior to removal. A small inexpensive work spread can be mobilized to the site prior to the arrival of the heavy lift equipment to perform this task. A window is cut into the jacket leg/pile and the submersible pump is then lowered down the jacket leg on a soft umbilical line.

(c) Alternative removal techniques. Most structures are removed with heavy lift equipment such as oceangoing derrick barges. In remote areas of the world, another concern in dislodging the platform from the seafloor is the availability of salvage support equipment. International Maritime Organization (IMO) guidelines permit the host government to allow a structure to remain in place provided that the structure is properly maintained to prevent failure. Maintenance costs over the life of the installation may eventually exceed the cost of the removal. When left in place, the platform may remain a hazard to navigation, exposed to collapse during storms or become a haven for refugees. These risks and liabilities may outweigh high removal costs to the host government and the operator, thus the decision to remove the platform may prevail.

Innovative methods of decommissioning, removal and disposal must be proposed to offset the lack of available salvage equipment and the high cost of equipment mobilization to remote areas. An alternative approach is cutting the platform into small, manageable components that lighter, more cost-effective equipment work spreads can handle. The equipment that may be used includes crawler cranes, A-frames and portable hydraulic cranes mounted on a cargo barge and these methods use readily available equipment that can be rigged up inexpensively.

Besides additional decommissioning hazards, other precautions must be taken during a sectional removal. Caution should be taken when cutting into a structural member as gases from scale or other sources may have built up over time inside of the member, and flame cutting into the member could result in an explosion. Each member should be drilled and checked for gases prior to any flame cutting operations. Sectional removal requires a detailed plan for lift sling connections and cut locations for each component to be removed. Lift slings should be properly attached so that a safe, level lift can be made, and a level, controlled lift will eliminate load shifting and allow for proper set-down on the transport barge without undo risk to personnel or equipment. Removal of a structure in sections may require multiple cuts underwater. The same concerns with load shifting and sling placement exist for underwater cuts as they do for above-water cuts. These cuts should be performed and/or supervised by skilled divers. Divers' activities can be reduced by using small shaped charges to sever members or by performing cuts with ROVs.

Other forms of less expensive salvage support equipment include barge-mounted 'stiff legs' and converted jack-up drilling rigs. Stiff legs have the capability to handle large lifts, but generally have limited hook height and are not easily maneuverable during the lifting and setting of components on transport barges. Stiff legs are generally built to work in protected waters and are affected by rough seas.

Converted jack-up drilling rigs are becoming more common in the abandonment industry. Companies are converting obsolete rigs to lift vessels to take advantage of the increased need to supply salvage support equipment. This type of equipment can work in heavy seas when in the jacked-up position, but in the floating condition maneuverability is limited.

Extreme caution must be taken when bringing transport barges near the jack-up rig to accept platform components. The legs of a jack-up rig cannot withstand any severe impact loading.

Another technique that can be used for the lifting of platform topsides is the Versatruss system (Figure 7.8). The method uses a series of A-frames mounted on tandem cargo barges. The combination of the A-frames, tension slings and the topside deck create a catamaran and truss effect for lift stability. This lift method also uses available equipment and requires relatively low-cost preparation.

(d) Alternative structure uses. In some areas of the world, the host government is either wholly responsible for structure removal or, through participation by a national oil company, is partially responsible for the cost of structure removal. The political entity may not want to dedicate funds to a non-revenue generating project. These states may decide that leaving the structure in place is the only alternative. IMO guidelines give local states the discretion to allow offshore structures to remain in place if the removal is not economically feasible. In these situations, operators will need to review the contract terms for possible ongoing or future liabilities.

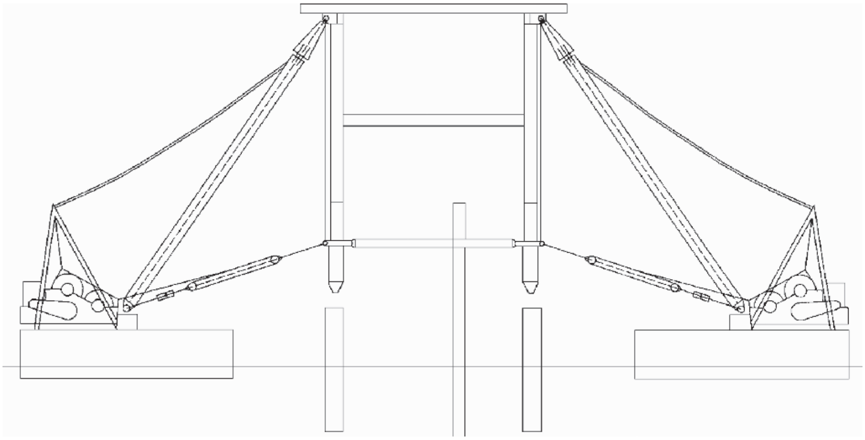


FIGURE 7.8. Versatruss method. Source: Versabar Inc.

Alternative uses for the platform should be explored. The benefit of the alternative use should offset the costs to maintain the structure in place. Some alternative uses may be as follows:

- fish farm;
- marine laboratory;
- military radar support structure;
- weather station;
- oil loading station;
- spur for deep-water developments;
- aviation/navigation beacon;
- tourism/recreational;
- power generation, i.e. wind/wave.

Leaving the structure in place should not create a hazard to local fishing industries or to navigation in the area.

(e) Platform reuse. Reuse is another option. If a potential development can finance the removal of a structure, this relieves the non-revenue producing property from absorbing the salvage costs. Platform reuse can reduce the cycle time to get the new development in production, generating cash. However, an immediate reuse should be identified when decommissioning is undertaken. Storage of the platform onshore prior to identifying a reuse can result in costs that may offset the savings from reuse.

(f) Partial removals. In the North Sea, the abandonment issue is coming into focus as some of the area's fields are reaching the end of their productive lives. Some of the world's largest structures will need to be removed before the year 2005. The large component weights will result in removal costs that may

exceed the cost of the original installation. These removal costs will largely be absorbed by the local governments because of tax breaks from removal costs available to the operator. Thus, local governments may need to regulate and monitor abandonment procedures to allow for a cost-effective removal strategy without compromising safety or the environment.

Any cost savings of abandonment in the North Sea will come from partial removal. Estimates show that total removal (Figure 7.9) of structures now existing in the UK continental shelf will cost \$6.6 billion and partial removal \$4.5 billion [8]. These partial removal methods will consist of the following:

- partial removal of jacket component (Figure 7.10);
- toppling in place (Figure 7.11);
- total removal of topside and toppling in place of the jacket only (Figure 7.12);
- emplacement (Figure 7.13);
- transport to rigs to reef site;
- deep-water dumping.

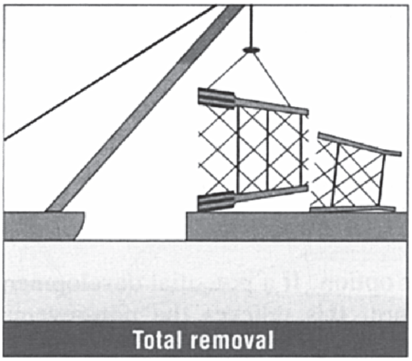


FIGURE 7.9. Total removal [12].

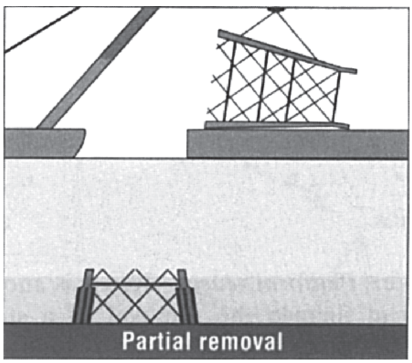


FIGURE 7.10. Partial removal [12].

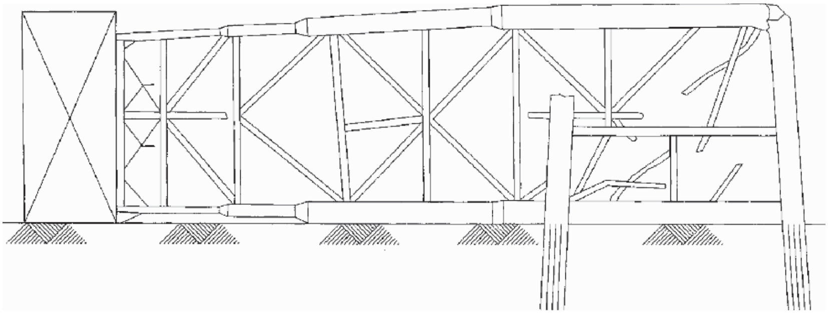


FIGURE 7.11. Hinge point in jacket leg.

FIGURE 7.12. Toppling [13].

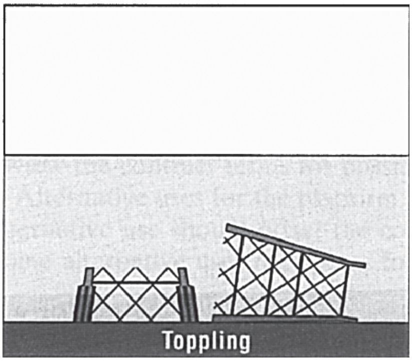
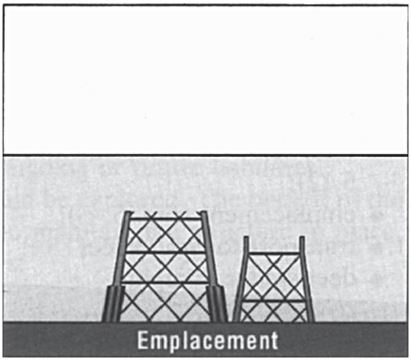


FIGURE 7.13. Emplacement [12].



The choice of removal method will depend on cost, proximity to disposal sites, availability of removal equipment, location of the removal relative to shipping lanes and fishing interests, and safety and environmental issues. In addition, the disposal method will play a key role in the decision on the removal method. The next section summarizes the alternatives and key issues concerned with structure disposal.

4.6 Disposal

Once a platform or portions of a platform have been removed, the structure must be disposed of. Some disposal options include the following:

- transport inshore for disposal, storage or recycling;
- toppling in place;
- disposal at a remote rigs to reef site;
- emplacement;
- deep-water dumping.

The owner must be aware of the social and political climate in the area where abandonment and disposal are to occur. Public perception will play a key role in performing a successful disposal program. All environmental issues should be addressed by the operator up front, all stakeholder groups and regulatory agencies should be informed of the disposal plans and environmental effects of the plan and alternatives must be addressed. Miscommunication and misinformation to or from interested stakeholders could lead to the downfall of an otherwise well planned abandonment strategy.

Non-jacketed designs such as floating production systems, concrete structures, steel gravity structures and spar loading buoys will probably be refloated in whole or in part and towed away, and disposed of in deep-ocean disposal sites or brought inland for dismantling. Steel-jacketed structures will probably be disposed of in one or any combination of the ways mentioned above. Explanations of these methods are detailed below.

(a) Disposal inshore. Generally, topside deck facilities will be disposed of inshore because of the difficulty and expense in completely removing all of the hydrocarbons and their by-products at the installation site rather than shoreside. When disposal inshore is chosen, the structural component will be either totally or partially cut up for scrap. Portions may be disposed of in landfills or hazardous waste sites or recycled. The component may also be stored for future use or refurbished immediately if a reuse is identified. Once a structure has been removed for inland disposal, possession of the removed structure and their components is usually turned over to the removal contractor in exchange for a portion of the scrap value. The steel in offshore structures is of relatively good quality and is readily taken by steel mills for recycling. The handling and disposal of all other materials associated with the removal should be detailed in the pre-abandonment disposal plan.

The UK Offshore Operators Association performed a detailed assessment of the amount of waste materials projected from the disposal of offshore structures from the North Sea. Disposal amounts were calculated and the effect on the available landfill space was determined [14]. Another study, performed by planners for a removal in Norway, detailed costs and benefits of recycling an old structure. The study compared the emissions placed in the atmosphere by melting and breakdown to the cost of the energy and associated emissions generated if the same component was built new [4].

An environmental assessment could be made based on these studies. These types of analyses would be beneficial to the operator and regulatory bodies when the decision is made to bring offshore components inshore.

(b) Toppling in place. This method is generally performed after the topsides have been removed. The legs are severed selectively so that the jacket can be toppled with two legs acting as hinges (Figure 7.11). The toppled structure must maintain 55 m of clear water column clearance as required by IMO guidelines. Another method is to cut the top section completely from the lower section, lift it off, place it on the bottom to the side and topple it with heavy-lift marine equipment (Figure 7.12). In the Gulf of Mexico, toppling may only be performed in established reef sites. In the North Sea, a 500 m clear exclusion area must be maintained for the benefit of the fishing industry, much the same as when the platform is operational. The site should be clearly marked with buoys. In the Gulf of Mexico, the buoys are maintained by the state, whereas in the North Sea the responsibility remains with the operator to mark and maintain the site. In other parts of the world, marking is negotiable between the operator and the host government. The site should also be placed on navigation charts.

(c) Rigs to reef. When an offshore structure is removed, a habitat for fisheries and a source of recreational fishing is lost. It has been estimated by the Gulf of Mexico Fishery Management Council that oil and gas structures account for 23% of the hard bottom habitat in that area [2]. Prior to the emplacement of petroleum-related structures, suitable habitats in which new species could expand their range did not exist. Countries may establish a rigs to reef program to maintain the hard bottom habitats that these structures provide. When performing a cost comparison between dumping a platform at a reef site or disposal inshore, the size of the platform, location of the platform in relation to the placement site and the transport costs are the main factors.

A common method of transportation is to tow the structure while on the hook of the removal barge crane. Derrick barges are not constructed for this purpose, so extreme caution should be taken if this method is used. Weather and obstructions both below and above the water along the tow route should be anticipated. If the heavy-lift equipment has to accompany the structure to the placement site, this subjects the project to costly weather and operational delays. The need for the derrick barge at the disposal site can be avoided by setting up a winch and snatch block system to push the structure off the transport barge. These costs have to be weighed against the removal and transport of the platform components inshore. A rigs to reef program benefits the fish population and provides a popular source of recreational fishing while giving the project engineer an additional option to reduce platform removal costs.

(d) Emplacement. Emplacement (Figure 7.13) is much the same procedure as toppling except that the top section is completely cut from the lower section, lifted off and placed next to the lower section.

(e) Deep-water dumping. This method is particularly reserved for huge floating systems located in the North Sea. Essentially, the structure is disconnected from its moorings and towed to the deep ocean waters where it is then flooded and sunk. Prior to any dumping operations, it is important to confirm that all components placed in the ocean waters are free of hydrocarbons in harmful quantities to avoid pollution of the open sea.

Partial removal may consist of any combination of the above-listed options. The method of structure and component disposal should be based on legal, environmental, safety, financial and timing issues. Identification of a disposal site and its proximity to the removal site must be considered to perform a cost analysis on the most effective disposal method.

An inherent concern with any disposal method is tying down the salvaged component on the transport barges, which can be particularly difficult and dangerous in rough weather. A well thought out plan has to be enacted to assure a safe and stable lift and placement on the transport barges. All components should be tied down with a system that provides the same integrity as when the platform was towed offshore for installation.

A marine surveyor should be available on-site to monitor the tie-down operations. The marine surveyor's responsibilities include confirming that the structure is secure for tow, certifying that the tow route is free of overhead, width or bottom obstructions and verifying proper ballast of the transport barge.

4.7 Site clearance

The final phase of the abandonment process involves restoration of the site to its original predevelopment conditions by clearing the seafloor of debris and obstructions after platform removal. If the abandonment was a partial removal, site clearance procedures may vary from a total removal. In the case of total removal, debris should be removed, leaving the site trawlable and safe for fishing or other maritime uses.

A site clearance plan may consist of two or three phases, depending on the information gathered during the preabandonment surveys and the water depth at the location. The first phase may occur before actual removal with divers making sector sweeps around the platform site during pipeline decommissioning. High-frequency sonar can be used to locate obstructions and direct divers to debris. Searches should be performed inside and outside the platform a distance of at least 100 m. Following this initial debris removal, site clearance can be discontinued until the structure removal has taken place.

Once the structure has been removed, the site is ready for a final cleanup if required. In shallow waters, a trawling vessel can be used to simulate typical trawling activities that may occur in the area after the platform removal.

Deeper water sites may not require trawling simulations to clear the area. Proper planning prior to the removal of debris can make a significant difference in controlling the costs. The geophysical survey performed with the side scan sonar during the preabandonment survey phase should identify the major debris, and this information will provide the basis for selecting the most effective equipment, personnel and timing. Equipment and personnel can range from a dive crew retrieving debris off a boat during pipeline abandonment, through a small derrick barge with divers to a boat capable of mooring over debris targets away from the platform. In deep waters, it is crucial to determine the amount and type of debris to size the equipment and work crews properly. Upon completion of the bottom clean-up, job completion summaries should be submitted to the proper governing body.

5 Conclusion

The offshore oil and gas industry will be faced with more than 7000 platform removals, each of which will include a multitude of tasks, involving interaction between operators, contractors, regulatory agencies, governing bodies and the public. Of importance to the operator will be the cost effectiveness of the removal. The operator will also share in the public and regulator's concern on the effect that the removal will have on the environment. The operator should focus on early interaction with regulatory agencies, detailed preremoval planning and engineering, efficient interface and timing of equipment and personnel movements, safety and disposal to assure a cost-effective removal with minimum impact on the environment. Finally, all stakeholders should continuously pursue advances in rulemaking and technology to ensure each abandonment program improves on the one that preceded it.

References

1. (1995) Offshore abandonment heats up: North Sea, Gulf of Mexico deepwater platforms are costly, difficult to remove. *Journal of Petroleum Technology*, August, 643–5.
2. United Nations Economic and Social Commission for Asia and Pacific (1994) *Waste Recycling of Obsolete Oil and Gas Production Structures in Asia Pacific Waters (Overview)*, Volume 2, United Nations, New York.
3. United Nations Economic and Social Commission for Asia and Pacific (1994) *Waste Recycling of Obsolete Oil and Gas Production Structures in Asia Pacific Waters (Overview)*, Volume 1, United Nations, New York.
4. Habersholm, L. and Robberstad, L. (1994) Environmental impact from removal of offshore installations: the North East Frigg field case. *Second International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production*, 25–27 January, Jakarta, Indonesia.
5. (1995) Deepsea disposal for *Brent Spar. Offshore Engineer*, March, 12–9.
6. Dymond, P.F. (1995) The operators' perspective on the decommissioning of UKCS offshore installation. *Petroleum Review*, April, 176–8.
7. Hoff, G.C. (1995) Mobil Exploration and Producing Technology, personal communication, October.

8. Roberts, M. (1994) Abandonment (field decommissioning): the legal requirements, *26th Annual OTC* 2–5 May, Houston, TX.
9. Shaw, K. (1994) Decommissioning and abandonment: the safety and environmental issues, *SPE Paper 27235*, 293–300.
10. Velazquez, E. and Byrd, R.C. (2003) Gulf of Mexico Deepwater Platform Decommissioning. *Offshore Technology Conference*, 5–8 May, Houston, TX.
11. American Welding Society (1987) *Welding Technology Welding Handbook*, 8th edn, Volume 1, American Welding Society, Miami, FL.
12. UKOOA (1994) *Decommissioning UK Offshore Installations, the Right Balance*, UKOOA, London.
13. Snell, R., Corr, R.B., Gorf, P.K., and Sharp, G.K. (1993) Options for abandonment: an operator's perspective, IBC Technology Services, Ltd. *Decommissioning and Removal of Offshore Structures Conference*, 15–16 September, London.
14. UKOOA (1995) *An Assessment of the Environmental Impacts of Decommissioning Options for Oil and Gas Installations in the UK North Sea*, Executive Summary, Auris International, Aberdeen.

Further reading

Minerals Management Service (1992) *Notice to Lessees No. 92-02: Minimum Interim Requirements for Site Clearance (and Verification) of Abandoned Oil and Gas Structures in the Gulf of Mexico*, May.

Knott, D. (1995) North Sea operators tackling platform abandonment problems. *Oil and Gas Journal*, 20 March, 31–40.

Buckman, D. (1994) Abandonment – the North Sea's newest industry. *Petroleum Review*, September, 413–5.

Shaw, K. (1994) Decommissioning and abandonment: the safety and environmental issues. *Second International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production*, 25–27 January, Jakarta, Indonesia.

Bartlett, T.W. (1994) Deconstruction of an offshore platform. *26th Annual OTC*, 2–5 May, Houston, TX.

Chapter 8
Tanker Design: Recent Developments from an Environmental Perspective

G. Peet

1 Introduction

At four minutes past midnight on 24 March 1989, the *Exxon Valdez* went hard aground at Bligh Reef in Prince William Sound (Alaska). Oil began leaking from the vessel immediately, at a rate of tens of thousands of barrels per hour [1]. The *Exxon Valdez* was to become one of the icons of environmental disaster for years to come. Many publications, most with convincing illustrations, were telling the story to the world, e.g. some 40 pages of text and illustrations in *National Geographic* of January 1990:

> In the beginning, when the supertanker *Exxon Valdez* gutted herself on Bligh Reef and vomited 11 million gallons of crude oil into Alaska's exquisite Prince William Sound, it seemed truly like the ending of a world.
>
> Ashore it was war.

Vast quantities of oil on the shore do provide for excellent emotive publications and subsequently also for a strong drive for political action in response to these vast quantities of oil. This was also true in the case of the *Exxon Valdez*.

Whilst the human element was the major factor in causing the grounding of the *Exxon Valdez*, the political fall-out of this accident quickly focused on tanker design (i.e. on the double hull tanker design) as one of the major targets for political post-accident opportunism.

This chapter is primarily focused on the post-*Exxon Valdez* tanker design discussions at the international level (i.e. the International Maritime Organization) in the early 1990s as prompted by the developments in the USA. The post-*Exxon Valdez* debate will be put against the background of the information that was available at the time with respect to the importance of tanker accidents and tanker design in comparison to other sources of oil pollution.

Former Friends of the Earth Representative at the International Maritime Organisation, Heemraadssyngel 193, 3023 CB Rotterdam, The Netherlands

This chapter will also briefly discuss some of the developments that followed the adoption of the new tanker design regulations by the International Maritime Organization (IMO) in 1992 as well as more recent data regarding the various sources of marine oil pollution.

2 Tanker accidents

Many, at that time and still, believe oil tanker accidents to be the major source of marine pollution. It is not; other substances also pollute the environment. As for oil, the situation is as follows.

In the early 1990s over 1,500 million tonnes of oil were transported over the world's seas by ships as cargo (some 1,480 million tonnes in 1989), as fuel oil (an estimated 110,000 tonnes in 1989) or for other uses [2]. A relatively small but in absolute numbers substantial amount of oil never reached its destination as cargo or was effectively used in the ships' engines: it ended up in the marine environment either as a result of operational discharges or as a result of accidents with ships.

Various estimates had been made to assess the total amount of oil entering the world's seas and oceans. Table 8.1 summarizes some of these estimates, for the years 1973, 1981, 1990 and 1992. The estimate for 1981 provides an indication of the importance of shipping as a source of marine oil pollution. From an estimated total of 3.28 million tonnes of oil entering the marine environment, some 1.5 million tonnes (46%) were generated by shipping, of which some 410,000 tonnes (13%) were the result of (tanker) accidents.

At the time of the grounding of the *Exxon Valdez*, the most recent estimate of the respective contribution of the various sources of marine oil pollution was given in a report by GESAMP (the IMO/FAO/UNESCO/WMO/WHO/

TABLE 8.1. Estimates (1993) of the quantities of oil annually entering the marine environment[a] (million of tonnes)

	Year of estimate/publication			
Source	73/75	81/85	90/90	92/93
Natural sources	NA[b]	0.25	NA	0.25
Oil exploration	NA	0.05	NA	0.05
Shipping				
Discharge of bilge and fuel oil plus operational losses from oil tankers	1.08	1.02	0.41	0.41
Tanker accidents	0.20	0.41	0.11	0.11
Accidents with other types of ships	0.10	–	0.01	0.01
Other (ports, shipyards, scrapping, etc.)	0.75	0.07	0.04	0.04
Atmospheric deposition	NA	0.30	NA	0.30
Land-based sources	NA	1.18	NA	1.18
Total amount of oil per year	–	3.28	–	2.35

[a]Sources: Refs. 3 and 4.
[b]NA = Not available.

TABLE 8.2. Estimates (1993) of the quantities of oil annually entering the marine environment in various regional sea areas (millions of tonnes)[a]

Area	Quantity
North Sea	260,000
Baltic Sea	21,000–60,000
Mediterranean Sea	500,000
North west Atlantic	–[b]
Wider Caribbean	950,000
West and Central Africa	–[b]
South Africa	–[b]
East African region	–[b]
Red Sea, Gulf of Aden	–[b]
Arabian/Persian Gulf	160,000[c]
Indian Ocean, Arabian Sea	5,000,000
Indian Sea, Bay of Bengal	400,000
South east Asia	–[b]
South east Pacific	–[b]
North east Pacific	–[b]
Arctic Ocean	–[b]
Antarctic Ocean	–[b]
Total	~7,300,000

[a]Source: Ref. 3.
[b]No overall estimate.
[c]Pre-Iran-Iraq and Gulf wars.

IAEA/UN/UNDP Joint Group of Experts on the Scientific Aspects of Marine Pollution) and was put at an annual introduction of 2.35 million tonnes of oil in the marine environment [3]. GESAMP did not develop new estimates; its report merely used the most recent estimates available from previous studies (in Table 8.1 the figures are given in either column 2 or 3).

The 1993 GESAMP report then continued to provide data (taken from other publications) regarding regional sea areas (see Table 8.2). When the estimates for these regional sea areas were added, a different picture emerged: at least 7.3 million tonnes of oil were entering the world's seas and oceans annually if those estimates were to be correct.

More detailed estimates, providing information about the contribution of shipping, were, at that time, also available from other sources, e.g. for the North Sea (Table 8.3). The fact that the North Sea States could not jointly agree on the amounts of oil 'produced' by illegal discharges and tanker accidents did not mean that there were no estimates for, in particular, the amounts of oil discharged illegally. These estimates ranged from some 15,000 to as much as 60,000 tonnes per year for the whole North Sea. This, of course, added considerably to the total input given in the above list.

From all these figures, it was clear that shipping was only one (albeit not unimportant) source of marine oil pollution and that (tanker) accidents were not the most important source of oil entering the sea from ships.

TABLE 8.3. Estimates (1987) of the quantities of oil annually entering the marine environment in the North Sea (millions of tonnes)[a]

Source	Quantity	Sub-total
Transportation	0.001–0.002	
Legal discharges		0.001–0.002
Illegal discharges		No agreed estimate
Tanker accidents		No agreed estimate
Production platforms	0.029	
Atmospheric deposition	0.007–0.015	
Land-based sources	0.029–0.081	
Dumping operations	0.004–0.022	
Sewage sludge		0.001–0.010
Industrial wastes		0.001–0.002
Dredge spoils		0.002–0.010
Natural seeps	0.001	
Total	0.071–0.150	

[a]Sources: Ref. 5.

It is important, however, to keep in mind that these figures were nothing but estimates and that, if these figures were to be prepared on the basis of information available some five years later, the situation would have been different. The accident with the oil tanker *Braer* in 1993 off the Shetland Islands introduced some 85,000 tonnes of oil into the northeastern Atlantic (and North Sea). Had this accident happened in the North Sea, it would have more than doubled the total amount of oil in the lowest estimate, and it would have added more than half of the amount of oil to the highest estimate given in Table 8.3.

Based on the data available in the early 1990s several relevant conclusions could be drawn. The first was that although, on a global scale, the amount of oil entering the marine environment as a result of accidents may have been relatively small, on a regional or local scale the relative importance of such an accident would be substantially higher. In certain areas an accidental spill might even account for almost 100% of the total input of oil in that area. That is why the *Exxon Valdez* was an ecological disaster where it happened. That is how even a relatively small spill, such as the approximately 750 tonnes in the December 1988 accidental spill off Grays Harbour on the Washington State coast, could develop into a major environmental problem at the time it happened.

From these figures, it was also clear that there are no reliable data regarding the input of oil into the marine environment; the various estimates were too far apart. If it is possible to extract two completely different totals from just one publication (i.e. the 2.35 million tonnes estimate in the GESAMP report and the 7.3 million tonnes total that can be extracted from the same report), the only valid conclusion seems to be that we do not really know how much oil enters the marine environment, owing to a lack of reliable data.

The same is true with respect to the trends in the amounts of oil entering the marine environment. If one takes the figures from Table 8.1 it would seem that the total amount of oil introduced into the marine environment by shipping has dropped from an estimated 3.28 million tonnes in 1981 to 2.35 million tonnes in 1992; a substantial drop indeed and, if these figures are correct, the claim for success would be more than justified. The question is, of course, whether these figures were correct. It is likely that they were not.

An analysis of the method by which the figures for 1990 were determined shows that they are based on a large number of assumptions [6]. The estimate for operational discharges from oil tankers, for instance, is based on the amount of oil tankers can discharge legitimately under the MARPOL Convention [7] plus an estimate of the amount of oil that would be discharged unlawfully. The assumptions on which this assumption is based include the degree of compliance (estimated to range from 80% for oil tankers smaller than 20,000 DWT (deadweight tons) to 99% for oil tankers larger than 150,000 DWT) and on estimates of how much a non-complying ship would discharge unlawfully. Both estimates may be correct, but they may also be too optimistic.

It is important to note that it is not possible to conclude that less oil was being discharged into the marine environment if the figures used for that conclusion are based on the assumption that, in accordance with international regulations, less oil is being discharged.

3 Tanker design

If one looks closely at data with respect to the causes of major oil tanker accidents, one conclusion is evident: human error is a major cause. Human error may take the dimension of mistakes that provide the direct cause of an accident, but it also includes such (often implicit) decisions as allowing substandard maintenance of vessels, allowing substandard crews to run large and complex vessels, etc.

In a report written after the major tanker accident involving the grounding of the *Braer* on the rocks of Garths Ness in the Shetland Islands on 5 January 1993, important words are dedicated to the importance of the human element in shipping disasters [8]:

> In the last analysis it is individuals whose conduct leads directly or indirectly to pollution. It is generally accepted that human error is the cause of about four fifths of marine accidents. We are surprised that the figure is so low: we believe that human error, at some stage in a chain of events which could start with the design of a vessel, is the root cause of virtually all accidents. The only exception that we can see is the highly unusual case of unforeseeable forces overwhelming a vessel or her crew.

Whilst tanker design is definitely not a major cause of tanker accidents, the design could be an important element in determining the outflow of oil after an accident. Efforts to minimize operational pollution through design measures had already been introduced in the 1973 MARPOL Convention: requirements for segregated ballast tanks (SBT) were established for vessels of 70,000 DWT and larger to minimize accidental pollution. In 1978, the concept of protective location (PL) of SBT was introduced into the MARPOL Convention (Regulation 13E of Annex I at that time). It applied to vessels of 20,000 DWT and larger and was designed to provide protection for a percentage of the sides and the bottom of oil tankers. After 1978, additional accidents with subsequent pollution occurred, making a case for shielding the entire cargo block by protective spaces. These protective spaces would then have prevented or mitigated many of these accidents and subsequent pollution.

With the *Exxon Valdez* in mind, this concept was to be the driving force behind the post-*Exxon Valdez* efforts to develop improved tanker designs and to develop the necessary national and international regulations to ensure the future use of such designs in new tankers.

4 New tanker design standards: the USA takes the lead

As early as in October 1989, the International Maritime Organization (IMO) adopted a resolution calling for the development of an international convention on oil pollution preparedness and response. This resolution was a direct response to the *Exxon Valdez* accident. A draft text for such a convention was submitted by the USA to IMO's Marine Environment Protection Committee (MEPC) for discussion in March 1990, and the convention was adopted in November 1990 [9].

It was one of two major post-*Exxon Valdez* initiatives at the IMO by the USA. The second came in November 1990 when the USA delegation at IMO's MEPC presented proposals to amend the MARPOL Convention. At that time the 1990 Oil Pollution Act had already been developed and the proposal's intention was to make OPA 1990's double hull provisions part of the IMO instruments, i.e. part of the MARPOL Convention.

The USA-proposed amendments were designed 'to make double hull construction mandatory for new oil tankers and sought assistance of IMO in developing technically sound criteria for the construction of double hull tankers' [10]. In its proposal, the USA stated the following: 'Of immediate concern to the United States is the prevention of pollution from tankers that will be undergoing construction or major conversion under newly placed and future contracts. Given the current advanced age of the world tanker fleet and the large number of tankers now on order, it is reasonable to conclude that a significant number of tankers will be constructed in the near future'.

In the USA, a study had already been started by an *ad hoc* committee on Tank Vessel Design of the US National Academy of Sciences (NAS) Marine Board (in addition to 'traditional' experts, this committee also had one member from the environmental lobby, Sally Ann Lentz of the Oceanic Society and Friends of the Earth USA). This study [4] focused on how alternative tank vessel (tanker and barge) designs might influence the safety of personnel, property and the environment and at what cost. The study considered a wide range of engineering considerations (e.g. hull strength; tank proportions, arrangements and stability; salvage concerns; safety of life) and design alternatives (e.g. barriers; outflow management; penetration resistance). Some of its conclusions were as follows:

Results of this study indicate that no single design is superior for all accident scenarios. Therefore, the Oil Pollution Act of 1990 which mandated double hulls for tankers travelling in US waters, should be viewed as only an interim step to reducing oil spills. More work remains to be done. […]

Existing design standards should be strengthened to ensure proper

(1) corrosion protection […];
(2) dimensions of structural members; and
(3) use of high-tensile steel. […]

Furthermore, naval architects traditionally have not designed tank vessels, at the detail level, to withstand collisions and groundings. Design based on the possibility of accidents, a practice common in many industries, should be considered for tank vessels. […]

Available information is inadequate for decision making. […]

[…] double hulls should save (in absence of other risk-reduction measures) an estimated 3000 to 5000 tons of oil spillage per year in US waters from collisions and groundings. […]

Double hulls are particularly effective in low-energy (typically low-velocity) groundings and collisions. […]

[…] the committee does not favor hydrostatically balanced design options for new tank vessels. […]

The committee could not agree with respect to the merits of the design alternative with intermediate oil-tight deck with double sides (IOTD w/DS; also known as the mid-deck tanker).

[…] some committee members consider the IOTD w/DS a practical and innovative application of available technology, which, if treated as an equivalent to the double hull and allowed to trade in commerce to the United States, would reduce pollution in several classes of accidents, including high energy groundings (which have caused some of the largest oil spills). Others of the committee hold the judgement that the gap between theoretical principles and practical application is wide, that the design and its application are unproven. […]

Other design alternatives may be proposed in the course of future research. New proposals should be considered. […]

Double hulls need not increase incidence of fires or explosions, impair post-accident stability, or complicate salvage. […]

However, the risk cannot be ignored; planned maintenance and thorough inspection are critical. […]

Existing vessels will comprise the majority of the fleet serving the United States for many years.

The report of the committee was passed on to the International Maritime Organization.

5 New tanker designs: the international debate in the early 1990s

The USA proposal prompted a vivid debate at the International Maritime Organization. It was not welcomed unanimously.

The International Chamber of Shipping, for example, argued that [11]:

- there was no single solution to preventing ship casualties and that of the many measures that might be taken, new construction standards would not make a major contribution;
- no particular design can be shown to be superior overall with respect to preventing ship casualties;
- there was no experience with the double hull construction for large tankers whilst there were concerns regarding the potential hazards of this design for oil tankers; and consequently that
- it would be wrong to amend the MARPOL Convention so as to stipulate a one-design requirement for all new oil tankers.

Similar concerns were expressed by many delegations.

Japan offered an alternative. The Japanese delegation reported the outcome of a Japanese study on the effectiveness of pollution prevention and safety aspects of three methods of design and construction of oil tankers, i.e. double hull construction, the underpressure method and the double-sided tankers with mid-height deck. According to this study, the mid-height deck tankers would be as effective as, or even superior to, double hull tankers in terms of reducing oil outflow after accidents.

Several delegations expressed their wish that, if double hulls were to be adopted as an IMO design standard for oil tankers, the mid-height deck design should also be accepted as an equivalent design.

The discussion then moved from the MEPC to the Maritime Safety Committee (MSC) and back to the MEPC, where many delegations stressed the importance that decisions be taken. A decision was taken by the MEPC at its 31st session: draft regulations with regard to design standards for oil tankers were approved for circulation to MARPOL member states with a view to adopting these at the next session. The double hull requirement in this draft regulation read as follows:

The entire cargo tank length shall be protected by ballast tanks or spaces other than oil tanks as follows: […] wing tanks or spaces shall extend for the full depth of the ship's side or from the deck […] to the top of the double bottom […]

Double bottom tanks or spaces […] may be dispensed with, provided that the design of the tanker is such that the cargo and vapour pressure exerted on the bottom shell plating forming a single boundary between the cargo and the sea does not exceed the external hydrostatic water pressure […]

Other methods of design and construction of oil tankers than those described

[…] may also be accepted as alternative […] provided that such alternative provides the same level of protection against oil outflow in the event of collisions or strandings […].

With respect to alternative designs (i.e. the mid-height deck design) a special Steering Committee was set up to carry out a comparative study of two oil tanker designs: the double hull and the mid-height deck designs (members of this Steering Committee included representatives from the industry, one of the members of the National Academy of Sciences committee on tanker design, a representative from the environmental organization Friends of the Earth International and several member state representatives). This Steering Committee should provide the information and recommendations as to whether or not the mid-height deck design would be accepted as an alternative to the double hull design at the same time as the new regulation for oil tanker design was adopted.

The Steering Committee carried out its work under extreme time pressure but managed to have several studies completed to serve as a basis for its conclusions [12]. Several different tanker types were compared: double hull and mid-height deck (low and high mid-decks) tankers of 40,000, 90,000, 150,000 and 280,000 DWT.

Analyses were made of oil outflow after collisions and groundings by Det Norske Veritas, Lloyd's Register of Shipping, Registro Italiano Navale and Nippon Kaiji Kyokai using probabilistic tools as well as simplified oil outflow calculations, all based in various assumptions with respect to, for example, penetration, extent of damage, tides, quantities of oil and dynamic effects. In addition, model tests were carried out in the USA (David Taylor Research Center) and Japan (Tsukuba Institute, Ship and Ocean Foundation) to assess oil outflow after accidents.

The most important conclusions from this comparison were as follows:

When the whole range of probable collisions and groundings are considered cumulatively, the oil outflow performance of mid-deck tankers is at least equivalent to that of double hull tankers, but the Committee recognized that within this overall conclusion each design gives better or worse oil outflow performance under certain conditions, in particular:

- in groundings which would result in the rupture of the bottom shell plating of double hull and mid-deck tankers but not the inner bottom of double hull tankers, which represent approximately 80% of the total grounding accidents resulting in hull penetration, no oil spill will occur in double hull tankers, but some oil outflow, normally small in relation to the ship's deadweight, would occur in mid-deck tankers;
- in groundings which would result in the rupture of the bottom shell plating of double hull and mid-deck tankers and the inner bottom of double hull tankers, the amount of oil outflow of mid-deck tankers, calculated on the assumptions using reasonable values of current and tide, is less than that of double hull tankers;
- in collisions which would not result in the rupture of the inner hull, no oil outflow will occur; mid-deck tankers have less probability of collisions resulting in the rupture of the inner hull because of the wider wing tank spaces in order to meet segregated ballast capacity requirements;
- the amount of oil outflow of double hull and mid-deck tankers after collisions which result in the rupture of the inner hull will depend on the actual tank arrangements.

With respect to […] fire and explosion, raking damage, operation of tankers and residual strength, double hull tankers are deemed comparable.

[…] The Steering Committee, noting the present lack of knowledge to enable the evaluation of environmental performance of oil tanker designs with respect to fire and explosions and operational safety, recommends […] studies in this field […].

The Steering Committee noted with concern the results of the analysis which showed that oil outflow of double hull tankers without longitudinal bulkheads inside cargo tanks is considerable […].

The Steering Committee […] recommends that the MEPC consider whether the text [of the new regulation] should be modified to cover the other aspects [i.e. not just oil outflow but also fire and explosion, raking damage, operation of tankers, and residual strength].

In all fairness, it has to be said that the Steering Committee carried out an enormous amount of work in a very short period of time. One delegate at the 32nd session of the MEPC [13], where the findings of the Steering Committee were discussed, stated that 'the amount of work carried out […] exceeded whatever anyone may have expected'. Still, the work of the Steering Committee had, in spite of its name which included the words 'tanker design', concentrated more on oil outflow than on design aspects.

The conclusions of this Steering Committee were not supported by unanimously. The Friends of the Earth International representative reserved its position with regard to the conclusion of equivalence of the two designs and expressed a preference for the double hull design. Arguments for this position were the conclusion that there would be fewer spills from double hull tankers in the case of groundings, and that the double hull design had more scope for further improvements (e.g. wider wing spaces to reduce the oil outflow risks in cases of collisions, the longitudinal bulkhead) than the mid-deck design.

The USA also, although on different grounds, distanced itself from the conclusion of equivalence, and proposed that the paragraph in the new regulation with respect to the mid-deck tanker be deleted. This proposal was not adopted.

No substantial changes to the draft regulations were made in spite of some of the recommendations by the Steering Committee. The recommendation with regard to longitudinal bulkheads was not discussed, and the implicit suggestion (made explicit during the debate by one or two delegations) that larger wing spaces for double hull tankers would increase the safety of these tankers in cases of collision also was not given any consequence.

The only real problem in the final discussion of the new double hull and mid-deck tanker design standards was brought up by the Republic of Korea at almost the last moment of the discussions, shortly before the formal adoption. The delegation of the Republic of Korea 'expressed its concern on the recent application by a company for an international patent on the mid-deck concept' and implicitly threatened (a threat not reflected in the official report) that they could not support the mid-deck tanker provisions in the new regulation because 'regulations of the Convention should not be utilized for commercial purposes'. Korea called for an assurance that the mid-deck tanker provisions, if adopted, could be implemented without financial consequences associated with an international patent. Many wondered why Korea had waited so long to bring up this issue, but whatever the reason for that, the intervention was effective. The Japanese delegation reacted that it had been informed 'by the inventor of the mid-deck design that, if the application for the patent of mid-deck design by them were ever accepted, they *would not* claim their right on the patent, i.e. any shipbuilder in any country will be free to build mid-deck tankers […] without royalty and without permission by them'. The representative of Mitsubishi Heavy Industry in the Japanese delegation, the industry referred to by Japan as 'the inventor', confirmed this.

He also stated that 'the intellectual right of inventors should normally be protected, even for inventions of this character'.

The equivalence of double hull and mid-deck tankers was in the end accepted by the MEPC (and by implication also by the IMO): the new regulation 13F of Annex I of the MARPOL Convention was adopted.

6 Some developments since the adoption of the new MARPOL regulations in 1992

The adoption of the new MARPOL regulations was by no means the end of the debate. IMO's Steering Committee on Oil Tanker Design itself noted that more work needed to be done especially with regard to fire and explosion, and operational safety. It didn't take long for e.g. the US National Academy of Sciences to make recommendations such as the need to strengthen design standards to ensure proper corrosion protection, proper dimensions of structural members and proper use of high-tensile steel; design based on the possibility of accidents should be considered for tank vessels. In addition, many suggestions have been made since in various publications.

New design ideas were also brought forward. This was true already at the time the IMO Steering Committee on Oil Tanker Design was active. One of the interesting ideas in this respect was the so-called 'eco bulkhead' developed in The Netherlands (e.g. [14]). This eco bulkhead was a modification of a swash bulkhead having a closed watertight plate structure running from the deck to the bottom except for relatively small holes near the bottom. In cases of accidents with side damage (at present one of the 'less-strong' points of the double hull design), this principle prevents (or limits) accidental oil outflow on the basis of the hydrostatic balance principle. The eco bulkhead prevents the outflow of oil from the undamaged part of a tank. Another design alternative, available but largely ignored during the IMO post-*Exxon Valdez* discussions was the so-called *Coulombi Egg* tanker. None of these design alternatives has been given a chance.

It is also noteworthy that, since the adoption of the new design standards, no mid-deck tanker has been built or ordered. The major reason for that might well be the fear that, in spite of the international legal acceptance of this design, such ships could be denied entry into US ports or waters.

The only new developments that were to become as much a reality as the amendments of MARPOL had been were, as so often, accident driven.

On 11 December 1999, the single-hulled tanker *Erika*, carrying a cargo of some 31,000 tonnes of heavy fuel, broke into two in a severe storm in the Bay of Biscay, 60 miles off the coast of Brittany (France). About 20,000 tonnes of oil were spilled. Some 400 miles of the French coast were contaminated with oil. The magnitude of the spill and the length of coastline affected resulted in a large number of compensation claims. There are important coastal fisheries, mariculture (oysters and mussels) and tourism resources throughout southern Brittany and the Vendée. Salt production areas were also affected by oil pollution. Investigations into this accident lead to the conclusion that age, corrosion, insufficient maintenance and inadequate surveys were all strong contributing factors to the structural failure of the ship. As a result, there was a strong call for new international measures and the IMO duly delivered.

On 13 November 2002, the single-hulled tanker *Prestige*, carrying a cargo of 77,000 tonnes of heavy fuel oil, suffered hull damage in heavy seas off northern Spain. The vessel drifted towards the coast and was eventually taken in tow by salvage tugs. Access to a shetered safe haven in Portugal or Spain was denied and she had to be towed out into the Atlantic. Early on 19 November, some 170 miles west of Vigo, she broke into two. The two sections sank some hours later in water two miles deep. Some 1,900 kilometers of coastline were affected by the resulting oil spill. Again there were calls for new international measures and, again, the IMO duly delivered.

The international measures taken of the incidents with the *Erika* and the *Prestige* did not include new design standards for tankers but include a wide array of other types of measures. Among these:

– A revision of regulation 13 G of MARPOL to the effect that the phasing out of single-hull tankers was accelerated (i.e. brought forward to 2005 for category 1 t ankers and to 2010 for category 2 and 3 tankers), and
– amendments to the guidelines on the enhanced programme of inspections during surveys of bulk carriers and oil tankers with relation to the longitudinal strength of the hull girder of oil tankers.

7 Some observations regarding the effectiveness of MARPOL's double hull requirements

It is hardly possible to draw any conclusion with respect to the effectiveness of MARPOL's new double hull design standards. There have been no major oil spills involving a double-hulled tanker where there is no doubt that a single-hulled tanker would have caused a (much) larger oil spill than the double-hulled tanker did.

Whilst there are new studies regarding marine oil pollution, these data do not support a conclusion that the contribution of oil spills caused by tanker accidents to the total oil pollution of the world's seas and oceans has decreased significantly.

In 2002, the National Research Council of the U.S. National Academy of Sciences published a new estimate of the total worldwide annual release of petroleum from all known sources [15]: 1.3 million tonnes (albeit with a wide range from a possible 470,000 tonnes to a possible 8.4 million tonnes per year). These figures represented no clear difference from the estimates available in the early 1990s.

With respect to the importance of the various sources of marine oil pollution this report also produced new estimates, given in Table 8.4. Another estimate for the contributions of the different sources of oil pollution, also given in Table 8.4, was published by the Australian Petroleum Production and Exploration Association, APPEA, [16], also given in Table 8.4.

Table 8.4. Recent estimates of marine oil pollution from different sources compared to the 1993 GESAMP estimates

	NRC 2002	APPEA	GESAMP 1993
Natural seeps	46%	7%	11%
Land-based sources and operational Discharges from ships	37%	70%	70%
Tanker accidents	12%	14%[a]	5%
Extraction of oil	3%	[a]	2%
Atmospheric deposition	–	9%	13%

[a]The APPEA estimate combines tanker accidents and offshore oil extraction.

If these figures were correct, the conclusion would have to be that since the early 1990s the relative importance of marine oil pollution caused by tanker accidents has increased significantly. However, the range of uncertainty in the various estimates is so wide that such conclusions cannot be drawn. Consequently the data do not allow for any conclusions regarding beneficial effects of the double hull design standards either.

The real test for the effectiveness of the double hull design standards introduced after the *Exxon Valdez* still has to come. Until now double hull ships have been new ships, and, as one would expect from new ships, have been given crews that would meet high standards. But the double hull design standards are now some 15 years old, the oldest double-hulled tankers built in accordance with these standards are now coming of age. This is the time when issues with regard to operational safety and fire and explosions will see an increased relevance.

At the same time, the discussions regarding tanker design still need to be put in perspective: the problem of (oil) pollution of the world's seas and oceans still is not primarily a problem of oil tanker accidents. As far as ships are concerned, the most important problems are associated with operational discharges, not accidental discharges. In addition, the human factor, in terms of both quality and quantity (e.g. small crews), still needs to be addressed properly. Last but not least, it is not just the design of a ship that counts, its operation and maintenance are at least just as vital.

8 Epilogue

On 2 February 2006, the *Seabulk Pride*, a double-hulled and double-bottomed oil tanker, grounded in Kachemak Bay in Alaska. She was struck by an ice flow while transferring cargo; its mooring lines parted causing the vessel to drift and go aground. As a result some 75 gallons of petroleum product spilled. The accident revived memories of the *Exxon Valdez*, the media duly reported another tanker accident off Alaska, but neither the ice flow nor the grounding caused any damage to the cargo tanks [17].

References

1. United States Coast Guard, Department of Transportation (1993) *Federal On Scene Coordinator's Report T/V Exxon Valdez Oil Spill*, US Coast Guard, Washington, DC, September.
2. IMO (1990) *Petroleum in the Marine Environment. Submitted by the United States of America (MEPC Document 30/INF, 13)*, IMO, London.
3. GESAMP (1993) *Impact of Oil and Related Chemicals and Wastes on the Marine Environment*, IMO, London.
4. National Research Council (1991) *Tanker Spills, Prevention by Design*, National Academy Press, Washington, DC.
5. Scientific and Technical Working Group. Second International Conference on the Protection of the North Sea (1987) *Quality Status of the North Sea, Status Report*, Scientific and Technical Working Group, London.
6. IMO (1990) *Petroleum in the Marine Environment*, IMO, London.
7. MARPOL (1973, 1978) *International Convention for the Prevention of Marine Pollution from Ships*, MARPOL, London.
8. *Safer Ships, Cleaner Seas (Report of Lord Donaldson's Inquiry into the Prevention of Pollution from Merchant Shipping)*, HMSO, London, 1994, p. 11.
9. See, e.g., IMO documents: *MEPC 29/22* (report of MEPC's 29th session, 12–16 March 1990) and *J/5893* (Status of Multilateral Conventions and Instruments in Respect of which the International Maritime Organization or its Secretary-General Performs Depositary or Other Functions as at 31 December 1994) for further details of this convention.
10. IMO documents: *MEPC 30/7/1* (submitted by the USA), *MEPC 30/INF.23* (submitted by the USA) and *MEPC 30/23* (report of MEPC's 30th session, 12–16 November 1990).
11. IMO Document *MEPC 30/7* (by the International Chamber of Shipping).
12. IMO (1992) *Report on IMO Comparative Study on Oil Tanker Design*, IMO, London, February.
13. *IMO Document MEPC 32/20* (Report of the 32nd session of the MEPC, 2–6 March 1992).
14. van der Laan, M. (1995) The eco bulkhead, outflow reduction by simple Archimedes, *HSB International*, February.
15. U.S. National Academy of Sciences *Oil in the sea III: Inputs, fates and effects*, Report by the National Research Council, 2002.
16. Australian Petroleum Production and Exploration Association (APPEA), *Discovery: Explore the World of Oil and Gas: Oceans and Oil Spills*.
17. Alaska Department of Environmental Conservation, Division of Spill Prevention and Response, Prevention and Emergency Response Program *Situation report (SITREP#: 9 & Final)*, 8 February 2006.

Chapter 9
Pipeline Technology

A.A. Ryder and S.C. Rapson

1 Introduction

Thousands of years ago – long before the Romans – the Chinese were making use of timber to construct primitive interlinked conduits/pipelines for the transportation of irrigation water. Throughout history, pipelines have consistently been the most efficient mass-transportation method for liquids. However, it is only in the last century that pipeline design, construction and operation have affected the evolution of the pipeline into a safe and reliable method of transporting vast quantities of hydrocarbons over long distances.

Transportation by sea-tanker certainly hasn't been given good press, with high-profile sea-tanker incidents such as 1978's Amoco Cadiz (220,000 tonnes), 1989's Exxon Valdez (38,000 tonnes), 1993's The Braer (80,000 tonnes) and 1996's The Sea Empress (72,000 tonnes) causing widespread detrimental impact on the environment. In 1999, the Erika spilled 13,000 tonnes of heavy diesel oil off the coast of Brittany, causing $860m of damage and sparking EU legislation to ban tankers more than 25 years old. In April 2001, the International Maritime Organisation (IMO) decided single-hulled tankers built in 1973 or earlier should be withdrawn by 2007, and more recent ones by 2015.

Though the volumes of product transported in a single road tanker are much smaller than anything a pipeline or tanker could contain, the consequences can still be devastating. In 1978, at San Carlos, Spain, a tanker designed to carry ammonia was overloaded with propylene, causing it to burst and spread 22 tonnes of propylene over a campsite loaded with ignition sources. The resultant fireball killed 200 people (Health and Safety Commission, 1991).

Rail transportation has a similar potentiality for disaster. A well-publicized point-in-case occurred in Mississauga, a city on the north shore of Lake Ontario, west of Toronto, on 10 November 1979, when 24 cars of a 106-car freight train (2 km long) were derailed at a level crossing. Twenty-two of the cars contained chemical products, including propane, toluene, caustic soda, chlorine and styrene. The subsequent explosions and fires ruptured propane tankers and a chlorine tanker, leaking the contents of the latter and threw the

RSK ENSR Group plc., Spring Lodge, 172 Chester Road, Helsby, Cheshire, WA6 OAR

tankers up to 700 m in all directions, causing the evacuation of 75% (217,000 people) of Mississauga's population (Burrows, 1990).

Overall, the pipeline industry has been free of major disasters. Pipeline related bloodbaths are prevalent in Nigeria and all over the news. In 1998, 1000 were killed in a pipeline blast in Warri, and in 2000 a further 300 died in a similar explosion adjacent to Warri – though this was the result of direct sabotage rather than inherent pipeline flaws.

In recent times, the most noticeable incidents of pipeline malfunction have been in Russia, where the problems tend to be related to the age of the pipelines, their length and severe climatic regimes. In addition, Russian pipelines are characterized by a lack of pigging facilities – a moot point given that most are un-piggable, due to varying pipe diameters and other inherent problems. Typical pipeline failures include pipes floating up in bogs or, due to the freezing conditions, metal fatigue resulting from the formation of ravines and crevasses in the ground (Gritzenko and Kharionovsky, 1994). One of the most famous pipeline failures occurred on 3 June 1989, when a train ignited a gas cloud between the towns of Ufa and Asha, south-east of Moscow, leaving a reported 706 people hospitalized and 462 dead or missing. Instead of investigating the leak, engineers had increased the pumping rate to keep up the pressure, causing LPG to escape and form pockets in two low-lying areas. The turbulence caused by the presence of two trains mixed the LPG with the air to form a flammable cloud, which was then sparked by one of the trains. The scale of the explosions is illustrated by the fact that trees 4 km away were flattened and windows 13 km away were broken (Det Norske Veritas, 1993). Another well-known incident is the mass leakages produced by the 43 km Vozey–Usinsk pipeline in Russia's Arctic Komi Republic. Built in 1975, the leaks began in 1988. By 1994, leaks averaged 17 a month and in August 1994, a record 23 leaks were recorded. Dams were built to contain the oil that was saturating the marshy ground. In August 1994, multiple leak-resulted spills totalled an estimated 30,000 tonnes. Further spills occurred on 16 September and on 28 September one of the dams broke. The other dams collapsed soon after. Ironically, the Russian media learned of the disaster from US sources (*Russian Petroleum Investor*, December 1994/January 1995). The total loss varied from the official estimate of 14,000 tonnes to the 270,000 tonnes claimed by American oil workers in the area (*Moscow Tribune*, 9 November 1994).

Fortunately, it's good news for the West according to the oil industry group CONCAWE, whose 2003 report of oil industry pipeline failures identified only 10 reported oil spillages (the average per year since 1971 has been 12.7). The gross spillage was 2830 m^3, equivalent to 3.5 parts per million (ppm) of the total volume transported, of which nearly 90% was from a single event. A total of 1210 m^3, i.e. 43% of the spillage, was recovered or safely disposed of. The net oil loss into the environment, therefore, amounted to 1620 m^3, or 2.0 ppm.

No associated fires or injuries were recorded. With the exception of one mechanical failure, all incidents (including the substantial one) were the result of third-party activity.

In this chapter, we consider the environmental pressures on pipeline owners and operators in the 21st century and examine the ways in which the industry is responding to these pressures during design, construction and operation. It focuses on European and mainly UK experience, but in many cases this has international implications.

For convenience, the remainder of this chapter is divided into four parts. Environmental pressures looks briefly at the reasons behind increasing environmental awareness in the pipeline industry. The sections on Onshore pipelines, Offshore pipelines and Pipeline landfalls consider the measures taken by pipeline operators to initiate, implement and monitor environmentally sound working practices. These last three sections use illustrative examples of the ways in which the industry is responding to the pressures.

2 Environmental pressures

In recent years academic and public concern over the state of our environment has trigged a proliferation of legislation designed to mitigate the impact of any form of development. UK pipelines have always been subject to controlling measures to ensure safe operation though increasingly there have been calls for closer attention to be paid to health and safety, their visual and environmental impact. Consequently, this has been mirrored in legislation.

The authorizations, consents and specifications for building and operating pipelines in the UK are contained in numerous Acts of Parliament, the most prominent being The Pipe-lines Act 1962 (onshore) and The Petroleum and Submarine Pipe lines Act 1975 (offshore). Various clauses in these acts proclaim that steps must be taken to avoid, or reduce, danger to wildlife and human activity.

In addition, a pipeline must be designed, constructed and operated in a manner that ensures it is safeguarded from damage. However, it was not until June 1985, when the member states of the European Community adopted Directive 85/337/EEC on the assessment of the environmental effects of certain public and private projects, that environmental assessment became formalized, widely recognized and methodically implemented.

The result of this Directive has been the widespread adoption of what is known as 'environmental assessment', in which information about the environmental effects of a project is gathered and evaluated. Where significant effects are identified, measures for reducing those effects are also included. Normally, the developer will commission environmental specialists to produce an environmental statement for inclusion in the application to the planning authority.

Proposed onshore pipes (except those of public gas transporters, the Government and the water companies) that are more than 10 miles long require a pipeline construction authorization (PCA) from the Secretary of State under Section 1 of the Pipe lines Act 1962. Such applications have been subject to Environmental Impact Assessment (EIA) since 1989 by virtue of the Electricity and Pipe-line Works (Assessment of Environmental Effects) Regulations 1989, which were replaced in their entirety by the Electricity and Pipe-line Works (Assessment of Environmental Effects) Regulations 1990. These Regulations implemented Council Directive 85/337/EEC on the assessment of the effects of certain public and private projects on the environment. The purpose of the Pipe-line Works (Environmental Impact Assessment) Regulations 2000 is to implement the requirements of Council Directive 97/11/EC which amends Council Directive 85/337/EEC.

Under the 2000 Regulations, an EIA has to be carried out for all relevant pipes (Regulation 3(1)(a)) unless the Secretary of State has given a direction under regulation 4 that EIA is not required. (Relevant pipes are those pipes subject to the requirement for a PCA that are either oil or gas pipes or are chemical pipes more than 800 mm in diameter and more than 40 km in length.) However, such a direction cannot be given in respect of a proposed oil, gas or chemical pipeline that is more than 800 mm in diameter and more than 40 km in length – EIA for such pipes is mandatory by virtue of the amending Directive.

Where an EIA is required, the Regulations lay down a procedure for public consultation on the environmental statement (and on any further information supplementing it) after which the Secretary of State may issue a PCA, with or without environmental conditions, if he judges it appropriate to do so, taking into account the environmental statement and consultation. A proposed pipe cannot be installed until a PCA has been issued.

By law, an environmental statement must comprise:

- a description of the proposed pipeline;
- the data necessary to identify and assess the main effects of the pipeline on the environment;
- a description of the likely significant effects; and
- a description of measures envisaged to avoid or remedy those effects.

Amongst the environmental aspects in need of consideration are human beings, plants, animals, soil, water, air, climate, landscape, material assets and cultural heritage.

Offshore oil and gas-field developments (including any associated developments) are required to be subject to environmental assessment through special additions attached to a licence. Environmental statements have to comply with the requirements of the Directive (Cobb, 1993).

3 Onshore pipelines

Onshore pipelines are generally one of three types: those built within the oil and gas fields for the collection of oil (infield lines), those built to cover longer distances between the point of production and consumption (cross-country pipelines) and smaller diameter, low-pressure pipelines used for distribution and supply (usually natural gas).

With the exception of the low-pressure distribution and supply pipelines, the traditional material used in construction is high tensile steel. Individual joints of pipe are welded together to form a continuous tube. Valves and tee pieces may be installed along the length of the pipeline and pig traps may also be installed at intervals along the pipeline as well as at the ends. A valve is used to restrict or prevent flow, a tee piece for diverting flow and a pig trap for the launch and recovery of pipeline 'pigs' (devices put into the pipeline for construction or operational reasons). Pigs are often spherical or cylindrical in shape and have all manner of uses, e.g. cleaning, separating batches of product and the gathering of information. A pipeline, therefore, should be thought of not just in terms of the pipe, but also the associated apparatus that makes up the system, including valves, tees, pig traps, pumps or compressors and other miscellaneous ironmongery.

3.1 Design

3.1.1 Preliminary design

The real opportunity to minimize the environmental impact of a pipeline is at the early design stage. This is the point that the route is being chosen and it is here that environmentally sensitive areas can be avoided. By avoiding sensitive ecological areas such as ancient woodlands, species-rich grasslands, heaths and archaeological sites, many impacts can be avoided completely. It is often easier and more cost-effective to avoid a site completely than it is to implement specialized construction and reinstatement practices.

Today it is standard practice for environmental impact assessments to begin during the preliminary design stage of an onshore pipeline project. Typically, a 2 km wide topographically defined corridor that avoids centres of population is established and screened for features that would have a direct bearing on route considerations. At this stage, the environmental impact assessment has a dual purpose: the identification of environments on which a pipeline would have a significant impact and the identification of environments that would have a significant impact on the pipeline. The opportunity is also taken to identify other linear developments – including other pipelines – as there are obvious advantages in parallel and adjacent routing. In particular, it minimizes the cumulative effect on land use and offers definite advantages in woodland areas that may already have an easement cut through them.

The issues addressed at the route concept stage are:

- existing linear developments and established corridors including motorways, trunk roads, railways, canals, overhead electricity cables and pipelines;
- historic buildings;
- archaeological sites;
- areas subject to subsidence;
- geographical features;
- estuaries and rivers;
- geology and mineral resources;
- aquifers and water resources;

- conservation areas and landscape; and
- areas of woodland.

By utilizing the right design, construction, materials and restoration techniques, there are few onshore environments where it is impossible to lay a pipeline. Nevertheless, the aforementioned issues will present varying degrees of construction difficulty and may necessitate increased expenditure on construction materials and/or restoration. The objective at the routing stage is to achieve the most cost-effective route by attempting to minimize the length and ensure that risk to the environment and public is minimized.

The assessment is usually conducted as a desktop exercise, aided by an aerial video of the whole route. Video facilitates a rapid method to update maps and provides a visual reference tool for the project team. Screening a 2 km wide corridor for fundamental features should ensure that there is no need to undertake a reassessment – so long as the route remains within the appraised corridor.

Consultation with organizations that have a responsibility for environmental protection at national, regional and local levels will assist in the identification of areas that require protection and should form an important part of the assessment process. The consultation process should lead to the identification of all major sites of environmental interest and set the parameters for the subsequent ecological and archaeological surveys. Consultation, field surveys, the study of maps, aerial photographs and aerial videos should enable a composite set of constraint maps to be produced. Computer-generated geographic information systems (GIS) are now routinely used for major long distance pipelines. These are initiated at the conceptual stage and added to as information from various stages of the pipeline's evolution is undertaken – surveys, constraints, construction, etc. They allow project teams to share a common platform for information storage and retrieval and can be intranet-mounted for remote user access. Although computer based, most GIS allow prints of the pipeline route to be generated with topographical details, pipeline data and any other stored information as overlays.

3.1.2 Detailed design

Once the principal features affecting the pipeline route have been identified, the role of the environmental assessment is to identify in detail the possible impacts of the proposal. The corridor principle still applies and its width can be reduced to around 500 m. Within this zone, significant environmental features are identified.

(a) Consultation. Once a preliminary route has been established, it is usual for representatives from the pipeline company to visit all relevant statutory authorities along the proposed route to discuss the possible implications. After these preliminary discussions, numerous meetings are organized to

focus on regional and local issues associated with pipeline construction. The authorities are usually extremely helpful in providing detailed information about their districts. Throughout the project's life cycle, consultation with other statutory and non-statutory bodies responsible for nature conservation, archaeology, landscape and recreation should be maintained.

(b) Examination of the existing environment. A vital part of the environmental assessment is the acquisition of good baseline data. A qualitative and quantitative description of all aspects of the environment is required to provide the basis for design and assessment, as well as to maintain a record of the existing situation. The following phased studies are typically associated with a pipeline development:

- nature and distribution of land cover;
- nature and distribution of land forms;
- a geological investigation of the pipeline route;
- a landscape assessment;
- an ecological assessment in three or more phases;
- archaeological assessment in five or more phases;
- an agricultural assessment;
- the distribution of soils; and
- a study of hydrological implications.

The multitude of work phases reflects the requirements for an increasing amount of detail. For instance, an archaeological assessment may involve five phases. Phase 1 would screen a 2-km-wide corridor for known sites of national importance; phase 2 would screen a 500-m-wide corridor for all other known monuments and sites; Phase 3 is detailed field survey work along a 40-m-wide corridor; Phase 4 involves the excavation of sites that are threatened by construction; and Phase 5 would comprise a watching brief throughout construction and the subsequent publication of results.

(c) Impact appraisal and prediction. Environmental data generated from baseline survey work and considered in conjunction with detailed project studies is used to identify the probable environmental implications of the development. Examples of studies that might be undertaken are as follows:

- atmospheric emissions during construction and operation;
- noise implication of construction and operation;
- blasting and vibration;
- agricultural implications of construction;
- socio-economic implications of pipeline construction;
- strategic-economic appraisal of the project; and
- safety.

The techniques used for impact prediction are established and well documented. Some aspects such as the propagation of noise and dispersal of contaminants in the atmosphere are relatively easily modeled and produce quantitative outputs to reasonable degrees of accuracy. Others require a more qualitative approach and rely more on the judgement of experts than on comparison with accepted criteria.

Some issues have well-defined criteria that have been established by standards against which to assess impacts. These are associated with the physical, chemical and hydrological impacts connected with construction and operation. The impacts associated with land-take and ecology do not have easily definable criteria against which to assess impact. The predictions of impact in these situations tend to be presented as qualitative descriptions and the demonstrations that impacts have been minimized by design and other mitigative measures.

Criteria for assessing environmental risk are not well established, although presentation of risk helps to put certain impacts into perspective. The overall perception of environmental risk is influenced by the concept of risk acceptability – the process that has been applied when considering the effects of major accidents on the people living adjacent to the route.

(d) Identification of mitigative measures. For large pipeline projects adverse environmental impacts as a result of disturbance to the land surface is usually inevitable. These effects can be minimized by considering details of routing, construction techniques and site-specific reinstatement and aftercare programmes. For example, one recently constructed UK pipeline managed when crossing most moorland sites to reduce the normal working width of 20 m to 12 m, and topsoil-stripping operations were restricted to the width of the pipe track only. Instead of stripping topsoil across the whole width, a sand, bog mat or subsoil road was constructed directly on the vegetation. Turves were lifted from the pipe trench area, stored to one side and put back. The road was then lifted and the working area scavenged for debris.

(e) Proposals for future monitoring. The environmental statement broadly identifies the potential environmental impacts of the development. Monitoring programmes need to be established to:

- obtain, where appropriate, baseline data for the environment prior to the construction, commissioning and operation of the pipeline;
- monitor any significant alteration to the biological, chemical and physical characteristics of the local environment;
- monitor emissions and discharges at all stages of the development to ensure they meet the national, local and company management standards;
- monitor any alteration to the inter-relationships of different aspects of the environment;
- determine whether any environmental changes that may occur are the result of the development or result of natural variation.

The intention is to determine, where appropriate, both the natural fluctuations of environmental parameters and the extent of other anthropogenically induced changes before, during and after construction of the pipeline and throughout its operational life.

(f) Preparation of the environmental statement. Environmental assessment is the process of environmental input to project planning and the prediction of its likely impacts. The products of the process are often a series of technical reports that are summarized in a user-friendly form as an environmental statement. The report may be submitted to the statutory authorities in draft form. Then, after further consultation, the final document can be made available to the public and other interested parties.

(g) Contract documentation. The key to effective environmental management is to translate the products of the environmental assessment into action. For the environmental assessment to have some impact upon the reality of construction, the results must be built into the technical specifications and included where necessary in contract documents (including alignment sheets).

There is no single way to achieve this and, as with all contractual matters, a balance between providing the contractor with too much and too little information needs to be found. It has been argued that too much environmental information will cause the potential contractor to react adversely and charge a premium on the basis that perceived environmental sensitivity presents a risk. Conversely, if inadequate information is provided then there is a risk of claims for additional work and the possibility that adequate environmental controls will not be implemented. One solution is for the contractor to produce a method statement. The basic requirements needed to comply with the environmental statement are set out in the contract document. The contractor is then invited to produce a method statement that adds detail to the information provided by the design engineers in the contract.

3.2 Construction

It is clear that during the planning and design phase of a pipeline considerable effort is expended in the identification of potential environmental impacts, the identification of suitable mitigation measures, the inclusion of mitigation measures into the design and, where appropriate, their stipulation in contract documentation. For those mitigation measures to be implemented effectively during construction, they must be *known, understood* and *implemented* by all relevant personnel. These three basic requirements are the cornerstones of effective environmental management and arguably the most difficult to meet.

3.2.1 Raising awareness and understanding

Raising awareness is perhaps the first step towards achieving satisfactory environmental performance. Management must appreciate the significance of environmental issues and be committed to achieving a high standard of environmental performance. This commitment will be strongly influenced by the level of importance the company's senior management ascribes to environmental issues. A company with a strong commitment to environmental protection and a visible environmental policy is more likely to achieve the commitment of its project management team.

A project's workforce will need to become familiar with the environmental issues specific to the project. This can be achieved in a number of ways, for example:

- A full-time environmental supervisor may be appointed to the management team from the outset of the project. He or she would have the responsibility for briefing the project, construction and engineering managers on environmental issues.
- Monthly health, safety and environment meetings may be held, allowing issues of concern to be discussed by the management team.
- Informal workshops may take place. For example, on one recent project, an archaeological dig took place along the pipeline prior to construction and many members of the project team took part under the supervision of trained archaeologists. In the evenings, there were presentations about archaeology and what had been found along the pipeline route during the preconstruction surveys and what was likely to be found during construction.
- Health, safety and environment workshops may be held once construction contractors have been selected. Members of the client team and the construction contractors participate to ensure that all senior management appreciates the importance of environmental issues on that project and understand the mitigating measures that have been designed and incorporated into the contract documents.
- All personnel should go through a programme of induction training before they are allowed to work on-site. This may take the form of a talk from the site safety and/or environmental officer.
- Toolbox talks may be held on an as-required basis with different construction crews. Typically, these are held on weekly basis, or before entering a special section by the supervisor or foreman. However, if a special environmental crossing is about to be encountered, an environmental officer would explain what is important about a site and how to protect it.
- Signs should be erected along the spread indicating the beginning and end points of areas where special precautions have to be taken.

3.2.2 Site supervision

The number of inspection staff required is always contentious, with financial constraints likely to mean the reduction of such staff. Nevertheless, quality assurance philosophy maintains that well-written procedures and the use of appropriately trained staff can help to reduce the number of inspection staff required. Experience suggests that the higher the level of supervision, the better end product.

It is essential that environment, like safety, is perceived as a line responsibility and not the sole responsibility of the environmental officer. All supervisors and inspectors can help ensure that environmental requirements are implemented. However, the effectiveness of this is dependent upon the supervisor appreciating and implementing a project's environmental controls. In sensitive areas, a greater input will be needed from an environmental officer. They will most likely have been involved in designing mitigation measures and will therefore know how flexible those measures are. A well-informed environmental officer with knowledge of the site will be better placed to advice on how to overcome any potential problems.

3.2.3 Reporting

A client-appointed manager and a dedicated project team manage the construction of most pipelines. Reporting to that manager will be various management disciplines, such as construction, engineering, health, safety and environment (HSE). Most organizations have a corporate HSE group, so it is useful to maintain a link between a project's HSE group and the corporate HSE group. This provides a mechanism whereby a project manager can be circumvented if need be.

3.2.4 Contractor plans

Contractors should be encouraged to prepare their own environmental management plans. This will allow the contractor to implement procedures that are tailored to their organization and way of working. Plans may be required to cover:

- archaeology – what to do in the event of an archaeological find;
- waste management – including waste minimization, reuse, recycling and disposal;
- pollution prevention – including avoidance, containment, clean-up and reporting arrangements.

3.2.5 Construction methods

The standard method for the construction of welded steel cross-country pipelines across normal agricultural land is based upon the spread technique. A 'spread' consists of all the people and equipment necessary to conduct the construction operation, from surveying the route to restoration. The work is carried out on a continually moving assembly line basis, with each sequential activity maintaining a consistent rate of progress. On a long pipeline, there may be a number of spreads with work being undertaken by different contractors on different spreads. Progress may be as much as 1 km per day. In the UK, construction is usually confined to the period from March to October when weather conditions are most favourable.

Each spread contractor will need a number of different crews. They will undertake the following task.

(a) Location of existing services
The main route surveys will have identified the existence of third-party services such as pipelines and cables that cross the Right of Way (ROW) and it is important to establish their exact location and depth and mark them so that the operations that follow avoid damaging them. Overhead cables also need to be identified and clearly indicated so that they can be seen by approaching plant operators.

(b) Setting out and fencing
The ROW is pegged out and the working width fenced on both sides. Fencing should be designed to suit the nature of the terrain and will range from simple demarcation fencing (to indicate the working width to operators working on the spread) to stock-proof fencing for farmland. It may also be necessary to incorporate barriers in the fencing to prevent protected species such as great crested newts from straying onto the working width.

(c) Preparation of the working width
The preparation of the working width includes a number of activities depending on the terrain. For cultivated land, it is likely to include topsoil stripping and storage, diverting ditches and minor drainage channels to prevent water entering the pipeline trench, clearing hedges and trees and preparing access to the working width. It may also be necessary to undertake the same work for designated pipe storage areas and office compounds. In all cases, measures should be taken to mitigate damage to the underlying ground by using geotextile fabrics.

(d) Land drainage
Land drainage issues are relevant to pipeline routes that pass through cultivated areas with land drains leading to watercourses. The requirement is to survey the existing drainage to ensure that temporary drainage is provided during the construction works and reinstate to at least the original condition. It is essential to ensure that water run-off from drainage systems affected by the construction works is not contaminated and, therefore is non-polluting.

(e) Line-pipe stringing
Pipe is usually procured in 12 m lengths and is delivered to site with corrosion protection coatings applied and with end caps to prevent ingress of debris. For long pipelines, it is usual to have delivery areas at intervals along the route where pipe is stockpiled ready for transportation along the working width. The stringing operation entails distributing pipe along the spread ready for welding.

(f) Field bending
Field bends are used to allow the welded pipeline to accommodate the vertical and horizontal profile of the route. The route surveys determine the radius

that is necessary and individual pipes are bent to suit using field bending machines. The limits to which a pipe can be bent and still remain within allowable metallurgical parameters for the pressure design depends on the diameter, thickness and grade of steel. If a bend radius below this limit is necessary, forged or fabricated bends may be used. Small radius bends are used for crossings of ditches and other features, whereas larger radius bends are used to accommodate the natural undulations of the route where they are beyond the natural radius of the welded pipe.

(g) Welding

The pipeline is welded into a continuous length alongside the trench. There are two types of weld – sleeve or butt. Butt-welding is the most common for high-pressure oil and gas pipelines.

During the design stage, a welding procedure will be prepared specifying the end preparation requirements, the alignment and gap dimensions between pipe ends and the number and type of weld pass that will be necessary to complete the joint. A weld pass is an individual run of weld. Several passes are required to complete a butt-welded pipe joint. Test welds are carried out to verify the welding procedure with non-destructive (radiographic or ultrasonic) and destructive metallurgical techniques used to check that the weld material and weld effected zone meet requirements.

Pipe that has been strung along the working width will have had its ends prepared for welding at the manufacturing stage or on-site prior to stringing. The ends will be checked and if necessary mechanically cleaned to remove any oxidation or other impurities that will impair the weld. The pipes will then be aligned using an internal line-up clamp that will control the roundness and gap between pipes to within the required tolerances.

Manual welding is the most common method for pipelines although automatic welding machines, initially developed for offshore laybarges, are now used for land pipelines. With both methods, the welding procedure will dictate the number of passes required, the weld material and any preheat requirements. Typically for manual welding these will include an initial root pass, filler passes depending on the wall thickness and a final capping pass. Fewer passes are necessary with automatic welding.

The welding process is usually carried out sequentially starting with a welding station for the root pass. As each root pass is completed, the welding station is moved down the line to the next joint and the process of alignment and welding is repeated. Welding stations for the filler passes and the capping pass follow, also in sequence. Welding equipment for the various passes is portable and often mounted on tracked side-boom lifting machines.

Welding is a highly specialized technology and there are many national and international codes and standards that govern requirements.

(h) X-ray and inspection

All welds for high-pressure pipelines are 100% non-destructively tested using radiographic techniques with X-rays as the source. The testing procedures are carried out by specialists trained to handle radioactive isotopes and in the interpretation of the resulting X-ray photographs of the weld area. Imperfections such as weld slag intrusion or hairline cracks are cut out and re-welded.

(i) Coating and wrapping field joints

When the weld has been tested and passed as satisfactory, the external and internal surfaces of the weld and adjacent pipe are mechanically cleaned by shot blasting or other means. Corrosion protection coatings compatible with the main part of the pipe are applied to complete the joint.

(j) Trenching and lowering

Trench excavation follows the welding, testing and joint completion work, which is carried out alongside the route centreline with sufficient clearance to allow trenching equipment to operate safely adjacent to the fabricated pipeline. Trench excavation can be undertaken with standard backhoes or with proprietary pipeline trenching machines. In both cases, the excavated material is stockpiled alongside the trench for reuse as backfill.

If rock is present it may be necessary to use explosives or specialist rock excavation plant to excavate the trench and a bedding material may be required to prevent damage to the pipeline when it is lowered into the trench. Wet conditions may also require specialist attention to achieve a ‘dry’ trench. Suction pumps can be deployed to remove water that drains from the surrounding area and in extreme conditions where the excavation is below the water table, it may be necessary to use a well point dewatering system. This consists of suction tubes that are driven into the ground alongside the trench. The tubes are connected to a pipeline manifold suction arrangement driven by pumps that discharge into adjacent watercourses. It should be noted that discharge arrangements might require consents from the regulating authority. The system lowers the water table to below the bottom level of the trench. In extreme conditions where the ground is highly permeable and well point dewatering systems cannot cope with the quantities of water, ground-freezing techniques using liquid nitrogen can be used.

As with all excavations, it is necessary to comply with safety regulations and procedures to ensure that adequate precautions are taken to prevent people or equipment from accidentally falling into the trench. If people are required to work within the trench, trench sheeting should be used to prevent the sides collapsing and causing injury.

Immediately behind the trenching operation, side booms are used to lift the fabricated pipeline from the temporary supports on the welding line. The pipeline is supported within rollers suspended from the side booms so that they can progressively move forward and, at the same time, ‘snake’ the pipeline into the trench maintaining a predetermined safe curvature that will prevent overstressing.

(k) Backfill

Backfill supports the pipeline structurally and, if placed correctly, prevents future settlement along the pipeline route. Structural support is particularly important with large diameters and is achieved by placing and compacting granular material or lean mix concrete around the pipeline and immediately above it. This initial backfill should be placed carefully to prevent damage to the corrosion coating. The excavated material can then be used to fill the trench providing it consists of readily compactable soil, i.e. substantially free of clay and organic material such as tree roots. Compaction will be necessary to prevent settlement and it is good practice to replace the excavated material in as near as possible the same sequence of layers that it was originally excavated in.

(l) Reinstatement and restoration

Reinstatement and restoration of all land affected by the pipeline construction works, including access roads, office or storage areas, is one of the last operations to be carried out and involves replacing top soil, land drains, natural features and boundaries such as hedges. Programming may also be affected by seasonal weather conditions and it may be necessary to wait for dry weather or conditions that suit seeding and planting vegetation or hedgerows.

(m) Hydrotesting

As with reinstatement, this is one of the last operations to be undertaken and is used to prove the fitness of purpose of the completed pipeline including above ground installations. Long pipelines are often tested initially in sections with a final full-length test on completion of tie-ins between sections, with crossings or at above ground installations (AGI).

The test procedure will include pigging to remove debris, the use of gauging pigs to check for damage that may have occurred during construction, filling with test water and subsequent removal of test water to approved disposal points.

Test water may be moved from one section of the pipeline to another for reuse during the sectional tests. Test water may require additives to act as oxygen scavengers and biocides. They prevent corrosion to the pipe material and inhibit formation of microorganisms.

The test procedure will stipulate the pressures to be used and the duration that pressures are to be maintained for. The usual requirement is to have an initial low-pressure stage to check for leaks and a higher-pressure stage applied to test the integrity of the pipeline system as a whole. The higher-pressure stage is set at a level above the operating pressure and will generally be specified in design codes and standards. Before applying pressure, the ambient temperature and test water temperature have to be monitored so that variations during the test period that will alter the pressure can be allowed for.

(n) Commissioning

When the final tie-ins and hydrotesting have been completed, commissioning operations can commence and generally consist of purging and drying the pipeline system to remove test water. Slugs of chemicals that are readily miscible with water, such as methanol, are driven through the pipeline system between pigs. Alternatively, vacuum drying or dry air can be used. The product to be transported governs this choice and when the process is complete, nitrogen may be used as inert filler before the product is introduced.

The commissioning process should also be used to check control and monitoring systems. This will be aimed at testing the telemetry systems that remotely actuate valves and safety systems, such as emergency shut-off valves.

(o) Post construction documentation and records

As-built records and drawings should be developed throughout the construction and commissioning phase and if a GIS is in use, they can be incorporated into the system for future reference. The same system can also be used to record events during the life of the pipeline system and can incorporate risk assessment processes to enable integrity monitoring to take place.

In environmentally sensitive areas such as Sites of Special Scientific Interests (SSSIs) and other conservation areas, special construction methods are needed. Each of the areas of concern will need to be the subject of a separate study prior to construction to determine the best crossing method. Possible methods at such sites include reducing the working width, use of temporary roads, stripping for only the pipe trench, rather than the whole of the working width, turfing, fluming and boring beneath.

3.2.6 Monitoring

Most environmental monitoring will take the form of checks to ensure that the contractor is complying with contractual requirements such as waste management and the use of designated disposal sites. Some special forms of environmental monitoring may be required at particular locations. For example, at river crossings it may be necessary to monitor dissolved oxygen and suspended solids. When working in close proximity to residential areas, it will be important to monitor noise levels.

3.2.7 Audits

Any management system should be subjected to audits to allow shortcomings to be identified and, importantly, to allow improvements to be made. For example, corporate HSE may audit the project's HSE group and the project's HSE group may audit the construction contractor or specialist environmental contractors.

3.2.8 Case study: the North Western Ethylene Pipeline, UK

Such special construction methods are well illustrated, and were rigorously tested during the construction of the UK's largest pipeline, Shell's North Western Ethylene Pipeline in 1991–1992 (Figure 9.1). The 10 inches (25 cm) diameter pipeline was built because ethylene, which is made from natural gas from the North Sea, needed to be transported from Grangemouth (near Edinburgh) to Shell's petrochemicals plant at Stanlow in Cheshire, where it

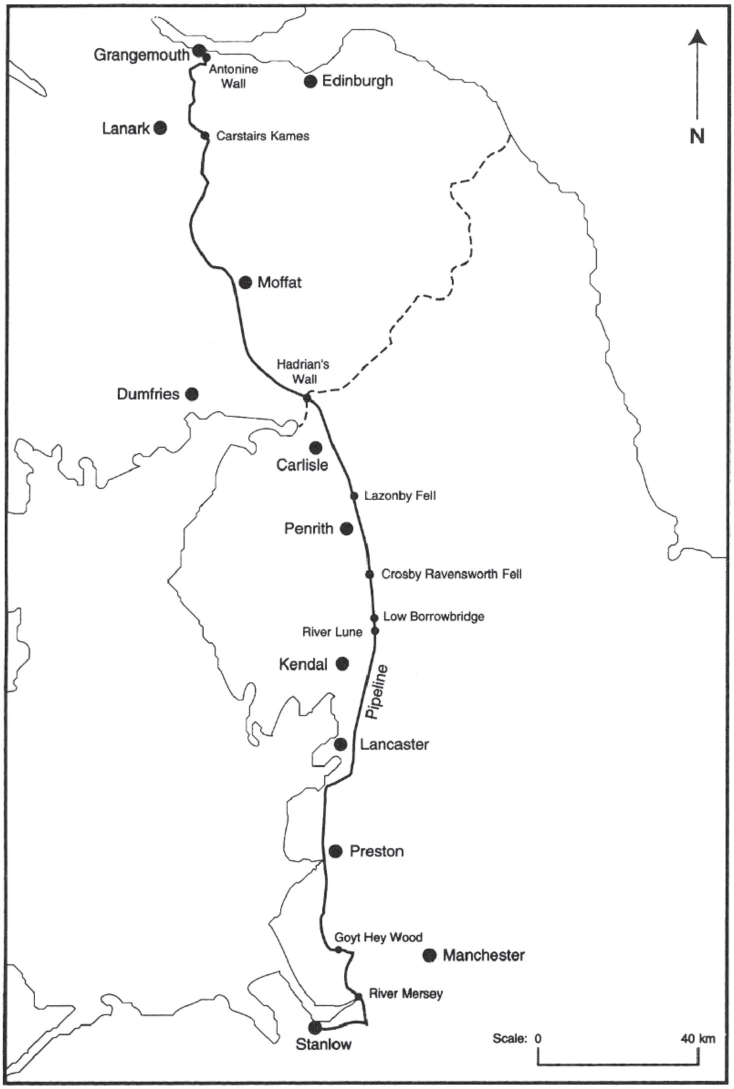


FIGURE 9.1. Map showing the route of the North Western Ethylene Pipeline and the sites mentioned in the text.

is used in the manufacture of plastics and solvents. It was the first pipeline to be subject to the Electricity and Pipe-line Works (Assessment of Environmental Effects) Regulations, 1989, which emerged as a result of EC Directive 85/337/EEC. Nowadays, the pipeline – 411 km in length, 10 inch in diameter and containing 17,100 tonnes of steel – lies buried 1 m underground and is invisible to all but the informed eye.

As it was such a long pipeline, and because it had to follow a line that was already littered with other pipelines, railways and roads, it was impossible to establish a route that did not affect any important areas. In particular, it had to cross two Roman walls (the Antonine Wall and Hadrian's Wall), both of which are Scheduled Ancient Monuments and are protected by law. In addition, it had to cross four SSSIs that were also protected by law. After a public inquiry and careful negotiations, Shell was allowed to cross these and other important features (Rapson, 1994).

Shell took care to ensure that all construction was undertaken in an environmentally sound manner. For example, trees near the working width had their roots protected from vehicles by fencing, fuel containers were kept in trays to avoid spillage and sediment in water had to be allowed to settle out before it could be discharged into watercourses. Four environmentalists and four archaeologists monitored day-to-day construction.

Special construction methods were agreed for all the sensitive environmental and archaeological sites. Carstairs Kames, near Lanark in Scotland, with its important geomorphological features surviving from the last ice age and designated SSSI, had to be crossed. A low point was chosen for the crossing, and where the pipeline had to run parallel to the edge of the kames, the width of the working area was reduced to as little as 4 m.

Lazonby Fell, an area of heathland near Penrith, is another SSSI that required special attention. Before construction began, the heather was cut to promote new growth in the following year. A 12 m wide strip was fenced off, a temporary road was laid and turves were only removed from the area of the pipe trench. After the turves had been replaced, collected heather cuttings were spread over the area to help new growth. By the summer of 1992, new heather plants were growing in the thinly vegetated areas, demonstrating how successful reinstatement had been.

Similar methods were used at SSSI, Crosby Ravensworth Fell, near Shap in Cumbria. As a large area of upland, it was not considered practicable or necessary to turf the whole area; instead, turfing was confined to floristically rich areas that had been identified by botanists before construction began. In remaining areas, the vegetation layer was scraped off using an excavator bucket and stored separately from the topsoil and subsoil beneath, so that it could be replaced on the surface at a later date, thus encouraging existing plants to grow and to maintain the plant rhizomes and the seedbank. Subsequent monitoring has shown that the turved areas recovered extremely well within a very short time. The remaining areas fared less well, and a special upland grassland seed-mix had to be applied to aid vegetation. Nevertheless, this was expected, as wet upland areas take a long time to recover and, in general, reinstatement is considered satisfactory.

A narrow strip of woodland called Goyt Hey Wood, near St Helens, had to be crossed. A point was chosen where it was not necessary to fell any mature trees, the working width was reduced to only 4.5 m and special small excavators were used. The soil containing the bulbs and seeds of the important ground flora was carefully stored and replaced. It was encouraging to see bluebells growing on the working width the following spring.

Shell had to cross several rivers along the pipeline route, including the River Lune in the Tebay Gorge. Here excavators working in the river caused much sediment to be disturbed, but by working quickly and by stopping for periods to allow clear water through, the effect was reduced. However, the River Mersey was too large for this method to be used and the horizontal directional drilling technique was used.

Archaeological sites called for a different approach. Some required excavation before construction began. For example, near Grangemouth, where archaeologists knew the exact location of the Antonine Wall, an excavation was carried out. Evidence of the wall and of a fort was found. Other sites could not be excavated beforehand because no one knew they were there. This was the case at Low Borrowbridge, where construction stopped whilst a Roman cemetery was uncovered.

Shell has a commitment to looking after the land along the pipeline route for the life of the pipeline, which is at least 25 years. For five years, they monitored the success of reinstatement of its 40 most sensitive sites. They will also checked the growth of the hedges and trees planted to replace those felled.

3.2.9 *Case study*: Environmental and Social Assessment of Azerbaijan Sector of BTC Pipeline

The Caspian Sea has long been known to be a significant hydrocarbon reserve by major oil companies. That the resources existed was seldom in dispute, the challenge was how they could be developed, transported and integrated into the world market.

Formerly a part of the Soviet Union and landlocked, Azerbaijan had been unable to fully develop its offshore oil and gas resources and find a viable method of export to international markets.

With the introduction of foreign oil companies as operators of oil and gas fields in the early 1990s, additional focus was placed on securing safe export routes from Azerbaijan. The two first export routes developed, which became operational in the mid to late 1990s, were the Western Route Export Pipeline (WREP, Baku–Supsa) and the Northern Route Export Pipeline (NREP, Baku–Novorossiysk).

While undoubtedly important, these two pipelines, with a combined capacity of approximately 220,000 bpd, did not have the capacity to enable full development of the Azerbaijani offshore fields. To further complicate matters, the oil from each of these pipelines had to be transported to market by tanker, through the already congested and environmentally sensitive Turkish Straits.

A solution was devised when a consortium of international oil companies lead by BP came up with an ambitious export solution: the Baku–Tbilisi–Ceyhan (BTC) pipeline project.

In one of the world's largest energy transportation schemes, the plan envisaged a pipeline traversing Azerbaijan, Georgia and Turkey and finishing on the Mediterranean coast at Ceyhan, from where the oil would be available to the world market.

Consisting of more than 1,760 km of buried pipeline, constructed from over 150,000 individual joints and with the capacity to transport 1 million barrels of oil a day, the statistics are certainly impressive.

Following competitive tender, the contract to carry out the Environmental Impact Assessment (EIA) of the 443 km section of the BTC pipeline within Azerbaijan was awarded to RSK Group's Azeri subsidiary company AETC (Azerbaijan Environment and Technology Centre). AETC worked closely with the Social Impact Assessment (SIA) consultants to produce a combined Environmental and Social Impact Assessment (ESIA) report.

Given that the same methodology of ESIA had to be employed throughout all three of the host countries, all consultants were required to work closely together, in doing so setting a precedent for scope, quality and consistency.

As the BTC project was part financed by a group of lending institutions, including the International Finance Corporation (IFC) and the European Bank for Reconstruction and Development (EBRD), it was required to achieve certain, rigorous standards of environmental and social performance. In addition, the requirements of the host governments had to be met.

During the ESIA process, all potential impacts of the pipeline were evaluated against applicable environmental and social standards, regulations and guidelines, existing environmental conditions and issues raised by stakeholders.

Though the potential for media and pressure group interest was ever present, ERM (who carried out the Social Impact Assessment) found that local opinion on the project was largely positive.

Of the 83 communities identified along the route in Azerbaijan, 94% were optimistic about the benefits the pipeline would offer them and their country (the majority had already experienced the construction of the Azerigaz and WREP pipelines).

Initial studies, including an Environmental Risk Assessment (ERA) to determine the relative risk of oil spills, had already discounted a succession of other transportation options before it was decided to opt for the pipeline method. For instance, it was estimated that the BTC route would eliminate the need for an additional 350 tanker cargos per year through the Bosphorous and Dardanelles straits.

Though the route from Azerbaijan to Turkey had been shown to be the most feasible method during initial routing studies, it was not without its problems. Within the Azerbaijan section alone, the pipeline crossed a number of fault zones, major rivers and ran through areas of archaeological and ecological importance.

As a starting point, a scoping process was conducted to identify key issues and develop appropriate terms of reference for a full assessment. At this stage, it was considered essential to identify the likely environmental and social impacts and to define the project's area of influence. It was integral to the ESIA that the scoping process was initiated early and in an open manner that involved appropriate degrees of disclosure and consultation with relevant stakeholders.

The project set about disseminating information to the affected local communities, national scientists, academic institutions and NGOs, as well as the authorities and regulatory bodies. A period of sustained consultation followed, with the purpose of focusing the ESIA on issues of local as well as international importance. Through this process, it was possible to define the project in sufficient detail to allow the scoping exercise to effectively and efficiently shape the full ESIA. Crucially, gaps in baseline data were identified and agreements with stakeholders were made on any necessary fieldwork and studies to fill these gaps.

Using a combination of local scientists and international experts, detailed environmental baseline studies of a 100 m corridor centred on the proposed BTC pipeline route was conducted. In addition, BTC surveyed the region and identified potential sites for construction camps, pipe yards and above ground installations (AGIs), which were then assessed against environmental and social criteria. Sensitive receptors and pathways to oil spill were also noted over a wider area.

A considerable amount of baseline environmental information applicable to the BTC project was already available from previous projects including WREP. However, where data were lacking or out of date (particularly in relation to assessing oil spill sensitivities), additional environmental baseline data were collected.

The survey work included initial routing surveys, baseline field surveys of the optimum route (botany, zoology, archaeology, landuse, hydrology, soils and geology), detailed botanical and zoological studies of areas of high sensitivity, pump station surveys (noise, landscape and air quality), traffic surveys, and contamination baseline and river corridor surveys. Geographical Information Systems (GIS) were used to manage, interrogate and interpret all data.

AETC and ERM considered the impact upon all environmental and social parameters that could potentially result from the development of the BTC pipeline in Azerbaijan that, according to ISO 14001's definition of environmental impact encompasses any change to the environment, whether adverse or beneficial, wholly or partially resulting from an organization's activities, products or services.

It was determined that the most tangible impacts were likely to arise during the construction phase, and would include transient construction noise, increased traffic, infrastructure disruption and other temporary impacts.

Some potential impacts upon ecological and archaeological features were identified and mitigation measures to remove or minimize these impacts were developed.

During the operation of the pipeline, the most significant risk was determined to be oil spills. The impacts of a spill could be significant depending on the scale of the event, site conditions and the local metrological, geographical and hydrological conditions. However, the environmental assessment showed that the probability of a spill occurring was extremely remote, and in the unlikely event of a spill a comprehensive oil spill response plan would be in place to mitigate its impact.

The ESIA specified that during construction impacts would be mitigated through the implementation of good construction practice, the development of management plans and through the application of localized measures to protect specific or sensitive receptors.

AETC's conclusions suggested that careful management and adherence to the mitigation measures outlined in the comprehensive ESIA document would ultimately reduce any potential impacts and, importantly, bring about a series of short- and long-term benefits to the region.

Most mitigation measures diminished impacts to Low or even to Beneficial. Some remained at Medium or High (for example ecological studies in the Gobustan desert, estimated that it would take 10–12 years for full habitat revival), but overall the positive effects—sociological, political and environmental—far outweighed the negative.

On 18 May 2005, oil began flowing into the BTC pipeline from the Sangachal terminal outside of Baku, heralding a new chapter in oil pipeline history. The pipeline's operation is in its infancy, but it is sure to play a leading role in regional development for decades to come.

3.3 Operation

Pipelines are generally believed to be the safest means of transporting large quantities of hazardous fluids and gases over long distances. From an environmental perspective, pipelines remain the preferred mode of transport: there is a reduced likelihood of accidents and spillage of products, and the environmental impact of operating pipelines is less than for rail or road transport. However, as a follow-on effect from increasing public awareness of environmental issues and tightening legislation throughout the world, pipeline operators are under continual pressure to make pipelines even safer. This becomes increasingly important as pressures on land increase and pipelines become squeezed into narrower and narrower corridors.

Pipelines can fail through material defect, corrosion, natural causes (e.g. earthquakes) and third-party interference (CONCAWE, 1995). Through rigorous adherence to design code standards and stringent monitoring procedures, failure from material defect, corrosion or natural causes is now much less of an issue. To ensure that pipelines have a minimal impact during operation, there are two areas that require action:

- avoidance of spills resulting from pipeline failure and adoption of plans to deal with potential leaks;
- preparation and implementation of a restoration plan.

To achieve these aims, a number of actions are required, many of which are simple components of a good management system, e.g. pipeline integrity monitoring and maintenance, prevention of third-party interference, emergency planning, record keeping, monitoring and audits and reviews.

3.3.1 Testing, commissioning and operation

After pipelaying, a pipeline must be cleaned and checked. Pipeline pigs are used to clean and check the pipe in the initial stages before hydrostatic testing takes place. Where possible, water for testing is drawn from a nearby river after agreement with the relevant authority. If this is not possible, tankers will be required. In instances that require this procedure, pressure will be generated by a diesel-driven reciprocating pump, creating some noise, though if normal standards of noise control are in place (e.g. exhaust silencer and standard enclosures), noise levels would be expected to be no greater than from other normal pipeline construction activities. The water is then discharged at a controlled rate to a site agreed with the appropriate authority. After dewatering, pumps may be used to dry the pipe. These pumps may have to operate over a period of several days so strict noise targets may have to be imposed. As an alternative/addition to vacuum drying, the tested sections may be swabbed to remove residual water by passing specially designed pigs propelled by compressed air/gas through the pipeline.

During normal operation, there will be no significant impacts on the environment resulting from an onshore pipeline, although there may be some noise from pump units. Careful planning at the design stage should ensure that these noise levels are not sufficient to cause nuisance to nearby residents.

3.3.2 Pipeline integrity monitoring

Today's pipelines have sophisticated loss monitoring detection systems. One such example is the supervisory control and data acquisition (SCADA) system, which can indentify leaks through a drop in pressure. This kind of system enables early detection of leaks, and allows the operators to shut down the pipeline, identify the location of the leak and isolate it by shutting off block valves on either side. Remote operation of the compressors and block valves from a central control unit means that a shutdown can take place within minutes. To enact the same process manually would take hours. Sophisticated telemetry enables the system to be continually checked to ensure failures are identified and rectified.

Also built into today's pipelines are facilities to pre-empt and detect corrosion. Pipelines are in the first instance protected from corrosion by the application of a protective coating or wrapping in the factory. A similar coating or wrapping of joints will also occur in the field. The pipeline's protection will also be bolstered by cathodic protection, which stops corrosion by preventing current flow from the pipe (the cause of corrosion is the removal of metal ions by the flow of current). The metal is made electronegative to its environment to such a degree that no current can leave at any point. The current, which under natural conditions would leave the metal, is opposed by the flow of the current in the opposite direction. This opposing current is either equal to or greater than the total of all the currents naturally leaving the structure. The power-impressed systems traditionally used on onshore pipelines comprise a DC power supply with the negative connected to the pipeline and the positive connected to an earth electrode. The latter is normally referred to as the groundbed.

Pipeline integrity can be further maintained by regular internal checks using a remotely operated spherical or cylindrical pig. Some pigs will simply clean the pipeline, whilst more sophisticated models will record data about wall thickness, corrosion, the location and size of dents and other pipeline deformities.

3.3.3 Prevention of third-party interference

Third-party interference is widely recognized as the most probable cause of pipeline failure. It can arise from four major sources: landowners and tenants, utility companies, contractors and local authorities. Research on recent UK pipelines has shown that, despite pipeline operators expending considerable time and money informing landowners and tenants, a third of those questioned did not inform staff or contractors about what precautions to take when working near pipelines. Furthermore, they were unclear about the safe working distance from a pipeline and the kind of work that needed to be brought to the pipeline operator's attention. Most interviewees judged the pipeline route from marker posts and did not have accurate maps showing the route. Although most had an emergency contact telephone number to hand, one third were unaware of the full range of services and advice that the operators provided free of charge (Sljivic, 1995).

The study also found that many cross-country pipeline operators are not included in the routine contacts made by utility companies and their contractors before beginning an excavation. It is possible that the current trend towards deregulation of the utility companies could make this situation worse. It was also discovered that local authority planners responsible for identifying planning applications adjacent to pipelines, often held poor information on the pipeline routes.

Third-party education about the risks associated with pipelines is clearly an essential part of a pipeline operator's job and will help to reduce risk of pipeline failure. Within the industry itself, there is also much that can be done, particularly with regards to the implementation of information technology. In particular, many pipeline operators are now implementing, or considering implementing, geographical information systems, one-call systems and improved surveillance techniques.

Geographical information systems (GIS) are useful in a number of respects. First, they allow root cause analysis to be carried out on excavation work, authorized and unauthorized, near a pipeline. Regular analysis of the cause and nature of infringements will help pipeline operators target those parties most likely to offend more effectively. Affordable, tailored PC-based systems that can manage data relating to the day-to-day operation and inspection of pipelines are now readily available, and analysis of third-party activity is quick and efficient. Thematic maps can be produced showing the location and type of offenders, excavation hot spots and notifications of works in roads, in the vicinity of rivers,etc. A further benefit of GIS output is its capability to produce customized maps for third-party use. In the USA, the Office of Pipeline Safety has implemented a national mapping system.

One-call systems, where those wishing to carry out an excavation can telephone a central number to register their intentions, have become increasingly popular in recent years. Improvements in internet technologies have facilitated similar web-based systems (linewatch.co.uk is one example), whereby the user can register an intention to dig and receive immediate confirmation as to the location of nearby utilities. Should the location fall within a particular distance of other utilities, that operator will be informed immediately. Two types of systems are in operation: those that cover a defined geographical area and include all or most utilities (requiring a great deal of investment and utility company cooperation), and those that are utility specific and provide data only on the location of their particular underground pipe (quicker and cheaper but of limited scope). The Netherlands already has a legal requirement to subscribe to a countrywide all-utility scheme, with a similar scheme being proposed in the USA. In the UK, there is no such government-led incentive, though companies are moving towards these kinds of schemes as a means of fulfilling their safety obligations.

Surveillance techniques to detect third-party interference have traditionally involved helicopter or aeroplane flights along pipelines. These enable an observer to spot any violations of the easement from the air and, if a helicopter is used, to land in order to stop interference taking place. However, it has been observed that flights of this nature, even if done on a regular basis, only identify infringements that occur within a very short time span. In addition, such flights do not allow an observer to examine the pipeline in detail and vital clues may be missed, though this may be overcome by the use of a real-time video record made at the time of the flight.

Advances in pipeline inspection technologies, primarily Pipe Integrity Gauge (PIG) surveys, have lead to improvements in identifying and locating pipeline defects. Use of inertial navigation systems coupled with above ground Global Positioning Satellites (GPS) surveys now means that individual features and defects can be given real world coordinates. Using a high accuracy GPS, features can now be located immediately, irrespective of alignment sheet inaccuracies, new above ground developments etc.

At least one pipeline operator in the UK has decided to increase the effectiveness of its ground survey techniques. To this end, it commissioned a risk analysis to determine which parts of its pipeline were likely to cause most risk to people. Pipelines through heavily built-up areas were deemed to pose most threat whilst remote upland areas pose least threat. Consequently, they developed a strategy that involved frequent monitoring of the highest risk areas, less frequent survey of medium risk areas and infrequent monitoring of low risk areas.

3.3.4 Emergency planning in the event of a spill

All pipeline operators have plans that can be acted upon in an emergency. These clearly state the line of responsibility in such an event and detail what will happen. Emergency response vehicles containing necessary equipment are held by the operators at convenient locations, and regular training is given to the staff involved. The emergency services will also be familiarized with the plans.

3.3.5 Record keeping

In its simplest form, a GIS is no more than a store of information and, as such, it allows huge amounts of information to be easily accessed and readily updated. In order for pipeline managers to access information, all they have to do is look at a VDU screen with a map of the pipeline route, point the cursor to a location of interest on the pipeline route and request the information need. This could include:

- name, address and telephone number of the landowner;
- engineering data, e.g. depth of burial, pipe wall thickness;
- crop compensation data since pipe installation; and
- aerial photographs, video images or other photographs of the site.

Any information needed by a pipeline manager can be added to the GIS, making it a central store for everything relating to a pipeline.

The potential for this type of technology is enormous, and the data retrieval option described above is the least demanding of the capabilities offered by such systems. For instance, GIS can be used to give the answers to 'what if' questions – if the pipeline were to leak at a particular location, the GIS could tell:

- the best access route to that section of pipeline;
- who to contact (including with name and telephone number); and
- which settlements fall within the area affected by the release.

GIS can interface with simulation models and present the results in an easily understood form; for example, in the case of a gas cloud, its size and travel route under certain weather conditions.

However, for all its potential, the wizardry of GIS cannot compensate for poor information on a pipeline. GIS records are only as accurate and comprehensive as the data inputted. Complete, up-to-date records are essential, irrespective of whether or not GIS is used. These records must be diverse and manifold, i.e. environmental records and waste management records.

Information about the state of the environment is essential. Data should be kept on the location of archaeological sites, recreational areas, water resources (including aquifer protection zones), areas of conservation importance (including SSSI), landfill sites, landscape features and so forth. Information on the location of these sites and the reason for their sensitivity is beneficial when planning maintenance work or responding to emergencies. If this information is unavailable it may be a good investment to undertake an environmental review of the pipeline system to focus upon the location of environmentally sensitive sites, the company's relationship with third parties and the availability of emergency response equipment.

It is vital that records are kept on the subject of waste management. In the UK, the 'Duty of Care' requires that the originators of waste keep records of what was disposed of, who transported it and what the final destination was. The exact requirements are specified in the Duty of Care published by the Department of the Environment.

3.3.6 Monitoring

It is important that the success of reinstatement is measured and that unsatisfactory areas are improved. In agricultural land, this is often a question of repairing damage to soil structure and/or drainage. Occasionally, environmentally sensitive areas have been overlooked in the past, probably owing to their low economic value from an agricultural perspective. Such areas may include moorland, heathland, unimproved grasslands, species-rich wetlands and deciduous woodlands. It is possible that hedgerows should also be added to this category, as they are often the most publicly visible. Regrettably, it is a common occurrence for new hedges to be planted at the end of construction and then not maintained, causing many to die and stirring up public anger. The type of monitoring required will depend on the nature of the site and the purpose of the monitoring. In some cases, a simple 'look see' and brief report will suffice. In other cases a detailed ecological survey will be needed, using, for example, quadrats across a permanent transect.

The only additional monitoring that is likely to be required is noise monitoring in the vicinity of pumps/compressors. This will be of particular importance if the pump house or compressor station is located adjacent to a residential area. If there are other emission sources it may be necessary to undertake monitoring, although these are likely to be associated with activities other than the pipeline.

3.3.7 Audits and reviews

Audits should be undertaken to assess compliance with the company's environmental policy or legislative requirements. Some pipeline operators have been doing this, such as British Pipelines Agency and Shell Chemicals UK. British Pipelines Agency has been undertaking audits to help them set priorities for remedial maintenance work (Barr, 1993). In some case, a more general review may be appropriate. A review is not a test, it is the collation of information. An audit will be verifying actual practice against a benchmark such as a company's environmental policy.

3.4 Decommissioning

To date, few onshore oil and gas pipelines have been decommissioned. Generally, they are cleansed and simply left *in situ*. It is important to ensure that the entire entity and associated products are removed from the line in order to prevent pollution of soil and groundwater. Usually, the removal of the pipeline would cause greater environmental impact than leaving it in place.

4 Offshore pipelines

Offshore pipelines have three functions (Haldane et al., 1992). Intrafield lines carry product from sub-sea installations to another sub-sea installation or a production platform. Pipelines between two neighbouring platforms within the same field are also usually classified in this manner. Interfield pipelines carry product from one production facility to another or to a connection to another pipeline, and their function is normally to transport the oil or gas to the next link in the system: another pipeline or perhaps a tanker. Lastly, trunk lines link the pipeline transportation system to the shore terminal.

Most pipelines on the UK Continental Shelf are constructed of carbon–manganese steel or low-alloy steel and are cathodically protected (most commonly by the use of zinc- or aluminium-based sacrificial anodes). They are also externally coated to protect against erosion. Many pipelines have a concrete coating that provides additional protection, though the primary purpose of this method is to add weight to the pipeline to prevent buoyancy. When building pipelines in the UK sector of the North Sea, it is a mandatory requirement to comply with the Submarine Pipelines Guidance Notes issued by the Department of Trade and Industry in addition to other regulatory documents.

4.1 Design

As with cross-country pipelines, environmental assessment is a process that begins at the preliminary design stage and continues throughout detailed design. Consultations with relevant statutory and non-statutory bodies are essential. Examination of the existing environment is required together with impact appraisal, impact prediction and the identification of mitigative measures where necessary. In addition, proposals for the future monitoring of the environment will be needed together with an environmental management programme to ensure contract documentation takes account of the findings of the assessment. The end product is the environmental statement, which will be required as part of the application for Pipeline Construction Authorization.

There will, however, be essential differences in the nature of the existing environment. Consequently, the resultant impacts, the proposed mitigation measures and the requirements for future monitoring will differ. These are discussed in some detail below.

4.1.1 Preliminary design

During the preliminary design stage, engineers and environmental scientists are concerned with finding a broad corridor for the pipeline route. This is normally determined by:

- seabed topography – a seabed that is too rough could lead to spanning of the pipe;
- potential landfall sites – these will limit the location of the end points of a pipeline route;
- flora and fauna of the area – known sensitive sites should be avoided if at all possible at an early stage; and
- any military activity in the area – including military exercises and munitions dumps.

4.1.2 Detailed design

(a) Consultation. The importance of consultations with both statutory and non-statutory bodies through the detailed design stage of a pipeline project cannot be overemphasized.

(b) Examination of the existing environment. At this stage, as with onshore pipelines, it is essential to gather good baseline data. However, as the offshore environment is very different from the onshore environment, there is clearly a need for a different set of criteria. For an offshore pipeline, these will generally include:

- physical conditions – bathymetry, seabed geology and sediments, sediment transport, water levels, water currents, water temperature, winds and waves;
- biological environment – nearshore benthic communities, offshore benthic communities, nearshore and offshore fish, plankton, seabirds and shorebirds, marine mammals; and
- human activities – commercial fishing, shipping and navigation, Ministry of Defence areas, cables and oil and gas exploration, minerals and

dredging, marine archaeology, conservation designations, recreation, waste disposal and planning policies.

(c) *Impact appraisal and prediction*. Baseline surveys and other detailed project work will generate the data required to appraise and predict the likely impacts of a sub-sea pipeline. As with onshore pipelines, some of the predictive techniques are necessarily qualitative and some quantitative. The main studies at this stage are likely to concentrate on:

- physical conditions – the effect of anchor mounds;
- biological conditions – the effects of physical intervention; sediment disturbance and noise on benthic communities, fish, plankton, bird and mammal communities; and the reef effect of the pipeline (a well-documented phenomenon whereby fish are attracted to structures providing shelter, causing some to fishermen trawl the length of the pipeline to benefit from the extra fish); and
- human activities – the effects of exclusion of vessels from an area during construction, on fishing, on cables, on munitions dumps, minerals and dredging, marine archaeology and waste disposal.

(d) *Identification of mitigative measures*. As with onshore pipelines, mitigative measures are often not needed if the pipeline route has been carefully selected in the initial phases of design. If special measures need to be taken, these might include:

- removal, or partial removal, of anchor mounds;
- avoidance of environmentally sensitive areas;
- adaptation of working methods within them to minimize disturbance, carefully planned crossing of obstacles such as cables; and
- avoidance of munitions dumps and known archaeological sites.

(e) *Proposals for future monitoring, preparation of the environmental statement and contract documentation*. There will be a need for construction and post-construction monitoring; requirement for the production of an environmental statement to accompany the construction authorization application and, subsequently, a need for contract documentation incorporating the environmental requirements of a project.

4.2 Construction

Construction methods for an offshore pipeline are clearly very different from those required for an onshore pipeline. A brief summary of the main methods employed is given below together with two case studies.

4.2.1 Good site practice

Raising awareness, site supervision, good reporting procedures, preparation of contractor plans and regular monitoring and audits are all essential elements of a good health, safety and environment programme and should be well established before the start of construction.

4.2.2 Construction methods

There are three standard methods of laying submarine pipelines:

- Reel barge method – this is only used for laying small diameter pipelines in shallow waters.
- Bottom pull method – this is used in inshore waters; the pipe is fully prepared on land and is pulled into the sea by barge. Welding and concrete coating can take place on land, and any damage to the pipe is more likely to result from friction along the seabed than from bending the pipe.
- Laybarge method – this is the most common way of laying pipe. The barge acts as the pipeline factory, where pipelines are welded, X-rayed and the joints coated. Lowering the pipe into the sea is difficult, and the pipe may need to be supported by a 'stinger' so that the bend does not exceed a maximum permitted curvature. Such barges need anchors at each corner.

There are several different methods for laying pipelines on the seabed; including partial trenching, complete trenching, trenching and back-filling and rock armouring. In UK shallow waters, pipelines are trenched and buried where possible, regardless of their dimensions, due to the potential that can be caused by currents and waves. In soft, sandy sediments, the trench tends to backfill itself with time. The most common method of trenching is 'jetting', where a 'trencher', a saddle-shaped construction, is placed on top of the pipe (which has already been lowered on to the seabed). The trencher is equipped with water jetting nozzles or a rotating cutterhead (depending on the sediment), and the apparatus is towed along the pipeline. The spoils are sucked into a pipe, discharged and carried away by prevailing currents, and the pipeline automatically lowers itself into the newly cut trench. Where trenching is not possible due to a hard seabed, the pipeline may be laid on the seabed and rock armoured. In deeper waters (>60 m), it is usually unnecessary to trench or bury larger pipelines for engineering reasons. However, even where the pipeline has been left proud, it may sink over time.

In recent years, there has been much dispute over the value of trenching and burial. Trenching and burial have the advantage of protecting a pipeline from some of the most frequent physical impacts such as those from fishing gear, strong currents and occasionally dropped objects. Clearly, there will be no impact on fishing gear if the pipeline is buried. Trenching and burial may also minimize problems associated with scouring and spanning, making it possible to offset some of the additional costs of burial against costs incurred in span correction. In addition, burial may make future abandonment a more viable option. When Shell and Esso began plans for the 36 in Flags gas line, they initiated a series of studies to test the notion that large pipelines in deep water did not need to be trenched. The studies found that impacts from fishing gear were unlikely to result in serious damage to pipelines, that buried pipelines were not protected from anchors from large ships, and that concrete coating does a more reliable job of weighting the pipe to provide stability. It is now generally accepted that large diameter, proud pipelines in deep water are unproblematic.

Special construction methods in environmentally sensitive areas can involve the minimization of disturbance of sediments, minimization of rock blasting, reduction of noise levels emitted from plant and machinery, careful timing of operations in order to avoid bird breeding periods and even drilling under particularly sensitive nearshore habitats.

4.2.3 Case study: Scotland to Northern Ireland Natural Gas Pipeline (SNIPS)

This 42 km long pipeline (Figure 9.2), built in 1995, was laid using a pipeline largely anchored to the seabed. Where feasible the pipeline was trenched, although in certain areas the nature of the seabed did not permit this, making it necessary to place rock over the pipeline.

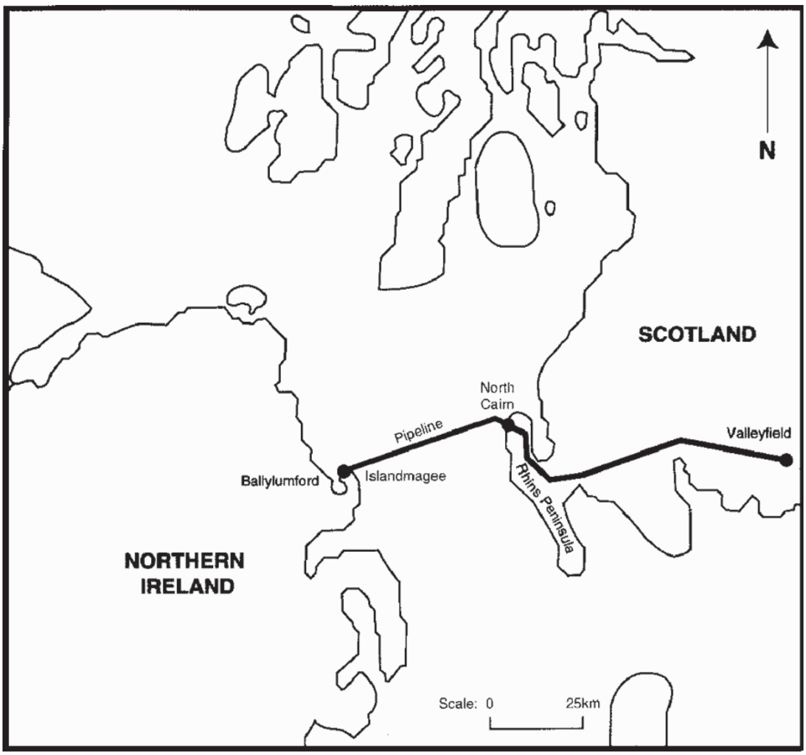


FIGURE 9.2. Map showing the route of the Scotland to Northern Ireland Natural Gas Pipeline (SNIPS).

At the preliminary design stage, 16 possible crossings of the North Channel, from the Rhins Peninsula in South West Scotland to Islandmagee on the east coast of Northern Ireland, were considered (Premier Transco Limited, 1994). The cliffs along much of the coastline precluded wide areas of the coast as landfall sites, though it was possible to identify two potential areas on each side of the North Channel.

Coastal surveys were undertaken at each of the sites to assess the seabed and coastal conditions. Offshore surveys were undertaken to assess the physical conditions along the potential routes across the North Sea. The main factors influencing the selection of the corridor were:

- the operational risks associated with laying a pipeline across Beaufort's Dyke, owing to the steep slopes on the faces of the dyke and the sediment conditions;
- an independent assessment of the landfall options that identified areas within the North Cairn, Browns Bay, Ferris Bay and Port Muck survey areas as the most suitable for the pipeline landfalls;
- the desire for the selected route to minimize the amount of disruption to the seabed that would be required; and
- the need for the selected route to avoid Danger Area D411 and the munitions dump area identified by the Ministry of Defence.

During the detailed design stage, a number of potential environmental impacts had been identified by environmental scientists. Many of the impacts would have been associated with any offshore pipeline, such as the creation of anchor mounds, temporary exclusion of fishing, changes in the habitats of benthic flora and fauna, stress to plankton organisms, change in behaviour of fish species and localized avoidance of the area by some seabirds. Others, discussed below, were specific to the area concerned.

With regard to the physical environment, one of the main concerns was the presence of a dredge spoil dump to the north of Larne. It was believed that the dumping may have led to contamination of sediment within the pipeline corridor. Dredging close to Larne could disturb the sediments, causing pollution and if contaminated sediments had to be removed from the seabed there could be problems obtaining a licence for disposal.

Also of concern were three environmentally sensitive Irish coastal areas close to the pipeline route: the bird nesting and roosting areas on the Isle of Muck and Skernaghan Point, and the diverse benthic habitats of Castle Robin. At the Isle of Muck (a bird reserve) and Skernaghan Point, there was concern about the effects of construction noise. At Castle Robin, there was concern about the effects on the diverse benthic communities of nearshore blasting through hard rock. Options for minimizing the effects on birds included avoidance of sensitive areas where possible, careful timing of construction to avoid the breeding season in spring and early summer, careful choice of plant in order to minimize noise, including the fitting of noise attenuators. Mitigation measures identified for Castle Robin included possible avoidance of blasting if a suitable route through softer sediments could be identified, minimizing the use of explosives and rock-ripping, using controlled rock splitting where possible, and avoiding the most sensitive benthic communities where possible.

It was apparent that, before construction could begin, there was a need for further studies of the pipeline route close to the sensitive areas described above. These studies led to the inclusion of special specifications in contractors' documentation that ensured the correct procedures were carried out during construction.

4.2.4 Case study: the Gas Interconnector Pipeline (GIP)

The Gas Interconnector Pipeline was built by Bord Gais Eireann between Moffat, South West Scotland, and Ballough (20 km north of Dublin, Ireland), in order to supply gas to Ireland from the North Sea (Figure 9.3). As with the SNIPs project, the detailed design stage of this pipeline was concerned primarily with the identification of landfalls on the Irish and Scottish coasts and the identification of broad corridors across the North Sea suitable for the pipeline. In particular, the landfalls were the subject of extensive study

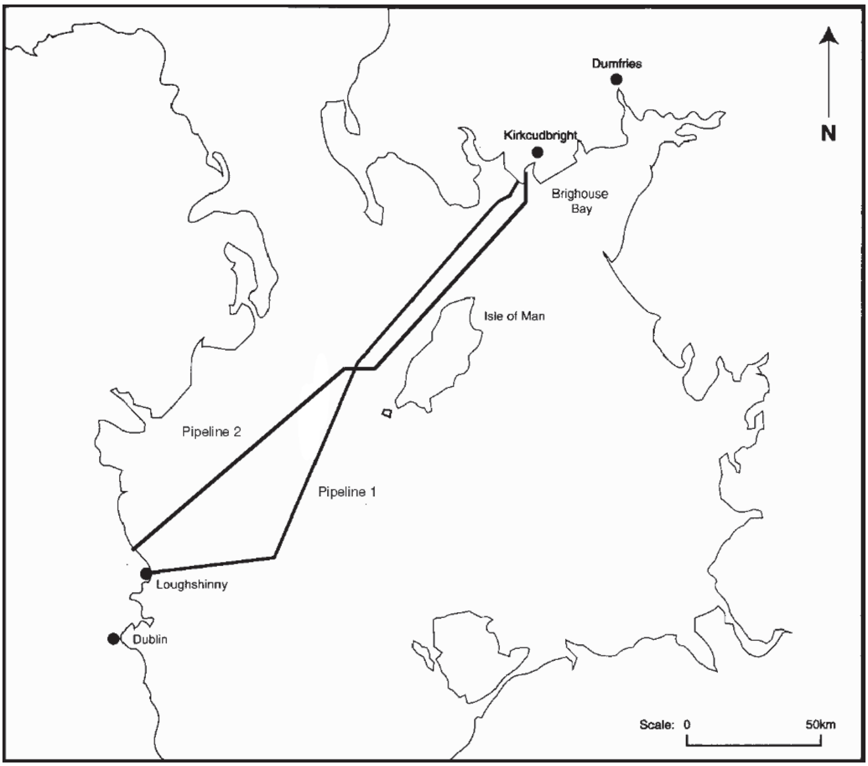


FIGURE 9.3. Map showing the route of the Gas Interconnector Pipeline.

(the exact methods employed for the Scottish landfall at Brighouse Bay are discussed later in this chapter). During consultations with affected bodies, Bord Gais Eireann discovered that fishermen were concerned with the proposal not to bury some of the pipeline. In the end, the project managers had to agree to bury the whole length of the pipe; however, as much of the pipeline was expected to sink in soft clays, it did not involve trenching the whole length. During detailed design, the environmental assessment identified many of the same potential impacts as on the SNIP pipeline, though some were specific to the GIP. One aspect needing consideration was the temporary loss of access to a 15 m wide strip along the nearshore fishing grounds at Kirkcudbright. To enable the pipeline to be laid, fixed gear such as creel pots had to be moved and mobile gear such as trawling nets had to be restricted in their operations. Unlike fishermen working further out at sea, the shellfish fleet operating out of Kirkcudbright had limited alternative areas in which to fish. In order to minimize problems associated with the shellfish fishing, the fishermen were fully involved in the decision making process: they were given early notice of the timing of the work, and they were contracted to lay the approach channel buoys. However, during the actual pipelaying operation, there was no choice but to exclude the fishermen from the pipelaying zone.

4.2.5 Case study: the Gas Interconnector Pipeline 2

By 1997, over 80% of Irish gas supplies were being imported by the first Gas Interconnector pipeline. The magnitude of volume meant that capacity constraints were beginning to surface and that if any supply interruptions were to occur, they would cause substantial negative economic impacts. In 1998, Bord Gais Eireann, in collaboration with the Department of Public Enterprise, undertook a study to identify Ireland's long-term gas infrastructural requirements. Known as the Gas 2025 Study, its purpose was to facilitate a detailed analysis of future gas supply options to ensure that supply would meet demand until 2025. The data gathered suggested that one of the main ways to achieve this would be to construct a second interconnector pipeline linking Beattock in south-west Scotland to Ballough, north of Dublin in Ireland. The selected route would include three associated above-ground infrastructure developments at Beattock and Brighouse Bay in Scotland and Gormanston in Dublin. The design phase conformed to DNV 2000 standards, while the Scottish and Isle of Man onshore sections in Scotland conformed to BS 8010, and the Irish section to IS 328. Costs were minimized by selecting a route that would traverse the shortest possible distance. To achieve swathe bathymetry, a multi-beam Seabat and DTM were extensively used, supplemented by a series of on-line assessment systems onboard the engineering survey vessel. For Interconnector 2 to become reality, considerable consultation had to be carried out. Spanning UK, Irish and Manx authorities, 11 separate bodies (excluding third-party crossing operators) were engaged with. The discussions noted that 20 permits would be required, 226 conditions to satisfy had to be met and that a treaty explicitly designating ownership of the seabed (thus avoiding the 'dog leg' that was feature of IC1) had to be enforced. Amongst the various parties' concerns were issues pertaining to anchor mounds, trench spoil heaps, turbidity and the impact on fishing activity.

Anchor mounds became less of an issue once a DP vessel was used for the main offshore lay. In the nearshore sections, the mounds were surveyed and levelled where required. Trench depth was minimized during the design phase, partly to minimize any spoil heaps. Levelling/backfill was required for any excessive heaps. Turbidity was not permitted in the northern half of the route, where a filter feeding scallop was ironically blocked by too much food in the water column. Subsequently, no jetting was permitted in the north. Largely as a result of IC1, fishermen had a number of concerns – including the impact the IC2 might have on very specific fishing techniques utilized on scallops to the north and off IOM and prawns to the south in clay basin. As a result, a considerable effort went into alleviating fears and mitigating impact. So in addition to addressing specific concerns, agreements were reached to allow the fishing organizations to contribute to the project success. To optimize continuity, a full-time engineer, who was originally a member of the EIS survey team, supervised the environmental aspects of construction. Though being involved in the project from the outset, the environmental engineer was knowledgeable about the various seasonal and other constraints and crossing of rivers and canals. For instance, they were able to provide valuable input such as the fact that certain rivers could not be crossed during spawning season and certain situations called for limitations to be placed on the use of blasting. The need for noise monitoring was required at various sensitive locations throughout the project and electofishing was necessary in some of the rivers prior to open-cut crossing. To limit the effects of siltation, continuous sampling of crossing waters upstream and downstream was carried out. A particular environmental challenge was the routing into Ross Bay in Scotland where a geological SSSI skirts most of the coastline. Following a number of site surveys in the area, a gap in the exposed rock was found on the north side of Ross Bay. This shingle beach gave the access required with a heading that was compatible with the offshore route, thus avoiding the need for special construction techniques. Project ecologists and archaeologists representing Duchas (an Irish heritage organization) were integrated into project management team. This meant that any unforeseen environmental conditions could be dealt with as they arose. Examples included the appearance of the marsh fritillary butterfly adjacent to the working area in County Clare and the need to ensure that the bats inhabiting the caves of south Galway were not prevented from reaching their feeding grounds at night due to the lack of hedgerows across the working spread. There was also a contract specification and on-site follow-up regarding damage to mature trees within the working area. Other issues dealt with by the environmental specialists included waste management practices on the various sites and liaison with local media and environmental interests when issues of interest arose.

The presence of the archaeologist proved to be particularly serendipitous when his expertise prompted the discovery of a 3000-year-old boat (which can now be found at a museum in Portsmouth). The realization of the IC2 represented the culmination of five years of detailed feasibility, planning, design and construction to preset objectives, programme constraints and control budgets. The project was completed within budget and on schedule.

4.3 Operation

During testing, commissioning and normal operation, there will be little effect on the marine environment. Severe effects will be felt only in the event of a spill. In order to prevent such a spill, pipeline operators commission regular inspections of their sub-sea pipelines, and carry out repair and maintenance where necessary. This clearly will be much more difficult in a sub-sea environment than on land and has necessitated the development of sophisticated sub-sea equipment and machinery.

4.3.1 Testing, commissioning and normal operation

The possible effects on the physical and biological environment and on human activities of offshore pipeline commissioning are related primarily to the discharge of test water. The composition of the test water for a pipeline will need to be the subject of study, and dispersion modelling will be required in order to determine its effects on the area concerned. The use of test chemicals such as biocides and corrosion inhibitors is subject to prior statutory or regulatory authorization. However, in general it is likely that any effects, relating principally to the toxicity of the test waters, will be minor and short term.

During operation, the main concern is the effect of the pipelines and associated debris on fishermen. The Scottish Fishermen's Federation claims that debris on the sea floor is much more damaging to fishing gear than the damage caused by pipelines and their associated rock dumps, yet some fishermen regularly claim that they lose or damage their gear on submarine pipelines. However, it is difficult to prove that this is the true origin of the damage. According to de Groot (1982), fishing gear often hits rocks and ship wrecks, which cause the same sort of damage and effect as a pipeline would.

4.3.2 Emergency planning in the event of a spill

Severe and long-term damage to the offshore environment, and in turn to human activities, can occur in the event of a pipeline spill. As a result, operators of sub-sea pipelines are required to prepare emergency response plans. In the North Sea there have only been two significant spills from pipelines (Haldane et al., 1992). One was on 7 April 1980 from the Thistle–Dunlin pipeline. The rupture, believed to have been caused by a vessel dragging an anchor over the line, was identified after a drop in pressure in the pipeline, and it was thought that about 1000 tonnes of oil was lost over a period of 25 min.

The other was from Occidental's Claymore pipeline on 26 November 1986. In this instance the leak was from a valve spool and it was estimated that between 1000 and 2000 tonnes of oil was spilled. The slick moved towards the Norwegian coast, and when after 8 days of extremely rough weather it had still not broken up, Norwegian pollution control vessels were mobilized to monitor and to attempt recovery of the oil as it approached the coast. On 6 December, the wind changed direction taking the slick offshore and by 7 December the slick had dispersed. In view of the nature of the Norwegian coastline, and in particular the large numbers of fish farms, environmental teams were mobilized to survey the area, but only minor traces of oil that may have resulted from the spill were found.

4.3.3 Pipeline integrity monitoring

Sub-sea pipelines are regularly monitored to check for corrosion (to which they are particularly subject because of the salt water, despite cathodic protection measures), third-party interference (interaction with vessel anchors and fishing gear) and scouring and spanning (removal of the seabed from beneath the pipe due to currents). A range of monitoring techniques are available:

- visual;
- electrical potential difference;
- magnetic particle inspection; and
- ultrasonics.

These are carried out using a variety of undersea vehicles or by pigging. Undersea vehicles can be manned or they can be unmanned, remotely operated vehicles (ROVs). ROVs usually have on board a video camera, a trench profiler, a pipe tracker and a cathodic protection probing system. Pigs may be used for cleaning and for measuring pipe diameter, roundness and wall thickness.

4.3.4 Pipeline maintenance and repair

Pipelines in a marine environment will require more maintenance and repair than land-based pipelines. In particular, they will need protection against scouring and spanning. This can be done by a number of methods (Haldane et al., 1992):

- mechanical supports can be installed using diverless installation systems;
- grout bag supports can be installed by divers or by ROVs;
- rock infill is particularly suitable where the seabed is hard and where long distances are involved;
- jetting can be used but is diver intensive and is limited to relatively shallow waters; and
- trenching of shoulders is useful for short spans.

Other techniques tried include anti-scour mattresses and artificial seaweed. In some instances, it may be necessary to anchor a pipeline to the seabed using concrete, piles or clamps to prevent it moving.

Pipelines may also need additional protection from third-party interference. This can be done by trenching the pipeline, although special sections such as tie-ins can be covered with protective covers. In addition, cathodic protection anodes may need periodic replacement owing to excessive use, loss or damage.

Repair of a sub-sea pipeline may require a section to be cut out and replaced, which can be a very difficult or a relatively simple operation depending on the conditions. In shallow water divers may be used, but in deeper water this will not be possible and remote-controlled repair systems must be used.

4.3.5 Record keeping, monitoring and audits and reviews

Again, GIS is rapidly becoming the way forward in record keeping. Monitoring and auditing are becoming more important as companies have to become more and more accountable for their actions and, where information is not available, perhaps because it was not collected at the pipeline design and construction stage, reviews sometimes need to be carried out.

4.4 Decommissioning

Decommissioning of offshore pipelines is at present an issue of the future. There may be some pipelines where removal is the favoured option because of the possible interference with fishing gear. However, this may not be a viable option where the pipeline is buried, as its removal may cause more disturbance to the seabed, and thus to fishermen, than if it was left in place. It may become necessary to accurately map broken sections of decommissioned pipelines in order to make the information available to fishermen and other users of the sea (Haldane et al., 1992).

5 Pipeline landfalls

The term landfall is used to describe the connection between the marine or sub-sea section of a pipeline and the onshore section. In general terms, they cross the foreshore or intertidal area and any significant topographic features on land such as dunes or cliffs. Landfalls are part of the shore approach, which starts at the location that the main laybarge for the submarine section can operate in and commence laying pipe away from the coast towards the offshore destination. In some cases, the landfall has an intermediate section and a smaller first generation type laybarge capable of operating in inshore waters that will lay the pipeline between the main barge and the landfall. This is with an extended coastal shelf, or as mentioned above, under crossing classifications, which is often the case when deepwater gives way to inter-island areas. The point where an offshore pipeline comes ashore is known as a landfall. This interface of the land and the sea is the single critical element in a pipeline route that crosses the boundary between the two; often the energy levels impacting on the pipe from the marine environment, and hence the potential to damage the integrity of the pipeline, are greatest at this point and therefore the decision of where the landfall should be located requires considerable forward planning. Because of the critical nature of the landfall, it is considered here, in detail, as a separate issue.

5.1 Design

The planning process required essentially follows the same steps as for an onshore pipeline through the preliminary and detailed design phases, and an application for permission to construct a landfall is generally included within the same environmental statement as the application for the onshore pipeline associated with it. However, because both environmental and engineering constraints are often severe, it is particularly important that both are considered in great detail and that neither is considered in isolation. Environmental protection measures during landfall construction, while also following the same basic principles as for onshore pipelines, may require specialized techniques not used elsewhere. For these reasons, the landfall is often subject to separate study and separate technical reports can be produced.

5.1.1 Preliminary design

At the preliminary design stage, it will, as with the remainder of the pipeline, be necessary to carry out consultations and undertake surveys to identify a location for the landfall. As the route of the cross-country pipeline and the sub-sea pipeline will depend on the location of the landfall, it is clear that getting the siting of the landfall right as soon as possible is of fundamental importance. The nature of the coastline bears a direct relationship to the ease of construction of the pipeline, and therefore a study of its physical characteristics will prove invaluable in helping identify a suitable location. However, in addition to such a study, a number of other parameters play a controlling role in the suitability of a particular stretch of coast for the construction of a landfall:

- the form and nature of the seabed close to the coast;
- marine energy levels; and
- technical constraints.

In order to determine the suitability of a particular location for a landfall, a list of features that are considered desirable can be compiled together with a list of features that would be considered undesirable. These are shown in Table 9.1. In simplistic terms, it is easier to construct a pipeline across a narrow, sandy beach than a coastline in which rocky outcrops predominate. In addition, sandy beaches are generally far easier to reinstate than rocky shores. Sandy beaches need little extra protection for the pipe whereas a rocky landfall needs the importation of sand for bedding the pipe. Marine energy levels are often higher on rocky coastlines.

TABLE 9.1. Desirable and undesirable features of a landfall

Desirable features	Undesirable features
Stable beach – long-term integrity of the pipeline is preserved due to the sediment transport being minimal	*Population centres* – it is preferable to avoid population centres due to the effect of construction on the quality of life of residents
Water depth – a water depth of 15 m is preferable within 2–3 km of the shore; this reduces the amount and scale of excavation/dredging	*Rocky coastline* – span problems can occur; blasting may be required and restoration becomes difficult
Direct routing (linearity) of the shore approach – this would minimize length and ensure a less complicated construction technique; there would be less disturbance to the intertidal zone	*Exposed area of coastline* – exposed coasts may lead to the exposure of the pipeline by marine processes
Ease of reinstatement – the ability to achieve 'full' restoration of the landfall is of importance	*Long shallow approach* – extensive dredging required and hence the impact on marine life is greater; scale of construction operations would be larger
Trenchable seabed to deep water – a trenchable seabed avoids 'free spans' that may lead to stress failure of the pipe	*Steep slopes* – pipeline installation and long-term stable reinstatement difficult
Sandy beach – sandy beach provides a soft bedding for the pipe, it is easily excavated and can be readily reinstated	*Non-cohesive sediments* – these are unstable and susceptible to bearing strength failures and sediment mass movement
Good land access – minimize the upgrading of the road that is necessary to allow plant access to the beach	*High-velocity nearshore currents* – these can interfere with pipelaying activities and may entail additional protective measures
	Coastline designated as having landscape value and possibly experiencing recreational pressure – disruption must be minimized
	Nature conservation areas – the potential disruption of species and loss of habitat are to be avoided

However, environmental constraints cannot be categorized according to the coastline landform alone. All constraints need to be identified and by careful planning individual constraints must be minimized or avoided. In general terms, landfalls should avoid population centres, specific wildlife sites and areas of outstanding scenic beauty. The planning of a prospective landfall must also assess the surrounding land in terms of access for heavy construction plant and for any infrastructure that will be necessary for the operation of the pipeline, such as a receiving terminal, a compressor station or a pressure reduction station. Other particular problems encountered in some types of coastline include the low load-bearing capabilities of some intertidal muds and salt marshes and the longer term stability and reinstatement problems associated with cliffs. The visual element is equally important in this regard, where the results of pipeline construction may be visible for a number of years. If hard structures are required to protect the pipeline and provide stability, then the construction may be visible for as long as the life of the pipeline. An ideal landfall would be a stable, sandy, sheltered, low-angle beach with no statuary designations relating to flora, fauna or scenic value.

It can be seen that, with all the constraints discussed above, a long stretch of coastline may have to be investigated before a suitable location for a landfall can be found.

5.1.2 Detailed design

Once a suitable landfall site has been found, detailed field studies of the existing environment will be required, a precise route chosen and impact appraisal and prediction carried out in the same manner as for onshore pipelines. However, proposals for mitigative measures to overcome predicted impacts will often have to be innovative and very site-specific.

5.2 Construction

5.2.1 Construction methods

(a) Pull ashore

In this case, the pipeline is welded on the laybarge and pulled ashore using winches. As mentioned above under the laybarge method for major crossings the laybarge anchor winches can be used with a sheave block on land providing they have sufficient capacity for the weight of pipe to be pulled. For bigger diameters and longer pulling lengths, winches will be on land and sized to suit the weight of pipe. Typically, 200 to 250 tonne linear constant tension winches will be used in tandem with an anchoring arrangement consisting of sheet steel piles or rock anchors. Depending on the number of purchases within the wire layout, up to 1200 tonnes of pipe can be pulled ashore in this way covering distances of up to 5 km.

The length of the landfall depends on the location that the laybarge can safely station itself at near the shore, and for a second or third generation laybarge of the sponson variety this will be around the 10 m or 12 m contour relative to lowest astronomical tides (LAT). The larger ship-shaped third-generation barges are more limited and cannot usually operate within the 15 m to 20 m contour. When selecting the landfall location, apart from the feasibility of laying the land section, water depths and the resulting length of landfall should be considered. If the length results in excessively high pulling loads, buoyancy may be considered or a smaller laybarge may be necessary to fill in the gap. Burial of the landfall section is usual, and the trench would normally be dredged using cutter suction dredgers or a combination of trailer and cutter suction. Trailer dredgers are ideal for bulk removal of material in open water whereas cutter suction dredgers can operate close inshore and can deal with consolidated sediments and clays. Blasting may be necessary before dredgers can be used in order to fragment hard material such as rock or over consolidated sediments. The immediate foreshore section of trench that cannot be reached by the dredger will be excavated by land-based equipment working off the beach or if this is not possible on a raised causeway or jetty. Trenches in the foreshore area are generally relatively unstable and can easily be in-filled especially during rough sea conditions. If this is likely, retaining walls using sheet steel piles will be constructed with the added advantage of reducing the disturbed area. Alternatives to dredging where ground conditions permit are post-lay trenching systems such as underwater mechanical cutters or jetting machines. The need to backfill landfall trenches will again depend on ground conditions and self-restoration of the seabed may be environmentally more desirable than stockpiling excavated material for reuse or importing new material.

(b) Pull offshore

This is the reverse of the pull ashore where pipe is fabricated into strings onshore and a barge-mounted pulling system used to pull the pipe into the sea. The process is similar to the open-cut method described for intermediate crossings, but with the pipeline end left capped on the seabed for recovery by the laybarge so that offshore pipelaying can commence. The reasons for doing this are usually associated with programming the laybarge to best suit the weather conditions, and where the landfall is long and complex in pulling terms, thus avoiding the expense of the laybarge during the landfall programme and the risk of expensive delays should the operation take longer than expected. The comments regarding trenching mentioned above under the pull ashore method (3.1) apply.

(c) Horizontal directional drilling

The methodology for directional drilling is discussed above under the minor and intermediate crossing sections and is much the same for a landfall. It becomes particularly attractive to use directional drilling when there are environmentally sensitive features such as reefs, tidal mud flats, cliffs and dunes, and has the obvious advantages shared by all the no-dig techniques. The length that can be directionally drilled is a limitation and should not be greater than approximately 1000 m. Consequently, the use of a small inshore laybarge may be considered to bridge the gap to where the main laybarge can operate. The usual arrangement is to drill from the shore and to use a laybarge or work barge at the offshore end to handle the reamers and eventually fabricate the pipeline. In order to avoid the stop start process of a laybarge, a length of pipe equivalent to the full length of the landfall is laid onto the seabed and connected to the final reaming run so that it can be pulled into the drilled hole. A variation to this is to forward ream using winches on a barge to pull the reamer from the drilling rig and eventually to pull the pipeline into the hole from a shore fabrication area, thereby avoiding the need for the laybarge. The risks of the drilling, reaming and pipe pulling operations are discussed above where directional drilling is mentioned for the minor and intermediate crossings. Undertaking the operation for a landfall introduces further risks associated with the complexity of handling drill or wash over pipe offshore and with the escape of drilling fluids onto the seabed. As with all methods, a full environmental impact assessment should be carried out to identify the risks and to enable mitigation measures to be introduced at an early stage. Despite these risks, horizontally-drilled landfalls have been successfully carried out with significant cost savings compared to open cut methods and with minimal disturbance to the seabed and intertidal areas.

(d) Tunnelling
Tunnelling using the methods described above has been used for a number of landfalls and is particularly worthwhile where more than one pipeline is required to share the same landfall location. Notable examples are in Norwegian fjords where the foreshore is rock and slopes steeply into the water enabling laybarges to lay pipe that can be pulled directly into the tunnel. The choice of construction method will be determined by the nature of the onshore and nearshore environment. As each landfall is unique, whichever is chosen will have to be adapted to suit the individual needs of the site. The examples discussed below serve to illustrate some of the ways that coastal environment environmental constraints have been managed in recent years.

5.2.2 Case study: the Gas Interconnector Project (GIP) landfall at Brighouse Bay

The critical points on the GIP pipeline that determined its route were the landfalls on the Irish and Scottish coasts. In particular, the landfall on the Scottish coast is in an area of significant environmental sensitivity and is classified as an area of Regional Scenic Significance and as a Site of Special Scientific Interest (SSSI); it is that landfall that is considered here (Figure 9.4).

The steps outlined below indicate the planning stages followed to determine the optimum landfall location:

- Determination of the area of interest, in this case the coastline of Dumfries and Galloway (obeying the straight-line principle between Moffat and Ballough).
- Identification of all marine and terrestrial constraints in the vicinity of the landfall that may impact on the construction of the landfall. These were plotted on a constraints map.
- Hand-in-hand with the above approach, constraints had to be identified on both the sub-sea and landfall routes that may preclude a particular landfall option. This was considered by tabulating matrices having identified the parameters crucial to the construction of the pipeline.

Sub-sea constraints ranged from water depth and the nature and topography of the seabed to the presence of fishing grounds and military bombing ranges. Landline constraints included such considerations as landform relief, protected areas and the number of road and river crossings. An additional consideration in the early planning stages was the requirement for a compressor station as close to the Scottish landfall as possible. This was

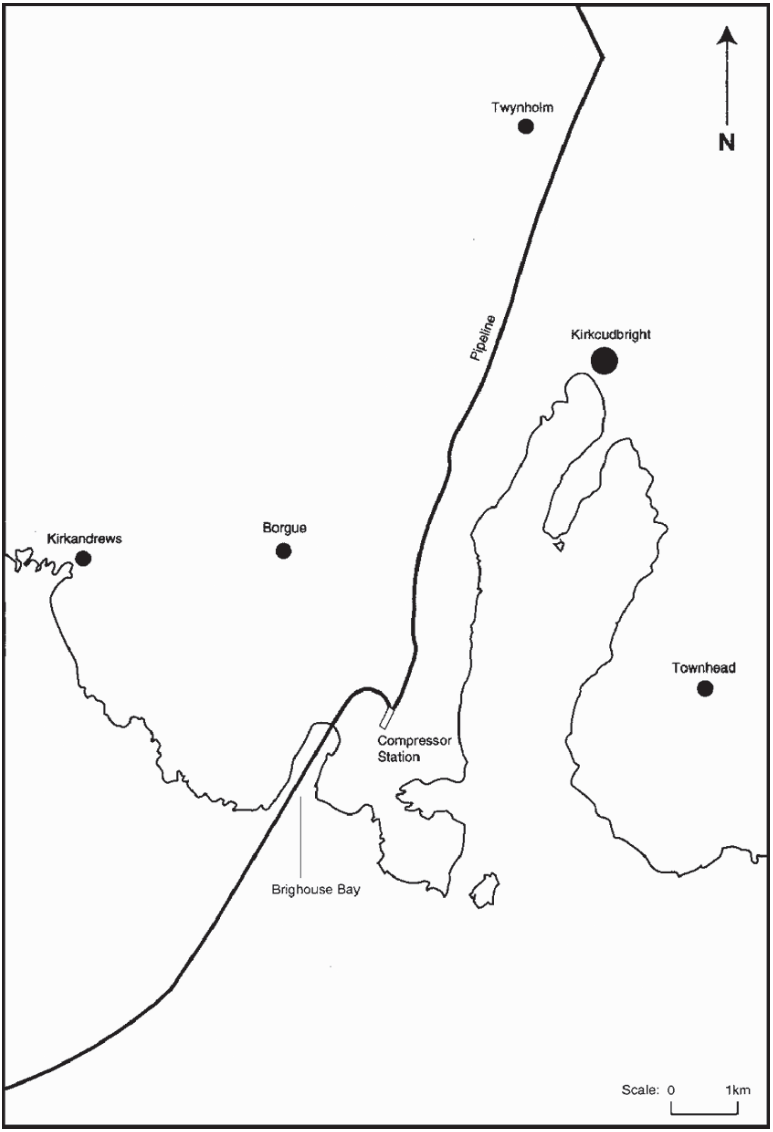


FIGURE 9.4. Map showing the Gas Interconnector Pipeline landfall at Brighouse Bay.

needed to generate sufficient pressure to permit the transmission of gas to Ireland. Owing to the attractiveness of the Dumfries and Galloway coastline, the siting of the compressor station was a crucial issue. Zones of Visual Influence (ZVIs) were identified to help identify the optimum location and hidden line perspectives were generated to ensure that any visual intrusion was minimized.

The exercise outlined above indicated that 13 potential sites were worthy of further consideration. In order to evaluate these sites, a matrix was completed that identified the following parameters grouped under six headings:

- marine environment: tidal streams, maximum fetch, site exposure, wave activity, tidal range, predominant wind direction, military activity;
- physical constraints: beach composition, beach dynamics, beach and near-shore profile, shore topography, sea access, presence of bedrock, water depth, land access;
- biological constraints: fragile habitats (land and marine);
- environmental constraints: recreational pressure, land designation, archaeology;
- availability of land for compressor; and
- construction: technical notes, resultant impact, restoration problems, relative extent of landfall construction.

The completion of a matrix identifying all the parameters considered to have an impact on the landfall location enabled a more considered judgement to be made as to the optimum landfall location. One of the most important criteria was the ability of a site to be fully reinstated. Having considered all the options, Brighouse Bay, near Kirkcudbright, was selected as the optimum landfall location on the Solway coast.

Because of the environmental sensitivity of the Brighouse Bay landfall, it was most important that the constraints and specifications particular to the landfall location were made known to the contractor prior to their appointment. The constraints arose from a number of sources, including:

- the environmental statement;
- specific technical reports commissioned during the environmental assessment;
- stipulations attached to the Pipeline Construction Authorization;
- planning permission requirements;
- requirements detailed by statutory and non-statutory bodies; and
- general requirements as a result of far-ranging dialogue.

From the wealth of information arising from the project, the contractor for the Brighouse Bay landfall had to ascertain the environmental and engineering controls imposed on construction and devise measures by which the environment and particularly sensitive areas would be protected. These were written into method statements by the contractor prior to construction and had to be submitted to Bord Gais Eireann, the planning authorities and other statutory bodies for approval.

Brighouse Bay was identified as the optimum landfall location in the south-west of Scotland primarily because of the sandy nature of the bay and hence the ability of the landfall to be fully reinstated. However, because it experiences heavy recreational pressure and is designated as important for its landscape, wildlife and geological value, special construction methods were essential.

Scheduling construction activities for the winter months overcame, to a large extent, the problems associated with recreational pressure. However, Brighouse Bay is part of the extensive Borgue Coast SSSI and is particularly sensitive on botanical grounds. In particular, the presence of perennial blue flax, the pyramidal orchid and lesser meadow rue provides considerable botanical interest. A detailed botanical survey identified a zone where the distribution of the above species was sparse and therefore the line of the pipe was centred on this area. In fact, not one flax plant was identified within the 26 m working width. Therefore, although at first sight the bay appeared an unlikely choice for a landfall, the fact that full reinstatement could be achieved and that the botanical interest was not being compromised determined that Brighouse Bay was the optimum choice.

It was decided by environmental specialists that the best way to ensure rapid reinstatement of the sensitive dune area crossed by the pipeline at Brighouse Bay was to turf it. From the nine specific habitats that were identified by an ecologist, turfs 1 m^2 and 20 cm deep were cut, lifted on to pallets and transported some 500 m to a laydown area for the duration of the construction period. The location of the habitats and turves from each habitat were clearly identified and the turves from the different habitats were stored separately. In total, almost 3000 m^2 of turf were lifted and stored for reinstatement. In addition, hawthorn bushes up to 2 m high were transplanted, using a large excavator bucket to dig out the complete root system. The method proved to be very successful, and the following year it was only necessary to supplement the turves with seed collected from the site the previous summer.

5.2.3 Case study: the Gas Interconnector Project (GIP) landfall at Loughshinny

Loughshinny is the location of the Gas Interconnector Pipeline landfall on the Irish coast just to the north of Dublin (Figure 9.5). It provides an example of landfall construction through a boulder clay cliff some 15 m high. Slumping on the face indicated that there was potential for erosion, although historical records showed that the current position of the cliff face was within 1 m of a survey conducted over 150 years ago.

The main concern at Loughshinny was to ensure that the methods utilized to stabilize the cliff face were in keeping with the surrounding area so as not to create a visually intrusive monument. The neighbouring headland and Martello Tower are a favoured area for walkers. To this end, a gabion base at the toe of the cliff was constructed as the main support. Layers of terram folded back on itself provided stability at the face. The cliff was seeded to provide protection against erosion and to blend in with the surrounding cliffs.

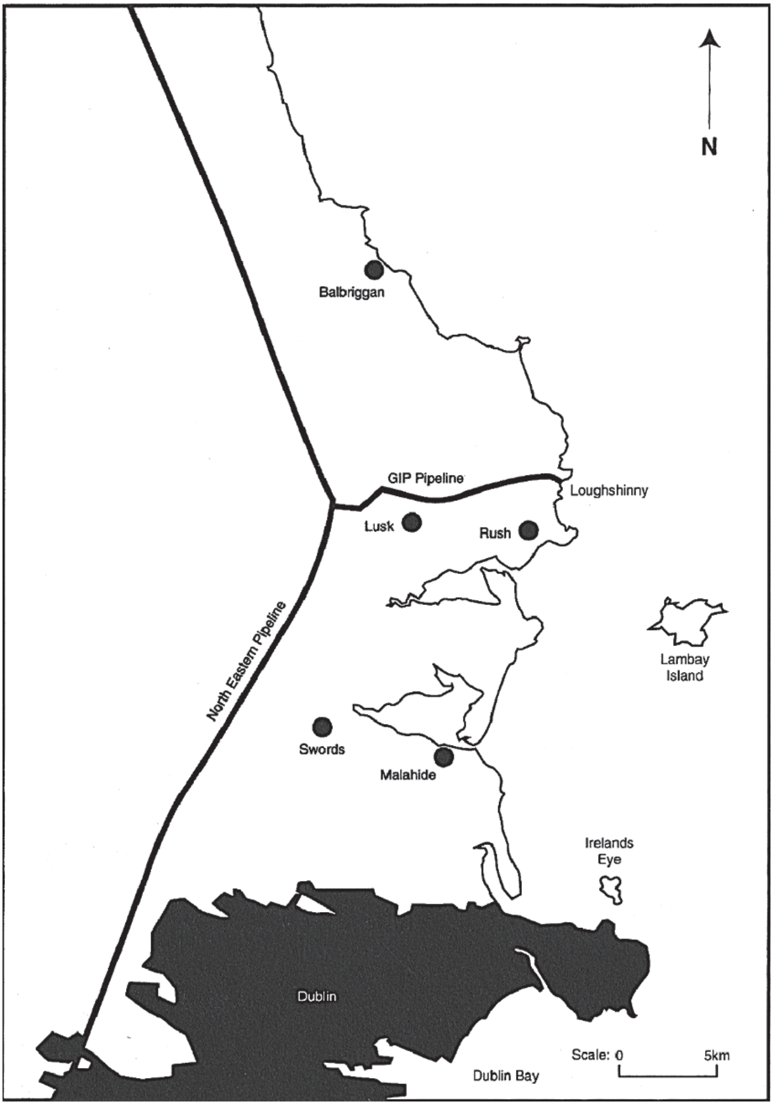


FIGURE 9.5. Map showing the Gas Interconnector Pipeline landfall at Loughshinny.

5.2.4 Case study: the Theddlethorpe landfall, Lincolnshire

In 1992, Conoco UK installed a 26 inch diameter natural gas pipe from the Murdoch Platform to the Theddlethorpe Gas Terminal (Figure 9.6). This was the fourth landfall to be brought ashore over a short stretch of coastline.

The flat, sandy beach at Theddlethorpe is backed by an ancient dune system that is designated as a National Nature Reserve. The previous three landfalls had utilized an open cut through the dune system. However, for

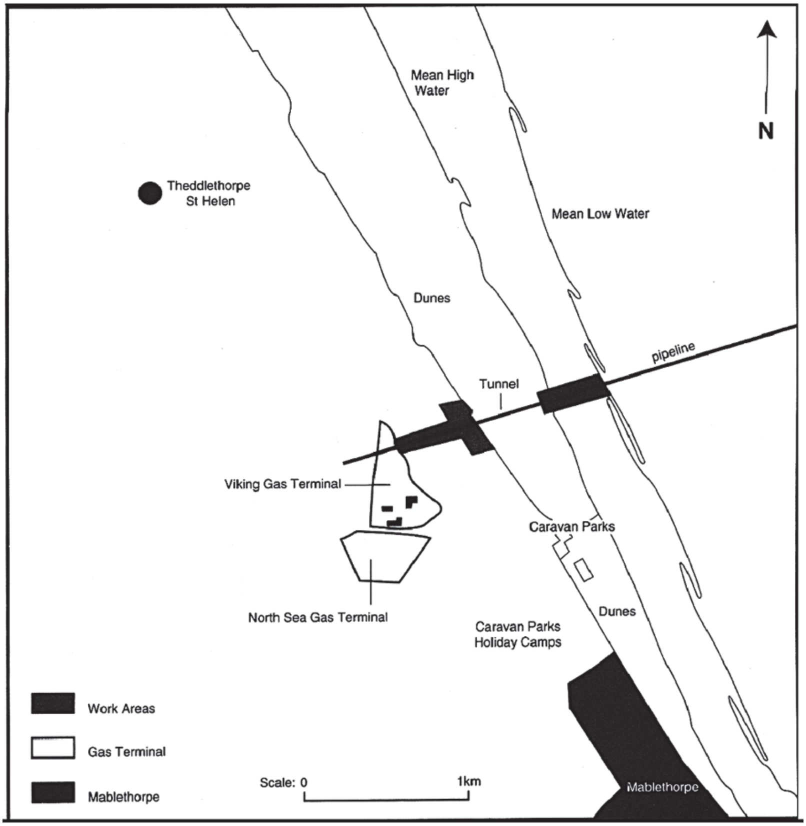


FIGURE 9.6. Map showing the Theddlethorpe pipeline landfall.

this landfall Conoco proposed the construction of a concrete-lined tunnel, using conventional pipe-jacking techniques, in order to leave the ancient dune system intact. The pipe-jacking operation was successful with the majority of the ancient dunes remaining undisturbed, although the final 75 m of the operation had to be open cut owing to a survey problem resulting in the concrete casing being off-line. The dunes that were affected, at the edge of the ancient dune system, were covered by sea buckthorn, which grows vigorously, and were considered to be the least sensitive part of the system by English Nature. In order to aid dune stability, a marram replanting exercise was undertaken over the embryonic dunes adjacent to the beach.

5.2.5 Case study: the Walney Island landfall, Cumbria

British Gas has recently constructed a 3.5 km long pipeline across Walney Channel, a tidal estuary comprising saltmarsh and intertidal flats near Barrow-in-Furness (Figure 9.7). The pipe, which was winched from a string fabrication yard on the mainland across to Walney Island, forms part of a

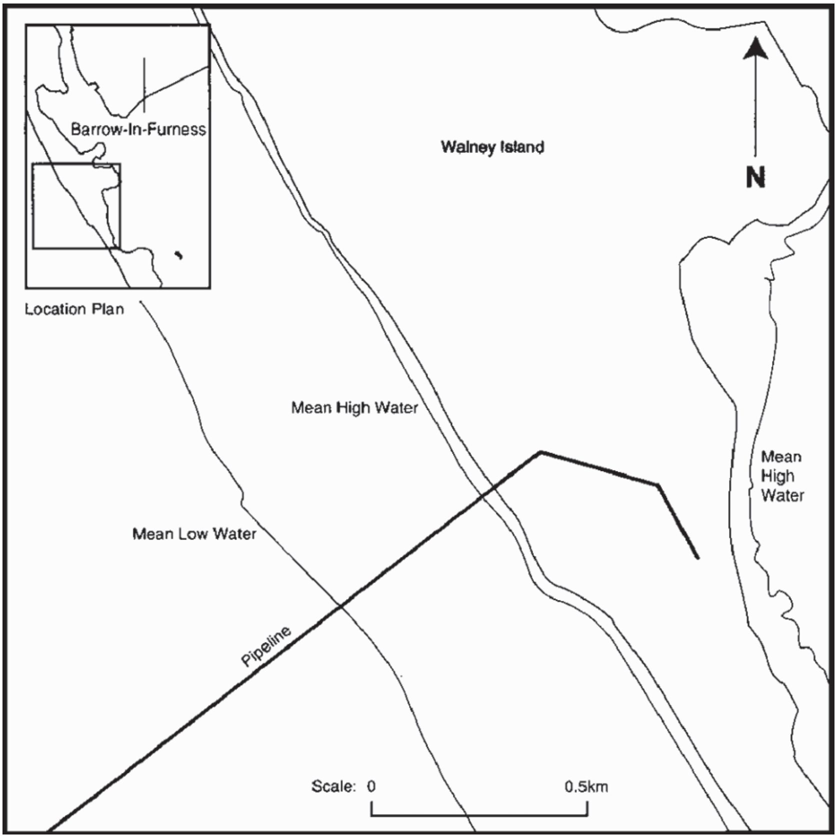


FIGURE 9.7. Map showing the Walney Island pipeline landfall.

larger project to bring gas from the North Morecambe Bay gas field to a new gas terminal at Westfield Point, to the south-east of Barrow-in-Furness.

Virtually, the whole length of the pipeline falls within the South Walney and Piel Channel Flats SSSI, and therefore it was not surprising that special construction techniques were needed to overcome a number of botanical issues. The most sensitive of these was the fact that the intertidal area contained the only recorded site in north-western England of the nationally scarce *Zostera angustifolia* (narrow eelgrass). It was decided that it was not possible to store the sediment containing the *Zostera* for the duration of construction in a manner that would allow the diurnal tidal inundation on which it thrives and at the same time prevent erosion of the material. Instead, in the hope that the plant would survive, and in the knowledge that this layer would contain the rhizomes and seed of the *Zostera* as well as a significant invertebrate population, shallow (10 cm) cuts of sediment were transferred from the most densely populated areas on the pipeline route to a ready excavated site away from the working area which contained relatively few plants but had similar tidal conditions. In this way, although the plants could not be replaced in their original location, disturbance was minimized.

References

Barr, J. (1993) On-line inspection: BPA's experience. *Pipes and Pipelines International*, **38**(1), 14–19.

Burrows, D.K. (1990) The great Mississauga evacuation, in *States of Emergency: Technological Failures and Social Destabilisation* (ed. P. Lagadec), Butterworth-Heinemann, London, pp. 66–73.

Cobb, G. (1993) Administration of UK pipelines' legislation. *Pipes and Pipelines International*, **38**, 3.

CONCAWE (1995) *CONCAWE Report*, 4/95.

de Groot, S.J. (1982) The impact of laying and maintenance of offshore pipelines on the marine environment and the North Sea fisheries. *Ocean Management*, **8**, 1–27.

Det Norske Veritas (1993) Upgrading Russia's 140,000 km of gas pipeline. *DNV Forum*, No. 3/93.

Gritzenko, A.I. and Kharionovsky, V.V. (1994) Problems of pipeline integrity in Russia. *Pipes and Pipelines International*, **39**, 6.

Haldane, D., Paul, M.A., Reuben, R.L. and Side, J.C. (1992) Submarine pipelines and the North Sea environment, in *North Sea Oil and the Environment* (ed. W.J. Cairns), Elsevier Applied Science, London, pp. 481–522.

Health and Safety Commission (1991) *Major Hazard Aspects of the Transport of Dangerous Substances*, Advisory Committee on Dangerous Substances, H.M. Stationery Office, London.

Premier Transco Ltd (1994) *Scotland to Northern Ireland Natural Gas Pipeline Project: Offshore Pipeline Environmental Appraisal Report*, Premier Transco Ltd, Larne, Co. Antrim.

Rapson, S. (1994) Environmental assessment of cross-country pipelines. *Geography Review*, **7**(5), 21–4.

Sljivic, S.C. (1995) Pipeline safety management and the prevention of third-party interference. *Pipes and Pipelines International*, **40**, 6.

Further reading

Berry, K.G., Bianchini, M., Muller, B. et al. (1995) *Performance of Oil Industry Cross-Country Pipelines in Western Europe*, Report 4/95, November, CONCAWE, Brussels.

British Standards Institution (1992) *Specification for Environmental Management Systems BS 7750:1992*, BSI, London.

Department of Energy (1989) *Electricity and Pipe-line Works (Assessment of Environmental Effects) Regulations 1989*, Statutory Instrument 1989 No. 167, H.M. Stationery Office, London.

Department of Energy (1989) *Electricity and Pipe-line Works (Assessment of Environmental Effects) Regulations 1989*, Statutory Instrument 1990 No. 442, H.M. Stationery Office, London.

Department of the Environment (1988) *Environmental Assessment Implementation of EC Directive Draft Circular*, H.M. Stationery Office, London.

Department of the Environment (1991) *Waste Management: the Duty of Care. A Code of Practice*, H.M. Stationery Office, London.

Department of Trade and Industry (1992) *Guidelines for the Environmental Assessment of Cross-Country Pipelines*, H.M. Stationery Office, London.
Eberlein, J. (1986) Implications for project design and management. Presented at EEC Environmental Assessment Directive: Towards Implementation, January, London.
European Community (1985) *Council Directive on the Assessment of the Effects of Certain Public and Private Projects on the Environment*, 85/337/EEC, *Official Journal*, EC, Brussels.
Fairclough, A. (1986) Objectives and Requirements of the Environmental Assessment Directives. Presented at EEC Environmental Assessment Directive: Towards Implementation, January, London.
Lednor, M.C. (1993) Environmental input to pipeline landfalls. *Pipelines, Risk Assessment and the Environment*, 9–11 June, Manchester, (*Pipe and Pipelines International*).
MCS International/ICT (1992) *Gas Interconnector Project: Subsea Pipeline*. Bord Gais Eireann, Dublin.
Pipe nightmares. *Russian Petroleum Investor*, December 1994/January 1995, 39.
Richardson, S.C. (1995) *Pipeline Safety Management Programme: Once Call Feasibility Study*, RSK Environment, Helsby, unpublished report.
RSK Environment Ltd (1992) *Gas Interconnector Project: Irish Onshore Pipeline*. Bord Gais Eireann, Dublin.
RKS Environment Ltd (1992) *Gas Interconnector Project: South West Scotland Onshore Pipeline*. Bord Gais Eireann, Dublin.
Ryder, A.A. (1993) Implementing environmental controls in the planning and operation of new cross-country pipeline. *Pipelines, Risk Assessment and the Environment*, 9–11 June, Manchester (*Pipeline and Pipelines International*).
Ryder, A. and Smyth, M.A. (1992) *UK Environmental Legislation Affecting Pipelines*, RSK Environment Ltd, Helsby, unpublished report.
Shell Chemicals UK Ltd (1989) *The North Western Ethylene Pipeline, Environmental Statement*, Shell Chemicals, Chester.
Smyth, M.A. (1992) *Impact of Offshore Pipelines on Trawling*, RSK Environment Ltd, Helsby, unpublished report.
The Pipeline Inspectorate Petroleum Engineering Division (1984) *Submarine Pipeline Guidance Notes*, Department of Energy, H.M. Stationery Office, London.
Willis, DA (2002) Pipeline Crossings – Methods and techniques and how they apply to pipeline specifications, environmental constraints and costs. Paper presented at Land Pipeline Conference.
Willis, DA (2002) Pipeline Crossings and Environmental Impacts. Paper presented to the 6th International Conference on Land Pipelines, Amsterdam, organised by IBC.
Willis, DA (2002), Pipeline construction in fragile environments, Standard Construction and Crossings Glossary.
Willis, DA(2004) Paper comparing international and national standards for pipelines presented at Offshore Pipeline Technology Conference, Amsterdam, organised by IBC.
Willis, DA, and Roach L, Domeney (2004) The case for early contractor involvement to minimise risks associated with routeing and construction of pipeline projects.

Chapter 10
Environmental Management and Technology in Oil Refineries

H. Amiry[1], H. Sutherland[2], E. Martin[3], and P. Goodsell[1]

1 Function of an oil refinery

The purpose of oil refineries is to produce marketable products from crude oil or other hydrocarbon feedstocks. Crude oil, the basic feedstock, is a mixture of a large number of different hydrocarbons and other organic compounds, with widely ranging molecular structures from gases to substances with very high boiling points. Crude oils can vary greatly in their physical and chemical characteristics, depending on their origin.

Refineries produce a wide variety of products including:

- fuels such as LPGs, gasolines, aviation fuels, gasoils/diesels, fuel oils and marine fuels;
- chemical feedstock – naphtha, gasoils and gases;
- lubricating oils, greases and waxes;
- bitumen and asphalts;
- petroleum coke;
- sulphur.

A refinery consists of a number of plants using a variety of chemical and physical processes. Each plant has its own specific function, the output of some plants often forming the inputs for others, as well as providing the components of products. These plants are supported by a number of utilities supplying steam, power, water, hydrogen, etc.

Refinery process plants fall into the following major categories:

- physical separation process, such as distillation, extraction and various separation techniques;
- chemical conversion processes, such as reforming, catalytic cracking, isomerization, alkylation, etherification, hydrocracking and thermal cracking/visbreaking;

[1]*BP International Ltd., Sunbury-on-Thames, UK*
[2]*Oil Industry Consultant, Cobham, Surrey, UK*
[3]*Oil Industry Consultant, Bookham, Surrey, UK*

- purification processes, such as hydrodesulphurization, desalting, gas sweetening, sour water treatment, sulphur removal and recovery;
- utilities and general facilities – steam and power supply, fuel system, flare system, water, air, hydrogen and nitrogen supply, hydrocarbon slops treatment, blending, storage and loading facilities for road, rail and sea;
- environmental controls – aqueous effluent treatment, combustion and other air emission controls, waste disposal, odour and noise controls.

All of the above activities may have an impact on the environment.

2 Overview

In order to maintain our quality of life and sustainable development, it is vital that the environmental impact of all industrial practices is reduced as far as is reasonably practicable. Thus, as refiners, environmental management has become a major part of our culture both inside and outside the refinery, resulting in significant progress in performance with respect to neighbours and the general public.

Nevertheless, over the past 15–25 years a steady stream of legislation worldwide has been introduced aimed at further cleaning up industrial operations and reducing their environmental impact. The growing public awareness of the adverse consequences of poor environmental management and disposal practices is a major factor. Most recently the main driving forces for environmental control throughout industry are the current perceived global environmental risks such as the depletion of the ozone layer, acid rain, greenhouses gases, the quality of the rivers and lakes and the poor air quality in some large cities.

A key piece of legislation in Europe for refineries has been the EU IPPC Directive [1]. IPPC stands for Integrated Pollution Prevention & Control. This directive has been transposed into national laws and its thrust has been for new operational permits for many industries including refineries. These permits must be based on the concept of Best Available Techniques (or BAT).

There are approximately 110 refineries in Europe. These vary enormously in the processes used, type of oil processed, size, throughput, location and age. Because of this variation, there is no such thing as a best environmental practice applicable to all refineries. Therefore, many of the techniques mentioned in this chapter may not be practised or be appropriate in many refineries.

One thing that many refineries have in common is that they were established before the time when environmental concerns became a major issue for the public, government or industry, with some having been commissioned over 80 years ago. Even then, measures were taken to protect the environment such as the spin-offs from the essential precaution to ensure closed containment of petroleum during processing, although refinery design did not include many elements which today would be considered essential for environmental protection.

The process by which environmental standards are determined utilizes the expertise of a number of professions, including legislators, scientists, engineers and planners. As well as the setting of emission standards, decisions have to be made on the most appropriate technology and techniques to be applied and the appropriate monitoring programmes to be implemented. Whilst complete elimination of all pollution is not an attainable goal, steps can be taken to minimize environmental impact through pollution reduction at source, recycling, emissions control and responsible waste disposal. The preferred option is reduction at source, which encompasses both good operating practices and good housekeeping, as well as technological change.

The refining processes have environmental impact on their neighbours and on the air, water and land, and it is important that refiners at least meet the standards set and implement continuous improvements to minimize their impact if they are to retain community acceptance. Some improvements to environmental protection can be readily integrated into an existing plant, whereas others are very difficult, if not impossible, to implement in an existing refinery. In general, the most obvious and lowest cost steps have already been taken and successive steps can only be achieved at progressively increasing cost. This chapter looks at the technologies and techniques available to enable refineries to meet environmental standards through pollution prevention.

3 Control of atmospheric emissions

Emissions to the atmosphere are the most obvious form of pollution and have been the first target for control in many countries. Consequently, there are comprehensive regulations in most parts of the world to cover this topic. The quantity and type of atmospheric emissions by refineries vary greatly, depending on crude oil capacity and type, the particular refining processes used, air pollution control measures in effect and the general level of maintenance and housekeeping.

The principle emission sources from a refinery include:

- sulphur removal units;
- catalytic cracking units;
- coke plants;
- storage and loading operations;
- combustion processes;
- emissions from regeneration of catalyst;
- fugitive emission sources;
- flares.

In industrial plants with multiple emission sources, there are two main philosophies of control; either standards can be set for each individual source or alternatively a ‘bubble’ concept can be applied. In the latter case the refinery is treated as a single source with an overall mass limit for each pollutant over a given time period. With this system, process units, feedstocks and emission controls can be managed most efficiently to reduce the overall emission levels.

Air emissions from refineries include the following:

- sulphur dioxide (SO_2) and other sulphur compounds (SO_x);
- oxides of nitrogen (NO_x);
- particulates (including smoke);
- carbon dioxide and other carbon compounds (CO_x);
- VOCs (volatile organic compounds);
- malodorous materials.

The main techniques for minimizing and controlling air emissions are discussed below.

3.1 Minimizing combustion-related emissions

Between 4% and 9% of refinery crude oil feedstock is used as fuel at the refinery. This generates flue gas that is discharged to the air. In Europe, many air quality regulations initially specified minimum discharge stack heights to ensure good dispersion of the flue gas, but did nothing to control total emissions. Now, however, regulations passed in many countries demand control of specific pollutants, such as SO_x, NO_x, particulates and even CO_x in both mass emissions and concentration permitted in the flue gas.

About 78% of the SO_x emanating from a refinery are attributable to fuel uses in the refinery such as boilers, furnaces and FCCs [2]. In 1998, this resulted in some 387 kt of sulphur released to atmosphere from Western European refineries. This corresponds to some 7.66% of total emissions from those European states [3]. Over the same period there has been a significant increase in removal of sulphur within the refineries to meet new sulphur specifications on refinery products such as gasoline and diesel fuels.

(a) SO_x control. Sulphur oxide emissions typically emanate from fuels consumed, the catalytic cracking process, and sulphur removal and recovery operations. To control SO_x emissions, refiners can adopt one of the following measures:

- process low-sulphur crude oils;
- burn low-sulphur fuels; in refineries there may be the flexibility to fire more gas in place of oil, and sulphur emission limits can often be met by appropriately mixed gas/oil firing;
- pretreat fuels and feedstock to remove sulphur;
- install exhaust gas clean-up (flue gas desulphurization) systems; methods available for SO_2 removal from combustion plant are generally very expensive and involve downstream flue gas clean-up, by either wet processes (non-regenerable or regenerable) or dry processes;
- modify catalyst formulations;
- install enhanced sulphur recovery units (i.e. tail gas treatment).

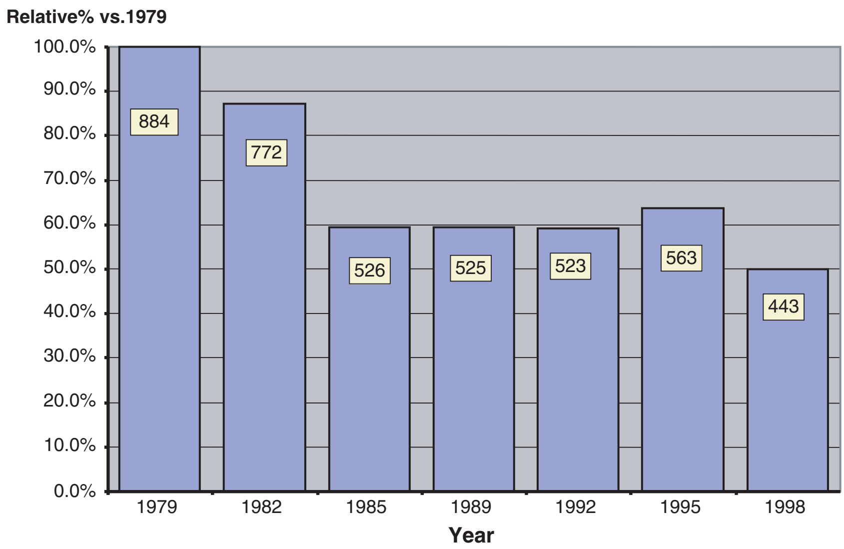


FIGURE 10.1. SO_2 emissions from refineries in Western Europe [2, 3] (*See Color Plates*).

It has been observed that coals containing alkaline ash will burn giving reduced SO_2 and SO_3 emissions due to the formation of metallic sulphates. Recent studies have shown that the addition of alkali metal compounds to fuel oils has the same effect. However, in addition to the increased cost, the disadvantage is that high levels of alkali metals will increase particulate emissions and deposits in the heater which will eventually need to be disposed of (see Figure 10.1).

(b) NOx control. Nitrogen oxides, from refineries, are generated in the combustion processes and originate from the oxidation of atmospheric nitrogen (thermal NO_x) and the indigenous nitrogen (fuel NO_x) in the fuel. Apart from removing nitrogen compounds prior to combustion by hydrotreating processes, there is little that can be done to avoid emissions due to the fuel quality. The formation of thermal NO_x is promoted by the intensity (temperatures) of combustion, the availability of oxygen and the residence time in the combustion zone.

Unfortunately, what is good practice for efficient combustion and minimum particulate emissions is not always good for nitrogen oxide prevention. For instance, forced draught burners increase burnout temperatures and reduce residence times, which can reduce particulate emissions, but overall produce more NO_x. In the combustion of sweet natural gas, the formation of thermal NO_x can double with air preheat. Results on test rigs show the effects of combustion air preheat, fuel-bound nitrogen and excess oxygen levels.

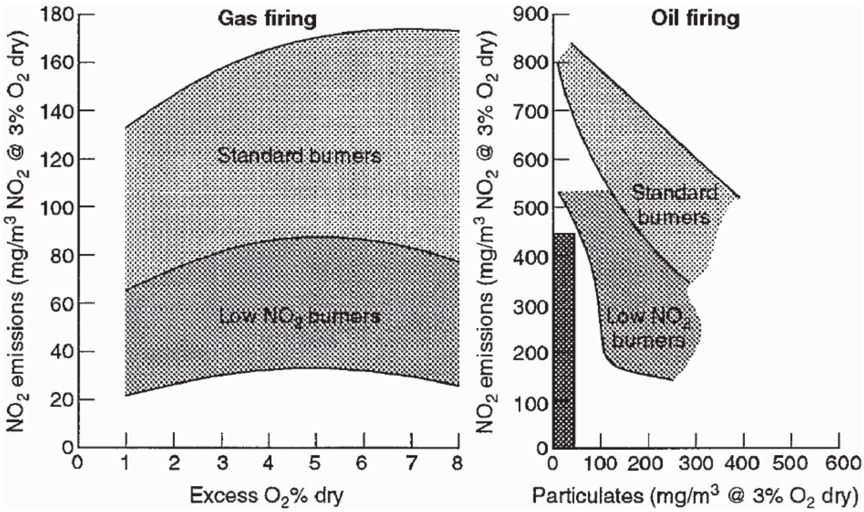


FIGURE 10.2. Performance of low NO_x burners and conventional burners firing natural gas and heavy fuel oil on a burner test rig.

The general rules to reduce NO_x are the opposite to its formation:

- reduce nitrogen in feed – not always a practical consideration;
- reduce oxygen – with less oxygen available, less NO_x is formed (Figure 10.2); this is generally a very good policy since it is also energy saving, but it does run the risk of increasing particulate emissions;
- reduce the residence time – this is a design feature and burner manufacturers have for at least the last decade been developing low NO_x burners (Figure 10.3), which often used staged combustion or flue gas recycling to limit the production of NO_x at the burner by reducing peak flare temperatures;
- reduce the combustion temperature – for the same excess air this will reduce the peak temperature, and thus reduce NO_x, but this is not a very convenient route for operations. Reducing the air preheat temperature has a dramatic effect on NO_x emissions. However, this is counter-productive with energy conservation and particulate emissions, and should only be considered as a last resort since heater efficiencies can drop by up to 12%.

In addition to the above NO_x reduction technologies, other preventive technologies such as catalytic and non-catalytic flue gas treatment are available. However, these are expensive to implement and generally economically viable only on plants larger than those usually found in refineries.

(c) CO_x emissions. There is at present no treatment method for reducing CO_x emissions, and the main abatement instrument is increasing the efficiency with which energy is used on the plant. It should be borne in mind that control techniques for other emission pollutants and product upgrading may be significant

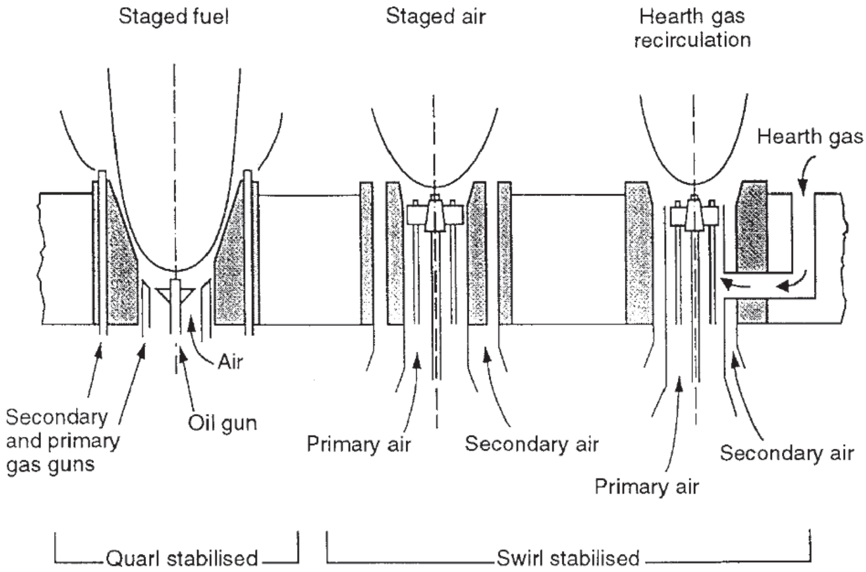


FIGURE 10.3. Schematic diagrams of the three types of low NO_x burners.

energy users and therefore cause CO_x emissions to increase. In addition, demands for improved fuels to reduce emissions from the use of oil products have meant that more energy has to be used in the refinery.

CO emissions can be controlled by good management of fuel combustion and are generally not a problem in refineries.

(d) Particulates control. Particulate emissions from refineries come from three sources:

- fuel combustion;
- process units;
- flares – a special case (Section 2).

(i) Fuel combustion. Ash and unburned hydrocarbons agglomerate to form particulates (typically 1–100 μm in diameter) when gas or oil are combusted. The level of particulate emissions is related to the intensity of combustion and the fuel quality. Low-quality fuel oil has higher levels of 'unreactive carbon' such as asphaltenes and sulphur, giving slower burnout, which increase particulate emissions.

Particulate emissions can be reduced by suitable changes to the burner or to fuel technology, and primary low-cost techniques such as those described below should be the first avenue of approach to emission reduction.

Combination firing. With some burners, combination firing of oil and gas is known to reduce overall particulate emissions compared with burning in separate burners.

Improve atomization. Finer atomization of fuel oil will increase the carbon burnout rates by making a larger oil surface available in the flame and so lowering particle emissions. Modern F-jet atomizers can give a ten-fold decrease in particulates formation. Increasing atomizing steam will also improve atomization and burnout, therefore reducing particulate emissions, although each incremental increase in steam is less effective than the previous one. Alternatively, increasing oil preheat gives a thinner oil which is easier to atomize. However, once the viscosity reaches 10–15 cSt (10–15 mm^2 s) at the burner tip there is little further benefit in additional heating.

Lowering particulates by better atomization has a drawback since finer atomization leads to higher flame temperatures owing to more intense combustion, which tends to increase the formation of thermal NO_x.

Improved air–fuel mixing. Increasing the system energy will improve combustion and reduce particulates. The draught loss across a burner is an indication of the system mixing energy. Higher draught is achieved through improved burner design and increased combustion air pressure or increased oil pressure. However, as with atomization, the better combustion also increases thermal NO_x production.

Increase excess air. The more excess oxygen is available, the greater is the rate of carbon burnout. However, there is a very high cost penalty in terms of energy usage and this really should only be considered as a last resort. Also, at high excess air rates flame chilling can occur, which tends to increase particulates.

Use of selected combustion improver additives. Recent studies have shown that it is possible to introduce selected metal-containing additives to the fuel and thereby catalyse the combustion process. Although the additives add overall to the inorganic ash produced, they can substantially improve carbon burnout and therefore reduce total particulate emissions.

Water–oil emulsions. There is good evidence that water–oil emulsions containing 25–30% of water improve combustion. The theory is that the water droplets explode as they enter the combustion zone, giving a substantial increase in fuel oil atomization. Currently, water–oil emulsions are being used on boilers firing fuel oil but are not widely used in refineries. Trials have shown that it is possible to achieve energy savings whilst maintaining the same level of particulates, or for the same oxygen level decrease particulates. The other benefit is that NO_x levels also decrease, probably owing to the quenching impact of water vapourization.

Increase air preheat. Increasing the air temperature increases the volume of air and achieves better mixing and burning. However, it is an expensive option and also increases the NO_x formation.

(ii) Process units. Particulates can be a major emission from some refinery process units. Typical sources are catalytic cracking units and cokers.

In catalytic crackers, the particulate emissions are mainly catalyst fines with associated carbons and as such are mainly inorganic (e.g. zeolites). The use of cyclones and electrostatic precipitators and careful catalyst selection all help to minimize particulates emissions from this source.

In cokers, where petroleum coke and some lighter oils are produced from heavy oil, the particulate emissions are mainly organic (e.g. coke). The coke is formed in drums and then cut out using high-pressure water. The coke is maintained in a damp condition to minimize escape of these fine particles.

3.2 Minimizing flare-related emissions

The main purpose of the flare is to collect and dispose safely the gases produced during upset conditions. Owing to the intermittent nature of flare gas flows, it may be uneconomical and not energy efficient to recover all of the gases. Flare operation is a special case of combustion emissions. Flares in refineries contribute to SO_x, NO_x and particulate emissions. Flaring represents a direct loss to the business and can be the biggest single hydrocarbon loss from refineries in monetary terms.

Traditionally, flares in refineries have been high-level open pipes. Emission of light is an inevitable consequence of high-level flare operation. The impact can be reduced by the use of ground flares (enclosed combustion incinerator) for a standard flaring load, with sequential release to a high-level flare for emergency conditions. Flickering of the flare flame should be avoided by using properly designed water seal pots at the base of the flare, which also act as a safety feature in preventing any flashback from the flare to the process units.

All the problems described above can be reduced by minimizing hydrocarbons entering the flare at source and avoiding unnecessary flaring. The management of flares not only makes good business sense, it also makes good environmental sense. Leakage from relief or safety valves contributes to a base load. Management of flares should concentrate on reducing the base load to the flare by regular checks on relief valves to determine those passing to flare. There are various techniques available to identify leaking valves, including inspection and ultrasonic detection. Frequent emergency flaring also needs investigation as to its cause and process solutions should be put in place to reduce it. Also, steps should be taken to improve combustion by injecting steam to give good mixing with air. Steam injection rates can be automated using luminosity, infrared or flow detectors.

As an end-of-pipe solution, flare gas recovery systems can be used (Figure 10.4). These typically compress flare gas back to the fuel gas system, assuming there is sufficient capacity to receive this. Flare gas can contain valuable products such as LPG, and modern recovery systems include hydrocarbon condensate recovery as well as compression and sweetening facilities.

3.3 Minimizing fugitive emissions

Fugitive emissions are volatile organic compounds (VOCs) that escape mainly from the process and off-site areas such as tankage and oily water sewer/effluent treatment systems. If not well controlled, fugitive emissions can represent a significant loss to the refinery. Not only are fugitive emissions a financial

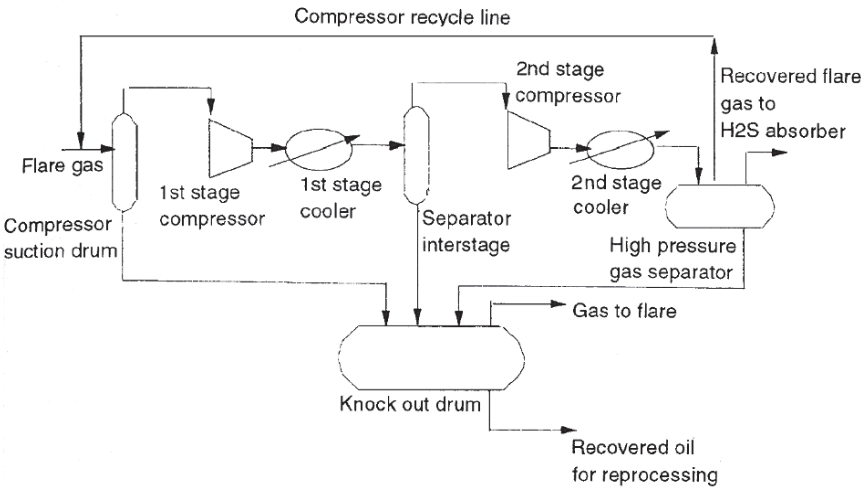


FIGURE 10.4. Simplified scheme of refinery flare gas removal unit.

loss, but they also have an environmental impact owing to the part they play in photochemical smog and ground-level ozone production.

There are many discrete emission sources in a typical refinery emitting hydrocarbons to the atmosphere. A detailed study carried out by the Radian Corporation for the US Environmental Protection Agency measured fugitive emissions from all detected sources in five US refineries and calculated the total emission levels. Interestingly, they found that 70% of all emissions from a process unit originated from around 1% of the leaks sources. Typical sources are control valve stems, flanges, compressor/pump seals, tanks and loading facilities.

Valves represent the largest source of process fugitive emissions in a typical refinery. Furthermore, a very high proportion of the losses is contributed by a small number of large leakers. Simple tightening of valve seals can often eliminate leakage once detected. For known troublesome valves or those which cannot be repaired on-stream, graphite gland packings can significantly reduce both fugitive emissions and maintenance costs. A number of special low-emission packings are now commercially available.

Evaporative losses from refinery tankage also represent a significant proportion of the total loss. Volatile products are generally stored in external floating roof tanks, and this design of tank can experience significant losses and offer the opportunity for reductions to be realized. Evaporative losses from external floating roof tanks (EFRT) are dependent on the properties of the stored product (composition, volatility) and external conditions (wind speed, ambient temperature and solar temperature gain on the roof). Refineries with high average ambient temperatures, solar radiation and also those with high average wind speeds are more susceptible to these losses.

The effects of ambient conditions can be minimized by modification to fittings and roof seals.

Reductions in VOC emissions from tanks can be achieved through the use of techniques such as vapour recovery on fixed roof tanks and the use of secondary tank seals and stillwell covers for hydrocarbon control on floating roof tanks. Other areas where hydrocarbons can gather on the surface of water, where they can be lost as fugitive emissions, are API (gravity) separators and interceptors. Floating covers can be fitted to the API separators to reduce VOC emissions. Atmospheric vents on oily sewers are another major source of VOC emissions and these can be controlled by closing the sewers or by installing carbon scrubbers on atmospheric vents. There are two methods that can be used to determine the quantity of VOCs emitted. The differential absorption (DIAL) method relies on the absorption of laser beams by airborne hydrocarbons to measure atmospheric concentrations. The American Petroleum Institute (API) method estimates emissions using average emission factors for different sources and hydrocarbon service. CONCAWE have carried out a trial of the DIAL method at an oil terminal and compared the results (Figure 10.5) with calculations using the API method. The results showed good agreement between the two methods provided that the DIAL results were averaged over a long enough period of time (30 h).

The fugitive emissions which have attracted the most attention are the so-called air toxins such as benzene, which is a known human carcinogen and linked to adult leukaemia. Although the cause for further action at very low concentrations remains equivocal, specific legislation has been

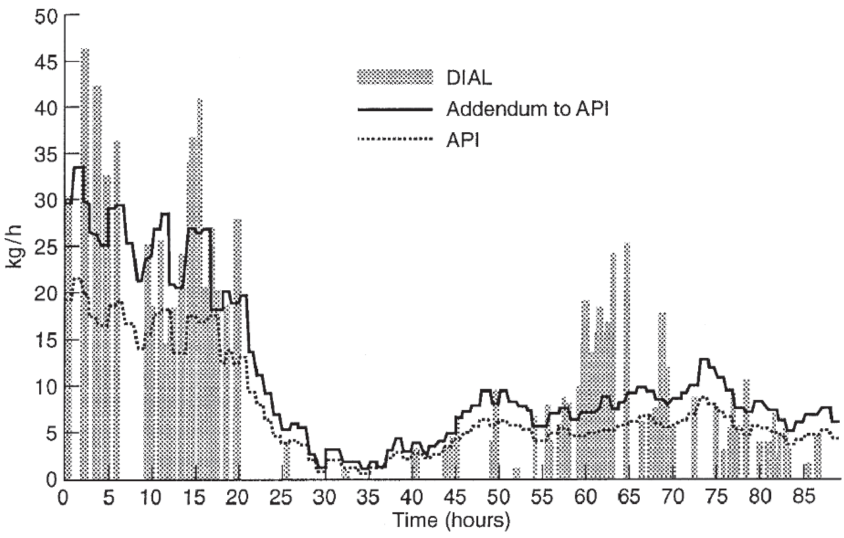


FIGURE 10.5. Emissions: DIAL measurements versus API calculations [4].

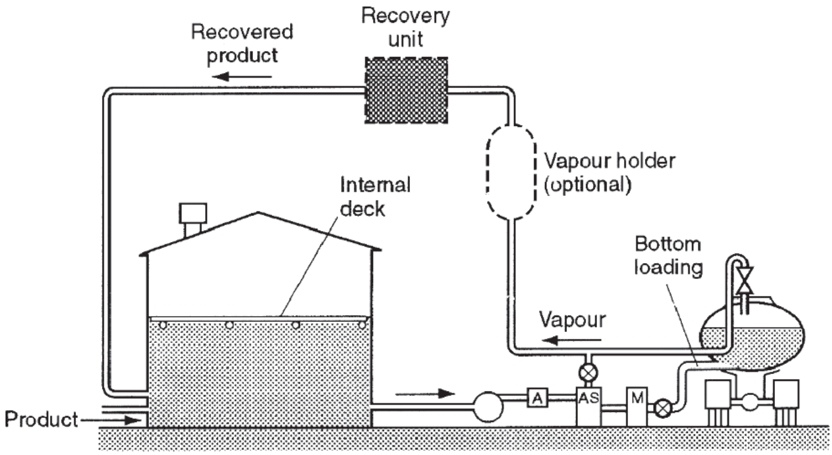


FIGURE 10.6. Vapour capture and recovery at terminal.

adopted/proposed on both sides of the Atlantic. The US EPA has requested actions at service stations and bulk gasoline plants (Figure 10.6) to reduce benzene emissions by some 90%. There are also benzene rulings for waste water systems that may trigger expensive modifications. In the EU, particular regulations apply to streams containing 15% or more benzene. Loading and discharge of bulk gasoline/benzene/reformate streams need to be closed.

3.4 Odour control

Typically 80% of all public complaints regarding refineries are due to odours. Extremely malodorous compounds, such as mercaptans and hydrogen sulphide, are the source of many of these complaints.

An odour is often the first indicator of exposure to a chemical. However, the ability to smell the presence of a chemical does not of itself indicate toxicity or a health risk.

The common sulphur-containing industrial gases, hydrogen sulphide and methyl mercaptan, are among the most common odorants from a refinery. Although they have odour thresholds significantly lower than levels known to cause toxicity, they are nonetheless most often associated with annoyance at levels just exceeding their odour threshold.

The main reduction techniques available to refiners are:

- control of fugitive emissions;
- control of flares;
- control of fuel quality;
- scrubbing of odorous gases;
- incineration of odorous gases;
- biotreatment.

3.5 *Sulphur removal and recovery*

Sulphur emissions are recognized as a major pollutant owing to the part they play in acid rain formation. SO_2 in the presence of catalyst gases such as NO_x forms SO_3, a very acidic species which is washed from the atmosphere during rain, and if the area on which it falls has little natural alkalinity, lakes and rivers can become acidic and not support higher life forms such as fish.

Sulphur dioxide emissions from refineries have decreased substantially in recent years owing to the greater availability of sweet refinery fuel gas resulting from increased upgrading capability (conversion of heavy oils to lighter) and authority restrictions. High-sulphur fuel oil can be a major source of SO_2 emission, as can be the catalytic cracker catalyst regenerator where some sulphur from the feedstock is burnt off. One method of reducing these sulphur emissions is to use lower sulphur fuel oil and feedstocks in the catalytic cracker. Alternatively, both the fuel oils and feedstocks can be desulphurized in a hydrotreating unit. This option is expensive, requiring significant capital investment and incurring increased operating costs, although coincidentally it also yields further light product and enhances feedstock quality.

H_2S formed in the gases through the processing of crude oil and other feedstocks is treated in an amine treater (Figure 10.7) where H_2S is absorbed from refinery gases and the rich amine is regenerated to release a H_2S-rich stream. This stream forms the basic feedstock for refinery sulphur recovery plants (Figure 10.8) where elemental sulphur is recovered in the Claus process. Depending on the complexity of these individual plants, sulphur recovery efficiency can vary from 92–93% up to 99.5%, although with substantially increased cost for each incremental improvement.

Other sour gases containing H_2S and ammonia are removed from collected refinery sour waters in a sour water stripper. The gas is removed and also forwarded to the sulphur plant, where a special stage destroys the ammonia.

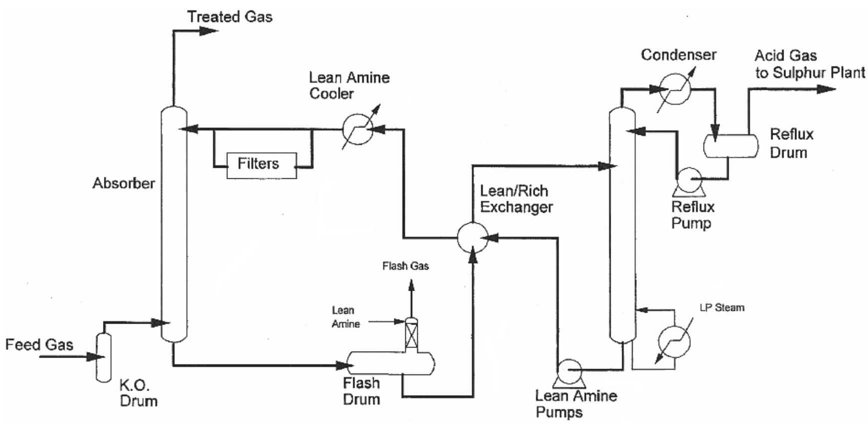


FIGURE 10.7. Typical flow diagram of amine unit.

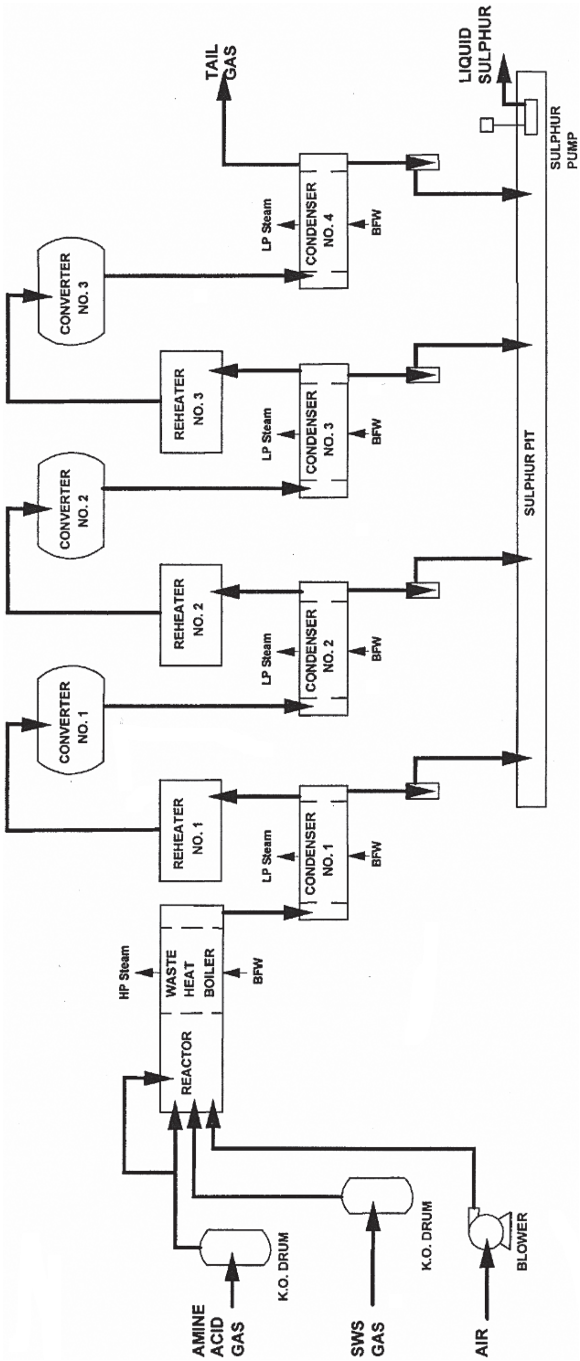


FIGURE 10.8. Typical three-stage Claus sulphur unit.

4 Control of aqueous emissions

Water pollution is caused by the release of contaminants into water sources which are either damaging to aquatic life (either because of their toxicity or through their reduction of the normal oxygen level of the water) or aesthetically unpalatable.

Potential water contaminants in refinery effluent are:

- acids, alkalis (pH);
- oil (free and dissolved);
- sulphides;
- ammonia/nitrates;
- cyanides;
- heavy metals;
- heat;
- other organic materials;
- nutrients;
- settleable solids;
- colour;
- taste and odour producers;
- toxic compounds.

All water discharges from refineries should be treated at least to a minimum standard. Often composite measurements are used to monitor the quality of discharge. Empirical assessment of total contaminant levels include:

total suspended solids	finely divided solid matter suspended in water
total dissolved salts	total inorganic salts dissolved in water
chemical oxygen demand (COD)	amount of oxygen consumed in the chemical oxidation
biological oxygen demand (BOD)	index representing content of biode gradable substances in the water
total organic carbon	determination of all organic carbon present
total nitrogen	determination of all nitrogen

The major sources of refinery aqueous effluents are process water, ballast water, rainwater run-off and cooling water. The contaminants picked up by process waters and rainwater are eventually routed to sea or river, and if untreated can have a major impact on the aquatic environment. All countries have legislation to control the level of contaminants in refinery waste water. The use of advanced waste water treatment plants has led to continuing reductions in contaminant levels. This is reflected in the fact that 747 tonnes of oil were discharged with the aqueous effluents from 84 European refineries in 2000 compared with 3340 tonnes from 95 refineries in 1990. In the 84 European refineries surveyed there has been a 78% reduction in the ratio of

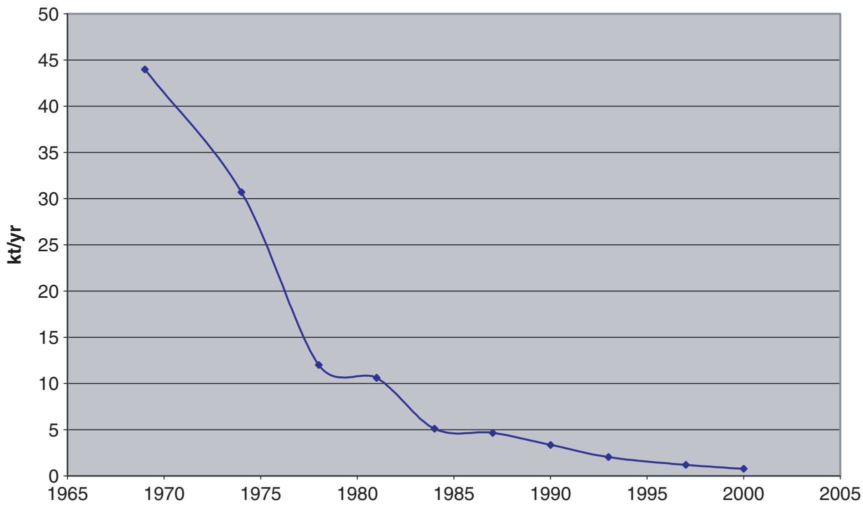


FIGURE 10.9. Oil discharged in the period 1969–2000 [6].

oil discharged to oil processed since the 1990 survey, i.e. it fell from 6.7 tonnes per million tonnes of oil processed in 1990 to 1.42 tonnes per million tonnes in 2000. On a longer term view (Figure 10.9), there has been a 98% reduction in oil discharged in European refinery effluents since 1969 [5].

4.1 Source control

Effluent treatment plants (ETPs) are often classified as end-of-pipe treatment, where all the waste water streams are collected and treated downstream of the process units and other sources. Effluent treatment is much easier and more effective if the contaminant loading can be controlled or limited at source so that the ETP is not overloaded but treats only the minimum quantity of contamination.

In addition to adequate equipment and hardware within the process plants, good source control requires both motivation and training of refinery staff, operators and maintenance personnel such that they are aware of environmental issues and able to avoid unnecessary release of contaminants.

Some examples of pollution control measures at source are given below.

Sour water strippers are used to remove hydrogen sulphide and ammonia selectively from a variety of process waters. In a typical sour water stripper the feed sour water is brought into counter-current contact with steam in a packed tower. H_2S and NH_3 are selectively stripped by the steam, which is then cooled and condensed. The incondensable off-gas containing the H_2S and NH_3 is routed to the sulphur plant. In this way H_2S is neither passed to the effluent treatment plant nor released to the atmosphere where it would cause a smell (Section 5).

Cooling water systems are used to produce cold water to cool hot process streams. In once-through systems, natural cooling water is used to cool process streams and then returned to the environment. In addition to introducing heat pollution into seas and rivers, this system risks contamination by the process stream in the event of leaks occurring in the heat exchangers. An alternative system is to recirculate this water. The water can be re-cooled with more natural water, thus reducing the risk of contamination. Alternatively, a closed cooling water network can be employed where the water is cooled either in a cooling tower or cooling exchangers using refrigeration technology. In cooling towers water is cascaded over packing and intimately mixed with air. The heat is dissipated by sensible heat loss and evaporation. In cold climates this can mean the formation of a visible cloud of evaporated water above the towers. Although cooling exchangers using refrigeration technology avoid air emission problems, they do run the risk of tube leakage whereby refrigerant can leak into the water, requiring further treatment before final discharge. The advantages of closed cooling water networks include lower water consumption rates and minimal heat pollution at final discharge. However, they require the injection of chemical additives to hinder corrosion and bacterial growth and periodic purging to prevent build-up of dissolved solids.

Desalter operations produce oily waste water with a high salt content, which represents a high treatment load. The load on the effluent treatment plant can be minimized if this water is first directed to a break tank where, with the use of demulsifiers and sufficient residence time, the oil and water are separated through decantation. The oil is then recovered and reprocessed. Thus only the water drained from the break tank needs to be sent to the effluent treatment plant. The use of robust and reliable interface detectors on the water drains will help ensure that minimum oil is purged into the drain.

Clean water segregation is vital if the volume of effluent requiring final treatment before discharge is to be minimized. Where possible, rain- or storm water should be handled separately from refinery oily water streams so as to avoid contamination of these clean streams. One way to ensure minimal contamination of rainwater is to minimize the area of paving on-site where oil and chemicals are likely to be spilt. This is usually possible by bunding in areas so as to limit any oil or chemical spills. The bunded areas can then be drained directly to the oily water sewers whilst the uncontaminated rain falling on clean paving can go to the clean water sewers. Similarly, well maintained tank roof drains are important if they are to direct clean rainwater to the clean water sewers. If the roof drains are blocked, rainwater can enter into the tank and become oily. It will then be drained from the tank as oily water and contribute to the effluent water treatment plant total load.

Leakage to sewers can occur when the sewer walls leak and groundwater can enter the oily water sewers. This usually happens after rainfall when the water table can rise to the same level as the oily water sewers. It is important that sewers are inspected regularly to avoid in-leakage of groundwater and the additional cost of its treatment.

Sampling systems should be closed where sample is returned to the process or collected where it is later recycled. Both of these techniques will help to reduce refinery loss and minimize the impact on the environment.

Tank draining should be routed to interceptors where oil can be separated out and recovered. Alternatively, interface detectors can be installed on the tanks to minimize oil loss to the drain.

Cross-contamination of clean water with dirty water can occur where the two lines run in close proximity to each other and when there is a risk of sewer damage. Collapse of the dividing walls between the two sewer systems can go undetected for some time, during which clean water can leak into the oily water system and create additional contaminated water.

Generation of solids in sewers can lead to operating problems in the effluent treatment plant, and should be avoided. Solids can be generated inadvertently in the sewers through chemical reactions which lead to precipitation or crystallization of solids compounds. Typical examples include the precipitation of calcium compounds when caustic solutions are mixed with water with a high calcium salt content, or salt precipitation when acid and alkali streams are mixed in the sewer system.

4.2 Effluent treatment

(a) Pretreatment. Aqueous waste which cannot be eliminated at source is usually treated using one of the following techniques before it is sent to the final effluent treatment plant.

Neutralization is a basic reaction for a number of waste water treatment operations. It is the reaction between an acid and an alkali used to adjust the pH of the solution to within the desired range so the water is suitable for discharge. Neutralization may also be necessary to establish proper conditions before an oxidation-reduction chemical reaction, for precipitation of heavy metals as hydroxides, for proper clarification and for better adsorption.

Emulsion breaking is a pretreatment step used for certain oil-water mixtures. Emulsified oils are used in machine operations and as coolants. These emulsions must be broken so the oil and water can be separated. Emulsion breaking is usually accomplished as a batch process. The spent emulsions are collected in a holding tank which is equipped with agitator(s) and skimmers. The tank contents are held undisturbed for 2-8 h to give insoluble oils time to rise to the surface for removal. The tank contents are then agitated and emulsion-breaking chemicals such as coagulants, flocculants and wetting agents added. After the emulsion has been broken, the freed oil is separated using gravity separators or liquid-liquid cyclones. The pH of the water is then adjusted and the waste water clarified by flotation or clarification.

(b) Primary treatment. Finally, all unavoidable contaminants or those most conveniently treated at end of pipe are passed to the effluent treatment plant (Figure 10.10). The first step is primary gross oil removal, intended to take off free oil from the effluent. The effluent is passed through gravity separators

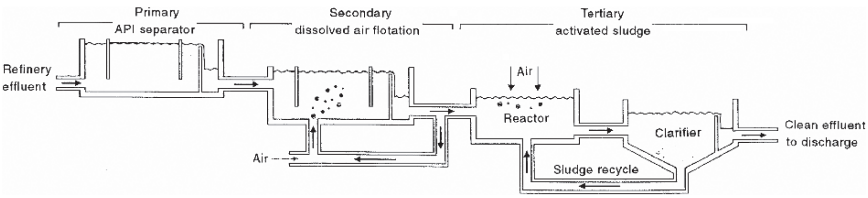


Figure 10.10. Typical three-stage effluent treatment process.

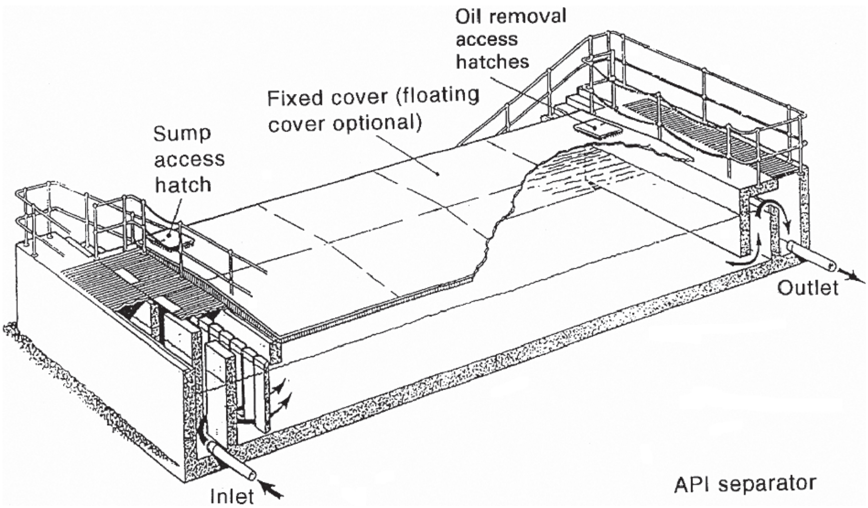


FIGURE 10.11. API separator.

(Figure 10.11) or corrugated plate interceptors with sufficient residence time to allow free oil to rise to the surface, where it is skimmed off. This treatment has virtually no impact on soluble components. Substantial quantities of sludge can also collect in these separators.

(c) Secondary treatment. As a second-stage treatment, air flotation or filtration units are used for the removal of fine oil droplets from water. Flotation units (Figure 10.12) work on the principle that oil droplets are carried to the surface by small gas bubbles. Air is introduced into the system, forming small bubbles which attach themselves to oil globules or suspended particles and float them to the surface, from where they are removed for further handling. Chemicals such as coagulants, acids and/or alkalis are often added ahead of the system to promote more complete removal. In filtration systems the oil is filtered from the aqueous stream using a filter medium such as sand or anthracite. This medium is then backwashed to prevent excessive pressure drop and to remove the oil collected there. Again, there is no removal of soluble contaminants through the use of these techniques.

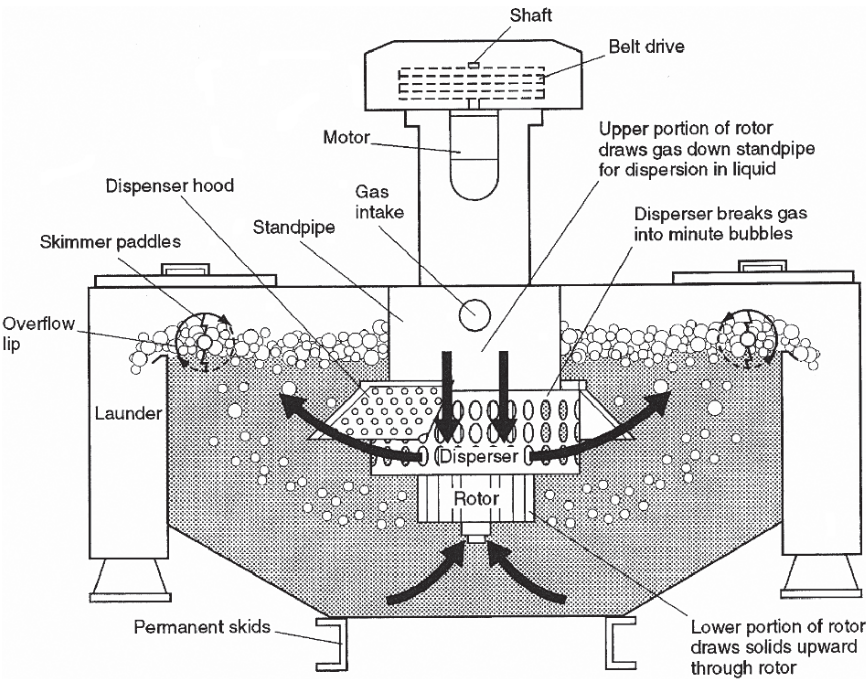


FIGURE 10.12. Depurator machine float cell (section view).

(d) Tertiary treatment. Once the majority of the free oil has been removed, biological treatment is used to remove the water-soluble constitutents in the effluent so as to reduce the biological oxygen demand (BOD) and specifically identifiable organic materials such as phenols. The process relies on the use of biological activity to degrade pollutants. When organic material is discharged into a receiving stream, a biological chain of events occurs, in which naturally present bacteria in the receiving stream metabolize and stabilize the organic material, consuming oxygen in the process.

For most waste waters, the destruction of organic material will take place under aerobic conditions in which a measurable oxygen residual is present. For certain concentrated organic wastes, anaerobic treatment (in the absence of oxygen) can be used, although its applicability is relatively limited, and it is usually followed by aerobic treatment for complete stabilization.

The most widely used biological process for industrial waste water is the activated sludge process. Incoming waste, with or without primary treatment for suspended and settleable solids removal, is mixed with return activated sludge and enters an aeration tank. This tank is aerated to maintain residual dissolved oxygen so biological growth and activity occur. If necessary, nutrients can be fed in at this point. The wastes and the bacteria are held in contact long enough to stabilize the incoming organic material and accomplish the desired effluent quality. The mixed waste goes to a final settling tank where the bacteria settle from the water, the waste is discharged and the bacteria are recycled.

Sludge will build up in the system in most cases to the point where some will have to be removed for ultimate disposal.

(e) Final polishing. Some refineries have a final polishing stage prior to final discharge of the effluents to remove any remaining bacteria, but this is by no means standard practice. Typically these consist of either a sand or a perforated drum filter or a final settling pond.

Sand filters utilize media such as anthrafilt or sand, although modern filters use mixed media, graded coarse to fine, in the direction of the water flow. The filters are regularly backwashed to remove the collected bacteria. In the perforated drum filter, water passes through the drum and the solids are retained on the drum. Solids are then removed from the drum and handled similarly to filter backwash water. Since slurry is produced at a more uniform rate, intermittent storage requirements may not be as critical as is the case with backwash water.

Settlement basins are artificial ponds or lakes used to hold water to effect the removal of suspended solids and insoluble oils. Lagoons are also used as retention ponds after chemical clarification to polish the effluent and to safeguard against upsets. The basin needs to have sufficient residence time for further biological activity.

A few refineries have used wetland technology to achieve final polishing. Reeds which thrive in wetlands can help the breakdown of effluent contaminants which are nutrients for certain microorganisms. The reeds' small roots host colonies of these microorganisms and the larger roots help to develop hydraulic transport pathways through the soil and supply oxygen to the bacteria.

5 Soil and groundwater protection

Pollution of air and surface waters can be readily identified. Pollution of soil and groundwater is more difficult to determine but is very important for the whole oil industry, including refineries. Wherever oil products have been handled for many years, it is highly likely that oil will have entered the ground and refineries are no exception. However, the significance of this varies with the hydrology of the ground under the site. In areas where the sub-soil is of very low permeability, then the problem remains localized within the site. In other cases, the contamination can spread outside the site, which may be particularly harmful where groundwater is used for drinking water supply. Although the most obvious source of ground pollution from a refinery is oil, other pollutants can enter the ground. These are considered under Section 6 on solid waste control.

5.1 Source control

Oil enters the ground in refineries in three main ways: through operational practices such as sampling or drawing water from tankage; through leaks from oily water sewers, underground pipe work, underground storage tanks and normal tanks; and from accidental spills of petroleum products into the ground.

Measures to control the first of these sources are basically the same as those already covered under the control of aqueous emissions (Section 4), coupled with ensuring that areas where oil is regularly handled are covered with an impermeable surface and drained to the oily water sewer. Such areas should include maintenance areas such as heat exchanger cleaning areas.

Leakage of groundwater into sewers has already been mentioned in Section 4. The reverse also occurs, leading to oil entering the ground. Again, regular inspection and repair, possibly by lining, are required.

Leakage from underground pipes is difficult to detect and can best be prevented by running oil-containing pipe-work above ground wherever possible. Similarly, the use of underground storage tanks should be limited as far as possible.

A primary cause of land contamination is leakage from pipes and tanks. During operational situations it is often difficult to identify which tank is leaking. However, since continuing contamination gives rise to further waste and future liability for clean-up, refiners are making a major effort with leak detection for both tanks and underground piping.

5.2 Monitoring

Given that most refineries are likely to have at least some contamination of soil and groundwater, monitoring surveys are often necessary. These are required by national legislation in many European countries.

Before remediation of the soil and groundwater can be undertaken, it is important that a thorough assessment of the type and extent of contamination is completed. These assessments are usually phased. Many techniques have been developed for this purpose but they generally fall into two categories, non-invasive and invasive. The following are some of the more typical techniques used to assess the contamination of soil and water by the oil industry.

Non-invasive

- soil hydrocarbon vapour measurement;
- geophysical methods;
- resistivity methods;
- magnetic flux methods.

Invasive

- borehole drilling and sampling;
- cone penetrometer with soil conductivity or laser fluorescence sensors;
- vadose zone vapour probe; this is hydraulically advanced into the soil, a porous element exposed, a vacuum applied and a vapour sample taken, which is analysed immediately;
- groundwater wells.

A disadvantage of non-invasive methods is that they sometimes give a false impression of conditions underground and are therefore mainly used as screening techniques to allow focusing on the more expensive invasive techniques.

Once contamination has been detected and the source stopped, investigation of the hydrocarbon type and distribution will help to confirm the source and the migration mechanisms. This understanding allows steps to be taken to prevent the spread of contamination. Many methods are available but typically the installation of interceptors or cut-off trenches are used to collect the polluted water in the soil through natural drainage. The collected water is then removed for treatment.

5.3 Remediation

Once the ground and contamination conditions have been established, an assessment of the risk to human health and the environment is made. This helps to determine the remediation need and allows any clean-up standards to be set. Recent emphasis in treatment techniques for soil and groundwater in the oil industry has been on in situ treatment in contrast with previous methods which addressed in situ treatments such as land farming/biodegradation of sludges.

Perhaps one of the most applicable *in situ* techniques is that of biodegradation, where the controlled addition of oxygen and sometimes nutrients can accelerate the growth of microbes, which beneficially degrade contaminants. *In situ* biodegradation is a long-term passive treatment technique; an example is soil venting combined with air sparging, where air is bubbled into the groundwater and vapours from the soil are continuously drawn off. The vapours are analysed, and treated in a biosystem before discharge to the atmosphere. This has the effect of desorbing hydrocarbons from the soil and inducing more oxygen into the soil, which accelerates microbial growth. It works best where sandy ground has been contaminated with volatile hydrocarbons.

Methods used for treating contaminated groundwater include closed-loop systems, where groundwater is pumped to the surface, treated and then returned to the subsurface via wells. Surface treatment of the groundwater can include separation, air stripping, addition of oxidizing chemicals and bioreactors.

5.4 Preventive techniques

A number of preventive techniques are available either to reduce the risks of groundwater pollution or to limit the spread of such pollution once it has arisen. Many of these methods are very costly, particularly when retrofitted. Their use should be considered after a rigorous assessment of the reduction in risk of the alternatives versus the cost in both financial and environmental terms.

Measures which can be considered include double bottoms in tanks, impermeable layers under tanks and impermeable surfaces for tank bunds.

To prevent migration off-site, either mechanical or hydraulic measures can be applied. Mechanical measures include cut-off walls or ditches. Hydraulic methods include the pumping of groundwater from within the site so that the flow is inwards rather than outwards. This can be combined with remediation of contaminated groundwater. However, most of these methods in themselves constitute an alteration in the natural groundwater hydrology and hence have environmental effects which need to be taken into account.

6 Control of solid wastes

Waste is defined as any material of no further primary use, and excludes aqueous and gaseous effluents from operating units. It is essentially any material that remains as an unwanted by-product of refining that needs to be disposed of. Whilst waste production in refineries and terminals is a smaller average percentage of total throughput compared with most other industries, it nonetheless represents a high cost in loss and potential environmental risk, and as such its minimization is a priority. However, generation of some waste is an inevitable consequence of refinery operation, and wastes generated fall into two categories, non-hazardous waste and potentially hazardous wastes, e.g. sludges with a high metals or hydrocarbon content. Generally refinery wastes fall into the first category, although regulatory authority definitions are changing to bring more and more waste types into the second category. Typical wastes generated from refining operations are shown in Table 10.1.

Segregation of different wastes is a first priority. Addition of a small quantity of hazardous waste may turn a large quantity of inert waste into hazardous waste. A number of routes are available for the disposal of refinery wastes. Figure 10.13 shows some of the routes used by the Western European refining industry.

6.1 Source control

It is most cost-effective to minimize the amount of waste at source, since waste represents a loss of either raw materials, intermediates or products which require both time and money to manage and recover. In addition, the generation of

TABLE 10.1. Typical wastes generated from refining operations

Waste	Source
Oily sludges	Tank bottoms, interceptor sludges, waste water treatment sludges, contaminated soils, desalter sludges
Solid material	Oil spill debris, filter clay, acid tar, filter material, packing, lagging, activated carbon
Drums and containers	Metal, glass, plastic, paint
Non-oiled materials	Spent catalyst
Construction debris	Scrap metal, concrete, asphalt, soil, asbestos, mineral fibres, wood

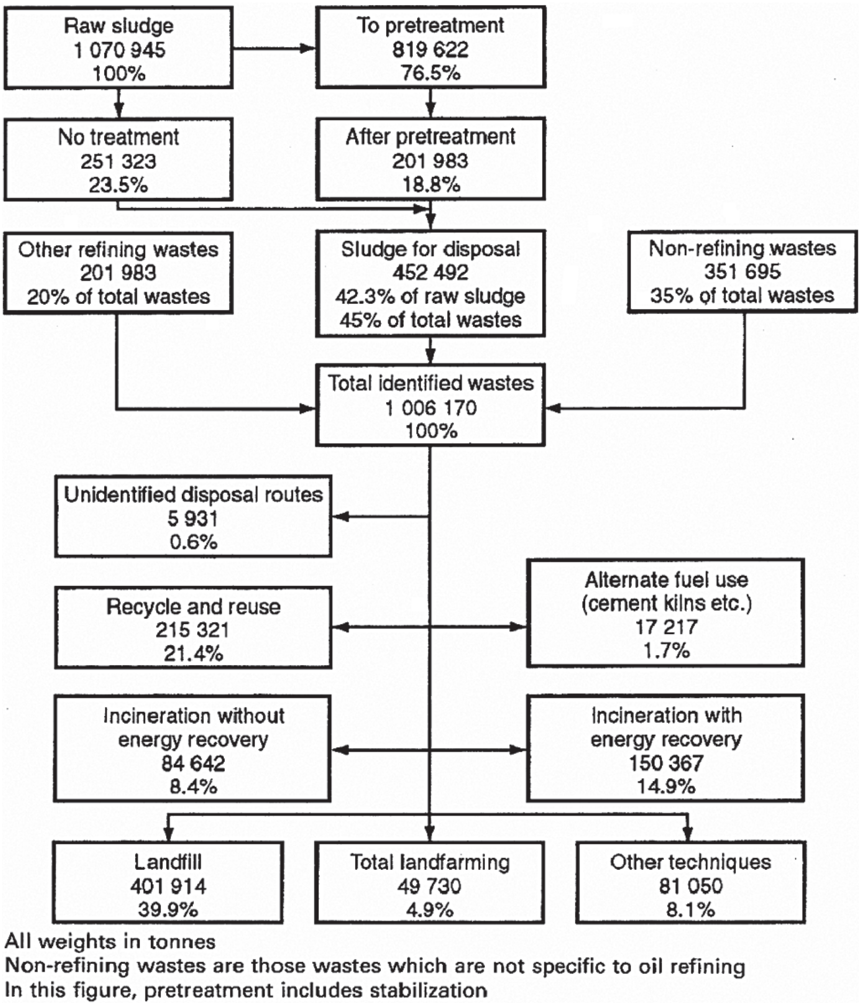


FIGURE 10.13. Summary of total waste generation and disposal routes (Western Europe) [6].

wastes and their subsequent recycling or disposal can present a range of regulatory, health and environmental risks or liabilities. Thus good source control is the most effective method of minimizing the impact of the refining operations on the environment. In a number of cases, relatively minor modifications can result in appreciable waste minimization. The following are some common and effective source control techniques used to minimize refinery waste:

- installing mixers on crude oil storage tanks to reduce sludge accumulation;
- closed-loop sampling systems on product tanks to reduce waste/slop oil production;

- use of antifoulants and corrosion inhibitors;
- dissolved air flotation (DAF) units; use of polyelectrolyte instead of inorganic flocculants to reduce the mass for final disposal;
- regenerative rather than once-through processes (e.g. Merox process instead of caustic treatment).

General good plant operation and economy in the use of chemicals will result in the minimization of wastes for disposal. Good housekeeping is essential to waste minimization. Seemingly unimportant procedural aspects in operations and maintenance may have a large impact on waste generation.

One way in which waste is generated is through spills and leaks in the plant. Thus proper material handling and storage will reduce waste generated by this method. Examples include:

- storage of drums off the floor to prevent corrosion through concrete 'sweating';
- bunding of storage/process area to contain spills;
- using larger containers instead of drums; larger containers are reusable when equipped for top and bottom discharge, whereas drums have to be recycled or disposed of as waste;
- equipping storage tanks with high-level alarms and automatic pump shut-offs;
- installing leak-proof valves;
- when there is a risk of leaks, the soil or floor should be rendered impermeable and a collection system provided.

Also cleaning, by its nature, generates waste. By choosing the right procedure and technique, this waste may be minimized or its nature altered so as to make it more easily disposable:

- drain equipment into closed systems where possible;
- use on-site pretreatment whenever possible, e.g. wash-steam filter material prior to dumping;
- minimize tank sludge prior to cleaning (through use of solvent and mixers).

Waste handling, when correctly done, optimizes the economics and minimizes the ecological impact of the final disposal.

6.2 Waste treatment

Since some waste generation is unavoidable, treatment of the waste is required to minimize its physical size before final disposal. The following are some of the more common techniques used by refineries to dewater or deoil the waste to decrease its quantity and to recover oil.

(a) Sludge dewatering. This is an intermediate process for the concentration of sludge for disposal. Sludge from a clarifier or a final biological sedimentation tank averages 1–3% solids by weight. Some thickeners handling particulate material yield solids running as high as 10% by weight. The first step is the

use of a thickener, which is a holding tank for settling the produced solids more compactly through gravity. A thickener can increase solids concentration from 3% to 10–15%.

There are other intrinsic values in the use of thickeners. Inclusion of thickeners in the system enables the operator to control the clarifier for optimum clarity of effluent and still schedule further sludge handling. With biologically active sludge, a digester functions also as a thickener and sludge reducer through further biological activity. The compacted sludge is then further dewatered by filtration or centrifugation.

(b) Filtration. Filtration is a means of dewatering sludge suitable for treating sludges with a low oil concentration as oil can blind or smear the filter cloth. Filtration usually yields a rather oily cake, with little oil in the liquid phase. If the final disposal route of the sludge is incineration, leaving oil in the cake can reduce the fuel costs. As regards landfilling, filtration reduces the transport and disposal costs, because the sludge contains less water.

(c) Centrifuging. Centrifuging is particularly applicable when the oil content of the sludge is higher than 10%. The feed enters the machine and forms a concentric pool through which the solids settle to the outer wall. Solids are continuously removed by a scroll conveyor across a drying beach to discharge ports. The liquid flows counter-currently through a cylindrical section to an overflow dam of variable elevation, which affords pool-volume regulation.

(d) Drying of sludges. Drying of refinery sludges removes water and volatile organic compounds by heating using a steam coil. The vaporized materials are condensed and separated in a drum into an oil phase and a water phase. The solid phase is discharged.

The feed can be raw sludge or the solid phase from a filter press or centrifuge. Thermal treatment has proved to be effective in processing biological effluent treatment sludge, thereby converting the sludge into fertilizer or composting material. Alternatively, oil-containing sludges may be converted into low-grade fuel pellets which can be used in other industries.

(e) Solidification. Solidification is a process designed to improve waste handling and physical characteristics, decrease the surface area across which pollutants can leach, or limit the solubility of hazardous constituents, in which materials are added to the waste to produce a solid. It may involve a solidifying agent that physically surrounds the contaminant such as cement or lime, or it may utilize a chemical fixation process such as with sorbents. The resulting waste is usually an easily handled solid with low leachability.

(f) Stabilization. Stabilization is the conversion of a waste to a chemically stable form that resists leaching. This may be accomplished by a pH adjustment. Stabilization also generally results in a solidification of some sort.

Chemical stabilization is based on the reaction of lime with waste materials and water to form a chemically stable product. This technique is suitable to immobilize watery sludges to yield a powdery hydrophobic product which can be compacted. The immobilized product is water-repellent with a low risk of leaching. It hardens with time and has very good properties for civil engineering applications such as foundations, tank bases, bund wall and road making.

(g) Encapsulation. This involves complete coating or enclosure of a waste with a new, non-permeable substance. Microencapsulation techniques are based on the reduction of the surface-to-volume ratio of the waste by formation of a monolithic, hard mass with a very low permeability. Macro-encapsulation is the enclosing of a relatively large quantity of waste with a stiff, weight-supporting matrix and a seam-free jacket.

Encapsulation is suitable for on-site treatment of accumulated spent acid tars and oily sludges which are difficult to transport and to dispose of by other means. A disadvantage is that the treated product occupies a larger volume than the original sludge.

Because it can be applied on-site, the encapsulation process may be considered for single applications such as rehabilitating refinery sites after decommissioning or cleaning up an oil-polluted site after a spill. The decision to apply the process depends on the future use of the site and local legislation. The process is less attractive for the treatment of regularly produced sludges because of the increased mass generated for disposal.

6.3 Waste disposal

The following are some of the principal waste disposal and redemption techniques practised in the oil industry.

(a) Landfills. A landfill is a disposal route where waste is deposited in an artificial or natural excavation for an indefinite period of time. The deposition of wastes on land as a method of disposal will always be an activity which is controlled under legislation. In some countries it remains one of the cheaper methods of disposal, although the shortage of satisfactory sites and the difficulties in obtaining licenses from the regulatory authorities is driving prices higher.

The key consideration in the operation of a landfill site is the protection of groundwater from contamination by the materials contained in the landfill. Wastes that contain water-soluble materials which can be leached by rainwater may ultimately contaminate nearby springs and streams, possibly rendering water sources unusable. Therefore, essential factors for such wastes are the following:

- The lining of the containment should be impermeable. Clay is the preferred material in some parts of Europe. In others, a lining of plastic sheeting is used. In some countries it is required to have multilayer linings with integrated drainage systems for new landfills.
- Monitoring bore holes are used in order to inspect the effectiveness of the containment.

- The deposition of liquid wastes is not permitted except under rigorously controlled conditions. Whether or not liquid deposition is allowed, arrangements should be made for the collection and treatment of leachate.

A consideration for the disposer is that wastes deposited in landfill are not immediately destroyed but only stored. They must not be capable of reacting in a harmful way to generate heat or noxious gases. If flammable gases, e.g. methane, are generated they should be collected. Land is usually not usable until several years after a landfill operation is complete so that degradation of the material can take place. The overall economics of landfill or disposal methods are affected by several factors: the cost of transportation from the source to the site, the cost of the land and the cost of the landfill operation itself. The last factor is a minor part of the total.

With the cost of transportation and land increasing at alarming rates, this method may soon be less attractive than it has been previously.

Landfill is, however, the most practicable method of disposing of inert wastes such as building rubble.

(b) Incineration. Any process that uses combustion to convert a waste to a less bulky, less toxic material is called incineration. An incineration system must produce as complete a combustion as practical using an optimum selection of governing parameters such as time, temperature and turbulence, and provide air pollution control devices to minimize the emission of air pollutants. Many waste materials are readily combustible and the products of their combustion are harmless gases which are easily disposed of through vents or stacks to the atmosphere. In such cases, incineration is often the soundest method of waste disposal.

Some of the factors that characterize incinerators with good performance are:

- complete combustion;
- clear stack;
- low maintenance;
- minimum materials handling;
- minimum operating labour;
- adequate capacity;
- adequate availability;
- adequate flue gas treatment.

There are several types of incinerator designs to handle a variety of wastes, as shown in Table 10.2.

(c) Biodegradation. Many potentially hazardous chemicals present in refinery waste can be converted by microbiological methods into harmless compounds such as water and carbon dioxide. In general, the microbiological degradation of contaminants in soil is very slow in nature, because process conditions for such degradation are seldom favourable. To accelerate and optimize degradation the following conditions have to be fulfilled:

Table 10.2. Types of incinerators

Type	Feed	Comments
Fixed hearth incinerators	Solid, sludge and viscous oil	Low operating costs, small batch sizes
Multiple hearth incinerators	High water content sludge	High volumes, high operating costs
Fluidized bed incinerators	Partially dewatered sludge	Flexible wet sludge composition
Rotary kiln incinerators	Most wastes	Versatile and durable
Liquid fuel incinerators	Gasified or atomized liquids	–

- sufficient number of microorganisms of the right strains;
- non-toxic concentrations of contaminants or other compounds;
- sufficient water;
- sufficient nutrients;
- sufficient oxygen for aerobic processes and a full depletion of oxygen for anaerobic processes;
- favourable temperature;
- sufficient availability of contaminants (preferably without high peak concentrations);
- pH of soil.

Several types of techniques are possible for the microbiological treatment of contaminated soil, as follows:

Land farming. Land farming systems have been used for the treatment of petroleum industry wastes for many years. The process involves the controlled application of waste on a soil surface in order to biodegrade the carbonaceous constituents by utilizing the microorganisms that are naturally present in the soil. The conditions under which the degradation takes place are typically aerobic. The advantages of land farming are that it is a relatively cost-effective and simple technique, which is environmentally acceptable provided that it is properly designed, operated and monitored.

In most locations, permission from the authorities is required before a land farming facility can be started. In a number of countries the technique is not permitted at all.

Composting. Composting is a biological process where fresh organic wastes are transformed by decomposition into a stable humus-like substance. The processing is accomplished mechanically in a rotating cylinder. The waste is delivered to the cylinder in a moistened condition by the addition of water or sewage sludge. Air is added at low pressure and in controlled amounts throughout the length of the cylinder. In this manner an environment is created where the action of aerobic microorganisms ensures rapid decomposition of the wastes under inoffensive conditions. As with the backyard compost pile, the microorganisms which effect the decomposition are indigenous to the wastes themselves. The final process material is then screened and the compost is separated. The resulting compost is suitable for use as a fertilizer and soil conditioner.

Mechanized processes. The third category consists of wet and dry bioreactors and/or fermenters in which the soil is continuously mixed intensively. The biological composting/decontamination process can be accelerated if the necessary process conditions are closely controlled and monitored in pressure tight vessels. Typical hydrocarbons need a few hours to degrade, whereas PCBs require several days.

7 Recycling to minimize waste

Recycling waste materials for reuse may in many circumstances provide a cost-effective alternative to treatment and disposal. The success of recycling depends on both the ability to segregate recoverable and valuable materials from a waste and the ability to reuse waste materials as a substitute for an input material.

7.1 *Reuse on-site*

The optimum place to reuse wastes is within the refinery itself. The following are some typical examples where waste has been recycled within the refinery.

(a) *Use of closed water circuits and cooling towers*. Previously once-through cooling water discharged into the environment is now retained on-site, cooled and recycled to the process units. Thus the use of cooling towers allows an overall reduction in water intake and discharge.
(b) *Reuse of water in crude distillation unit desalters*. Water in the crude oil and water recovered in the crude distillation unit can be used to substitute fresh water into the desalter, thus reducing total oily water production to be treated.
(c) *Use of caustic cascades*. Spent caustic from one process plant may still be sufficiently strong for use in another. For example, spent caustic can be further utilized in crude distillation units as a corrosion inhibitor or injected into biotreaters for pH control.
(d) *Centrifuge reprocessing of oil recovered*. Recycling recovered oil eliminates the need for disposal and allows partial recovery of value in final product.
(e) *Reprocessing of off-specification products*. Reprocessing of off-specification product eliminates the need for disposal and allows the recovery of final product value.
(f) *Reprocessing of oily emulsions*. Reprocessing of oily emulsion (e.g. from an air flotation unit) in the distillation column eliminates treatment with demulsifiers and disposal costs and allows conversion of the oil to product.

7.2 *Off-site recycling*

Wastes may be considered for use or reclamation off-site. Materials commonly reprocessed off-site by chemical and physical methods include oils, solvents and scrap metal. A strong commitment is required from the recycler not only to upgrade the waste materials for sale or exchange but also in finding suitable markets.

Examples of off-site recycling of refinery waste include:

(a) *Recycling FCCU catalyst*. Spent FCCU (fluid catalytic cracking unit) catalyst can be used as equilibrium catalyst in the start-up of new units.
(b) *Cascading FCCU catalyst*. Spent FCCU catalyst can be further utilized in other units operating at lower severity.
(c) *Sale of FCCU catalyst*. Spent FCCU catalyst may be used as an additive in cement manufacture. When the cement is used, the catalyst component forms insoluble hydrates with the chalk present in the cement mixture, which also gives beneficial fixation of the heavy metals present on the catalyst. It can also be used in brick manufacture.
(d) *Disposal of spent catalysts*. Industrial catalysts can contain heavy base metals and promoters/inhibitors such as phosphorus compounds. Sometimes these catalysts can be regenerated and reused. Alternatively, another disposal option is to return the spent catalysts to the manufacturers or to metals reclaimers for reprocessing. There is also a special group of precious metal catalysts used in oil refining, but they are not associated with disposal problems, and are always recycled because of their metal values.
(e) *Sale of gypsum or sulphuric acid*. SO_2 present in flue gas desulphurization units can be converted through additional processing into gypsum or sulphuric acid, which can be sold.
(f) *Drums/containers*. Drums and other containers can often be recycled after suitable reconditioning.

8 Environmental management

Environmental management, like safety management, is now an integral part of the management process in most oil refineries. Many refineries have environmental management programs such as those under ISO 14001[7] or EMAS [8] which provide for continuous improvement in Environmental performance. Even without these, environmental policies for the refineries should be written to provide continuity and consistency in environmental protection programmes. The policy indicates the emphasis that the senior manager places on the programme, and outlines the major responsibilities and involvement of managers at each level and employees.

8.1 Environmental control

While a senior refinery manager will be responsible for the overall programme, there are many tasks and details to be looked after. A programme coordinator is often appointed in writing and given express authority necessary to administer the programme across functional lines of the organization. The coordinator should have adequate technical and administrative assistance to perform the planning, sampling and other functions of the environmental programme administration.

Many requirements for environmental protection measures are detailed in legislation and implementing standards, codes and regulations. All pertinent legislation should be clearly understood by the coordinator.

8.2 Environmental training

Environmental protection activities require specialized knowledge to organize and perform the managerial and technical tasks. A programme should be set up to include pertinent training for managers at the various levels and for employees whose work requires interfacing with environmental hazards.

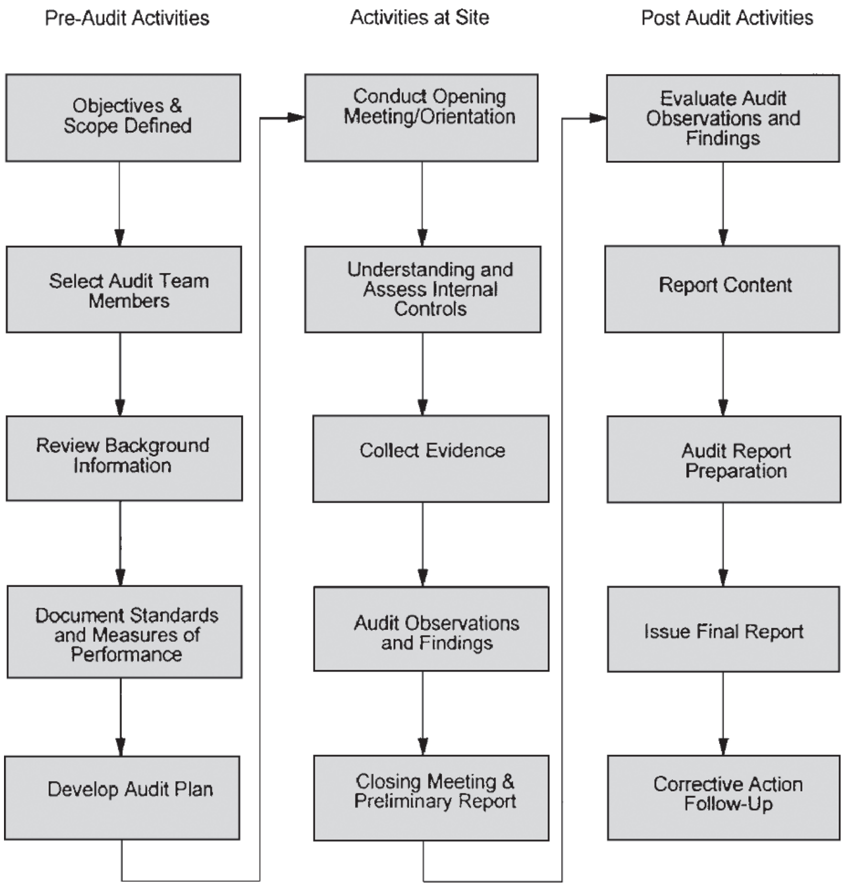


FIGURE 10.14. Basic steps of an environmental audit.

Each process, or each variation in process, can have differing impacts on the environment. Assessment of these impacts is critical to defining the degree of risk and selecting the appropriate controls.

Prior to construction, many processes require permits, licenses or other written approvals. This may require research and an understanding of legislation to identify and secure these various requirements.

Following construction, modification or overhaul, facilities should have operational safety inspections to ensure that they are safe to operate. These should include the evaluation and contact of potential spills and other emissions that could harm the environment.

8.3 Environmental auditing

Auditing is often used to ensure that management of environmental procedures and control are assessed and opportunities for improvements and also weaknesses are identified and corrected. Figure 10.14 above shows the basic steps of an environmental audit programme. This process should be carried out at regular intervals and may involve both internal and external auditors.

References

1. Council Directive 96/61/EC of 24 September 1996 concerning integrated pollution prevention and control Official journal of the European Communities No L257 10.10.1996
2. Sulphur dioxide emissions from oil refineries and combustion of oil products in Western Europe in 1992. *CONCAWE Report* 6/94
3. Sulphur dioxide emissions from oil refineries and combustion of oil products in Western Europe and Hungary. *CONCAWE Report* 10/02
4. VOC Emissions from external floating roof tanks. Comparison of remote measurements by laser with calculation methods. *CONCAWE Report* 95/52
5. Trends in oil discharged with aqueous effluents from oil refineries in Europe 2000 survey. *CONCAWE Report* 4/04
6. Oil Refinery waste disposal methods, quantities and costs – 1993 survey. *CONCAWE Report 1/95*
7. *ISO14001 Environmental Management Standard, Environmental Management Group, Moss Lane, Bootle, Merseyside, UK. (www.iso14000.com)*
8. *EMAS, Eco-Management and Audit Scheme. (www.emas.org.uk)*

Chapter 11
Distribution, Marketing and Use of Petroleum Fuels

T. Coley[1] and J. Price[2]

1 Introduction

A typical oil refinery operates continuously, manufacturing a wide range of products for a variety of end uses. The products pass from the processing units to refinery tankage but, as storage capacity at refineries is finite, their early transfer into the distribution network is essential for operation to continue at or near the designed throughput.

Refineries have the capability to manufacture many different types of material: gases, solvents, jet and burning kerosine, cracker and petrochemical feedstocks, gasoline, diesel fuel, domestic heating oil, residual fuel, lubricants, waxes and bitumen. Applications in which these products are used vary widely but a very high proportion of refinery output is burned as fuel.

2 Main refinery product types

The main fuel types, representing 80–85% of the production from a typical refinery, are gasolines, middle distillates and residual fuel oils. Gasolines are the grades of petrol used in piston-type engines for aircraft, passenger cars and equipment such as lawn mowers and small generator sets. Middle distillate fuels include aviation jet kerosene, burning kerosine, heating gas oil and diesel fuels for automotive, agricultural, industrial and marine engines.

Residual fuel oils, consisting largely of the heavy non-distilled residue from crude oil, are used in industrial heating systems and as diesel fuel in large, slow-speed engines for marine propulsion and industrial pumping, heating and power generator installations.

The balance is comprised of liquefied petroleum gases (LPGs), solvents, lubricants, waxes, petroleum coke and bitumen. Refinery fuel consumption accounts for about 2.5% of the total crude throughput at a simple hydro-skimming refinery, consisting only of process units for distilling,

[1] *Petroleum Quality Consultant, 29 Hanson Road, Abingdon, Oxon, UK*
[2] *Intertek Sunbury Technology Centre, Brooklands Close, Sunbury-on-Thames, UK*

TABLE 11.1. Regional fuel consumption demand patterns 2004 (million barrels daily) (1994 totals in brackets)

Product group	Europe	Asia Pacific	North America	Rest of world (excluding FSU)	Total
Gasolines	3.9 (4.0)	6.4 (4.0)	11.1 (9.2)	3.2 (2.3)	24.6 (19.5)
Middle Distillates	7.5 (5.9)	8.9 (6.4)	7.1 (5.9)	4.6 (3.5)	28.1 (21.7)
Fuel oil	1.9 (2.2)	3.5 (4.1)	1.3 (1.6)	2.5 (2.2)	9.2 (10.1)
Others[a]	3.3 (2.7)	4.7 (3.1)	5.4 (4.6)	2.6 (1.9)	16.0 (12.3)
Total	16.6 (14.8)	23.5(17.6)	24.9 (21.3)	12.9 (9.9)	77.9 (63.6)

[a]Others consists of refinery gas, LPGs, solvents, petroleum coke, lubricants, bitumen, wax and refinery fuel and loss.

catalytically reforming and hydrotreating. In a more complex refinery, with all the more severe processing needed to convert heavy products into lighter ones for gasoline and diesel manufacture, refinery fuel requirements are considerably higher, requiring up to 8% of the total throughput. This gives an indication of the real cost, in terms of both fuel requirement and increased emissions, of producing more ‘environmentally friendly’ fuel components.

Production patterns depend on demand in the particular markets supplied by the refineries and Table 11.1 shows the breakdown of oil product requirements for the principal regions of the world for the year 2004 (million barrels per day). The total consumption (million barrels per day) is also given for each of those regions for the same year. The figures in brackets are the corresponding values for the year 1994 and are included to illustrate how trends have changed over the ten year period.

Throughout the progression of a fuel from the refinery to the end-users’ equipment, there are potential risks to the environment as a result of spillage, leakage and evaporation. Experience over many years has led to the development of regulations and Codes of Practice to avoid or minimize pollution of seas, rivers, canals, soil, groundwater and the atmosphere. At the present time, these controls continue to be under close review in many regions of the world and, where appropriate, stricter legislation continues to be introduced.

The procedures adopted by oil companies to control pollution have evolved out of a combination of good operator training, properly designed containers, reliable connecting equipment and frequent inspection checks. These standard practices are complemented by technological developments in the field of automated metering and inspection devices, allowing periodic or continuous monitoring during product transportation, storage and transfer.

Risks to the environment are not over after delivery by the oil company into customers’ fuel tanks. When the fuel is burned, the products of combustion will be discharged into the atmosphere and, as owners of motor vehicles are well aware, much new legislation has been introduced in recent years to minimize the amount of noxious emissions from vehicle exhausts.

These changes have posed tremendous challenges to both the motor and the petroleum industry and the very impressive developments in petrol and diesel engine technology will also be covered in this chapter.

Currently, since the pollutant emissions from new road vehicles have been dramatically reduced, the focus of attention has shifted to green house gas emissions (GHG). In this context, it is recognized that in order to achieve road transport sustainability in the coming years a range of interested parties need to be involved not just those representing car manufacturers and fuel suppliers. In Europe, the European Road Transport Research Advisory Council (ERTRAC) has been set up both to develop a shared vision of road transport in 2020+ and to formulate an associated strategic research agenda. The 7th Research Framework Programme (FP-7) was presented in April 2005 and will commence in 2007. The two main themes will be (i) reducing GHG emissions and more efficient energy use, including more efficient internal combustion engines and (ii) impact of transport on the environment, including the impact on communities and natural habitats.

3 Protection of the environment

A great deal of emphasis has been directed in recent years to the protection of the environment against pollution. Voluntary Codes of Practice and legally enforceable regulations have been introduced to provide means of controlling and minimizing both deliberate and accidental contamination of the environment from synthetic sources of pollution.

Petroleum (literally, rock oil) is a natural material, formed over millions of years by the decomposition of organic matter under the very high pressure and temperature conditions prevailing deep inside the earth. Petroleum deposits are usually trapped beneath layers of impervious rock but movement of the earth's crust brought some of the deposits nearer to the surface from where, as a result of seepage through fissures in the rock, it was found and used by early civilizations. Crude oils vary widely but they are all made up of mixtures of hydrogen and carbon atoms, known as hydrocarbons, together with a variety of mineral impurities, depending on the geological strata with which the crude was in contact.

In the one and a half centuries since the first well deliberately seeking oil was drilled by 'Colonel' Drake in 1859, at Titusville, Pennsylvania, petroleum has become virtually essential for modern living, with a world annual consumption of around 3 billion tonnes. However, crude petroleum and its products are now considered by many organizations to pose a serious threat to the future, through contamination of the environment.

3.1 The atmosphere

Pollution of the atmosphere has become a high-level concern virtually throughout the developed world. A significant role is attributed to the use of petroleum products, with emissions from road transport vehicles being specifically highlighted.

Emissions from vehicle exhausts have been heavily targeted in recent years, but another concern which is currently receiving attention is that of evaporative losses from volatile petroleum products into the atmosphere. Initial controls were directed at minimizing the emission of fuel vapours from petrol-engined passenger ears, details of which will be discussed later. Steps have now been taken to reduce emissions of volatile organic compounds (VOCs) from storage and transport container throughout the distribution system, both during transportation and whilst the product is being transferred from one container to another.

To put the situation in perspective, baseline nation-wide surveys made in the UK during 1991 revealed petrol and diesel road vehicles as contributing an important proportion of the total emissions of carbon monoxide and dioxide, nitrogen oxides, black smoke and also VOCs. On a broader scale, the contribution of synthetic hydrocarbon emissions into the atmosphere in Western Europe are presented in Figure 11.1. This shows that the major contribution of 40% came from volatile industrial solvents, whilst 25% was identified as coming from the exhausts of petrol-engined cars. Evaporative losses from refineries, during distribution and refuelling and from the car itself, amounted to a further 18%. Synthetic sources, in Western Europe alone, are estimated to emit annually about 10 million tons of VOCs, including hydrocarbons but excluding methane.

The same safeguards for equipment and personnel training are required to minimize uncontrolled VOC losses from oil company sites as those for avoidance of spillages when loading and unloading products from rail and road tankers.

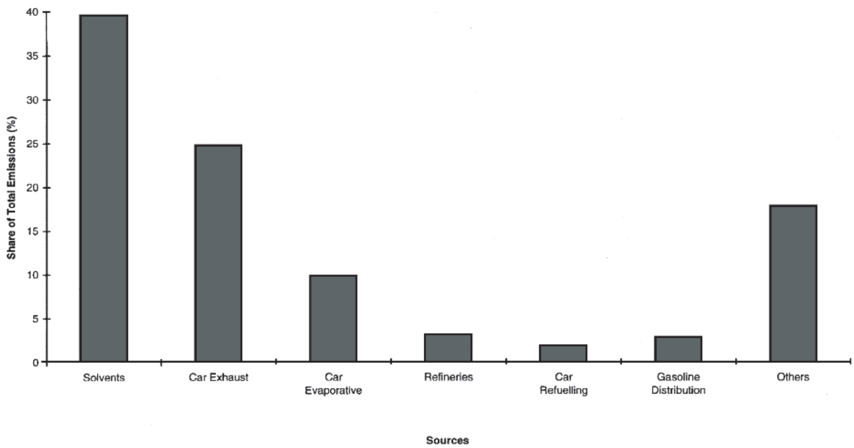


FIGURE 11.1. Synthetic hydrocarbon emissions to the atmosphere (Western Europe): source contributions.

3.2 Sea waters: compliance with maritime regulations

Strict controls are now in force to protect the seas from oil pollution. Collaboration on a world-wide basis by members of the International Marine Organization (IMO) resulted initially in the publication of the International Convention for the Prevention of Pollution from Ships in 1973 and which was then modified by the Protocol of 1978 (MARPOL 73/78). Since then, these regulations have been reviewed on an almost annual basis (latest is October 2004) and issued as amendments. The time scales for implementation are often for several years in advance in order to allow the Industry to evolve. These amendments cover a wide range of activities ranging from identification of restricted areas, e.g. Mediterranean Sea, Black Sea; North West European Waters to defining the procedures for disposal of oily waste by carrying out normal routine operations, such as emptying the bilges and cleaning and ballasting of crude and product tanks. Of particular significance is the promotion of double hulked tankers and limitations on the shipping of designated products, e.g. heavy fuel oils in single hulled vessels.

3.3 Soil and groundwater

In Member States of the European Union (EU), legislation for the protection of soil and groundwater quality has tended to be concentrated primarily on the protection of groundwater, which is a major source of drinking water. Legislation is directed at the control of any discharges to the environment which could result in contamination of groundwater.

(a) Potential sources of contamination

Pipelines. Leakages may occur as a result of failure of a pipeline due to corrosion or physical damage. Human errors at pumping stations and pipeline terminals can also result in oil spillages. Although pipelines tend to be mostly underground, they are not immune to leakage, so good operational procedures are necessary to avoid inadvertent pollution of the soil and groundwater.

In Western Europe, at the end of 2003, there were 250 separate cross-country pipelines with a total length of 36,422 km, for carrying both crude oil and finished products (817 Mm^3). The volume constituted a 11% increase on 2002. Table 11.2 gives an analysis of pipeline incidents in Western Europe during 2003, involving spillages of more than 1.0 m^3.

The figures indicate the relatively modest number of occurrences. However, the major incident required the clean up of 80,000 m^2 of soil, involving the contamination of both surface and groundwater. The total bill was 2 million Euros.

It is also worth noting that nine of the ten incidents were due to third-party action. This analysis suggests there is still serious need for a greater awareness of pipeline locations.

TABLE 11.2. Analysis of 2003 pipeline incidents in Western Europe

Main category	Number of incidents	Spillage (m^3) Gross	Recovered	Net loss
Mechanical failure	1	30	30	0
Operational	0	0	0	0
Corrosion	0	0	0	0
Natural hazard	0	0	0	0
Third-party activity	9[a]	2830	1210	1620
Total	10	2860	1240	1620

[a]One incident accounted for 90% of the total spillage for third-party activity.

Couplings and connectors. Major spillages tend to occur during product transfer to or from ships, rail tankcars, road tankers or storage tanks, generally as a result of equipment failure compounded by human error. Regular inspection and maintenance of pumps, loading gantries, shut-off valves and other equipment in high-risk areas are an essential precautionary measure, together with effective supervision and training of operators.

As well as by checking that couplings are properly connected before delivery starts, the risk of spillage can be avoided by ensuring that the receiving tank is not over-filled. It is also necessary to ensure that the delivery line from the road or rail tanker has been emptied before disconnecting it from the receiving tank inlet connection.

4 Distributing the products

Finished products are delivered to the end-user customers through the distribution systems of oil companies and their agents.

Depending on the location of the refinery and its markets, the fuels will be transferred from refinery storage to the oil company's main terminal tankage for distribution in a variety of ways. These can include ocean going and coastal tanker ships, barges on inland waterways, pipelines, railways and road tankers delivering to terminals, from where the products will be supplied by road to the network of depots within the local marketing area.

4.1 Distribution systems

(a) Tanker ships and barges. With crude oil exploration and production continuing in the established oil fields and in new areas all around the world, sea transportation in large crude oil carriers is the only practical way in which much of the crude can be delivered to the refineries and markets where it is to be processed and sold.

Water-borne transport can also be a logical option for the distribution of finished products. Several oil-producing countries, which formerly only exported crude oil have, for the best economic reasons, expanded their refining capacity and begun manufacturing finished fuel products meeting the specifications of foreign export markets. Some of the products may go by pipeline to nearby countries but other export grades are likely to be transported by sea to their distant markets.

Delivery by coastal tanker from indigenous refineries is common in many countries with lengthy coastlines. Where there is also a network of navigable inland waterways, as exists in Europe and the USA, the use of barge transportation provides a convenient, practical and economical way of moving large volumes of oil products.

(*b*) *Pipelines*. Pipelines are used to transport crude oil from the well to oil terminals, for loading at oil jetties into crude-carrying tanker ships and from tankage at receiving ports to the refinery. In many countries they also provide a practical, unobtrusive and economic way of distributing large volumes of the refined products around the marketing region.

An indication of how the pipeline distribution systems of Western Europe referred to above have developed is given in Figure 11.2, showing the extensive network of product lines serving the main terminals.

There is, of course, a complex of pipelines for the distribution of imported crude oil from the ports to refineries in those areas, and a corresponding network of crude oil and finished product pipelines connecting oil fields,

FIGURE 11.2. Map of refineries and oil pipelines in Western Europe 2003 (Reproduced with permission from performance of European, cross-country oil pipelines – statistical summary of reported spillages 2003; published by CONCAWE, 2003) (*See Color Plates*).

ports, refineries and terminals around the world, wherever petroleum and its products are handled.

(c) Rail tankcars. Most countries use railway networks for bulk transport of finished products to terminals and depots not served by pipeline. Railways provide an effective and economic distribution system, with a lesser likelihood of problems due to traffic congestion or accidents than on the roads.

Railcars are filled at the refinery or main terminal, generally from an overhead loading gantry discharging product through an inlet on the top of the tank. On arrival at its destination, the product will be unloaded by pumping from a bottom outlet of the railcar into the receiving tank.

Distillate fuels are normally carried in unheated tanks, except when climatic conditions during transit are likely to chill the fuel to below the temperature at which wax formation will occur and cause problems of incomplete tank emptying and non-homogeneity of the product. Residual fuels, which have much higher viscosities, are normally carried in insulated and heated tanks, to permit easy and complete unloading of the consignment.

(d) Road tankers. The situation with road tankers is similar in most respects to that with railcars. Gantry loading systems and screw-connected fittings for unloading are normally involved. As with railcars, insulated and heated tanks are required for residual fuels.

An additional factor, which could increase the chances of accidental spillages, is that road tanker drivers delivering to domestic, agricultural or small industrial consumers generally have to make several unloading operations to individual customers before all the tanker compartments are empty.

5 Anti-pollution controls

5.1 The atmosphere

Atmospheric pollution by emissions from chimney stacks and vehicle exhausts, as well as a result of uncontrolled evaporation of VOCs, has been a growing concern for a number of years, largely because of dire predictions about global warming and observed reductions in the ozone layer.

Limitation of the synthetic emissions illustrated in Figure 11.1 is being enforced through legislation and regulations applying to the areas within the jurisdiction of the legislating or regulating authority.

The situation relating to atmospheric pollution controls will be described in the following sections. Although not covered in this chapter, corresponding control measures are being applied to processes at industrial plants where volatile solvents are used.

5.2 The high seas

Sophisticated modern navigational aids and weather forecasting techniques have helped to overcome or avoid many of the inherent hazards of sea travel but the risk of accidents cannot be entirely eliminated. In recent years, there have been several highly publicized incidents with tanker ships which resulted in massive spillages of crude oil. Although emergency actions have enabled significant amounts of spilled crude or heavy oil product to be recuperated, considerable damage has been caused to fish, sea birds and sea animals, and also to plant life, when the spillages have been close to the shore. Replacement of single hulled tankers with new double or even triple hulled tankers will provide additional protection in the future.

Sea-water pollution has also been caused when oil tankers have discharged oily waste water from tank ballasting and cleaning operations but, as was mentioned above in Section 3.2, these practices are now being more tightly regulated and strict observance of the IMO regulations is now required of all oil tanker operators.

Contaminated water from tank washing has to be drained into a slop tank, from where it may be discharged, either into shore tanks or legally at sea, provided IMO regulations criteria are observed. Until 1992, it was possible to decant slops containing up to 100 ppm of oil into open water at sea, but the current permitted level has now been reduced dramatically to 15 ppm. Whilst the regulations generally allow disposal at sea of water from tank-washing operations, provided the maximum level of oil contamination is not exceeded, dumping is not permitted at all in some seas, e.g. Mediterranean, the Baltic, Black and Red Seas.

Similar tight constraints also apply when cleaning the bilges, an operation common to all ships. Contents of bilges have to be pumped into a separator tank, for recovery of the oil and to allow settling of the water phase before it can be diluted, as necessary, prior to discharging at sea. Coastal tankers tend to retain their contaminated waters from bilge emptying and also from tank cleaning and ballasting until they can be discharged into shore tanks and disposed of correctly.

Full and detailed records of these operations must be kept and be available for inspection at all times.

The absence of common international regulations for emission controls on tankers carrying gasoline on the high seas prompted the IMO to take action on vapour-collecting systems on tanker ships carrying cargoes of volatile products.

The IMO Standards have been drafted for vapour collection systems on sea-going tankers and for emission control systems at terminals. These take account of work carried out by the US Coast Guard and reported by the US Environmental Protection Agency (EPA). High-level or high-velocity vents are typically installed to provide means for vapour release during cargo loading or tank ballasting operations.

Studies carried out in the European region measured the hydrocarbon levels in vapours emitted from the tank compartments of gasoline-carrying ships and barges during loading and these are illustrated in Figure 11.3. Higher hydrocarbon levels are found with barges because of their relatively shallow

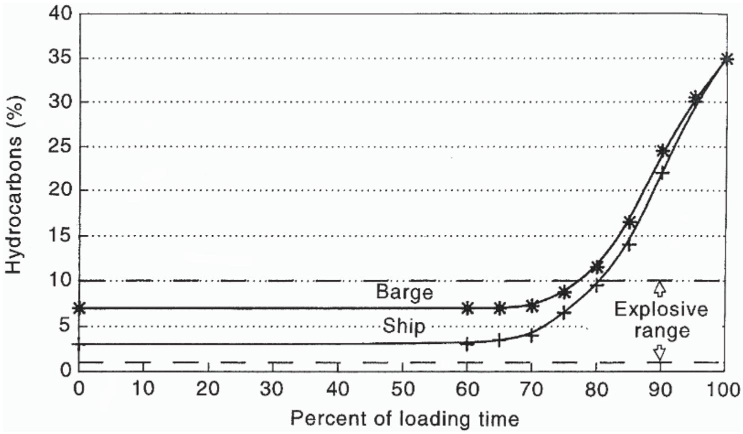


FIGURE 11.3. Hydrocarbon concentration profile during loading: waterborne transport of gasoline. Data based on weighted averages. (Reproduced with permission from *CONCAWE Report No. 92/52,* VOC emissions from the loading of gasoline into ships and barges in EC-12:control technology and cost-effectiveness; published by CONCAWE, 1992)

tank compartments compared with those of sea-going ships, so the existing mixture of vapour from the previous cargo and air taken in during unloading tends to be richer in hydrocarbons.

It was found that the vapour concentrations from ship and barge tanks were in the flammable range for up to 80% of the loading time, a situation which necessitates extreme care being taken to control vapour emissions during loading operations. At sea, the high-level or high-velocity vents installed for safety reasons would have to be closed when vapour emission control systems are in use.

The actual hydrocarbon content of vapours emitted during loading is high, ranging from around 5% initially up to 35% and averaging around 10% throughout the loading period. With Europe's annual gasoline throughput of over 120 million tonnes, the total emissions of hydrocarbon vapour whilst vessels are being loaded represents a significant amount of environmental pollution.

5.3 Coastal and inland waterways

Procedural measures for coastal oil tankers and barges were introduced initially for reasons of safety and to reduce the exposure of crew members to hazardous vapours, e.g. hydrogen sulphide, but attention has now also been turned towards vapour recovery from gasoline or other flammable cargoes. The potential benefits from effective vapour recovery measures applied to sea-going ships and barges on inland waterways during loading operations are evident from the data presented above.

Standards for vapour emission control systems for barges carrying flammable liquids such as gasoline in the Rhine basin are set by the ADNR (Accord Européen Relatif en Transport International des Marchandises Dangereuses par Voie de Navigation Intérieure/Rhin). The requirements include a vapour-collection header with a high-velocity vent to atmosphere, means for connection to an on-shore vapour recovery unit (VRU) and, at each tank outlet, a pressure/vacuum relief valve and detonation arrestor.

Although few, if any, ships or barges operating in and around Europe have onboard vapour-recovery systems, some have vapour-collecting systems which are suitable for, or adaptable to, connection with an onshore VRU, for emissions control during loading of volatile cargoes.

Technologies are available for vapour recovery during gasoline loading, drawing on experience associated with tanker truck loading facilities. They include the following options:

- absorption of the vapours in a low-volatility liquid;
- adsorption of the vapours on activated charcoal;
- condensation of the vapours in a heat exchanger set at a low temperature, such as −80°C;
- separation by means of a hydrocarbon-specific membrane.

5.4 Soil and groundwater

In the early days of the oil industry, relatively little thought was given to contamination of the soil and groundwater. Later, possibly influenced by the commercial instinct to minimize the loss of valuable product, good housekeeping practices evolved and have contributed significantly to soil and groundwater protection.

In view of the high cost of cleaning up contaminated groundwater, the emphasis has been on preventing or minimizing the amount of leakage and spillage of oil products. The quality of material leaking or spilled is also of importance and several countries specify maximum concentrations of contaminants allowed in discharges into the air, surface water or soil. The Appendix to Swiss Ordinance for Waste Water Discharge 814.225.21, which came into effect on 1 January 1976, defines the permitted limits pertaining to surface water flows and impounded river water, to effluents discharged into surface waters and to effluents discharged into public sewers.

The constraints include limits on warming by cooling or waste waters, turbidity, colour, odour and taste, toxicity salt content, suspended and precipitated solids, pH (acidity or alkalinity), oxygen content, surface tension, and a number of specific contaminants, both inorganic and organic. A selection of parameters and maximum levels for organics in effluents discharged into surface waters is given in Table 11.3.

(a) Underground protection. Buried pipelines are potential sources of contamination in areas which are not protected by impermeable surfaces, so preventive measures have to be taken beforehand, as well as arranging for regular inspection procedures whilst the pipelines are in operational use.

TABLE 11.3. Parameters and maximum levels for organics in effluents discharged into surface waters in Switzerland

Parameter	Level permitted in effluents
Dissolved organic carbon (DOC)	15 mg/l maximum (24 h average)
Total organic carbon (TOC)	Not more than 7 mg/l above DOC level
Biochemical oxygen demand (BOD)	20 mg O_2/I (24 h average)
Aromatic amines	Each Canton sets conditions in agreement with Federal Office for Environmental Protection
Total hydrocarbons	10 mg/l
Chlorinated solvents (trichloroethylene perchlorethyleene methylene chloride, etc.)	0.1 mg/l (measured as chlorine)
Phenols: volatile and not steam-volatile	0.05 mg/l

Protection of underground pipelines is provided by the application of anti-corrosion coatings such as bituminized enamel or plastic tape. Cathodic protection, by means of sacrificial anodes or an impressed current, depending on soil characteristics, is normal practice. Leak detection equipment is also employed.

To segregate consecutive batches of product and also to clean deposits from the line, pipeline operators use solid plugs, known as 'pigs', which fit inside the pipeline and are pushed through by the fluid pressure. Care has to be taken to avoid spillages at the locations where the pigs are inserted and removed from the pipeline.

Technological developments of the pig concept are the metal loss detection intelligent pig, to search for pipeline corrosion, the ultrasound pig, for detecting small leaks, and the self-propelled pig, equipped with a video camera, for visual inspection of the inner surfaces of pipelines. These facilities make it possible for line owners to set up regular monitoring routines to minimize the likelihood of unexpected problems due to pipeline failure.

(b) Above-ground protection. Existing protection measures involve impermeable surfaces to prevent contamination due to leaks and spillages. These are normally installed in loading/unloading areas, underneath overground storage tanks and in spillage basins and bunds, from where the spilled liquids can be recovered.

Some domestic heating oil tanks have a whistle fitted in the vent pipe to help prevent over-filling. More usually, it is avoided by first dipping the tank to verify what space is available and then setting the automatic cut-off on the pump control unit to deliver an appropriate quantity of fuel. A typical control unit printout sheet will show the driver's name, delivery date, customer name and identify the product grade, as well as giving the quantity delivered and the other details such as unit price, total cost and even the relevant value-added tax (VAT) rate.

(c) Treatment and recovery practices. Complete recovery of oil spillages is not always possible and, in such cases, disposal of the contaminated soil in

landfill sites has often been employed. The imposition of more stringent regulations limiting the oil content of waste for land disposal is necessitating the use of more acceptable, albeit sometimes destructive, processes such as incineration.

Recovery of contaminated groundwater is usually achieved by means of oil–water separators. However, further treatment of the separated water may sometimes be needed to satisfy the purity standards required by local regulations.

Wastewater treatment procedures which might be used include:

- gravity separation in tanks or with plate interceptors;
- advanced treatment, such as filtration, sedimentation, flocculation or air flotation;
- biological treatment, such as with biofilters, activated sludge or aerated ponds.

The pipeline leakage in a mountainous region, which cracked due to an earth slip following heavy rain, reported in Table 11.2, caused some contamination of groundwater and as soil pollution in the locality. Precautions were needed to protect the drinking water and 3 m^3 of the 30 m^3 spill were recovered by forming shallow channels and using water-washing to flush out the oil so it could be separated and recuperated. The remainder was contained within contaminated soil which was removed for safe disposal elsewhere.

6 Marketing the products

The mode of delivery of fuels and other oil products to the customer will depend very much on the type of end-user equipment and the quantity to be delivered. In certain cases, the frequency at which fresh batches will be required can also have an influence.

6.1 Large industrial customer installations

Siting an oil refinery adjacent to or reasonably close to an oil-fired electricity-generating station allows the fuel to be supplied on a continuous basis by pipeline. Similarly, another convenient arrangement is to locate industrial units such as petrochemical complexes on sites adjacent to the oil refinery, in order to minimize the length of pipelines needed for delivery of fuel or feedstock. Provided normal precautions are taken to open and close the correct valves and to avoid overfilling the receiving tanks, there is minimal likelihood of spillage in these situations.

Where oil-fired power plants are remote from any refinery and, if there is no pipeline supply available or feasible, their large consumption requirements will be best served by railcar deliveries. Operational procedures to minimize the risk of spillages have been discussed above.

6.2 Small industrial and domestic customers

Regulations on oil storage facilities for small industrial plants and for domestic customers differ from country to country. In some European countries, however, strict standards have long been established for protection of the soil and ground water. Future trends suggest that these criteria will be adopted more widely.

Anticipated requirements are for above-ground storage tanks to have double bottoms, with a leak detection device in the space between the double bottoms. An impermeable surface or containment space beneath the tank may be specified as an alternative or even an additional requirement.

For buried steel tanks, a bunded containment with an impermeable surface lining will be required, possibly together with the use of an impermeable lining for the tank itself. Corrosion-resistant glass fibre-reinforced storage tanks are already mandatory for some buried installations. Buried pipework will also be subject to stringent controls, such as being laid in impervious channels and being pressure tested for leak tightness.

The use of technological developments such as high-level alarms to avoid over-filling and electronic devices for detection and prevention of leaks is likely to increase.

6.3 Service stations

Most service stations dispense the different grades and types of fuel from buried tanks. These installations must conform to the pertinent legislation and regulations of the licensing authority relating to environmental protection. These define the minimum standards for the location of underground storage tanks and will include such features as thickness of the concrete chamber for the tank, impermeability requirements, installation depth, layout of pipe runs and anchorage of the tank, to prevent it from floating if flooding should occur.

For safety reasons, vent pipes are run underground from each tank to a relatively remote location, from where they emerge to provide a high-level outlet for the vapours. Generally they are located conveniently close together. This will be advantageous as it is likely that additional measures, such as carbon canisters for collection and recuperation of VOCs, will be required at petrol service stations.

Service stations are an important supplier/customer interface and, since many of them operate on a self-service basis, part of the responsibility for environmental protection is transferred from the oil company to the customer/end-user.

The most obvious expectation is that the customer will take care to avoid spilling fuel when topping-up the vehicle tank. This is helped by the automatic cut-off device in the pump nozzle, which stops the flow when the level reaches the nozzle. However, trying to fill the tank completely or inadvertently pressing the switch when the nozzle is out of the tank can result in spillage on to the ground. The further responsibility of the customer is to ensure that the vehicle's fuel system and engine are maintained in proper working order.

7 Environmental technologies related to product use

7.1 *Fuels*

The previous sections in this chapter have dealt with the working practices, regulations and legislation which have been introduced to minimize the risks of environmental contamination by oil fuels. Once the fuel is transferred into the customer's system, the potential pollutants other than the fuel itself are the products of combustion.

Fuel specifications initially came into being to provide the end-user with products conforming to a realistically defined standard of purity and performance requirements. Other criteria which also needed to be satisfied included legality, safety and handling, reliability and, more recently, environmental considerations. As an example, Table 11.4 shows the make up of a typical automotive diesel specification, e.g. EN590, with justifications for the particular fuel characteristics.

Interestingly, the first fuel property to come under scrutiny as harmful to the environment was sulphur, which is still regarded as one of the major pollutants in virtually all fuels. The influence that environmental protection legislation is having on sulphur levels and the trend with other fuel properties will be discussed in the following sections.

7.2 *Marine diesel engines and fuels*

Large marine diesels are slow-speed engines that can operate satisfactorily on the relatively poor quality, low-cost residual fuels for marine use, which are generally referred to as bunker fuel oils. Auxiliary engines for pumping and

TABLE 11.4. Automotive diesel fuel specification criteria

Justification	Parameter
Legalistic	Distillation
	Sulphur
Purity	Water
	Sediment
Safety/handling	Flash point
	Cold properties
Performance/reliability	Cetane number
	Density
	Viscosity
	Cloud point
	Cold filterability
	Distillation
	Ash
	Acidity
	Carbon residue
	Stability
Environmental protection	Sulphur

other functions normally run on a lighter distillate diesel fuel, which is also used for smaller, faster revving marine propulsion engines.

(a) Shipboard pretreatment. Onboard pretreatment of marine bunker fuels is required for several reasons. Heaters will be installed to enable the fuel to be pumped from the ship tanks and further heating will be necessary to melt waxy solids and lower its viscosity to the level required to ensure good atomization by the fuel injector. However, before reaching the injection pump, the fuel has to be cleaned by centrifuging and filtration, to remove sediment and other solid impurities which could damage the fuel system components.

(b) Ignition quality. The cetane number indicates the readiness of a fuel to ignite spontaneously when injected into the hot, compressed air in the combustion chamber; the higher the cetane number, the shorter is the ignition delay. Residual fuels are low in cetane number but the slow running speeds of the larger marine engines allow sufficient time to accommodate the delay between injection and ignition.

Residual fuels are available in several grades, relating to their viscosity. The highest viscosity grades, which also have the highest sulphur contents, are the heavy residues from the refinery distillation units.

(c) Sulphur levels. Recent surveys of marine fuels supplied from bunkering ports in the UK, France, Belgium and The Netherlands to ships operating in the busy English Channel area showed maximum sulphur levels no higher than 2.7% m/m although up to 5.0% m/m is permitted by the current ISO 8217 specification (reduced to 4.5% m/m in 2005). The lower viscosity (and more costly) grades are obtained by blending the heavy residue with different proportions of a distillate stream. The lighter residual fuels have lower sulphur contents, with maximum levels up to 3.0% m/m for the medium grades and around 2.5% m/m for the low viscosity grades.

With the current emphasis on environmental protection, the high sulphur levels of bunker fuel oils have resulted in ships usually being required to be operated on a distillate fuel when in port. Distillate marine fuel grades have maximum sulphur levels, as specified by ISO 8217, which range between 1.0% and 2.0% m/m and will be cleaner burning than the residual fuels. The survey referred to above estimated a total of 100 ktonnes/year of sulphur emissions in the study area, of which 26% were in port. A breakdown of the estimated emissions is given in Table 11.5.

One of the combustion by-products of any fuel containing sulphur is sulphur dioxide (SO_2) which readily reacts with other oxygen atoms to

TABLE 11.5. Marine sulphur emissions (ktonnes/year) in the English Channel area

	Bunker fuel oil				
Location fuel	High viscosity	Medium viscosity	Low viscosity	Total	Distillate
At sea	46.4	18.6	5.2	70.2	5.8
In port	14.6	5.5	2.3	22.4	4.9
Total	61.0	24.1	7.5	92.6	10.7

become sulphur trioxide (SO_3) This, in turn, will combine with the water of combustion (H_2O), which condenses as the exhaust gases cool, forming sulphuric acid (H_2SO_4) a very corrosive pollutant.

For Northern Europe which has been particularly affected by acid rain, current draft EU legislation includes:

(i) A limit of 1.5% m/m sulphur content for marine fuels used in the North Sea, English Channel and the Baltic Sea by May 2006.
(ii) A limit of 1.5% m/m sulphur content for marine fuels used by passenger vessels within the EU by the same date.
(iii) A limit of 0.1% m/m sulphur content for marine fuels used by inland water vessels and ships berthed in docks, beginning in 2010.

Reducing sulphur emissions from marine engines. Although high sulphur levels are still predominant in marine bunker fuels, environmental concerns are targeted at reducing the sulphur content. This can be achieved to some extent by selecting lower sulphur crude oils or altering the proportions of high- and low-sulphur components used in blending marine bunker fuels. However, if neither option is possible on a long-term basis, the only possible answer may be to treat the residue to reduce its sulphur content by means of hydrogen treatment.

The desulphurization or hydrodesulphurization (HDS) process treats products containing high molecular weight and other sulphur compounds with hydrogen, at elevated temperatures and pressures, in the presence of a catalyst. In the reactions which take place, sulphur from the compounds forms hydrogen sulphide (H_2S). The H_2 S from the process normally goes to a sulphur recovery unit, where it is converted into elemental sulphur.

HDS is used routinely to reduce the sulphur levels of diesel fuel, kerosine and some lighter distillate streams. A process for residue desulphurization (RDS), which requires higher temperatures and pressures, has been developed from 1 – to produce low-sulphur fuel oil components. RDS units are generally designed for 80–85% removal of sulphur from the feedstock. Consumption of hydrogen is high and residue desulphurization is a fairly costly process.

A study was carried out by CONCAWE, the oil companies' European organization for environment, health and safety (and the major source of information given in this chapter), to look at ways to reduce sulphur oxides emissions from ships. Two considerations studied were reduction of the fuel sulphur content and removal of sulphur oxides from ship exhaust gases.

The first option, described above, is carried out at the refinery but the second is the responsibility of the ship owner/end-user. The procedure for removing sulphur oxides (SO_x) from the exhaust gases is by sea-water scrubbing, which makes use of the ability of sea water to neutralize SO_x.

Sea water is sprayed into a flash chamber/particle scrubber, where evaporation of the water cools the gases, which then pass into a packed column washing tower, where a counter-current flow of sea water removes the SO_x. A heat-exchange system reheats the cleaned gases before they leave the funnel, to avoid a white plume of water vapour. Further work on this technique is needed to overcome some operating problems but the broad findings have been environmentally favourable. Although the discharged wash water is markedly more acidic than normal seawater, when discharged at sea it will be diluted rapidly in the ship's wake and will not have any effect outside the discharge mixing zone.

7.3 Fuels for large industrial power plants

High-viscosity and often also high-sulphur fuels are used in many of the large stationary engines used for electric power generation plants, industrial pumping installations and steam-raising plants. Such fuels were also commonly used as boiler fuel by steam ships but these have largely been replaced by diesel-engined ships, which were discussed above.

Being located on land, the environmental constraints on industrial plants are generally more stringent than those currently in force for marine engines, which emit their more sulphurous pollutants when on the high seas.

(a) Reducing sulphur, emissions from large industrial plants. In addition to being required to run on lower sulphur fuels, other clean-up operations may be necessary to reduce the level of sulphur compounds and other pollutants in the flue gases.

A study was carried out two decades ago on ways of reducing sulphur emissions from residual fuels in the then 10-member European Economic Community (EEC). Other countries have joined since then and the European Union (EU) now has 25 members, contributing to the total emissions of sulphur and other atmospheric pollutants, who are all bound by EU law to conform to the lower emissions levels. At the time of the study, it was estimated that by the year 2005, power stations would be responsible for 25–35% of, the total sulphur emissions from oil-burning equipment.

Residue desulphurization (RDS) was one of the ways considered for reducing sulphur emissions, although it was felt that alternative low sulphur fuels, such as low sulphur coal or natural gas, could make RDS economically unattractive. An option for the plant operator, which was calculated to be more cost-effective than RDS, was flue gas desulphurization (FGD). Although costly, it was estimated that FGD applied at power stations would replace the need for between five and ten refinery RDS units achieving somewhat lower levels of desulphurization.

7.4 Fuels for small industrial and domestic installations

(a) Heating gas oil quality constraints. The most commonly used fuel for small industrial and domestic heating systems is a distillate grade commonly referred to in the oil industry as gas oil, as it was formerly used to supplement the heat content of town gas manufactured from coal. Heating gas oil, or domestic heating oil, is similar to automotive diesel fuel but with a slightly

less stringent specification. From the viewpoint of environmental pollution, one of the principal contributors is, once again, sulphur.

The distillation characteristics of a gas oil can have an influence on its smoking tendency. If the gas oil contains some high-boiling components, they may not burn completely inside the combustion chamber of the furnace and will be emitted from the chimney as particles of soot. In Europe the Common Customs Tariff agreement legally defines a gas oil as a petroleum oil having a maximum of 65% recovered at 250°C and a minimum of 85% recovered at 350°C, in the ISO 3405 distillation procedure.

As there is no limit on the distillation end-point of the gas oil, some heavy fractions, which may not burn completely, could be present. The responsibility for ensuring an acceptably low level of smoke rests with the owner and the engineer who services the burner. The permitted viscosity range of 1.5–5.5 cSt (mm^2/s) at 40°C is suitable for typical pressure-jet burners, providing good mixing of the atomized fuel with the combustion air.

New house building developments now tend to be designed around heating systems operating on either gas or electricity, usually decided by the developer or determined by the availability of the utility suppliers' services in the particular locality. Although the purchaser has virtually no say in the choice of system, there is also no need for a separate fuel storage tank, with its potential for costly environmental control measures at some future date.

(b) Quality controls on domestic kerosine. In the UK, kerosine has been a popular fuel for domestic use in small, portable, wick-fed heaters, vaporizing burners and even for some pressure-jet burners/boiler units, where its clean burning characteristics result in low maintenance and service needs.

Heating kerosines are manufactured to specifications which define, amongst other properties, their maximum sulphur content. The current British standard for kerosine (BS 2869) allows a maximum of 0.2% by mass of sulphur for the regular grade kerosine used in burners with a flue or chimney to vent the exhaust gases outside the building. A much lower level of 0.04% by mass is specified for wick-fed appliances, which are not normally connected to a flue.

In addition to the need for a low sulphur content, other important quality criteria for wick burners are a high smoke point and a low char value. The smoke point, measured in millimetres, is the maximum wick height at which fuel vaporized from the wick will burn without smoking. The higher the smoke point, the greater is the amount of heat (or light) which can be produced. The char value indicates burning quality and is measured by the charred material which remains on the wick after a specific amount of kerosine has been burned. The greater the ratio of char to kerosine, the poorer is the burning quality of the fuel. These properties will be influenced by the distillation end-point, by hydrotreating to reduce the sulphur content and by refinery 'sweetening' processes, such as caustic washing and Merox treating. The Merox processes were developed by Universal Oil Products (UOP) to oxidize extremely unpleasant-smelling mercaptans (thiols) to non-odorous disulphides.

In other countries where domestic kerosine is used, permitted sulphur levels vary widely, e.g. from as high as 0.25% m/m in India down to 0.015% m/m in Japan.

(c) General guidelines for efficient burner operation. For reasons of economy and environmental protection, the burner should be cleaned and serviced regularly by the owner or a specialist service engineer, to ensure it is operating at or close to optimum efficiency and that there is little or no visible smoke.

Diurnal temperature variations will cause a fuel tank to breathe, drawing in air as the temperature falls at night. This can result in moisture from the air condensing and settling to the bottom of the tank. Drain taps on the storage tanks should be opened from time to time, to drain out any settled water and the tank itself checked for rusting which could, in time, cause leaks.

7.5 Aircraft engines and fuels

Aviation fuels are, understandably, subject to strictly controlled specifications, to minimize the likelihood of engine failure whilst in flight. There are some differences between military and civil grades but the main safety considerations apply to both applications.

(a) Gasoline for piston-engined aircraft. Most large passenger and freight aircraft are powered by jet engines but piston-engines tend to be predominant in the light aircraft used for private aviation and also for commercial operations such as flying schools, air taxis and crop spraying. There are also some piston-engined military aircraft.

The number of grades of aviation gasoline is decreasing (and the volume in relation to jet fuel consumption is modest), but currently four grades are available. Aircraft piston engines tend to require a high-octane fuel and those octane levels, particularly the higher ones, have to be attained by the addition of an octane booster, tetraethyl lead (TEL). This and a similar additive, tetramethyl lead (TML), were widely used in automotive gasolines but lead additives have largely been eliminated from the automotive grades.

The 80 octane grade is either low in lead or, for the UK market, completely lead-free. The other grades are 100 LL (low lead), 100 leaded and a special leaded high-performance 115 octane blend originally used for WWII military aircraft. The maximum levels of TEL are given in Table 11.6.

The 115 octane grade is now almost non-existent and there is limited demand for the 80 octane grade. This means that only 100 LL octane aviation gasoline (Avgas) is being produced in any significant quantities, to universally accepted UK/US specifications.

(b) Aviation jet kerosine. Measures taken to avoid fuel-related problems which could cause pollution of the atmosphere include the use of antioxidant and metal deactivator additives. These improve the fuel stability and suppress the formation of gums and sediment which could restrict normal operation of the fuel system components. Other additive types used in the aviation fuels are corrosion inhibitors and lubricity additives to protect the fuel system from chemical and mechanical damage, anti-icing additives to dissolve any

Table 11.6. Lead contents of aviation gasolines

Octane grade	TEL (ml/US gal)
80	0.5
100LL	2.0
100	3.0
115	4.6

free water in the fuel, which might freeze at altitude and block fuel lines, and biocides to prevent fungal and bacterial growths which could block or restrict flow in the fuel system or cause corrosion.

The cleanliness and high chemical purity of aviation fuels mean that they have a very low conductivity. To avoid the risk of spark-induced explosion and fire, anti-static additives are routinely used to dissipate charges of static electricity which could build up as a result of the high pumping rates used when transferring fuel into storage tanks and during aircraft refuelling.

Modern jet aircraft engines consume fuel at a very fast rate and the steady expansion of air travel for business and holidays is drawing attention to their contribution to the total environmental pollution. A large proportion of the jet engine exhaust is dispersed at high altitudes, but travellers and residents near airports are keenly aware of pollution caused by exhaust fumes and droplets of unburned fuel. A reduction in sulphur content below the maximum level of 0.3% m/m permitted in current jet kerosine specifications seems the most likely first course of action.

7.6 Engines for rail transport

The number of coal-fired steam engines operating in Europe has been dramatically reduced during the past 50 years but, while many have been replaced by electric locomotives drawing power from overhead cables, there are large numbers of diesel engines in operation, in diesel/electric locomotives, shunters and railcar units. Railroad diesel engines generally run on automotive diesel fuel or a fairly similar grade and, as with autodiesel, the fuel property regarded as the principal contributor to atmospheric pollution is sulphur.

In 1987, the Council of Environment Ministers in the European Commission issued a directive reducing the maximum sulphur content of all gas oils, except those used by shipping, to 0.3% m/m by 1989 and allowing a stricter limit of 0.2% m/m to be set in heavily polluted areas. At the same time, a proposal for a single limit to apply throughout the Community was put forward and the European diesel fuel specification, issued in 1993 by the European Standards Organization, CEN (Comite Européen de Normalisation), imposed a maximum limit of 0.2% m/m throughout the EU.

7.7 Automotive engines

A significant proportion of legislation to protect the environment from oil-associated pollution has been directed specifically at the growing road transport sector. This has necessitated vast investment, of money and resources, by the motor and petroleum industries into research programmes to meet the increasingly tight limits on exhaust emissions. The results of their endeavours to meet the required levels of emissions from vehicle exhausts, within the prescribed time-scale, will be discussed in the following sections.

(a) Spark ignition engines. Design trends in spark ignition engines over recent years have resulted in lower rates of fuel consumption, often coupled with enhanced performance.

A significant factor has been the increase in the size and/or number of valves per cylinder. Initially two valves, one inlet and the other exhaust, were normal for small automotive engines. Then a second inlet valve was introduced and, at the present time, engines with four valves per cylinder, two inlet and two exhaust, are becoming more and more common. Larger or multiple valves per cylinder, providing less restriction to the flow, have allowed better filling of the cylinder with the air–fuel mixture during the intake stroke and more complete exhausting of the burned gases, resulting in improved engine efficiency.

Another trend has been the progressive replacement of the carburettor by the fuel injection system, almost throughout the size range of passenger car engines. Effectively, the carburettor is no longer fitted, as it cannot provide the close control of air/fuel ratio (AFR) needed for three-way catalyst emission control systems. Although in its early stages of development fuel injection into the inlet manifold gave better throttle pedal response and acceleration, it was achieved at the cost of higher fuel consumption. However, developments in injector design and fuel control systems brought marked improvements in fuel economy.

Current engine models largely use multi-port injection and sophisticated electronic engine management systems. These use sensors to monitor a variety of engine operating conditions and are able to ensure that the optimum of air/fuel ratio, spark advance and other key factors are always attained.

Although the immediate advantage of more fuel-efficient engines is felt by the motorist who buys the fuel, there are also environmental benefits, because of the overall reduction in specific fuel consumption per vehicle. This at least partly compensates for the growing number of vehicles on the road!

After combustion, the gases are emitted into the atmosphere through the exhaust pipe. The original purpose of the vehicle exhaust system was reduction of noise, which, for at least a decade, has been regarded as a pollutant. Recent legislation has imposed the need to modify the gaseous components into less noxious forms. Modification of the gases is achieved by three-way catalytic converters, in which the platinum, palladium and/or rhodium catalyst converts carbon monoxide, unburned hydrocarbons and nitrogen oxides in the exhaust to less harmful carbon dioxide, nitrogen and water.

In the USA and Japan, three-way converters have been mandatory in the exhaust systems of new cars since 1975. They became mandatory in Europe in 1993 and their use is increasing elsewhere in the world. They were the primary reason for the change from leaded to unleaded gasoline because lead will poison the catalyst and nullify its effectiveness.

Discontinuing the use of lead anti-knock additive necessitated other changes, as deposits from combustion of the additive had protected exhaust valves and seats from damage by the hot exhaust gases. Most engines required different metallurgy for the valve seats to avoid the problem of burning and recession when running on lead-free gasoline.

The technique to control evaporative losses of VOCs from cars is to use onboard carbon canisters to absorb the vapours. Figure 11.4 gives a typical layout for the vapour control system and shows the function of the carbon canister. The canister contains activated charcoal which absorb the gasoline vapours. The vapours are trapped in the canister whilst the engine is stopped, but when the engine is running the gasoline vapours are drawn into the inlet manifold and the incoming air purges the canister.

The impact of a closed system for gasoline, making use of the 'best available technology' (BAT) approach to control emissions from distribution, refuelling, car evaporation and the exhaust, is illustrated in Figure 11.5. The emissions, in kilotonnes/month, are based on figures collected during the summer period, when ozone formation is more likely, owing to higher

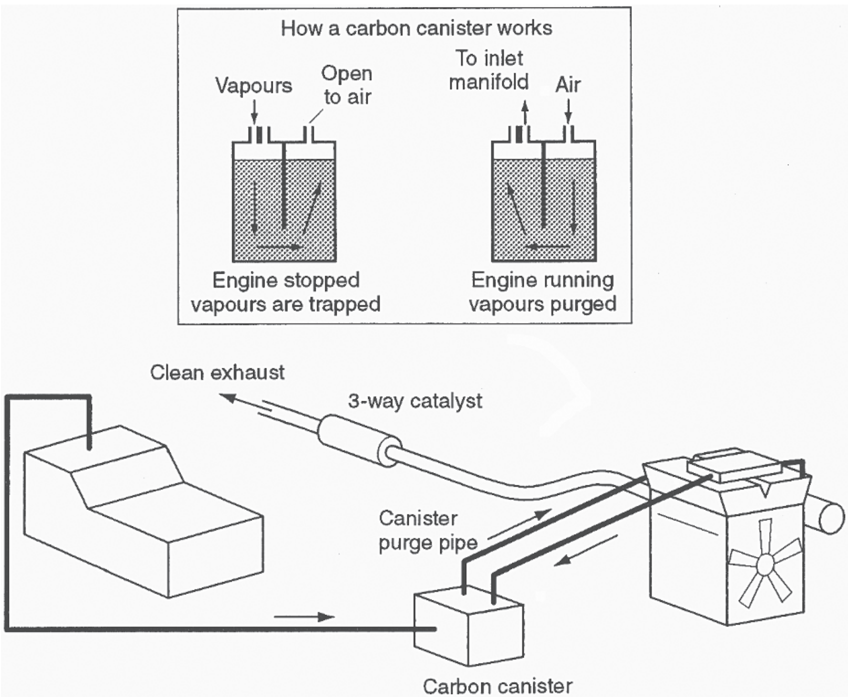


FIGURE 11.4. The closed fuel system. (Reproduced with permission from *Gasoline Vapour Emissions – a European Concern*; published by CONCAWE, 1990.).

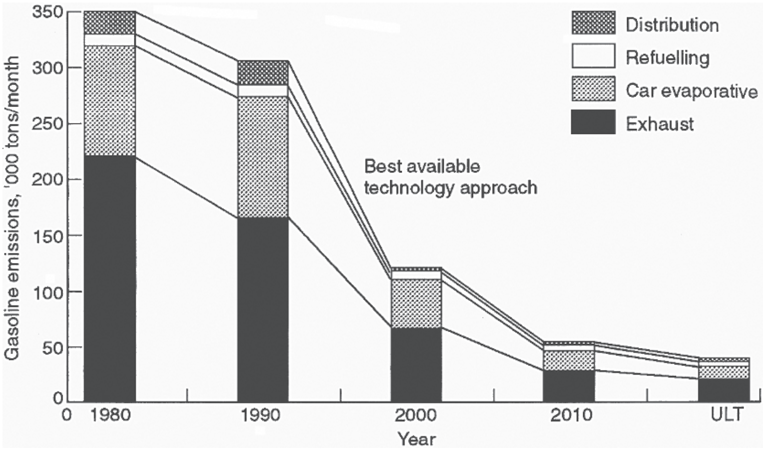


FIGURE 11.5. Impact of closed system on gasoline emissions for May–September in EC-12. (Reproduced with permission from *CONCAWE Report No. 31/90,* Closing the gasoline system – control of gasoline emissions from the distribution system and vehicles; published by CONCAWE, 1990.).

ambient temperatures. The 'ultimate' (ULT) level of control would eventually be achieved when three-way catalysts and enlarged carbon canisters are fitted to all gasoline cars.

Dialogue between the European Commission and the relevant motor and oil industry associations (ACEA and EUROPIA) resulted in a series of European Programmes into Emissions, Fuels and Engine Technologies (EPEFE) during the nineties. The resulting European Auto/Oil programmes had the objectives of providing test data on the influence of exhaust clean-up technologies and fuel properties on gasoline and diesel vehicle emissions. The outcomes from these studies have strongly influenced both the development of 'clean' fuels and new engine technology.

Gasoline quality developments. A common feature of most gasolines, for over 50 years until fairly recently, was the presence of an additive, tetraethyl lead (TEL). The need for better quality gasoline became evident in the 1920s, when attempts to improve engine efficiency by the use of higher compression ratios revealed the phenomenon of pinking or knocking, which can lead to catastrophic engine damage.

Extensive research studies during the early 1920s identified TEL as having the greatest effectiveness as an anti-knock agent and the best potential for commercial development. For several decades TEL was virtually the only anti-knock additive but later a closely related product, tetramethyl lead (TML), was also commercialized. The use of lead-based compounds to increase the octane rating of gasoline continued until, in the 1970s, concern about the harmful effects of lead on humans resulted in many countries legislating against its use. The historical reduction in the maximum lead content of the

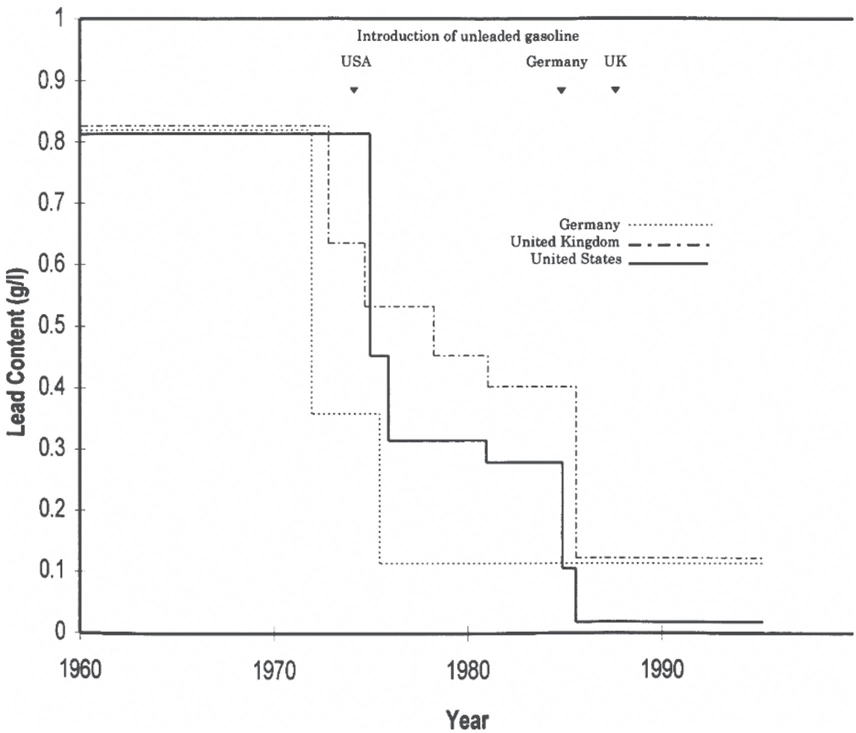


FIGURE 11.6. Trends in premium gasoline lead content.

top gasoline grade in Europe and the USA is shown in Figure 11.6. Since 1995, the rapid introduction of unleaded gasoline has meant that this is now the standard in both areas. As lead is often present naturally in crude oils, a maximum lead content of 0.013 g is permitted in the European unleaded gasoline specification EN 228.

Maintaining the volume of gasoline produced, in addition to its quality, without the use of lead has required significant restructuring of gasoline manufacturing and blending operations. Although other metallic compounds were found to give anti-knock benefits they have been rejected for various reasons, which include deposit formation, wear, toxicity and cost. Some organic anti-knock compounds were also rejected as being less cost-effective than lead alkyls or further refinery processing.

Studies of other ashless compounds identified some promising candidates with anti-knock capabilities and, consequently, oxygenated compounds such as alcohols, e.g. methanol, ethanol and ethers, e.g. methyl-tertiarybutyl ether (MTBE) have become widely used as blend components in lead-free gasolines. Use of so-called biofuels or bio-fuel supplements arising from biomass fermentation is also having an increasing impact as additional feedstock. Many countries around the world now have 'clean' or reformulated gasolines, which are designed to give reduced levels of vehicle exhaust and evaporative emissions.

Reformulated gasolines reduce emissions in a number of ways: their lower vapour pressure reduces evaporative emissions; smog-forming benzene and other hydrocarbons in exhaust emissions will be reduced because of the lower content of aromatics and olefins, oxygenates in the fuel will result in lower levels of carbon monoxide and hydrocarbons in the exhaust, whilst the lower sulphur content will also be beneficial. The total effect on exhaust emissions resulting from switching to the ARCO (Atlantic Richfield Co.) Emission Control gasoline, EC-1, introduced in Southern California in 1989, are evident from the data given in Table 11.7.

The stringent controls imposed in certain areas of the USA have initiated directionally similar actions elsewhere, particularly in Japan and Sweden, whilst other European countries are following. E.g. Germany, Austria and Switzerland have moved to 10 mg/kg sulphur for both gasoline and diesel since 2003.

In the USA, reformulated gasoline has been defined as a result of the regulation–negotiation (reg–neg) between the Environmental Protection Agency (EPA) and the oil industry, which is summarized in Table 11.8.

Table 11.7. Reductions in vehicle emissions with EC-1 fuel

Type	Approximate reduction (%)
Exhaust emissions	
Hydrocarbons	5
Carbon monoxide	10
Nitrogen oxides (NO_x)	6
Benzene	43
Evaporative emissions	22

Table 11.8. USA 'reg–neg' agreement on reformulated gasoline

Specification item	Target value (psi/kPa)	Refinery average limit (psi/kPA)	Absolute limit (psi/kPa)
RVP Class A[a]	7.2/49.7	7.1/49.0	7.4/51.1 max.
RVP Class B	8.1/55.9	8.0/55.2	8.3/57.3 max
Oxygen	2.0% by mass	2.1 by mass	1.5% by mass mm.
Benzene	1.0% by vol.	0.95% by vol.	1.3% by vol. max
Heavy metals	None without EPA waiver		
T9OE	Average no greater than refiner's 1990 average		
Sulphur	As above		
Olefins	As above		
Detergent additives	Compulsory but not yet defined by the EPA		

[a]For 1995–1996 only; 1997–1999 VOC emissions must be reduced by at least 16.5% relative to 1990 average gasoline.

Lead anti-knock additives are still being used in many parts of the world, but they have been eliminated or are being phased out from those countries taking a strong line on environmental protection. However, other types of additive are being used to help reduce pollution from gasoline engine exhausts, by maintaining the condition of the engine and fuel system. Amongst those currently employed are: additives to reduce the increase in octane requirement (anti-ORI) that occurs as vehicles accumulate mileage and lay down deposits in the combustion chamber and valve ports; antioxidants to improve oxidation stability and prevent the formation of sediment and gums; detergents to prevent deposit formation which could impede the function of the fuel injector or carburettor; and additives to prevent 'soft' valve seats from recessing when operating on low-lead or unleaded gasoline.

Other additives which may be included are anti-icers to prevent ice forming in the carburettor during warm-up in near-freezing conditions and high humidity, demulsifiers to prevent problems due to water pick-up from tank bottoms, corrosion inhibitors to protect metal surfaces and spark-aider additives to improve the spark when operating at borderline air/fuel ratios and improve emissions by helping to prevent misfiring.

The EPEFE programme referred to above was completed during 1995 and conclusions drawn from the accumulated data have provided the basis for new EU directives on vehicle emissions and fuel quality, up to the year 2010. The current version of EN 228 (2002) states that, for all premium and regular unleaded gasolines, the sulphur content has to be below 50 mg/kg since 1st January 2005. The accompanying directive also states that EU Countries should make available 'sufficient' supplies of 10 mg/kg sulphur gasoline grades from this date with the intention to convert fully to 10 mg/kg sulphur fuels by the end of 2008. Benzene contents have been set at a maximum limit of 1.00%v/v and a total aromatics content of 35%v/v.The evolution in gasoline and diesel passenger car exhaust emissions standards in Europe, as set by directives issuing from the European Commission is illustrated in Figure 11.7.

(b) Automotive diesel engines. Recent years have seen a tremendous increase in the numbers of diesel-powered passenger cars in the developed countries, with the exception of the USA and Canada, where the gasoline engine is still the most popular for personal transport. The diesel share of new passenger car registrations in Europe is approaching 20% and close to 100% for commercial vehicles in most of the world.

One of the main attractions of the diesel car over the gasoline model is its lower fuel consumption. Disadvantages in earlier years were the poorer performance, higher noise levels and higher cost of the diesel version. However, the modern passenger car diesel can provide almost the same performance as its gasoline counterpart, with better fuel economy and an acceptably low noise level, and with little or no price difference. These impressive improvements have been achieved as a result of extensive (and expensive) research programmes into the diesel combustion process.

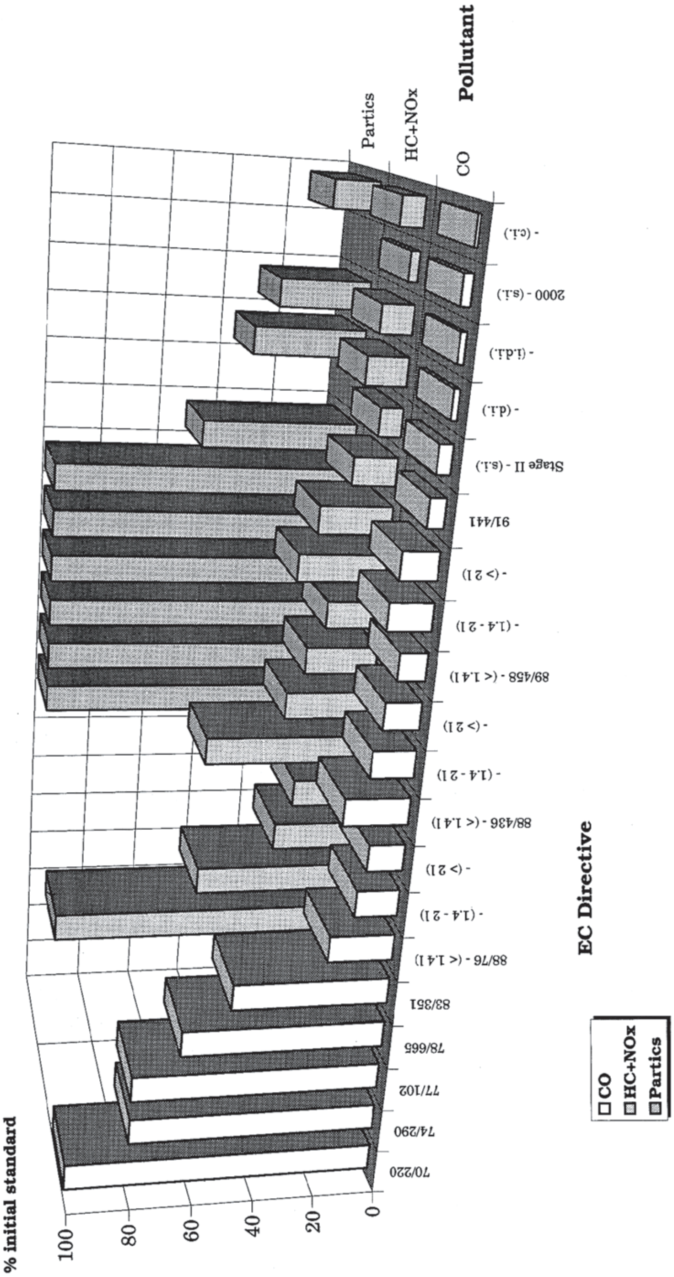


FIGURE 11.7. EC passenger Car emission standards 1970-2000.

Included in studies on engines for passenger cars and commercial vehicles were the benefits of turbocharging, aftercooling and exhaust gas recycling, together with changes to fuel injectors, injection timing, higher injection pressures, exhaust catalysts and particulate traps. Sophisticated engine management systems, to monitor engine conditions and ensure that the right amount of fuel is injected at the optimum moment in the engine's operational cycle, have also had a significant effect. Turbochargers, intercoolers and also electronic management systems are becoming the standard for a significant segment of commercial truck and bus fleet operators.

The EPEFE programmes to collate data on the influence of fuels and engine technologies on emissions showed that, in the light-duty diesel test cycle, increasing cetane number and decreasing density had the greatest influence in lowering hydrocarbon emissions. Back-end volatility of the fuel, T95 (95% recovery temperature) and the polyaromatic content also had significant effects on emissions, with NO emissions levels going down as polyaromatics decreased but increasing as the T95 was reduced. However, heavy-duty (HD) engines (which consume about 70% of the diesel fuel sold in Europe) showed opposite trends.

Criticism of diesel vehicles by the general public is largely associated with exhaust smoke, which is usually the only emission that is visible (from either gasoline or diesel vehicles), other than steam and water during warm-up. Black smoke consists mainly of particles of carbon (soot) associated with small quantities of partially burnt hydrocarbons from the fuel and the small amount of engine lubricant which finds its way into the cylinder. Sulphates, which are formed during combustion of sulphur in the fuel, will also contribute to particulate formation.

Lowering the fuel sulphur content will decrease particulate emissions but technological developments on the hardware side are particulate traps and catalytic converters. Catalytic converters are used in small passenger car systems and the heavy hydrocarbon content of the exhaust gas, which normally contributes to the total mass of particulates, is reduced by the oxidation catalyst.

Particulate traps (DPFs) tend to be too bulky for passenger cars and are more suitable for large commercial vehicles. They are installed in the engine exhaust system and trap the soot particles in wire mesh or ceramic fibres or in porous ceramic foam. Particle retention will vary according to the type of trap and also with time, as some types are blockable. They all require frequent regeneration to burn off accumulated soot deposits by means of electrical or fuel-fed heaters.

A further development is a continuously regenerating particulate trap that oxidizes the particles into carbon dioxide and water. This is achieved by using a platinum catalyst to convert some of the NO_x in the exhaust to nitrogen dioxide, which will stimulate oxidation of the carbon particles. It works as a continuous process and operates at normal diesel exhaust temperatures, as low as 275°C.

The sulphur content of the fuel has an important influence on the efficiency of the particulate material (PM) removal. At 3 mg/kg, both a catalysed

DPF (filter directly coated with a catalyst) and a continuously regenerating DPF (catalyst located upstream of the filter) reduced PM emissions by 95%. At 30 mg/kg, the efficiency dropped to 72%. For a 85% reduction, it is calculated that the sulphur content of the fuel needs to be 15 mg/kg or less. The most modern units use silicon carbide components and achieve 99% soot reduction. In these cases, the back pressure in the exhaust system is actively monitored and, once it reaches a pre-set point, a diesel fuel duct burner is activated. This heats the exhaust and burns off the soot until the back pressure returns to normal. The advantage of this system is that the frequency of burn off is dictated by engine loading, etc. rather than set time intervals.

Diesel fuel quality developments. Automotive diesel fuels are normally made by straight-run petroleum fractions from the atmospheric distillation unit with 'cracked' gas oils from one or more of the cracking processes, in proportions depending on the specification criteria to be met.

The different sources of gas oils which could be used as blend components for automotive diesel fuel are shown in Figure 11.8. However, not all refineries are likely to have the full selection available. The encircled areas on the diagram indicates the approximate ranges in density and cetane quality of typical gas oils from each refinery process, including that of the major blend component, straight-run gas oil from the atmospheric distillation unit. The shaded area shows that the European auto diesel specification imposes a very tight constraint on the refiners, who have to produce fuels of more than 51 cetane number whilst at the same time falling within a limited tolerance band for density (820–845 kg/m^3).

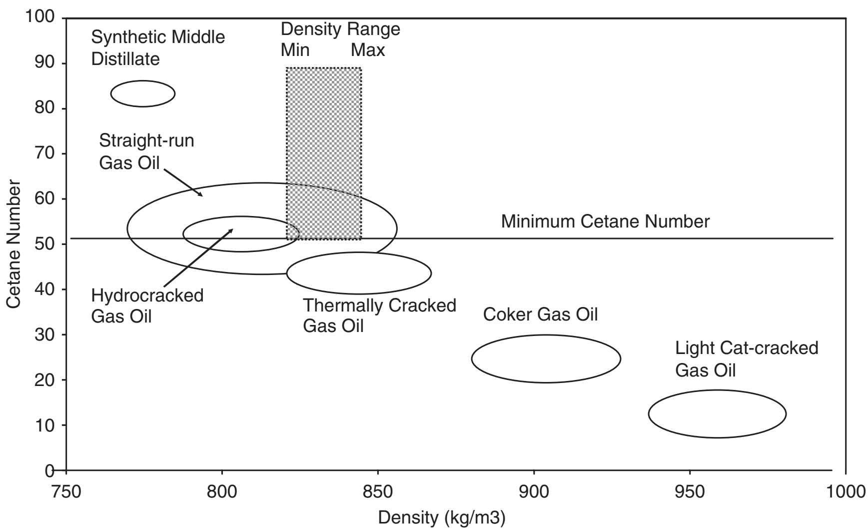


FIGURE 11.8. Density and cetane number characteristics of gas oil types. (Reproduced with permission of Shell International Oil Products.).

Demand for domestic heating oil is shrinking but, as heating oils usually contain a high proportion of low-cetane cracked gas oil, they are not suitable as direct replacements for diesel fuel. However, a cetane improver additive may be used to restore the ignition quality if some cracked gas oil is incorporated to increase diesel fuel yield.

Consumption of automotive diesel fuel is increasing in most parts of the world and cold flow improvers are widely used to enable refiners to meet the demand. Diesel fuels are complex mixtures of hydrocarbons, with a typical boiling range of 160–370°C. As much as 20% of the fuel can be relatively heavy paraffinic hydrocarbons which have a limited solubility in the fuel and, if cooled sufficiently, will come out of solution as wax. The polymeric flow improver additives work by modifying the way in which the wax crystals form, making them smaller and less likely to restrict the fuel from flowing thro the vehicle fuel system.

Over the last five years, increasing use has been made of 'biofuel' supplements, particularly fatty acid methyl esters (FAME) derived from vegetable sources, e.g. rape seed. The current EN 590 standard allows up to 5% by volume of FAME to be added to European diesels. However, new engine technology is currently being developed to run on 100% FAME. At present, clean, 'reformulated' diesel fuels tend to result from further or selective processing of conventional petroleum-based components to produce fuels having extremely low levels of undesirable, pollution-forming characteristics. From January 1st 2005, all EU diesels need to conform to a maximum 50 mg/kg sulphur content. In addition, as highlighted above for gasolines, 10 mg/kg diesel also needs to be available in sufficient quantity to meet localized demand.

Product enhancement additives are becoming widely used to improve fuel characteristics which are not controlled but which can bring environmental benefits. These include detergents, anti-wear agents and lubricity additives to protect fuel injection systems from harmful deposit build-up and wear, anti-foamants to minimize the risk of spillages during refuelling and corrosion inhibitors to protect storage tanks and vehicle fuel systems.

A technique for producing a very clean diesel fuel has been developed by a major oil company. The Shell Middle Distillate Synthesis (SMDS) process converts natural gas into a liquid, from which a light gasoline fraction, kerosine and gas oil can be obtained by distillation. These products are virtually free of sulphur and nitrogen and, being wholly paraffinic, the gas oil has a very high cetane number. At present SMDS capacity is limited but it has good potential.

Sulphur reduction in automotive diesel fuel has, once again, been the primary environmental objective. Additionally, specifications for cetane number, final boiling point and aromatics content have also been tightened because of their influence on carbon monoxide, nitrogen oxides, hydrocarbons and particulates (soot) emissions in the exhaust.

In 1993, CEN, the European Standards Organization, issued the first pan-European specification for automotive diesel fuel, with which the Member

States are bound to comply. To take account of the wide range of temperature conditions across Europe, a series of climatically related requirements were drawn up, from which each member could select appropriate summer and winter grades. These cover cold properties, density, cetane quality and distillation. All members must comply with the generally applicable requirements, consisting of flash point, carbon residue, ash, water and particulate matter (dirt), copper strip corrosion, oxidation stability and sulphur content.

Sweden was the first country to introduce two 'city diesel' grades, with tax incentives to encourage their use. Characteristics of these new urban–environmental grades and the standard diesel grades are given in Table 11.9.

These new urban grades have proved to be very popular, not just because of their lower price but also from improvements in air quality particularly during the winter months. The environmental benefit of using such fuels stimulated several oil companies to market imported urban diesel fuel in the UK whilst their refineries were being reconfigured to meet the lower sulphur limits.

A significant proportion of conventional diesel fuels are now treated with a variety of additive types, usually in the form of a 'package' prepared to suit the specific requirements of individual oil companies. Most contain a cold flow improver additive to avoid problems during normal winter conditions.

Other additives which may be present include cetane improvers for easy starting, stabilizers to prevent sediment and gum formation, detergents to control deposits, anti-corrosion additives for metal protection, anti-wear additives to protect fuel-lubricated surfaces of injection pumps and anti-foamants to permit fast refuelling rates and reduce the likelihood of spillages. As the odour of diesel fuel can be very persistent and not particularly pleasant, some fuels may be treated with a re-odorant, to make it more acceptable. A manganese-based additive, methylcyclopentadienyl manganese tricarbonyl (MMT), has been found effective in reducing particulate formation and diesel fuel treated with this product is being marketed in the UK by the Mobil Oil Company.

TABLE 11.9. Swedish Diesel Fuel Classifications

Fuel characteristic	Urban diesel 1	Diesel 2	Standard grades
Sulphur (% mm) (max)	0.0001	0.005	0.20
Aromatics (% v/v) (max)	5	20	–
	0.002	0.01	–
Polyaromatic hydrocarbons (PAH) (%v/v) (max)	180	180	180
Distillation			
IBP (°C) (min)	180	180	180
10% (°C) (min)	–	180	–
95% (°C) (max)	285	295	370 (summer) 340 (winter)
Density (kg/m^3)	800–820	800–820	820–860 (S) 800–845 (W)
Cetane number	50	47	49 (S) 45–58 (W)
Tax rate \$/m^3	126	165	199

7.8 *Into the next millennium*

Despite the increasingly severe legislation against environmental pollution by the road transport sector, the motor and petroleum industries, aided by the additive companies, have been able to meet the targets set so far. European specifications for gasoline and diesel fuel have seen a step change reduction in sulphur content to 50 mg/kg in 2005 and the rapid introduction of 10 mg/kg sulphur fuels in a number of countries. Though some of the new members of the EU will have limited time delays for implementation of the directives, overall progress in refinery revamping, etc. is ahead of schedule to meet the 2008 deadlines. Similarly, recent legislation in the USA (and California in particular), e.g. 30 mg/kg limit on sulphur in diesel to be implemented in 2006 will give the lead for stricter constraints on emissions elsewhere in the world.

Considerable work is in progress on alternative fuels, e.g. LPG, hydrogen, etc. but gasoline and diesel fuel will continue as the principal fuels for the vast majority of road transport. Three-way catalysts for gasoline vehicles are now mandatory in many countries but there is still room for improvement of the catalyst, to maintain its emission control effectiveness for longer periods. European environmental ministers have set a target of reducing average carbon dioxide emissions from new cars to 120 grams of carbon dioxide per kilometre (g/km) by 2010 from an EU average of 186 g/km in 1995. An interim target of 140 g/km is proposed for 2008 to cover European manufacturers and 2009 for Japanese and Korean manufacturers.

At the present time, the diesel engine is under heavy criticism because of the potentially carcinogenic hazard of the microscopic PM_{10} (less than 10 μm in size), which are claimed to be retained in the lungs after inhalation. Banning diesel-powered vehicles, on which the infrastructure of most developed countries depends, has been suggested but that is as impracticable as total elimination of particulates. What appears more likely is the imposition of even higher excise duty on diesel fuel (and also probably on gasoline) to restrict its use by private motorists.

Continuing research towards cleaner burning automotive engines and fuels will certainly be necessary to reduce exhaust emissions further. The successes of the past four decades provide hope that the interests of future generations will be protected, but enhanced inspection and maintenance procedures will be necessary to ensure close adherence to the emissions criteria.

Further reading

CONCAWE (1986) Sulphur emissions from combustion of residual fuel oil based on EEC energy demand and supply, 1980–2000. *CONCAWE Report No. 5/86*.

CONCAWE (1988) Capital and operating cost estimating aspects of environmental control technology – residue hydrodesulphurization as a case example. *CONCAWE Report No. 88/51*.

CONCAWE (1988) The control of vehicle evaporative and refuelling emissions – the ‘on-board’ system. *CONCAWE Report No. 88/62.*

CONCAWE (1990) European soil and groundwater legislation: implications for the oil refining industry. *CONCAWE Report No. 4/90.*

CONCAWE (1992) The environmental benefits and cost of reducing sulphur in gas oils. *CONCAWE Report No. 3/92.*

CONCAWE (1992) VOC emissions from the loading of gasoline into ships and barges in EC 12: control technology and cost-effectiveness. *CONCAWE Report No. 92/52.*

CONCAWE (1992) *CONCAWE Product Dossier No. 92/103*: Gasolines.

CONCAWE (1992) *CONCAWE Review,* 1(2), October.

CONCAWE (1993) The European environmental and refining implications of reducing the sulphur content of marine bunker fuels *CONCAWE Report No. 1/93.*

CONCAWE (1993) *CONCAWE Review*, 2(2), October.

CONCAWE (1994) The contribution of sulphur dioxide emissions from ships to coastal deposition and air quality in the channel and southern north sea area. *CONCAWE Report No. 2/94.*

CONCAWE (1994) Trends in oil discharged with aqueous effluents from oil refineries in western Europe – 1993 survey. *CONCAWE Report No. 3/94.*

CONCAWE (1994) Motor vehicle emission regulations and fuel specifications: 1994 update. *CONCAWE Report No. 4/94.*

CONCAWE (1994) The performance of oil industry cross-country pipelines in western Europe. *CONCAWE Report No. 5/94.*

CONCAWE (1994) *CONCAWE Review*, 3(2), October.

CONCAWE (1995) *CONCAWE Review*, 4(1). April.

Department of the Environment (1993) *Diesel Vehicle Emissions and Urban Air Quality, Second Report of the Quality of Urban Air Review Group*, H.M. Stationery Office, London, December.

Owen, K. and Colcy, T. (1995) Automotive *Fuels Reference Book*, 2nd edn, Society of Automotive Engineers, Warrendale, PA.

CONCAWE (1995) Interim report on the European refining implications of severe reformulation of gasoline and diesel fuel. *CONCAWE Report No. 95/54.*

CONCAWE (1997) Motor vehicle emission regulations and fuel specifications – Part 2 Detailed information and historic review (1970–1996). *CONCAWE Report No. 6/97.*

CONCAWE (1999) Fuel quality, vehicle technology and their interactions. *CONCAWE Report No. 99/55.*

CONCAWE (1999) Potential of exhaust after treatment and engine technologies to meet future emissions limits. *CONCAWE Report No. 99/62.*

CONCAWE (1999) Best available techniques to reduce emissions from refineries. *CONCAWE Report No. 99/01.*

CONCAWE (2000) Impact of a 10 ppm sulphur specification for transport fuels on the EU refining industry. *CONCAWE Report No. 00/54.*

CONCAWE (2001) Motor vehicle emission regulations and fuel specifications: Part 2 Detailed information and historic review (1996–2000). *CONCAWE Report No. 2/01.*

CONCAWE (2002) Sulphur dioxide emissions from oil refineries and combustion of oil products in western europe and hungary (1998). *CONCAWE Report No. 10/02.*

CONCAWE (2002) VOC emissions from loading gasoline onto sea-going tankers in EU-15: control technology and cost effectiveness. *CONCAWE Report No.6/02.*

CONCAWE (2002) Evaluation of diesel fuel cetane and aromatic effects on emissions from euro-3 engines. *CONCAWE Report No. 4/02.*

CONCAWE (2002) Western European pipelines. 30 years of spillage performance monitoring. *CONCAWE Review*, 11(1), April.

CONCAWE (2003) Fuel effects on emissions from modern gasoline vehicles: Part 1 Sulphur effects. *CONCAWE Report No.5/03.*

CONCAWE (2003) Fuel quality and emissions – rising to the challenges of increasingly demanding fuel specifications. *CONCAWE Review*, 12(2), October.

CONCAWE (2004) Motor vehicle emission regulations and fuel specifications: Part 1 2002/2003 update. *CONCAWE Report No. 9/04.*

CONCAWE (2004) Trends in oil discharged with aqueous effluents from oil refineries in Europe 2000 survey. *CONCAWE Report No. 4/04.*

CONCAWE (2004) The City Delta Project – assessing urban air pollutant effects. *CONCAWE Review*, 13(1), April.

CONCAWE (2004) Advanced vehicles and fuels – some recent emissions results. *CONCAWE Review,* 13(1), April.

CONCAWE (2004) Joint European Well to Wheels study – an analysis of future automotive fuels and powertrains in the European context. *CONCAWE Review*, 13(1), April.

CONCAWE (2005) Fuel effects on emissions from advanced diesel engines and vehicles. *CONCAWE Report No. 2/05.*

CONCAWE (2005) Performance of European cross-country oil pipelines. Statistical summary of reported spillages – 2003. *CONCAWE Report No. 3/05.*

CONCAWE (2005) A European framework for waste quality. Key features and potential impacts on the downstream oil industry. *CONCAWE Review*, 14(1), Spring.

CONCAWE (2005) ERTRAC – A unique opportunity to improve the effectiveness of research on road transport in Europe. *CONCAWE Review*, 14(1), Spring.

Chapter 12
Lubricants

C.I. Betton

1 Introduction

The activities of the oil industry are aimed primarily at the production of fuel. The proportion of crude oil that is refined into a lubricant base oil is only 1% of the total (Institute of Petroleum, 1992). It could be argued that the base oils produced by a refinery are a by-product of the refining process and that the integrated oil company regards lubricant production accordingly. Lubricants, however, represent a high technology, specialist, high added value group of products with high potential environmental impact. The environmental aspects of lubricants extend beyond the obvious direct impacts to secondary impacts such as energy savings due to improved performance.

The perfect lubricant from an environmental point of view would consist of a material that:

- was obtained from a renewable resource;
- did not require a large amount of energy to produce;
- was a perfect lubricant in that it reduced friction to very low levels;
- was unaffected by heat and pressure;
- did not contain any potentially toxic or harmful components;
- was not ‘used up’ during the process of lubrication;
- was not dependent on temperature in order to function;
- was readily degradable to non-harmful components if spilled;
- worked for the lifetime of the device being lubricated;
- was recoverable and reusable.

Unfortunately, such a material does not exist nor, based on the current state of knowledge of how lubricants work (Mortier and Orszulik, 1992), is it ever likely to exist.

Since the publication of the first edition of this chapter, the priority governing environmental issues affecting regulators and scientists alike have changed. Fifteen years ago, the concept of global warming was an object of

Delphic HSE Solutions Limited, Delphic House, Frimley, Surrey, UK

discussion among environmentalists and theoretical ecologists but few other groups, and certainly not Tribologists. Now however with metereological records showing that the 10 warmest years on record have all occurred within the past 15 years and CO_2 measurements taken from ice-cores able to show that the amount of atmospheric CO_2 is now at an unprecedented level, the environmental priorities and emphasis are different.

The environmental grouping previously suggested of

- performance;
- components;
- effect on the environment if spilled (toxicity);
- rate of removal from the environment if spilled (degradability).

Has been skewed significantly in terms of performance. Today when CO_2 and emissions of other greenhouse gasses are continuing to rise, the performance of lubricants in reducing friction, increasing efficiency is of greater importance than ever before. Environmental advantages related to reduced toxicity and biodegradability are increasingly met by management and it is important that these are in addition to, not instead of, the maximum level of performance that can be attained. To take an example of a motor car engine oil, modern engines are not capable of existing on the lubricants based on castor oil that were adequate for the engines of the 1920s, even though such a lubricant would meet many of the 'environmental' criteria listed above. What is easy to ignore are the substantial benefits in fuel efficiency and emissions reduction that are achievable from a modern engine, compared with an early 'gas guzzler'. If an old-fashioned oil were used in a modern engine, the engine would be destroyed in a few thousand miles and the environmental costs of replacing that engine in terms of the energy and foundry emissions, etc., from the production plant would far outweigh any benefits from the use of the 'old-style' lubricant. The impact of improved performance can be seen in the service intervals of today's vehicles. In the 1970s the typical service interval was 5,000 km, today the norm is 15,000 km with many manufacturers offering 20,000 km and some recommending 50,000 km. This is now possible by advanced lubricant technology but also electronic in-car monitoring of the lubricant itself, "condition monitoring". It is often the case that the service interval is now determined by wear and tear on components such as spark plugs and that the lubricant is still well within performance spec. This is shown by a reduction in the total volume of lubricants being used over the past 10 years, at a time when the number of cars has increased significantly (Fox, 2006).

Performance is and must always be paramount when assessing the environmental aspects of any lubricant; that is not to say, however, that it should be performance at any cost. Recent developments in metalworking oil technology with the elimination of materials such as chlorinated paraffins from some formulations (Howell, Lucke and Steigerwald, 1996) demonstrate that as knowledge of environmental and health effects increases, formulations can change accordingly. Such changes are not without cost and are not easily achieved, as in all cases performance needs to be maintained if not improved.

2 Performance

Performance of lubricants is measured in different ways depending upon the use to which the lubricant will be put. There are standard tests for some types of lubricant such as engine oils that convey to the customer some information concerning the quality of the oil that is purchased (SAE, 1996). It is not my intention to describe or review these methods here. There are, however, some points regarding the standard industry tests that are worth making, particularly when considering the most up-to-date lubricant technology and the environmental benefits that can be accrued.

Performance tests for lubricants are controlled by national (API) and international (ACEA) organizations, and some individual motor manufacturers also have their own test requirements (SAE, 1996). The tests are based upon the principles of ready availability and reproducibility. A test that is run by one institution must be, and be seen to be, the same as that by a different institution; the results must be comparable. As can be imagined, huge investment is put into establishing test methods and setting up facilities to run the tests; companies are therefore reluctant to chop and change tests without compelling reasons. The result of these restrictions is that the tests used to classify lubricants according to the internationally recognized standards are often lagging behind contemporary technology. The major lubricant companies and the motor manufacturers, being aware of the deficiencies in the standard classification tests, have developed their own methods of assessing performance that are in addition to the standard requirements. A series of motor car engine oils, for example, may all meet a particular standard but the performance of oils may be very different in actual driving conditions, with those of the major lubricant producers being far more effective than some others that are not designed to the same high standards. With lubricants you really do get what you pay for.

In conclusion, when considering the environmental benefits of any lubricant, the most important factor to be considered is the performance. A quality lubricant formulated according to recognized standard performance criteria from a major manufacturer will confer the highest level of environmental benefit possible by conferring long life due to reduced wear, lowest possible emissions due to reduced friction and maximum protection from corrosive attack due to correct formulation and lowest possible losses due to low consumption in use and compatibility with seal materials, reducing leaks.

3 Components

As mentioned earlier, a performance lubricant requires the presence of additive chemicals in order to enable it to work effectively. A typical lubricant therefore consists of a base fluid in which are dissolved a number of different chemicals, each performing a unique function. The additive chemicals are generally more expensive than the base fluid, so from a business point of view it is important to formulate the lubricant with sufficient additives to achieve the desired performance – but no more. Environmentally, the principle 'the least is best' applies. In a perfect world, no lubricant would ever reach the environment except in those instances where the design makes such losses inevitable, e.g. greases on railway points systems, chain bar lubricants on chain saws and any two-stroke engine oil such as those used in outboard motors, motor cycles, etc.

4 Base fluids

The choice of a base fluid for a lubricant is dependent upon the desired characteristics of the final product. I shall not consider this aspect of performance in this section. If further information is required, several excellent reference works are available that will assist the reader in understanding the performance aspects of base fluids (Prince, 1992; Randles et al., 1992).

From an environmental point of view, base fluids can be split into three categories: mineral oils, synthetic oils such as poly-α-olefins and esters, and highly refined and hydrocracked mineral oils, which some people regard as synthetic whilst others consider to be of natural origin depending perhaps on whether one is a buyer or a seller..

5 Mineral oils

Mineral oils are produced to a performance specification from the refining of crude oil. They vary in viscosity and composition, the major constituents being *n*-alkanes, isoalkanes, cycloalkanes (also known as naphthenics) and aromatics. The molecular weight distribution of the various components largely determines the performance characteristics (Prince, 1992). Analytical determination of the individual hydrocarbon components in a base oil is not a simple procedure (Bennet et al., 1990; Gough and Rowland, 1990; Betton, 1994). Gas chromatography in conjunction with mass spectrometry (GC–MS) is used to demonstrate the components of an oil. Typical CG–MS traces for two formulated oil products are shown in Figure 12.1 (Bennet et al., 1990). The oils themselves are characterized by an unresolved hump (unresolved complex mixture or UCM) starting at 20 min retention time (Gough and Rowland, 1990). This reveals that a typical base oil consists in part of monoalkyl and T-branched alkanes; there are 536 possible acyclic T-branched alkane structures with carbon numbers between C_{20} and C_{30} (Gough and Rowland, 1990). Of this complex mixture of hydrocarbons, only a small proportion are water soluble. The presence of ring components (naphthenics and aromatics) further increases the complexity of the base oil mix. Comparison of the traces of the whole product shown in Figure 12.1 with those for the water-soluble fraction

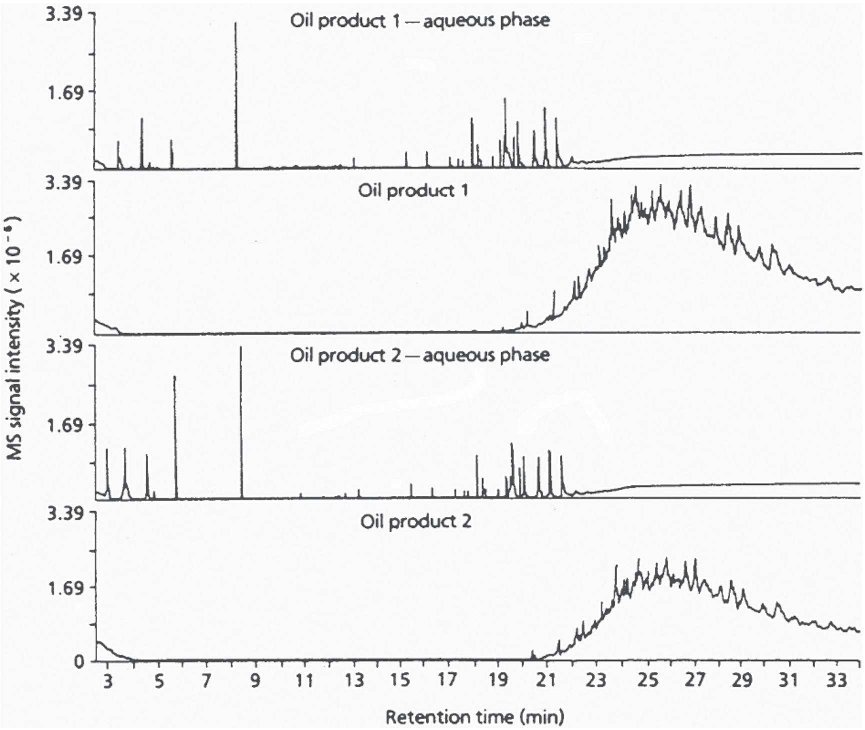


FIGURE 12.1. GC–MS trace for two formulated oil products and their aqueous phases at equilibrium. (Reproduced from Bennet, D., Girling, A.E., and Bounds, A., *Chemosphere*, 1990, **21**, 659–69.)

of the same oil shows that the identities of the majority of the water-soluble components are attributable to the oil additives used to enhance the base oil properties (i.e. imido-succinates, sulphur compounds, methacrylates). Base oil hydrocarbon components in the aqueous phase are present only in minor quantities – the additive components seen in the aqueous phase are not even noticeable when looking at the traces for whole product (Bennet et al., 1990).

The environmental effects of the base oil depend on two factors, the toxicity and the degradability. Toxicity is dependent on the availability of the material and, as we have seen, only a small proportion of the total mix is water soluble. Soluble components tend to be the lower molecular weight hydrocarbons; the higher the molecular weight, however, the higher is the acute toxicity (Coleman et al., 1984). The outcome of this paradox is that mineral base oils have low acute toxicity to aquatic organisms (BenKinney et al., 1991; Barbieri et al., 1993; Betton, 1994; CONCAWE, 1997). However, the rate of degradability has a capacity to affect the environmental impact of the base oil.

Bacteria can utilize various molecules as an energy source or by incorporating them into new bacteria – biomass. This process is known as biodegradation.

In general, the more linear a molecule is then the easier it is for bacteria to make use of it. As we have seen earlier, the various molecular structures present in mineral base oils are branched and ring structures with only a small proportion of linear hydrocarbons. For this reason, mineral base oils are regarded as poorly degradable. Such materials do ultimately degrade, however, as has been dramatically shown by the various catastrophic spills of crude oil that have occurred in Alaska and the coasts around Europe and the Middle East (Benyon and Cowell, 1974; Clark, 1982; Green and Trett, 1989; Pritchard and Costa, 1991).

If, however, it is desired to improve the environmental performance of the base fluid, then alternatives to mineral oil are required. Fortunately, bearing in mind our prime concern regarding product performance, the alternatives to mineral oil are also ‘better’ performers technologically.

6 Synthetic base oils

There are two principal types of synthetic base fluids in use, polyol esters and poly-α-olefins (PAOs). A full description of the technology of these materials is given elsewhere (Mortier and Orszulik, 1992). The advantages, environmentally of these materials are described below.

6.1 Polyol esters

There are three main types of polyol ester used in lubricants (Randles et al., 1992):

- pentaerythritol esters $C(CH_2OCOR)_4$
- trimethylolpropane esters $CH_3CH_2C(CH2OCOR)_3$
- neopentyl glycol esters $(CH_3)_2C(CH_2OCOR)_2$

These materials are structurally very similar to the naturally occurring glycerides (fatty acid esters of glycerol) found in living systems (Edwards and Hassall, 1971; Cain, 1990). As bacteria have evolved systems capable of metabolizing glycerides, they are readily able to make any small biochemical adjustments necessary to utilize the polyol esters as sources of energy or as anabolic feedstocks. In consequence, the polyol esters are generally readily biodegradable (Cain, 1990; Battersby et al., 1992).

6.2 Poly-α-olefins

Poly-α-olefins (PAOs) are generally hydrogenated oligomers of an α-olefin, usually α-decene. Full details of production techniques can be found elsewhere (Randles et al., 1992). For the purposes of the current discussion, it is important to recognize that PAOs are produced to meet viscosity requirements, and are classed according to the viscosity at 100°C, i.e. PAO 2, PAO 4, PAO 6, etc. The larger and more complex the structure of the molecule, the higher is the viscosity and the lower the degree of biodegradability.

7 Hydrocracked mineral oils

As mentioned earlier, mineral oils consist of a mixture of different classes of hydrocarbon. Further treatment of the 'standard' base oil by a combination of high pressure, hydrogen and passing over a catalyst (for details see Prince, 1992) causes the following changes in composition:

- hydrogenation of aromatics and other unsaturated molecules;
- ring opening, especially of multi-ring molecules;
- cracking to lower molecular weight products;
- isomerization of alkanes and alkyl side-chains;
- desulphurization;
- denitrogenation;
- reorganization of reactive intermediates, e.g. to form traces of stable polycyclic aromatics.

The environmental consequence of these changes is to increase the proportion of molecules present that are able to be utilized by bacteria, hence these products tend to exhibit excellent biodegradability (Cain, 1990).

8 Additives

The purpose of an additive in a lubricant is to impart those properties to the lubricant that are essential to its function but are not present in the base fluid. In consequence, the number and type of additives required to make any lubricant effective is dependent on the base fluid and end use of the lubricant. For details of the function of additives, see Mortier and Orszulik (1992).

Additive chemistry is a combination of high technology and alchemy (to the outsider) and the additive companies spend much time, effort and money developing additives to meet the requirements of the equipment manufacturers and the lubricant companies. Exact formulations of both individual components and additive packages are jealously guarded commercial secrets. The additive manufacturers under the guise of the Additives Technical Committee (ATC) have, however, published some background information on the effects of additives and their potential environmental impact (Linnett et al., 1996). They have also commissioned research into the toxicity and biodegradability of various component additives in order to generate data required for the classification and labelling of dangerous substances. These data have shown that the component additives have generally low aquatic toxicity when studied using standard test methodology in fish, daphnia and single-celled algae. The most toxic of the components are the zinc-based antiwear/antioxidant additives. These are normally present in a formulated engine oil at approximately 1–2%.

As the virgin oil and neat additive rarely enter the environment, other than as a result of an accidental spill, and bearing in mind the low toxicity of the base oil component, it can be legitimately argued that the composition of an oil does not present a hazard. The benefits that are gained from a quality lubricant in terms of extended engine life, reduced emissions and fuel savings clearly outweigh any minimal detrimental effects that may occur due to the components.

9 Actual environmental effects

It is not virgin oil that enters the environment. Used oil either leaking from cars via faulty seals and joints, or via the exhaust, and do-it-yourself oil changes, the proceeds of which are simply dumped on the soil or down the drain, are the major environmental inputs of lubricants. Estimates of the fate of lubricants sold in the European Union were made by the European oil companies' organization CONCAWE (CONCAWE, 1985) and are shown in Table 12.1.

The result of these estimates can be visualized in the centre of the lanes of any motorway as a black coating of oil or as the stains in any car park bay under the area where the engine comes to rest. The volumes of used oil involved are considerable and have been estimated as representing the equivalent of one *Exxon Valdez* per month over the area of the European Union countries (Betton, 1992). What are the consequences of such apparently large-scale inputs?

Research was carried out at the University of Sheffield in the UK on the environmental impact of roadway run-off from the M1 motorway at four separate sites (Maltby et al., 1995a, b). The effects of the lubricants lost from the traffic using the motorway were studied by comparing the biology and chemistry of the receiving water downstream of the run-off entry point with the situation upstream. In this way the only factor affecting the streams was judged to be the run-off from the motorway.

The most striking feature of the studies was the minimal effect on the environment of the run-off. Of the seven streams initially surveyed, only one of those, that with the smallest natural flow of water, showed any effect on the biology of the system. This was measured by comparing the number and diversity of animals and plants in the area downstream of the motorway drainage input with the area immediately upstream. In the one affected site, a decrease in diversity was characterized by fewer sensitive species and an increase in those species typically resistant to the effects of pollution. Hydrocarbons characteristic of used engine oil were found in significant quantities in sediment taken from downstream sites, but

Table 12.1. Estimates of fate of lubricants sold in the EU (CONCAWE, 1985)

	Tonnes per year ($\times 10^3$)	%
Total EU lubricant sales	4500	100
Consumed	2350	50–55
Recycled	700	15
Burnt as fuel	750	17
Unaccounted for	600	13
Poured down drain deliberately	100	2

not from upstream samples. Water samples were not found to contain any significant contamination. Laboratory investigations in which samples of contaminated sediment were extracted and separated into water-soluble (containing metals), aliphatic, naphthenic and aromatic fractions showed that the principal cause of toxicity was in the aromatic fraction. The other hydrocarbon components and the metal-containing portions did not appear to have any significant toxic effect. This is in line with the low toxicity of the components as discussed earlier.

Identification of the actual toxic components has revealed that the polycyclic aromatic hydrocarbons (PAHs) phenanthrene, pyrene and fluoranthene account for up to 76% of the observed toxicity. These particular PAHs have been found not to possess any carcinogenic potential (IARC, 1983).

10 Biodegradability

Oils are biodegradable. Accidents such as the *Torrey Canyon, Amoco Cadiz, Exxon Valdez* and *Braer*, in addition to deliberate pollution such as occurred during the 1991 Gulf War, have led to enormous sums of money being spent on clean-up and scientific investigation not only at the time of the incident but also for prolonged periods where recovery of ecosystems has been followed. Biological activity is primarily responsible for the recovery on both a macro- and micro-scale. Biodegradation by microbes is an essential part of the regenerative process (Cain, 1990; Battersby et al., 1992; Betton, 1992; Painter, 1992). It should be remembered that even if it were possible to eliminate all lubricant inputs, the environment would still be subjected to large volumes of oils and hydrocarbon materials from natural seepage. We are after all considering a natural product that has leached into the biosphere for many millennia and species have evolved to deal with long-term, low-level exposure to such chemicals.

When tested in standard OECD tests for ready biodegradability (OECD, 1981), oils do not perform well (Cain, 1990; APAVE, 1992). The standard OECD protocols require either a knowledge of the chemical structure to calculate theoretical values of oxygen uptake or CO_2 evolution or a determination of experimental values for these parameters.

Information on the purity or the relative proportions of major components of the test material is required to interpret the results obtained, especially when the result lies close to the ‘pass’ level.

Of the five test methods currently recommended by OECD for assessing ready biodegradation, the Sturm test is the one that has gained the most widespread acceptance for examining the biodegradability of oil products. A modified version of the MITI test has also been successfully applied. In addition, the Co-ordinating European Council for the Development of Performance Tests for Lubricants and Engine Fuels (CEC) has published a test method, Biodegradability of Two-Stroke Cycle Outboard Engine Oils in Water (CEC, 1993), which has been widely used in Europe by both industry and contract test houses for all types of oil products and poorly soluble hydrocarbons (Cain, 1990;

Betton, 1992). This method, however, relies on the use of Freon, a substance whose manufacture is no longer permitted under the terms of the Montreal Protocol on ozone-depleting substances. The life span of the CEC test is therefore severely limited. A new more appropriate method for measuring biodegradability of oils has been developed by CONCAWE (CONCAWE, 1999; Battersby, 2000), which is currently being assessed as a standard OECD test methods (OECD, 2003). For a detailed discussion of the biodegradation of oils, see Cain (1990) and Betton (1992, 1994).

Although it is not appropriate to concentrate here on the mechanism of biodegradation and its relationship to lubricants, it is important to consider the fundamental question of whether the environmentally desirable characteristic discussed in the Introduction need or indeed should be applied to lubricants.

The question of whether biodegradability is a desirable characteristic in a lubricant has been the subject of much, often heated, debate among product developers for many years. In the following paragraphs an attempt is made to highlight some of the areas of concern that have been raised and to give reasons why on balance biodegradability is desirable, always providing, of course, that performance is not compromised.

10.1 Biodegradation is not necessary in a lubricant

As shown earlier, a large proportion of the lubricant that is sold is 'lost' and unaccounted for. Lubricant *is* deliberately dumped into the environment. This total environmental burden does degrade, albeit at a relatively slow rate. Lubricants specifically designed to be more readily degradable will be less likely to foul the environment via leaks, spills or deliberate dumping.

10.2 A biodegradable lubricant will encourage dumping at the expense of collection and disposal

It is fundamental that environmental benefits should be in addition to performance, as was discussed earlier. If that is the case in a product it is probable that a biodegradable lubricant will be at the upper end of the price range. Individuals who specify such lubricants and who are prepared to pay for them are not the type of people who will deliberately dump oil. It is uninformed and socially unconcerned people and those who buy the cheapest product in a chain store who are likely to be involved in dumping.

10.3 A biodegradable lubricant will degrade in the engine

Biodegradability depends on bacteria to do the degrading. The environment of a motor car engine, with its extremes of temperature and pressure, is not conducive to the maintenance of bacterial life. In addition, bacteria tend to live in water and not oil; it is only when dealing with emulsions and water contamination that conditions conducive to bacterial growth and degradation of lubricants can occur.

10.4 A biodegradable lubricant will result in high concentrations of toxic residues that are detrimental to the environment

As we have seen, the additive components of oils are not particularly toxic, and degradation of the base oil will not leave a toxic residue. The work on road run-off has shown that it is PAHs, formed during combustion and deposited in the lubricant, that are responsible for the small degree of toxicity found. These materials are also those with the simplest structure and possess some degradative potential, in addition to which they are subject to degradation by ultraviolet light. It should also be remembered that PAHs are naturally occurring products of combustion and have been present in the environment for as long as there have been fires. Systems have evolved to cope with these materials.

10.5 Biodegradation is not necessary, as motor manufacturers are now producing sealed lubricant systems

A motor car may well not leak oil for the first few years of its life, although as examination of the Chief Executive's parking space will eloquently demonstrate, this is not always the case! Motor cars are now lasting for much longer periods and it is apparent that there are and will always be a large proportion of the cars on the road that leak oil to the environment. A biodegradable lubricant would be effective in minimizing the effects of those losses.

11 Collection and recycling of used oils

The recycling of used lubricants has been practised to various degrees since the 1930s and particularly during the Second World War when the scarcity of adequate supplies of crude oil during the conflict encouraged the reuse of all types of materials, including lubricants. Environmental considerations regarding the conservation of resources and sundry 'oil crises' have maintained interest in the concept of recycling up to the present day. A recent review (CONCAWE, 1996) has examined the environmental costs and potential benefits of the whole issue of collection and disposal of used oil in great detail. More recently, independent organizations have considered whether the concept of recycling is environmentally valid and whether the regulatory requirements actually deliver environmental benefits (Fox, 2006). Irrespective of this however there are currently legislative requirements for the recycling of used oils (EU, 2000, 1975).

It is essential to recognize that all used oils should be collected for controlled disposal. Some products, such as transformer oils and hydraulic oils, can be readily collected from large industrial concerns, regenerated to a recognized standard and returned to the original source.

Oils from automotive sources will include mono- and multi-grade crankcase oils from petrol and diesel engines, together with gear oils and transmission fluids. Used industrial lubricants that have been inadequately segregated may also be included. Apart from any degradation products from the in-service use of the oil, a wide range of contamination is possible, including the following:

- water – combustion by-product, rainwater/salt water ingress;
- fuels – residual components of gasoline and diesel fuel;
- solids – soot, additive and wear metals together with rust, dirt, etc.;
- chemicals – used oil can be used as an unauthorized means of hazardous waste disposal;
- industrial oils – inadequate segregation of oil types can allow contamination by fatty or naphthenic products.

Provided that efficient management systems are in place, many industrial oils should be largely contained and not escape into the environment. There are many potential sources of used industrial products; however, reprocessing is not an option for a large number of these products which are synthetic and fatty-oil based. Some specific types of industrial oils are suitable for relatively simple reprocessing before being returned to their original service. Typical processing methods involve filtration and removal of water and volatile decomposition products under vacuum, and can sometimes be carried out at the plant using mobile equipment.

Legislation around the globe is increasingly controlling the collection and disposal of all waste materials, including lubricants. Large-scale (greater than 3 m^3) waste oil collection vessels at service stations must now be licensed in the UK, as must any company that transports or treats waste lubricants.

The method of disposal that is utilized will be dependent on many different factors, however, availability of appropriate treatment facilities, raw materials, type of product being collected, levels of contamination and so on will all affect which is the most appropriate disposal route. A full life-cycle analysis of each situation would be required before a definitive choice of disposal option could be made. However, such analyses are complex, time consuming and necessarily subjective. The following used oil disposal routes are considered to offer the 'best environmental option':

- re-refining to base oil using modern technology to reduce PAH concentrations to acceptable levels (e.g. using severe hydrotreatment or solvent extraction);
- reprocessing to industrial fuel using modern technology (e.g. Trail-blazer process);
- recycling through a refinery as a low-sulphur fuel oil blendstock;
- direct burning as fuel in cement kilns;
- burning after mild processing in road stone coating plants (care must be taken to ensure that emissions of chlorine containing components do not exceed acceptable limits);
- gasification to produce fuel gas or petrochemical feedstock.

The following disposal routes are considered to involve unacceptable levels of pollution due to emissions to soil, air or watercourses and should not be countenanced under any circumstances:

- direct burning in space heaters (emissions of heavy metals and other products of low-level combustion causing localized pollution);
- re-refining using acid/clay and other old technologies (the majority of plants currently in operation) producing acid tars and oiled clay requiring specialist disposal;
- road oiling (high risk of groundwater contamination).

The economics of environmentally acceptable used oil disposal will be dependent upon the availability of local facilities. None of the environmentally acceptable methods listed above are considered to be financially self-sufficient without the application of some form of subsidy. This is largely related to costs of collection and transport. For a full discussion of the economic arguments, see CONCAWE (1996). This greater understanding of the total environmental impacts of waste oil recycling has led the EU to question the assumption that regeneration is always the favoured option and has entered into consultation on the 1975 Waste Oil Directive. The EU has yet to report, but it is to be hoped that a more environmentally aware policy may yet result and that the stated aims of the consultation process, namely that … *from an environmental point of view, each treatment operation should be judged principally in terms of how much impact it has on the environment. This approach, differentiating between scarcity and impact as environmental problems, was outlined in the Commission Communication* ***"Towards a Thematic Strategy on the Sustainable Use of Natural Resources".***

12 Conclusion

Environmental technology as applied to lubricants is related first and foremost to performance. The benefits to be gained from reduced wear and friction are substantial and in far outweigh all other aspects particularly in respect of CO_2, Climate Change and conservation of resources. There are environmental aspects of a lubricants performance, however, that when addressed can reduce what is after all a surprisingly small impact due to the inevitable losses that occur during use.

The perfect 'environmental' lubricant that was outlined in the Introduction does not, nor will it probably ever, exist. It is hoped that it is now apparent, however, that some of the ideal characteristics are not needed, and that those that are desirable are so for reasons of aesthetics and a desire to keep the environment clean, rather than for a compelling need to reduce toxicity and impact on ecosystems.

References

APAVE (1992) NF-Environment. Huiles et lubrificants moteurs. Projet de reglement technique. Rapporteur Michel Genesco. APAVE, Paris.

Barbieri, J.F., BenKinney, M.T., and Naro, P.A. (1993) Acute and chronic toxicity of petroleum base stocks to aquatic organisms. *Proceedings of Society of Environmental Toxicology and Chemistry (SETAC) Ecological Risk Assesment: Lessons Learned.* Houston, TX.

Battersby, N.S., Pack, S.E., and Watkinson, R.J. (1992) A correlation between the biodegradability of oil products in the CEC L-33-T-82 and Modified Sturm tests. *Chemosphere*, **24**, 1989–2000.

Battersby, N.S. (2000) Application of the CONCAWE Biodegradability test for oil products. *Journal of Synthetic Lubrication*, **17**(3), 225–232.

BenKinney, M.T., Novick, N.J., Cross, J.S., and Naro, P.A. (1991) Environmental characteristics of petroleum products and base stocks: an ecology assessment. *Proceedings of Society of Environmental Toxicology and Chemistry (SETAC) Conference on Environmental Interfaces: Scientific and Socioeconomic.* Seattle, WA.

Bennet, D., Girling, A.E., and Bounds, A. (1990) Ecotoxicology of oil products: preparation and characterisation of aqueous test media. *Chemosphere*, **21**, 659–69.

Benyon, L.R. and Cowell, E.B. (eds.) (1974) *Ecological Aspects of Toxicity Testing of Oils and Dispersants.* Applied Science, Barking.

Betton, C.I. (1992) Lubricants and their environmental impact, in *Chemistry and Technology of Lubricants* (eds. R.M. Mortier and S.T. Orszulik), Blackie, Glasgow, pp. 282–98.

Betton, C.I. (1994) Oils and hydrocarbons, in *Handbook of Ecotoxicology* (ed. P. Calow), Blackwell, Oxford, pp. 244–63.

Cain, R.B. (1990) Biodegradation of lubricants, in *Proceedings of 8th International Biodegradation and Biodeterioration Symposium*, Windsor, Ontario, Canada, 25–31 August 1990 (ed. H.W. Rossmoore), pp. 249–75.

CEC (1993) Biodegradability of two-stroke outboard engine oils in water. *Report CEC L-33-A-93*, Co-ordinating European Council for the Development of Performance Tests for Lubricants and Engine Oils, London.

Clark, R.B. (ed.) (1982) *The Long Term Effects of Oil Pollution on Marine Populations, Communities and Ecosystems*, Royal Society, London.

Coleman, W.E., Munch, J.W., Streicher, R.P., Ringhand, H.P., and Koffer, F.C. (1984). The identification and measurement of components in gasoline, kerosine and no. 2 fuel oil that partition into the aqueous phase after mixing. *Archives of Environmental Contamination and Toxicology*, **13**, 171–8.

CONCAWE (1985) The collection, disposal and regeneration of waste oils and related materials. *CONCAWE Report No. 85/5,.* CONCAWE, Brussels.

CONCAWE (1993) *Biodegradation Task Force on Method Development. Committee Research Programme*, CONCAWE, Brussels.

CONCAWE (1996) Collection and disposal of used oil, *Special Task Force WQ/STF 26 Report*, CONCAWE, Brussels.

CONCAWE (1997) Lubricating Oil Basestocks. Product Dossier submitted to EU on behalf of Oil Industry listing technical and toxicological information. Dossier No. 97/108. CONCAWE, Brussels, June.

CONCAWE (1999) A test method to assess the 'Inherent' Biodegradability of oil products. *CONCAWE* Report No. 99/59. CONCAWE, Brussels.

Edwards, N.A. and Hassall, K.A. (1971) *Cellular Biochemistry and Physiology*, McGraw-Hill, London.

EU (1975) The Waste Oil Directive. Council Directive 75/439/EEC of 16th June 1975 on the Disposal of Waste Oils and Subsequent Amendments.

EU (2000) The Waste Incineration Directive. 2000/76/EC.

EU (2005) Directive 75/439/EEC on Waste Oils. Consultation Document. http://ec.europa.eu/comm/environment/waste/oil/consultation.htm

Fox, M.F. (2006) Environmental implications and sustainability concepts for lubricants, *Handbook of Lubrication and Tribology*, 2nd Edn., Vol. 1, Application and Maintenance' (ed. George E. Totten), Taylor and Francis/CEC and STLE.

Gough, M.A. and Rowland, S.J. (1990) Characterisation of unresolved complex mixtures of hydrocarbons in petroleum. *Nature (London)*, **344**, 648–50.

Green, J. and Trett, M.W. (eds.) (1989) *The Fate and Effects of Oil in Fresh Water*, Elsevier Applied Science, Barking.

Howell, J.K., Lucke, W.E., and Steigerwald, J.C. (1996) Metalworking fluids: composition and use, in *The Industrial Metalworking Environment – Assessment and Control. Proceedings of the Symposium at Dearborn*. Michigan, USA, 13–16 November, 1995, American Automobile Manufacturers Association, Washington, DC, pp. 13–22.

Institute of Petroleum (1992) *UK Petroleum Industry Statistics: Consumption and Refinery Production 1990 and 1991.* Institute of Petroleum, London.

IARC (1983) *IARC Monographs on the Evaluation of the Carcinogenic Risk of Chemicals to Humans. Volume 32: Polynuclear Aromatic Hydrocarbons*, International Agency for Research on Cancer, Lyon.

Linnett, S.L., Barth, M.L., Blackmon, J.P. et al. (1996) Aquatic toxicity of lubricant additive components. *Proceedings of the Esslingen Tribology Colloquium*, 9–11 January, Vol. 2, pp. 871–82.

Maltby, L., Forrow, D.M., Boxall, A.B.A. et al. (1995a) The effects of motorway runoff on freshwater ecosystems: 1. Field study. *Environmental Toxicology and Chemistry*, **14**, 1079–92.

Maltby, L., Boxall, A.B.A., Forrow, D.M. et al. (1995b) The effects of motorway runoff on freshwater ecosystems: 2. Identifying major toxicants. *Environmental Toxicology and Chemistry*, **14**, 1093–102.

Mortier, R.M. and Orszulik. S.T. (eds.) (1992) *Chemistry and Technology of Lubricants*, Blackie, Glasgow.

OECD (1981) *Guidelines for Testing of Chemicals. Section 2: Effects of Biotic Systems*, OECD, Paris.

OECD (2003) Proposal for a new guideline 310. Ready Biodegradability – CO_2 in sealed vessels (Headspace Test) www.oecd.org/dataoecd/40/62/17131516.pdf

Painter (1992) *Detailed Review of Literature on Biodegradability Testing*, OECD, Paris.

Prince, R.J. (1992) Base oils from petroleum, in *Chemistry and Technology of Lubricants* (eds. R.M. Mortier and S.T. Orszulik), Blackie, Glasgow, pp. 1–31.

Pritchard, P.H. and Costa, C.F. (1991) EPA's Alaska oil spill bioremediation project. *Environmental Science and Technology*, **25**, 372–9.

Randles, S.J., Stroud, P.M., Mortier, R.M. et al. (1992) Synthetic base fluids, in *Chemistry and Technology of Lubricants* (eds. R.M. Mortier and S.T. Orszulik), Blackie, Glasgow, pp. 32–61.

SAE (1996) SAE Information report: international tests and specifications for automotive engine oils – SAE J2227, August 1995, *SAE Handbook 1996*, Society of Automotive Engineers, Warrendale, PA, pp. 1210–5.

Chapter 13
Climate Change Scenarios and Their Potential Impact on World Agriculture

C. Wallace[1] and D. Viner[2]

1 What causes the climate system to change?

The Earth's climate system is a complex interaction of a number of components, such as the ocean, atmosphere, ice masses (cryosphere) and living organisms (biosphere). Although the system is ultimately driven by solar energy, changes to any of the components, and how they interact with each other, as well as variability in the solar radiation received, can lead to a change in climatic conditions. There are many causes of climate change which operate on a variety of time scales. On the largest time scales are mechanisms such as the Milankovitch-Croll effect and geological processes.

The **Milankovitch-Croll** effect concerns the characteristic of the Earth's orbit around the sun and is thought to be responsible for governing the main glacial and interglacial episodes that are evident in the prehistoric climate record. Over a time scale of thousands of years variability is experienced in three important orbital characteristics. Firstly, the shape of the Earth's orbit is known to vary between that of a near-circle and a more exaggerated ellipse over a period of approximately 93,000 years. This controls how much solar radiation is received by the planet at a particular time during the year; a more circular orbit means less variation but an elliptic orbit will result in larger changes. A highly-elliptical orbit tends to *enhance* the seasons in one hemisphere and *moderate* them in the other. Many researchers cite this mechanism as the most important in triggering a glacial period due to cooler than normal summers which fail to melt seasonal snowfall in the middle and high latitudes.

The second Milankovitch-Croll effect concerns the tilt of the Earth's axis of rotation. The axial tilt is known to vary between approximately 21° and 24° over 40,000 years. A larger degree of tilt amplifies the seasons in *both* hemispheres. At present the axial tilt of the Earth is approximately 23.5° and appears to be on a descending leg of a 40,000 year cycle (Berger and Loutre, 1991).

[1]*National Oceanography Centre, Southampton, University of Southampton Waterfront Campus, European Way, Southampton*
[2]*Principal Specialist Climate Change, Science and Evidence, Natural England, Norwich, UK*

The final Milankovitch-Croll effect concerns the 'precession' of the north pole, that is where into space the north pole points. The procession has the smallest periodicity, about 20,000 years, and is independent of the axial tilt variations, but can affect the climate of Earth by altering the dates on which the closest and farthest distances to the Sun are achieved. Again, this affects the degree of seasonality which is experienced in each hemisphere. For example, the closest point between the Earth and the Sun at present occurs on January 4th, during the southern hemisphere summer.

Geological processes known to influence climatic conditions occur on an even longer time scale than orbital variations, but produce major changes. Continental drift or plate-tectonics occurs very slowly but can alter the climate by a number of mechanisms. Firstly movement of continental plates can upset and redirect ocean currents moving heat from one sector of the planet to another. Secondly, movement of the major continental plates adjust the latitude at which that particular land mass resides affecting the severity of seasonality and the mean annual temperature. Thirdly, continental drift is responsible for mountain range formation serving not only to cool the climate of the uplifted region, but redirecting atmospheric circulation which has climate implications for adjacent regions. It is important, though, to grasp the tardy nature of these effects; the location of the major continental plates has been approximately unchanged for the last 50 million years.

One geological process which affects climatic conditions on a much shorter time scale is **volcanism**. Large, explosive volcanic eruptions can inject huge amounts of soot and ash into the middle atmosphere where they are beyond the cleansing effect of rainfall forming processes. The strong winds typical of the higher altitudes are effective in transporting these particles around the planet where they reflect solar radiation back into space creating a 'global soot veil'. The climate impacts of volcanic event usually decay after one or two years, however, some evidence suggests that lower-frequency so-called 'super-eruptions' whereby whole regions are seen to erupt can alter the climate for enough time to cause radical species loss. Fortunately the return periods of these events is close to 50,000 years (Rampino, 2002).

In addition to geologic and orbital changes, the climate system is sensitive to inherent and periodic **internal variability** to any one of its components. A good example of this is the well known El-Nino event, where ocean upwelling in the Equatorial Pacific is weaker in one season than is the norm. The resulting changes to the wind patterns produces drought in some regions and floods in others as the weather systems respond to changes in sea surface temperatures. Other internal mechanism producing climatic changes include random (i.e. one off) changes to a particular ocean current which changes the pattern of heat distribution. It is important to acknowledge the **climate feedbacks** which exist and modify not only internal variabilities, but indeed any type of climatic change. For example, the ocean current switch might warm a high latitude region reducing its snow cover meaning more exposed land surface is able to absorb solar heat in the winter leading to even more warming. It is an overriding aim of climate science today to increase our understanding of such relationships and how internal processes relate to one another and might upset one component of the system and what climatic change might occur as a result.

Aside from the natural mechanisms capable of causing widespread changes to climatic conditions discussed so far, there is **anthropogenic climate change**, that is climate change caused by man's activity. This has many guises such as alteration of the planet's reflectivity and thermal properties by changing land cover type, but the most well-known anthropogenic influence concerns the enhanced greenhouse effect. Certain gases within the Earth's atmosphere are transparent to incoming energy, but opaque to outgoing heat and are responsible for maintaining an average global temperature of around 15°C. The greenhouse effect is natural, but since the industrialisation of many nations in the nineteenth century, additional quantities of greenhouse gases (namely CO_2) have been added to the atmosphere through the burning of carbon-rich fossil fuels. The vast additions to the atmosphere of CO_2 that have occurred in recent decades are now believed to have enhanced the natural greenhouse effect. Greenhouse theory and anthropogenic forcing of the climate system is discussed in greater depth in Section 3.

2 Past climatic changes

The Earth's climate system is changing today, but has experienced numerous changes in the past. Indeed, it is helpful to think of the climate system as constantly adjusting to the fluctuation in energy inputs and outputs (forcings) which result from the mechanisms explained in Section 1. Very recent climatic changes can be detected through analysis of thermometer readings. Reliable thermometer readings are generally accepted to have begun in the mid nineteenth century and accordingly the period from then up to the present is termed the **instrumental period**. However, climatic conditions can also be estimated further back in time through use of non-direct, **proxy**, measurements of climatic variables.

Climate reconstructions using the proxy method rely on a number of techniques, such as tree ring width data, analysis of ice core segments and chemical composition of ocean and geological sediments but to name a few. Proxy methods allow a reasonable estimate of temperature (and in some cases precipitation) for the past few thousand (tree ring) and hundreds of thousands (ice cores) of years. Whilst the *exact* dating of the latter records may be difficult the data are nonetheless sufficient to identify major climatic adjustments and help to place very recent climate change in the context of pre-human variations.

Analysis of oceanic and geological sediment has established that during the course of the past 800,000 years the Earth has experienced a number of warm **interglacial** and cold **glacial** periods, each of which last several (and maybe tens of) thousands of years. It is also possible to determine that we are currently experiencing a warm interglacial period which began approximately 10,000–12,000 years ago and marks the start of the current epoch, the **Holocene** (e.g. Lamb, 1977). The changes in temperature which accompanied the switch from the last glacial to the present interglacial period were not smooth and varied greatly over the planet. However, work focusing upon the British Isles has estimated that between 13,300 and 12,500 years before present, the mean temperature rose by 7–8°C in summer and ~25°C in winter (Atkinson et al., 1987).

With the advent of the Holocene Epoch and the flourishment of civilisations in the warmer climates, written historical records point to a number of climatic changes that have occurred over the past one to two thousand years. Lamb (1977) notes historical writings that suggest the period between 900 and 300 BC were especially cold over Europe; Roman writers reported severe winters in Italy, which match records of glacial advances within the Alps (Hueberger, 1968). Conversely, the final century BC seems to have been warmer and indicative of the onset of a less harsh climatic period. For instance, records suggest that Roman agriculture extended north and the Alpine Glaciers retreated (Lamb, 1977).

Several climate reconstructions based upon proxy records (particularly tree ring widths) have recently become available with which to investigate climatic changes in the last 1000 years (Figure 13.1). The last millennium is generally accepted to have experienced three main climatic epochs. The '**Medieval Warm Period**' characterised the climate of the 12th and 13th centuries, and was followed in the 16th and 17th centuries by the '**Little Ice Age**'. The final, more recent, climatic event has been **post-industrial warming**. The dates of the first two events are often the topic of much debate, particularly because many of the information pointing to their existence appears to vary in timing for different parts of the planet. Indeed, whether or not the terms are actually applicable in describing the average climatic conditions of the time is also increasingly questioned. Lamb (1977) cited colonisation of high-latitude regions and evidence of vine cultivation in Britain as evidence supporting a pronounced Medieval Warm Period (MWP) for Europe at least. However, others (e.g. Jones, 2002)

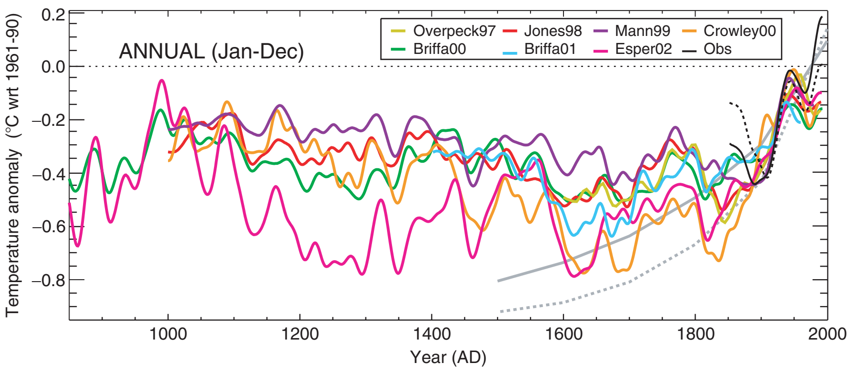


FIGURE 13.1. Estimated and observed temperature curves.

question the validity of the MWP pointing to a lack of a distinct rise in the proxy temperature record for the northern hemisphere average at this time and citing other reasons why agricultural changes may have occurred. The caveat is that, whilst some individual evidence may point to a warmer epoch, it is dangerous to infer a widespread warming event without hard and fast facts.

What is evident from many of the curves in Figure 13.1 is the existence of a cooler period during the 16th and 17th centuries. Glacial advances within Europe have been shown to be widespread and loss of agricultural land would have resulted. Many reconstructed climate records indicate that the coldest annual temperature in the last 1000 years occurred in 1601 (Jones, 2002). Nonetheless, the validity of the actual Little Ice Age has, like the MWP come under question itself. Some researchers point to the fact that many individual years during the Little Ice Age period saw temperatures as warm as present levels (Jones, 2002) and glacial advances occurred at different times during the supposed 'cold' centuries.

In 1815, as more reliable instrument-based measurements were becoming more frequent, the Indonesian volcano of Tambora causing a classic soot veil effect. The climatic and agricultural implications of the eruption were severe. Cool weather endured over northeastern USA, Canada and Europe the following year leading to catastrophic crop failures and a year 'without a summer' (e.g. Oppenheimer, 2003), highlighting the sensitivity of the climate system (and global agricultural) to violent, explosive eruptions.

The third climatic event of the last 1000 years, **post-industrial warming**, can clearly be seen in the observed instrumental record (the black curve in Figure 13.1 and a more detailed curve, Figure 13.2) and lends weight to the argument of human-induced climate change. Two warming events are

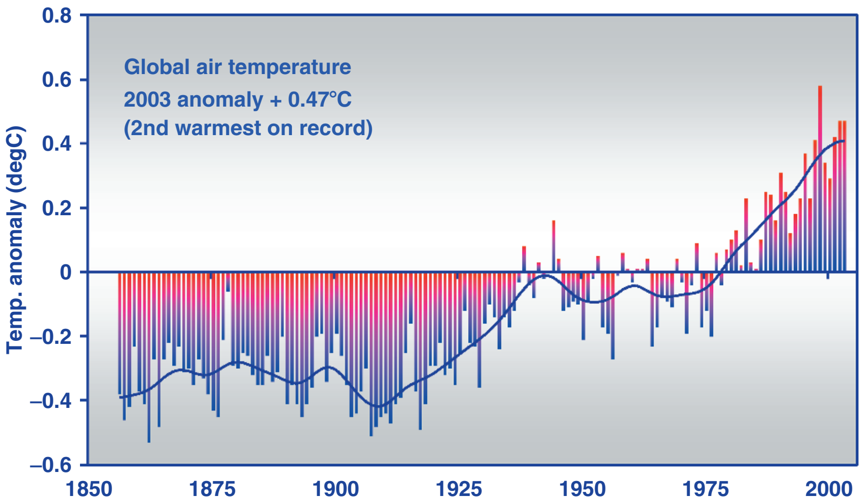


FIGURE 13.2. The observed temperature record.

apparent and these constitute the *only* statistically-significant events of the instrumental record (Jones, 2002). The first warming period occurred between 1920 and 1945; the second since 1975. Analysis of the observed record, in the context of the last 1000 years, reveals that the 1990s have been the warmest decade globally, and that 1998 was the warmest individual year. The lower, global curve in Figure 13.2 shows that compared to temperatures representative of the late 19th century, 1998 was ~0.8°C warmer.

The instrumental record indicates that this warming has affected the middle-high latitudes of the northern hemisphere the most with winter months warming more rapidly than summer months. For these regions, insofar as agriculture is concerned, an extended growing season has also been observed in some records (e.g. Menzel and Fabian, 1999), although changes to the rainfall regime of any individual region can complicate potential agricultural benefits.

3 Anthropogenic forcing of the climate system

Anthropogenic forcing of the climate system is primarily achieved through the release of greenhouse gases to the atmosphere as a result of industrial (and to a lesser extent agricultural and domestic) activities. These gases include CO_2, CH_4 (methane) nitrous oxide and halocarbon gases (which also have ozone-depleting characteristics).

Greenhouse gases vary in their ability to intercept outgoing radiation. For example methane is a very chemically efficient greenhouse gas, but the gas most commonly associated with anthropogenic forcing is CO_2, due to its greater abundance within the atmosphere. Measured levels of CO_2, methane and nitrous oxides via instrumentation and analysis of air trapped in ice cores for the past 1000 years show marked and unprecedented increases in atmospheric concentrations in recent times (Figure 13.3). The commencement of these increases coincides with the rapid industrialisation of the northern hemisphere during the late 18th and 19th centuries.

Since 1750, the global atmospheric concentration of CO_2 has increased by 31%. Analysis of extended data sources indicate the current atmospheric concentration of CO_2 is the highest for the past 420,000 years, and is likely to be the highest within the last 20 million years (IPCC, 2001). The percentage increase in methane concentrations is greater, having risen 151% since 1750, whilst concentrations of nitrous oxide have risen by 17% (IPCC) over the same period.

The impact that changes in the atmospheric concentration of any one greenhouse gas might have on the thermal properties of the atmosphere can be measured in terms of **radiative forcing**. In a steady, or unperturbed, state, the amount of energy leaving the top of the Earth's atmosphere *must* exactly match the amount of energy entering the system. If the energy input or output becomes unbalanced (i.e. does not exactly match) through either an increase in solar energy entering the system *or* a decrease in the energy

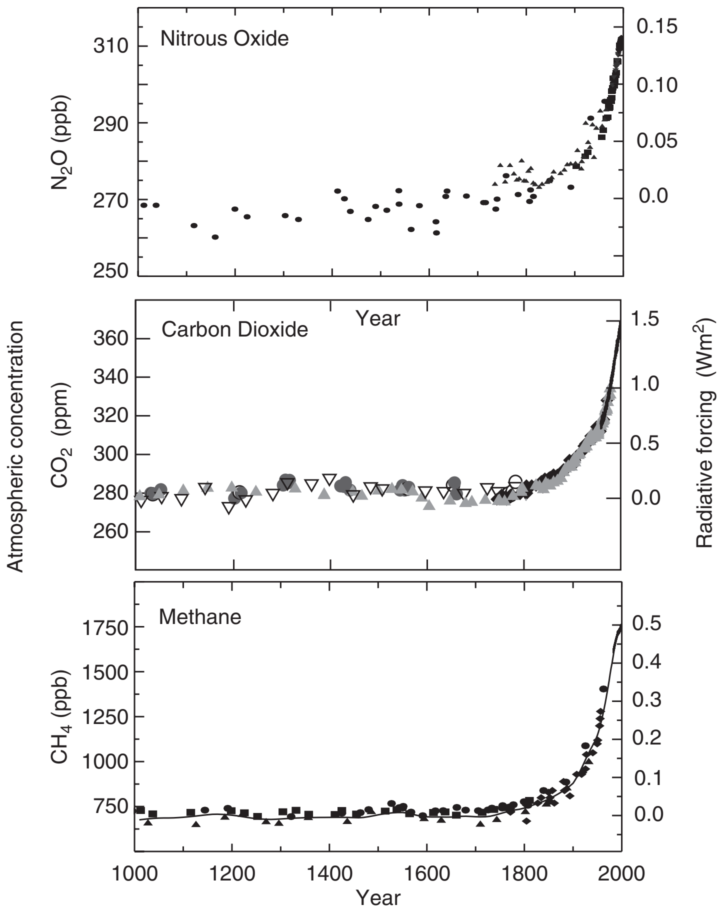


FIGURE 13.3. CO_2, NO_X and CH_4 curves over last 1000 years.

able to leave the planet's atmosphere, then there is said to be a radiative forcing placed upon the system. This extra energy is expressed in watts per metre squared (the area referring to the top of the Earth's atmosphere, where the climate system is separated from space) and results in the climate system altering its temperature in order to emit more energy and once again achieve a steady balance.

The elevated radiative forcing associated with the increased concentrations of the three main greenhouse gases are shown on the right-hand axis of Figure 13.3, although there are some uncertainties regarding these values. In total, however, increased atmospheric concentrations of CO_2, CH_4 and nitrous oxides are estimated to have placed an additional 2.1 Wm^2 of radiative forcing onto the climate system since 1750 (IPCC, 2001).

Exactly how the climate system might respond to such an alteration to its energy balance has been the quest of climate science for many years. The resulting change in temperature necessary to restore the system to equilibrium depends upon a whole host of factors and is generally referred to as the **climate sensitivity**. Nonetheless, computer simulations of the Earth's climate indicate that the level of observed global warming evident in the instrumental record is consistent with the estimated response to the additional anthropogenic radiative forcing. It is this fact along with the geographical pattern of the observed warming that has led the IPPC to conclude that 'in the light of new evidence and taking into account the remaining uncertainties, most of the observed warming over the past 50 years is likely to have been due to the increase in greenhouse gas concentrations' (IPCC, 2001).

4 Future changes in anthropogenic forcing

Projections of future climate change can be developed by computer simulation of the Earth's climate system. Simulations must consider likely future changes to both natural and anthropogenic radiative forcing. In respect of the latter, the IPCC (2001, mitigation report reference) has devised six possible future scenarios which attempt to quantify future greenhouse gas emissions through to the year 2100. Estimates of greenhouse gas emissions in each of the six scenarios are based upon changes that may occur in important social and economic factors (e.g. global population, degree of globalisation, investment and use of sustainable energy sources, etc.).

The six scenarios and their associated changes in social and economic factors are summarised in Figure 13.4 (SRES, Special Report on Emissions Scenarios). The first three scenarios are representative of the **A1** world. In this world, rapid economic growth occurs throughout the 21st century, coupled with an increase in globalisation characterised by regional convergence and increases in social and cultural interactions. Although population increases for the first part, it peaks and begins to fall by the end of the 21st century. Differences in regional income become lower. What distinguishes each A1 scenario from the other is their projected energy sources.

A1FI represents a future world which remains fossil fuel intensive. Conversely, in the **A1T** scenario the technological emphasis is upon non-fossil fuels; **A1B** represents a balance between the two. The 'environment' column in Figure 13.4 represents the differences in A1 energy sources. Accordingly the A1FI scenario (along with the A2 world) has the highest projected anthropogenic climate forcing, whilst A1T achieves one of the lowest forcings (along with the B1 scenario).

Like the A1 scenarios, the **B1** scenario also considers an eventual decline in global population and a move towards a more globalised community. Economic growth also continues but restructuring results in a service and information based economy. The material consumption of society decreases, and emphasis is placed up social, economic and environmental sustainability via global solutions. This scenario is similar to A1T, except that there are no additional climate driven initiatives to restructure energy sources.

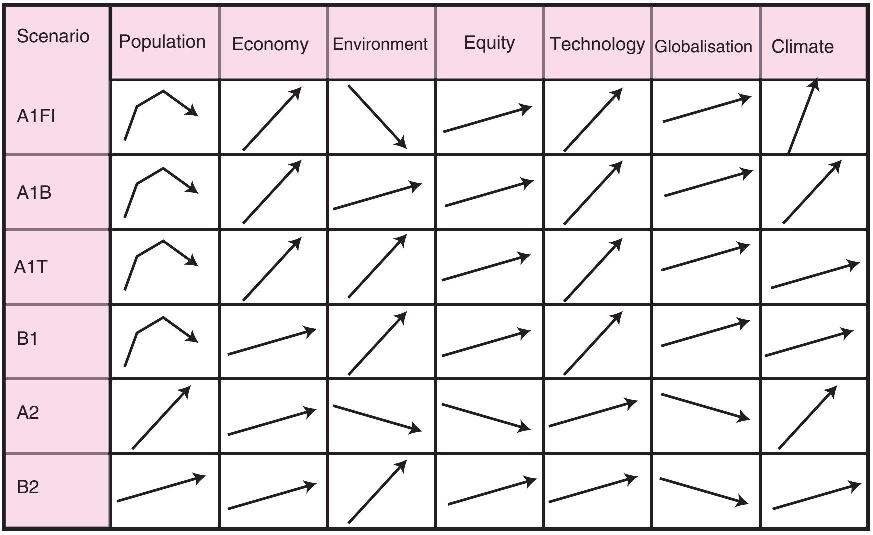


FIGURE 13.4. Summary of effects of the SRES scenarios.

The **A2** scenario envisages a world slow to globalise, where regional preservation is emphasised and the underlying theme is *self*-reliance. Fertility patterns are slow to homogenise across the planet and the global population continues to rise. Although economic growth and technological advancement continues, they do so regionally and are more fragmented than in other scenarios. This scenario therefore results in a high anthropogenic forcing of the future climate.

Finally, the **B2** scenario represents a regional world (like A2), but with an emphasis upon achieving economic, environmental and social sustainability via *local* solutions (compare with B1 where the same aims exist, but the solutions are *global* in nature). Although the global population continues to rise, the rate of increase is smaller than in the A2 scenario.

5 Implications of SRES scenarios on global climate

Projections of future climate change during the present century can be made by simulating the Earth's climate using complex global circulation models (GCMs). GCMs are mathematical approximations of the real physical climate system and are able to model the transport and exchange of energy between a number of the climate system's components. For example, all GCMs used by the IPPC to develop future climate change scenarios have interactive atmospheric and oceanic components, including representation of seasonal sea ice. Most GCMs also have an interactive land surface scheme which simulates the moisture and energy fluxes between the ground and the atmosphere; these fluxes change geographically within the model depending upon the imposed land surface type.

Although GCMs represent the most complex and cutting edge tools with which to project future climate change, there are many uncertainties associated with their results which should be acknowledged. For instance, some real-world climate system components are poorly understood, and so their approximation by mathematical equations is difficult. A good example of this, and a major ongoing debate in climate change, is the role that changing characteristics of clouds might play on the future climate. Uncertainties in the future climate projections also arise via the constraints and costs associated with the current level of computing power. For example, although some physical processes are very well understood it is necessary to simulate them on a crude geographical scale so that the cost of running simulations is kept practical. However, specific regional climate models (RCMs) have also been developed for specifically simulating the climate of a singular region only (as opposed to the whole globe). RCMs are able to approximate processes on a finer geographical scale and some of their results are considered in Section 6. The focus in this section, however, is the *global* response of the climate system to future changes in forcing.

5.1 Temperature

Due to the abnormally high levels of CO_2 in the Earth's atmosphere at present temperature increases can be expected during the present century even if all greenhouse gas emissions were to cease immediately. Such an event is, of course very unlikely; the SRES scenarios provide outlines for more likely changes in anthropogenic forcing in the coming century and are described in Section 4. The mean global temperature response to each SRES scenario (Figure 13.5) is different, reflecting the extent to which greenhouse gas emissions either stabilise, decrease or rise during the 21st century. For example, the temperature response in a fossil-fuel intensive future (A1FI, red small dotted line in Figure 13.5) by the year 2100 could be anywhere between ~3.0 to 5.8°C above mean 1961–1990 conditions. However, if a B1-type scenario is followed in the present century (green line Figure 13.5) then the temperature response, although positive, may be somewhat lower, in the range of ~1.4–2.6°C above the 1961–1990 'normal'. Acknowledging this range, the IPCC concluded in their third assessment report that 'the globally averaged surface temperature is projected to increase by 1.4 to 5.8°C over the period 1990–2100' (IPCC, 2001a). With this increase in mean surface air temperature, there are expected to be more frequent extreme high temperature events, and a lower frequency of extreme low temperature events.

The projected temperature increases are larger than those previously estimated (e.g. IPPC, 1995). This is due to the lower projected sulphur emissions in the SRES scenarios than in their predecessors. Sulphate aerosols have a negative forcing upon the climate system, reflecting incoming solar radiation

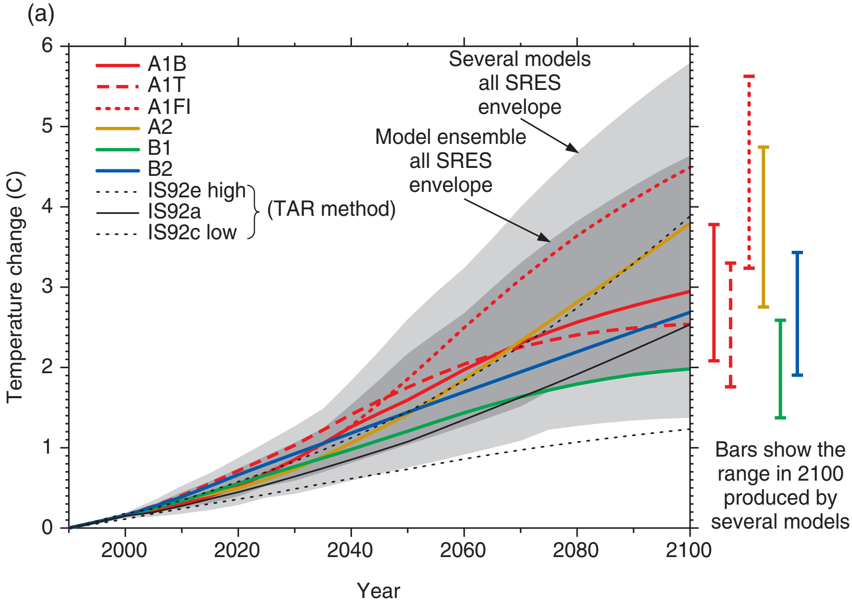


FIGURE 13.5. Mean global temperature change in 21st century.

and acting to offset some of the greenhouse-related warming. Sulphate aerosols are also responsible for the smaller *differences* in projected temperature increases between the SRES scenarios for the next 50 years or so depicted in Figure 13.5. In fossil fuel intensive scenarios (e.g. A1FI and A2) the rise in greenhouse gases is also accompanied by an increase in sulphate emissions (the greenhouse warming is therefore partly offset). Conversely, in scenarios where emissions of atmospheric pollutants decrease, lower levels of greenhouse gases are matched by lower levels of sulphur emissions (and the offsetting is lower). The net temperature changes in the near-term therefore are broadly similar. It is not until the second half of the 21st century that the longer-lived greenhouse gases such as CO_2 dominate over the sulphur emissions and the temperature responses diverge (IPCC, 2001).

5.2 Precipitation

As with temperature, *globally-averaged* precipitation is projected to rise during the 21st century. The precipitation increase can be directly linked to the rise in temperature. Not only do evaporation rates increase under warmer conditions, but a warmer atmosphere is also able to hold more moisture. The IPPC (2001) also indicate that increased levels of precipitation will be accompanied by a simultaneous increase in precipitation variability; although on average more rainfall will fall this may be delivered by short, intense outbursts leaving other periods prone to drought.

The average global precipitation response under the IPCC A2 scenario for the final 30 years of the 21st century is 3.9%, compared to mean 1961–1990 conditions, with a range of 1.3 to 6.8%. The B2 scenario, having a lower anthropogenic forcing, responds with a lower increase of precipitation, 3.3%, with a range of 1.2 to 6.1% for the same time period (IPCC, 2001). Accompanying the trend towards a wetter planet, there is evidence to suggest that the additional precipitation will be delivered by more intense precipitation events (IPCC, 2001).

5.3 Sea level rise

The range of projected globally-averaged sea level rise in the 21st century is large, lying between 0.09 and 0.88 m for the full set of SRES scenarios according to the IPCC (Figure 13.6). The mean increase by the year 2100 is 0.48 m which represents a two to four increase in the rate of sea level rise which was recorded in the 20th century. The amount of sea level rise experienced in each scenario differs only slightly in the first half of the 21st century (for those same reasons outlined in Section 5.1). Greater inter-scenario differences can be seen in the years after 2060, with larger rises in sea levels associated with the fossil-fuel intensive scenarios.

The majority of the projected sea level rise is due to thermal expansion of the oceans as the planet becomes warmer. Additional sea level rise is caused

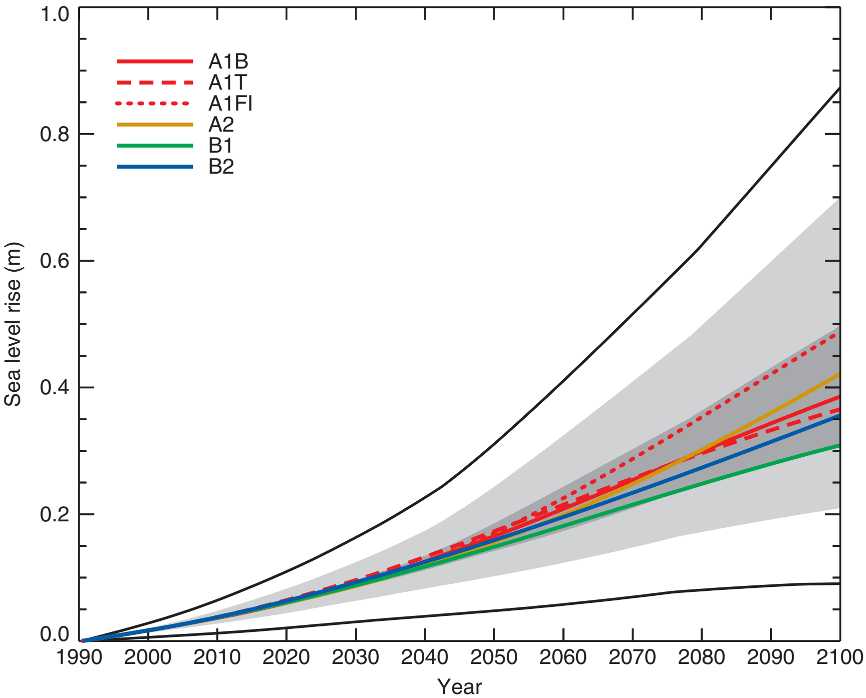


FIGURE 13.6. Sea level rise for each scenario.

by the input of fresh water from glaciers and the major ice sheets of Greenland and the Antarctic.

5.4 Mitigation possibilities within the agricultural sector

The magnitude of temperature, precipitation and sea level change depends upon which SRES scenario best describes the future levels of greenhouse gas emissions. Since the ratification of the Kyoto Protocol many of the world's governments are now committed to reducing greenhouse gas emissions to at least 5% beneath their recorded emissions in 1990. Much of the focus in meeting these commitments has addressed how to lower greenhouse gas emissions from the major sources, such as transportation and energy production. However, there are opportunities to lower emissions within other sectors and agriculture is no exception, and in itself is responsible for 20% of all anthropogenic greenhouse gas emissions (mainly in the form of methane and nitrous oxides).

Significant reductions in agriculturally-sourced greenhouse gas emissions can be achieved by 2010 through a change in a number of agricultural practises, outlined in the 2001 report of the Third Working Group (IPCC, 2001 WG3). For instance, a reduction in land use intensity and employing conservation tillage techniques (to protect the top soil) would both act to increase (or at least maintain) soil carbon uptake. Rice paddy fields are a major source of methane, the warm, shallow waters being ideal for methanogenisis; a shift towards rice crop varieties which can be grown under drier conditions would reduce emissions from this source. Another source of methane emissions is livestock. Shifting from meat to plant production would help in this case.

Insofar as nitrous oxides are concerned, significant reductions in agricultural emissions could be achieved by altering fertilising methods. One option is to replace the use of synthetic nitrogen sources with organic manures. Slow-release fertilisers and genetically-modified leguminous plants are also available, both of which limit the amount of nitrous oxides released into the atmosphere.

6 Implications of SRES scenarios on regional climate

When viewed globally, the likely future climatic changes to the SRES scenarios can be summarised fairly simply. A warmer, wetter world seems likely. But for each region of the planet the response is not so straight forward. Changes to the climate may not reflect the global response, or may do for one season but not for another. This section examines in more detail projected regional changes in climate for the current century.

6.1 Europe

Seasonal changes in temperature for Europe, compared with the mean global temperature change, under the A2 and B2 SRES scenarios are summarised in Figure 13.7. Two main patterns of change are apparent. In northern Europe,

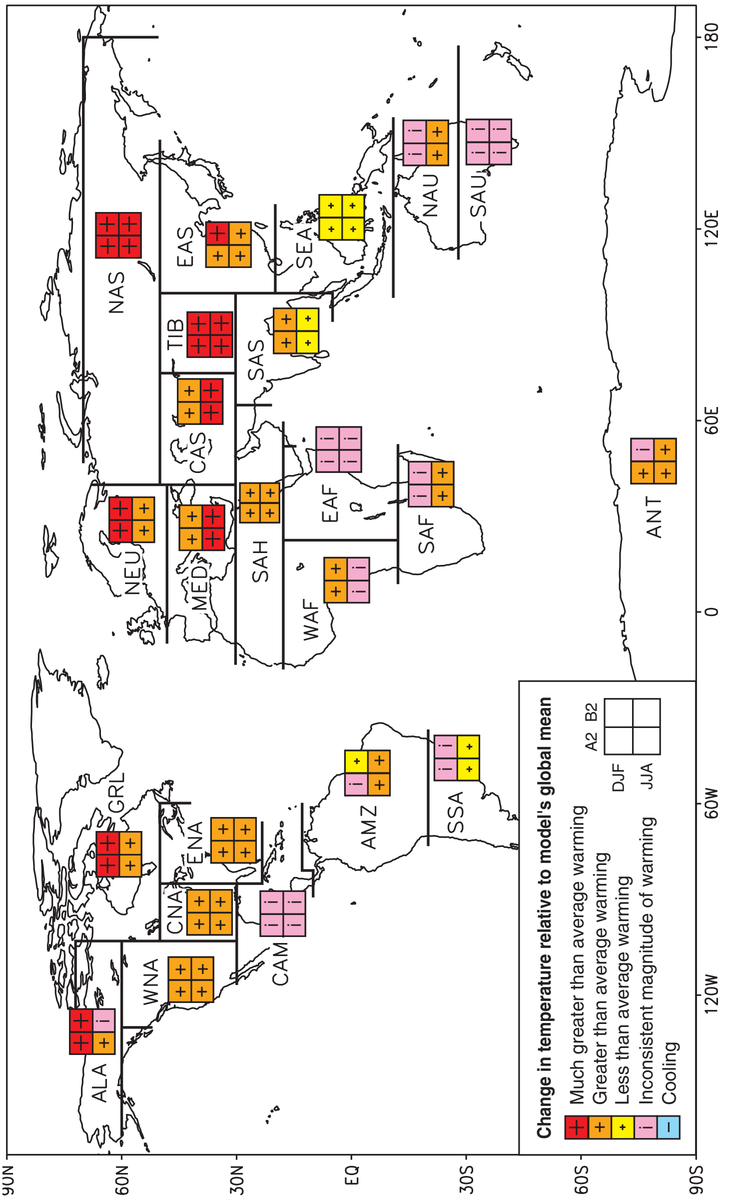


FIGURE 13.7. Regional temperature changes compared to global change.

more warming occurs in the winter months, whereas for the Mediterranean, greater warming occurs in the summer. The rate of annual warming for the present decade is projected to be between 0.1–0.4°C per decade.

An example of the pattern and magnitude of the projected summer warming over Europe (for the B2 scenario) is shown in Figure 13.8. Values are expressed as changes from the mean 1961–1990 period. The largest warming occurs over southern Europe, where by the end of the century summers 4.5°C warmer than the climatological norm are expected. There is, however, some level of uncertainty associated with these projections and the 'range' values in the right-hand panel acknowledge this, providing the absolute range of all GCM simulations used to assemble the projection. Summer warming over northern Europe, although smaller in magnitude, still amounts to ~2.0°C in places. In winter, Eastern Europe and western Russia warm the quickest (0.15–0.6°C per decade, IPCC, 2001 WG3), although by the 2080s over the whole of Europe, 'cold winters' (which were calculated to occur one in every ten years during 1961–1990) virtually cease to occur (IPCC, 2001 WG3).

GCM projections of European rainfall agree that wetter winters are probable over northern Europe in both the A2 and B2 scenarios (Figure 13.9). The rate of this change is estimated to be between 1 and 4% per decade. The change is smaller over southern Europe, where the main response appears to be a drier summer climate. However, accurate simulation of rainfall by GCMs is difficult, and this point is well illustrated in Figure 13.10, showing projected changes in summer under the B2 scenario. Firstly, the lack of values in some of the grid boxes indicates that the projected changes are not statistically significant from the variability in rainfall that is experienced within the climate model when it is run under 'normal' conditions (i.e. no change to future climate forcing). It is not until the 2080s that significant changes are visible, and, even then, the range of the projected changes is often greater than the median change, indicating that even the sign of the change may be incorrect.

It is also probable that the incidence of extreme weather events over Europe will increase as the planet continues to warm. This is especially so for hot summer events (the frequency of extreme cold events will fall) and for intense winter precipitation events. Indeed, there is compelling evidence that the latter trend is becoming noticeable already (Osborn, 2001).

Much work has also addressed the possibility of a collapse of the thermohaline circulation (THC) responsible for maintaining the Atlantic Gulf Stream. A complete collapse of the THC is possible if the anthropogenic forcing undergoes marked increases in the next decade (e.g. a quadrupling) and is applied to the climate system for long enough (Manabe and Stouffer, 1994). More plausible, however, is a weakening of the THC of around 20–50% due to the influx of fresh water into the North Atlantic from increased precipitation and ice melt (Rahmstorf, 1999). Nonetheless, the amount of cooling which might be associated with a THC weakening is not sufficient to negate the direct greenhouse warming, and so the net effect of Europe remains a warmer climate (IPCC, 2001 WG1)

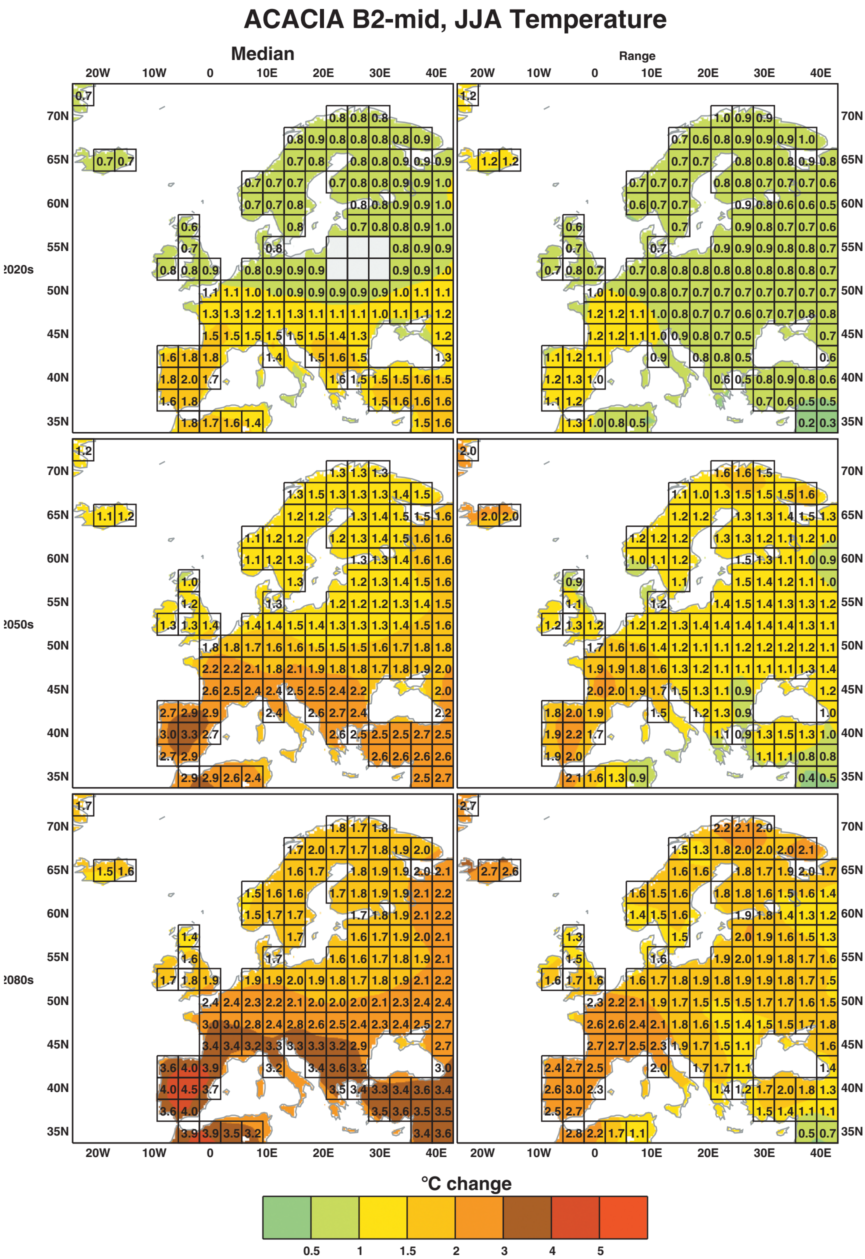


FIGURE 13.8. European summer temp changes (taken from acacia).

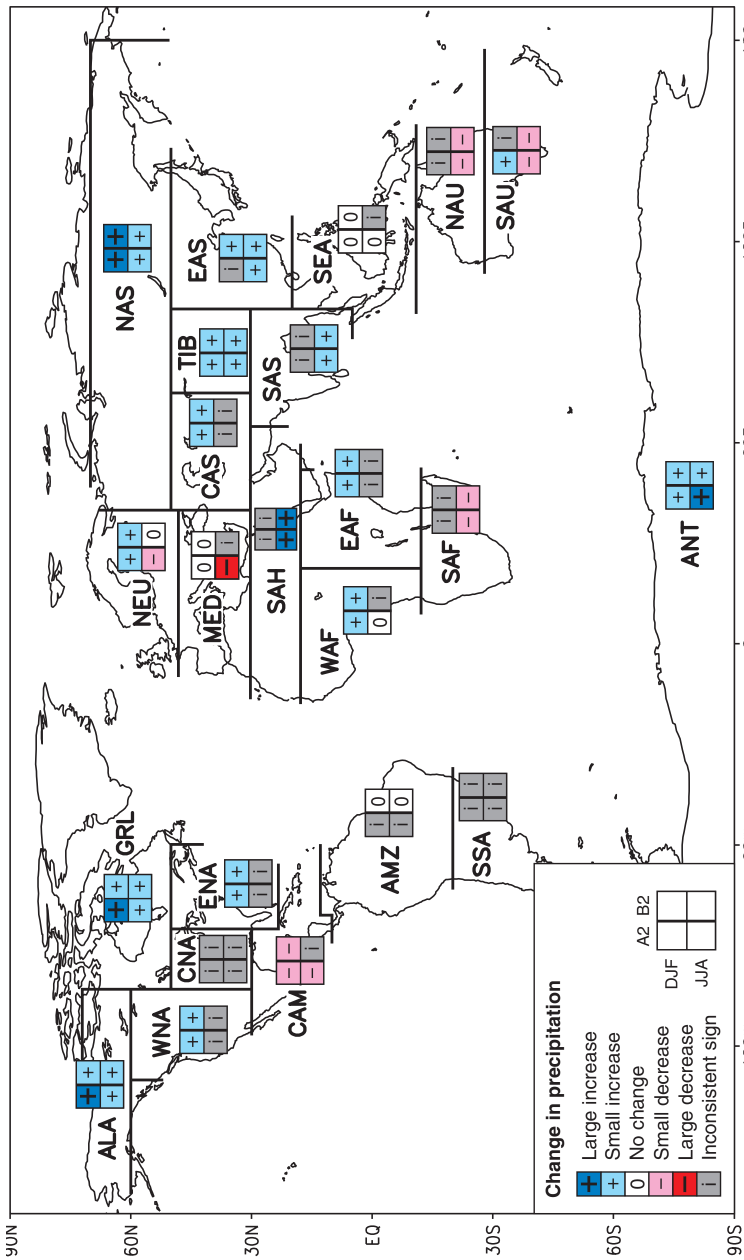


FIGURE 13.9. Regional rainfall changes.

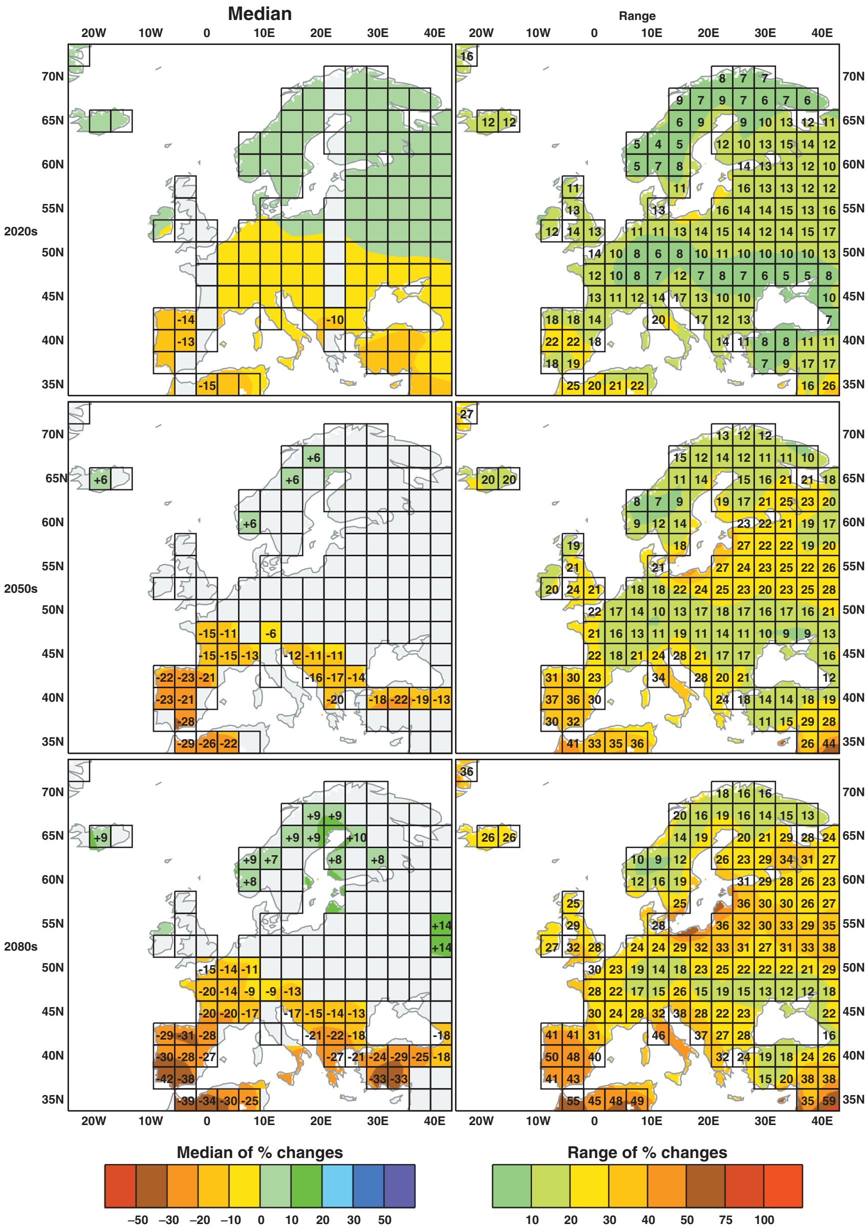


FIGURE 13.10. European rainfall maps (taken from acacia).

6.2 North America

Relative to the *global* temperature changes projected under the IPCC SRES scenarios, 'greater than average' warming is expected over North America in the 21st century (Figure 13.7). For the majority of the continent, the warming is consistent in both winter and summer seasons, but polar and sub-polar high latitudes tend to exhibit a greater amount of warming in the winter months in the climate model simulations used to construct the regional scenario. If a low-emission type scenario (e.g. B1) transpires in the 21st century, the amount of projected warming by the year 2100 is likely to be between 1–3°C. However, under a higher-emission type scenario, such as A2, the range of projected warming lies between 3.5–7.5°C. However, even the former scenario incurs a greater warming in the forthcoming 100 years than has been observed in the past 100 years over the continent (IPCC, 2001 WG2). Experiments conducted using one leading GCM (the United Kingdom Meteorological Office's coupled ocean-atmosphere climate model) also indicate that within a warmer climate, the Central North American region (35°–50°N, 85°–105°W) experiences an increase in summer temperature variability. Winter temperatures, whilst warmer, show a decrease in variability (Beersma and Buishand, 1999).

Projections of future precipitation are more variable. Some of the GCMs used to assemble the regional future projections exhibit substantial increases over North America, whilst others suggest only a very small increases. However, evidence from IPCC (2001, WG1) suggests that for the continental mid latitudes, 'small' increases (defined as 5–20% compared with present-day levels) in winter precipitation are likely (Figure 13.9). The sign of precipitation changes in summer are inconsistent between each climate model making confident projections impossible.

In general, winter increases are greater in the higher latitudes, amounting to more than 20% compared with present-day levels under the A2 scenario. Although the projected precipitation increases dominate in winter, it is expected that much will fall as rain, rather than snow, due to the simultaneous warming. Accordingly, shorter snow accumulation periods are expected in the 21st century (IPCC WG2).

7 Impacts of future climate change on agriculture

As much as the effects of future climate change vary from region to region, the same can be said of the implications of any change upon agriculture. For example, projected temperature increases may well be of benefit to farmers located in the temperature mid-latitudes, but not so beneficial for those within equatorial or tropical regions, where crops already grow close to the limits of their heat tolerance (Parry et al., 1999). Indeed, the agricultural implications of any change in climate must consider a number of factors, such as the seasonality of temperature/precipitation changes, changes to the hydrological cycle and possible changes in soil fertility. Here, a brief outline of the probable implications upon agriculture within Europe and North America as a result of climate change in the next century is presented.

7.1 Europe

Many studies identify conflicting changes to cereal production between western and eastern Europe. The latter, already possessing a continental-type climate (drier than the west), may experience an even drier climate leading to a decrease in cereal crop yields. Parry et al. suggest that decreases in cereal yield may become evident over this region as soon as the 2020s. Other areas where cereal production may be expected to decrease due to a combination of temperature and precipitation changes include southern Spain and Portugal (IPCC WGII). Elsewhere, many regions will experience an increase in wheat crop yield (Figure 13.11). Harrison and Butterfield (1999) suggest that over much of Europe, the increase is primarily a result of elevated CO_2 concentrations, rather than a direct response to increased temperatures. That said, increases in crop yield over Ferno-Scandinavia are probably a direct response to temperature changes as the zone of favourable wheat-growing conditions migrates north.

The implications of warmer temperatures for vegetable agriculture are mixed. On the one hand, vegetables whose growth is inhibited by flowering may experience decreased yields over much of Europe due to warmer temperatures and hence shorter growth opportunities. A similar change is expected in the yields of many seed crops too, again because their growth is determinate (Peiris et al., 1996). On the other hand, crops such as carrots will benefit from elevated temperatures (Wheeler et al., 1996). Other vegetables, for example lettuces, show little sensitivity to projected temperature changes, but their yield will benefit from increased CO_2 concentrations (Pearson et al., 1997).

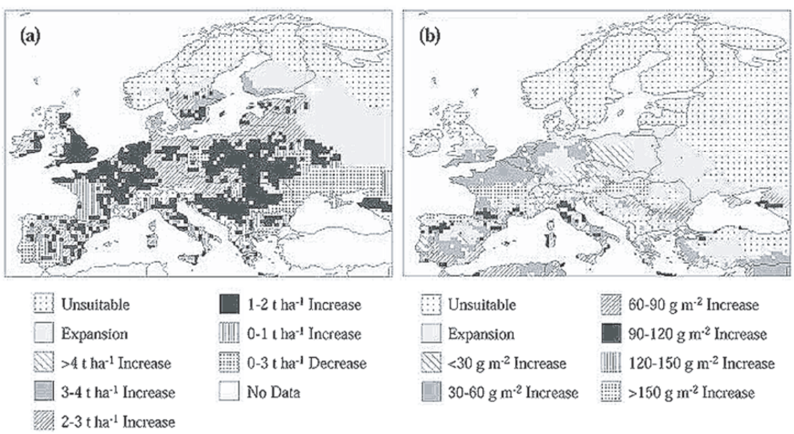


FIGURE 13.11. Change in water-limited yield for wheat (a) and potential yield for grapevine (b) using HadCM2 scenario for 2050 (Harrison and Butterfield, 1999).

Projected temperature increases are also likely to lead to a northwards expansion of the areas suitable for perennial crop growth. However, there is also additional evidence that increases in the year-to-year variability of yield amount and quality are possible (IPCC WGII).

Finally, future climate change will also influence livestock farming. These influences may be direct, such as the additional heat stress place upon animals during more frequent hot summers, or indirect, such as changes to pasture distributions (IPCC 1WG2). Nonetheless, some positive influences may also transpire, most notably the increased welfare of animals during milder winters, coupled with the reduced need for feed and heating.

7.2 North America

As is the general case within Europe, implications of climate change for North American agriculture are generally beneficial over northern regions, and adverse over the southern ones. Within the higher latitudes, and Canada especially, warmer temperatures lead not only to an expansion of suitable arable land, but also to an increased growing season (Brklacich et al., 1997). Such changes will especially benefit yields of corn and soybean (IPCC WG2). The gains are not exclusively confined to Canada, however. Within the United States, Reilly et al. (2000) identified the lake and mountain states in addition to the Pacific region as the main locales expected to benefit from temperature changes. Work by Rosenzweig et al. (1995) suggests a positive wheat yield response to temperature changes can be expected if the regional warming is less than 2°C. Warming over 5°C, however, produces a negative yield response. It is this level of warming, in conjunction with an increased demand for irrigation (as a combined result of reduced precipitation and increased evapo-transpiration) that leads to a reductions in cereal crop yield over many the south southern states in agricultural climate impact simulations (Peart et al., 1995).

Rising temperatures are expected to shift the citrus-growing thermal regime northwards; some central states may therefore benefit from this migration, but incidents of excessive winter heat are likely to reduced fruit yield further south, in places such as Florida and Texas.

Overall, the IPCC (2001 WG2) indicate that the net gains in arable production will exceed the losses, and therefore economic benefits for the consumer will result in North America as prices fall. However, how the level of certainty to be placed on this conclusion is unclear. At least one other study (e.g. Parry et al., 1999) reports a reversal in the sign of future arable production change when an agriculture production model is driven with the latest version of a climate model, due to changes in precipitation regimes.

The negative effects of regional climate change over North America are likely to outweigh any gains, where livestock farming is concerned. In particular extreme summer heat will adversely affect livestock farming in the Appalachian states and the southern plains.

References

Atkinson, T.C., Briffa, K.R., and Coope, G.R. (1987) Seasonal temperatures in Britain during the past 22,000 years, reconstructed using beetle remains. *Nature,* **325**: 587–592.

Berger, A. and Loutre, M.F. (1991) Insolation values for the climate of the last 10 million years. *Quaternary Science Reviews*, **10**: 297–317.

Beersma, J.T. and Buishand, T.A. (1999) A simple test for equality of variances in monthly climate data. *Journal of Climate*, **12**: 170–179.

Brklacich, M., Bryant, C., Veenhof, B., and Beauchesne, A. (1997) Implications of global climatic change for Canadian agriculture: A review and appraisal of research 1984–1997. In: *Chapter 4, Canada Country Study: Climate Impacts and Adaptation*. Environment Canada, Toronto, ON, Canada.

Harrison, P.A. and Butterfield, R.E. (1999) Effects of climate change on Europe-wide winter wheat and sunflower productivity. *Climate Research*, **7**: 225–241.

IPCC (2001a) *Climate Change 2001: The Scientific Basis*, Cambridge University Press.

IPCC (2001b) *Climate Change 2001: Impacts, Adaptation, and Vulnerability*, Cambridge University Press.

IPCC (2001c) *Climate Change 2001: Mitigation*, Cambridge University Press.

Jones, P.D. (2002) Changes in climate and variability over the last 1000 years.

In: *Meteorology at the Millennium* (Ed. R.P. Pearce), Academic Press, pp. 133–142.

Lamb, H.H. (1977) *Climate: Past, present and future. Volume 2*. Meuthen, London.

Menzel, A. and Fabian, P. (1999) Growing season extended in Europe. *Nature,* **397**: 659.

Manabe, S. and Stouffer, R.J. (1994) Multiple-century response of a coupled ocean-atmosphere model to an increase of atmospheric carbon dioxide. *Journal of Climate*, **7**: 5–23.

Oppenheimer, C. (2003), Climatic, environmental and human consequences of the largest known historic eruption: Tambora volcano (Indonesia) 1815. *Progress in Physical Geography*, **27**: 230–259.

Osborn T.J. and Hulme M. (2001) Evidence for trends in heavy rainfall events over the UK. *Philosophical Transactions of the Royal Society*, **360(A)**: 1313–1325.

Parry, M.L., Rosenzweig, Iglesis, A., Fischer, G., and Livermore, M. (1999) Climate change and world food security: A new assessment. *Global Environmental Change*, **8**: 51–67.

Pearson, S., Wheeler, T.R., Hadley, P., and Wheldon, A.E. (1997) A validated model to predict the effects of the environment on the growth of lettuce (Lactuca sativa L.): Implications for climate change. *Journal of Horticultural Science*, **72**: 503–517.

Peart, R.M., Curry, R.B., Rozenzweig, C., Jones, J.W., Boote, K.J., and Allen, L.H.J. (1995) Energy and irrigation in southeastern U.S. agriculture under climate change. *Journal of Biogeography*, **22**: 635–642.

Peiris, D.R., Crawford, J.W., Grashoff, C., Jefferies, R.A., Porter, J.R., and Marshall, B. (1996) A simulation study of crop growth and development under climate change. *Agricultural and Forest Meteorology*, **79**: 271–287.

Rahmstorf, S. (1999) Shifting seas in the greenhouse? *Nature,* **399**: 523–524.

Rampino, M. (2002) Threats to civilisation from impacts and super-eruptions. Conference Proceedings of *Environmental Catastrophes and Recoveries*, Brunel University, Uxbridge, UK.

Reilly, J., Tubiello, F., McCarl, B., and Mellilo, J. (2000) Climate change and agriculture in the united states. In: *Climate Change Impacts on the United States: The Potential Consequences of Climate Variability and Change. Report for the U.S. Global Change Research Program*, Cambridge University Press.

Rozenzweig, C., Parry, M.L., and Fischer, G. (1995) World food supply. In: *As Climate Changes: International Impacts and Implications* (Eds. K.M. Strzepek and Smith), Cambridge University Press.

Sarnthein, M. et al. (1994) Changes in east Atlantic deepwater circulation over the last 30,000 years: Eight time slice reconstructions. *Paleoceanography,* **9**: 209–267.

Wheeler, T.R., Ellis, R.H., Hadley, P., Morison, J.I.L., Batts, G.R., and Daymond, A.J. (1996) Assessing the effects of climate change on field crop production. *Aspects of Applied Biology*, **45**: 49–54.

Color Plates

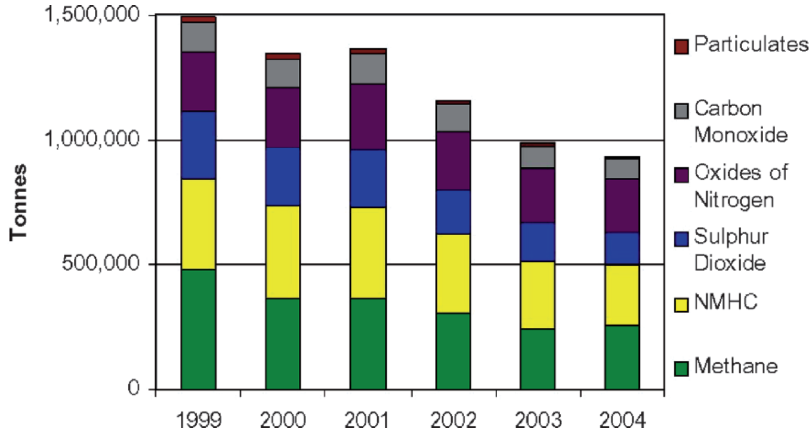


FIGURE 1.1. BP group annual total air emissions by pollutant 1999–2004.

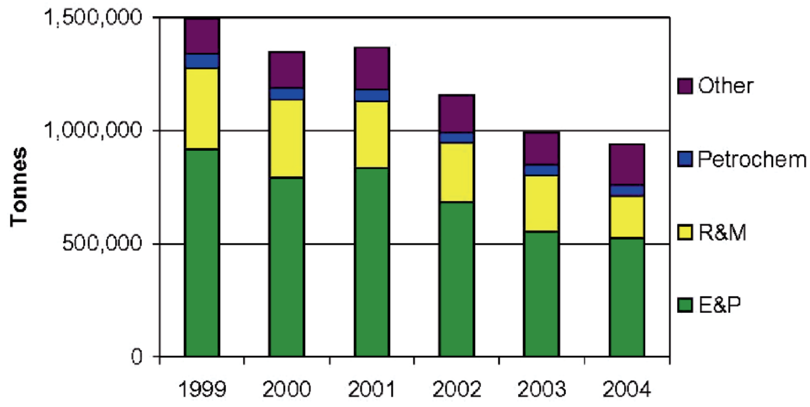


FIGURE 1.2. BP group annual total air emissions* by business 1999–2004.

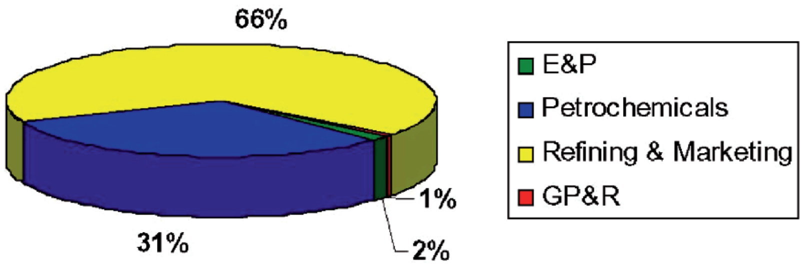


FIGURE 1.3. Fresh water withdrawal by BP business in 2004 (as volume percent of BP group total).

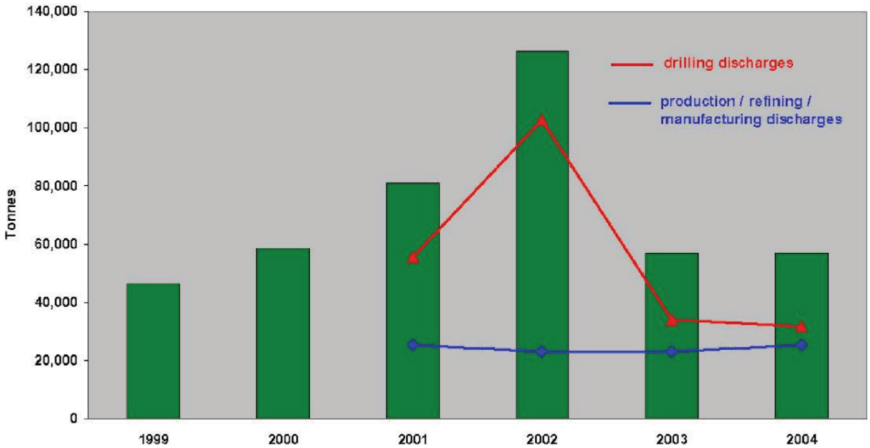


FIGURE 1.4. BP group discharges to water 1999–2004.

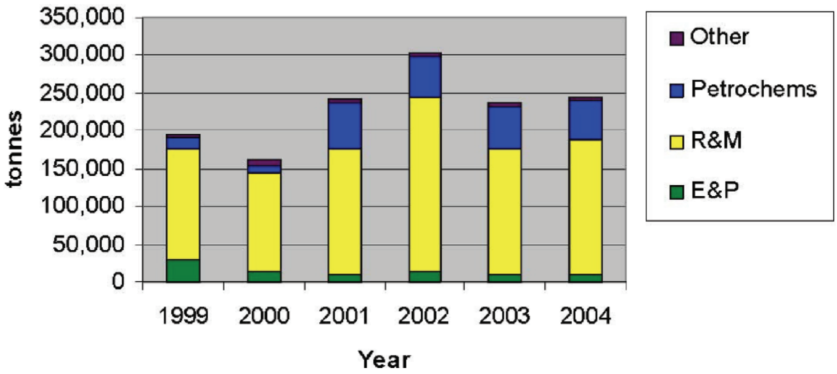


FIGURE 1.5. BP total hazardous waste 1999–2004.

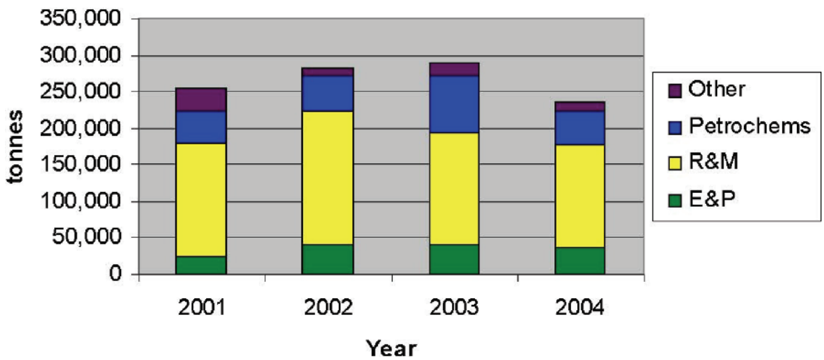


FIGURE 1.6. General solid waste disposal 2001–2004.

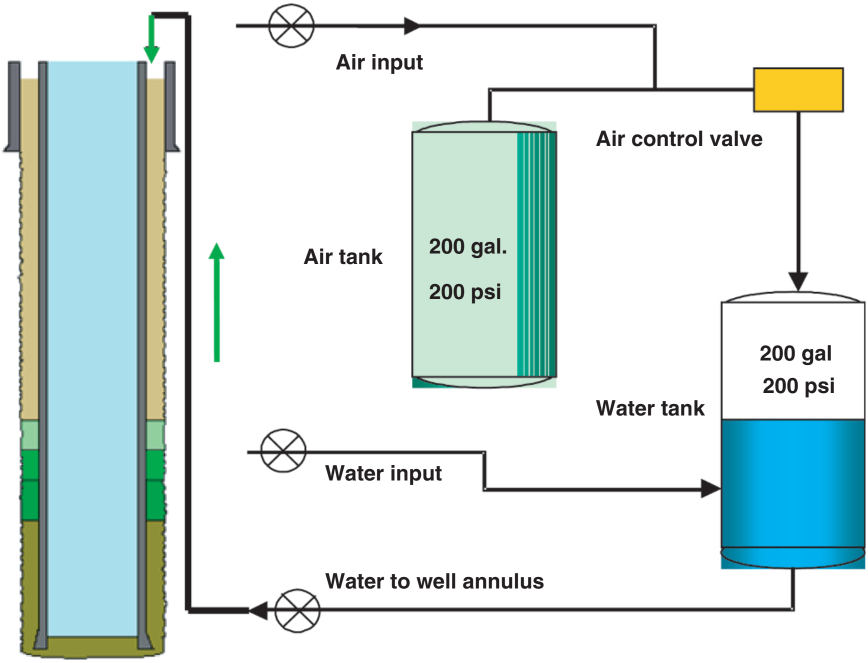


FIGURE 3.4. Principle of top cement pulsation method. (After Ref. 30.)

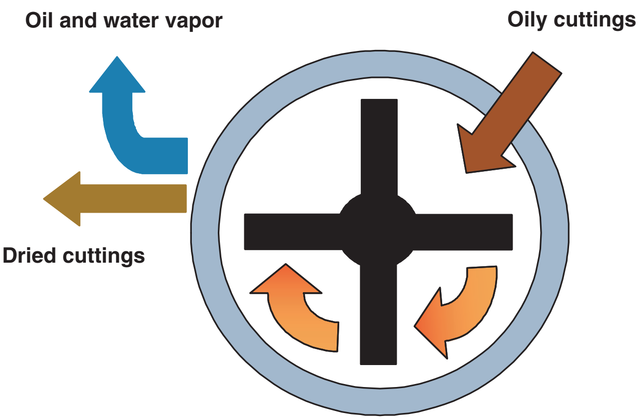


FIGURE 4.4. Principles of Hammermill thermal desorption unit.

FIGURE 7.5. Cell Spar.

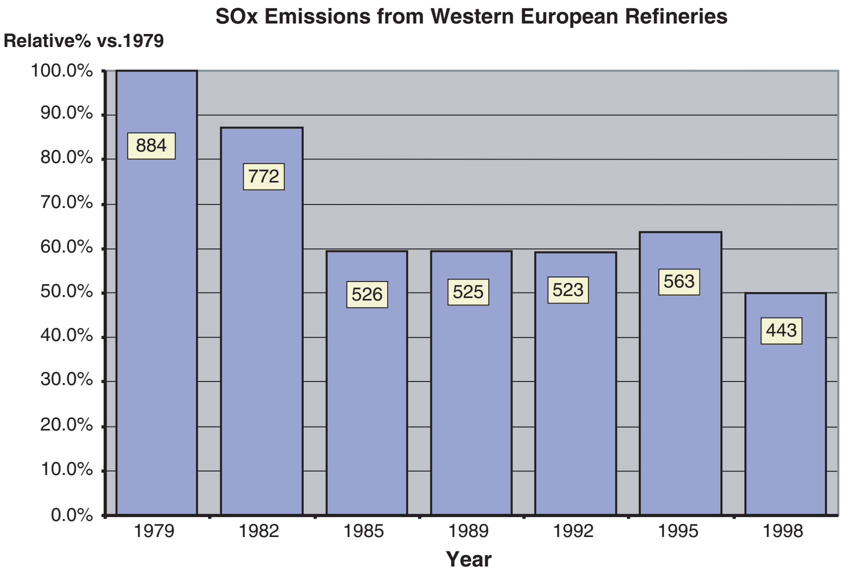


FIGURE 10.1. SO_2 emissions from refineries in Western Europe [2, 3].

FIGURE 11.2. Map of refineries and oil pipelines in Western Europe 2003 (Reproduced with permission from performance of European, cross-country oil pipelines – statistical summary of reported spillages 2003; published by CONCAWE, 2003)

Index

Page numbers appearing in **bold** refer to figures and page numbers appearing in *italic* refer to tables.

R