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Τμήμα Βιομηχανικής Διοίκησης & Τεχνολογίας

Διαχείριση Ενέργειας και Περιβάλλοντος

Τίτλος:Offshore Oil Drilling- Environmental safety

Επιβλέπων Καθηγητής: Δημήτριος Εμίρης

ΑΡΕΤΗ ΛΕΒΕΝΤΗ

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Offshore Oil Drilling- Environmental safety

Η εργασία υποβάλλεται για τη μερική κάλυψη των απαιτήσεων με στόχο την απόκτηση του διπλώματος

Διαχείριση Ενέργειας και Περιβάλλοντος

από

ΤΟ ΠΑΝΕΠΙΣΤΗΜΙΟ ΠΕΙΡΑΙΩΣ

Αρετή Λεβέντη

Τμήμα Βιομηχανικής Διοίκησης & Τεχνολογίας, 2015

Title: Offshore Oil Drilling- Environmental safety

Δήλωση

Η συγκεκριμένη διπλωματική εργασία έχει εκπονηθεί με σκοπό την απόκτηση του μεταπτυχιακού τίτλου σπουδών: Διαχείριση Ενέργειας και Περιβάλλοντος του τμήματος Βιομηχανικής Διοίκησης & Τεχνολογίας του Πανεπιστημίου Πειραιώς.

Περίληψη

Ο σκοπός της εργασίας αυτής είναι να καθοριστούν οι διαδικασίες που οδηγούν σε μόλυνση του περιβάλλοντος σε ένα υπεράκτιο έργο εξόρυξης πετρελαίου, οι παράγοντες που επηρεάζουν την επίτευξη ενός υπεράκτιου έργου εξόρυξης πετρελαίου και ποιοι από αυτούς είναι ικανοί να οδηγήσουν σε αποτυχία και ατύχημα, καθώς και ο ρόλος του project management στην επίτευξη αυτού του έργου. Για να καταλήξουμε σε συμπεράσματα θα έπρεπε να περιγράφει η διαδικασία από την αρχή, δηλαδή από το στάδιο της εξερεύνησης, μέχρι το στάδιο της γεώτρησης και εξόρυξης.

Ο τρόπος με τον οποίο συλλέχθησαν τα παραπάνω στοιχεία είναι μέσα από την επιστημονική βιβλιογραφία και δεδομένα διαθέσιμα στο διαδίκτυο. Η επιστημονική έρευνα για το θέμα αυτό είναι πολύ μεγάλη και έγινε μια προσπάθεια να αναπτυχθούν σύντομα τα διάφορα κεφάλαια και να καταλήξουμε σε κάποια συμπεράσματα.

Τα συμπεράσματα της παρούσας διατριβής συνοψίζονται ως εξής.

- Η λήψη αποφάσεων με περιβαλλοντικό χαρακτήρα σε έργα εξόρυξης πετρελαίου είναι συνήθως μια περίπλοκη διαδικασία λόγω αντικρουόμενων στόχων ή κριτηρίων, ασαφή δεδομένα, και αλληλεξάρτηση μεταξύ των ομάδων των φορέων λήψης αποφάσεων.
- Ο ρόλος της διαχείρισης του έργου είναι πολύ σημαντικός για την επιτυχία του έργου.
- Η βιομηχανία πετρελαίου και φυσικού αερίου έχει μετακινηθεί από μια αντιδραστική προσέγγιση σε μια προληπτική προσέγγιση για την ασφάλεια.
- Τα υψηλότερα επίπεδα του στρες και η κούραση, συνδέεται με χαμηλότερα επίπεδα επίγνωσης κατάστασης, η οποία με τη σειρά της είναι ενδεικτική της αυξημένης συμμετοχής στις ανασφαλείς συμπεριφορές στην εργασία, και αυξημένο κίνδυνο ατυχημάτων.
- Τα ατυχήματα έδειξαν ότι οφείλονταν σε ανθρώπινο λάθος.
- Στην περίπτωση του Κόλπου του Μεξικού, η πιο σημαντική αστοχία -και η σαφής αιτία για την έκρηξη - ήταν μια αποτυχία της διαχείρισης της βιομηχανίας.

Abstract

The purpose of this study is to establish the procedures that lead to pollution of the environment in an offshore oil drilling project, to set out the factors that influence the achievement of a such a project, and which of those are able to lead to a failure and to an accident, and the role of project management in achieving this project. To result to conclusions we should have described the process from the beginning, namely from the stage of exploration until the drilling stage.

The way that collected the above data is through the scientific literature and data available on internet. The scientific study on this issue is very large and there was an attempt to develop shortly the various sections and to result at some conclusions from it.

The conclusions of this thesis are summarized as follows.

- Environmental decision-making in OOG operations is usually a complicated process due to conflicting objectives or criteria, imprecise data, and interdependency between groups of decision-makers.
- The role of project management is very important for the project success.
- The oil and gas industry has moved from a reactive approach to a proactive approach to safety.
- Higher levels of stress and fatigue are linked to lower levels of situation awareness (WSA), which in turn are indicative of increased participation in unsafe work behaviours, and higher accident risk.
- The accidents showed that they were due to human error.
- In case of Gulf of Mexico, the most significant failure— and the clear root cause of the blowout — was a failure of industry management.

Βιογραφικό Σημείωμα

Ονομάζομαι Αρετή Λεβέντη και γεννήθηκα το 1985 στον Αρχάγγελο της Ρόδου, όπου και μεγάλωσα. Τελειώνοντας το λύκειο Αρχαγγέλου, άρχισα τις σπουδές μου στο Ε.Μ.Π. απ'όπου και πήρα το δίπλωμά μου ως μηχανολόγος μηχανικός το 2012. Το 2013 αιτήθηκα για την παρακολούθηση του μεταπτυχιακού προγράμματος σπουδών, Διαχείριση Ενέργειας και Περιβάλλοντος, του Πανεπιστημίου Πειραιά. Ενδιάμεσα παρακολούθησα πληθώρα σεμιναρίων για την κατάρτισή μου, πράγμα που συνεχίζω να κάνω. Σήμερα δουλεύω στον ιδιωτικό τομέα, σε εταιρεία που δραστηριοποιείται στην παραγωγή βιομηχανικών ανεμιστήρων, συστημάτων αερισμού, βιομηχανικών φίλτρων και αερολέβητων. Σύντομα ξεκινώ μαθήματα για την απόκτηση διεθνή τίτλου Μηχανικού Συγκολλήσεων.

ΕΥΧΑΡΙΣΤΙΕΣ

Η παρούσα διπλωματική εκπονήθηκε με σκοπό την απόκτηση μεταπτυχιακού προγράμματος σπουδών από τη φοιτήτρια Αρετή Λεβέντη του Αντωνίου, υπό την επίβλεψη του καθηγητή κύριου Δημητρίου Εμίρη, τον οποίο και ευχαριστώ θερμά για την καθοδήγηση και επίβλεψή του κατά τη διάρκεια υλοποίησης αυτής της εργασίας.

Από καρδιάς ευχαριστώ τον κύριο Λάμπρο Λάιο, τον πρόεδρο του μεταπτυχιακού προγράμματος, καθώς και τους καθηγητές του προγράμματος για την αφοσίωση τους, με σκοπό τη διατήρηση του υψηλού επιπέδου σπουδών.

Ιδιαίτερες ευχαριστίες θα ήθελα να απευθύνω στη γραμματεία του μεταπτυχιακού προγράμματος, για την άψογη εξυπηρέτηση της σε όλα τα θέματα και για τη συνδρομή τους παντού σε επίπεδο φιλίας.

Τέλος δε θα παρέλειπα να ευχαριστήσω τον σύντροφο της ζωής μου για την αγάπη του, την υπομονή και την κατανόησή του.

Αφιερώνεται στον αγαπημένο μου,
Βασίλη.

Contents

Tables

1. Introduction

The factors that can determine the success of an offshore drilling project is compliance with environmental regulations, the selection of the right location, the evolution of technology, the project management and the human factor. Environmental protection has a key role in the success of such a project and follows the project from the initial exploration stages until the implementation and transfer stages. Although, according to the scientific literature, a key role in causing accidents plays the human factor, in the case of the Gulf of Mexico the causes gathered in the supervision of the authorities, in project, risk and judgment management and to education of engineers.

2. Drilling Petroleum

Petroleum

Petroleum is a complex multiphase mixture: it contains a large spectrum of chemical components, from light hydrocarbons in gaseous form (e.g. methane) to heavy ones in liquid phase (e.g. naphtenes and cycloalkanes) and is extracted along with subsurface water. The aim of the processing plant is to separate efficiently the different phases to satisfy the different process and export constraints, and to maximize the hydrocarbon production. Crude oil consists mostly of medium- to heavy hydrocarbons, while natural gas mostly consists of light-weight alkanes.

Drilling(20)

Drilling is the process in which a hole is made in the ground to allow subsurface hydrocarbons to flow to the surface. The wastes generated during drilling are the rock removed to make the hole (as cuttings), the fluid used to lift the cuttings, and various materials added to the fluid to change its properties to make it more suitable for use and to condition the hole.

Production(20)

Production is the process by which hydrocarbons flow to the surface to be treated and used. Water is often produced with hydrocarbons and contains a variety of contaminants. These contaminants include dissolved and suspended hydrocarbons and other organic materials, as well as dissolved and suspended solids. A variety of chemicals are also used during production to ensure efficient operations.

Petroleum Product Life Cycle(1)

Here are seven major conceptual steps involved in the complete commercial “Petroleum Product Life Cycle”. These steps are

(1) Prospecting,

(2) Leasing or acquiring access,

(3) Drilling operations,

(4) Developing and producing,

(5) Transporting,

(6) Processing and refining,

(7) Marketing and sales.

Of the seven steps listed above, the first three steps are called the “exploration phase” and the forth step is the “production/extraction phase”.

System description(24)

Offshore platforms are large structures with facilities to extract and process petroleum from subsea reservoirs. Petroleum is processed in a processing plant where power and heat are consumed. The power is produced by gas turbines fuelled with a fraction of the produced gas, or alternatively heavy oil or diesel. The heating demand, if one, is either met by using fuel gas burners, electric heaters or by waste heat recovery from the utility plant. A schematic overview of the processing and utility plants is given in Fig.2.1.

Differences across offshore platforms can be summarised as follows:

- reservoir characteristics (e.g. initial temperature and pressure)
- fluid properties (e.g. chemical composition, gas- and water-to- oil (GOR and WOR) ratios)
- product requirements (e.g. export pressure and temperature, chemical purity)
- operating strategies (e.g. oil and gas recovery, gas treatment, condensate export).

These differences induce variations in temperatures, pressures and flow rates throughout the system as well as in demands for compression, heating, cooling, dehydration, desalting and sweetening. The structural design of the processing plant stays nevertheless similar. In the processing plant, oil, gas and water enter one or several production manifolds in which the well fluid streams are mixed and the pressure reduced to ease separation between the liquid and gaseous phases. The well fluid streams are fed into a separation system where oil, gas and water are separated by gravity in one or more stages, with throttling in between. Crude oil leaving the separation train enters a treatment and export pumping section. Gas leaving the separation and oil pumping steps enters the recompression train. It is cooled, sent to a scrubber where condensate and water droplets are removed, and recompressed to the pressure of the previous separation stage. It is then sent to the gas treatment train, where it is purified and possibly dehydrated by TEG (triethylene glycol). Gas may be compressed for export to the shore, lift or injection. Condensate removed from the recompression and gas treatment trains is (i) either sent back to the separation train and mixed with crude oil or (ii) processed in a condensate treatment section. Produced water enters a wastewater handling train, in which suspended particulates and dissolved hydrocarbons are removed. It is then discharged into the sea or enters an injection train where it is further cleaned and pumped to a high pressure level. In parallel, seawater may be processed on-site for further injection into the reservoir for enhanced oil recovery. The cooling demand is satisfied by using a direct cooling medium, e.g. seawater or air, or an indirect one, e.g. a glycol/water mixture. Heat exchanger networks between the different streams flowing through the system may also be integrated to promote heat integration.

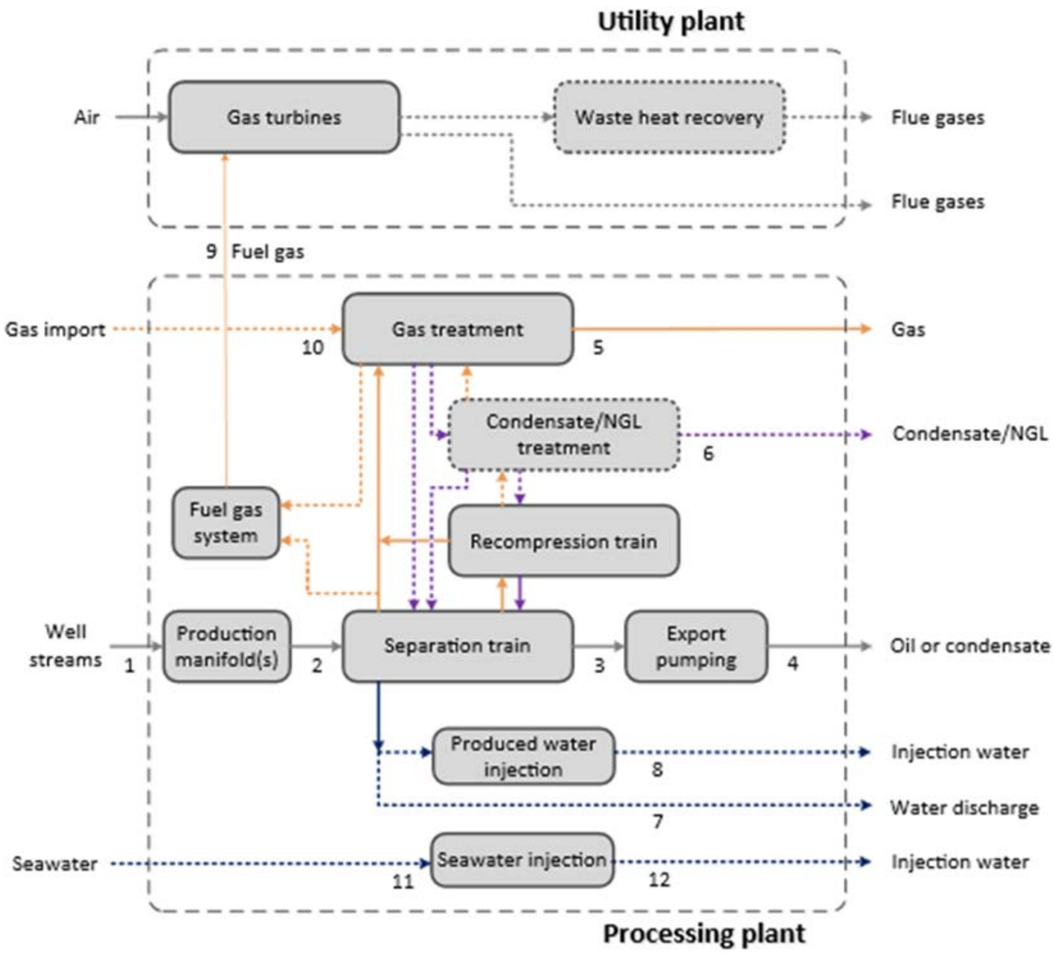


Fig 2.1: General overview of the processing and power plants

Searching Petroleum(1)

Holes are drilled in the ground to search for oil and gas, to acquire information about the geologic formation, and to develop hydrocarbon reservoirs. A hole made by a drilling bit is called a well. A company acquires a lease or contract area based on geological and geophysical data and conceptual plays, and invests in additional data and manpower refine their knowledge of the region. If the results of analysis are encouraging, exploratory drilling may result. A team of geologists, geophysicists, and engineers selects the well site and the drilling target based on magnetic, gravity, and seismic surveys. A well plan and a cost estimate are performed, typically from the drilling engineer, who has the responsibility for gathering the technical experts, letting contract, and ensuring the success of the operation. The well is then drilled. Substantial resources of money and time are invested to identify the geological target and the prognosis is confirmed or refuted on the basis of the results of the drilled, logged, and tested well. During drilling, evaluation is made from the cuttings and reservoir fluids that appear at the surface and from the drilling and coring indicators. A Drill System Test in which the pressure response of the reservoir is recorded during short production periods may be performed to gather additional information on the reservoir. The results from exploratory drilling are evaluated and may result in either an appraisal well program or an abandonment of the prospect. If hydrocarbons are detected, the company will typically confirm and delineate the field through additional appraisal drilling and well testing; if the field is judged to be economic, the company will develop and produce the reserves in accord with its particular risk-reward strategy.

3. From Onshore to Offshore extraction(4).

Oil has a central role in the global energy system and accurate projections of future production are important for effective planning and decision making in a globalized economy. Historically, oil supply has predominantly been made up by crude oil derived from fields located on land, but maturing fields and declining discoveries onshore have moved exploration and production to new frontiers, such as offshore and unconventional oil deposits. The importance of offshore production is commonly considered to be increasing in respect to geological as well as economic and political factors. The International Energy Agency (IEA) estimates that 42% of remaining recoverable resources of conventional oil are located in offshore regions and petroleum consultancy Rystad Energy AS (Rystad) projects that the share of offshore in total conventional world oil and NGL production will rise from today's 33% to 48% in 2030. Furthermore, 58% of offshore production came from non-OPEC countries in 2012, while the non-OPEC share of land production was 53%. With declining non- OPEC land production, this difference is expected to increase further. Consequently, expectations on offshore regions are high in regard to both total amounts, as well as for diversification of supply.

Describing with more details, between 1859, when crude oil production began, and 1954, the U.S.A. was both the largest producer and discoverer of oil in the world, as well as a net exporter of oil. By 1955, the U.S.A. had discovered 82 billion barrels of oil (35.8%of world discoveries), had produced 48 billion barrels (60.3% of world production), held 29 billion barrels of oil reserves (21.7% of world reserves), 198 trillion cubic feet of natural gas reserves, and had drilled 1.54 million oil and gas wells, accounting for 92.7% of world producing oil wells at the end of 1954. During the period between 1955 and 2002, the U.S.A. oil and gas industry drilled an additional 2 million well sand discovered an additional 122 billion barrels of oil and 794 trillion cubic feet of new natural gas. But the rest of the world was quickly catching up. Between 1955 and 2002, the U.S. became a net importer of 73 billion barrels of crude oil (35% of domestic consumption). By 2002, the U.S.A. would account for only 8.8% of world oil production, 1.6% of world proved reserves, 10.7% of cumulative discoveries, and 20.3% of cumulative world oil production.

Table 3.1: Evolution of oil exploration in U.S.A.

Descriptive statistics by state and U.S. total, 1955–2002.

State	Total wells drilled	Exploratory wells drilled	Development wells drilled per new filed	Exploratory success rate (%)	Development success rate (%)	Real average cost ($1000)	Crude oil reserves/ exploratory well (m. bbl.)	Natural gas reserves/ exploratory well (m. cft.)	Off-shore exploratory (%)	Federal land (%)
Alabama	214.8	46.4	34.4	14.9	73.7	668.8	0.37	5.73	0	3.41
Alaska	114	10.7	54.4	15	93.5	4,476	44.88	59.54	5.22	86.18
Arizona	11.2	7	5	5	44.5	1,255	–	–	0	44.58
Arkansas	468.8	78.1	69.4	9.1	66	273.2	0.18	3.24	0	9.48
California	2316	147.3	464.3	7	92.7	314.6	2.24	2.03	1.85	45.36
Colorado	1036	281	32.6	13	73.2	294.2	0.1	3.07	0	35.97
Florida	21	10.2	13.1	3.7	64.6	1871	2.23	2.9	0	10.15
Illinois	1418	197.6	232.5	4.7	65.3	82.2	0.14	0.13	0	1.68
Indiana	480.3	91	89.3	10.3	58.5	52.7	0.05	0	0	1.97
Kansas	3668	496	52	15	66.6	116.4	0.08	0.5	0	1.19
Kentucky	1426	89.1	188	14.9	62.7	72.4	0.33	5.39	0	4.93
Louisiana	3307	452.9	94	9.4	69.1	1413	1.31	13.36	29.75	3.7
Michigan	595.3	184.9	38	14.6	68.3	241.6	0.11	2.87	0	9.97
Mississippi	461.6	182.8	20.9	11.2	56	653.8	0.26	0.84	0	5.27
Missouri	47.6	7.3	23.3	10.7	72.3	154.3	–	–	0	4.78
Montana	528.2	184.9	21.1	15	72.3	271.2	0.18	0.4	0	29.25
Nebraska	344.9	170.5	12	9.8	56.9	146.7	0.06	0.02	0	2.04
Nevada	16.2	10.1	4.2	3.5	64.9	209.6	–	–	0	85.55
New Mexico	1376	142	63.2	27.8	88.3	428.3	0.56	8.71	0	33.74
New York	269	12.2	93.6	29.9	91.8	143.1	0.06	2.63	0	0.79
North Dakota	273.9	84.9	18.5	18.2	73.7	655.4	0.36	0.48	0	4.41
Ohio	1826	38.7	564.1	27.3	85.3	143.1	0.17	2.74	0	1.2
Oklahoma	4600	262.6	101.7	23.7	73.3	388.9	0.4	6.08	0	2.97
Oregon	7.2	2.4	9.2	3.9	59.2	122.7	–	–	–	52.15
Pennsylvania	1344	15.7	450.8	34.9	93.4	143.1	0.47	11.15	0	2.23
South Dakota	28.2	17	9.6	5.5	75.1	153.1	–	–	0	6.44
Tennessee	161	49	19.2	28.8	54.5	153.1	–	–	0	6.28
Texas	13,188	1899	45.3	17.9	79.6	444.2	0.32	2.79	2.638	1.77
Utah	257.5	54.4	32.7	19.2	83	827.8	0.55	4.76	0	64.97
Virginia	83.4	2.5	71.9	39.2	91.1	160	–	26.19	0	8.88
West Virginia	987.1	15.6	299.4	40.6	92	143.1	0.09	42.75	0	7.07
Wyoming	1324	284.2	31.6	15.3	76.9	537.8	0.34	4.07	0	48.69
United States	42,033	5514	115.4	16.1	73.4	551.6	0.34	3.07	1.19	17

Notes: Reported statistics are the average for each state over the period 1955–2002. In the row titled 'United States', the first two columns are the sums over all states of the number of wells drilled, while the remaining columns are the un-weighted averages across states. '–' indicates data disaggregated by state are not available.

The broad history, and evolving geography, of interest in offshore oil and gas resources are well documented. Early offshore activity took place in the Gulf of Maracaibo, Venezuela, in the middle Arabian Gulf, and in the southern Caspian Sea. The first major offshore developments with large-scale offshore oil and gas production, however, focused on the Gulf of Mexico (GOM) where, stimulated by an import embargo imposed by the U.S.A. government from 1959 to 1971, the industry turned to Texas and Louisiana waters. Since then, offshore operations in the GOM have played an important role in production and stabilization of energy supply in United States. Federal offshore production accounted for roughly 25% percent of total US oil and gas production, and the offshore fraction of domestic production has been increasing over time. Oil and gas production in Gulf of Mexico accounted for 88 and 99 percent, respectively, of total US offshore oil and gas production through 1997.

Gulf of Mexico activity was quickly followed by interest in the southern North Sea, where production began in 1967 and was given a powerful impetus by the economic and political challenges posed by the first oil crisis (1973–1974). From these dominant cradles on the US and European continental shelves, the offshore oil and gas industry has become global. The extent of this globalisation is effectively demonstrated by drilling rig activity data. Since the mid-1990s the industry has generally employed >300 drilling rigs to develop exploratory and production wells on the world's continental shelves and slopes. Although many have recently concentrated off the US Gulf Coast and in the North Sea, almost half of them have been deployed in waters around the Middle East, Africa, Latin America and the Asia Pacific region (Table 3. 2).

Table 3.2:

Regional distribution of operational drilling rigs, 1995–2000[a]

	1995 (%)	1996 (%)	1997 (%)	1998 (%)	1999 (%)	2000 (%)
North America	37	36	36	38	36	49
Europe	13	16	17	14	12	11
Middle East	7	9	7	8	9	6
Africa	8	9	9	8	9	4
Latin America	17	16	17	16	14	12
Asia Pacific	18	14	14	16	20	18
	100	100	100	100	100	100
Total rigs	327	350	395	412	347	292

[a] *Sources*: Hughes Christensen and Baker Hughes rig counts for the International Association of Drilling Contractors.

The outcome of this activity to date must not be exaggerated. Offshore oil and gas reserves exceeding 14 billion tonnes of oil equivalent (btoe) have now been proven, yet knowledge of onshore resources is so well developed that this offshore figure as yet accounts for only about 5% of total proven oil and gas reserves. So far as utilisation is concerned, however, the picture is different. Offshore oil output now satisfies more than a third of total world consumption, while for natural gas the figure is almost a quarter. Current estimates are that >90% of the world's undiscovered hydrocarbon reserves lie offshore.

As Fig. 3.1 demonstrates, one significant implication of this is that further spread of the industry away from its heartlands will have the potential to benefit the economies of numerous developing and newly industrialized countries around the world. Even today, although half the known offshore oil and gas fields lie in North American or European waters, these regions account for less than a quarter of the world's proven offshore reserves. Conversely, almost a third of the proven deposits are to be found in the Middle East, echoing this region's two-thirds share of onshore resources. Africa, meanwhile, has 13%, chiefly identified off West Africa. Here the waters from Cote d'Ivoire through to Angola have been targeted by the industry as key prospects for exploration and development. Led by Angola and Nigeria, there is a very real prospect that offshore West African oil output will match that of the North Sea by the end of this decade. Around Latin America, also with 13% of known reserves, the current leading prospects are Venezuela, Brazil and Mexico. And in south-east Asia a far-from-negligible 8% share reflects widespread significant discoveries, especially in waters around the Philippines, Malaysia, Thailand, Indonesia and Vietnam.

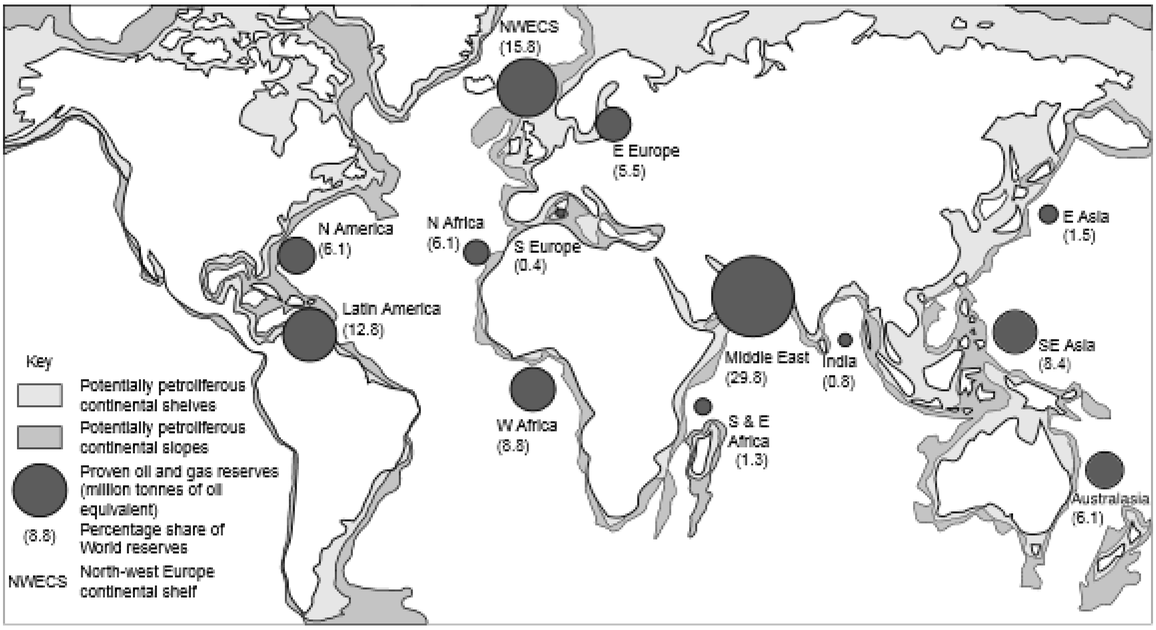


Fig 3.1: Potentially petroliferous offshore zones and regional distribution of proven offshore oil and gas reserves

According to the forecast by Douglas Westwood, the proportion of offshore oil in the global oil production will keep growing, and the offshore oil and gas resources, especially deep sea areas have become the new battleground for energy involving countries of the world. However, due to particular natural environment and complex accumulation conditions of offshore oilfields, the development faces with many difficulties such as large scale investment, high technical requirements, and difficult investment estimate. Foreign scholars mostly estimate total investment for offshore oilfields from a holistic perspective.

Producing petroleum

To find and produce oil and gas reservoirs, holes must be drilled into the Earth. A hole made by a drilling bit is called a well, and the primary objective of making a well is to produce underground fluids such as oil and natural gas, and to study properties of geologic formations. Drilling operations are complex and labor intensive, and although many activities continue to be automated, most jobs are still performed manually, 24 h a day, seven days a week, in all weather conditions. The work is strenuous and hard, and performed in traditional 12 h shifts on a 2-week on/off rotation, and only extreme weather or mechanical failure will shut down operations(1).

Offshore drilling requires a floating or bottom-supported rig to conduct operations. Although offshore rigs and facilities are functionally similar to land operations, the remote locations, offshore environment, and peculiar logistical requirements mean that offshore drilling costs will be higher than onshore drilling for similar depth wells. For example, in 2006, the average offshore well drilled in the U.S. was about twice as deep and four times as costly as the average onshore well. Large capital expenditures are required to drill an offshore well, with rates to rent the drilling rig costing anywhere from $50,000 to $500,000 per day, depending on the rig type, water depth, market conditions and offshore basin. When the cost of labor, fuel, materials and equipment are factored in, the final cost to drill and equip a well is about twice the rig dayrate. A well that takes 30 days to drill with a $200,000/day jackup, for instance, would be expected to cost about $12 million to complete.

Although the physics of drilling is the same everywhere in the world, wells vary widely in complexity and type. To evaluate the differences that exist in drilling a well and to compare performance, it is useful to establish general functional relations of drilling time and cost. To understand performance, it is necessary to isolate the factors of drilling and to quantify how these factors influence the operation. Historically, much of the work on assessing drilling performance has focused on the identification and elimination of non-productive time, such as freeing stuck pipe, fishing, repairing equipment, and waiting on weather. Cost estimation and performance evaluation are not usually made outside a small subset of wellbores because of the nature of the processes involved and uncertain operating environment, the pervasive impact of technology differentials, and the many unobservable characteristics that influence operations.

Two methods are commonly used to benchmark drilling performance. The first method is based on experimental design and controlled field studies. Typically, one or more parameters of drilling are varied to examine the impact of the variable on output measures, such as the rate of penetration or cost per foot drilled. A significant amount of experimental work has been done to study factor effects on drilling time and cost, and a large number of technical studies has been performed by industry. The second method to study factor effects is based on an aggregate assessment of drilling data. In this method, drilling data is sampled across many different operators and wells, and relationships that correlate drilling parameters are established through empirical modelling. Both approaches have their advantages and disadvantages, advocates and proponents.

As the ocean covers about 71% of the Earth's surface, the offshore hydrocarbon resources are quiet considerable. It is reported that the hydrocarbon resource is about 92.2x108 m^3 oil equivalent discovered in global deepwater areas in the past decade, which exceeds half of the global added discovered reserves. The offshore drilling is gradually heading to deepwater with the technological development of oil and gas exploration. The surface conductor, marine riser and under water wellhead are initial channels of deepwater drilling. Their stabilities are related to the whole progress of offshore drilling. At present, researches on offshore deepwater drilling riser system are mainly focused on the studies of the stability, strength and vibration performance of the riser (in water) and the calculation method of jetting depth of surface conductor (below the mud-line). However, few studies are found on the stability analysis of underwater wellhead. As offshore drilling turning to deep water, the lateral load induced by the ocean current will increase remarkably as the water depth increasing. The lateral loads are transferred to the wellhead through the bottom blowout preventer. Meanwhile, the subsea silt-clay shallow foundation has low bearing capacity and high compressibility. Consequently, it may lead to the rotation angle of Lower Flex Joint (LFJ) to exceed its limitation (usually 2 degrees) and more complex could appear during drilling. What's worse, it may cause the wellhead rollover (5).

To make quantified estimates of future production, detailed examination of historical and current production on field level is necessary. Forecasts based on data rich bottom up models have been showed to be accurate in the short term, and useful for supply analysis in the medium term. Field-by-field methods are relatively straightforward to implement when field level data are easily available as in the case for Norway and Denmark. For other regions and global aggregates where comprehensive field level data are more difficult to attain, use of field analogies is often necessary for these methods. For the analogy approach to be successful detailed documentation of production parameters of different categories of oil fields is necessary. There are studies that provide empirical estimates of depletion levels, depletion rates, decline rates and characteristic time intervals in offshore oil production. A field-by-field database is used to derive arithmetic and production weighted averages and statistical distributions of these production parameters for different categories of oil fields specified by size, location and water depth(7).

In the following paragraphs there is an analytic description, how the technological change impacts on oil exploration.

Oil exploration

Oil and gas production from a region is constrained by its economically producible reserves. As current reserves are depleted through production, new resource stocks must be located through exploration to replenish reserves. The amount of new resources discovered is affected by exploration effort, geological conditions, technology, and cumulative discoveries in the region through the depletion effect. Despite the important role that technological change has played in the offshore exploration-discovery process in the past 50 years, little research has been done on the long-term interaction of technological change and resource depletion in the offshore oil and gas industry. This is an important issue in that energy has an important role in the economy and estimates of future availability affect policy for leasing of public resources and potentially international relations with energy countries (4).

The purpose of this chapter is to examine the impact of technological change on petroleum exploration, using the Gulf of Mexico as a case study. The Gulf of Mexico is an interesting case since it is among the first areas in the world to be involved in large-scale offshore oil and gas operations. Production from the region began in 1947, grew rapidly during the first two decades, and has played a significant role in energy supply in the United States for more than three decades. To maintain output over time, the industry depends heavily on technological improvements for exploration in deep waters and for significant cost reductions. Recent examples of major technological innovations include three-dimensional (3D) seismology, horizontal drilling, and deep-water platforms (Bohi, 1997). These technologies have enabled firms in the offshore oil and gas industry to add economic reserves and to reduce discovery cost, as compared to a hypothetical constant technology situation.

Since the pioneering work of Fisher (1964), a substantial literature on oil and gas exploration has emerged. In the 1970s, empirical analyses were mostly based on aggregate national or broad regional data. Since mid-1980s,a growing number of studies have used state, regional, or firm-level data. There are clear advantages to using microlevel data, since aggregation of data across distinctive geologic provinces may obscure the effects of economic and policy variables on the pattern of exploratory activities (e.g. Pindyck, 1978a). Although the lack of data at the field level has been viewed as a major obstacle to carrying out disaggregated analysis, field-level behavior has been considered too erratic to model successfully in empirical studies (Attanasi, 1979). Geologic-engineering based techniques have been used to examine the exploration-discovery process (Arps and Roberts, 1958; Drew et al., 1982). A widely utilized approach involves the analysis of the quantity of oil and gas reserves discovered resulting from one unit of exploratory effort, or yield per unit of effort (YPE) (see Hubbert, 1967; Cleveland, 1992). The basic premise of YPE models is that the rate of discovery in an oil and gas region tends to decline as drilling proceeds. Cleveland and Kaufmann (1991) include economic factors in the geologic-engineering framework. They argue that the long-run path of YPE is the net result of two opposing forces: those that reduce costs, such as technological innovation, and those that increase costs, such as depletion. In their 1997 study, Cleveland and Kaufmann utilized cumulative drilling to capture the net effect of technological change and depletion, but they stressed the importance of including in future research, separate variables to differentiate the two effects. With separate variables, the dynamic interactions between technological change and depletion in different years can be examined. By contrast, a single variable (e.g., cumulative drilling) captures only the general trend of the net effect on YPE over the entire study period, obscuring the relative effects of technological advances and depletion. Several recent studies have documented the significant effect of technological change on resource depletion in the offshore oil and gas industry. Using data from 27 large US oil producers between 1977 and 1994, Fagan (1997) analyse the finding cost for crude oil in the offshore industry. She finds that the cost increase associated with depletion was 12% per annum, while the cost decrease associated with technological change was 18%. Thus, the effect of technological change outweighed that of depletion over that period. Jin et al. (1998) developed a framework for estimating total factor productivity (TFP) in the offshore oil and gas industry. Their model extends conventional TFP measurement by accounting for the effects of increasing water depth and declining field size. Applying regional data from the Gulf of Mexico between 1976 and 1995 to the model, they how that productivity growth in the offshore industry has been remarkable. Forbes and Zampelli (2000) examine success rate in exploration in the Gulf of Mexico from 1978 to 1995 using data from 13 large producers. They find that the small increase in the success rate from the early 1980s to 1995 was largely due to a substantial decline in price, as lower prices tend to discourage firms from pursuing less promising prospects. Before 1985, the net effect of technological change on depletion was very small. However, after 1985 technological progress resulted in an annual rate of 8.3% growth in the success rate (Forbes and Zampelli, 2000). Walls (1992) presents a comprehensive survey of studies on modelling and forecasting of petroleum supply. Her survey covers various geologic/engineering models and econometric models that describe the relationship between exploratory drilling and discovery. However, none of these models includes an explicit treatment of technological change. As a result, forecasts of future oil and gas supply from a region usually show a declining trend, which reflects only the effect of resource depletion (Walls, 1994). In empirical analyses, a time trend has been widely used as a proxy for technological progress, since it is usually difficult to construct variables capturing the dynamics of technological change. Cuddington and Moss (2001) develop a novel approach to quantify technological change over time by counting the number of technological innovations in the oil and gas industry reported in trade journals. In this study, we extend the Cuddington and Moss method by developing a weighted index for technological change. Our index accounts for the significance of each technological innovation in terms of its impact on offshore oil and gas operations as reflected in an industry survey of research needs, carried out by the National Petroleum Council (NPC) (1995). This importance weighted technological index enables us to separate the effect of technological change from that of depletion in our empirical analyses. Recently, Managi et al. (2003a) use a technique called data envelopment analysis (DEA) to estimate the technological change indexes using a field-level data set in the Gulf of Mexico. Technological change measures the shifts in the production frontier that is constructed by DEA. DEA is a set of nonparametric mathematical programming techniques for estimating the relative efficiency of production units and for identifying best practice frontiers (e.g.,F.are et al.,1994;Ray and Desli, 1997). DEA does not impose any particular functional form on production technology. Using the field-level annual data of oil output and gas output, Managi et al. (2003a) show that increases in productivity have offset depletion effects in the Gulf of Mexico offshore oil and gas industry over 49 year period from 1947–1996. Initially, depletion effects outweighed productivity-enhancing effects of new technology, but in later periods technological advance offset depletion. Their result is consistent with common reports of Gulf of Mexico production in which the Gulf of Mexico referred to as the ‘‘Dead Sea’’ in the early 1980s, but with recent reports of technologies that have led to a rapid pace of productivity enhancement (e.g., Bohi, 1997;Ray and Desli, 1997). Their model, however, focused more on development-production side and further analysis of exploration-discovery side is required. Here is presented the methodology, data and results of an analysis of the exploration-discovery process in the Gulf of Mexico, utilizing both field- and regional-level data. Specifically, is examined the impact of technological change on exploration and discovery at the field level, on yield-per-effort (YPE) at the regional level, and on drilling cost per well, using the technological change index and other relevant variables. The study is important for several reasons. First, both the discovery function and the drilling cost function are key components in nonrenewable resource exploration-extraction models (Pindyck, 1978b;Livernois and Uhler, 1987). Hence, improvements in the understanding of technological change in exploration and discovery will lead to improved modeling and forecasting of oil and gas supply. Since discoveries may be made at both the intensive margin (i.e., within existing fields) and the extensive margin (i.e., new fields), are tested both field- and regional-level models to understand the impacts of technological change on discovery. In addition, since technological change affects discovery of additional reserves, the economically producable portion of existing reserves, and the resource rent, this study is important for the assessment of mineral reserves in the national income accounts (Adelman et al.,1991). Finally, using data from 1947 to 1998, we provide what we believe to be the first empirical analysis of long term interactions between technological change and resource depletion in the offshore industry.

Field exploration and discovery(10)

Data used in this analysis are obtained from the US Department of the Interior, Minerials Management Service (MMS), Gulf of Mexico OCS Regional Office. A unique micro- (i.e. field) level database has developed using four MMS data files: (1) production data including well-level monthly oil and gas outputs from 1947 to 1998 (a total of 5,064,843 observations for 28,946 production wells); (2) borehole data describing drilling activity of each well from 1947 to 1998 (a total of 37,075 observations); (3) historical data on field reserves, including yearly oil and gas reserve estimates from 1975 to 1997 (a total of 13,541 observations); (4) field reserve data including 1998 oil and gas reserve sizes and discovery year of each field from 1947 to 1997 (a total of 957 observations). Relevant variables are extracted from these data files and merged by year and field. Thus, the project database includes field-level annual data for the following variables: oil output, gas output, number of exploration wells drilled, total drilling distance of exploration wells, total vertical depth of exploration wells, number of development wells drilled, total drilling distance of development wells, total vertical depth of development wells, oil reserves, gas reserves, and proved oil and gas combined reserves in barrels of oil equivalent (BOE). In addition, water depth and discovery year of each field are also included in the database.

Since field reserve history data are not available before 1975, are developed estimates of 1947–1975 yearly field reserve measures using the 1998 reserve data and a set of field-level reserve growth factors reported by the Minerals Management Service (MMS, 1996).

Since the MMS reserve growth factor may be too high (e.g., reserve size quadruples in 40 year), we develop a second set of yearly reserve estimates by lowering the MMS growth factors by 50% for sensitivity analysis. Finally, the yearly reserve estimates are adjusted using the oil and gas production data whenever the actual production exceeds the reserve estimates. From the yearly reserve estimates, we calculate the quantities of original and subsequent discoveries in each field. The resulting time-series and cross-sectional data set covers 933 fields from 1947 to 1998 and includes a total of 18,117 observations. In addition, merging relevant field-level data, annual oil and gas discoveries as well as resource stock depletion at the Gulf of Mexico regional level are constructed for regional-level analysis.

The amount of reserves discovered per unit of exploratory drilling effort is calculated (i.e., YPE) in the region. The yield includes both oil and gas reserves in BOE.

Fig. 3.2 illustrates the time profile of YPE based on conservative field reserve growth estimates (i.e., using half of the MMS growth factor value) from 1947 to 1998. Over the entire period, YPE exhibits a U-shaped trend, showing the net effect of resource depletion and technological change.

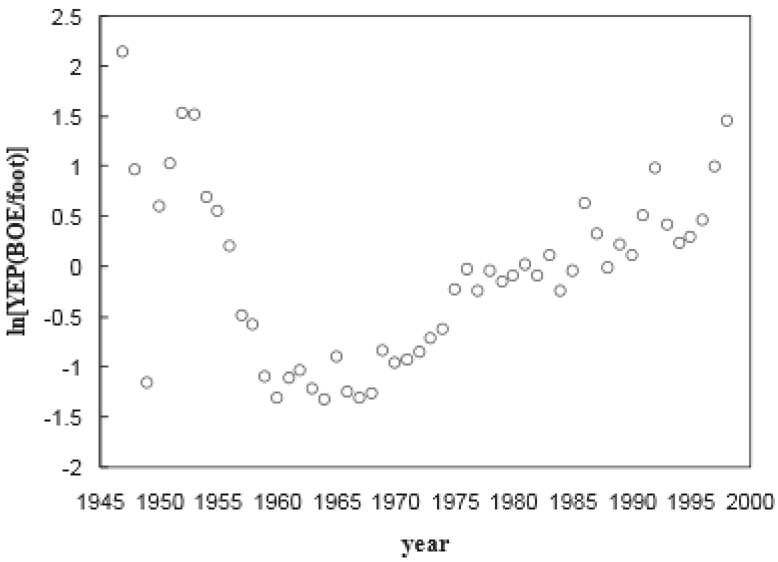


Fig. 3.2 YPE in the Gulf of Mexico.

Fig. 3.3 depicts the average water depth of all exploration and development wells in each year over the study period. A drastic rise in water depth started in 1985, resulting from innovations in deep water technologies.

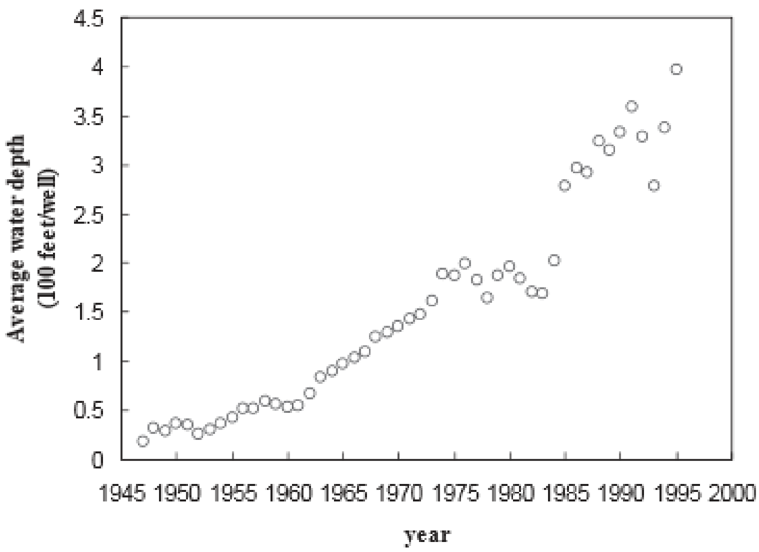


Fig. 3.3 Average water depth of wells drilled in the Gulf of Mexico.

Technological change (10)

Introductions to offshore technologies can be found in many studies (e.g., Massachusetts Institute of Technology, 1973;Giuliano, 1981;Bohi, 1997). A time line for major technological advancements in the offshore industry is shown in Table 3.3.

Table 3.3: Time line for major technological achievements in the offshore industry.

Technologies	Year
First offshore well drilled in Gulf of Mexico	1938
First OCS exploratory well drilled in Gulf of Mexico	1946
First offshore lease sale	1954
Production from water depths exceeding 100 feet	1955
First drillship	1956
First subsea well drilled	1961
First offshore concrete gravity base structure (Beryl platform)	1975
First fixed platform installed beyond 1000 feet water depth	1979
First compliant guyed-tower platform in Gulf of Mexico	1983
Production from water depths of 2000 feet	1984
First horizontal wells drilled offshore	1991
3D seismic data acquisition widely used	1992
First sub-salt discoveries in Gulf of Mexico	1993

Source: MMS.

Several recent technological innovations have had significant impact on the offshore industry. Three-dimensional (3D) seismic technology became available in the mid-1980s and has been widely used since 1992 (US Department of the Interior, 1996). The higher-quality images from 3D seismology have greatly improved the ability to locate new hydrocarbon deposits, to determine the characteristics of reservoirs for optimal development, and to help determine the best approach for producing from a reservoir. The new technology has substantially increased the success rate of both exploratory and development wells, which has led to reductions in the number of wells drilled for a deposit as well as in exploration and development cost.

Horizontal drilling technology has developed rapidly since the late 1980s. The technology involves a steerable down hole motor assembly and a ‘‘measurement-while- drilling’’ package. With horizontal drilling technology, drillers are capable of guiding a drill string that can deviate at all angles from vertical. Thus, the wellbore intersects the reservoir from the side rather than from above (Lohrenz, 1991;US Department of Energy,1993). Horizontal drilling has been widely used offshore to reach deposits far away from fixed platforms, thereby increasing access to distant reserves and lowering the cost of production. The time profile of horizontal drilling is shown in Fig. 3.4 and reveals a marked increase in horizontal/directional drilling since 1973. Deep-water technology encompasses two production systems: tension leg platforms (TLPs) and subsea completions. TLPs float above the offshore field and are anchored to the sea floor by hollow steel tubes. TLPs have been used in several deep-water fields in the Gulf of Mexico. Although deep-water technologies are mostly used for offshore development and production, they provide a driving force for explorations in deep waters. In most empirical analyses, the effect of technological change is usually examined by including a time-trend or dummy variables in regression models. Moss (1993) and Cuddington and Moss (2001) construct a technological change index based on counting specific technological diffusions in the exploration-development sector of the oil and gas industry (i.e., the number of technological innovations adopted by the industry) from 1947 to 1990. For their index, Cuddington and Moss treat all innovations the same and do not differentiate technological innovations in terms of their impacts on productivity improvements in the industry.

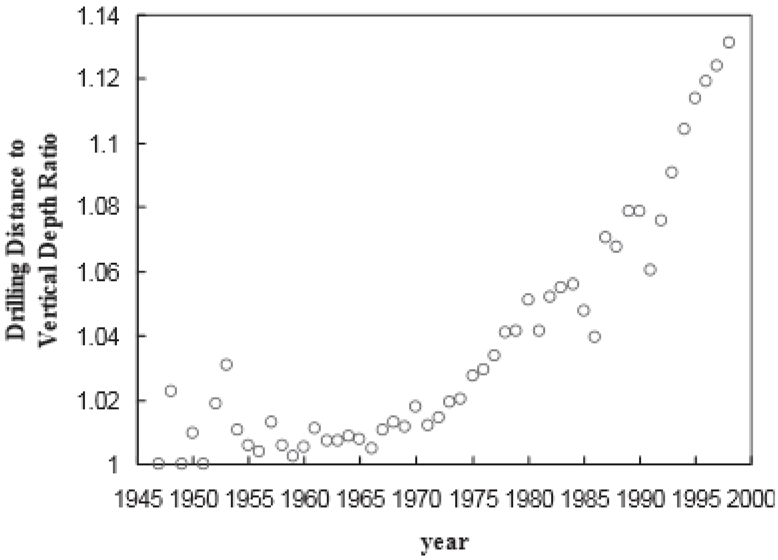


Fig 3.4. Horizontal and directional drilling

In this chapter, an alternative technological innovation index is constructed, as follows. First, we extend the Moss (1993) index from 1991 to 1998. Specifically, we collect information from Oil and Gas Journal and Hart's Petroleum Engineer International (formerly Petroleum Engineer International) to construct our technology index following the methodology described by Moss (1993). Examples of major innovations in the 1990s include 3D seismic data acquisition, and horizontal drilling. We then use data from the

National Petroleum Council (NPC, 1967, 1995) to weight each innovation. The NPC data contain survey results of firms' rankings of short- and long-term impacts of specific technologies on the industry. The NPC survey found most important categories of technological advance were: (a) more precise characterization of the resource; (b) better characterizing the reservoir, such as 3D geologic computer modelling for development; (c) well productivity and advanced fracturing techniques for drilling and completion; (d) simulation technologies for production; and (e) multiphase pumps and workers for deepwater offshore (see Managi (2002) for further discussion). Our technological innovation index covers the exploration-development stage and is constructed as

$$technology_t = \sum_{t=t_0}^{t} \sum_{i} \gamma_{it} N_{it}, \qquad (1)$$

Where technology is the cumulative weighted technological innovation index at time t; γ_{it} is the weight for innovations in technology category i at time t ; N_{it} is the number of technological innovations in technology category i at time t : As noted, N covers all exploration-development stage innovations.

Fig. 3.5 depicts annual growth (i.e., D technology) in the weighted innovation index in the study period. The yearly growth in innovation reveals a rising trend, with marked increases in 1971, 1995 and 1996.

Fig. 3.5. Weighted technological innovation index for the offshore industry.

In constructing her index, Moss (1993) presumes that one can identify a specific year when an innovation takes place. Her approach has been questioned by Forbes and Zampelli

(2002) for potentially serious misrepresentation of a technology's contribution. For example, there is probably not a single year when 3D seismic can be considered innovated. Our weighted index is an improvement over the original Moss index, since our weighting scheme allows the impact of each innovation to change over time. For example, our methodology provides a cumulative technology index, so that the weight for 3D seismic can increase over time to reflect factors such as continuing refinements or broader adoption, as reflected by expert judgment through the National Petroleum Council industry survey. The weighting scheme provides not only a better measure for technological diffusion but also a description of interactions among innovations Models Using our field-level data set, three sets of empirical models are developed to examine the impact of technological change on petroleum exploration in the Gulf of Mexico. The theory of non-renewable resources (see Pindyck, 1978b ; Livernois and Uhler, 1987) suggests that discovery of new reserves is affected by exploration effort (e.g., drilling) which is in turn influenced by economic and technical factors, such as exploration cost (i.e., drilling cost). Since resource discoveries may be made at both the intensive margin (i.e., within existing fields) and the extensive margin (i.e., new fields), we start with a field-level discovery model that describes how the initial and subsequent discoveries are affected by drilling effort and other factors within an individual field. We then analyze the long-term interaction between technological change and resource depletion at the regional level using a YPE model. Finally, a drilling cost model for the Gulf of Mexico region is developed using the JAS data.

Field-level discovery model(10)

A number of regional-level discovery models have been developed in both theoretical and empirical analyses (Pindyck, 1978b;Livernois and Uhler, 1987;Walls, 1992). In addition to exploration effort, the amount of new resources discovered is affected by geological conditions, cumulative discoveries in the region (the depletion effect), and technology. This discovery function is a key component in non-renewable resource exploration-extraction models, and it significantly affects future oil and gas supply. It is important to note that while most regional-level discovery models combine discoveries at both the intensive and extensive margins, our field-level analysis focuses on the intensive margin only. The reason for this is that data is only available for fields that were actually discovered and leased, and not on tracts that were explored but not subsequently leased. Our regional-level (YPE) analysis discussed below covers both intensive and extensive margins. Our field level discovery function is specified as:

$$discovery_{it} = f(technology_t, drill_{it}^{\exp}, well_{it},\\ waterdepth_{it},\ waterdepth_{it} \cdot year,\ price_t,\\ \sum_{t=1947}^{t-1} drill_{it}^{\exp}, \sum_{t=1947}^{t-1} drill_{it}^{\mathrm{dev}},\\ \sum_{t=1947}^{t-1} well_{it}, \sum_{t=1947}^{t-1} discovery_{it}), \quad (2)$$

(BOE), technology is the technological innovation index described in Eq. (1), $drill^{exp}$ is the average drilling distance (in feet) per exploratory well, $drill^{dev}$ is the average drilling distance (in feet) per development well, well is the total number of exploratory and development wells, waterdepth is the water depth of a field in feet, price is the real price of oil and gas in 2000 dollars per BOE, waterdepth ■ year is the product of water depth and year, and i is the field index, and t is time (i.e. year).

The expected sign for technology is positive, since technological innovations enable firms to locate new petroleum reserves. For each field, drilling effort is measured by both the number of wells drilled (well) and average distance drilled per well (drilPxp and drilldev). In addition, we consider cumulative ($cdrill^{exp}$, $cdrill^{dev}$ and cwell) drilling efforts. Although cumulative drilling may be used to capture depletion effect in an aggregate discovery model (see MacAvoy and Pindyck, 1973), we expect cdrilfxp, $cdrill^{dev}$ and cwell positively associated with discovery in our field-level model. This is because the initial discovery of a field is usually a result from cumulative drillings at the site in previous years. Development drilling is included in the discovery model, since it also generates useful geological information, which leads to subsequent discoveries of new reservoirs in the same field or of adjacent fields. Positive signs are expected for these variables capturing drilling effort (i.e., $drill^{exp}$ and well; $cdrill^{exp}$, $cdrill^{dev}$ and cwell).

As more resources are discovered in a field, subsequent discoveries in the same field become increasingly difficult, as fewer resources remain to be discovered. Thus, cumulative discovery reflects a depletion effect, and the expected sign on the associated variable (cdiscovery) is negative. The expected sign for water- depth is positive, as exploring deeper waters will identify significant new finds. And an interaction of waterdepth and year to capture the changes in deepwater productivity over time. The sign on this interaction is uncertain. On the one hand, new technologies will increase productivity in deep waters over time. On the other hand, there will also be a depletion effect as deeper waters become more heavily explored over time.

No agreement exists in the literature on the effect of oil and gas price on the average productivity of resource discovery. Higher prices justify exploration in less promising areas and development of smaller fields, so that higher prices could result in reduced average productivity. On the other hand, higher prices justify development of discoveries that are otherwise uneconomic, which would tend to increase measured productivity for exploration. Many previous studies utilized aggregate data to examine this issue. We extend these previous analyses by combining field level data with aggregate data to explore the net effect of price on the efficiency of exploratory efforts.

Eq. (2) is estimated as a two-way random effects model using our cross-section and time-series data. Since heteroscedasticity is present, the model uses White's heteroscedasticity adjusted standard errors. We estimate the model separately with two sets of data. The two data sets are the same except that different sets of growth factors are used for pre-1975 field reserve estimates. As described in the data section, the first data set is based on full MMS (1996) field reserve growth factors. For sensitivity analysis with respect to the growth factors, the second data set is developed using reduced growth factors. The results of two model estimates are presented in Table 2. Models 1-1 and 1-2 are associated with the first and second data sets, respectively. The results of the two model estimates are very similar, implying that the model is robust with respect to field reserve growth factors. The technology index (technology) is highly significant with positive sign, showing clearly a strong impact of technological change on discovery at the intensive margin. This is not surprising since innovations, such as horizontal drilling and 3D seismology, have drastically improved the efficiency of exploration.

The coefficients on $drill^{exp}$, well, $cdrill^{exp}$, $cdrill^{dev}$, and cwell are all significant with expected positive signs. The coefficient for cumulative discovery (cdiscovery) is negative and highly significant, indicating the depletion effect. Both waterdepth and waterdepth ■ year are significant with positive signs, suggesting that more new oil and gas reserves can be found if firms move to deeper waters, and that productivity in deep water has been increasing over time. The sign for price is negative and significant, suggesting that on average there is a negative relationship between price and productivity of exploration efforts at the intensive margin.

YPE model

To analyse the historical development of petroleum exploration and discovery in the Gulf of Mexico region, is used aggregate data from the region from 1947 to 1998 to examine the amount of reserves discovered per unit of drilling effort, a quantity called YPE (see Hubbert, 1967; Cleveland, 1992). There is a consideration that oil and gas resource discoveries in both new fields (i.e., extensive margin) resulting from exploratory and development drilling and existing fields (i.e., intensive margin) resulting from further exploratory drilling and development drilling.

The long run path of YPE is the net result of two opposing forces: technological change that reduces costs and depletion that increases costs (e.g., Cleveland and Kaufmann, 1991). When measuring the technological change, one must isolate the effects of depletion and innovation. Aggregated data are used to estimate YPE in order to test the hypothesis that technological change offset the depletion in exploration sector in the Gulf of Mexico following Cleveland and Kaufman (1997).

Compared with onshore oil and gas operations, the offshore case is unique because water depth has played an important role in offshore exploration and discovery (see Fig. 2). In general, large fields were first discovered in near shore shallow waters and as the best prospects in shallow waters are depleted, new large fields can be found only in deeper waters. Following Cleveland and Kaufmann (1991, 1997), we specify our YPE model as

$$YPE_t = YPE_0 \prod_i \exp(\beta_i x_{it}), \qquad (3),$$

where YPE is the YPE in BOE per foot in exploratory drilling, t is time (i.e., year), YPE_0 is the initial yield per effort, X_i is the *i*th independent variable, and β_i the coefficient associated with x_i. In this analysis, we consider a number of independent variables. There are two variables capturing current drilling activities: number of exploratory wells (well), and average distance drilled per exploratory well (drill) in feet. Is also used the technological innovation index (technology) defined inEq. (1) above. The expected sign of this variable is positive, since technological change leads to increases in YPE. The effect of resource depletion is measured by a depletion index (depletion), which captures the total resource discoveries to date. The depletion index is the cumulative proved reserves in each period (i.e., cumulative production plus remaining proved reserves). As this index increases, the reserves remaining to be discovered decreases, which is associated with reductions in YPE.

The use of separate variables measuring the combinations of technology and depletion has an advantage over use of a single index based on cumulative exploratory drilling, since it allow us to decompose productivity change into separate effects for depletion and techno-logical innovation. Is also considered the effect of energy price (2000$/B0E) on YPE. The sign on price may be positive or negative. On the one hand, increases in price will reduce minimum economic field size, leading to a greater number of identified deposits that are economical to develop and produce. On the other hand, an increase in price will tend to encourage exploration even at sites with lower potential, thereby reducing YPE. Waterdepth is the average water depth of all exploration wells at t. The expected signs for waterdepth is positive, since as water depth increases, the offshore area available for exploration expands to new frontier areas, which in turn, increases the number of undiscovered fields.

Double-log transformation of Eq. (3) for estimation using GLS correcting for autocorrelation of 2nd degree is took. The results are summarized in Table 3. As in the previous section, we estimate two models of Eq. (3) using the two data sets. The results associated with full/reduced reserve growth factors (first/second data set) are labeled as Models 2-1 and the 2-2, respectively. Again, results from Model 2-1 and 2-2 are very similar, indicating that the YPE model is robust with respect to field reserve growth factors. All of the coefficients are statistically significant. The signs of coefficients for technology and depletion are as expected. The positive sign on price is consistent with results in Cleveland and Kaufmann (1997) as well as in Forbes and Zampelli (2000). On average, there is a positive relationship between YPE and average drilling distance per well (drill). However, YPE is negatively related to the number of wells drilled (well), which likely reflects, in part, diminishing returns to increased drilling efforts holding other factors constant (e.g., remaining reserves, technology, etc.).

One would expect the relative effects of technological change and resource depletion to vary over time during the study period from 1947 to 1998. Therefore, the time profile is examined of the interaction using results of two model estimates in Table 3. Fig. 3.6 shows the impacts of technological change variable and depletion variable on the dependent variable (ln(YPE)) for Model 2-1 (with full growth factor). The two curves in Fig. 3.5 represent the estimated effects of technological change and depletion from Eq. (3).

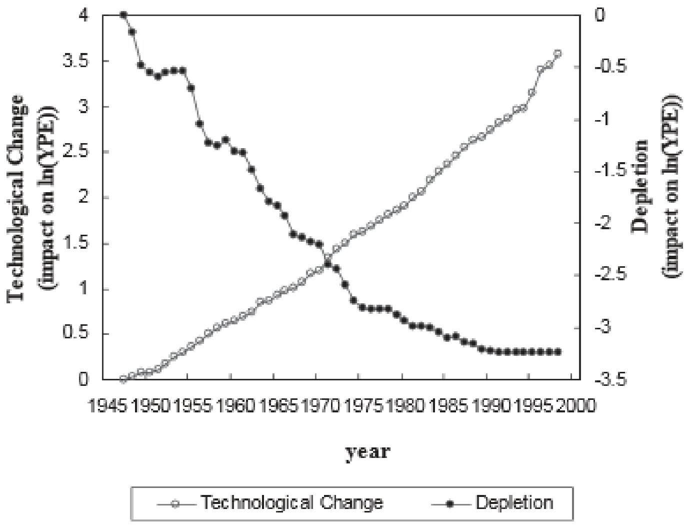


Fig 3.6.Technological change and depletion

The net effect of the two forces is depicted in Fig. 3.7. For sensitivity analysis, we also plot the net effect associated with Model 2-2 (with reduced growth factor).

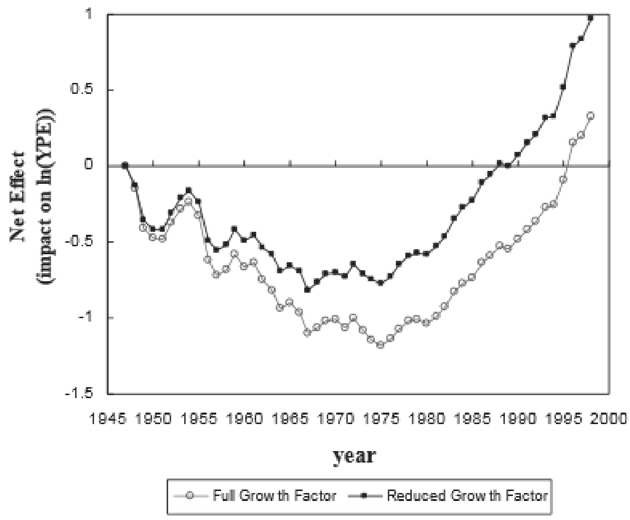


Fig 3.7. Net effect of technological change and depletion

Both curves in Fig. 3.7 reveal a U-shaped trend. The net effect on YPE declined from 1947 to 1965, and then flattened until 1975 when it started to rise. These results indicate that during the last two decades technological change was significant enough to offset depletion, although the opposite was true during the first two decades in the study period. In the case of full growth factor, technological change just offset depletion between 1995 and 1996 when the net effect equaled zero. With reduced growth factor, the net effect reached zero around 1988. The results are consistent with those of with that of Slade (1982) who analyse the prices of major metals and fuels. She concludes that the long-term movement of nonrenewable resource price usually exhibits a U-shaped path that reflects the diminishing ability of technological change to overcome the effect of depletion. The opposite results are found in that technology was unable to outpace depletion at first, but was able to do so later.

In summary, the net effect of the technology and depletion on YPE showed a decreasing trend from 1947 to 1975. During that period, the effect of depletion dominated technological change, and YPE declined. With operations limited in shallow waters, YPE decreased since decline in resource quality (e.g., field size) outweighed the effect of technological change. Since 1975, however, the pace of technological change has significantly increased. Several key innovations in enabling technologies, such as platform and drilling technologies (see Table 1) have drastically expended the offshore areas for oil and gas exploration. In addition, digital seismic recording and analytical techniques have improved exploration efficiency. Since 1990, new technologies like horizontal drilling, 3D seismology, improved computer technologies and deep-water platforms have contributed to the rise in the net effect on YPE.

As a result, the effect of technological change is able to compensate the effect of resource depletion.

The results of our field-level discovery model suggest that for a single field, the initial and subsequent resource discoveries are affected by exploration technology, exploration effort (i.e., drilling), cumulative drilling, cumulative discovery (through the depletion effect), and water depth. With our field-level data, we show significant effects of technological change, resource depletion, and water depth at the intensive margin (i.e., within a field). Using YPE models, we examine the net effect of technological change and resource depletion in offshore oil and gas exploration at the regional level. Our results suggest that, in the exploration-discovery process alone, the effect of technological change was able to offset completely the effect of resource depletion over the five-decade period, although depletion effect dominated technological change in the first two decades. The analysis of the JAS drilling data captures and the effect of resource depletion by using different variables representing the two opposing forces in our empirical models. This enables us to examine the long-term interactions between the two effects. The estimated results associated with our technological innovation index are useful for firms and management agencies to formulate research and development (R&D) policies. For example, the marginal effect of innovation on discovery and cost reduction provides crucial information for decisions regarding R&D investment. Similarly, our empirical results regarding the effect of resource deletion on discovery are important to firms for developing exploration-extraction strategies.

For each field in the Gulf of Mexico, the offshore operation consists of three stages: exploration, development, and production. Since this study focuses on the exploration stage only, our results on the net effect of technological change and depletion do not capture the entire picture of offshore operations. In fact, the impact of technological change on the development and production stages has been substantial. In modelling and forecasting of future oil and gas supply from the offshore industry, we must consider the effect technological change in the development and production processes as well.

Decision making

Environmental decision-making in offshore oil and gas (OOG) operations can be extremely complex due to conflicting objectives or criteria, availability of vague and uncertain information, and interdependency among multiple decision-makers. In following chapter there is an analytical description about the decision on oil and gas exploration in an Arctic area.

Drilling operations are complex and dynamic(1)

The objective in drilling is to make hole as quickly as possible subject to the technological, operational, quality, and safety constraints of the process. These objectives are frequently conflicting and themselves depend upon several factors (Fig.3.8). The formation geology at the site and the location of the target reservoir is a primary factor. Geologic formations vary across the world, and indeed, within the same producing basin. Hard, abrasive, and eterogeneous formations typically have low penetration rates, frequent drill string failures, and significant deviation from the planned trajectory. Deep reservoirs are usually characterized by low permeability, high temperature and pressure, complex fracture growth and stress regimes, and contaminants such as CO_2 and hydrogen sulfide, which increase the complexity of the well and requiring operators to deal with a number of issues concerning safety and operational performance.

Fig 3.8 : The time and cost to drill a well is influenced by a number of variations

The drilling methods used to make hole depend upon the geologic formation and the technology applied, the amount of information known about the formation, the experience and preferences of the operator, available equipment, and the drilling contractor's experience and execution. Well characteristics are specified by the drilling plan, the location of the target reservoir, and the conditions encountered during drilling. Site characteristics such as water depth, operator experience in the region, and environmental conditions influence the operator's decision regarding the selection of the contract and rig type, which in turn, influence performance metrics. Exogenous events such as stuck pipe, adverse weather, and mechanical failure cannot be predicted but can have a significant impact on the time and cost of drilling. In chapter 5 there is an analytical description about the drilling process and emissions and wastes.

Well construction process(1)

The well construction process consists of four stages: design, planning, execution, and analysis. The design and planning phases represent the foundation of well construction, and is usually initiated through the preparation of a drilling proposal by geologists and reservoir engineers. The proposal provides the information by which the well will be designed and the drilling program prepared, and includes project team selection; well design; health, safety, and environmental quality; tendering, contracting, and procurement; finance and administration; operations planning; and logistics. The drilling engineer prepares the drilling prognosis, and all the information that is required to safely and efficiently drill the well, including the well location and water depth, the vertical depth and total measured depth, the depth of the expected reservoir sands, downhole reservoir pressures, expected hydrocarbons, the presence of hydrogen sulfide or CO_2, evaluation needs (logging, side wall coring, drill stem tests), special drilling problems, final disposition of the well, and future side tracking. The well is then drilled according to the drilling plan, usually under a dayrate contract, although turnkey contracts – where the drilling contractor drills the well for a ''lump-sum'' (fixed) price – are also employed. Since the drilling budget represents a significant part of the capital expenditures for a field, usually between 40 and 60% of total development cost, drilling operations are carefully planned and closely watched, and operators maintain meticulous and detailed records of each well drilled. In order to better understand the drilling operations – what worked and what didn't, and why – a post-mortem analysis may be performed.

Cost estimation

Cost estimation is performed specific to the drilling prognosis. The usual procedure is to decompose costs into general categories of site preparation, mobilization and rigging up, drilling, tripping operations, formation evaluation and surveys, casing placement, well completion, and contingencies. Typically, several categories are specified, and the drilling engineer itemizes the expected time and cost per category. Each cost component is identified and categorized into minor cost elements, and the percentage contribution of the total cost is computed to identify the key cost drivers. To improve the range of the estimate, the uncertainty of the cost drivers is frequently quantified. This forms the framework of the well budget which is then sent to management for an Authorization for Expenditure (AFE) to drill the well.

In an AFE, intangible drilling and equipment costs, completion costs if the well is successful, and plugging and abandonment costs if the well is dry, are listed. The AFE typically includes estimates for the cost of the drilling rig, mud, logging, testing, cementing, casing, well stimulation, prime movers, pumps, tubing, separator, and other services and equipment required. In joint operations, the operating agreement typically requires that the operator get approval from the non-operators for drilling expenditures. AFEs inform non-operators as to the drilling plans, providing cost estimates, and obtaining necessary approvals.

Cost components (1, 23)

There are a number of ways in which drilling cost can be classified, based on functional category, time or depth dependence, or variable or fixed cost classification. Cost components usually fall across more than one category and allocation schemes are company-specific. The primary time-dependent costs include the time required to drill a well, which is influenced by the well plan (e.g., interval depths, number of casing strings, formation evaluation requirements), rate of penetration, and problems encountered. Rig costs and other services such as support vessels, aircraft, mud logging, and rental tools, are also time-sensitive. The costs for drilling fluids, bits, cement, logging and other consumables have a time-driven component, but are mostly influenced by well depth and downhole conditions. Some consumable items such as the wellhead and casing will be a fixed cost. Mobilization, demobilization, and preparation are fixed costs determined by the location of the site and the rig release location. Functional categories may also be employed to classify costs, with groupings that include pre-spud, casing and cementing, drilling rotating cost, drilling non-rotating cost, and trouble. The drilling rotating cost category includes all the costs incurred while the drill bit is rotating such as bit and mud cost. Drilling nonrotating costs include tripping, well control, waiting, supervision, and maintenance. Drilling problems are grouped together as trouble and include stuck pipe, fish, lost circulation, hole stability, casing and cement problems. Specialized services such as perforation and cementing are charged on the basis of a service contract, which involves both time and volume factors. Helicopter service will have an aircraft lease rate per month, a flying charge per hour, and a fixed cost for mobilization/demobilization, or may be contracted on an annual basis. Logging operations will typically combine fixed costs for mobilization/demobilization, time-dependent costs for tool rentals, and time-independent costs for tool charges. The proportion of cost in each category will vary from well to well, but typically, the time-dependent proportion of total cost varies between 40 and 70% of the total cost. For offshore wells with high rig and transportation costs, the proportion is toward the upper range, while for onshore wells with relatively low rig dayrates but high time-independent costs, the time-dependent variable cost will be toward the lower range. In the functional categorization, rotating drilling costs and casing/cementing are usually the dominant costs overall increasing with drilling interval and water depth.

Rig hire and the cost of oil services are the dominant components in drilling expenses, as illustrated in Fig. 3.9 by a representative well. Drilling expenses have increased sharply in recent years. According to the Norwegian Petroleum Directorate (NPD), it costs the same to drill just 15 exploration wells in 2006 as 35 in 1997. Key causes of this rise include declining drilling efficiency and higher rig rates.

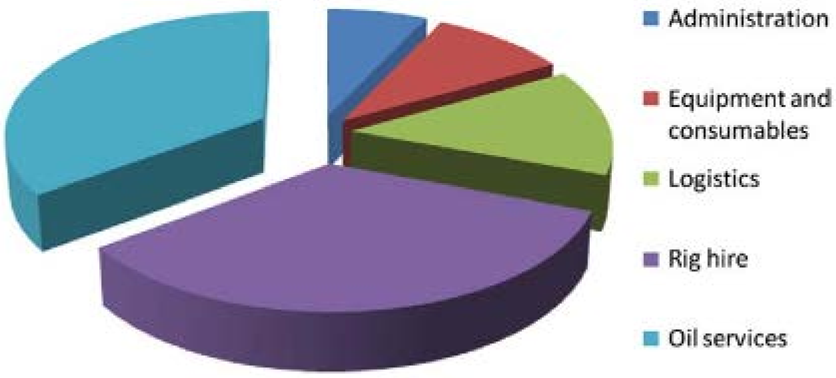


Fig. 3.9.Typical composition of drilling costs

We can see from Fig. 3.10 that rig rates have increased massively during recent years. Starting from less than USD 100,000 per day at the beginning of 2002, rig rates for high-spec semi rigs have now reached more than USD 400,000 per day. This reflects the oil industry boom sparked by the high price of crude, and the fact that few rigs were built over a fairly lengthy period.

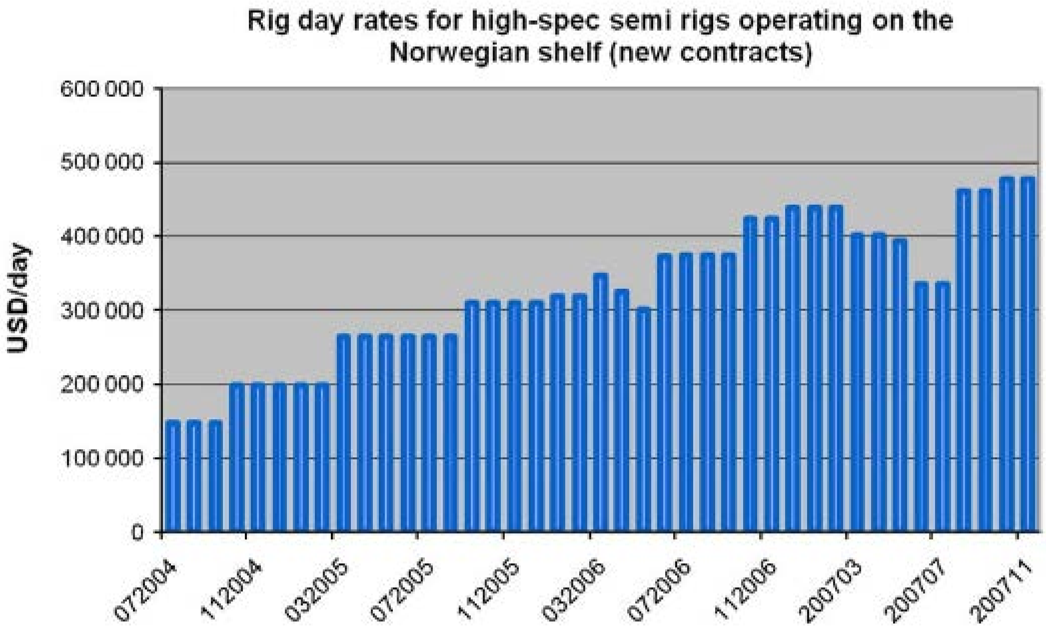


Fig. 3.10. Rig rates per day on the NCS. Source: ODS-Petrodata, North Sea Rig Report

Fig. 3.11 shows that drilling efficiency, measured by metres drilled per day, has declined substantially since 2001- from 102 m per day to 80 m at present. Given this very sharp fall in drilling efficiency, it is hardly surprising that various types of incentive contract have been tried out in this sector. But it can be added here that other measures might be better at identifying value creation in drilling. In addition to drilling speed, which affects the cost side, the amount of oil and gas which can be produced must be taken into account. This is not only a question of drilling fast, but also of drilling correctly. A trade-off may need to be made here, at least in parts of the well path. The causes of the decline in drilling efficiency (by conventional measures) have not been investigated in detail. One reason is that technological developments have made it possible to drill longer wells (including multilaterals) than before. Such wells are more demanding, but qualitatively better. Another reason is that remaining reserves are more complex and thereby more demanding to drill for. In view of these considerations, a decline in drilling efficiency is reasonable. New technology- with a higher probability of downtime- could also have contributed to a decline in drilling speed. Aging of the rig fleet might play a part, and maintenance may have been sub-optimal for various reasons, such as a focus on short-term accounting gain or very high capacity utilization. Another reason is quite simply declining efficiency in drilling operations, which would be unfortunate. Very high capacity utilization in terms of both equipment and personnel could be a key factor. When all hardware is in use, the average quality usually declines.

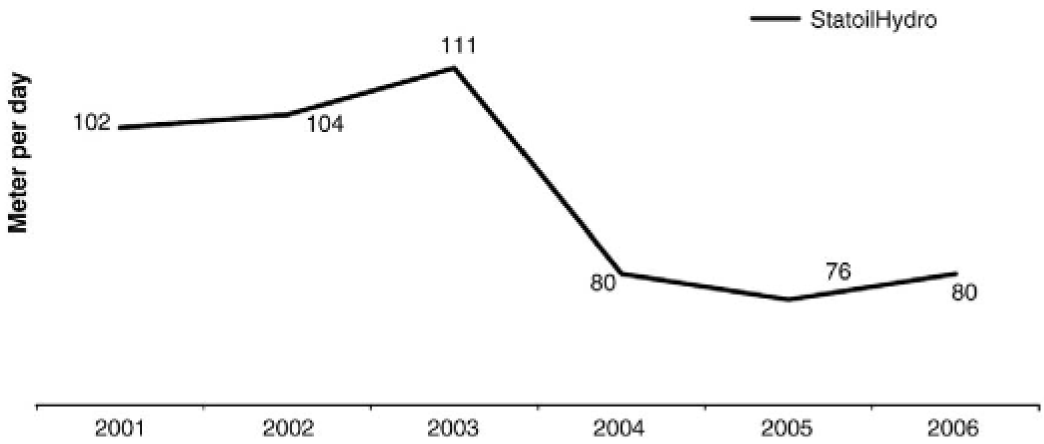


Fig. 3.11 Drilling efficiency on the NCS, measured by the average number of metres drilled per day. Source: Sund (2007)

Mobile offshore drilling units(1)

Offshore oil production began in 1947 when Kerr McGee Oil Industries drilled the first producing well beyond the sight of land in 18 feet of water, ten miles from the Louisiana coastline. Some 25 years later, offshore wells were being drilled in 1000 feet water depth, while today, drilling occurs in water depth over 10,000 feet deep. Offshore drilling operations are significantly more expensive, uncertain, and risky than onshore due to the harsh and unpredictable operating environment.

Oil and gas reservoirs are found in a wide variety of geographical and geological environments, and the rig which is used to drill a particular well must have the capability to drill in the environment in which it is to be used to the depth required to reach the reservoir. Exploratory drilling is most often performed from a mobile offshore drilling unit (MODU) such as a jackup, semisubmersible, or drillship. In the Gulf of Mexico, all of these types are employed. In shallow bays, marshes, and other protected waters where weather conditions are not harsh, drilling rigs are mounted on steel barges that are pushed into place and flooded to sit on the bottom of the water. These rigs are known as the ‘‘inland’’ rig fleet (or swamp barges) and typically work in 8–20 feet of water. Submersibles consist of a drilling platform mounted on vertical columns attached to pontoons. When water is pumped into the lower hull, the rig submerges and rests on the seabed when drilling, and when emptied, allow the rig to float and be tugged from one location to another. Swamp barges operate in swamp and marsh areas in Louisiana, Nigeria and Indonesia.

A jackup rig is a barge with legs that can be lowered or raised (Fig. 3.12).

Fig. 3.12. Mobile offshore drilling unit – jackup. Source: Pride.

Jackup rigs are the most common MODU used worldwide and are capable of drilling on a wide variety of tracks inwater depth up to 500 feet. For short distances, the platform is towed to site, while for major moves, the rig is transported as cargo on a heavy lift vessel. Once in position, the legs are lowered, hoisting the drilling platform above the water. Jackup rigs are either ‘‘mat-supported,’’ with the jacket legs attached to a submerged mat, or ‘‘independentleg,’’ where the individual legs are driven down independently into the ocean floor. Rig selection depends on availability and seafloor conditions. Independent-leg rigs are capable of working in deeper water and harsher environments than mat-supported rigs. After preloading the legs, the hull is raised above the sea surface to a height (called the air gap) that depends on the expected height of the waves or the height of the platform. A slot in the hull allows the wellhead to be positioned under the rig floor, or the rig floor and support structure can be extended (cantilevered) from the side of the hull to the desired drilling position. Independent-leg cantilevered rigs are usually priced at a premium over mat-supported slot rigs. In water depths greater than 500 feet, semisubmersibles and drillships (also called floaters) are used. Floaters require specialized technologies that are not used with bottom-support rigs, such as dynamic positioning systems, marine risers, and drill string motion compensators. A semisubmersible rig (semi) is designed to float in the water and is held in position by multiple anchors or equipped with dynamically positioned thrusters (Fig. 3.13).

Fig. 3.13 Mobile offshore drilling unit – semisubmersible. Source: Transocean.

Semisubmersibles are very stable during high seas and winds and the most modern semis can drill in 10,000 feet of water. Semis are normally self-propelled and supported by vertical columns on submerged pontoons. By varying the amount of ballast water in the pontoons, the unit can be raised or lowered. The lower the pontoons lie beneath the surface, the less they are affected by wave and current action. A drillship has a conventional ship hull with a large aperture known as a ‘‘moon pool’’ through which drilling takes place (Fig. 3.14).

Fig. 3.14.Mobile offshore drilling unit – drillship. Source: Stena Drilling

Drillships built before 1975 drilled in shallow waters while moored in place, but went out of favor in the late 1980s. A new generation of drillships built after 1975 were dynamically positioned which allowed drilling in water depths up to 10,000 feet.

4. Drilling

Stages of drilling(1)

The start of drilling a well is called ''spudding in''. To spud in, a large pipe, called the conductor or foundation casing, is either drilled, jetted, or hammered into the seabed from 100 to 500 feet to a point below the drill floor. The conductor serves as the top part of the well and creates a hole for the drillstem and casing to be lowered into.

Wells are drilled in stages:

- The bit and drill string is inserted into the hole and drills to a certain depth.
- The drill string is removed from the hole.
- Casing is put into the hole to line it, and in most cases, is cemented to the wall of the hole.
- The bit re-enters the hole and the process is repeated until the target is reached.

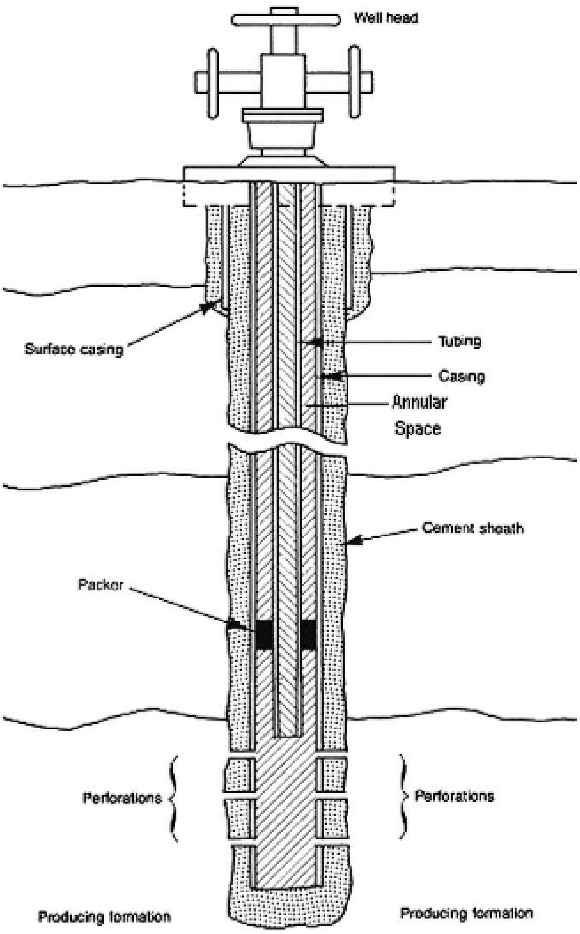


Fig 4.1

The drill string and bit represent the business end of drilling, and all the equipment on the surface and subsurface is used to support drilling with the bit. Wells are drilled ''open hole'' until it is necessary to run and cement casing to protect the integrity of the well. Wellbore stability can be a mechanical problem, where weak formations exist, or it can be a chemically based problem, where clays in the shales and other formations are weakened when exposed to the drilling fluid. The amount of open hole limits how long an interval can be and how long it may be safe to expose the formations to the drilling fluids.

A well penetrates many different types of rock formations (zones) until total depth is achieved, and as drilling continues deeper into the earth, the operating environment becomes more hostile and drilling becomes more difficult: temperatures and pressures increase, formations become more abrasive and harder, complex stress regimes and fracture growth develop, and the time and cost of drilling increases, often substantially. A well is usually spudded with a 36'', 300'', or 26'' casing, and as the hole deepens the casing becomes progressively narrower, perhaps finishing with 7& 3/8'' or 9& 5/8'' diameter at target (Fig. 4.1).

Surface casing protects freshwater acquifers, anchors the blowout prevention equipment, and protects the hole from potentially hazardous shallow formations. Intermediate casing protects holes from abnormally pressured zones and poor formations such as salt and sloughing shale. Most casing is thin-wall, 30 feet sections of seamless steel pipe and the space between the casing and the borehole is cemented to support the casing and to prevent the flow of underground fluids to the surface and/or into freshwater zones. The number of casing strings needed to drill a well depends on the formation and often varies from 3 to 8 strings. Troublesome formations such as high pressure zones, sloughing shale, and shallow water flows require more intermediate casing. A narrow pore pressure–fracture gradient will also require more casing strings, and because of the time involved to trip out the hole and set casing pipe, the cost of drilling increases with the number of casing strings. The drill bit is attached to 30 feet joints of steel pipe screwed or joined together as they go downhole. The drill pipe may be preracked into double and triple joints depending on the capability of the drilling rig. The pieces of formation which are cut away is called cuttings, and during the drilling process, drilling fluid (i.e., mud) is circulated down the drill string, through the nozzles in the bit, and then back to the surface through the annulus between the drill string and the borehole walls. At the surface, the drill cuttings, silt, and sand are removed from the drilling fluid before it is returned downhole through the drill string.

The role of mud

Drilling fluids, also referred to as mud, play a number of important functions in drilling: to control the pressures that exist in the wellbore at different depths, to carry the cuttings out of the hole, to lubricate the drill string, and stabilize the wellbore. Drilling mud consists of four basic parts: (1) base fluids – water, oil, synthetic material, or varying combinations – which classify the mud; (2) active solids – the viscosity building part of the system, often bentonite clays; (3) inert solids – the density building part of the system, such as barite; and (4) other additives – to control the chemical, physical, and biological properties of the mud, such as polymers, starches, and various other chemicals. Mud is classified into three general categories: water-based mud (WBM), oil-based mud (OBM), and synthetic-based mud

(SBM). WBM is made with fresh or saline water and is used for most types of drilling, often consisting of dissolved salts, additives, polymers, clays, and weight material such as barite. OBMs are water-in-oil emulsions with dispersed clay and weighting material. In SBM, the oil is substituted with long-chain esters, ethers, acetyls, and synthetic hydrocarbons. OBM and SBM have special operational advantages over WBM due to their low friction, good temperature tolerance, and inertness to formation clays. SBM were developed in response to the requirements for drilling fluids with performance comparable to OBM but without the adverse environmental implications. SBM and OBM are not generally used for the entire depth of the well; typically, WBM are used for the upper portion with a change to SBM below the 1600 or 1300 casing point at a depth of 5000 feet or more. Each mud program is well specific. Formation pressure can be unpredictable, and therefore, potentially hazardous. If the drill bit penetrates a high pressure zone unexpectedly, oil or gas, or a mixture of both, may rush into and up the wellbore, dilute the mud, and reduce its pressure. This is called a ''kick,'' and it can lead – if unchecked – to an uncontrollable gusher at the wellhead (a blowout). Drilling fluid and the experience of the drill team is the first line of defense to prevent this occurrence. The last line of defense situated below the wellhead control valves is the emergency blowout preventer (BOP); in deepwater, BOPs may be situated on the seabed. Kicks and blowouts can be detected by monitoring the density, viscosity, and other properties of the drilling mud. A drilling problem may require chemical additives (''pill'') to be injected into the mud, or heavy mud (''kill mud'') to circulate the kick out of the well. The density of the mud depends on the formation pressures anticipated or encountered, which in turn impacts the rate of bit penetration. Heavy mud retards bit penetration and can cause stuck pipe and skin damage. Light muds are used if the well is planned and drilled in underbalanced mode, where the pressure of the fluid column is designed to be less than that of the formation pressure. Drilling is usually performed underbalanced in non-permeable zones and overbalanced in permeable zones. In development drilling, the local pressure regime is usually known, while in wildcats, it is uncertain since the local geology has not yet been explored.

Generalized dayrate contracts (1)

The operator writes a drilling prognosis – which essentially is the recipe book for the well, and includes equipment and procedures that the operator will require, together with a well description, bid specifications, and drilling contract – and then the drilling superintendent will choose a group of companies with rigs that meet the demands of the project and which are in the general vicinity of the well to be drilled. The terms of the contract can be for one or more wells over a short- or long-term basis on either a ''dayrate'' or ''turnkey'' contract. After the contractors submit their formal bids, the drilling superintendent and his team select the rig that they believe will drill the well in the most cost effective and safest way. The operator selects the best bid according to price, availability, reputation, past experience, and other factors. The contract winner is not necessarily the lowest bid contractor. Drilling contracts are complex instruments because in addition to covering the financial, legal, environmental and health and safety aspects of the job, they must also accommodate the uncertainties inherent in the operation, so that neither party is unduly penalized for unforeseeable events. Offshore contracts originated from their land-based counterparts and developed over the years with increased sophistication, but there is still little standardization. The American Petroleum Institute, the International Association of Drilling Contractors, the American Association of Drilling Contractors, the United Kingdom Cost Reduction Network, and other organizations all have their own draft drilling contract forms. Operators also maintain forms which are designed to avoid problems encountered in their particular experience. A drilling contract is a service contract in which a company agrees to perform certain services for a monetary payment. The payment terms under a dayrate contract are usually decomposed in terms of four basic subrates: mobilization rate, operating rate, reduced rate, and special rate. The mobilization rate is used during the time the rig is mobilized/demobilized between well locations or shore, and covers port fees, towing cost, fuel and other expenses incurred by the contractor to arrive at site. Mobilization/demobilization may also be specified on a lump sum basis. The operating rate governs the cost during drilling and covers the rig rental, crew and consumables. The dayrate is primarily determined by water depth and rig capabilities, the supply/demand conditions that exist in the region at the time the contract is written, and the duration of the contract. Most shallow water rigs are relatively non-specific assets, capable of drilling on a wide variety of tracts. Deepwater rigs are more capital intensive and sometimes firm-specific.

The drilling business is highly competitive and dayrates typically follow utilization levels. The reduced or standby rate covers conditions when the rig is not drilling, such as during moves, logging or testing, while special rates are used when drilling is interrupted by adverse sea or weather conditions, mechanical failure, force majeure, or the concession holder’s inability to obtain the required permits or authorization. The total drilling cost under a standard dayrate contract is determined thus

$$DHC = \sum_{i=1}^{4} T_i R_i,$$

where DHC= total drilling cost ($), T_1 =total amount of time rig mobilized and anchored (h), T_2 =total amount of drilling time (day), T_3=total amount of time spent moving, logging, or testing (h), and T_4 =total amount of downtime spent on equipment failure or waiting on weather (h), R_1 = mobilization rate ($/h), R_2 =operating rate ($/day), R_3 = reduced rate ($/h), and R_4=special rate ($/h).

Contract terms are proprietary, but dayrates are widely reported and tracked by industry. The time for the rig to mobilize and anchor depends on the type of rig and the distance from its current location to the new site. The total amount of time spent coring, logging, and testing depends upon the well type, well design, and the success of drilling. The amount of time spent moving the rig or waiting on weather is a stochastic function depending on the region and time of the operation. Downtime spent on equipment failure or problem wells may be attributable to geologic conditions, operator and contractor experience, and a random forcing function.

Model factors

Drilling operations are complex and uncertain, and many factors influence the time and cost to drill a well. These factors are multidimensional, often interdependent, and usually stochastic; the factors can be classified as either observable or unobservable (Fig. 4.2).

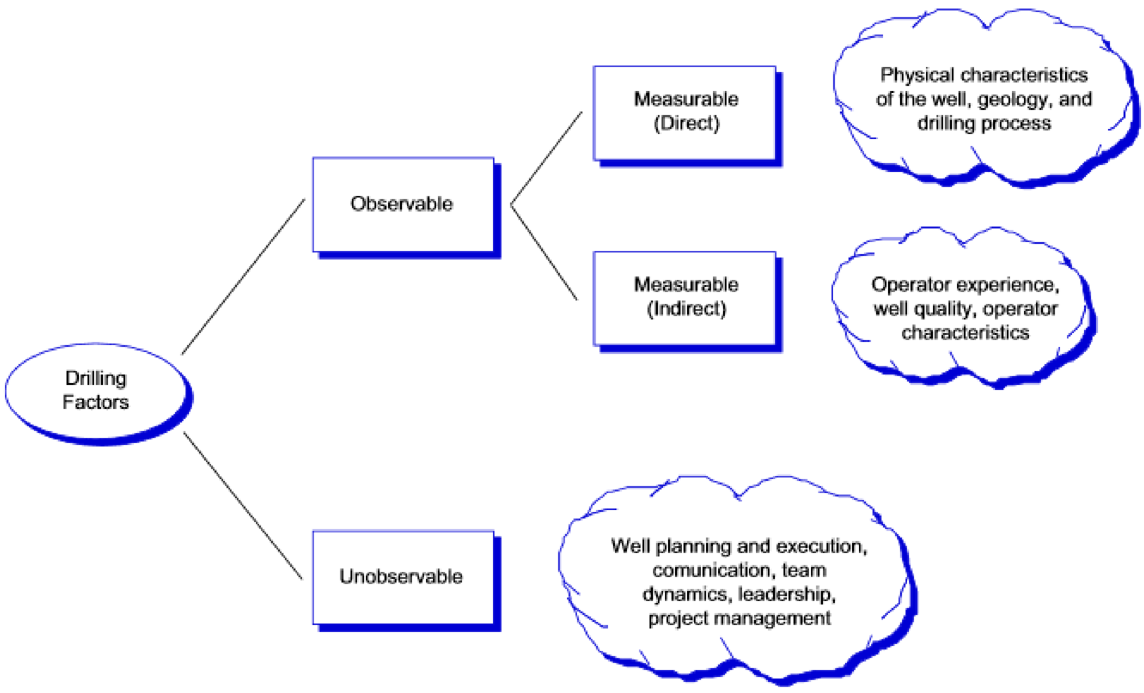


Fig 4.2: Drilling factors are classified into observable and unobservable categories

Measurable factors include the physical characteristics of the well, geology, and drill parameters; while indirect characteristics, such as wellbore design, contractor experience and hole quality, need to be proxied through other variables if they are to be incorporated in analysis. Factors such as communication, leadership, and project management skills will also impact drilling performance, sometimes significantly, but to capture and identify the influence of these (unobservable) variables is usually beyond the scope of analysis and the reporting capabilities of operators. The amount of data required to construct a reasonable representation of drilling operations depends in part on the nature of the data set and the system characteristics.

Well characteristics (1)

- Well type

There are many ways to classify wells. The most common distinction is between exploratory and development wells. Wells that are drilled in an unproved area to add reserves are exploratory wells, while wells drilled in the known extent of a field to produce known reserves are development wells.

Exploratory wells are drilled to find oil and gas, and their primary purpose is to gather information on subterranean conditions and confirm whether geological formations contain hydrocarbons.

Most exploratory wells are drilled as straight as possible 5 but in special circumstances, may be drilled at an angle or even horizontally. Development wells are drilled as part of a production plan. Usually only the first development well is vertical; subsequent wells are drilled vertical to a certain depth and then kicked off in a ‘‘J-shaped’’ or ‘‘S-shaped’’ pattern to total depth. A planned multilateral will involve sidetracking out of the well from a zone shallower than the original leg of the wellbore to reach a new section of the formation.

The first exploration well in an area will be drilled very carefully because the geologic formations are untested and the risk of overpressure may result in a blowout, but after a few wells the stratigraphic layers where overpressures can be expected are known, and drilling can often proceed at a faster rate. The time and costs to drill a development well is expected to be smaller than exploration wells because information gathered from exploration is applied in drilling. Learning economies are also well documented in development drilling.

Well status describes if the well hit ‘‘pay dirt’’ (successful) or was a ‘‘duster’’ (dry hole). An unsuccessful well will often lead to sidetracking to test a different section or zone. Dry wells will be plugged with cement and abandoned, and the extra time and cost of this operation suggest that dry hole cost will exceed, if all other things are equal, the cost to drill a successful well. This is generally true for onshore wells as reported by American Petroleum Institute drilling cost data, but in an offshore environment, the extra cost to plug and abandon a well is usually a small part of the total drilling cost and is not easily distinguished. Offshore, wildcats that find a commercial pay zone may be temporarily plugged and abandoned until the field is developed or permanently plugged if the location is not optimal from which to produce the field.

- Well geometry

A wellbore is a three-dimensional object which can be described in geometric terms with respect to the length, diameter, and curvature of the hole trajectory. The depth of a well measured from the rotary table in the XY-plane along the length of the wellbore is called total depth (or total measured depth) and denoted by TD, while the (true) vertical depth VD is the distance from the rotary table measured in a vertical plane to TD. Spud depth SD is the distance from the rotary table to the seabed. The drilled interval DI is the difference between the total depth and the spud depth, DI= TD-SD; the vertical interval is defined as VI= VD-SD.

The horizontal displacement HD is the distance in plan view6 from the rotary table to TD. Water depth WD is the distance from the waterline to the seabed. The problems, costs, and hazards of drilling increase with water depth and drilled interval. Water depth is an important factor in all offshore operations because as water depth increases, rig specifications also need to increase. Drilling operations with floaters require even more specialized technology which adds significantly to dayrates. The deeper the hole the more time is lost in round trips to replace worn bits and to run casing, tests, and logs. The number of formations encountered will typically increase along with the number of casing strings required to maintain well control. As the number of casings increase, the trip time, installation, cement, and cementing time will also increase. The direct cost of the additional strings has an effect, but there are also costs that occur because of well-diameter constraints. The ability to handle larger casing requires more expensive rigs, tools, pumps, compressors, and wellhead control equipment. Increasing the number of casing strings from 3 to 4 may result in a 10–20% increase in well cost; increasing the number of strings from 4 to 5 may increase cost by 20–30%; and so on. Offshore drilling mud is an expensive chemical preparation, and the deeper the hole, the more mud is needed. Beyond a certain depth below mudline (15,000 feet), technical complications and the opportunity for problems increase significantly. In many deepwater wells, the percentage of total well cost as a fraction of total depth is such that as much as 50% of the total cost can be spent on drilling the last 10– 20% of the well.

A well is composed of segments of casing string Si oriented at an angle A(Si) relative to a reference coordinate system. The maximum angle of the wellbore is computed as:

MA=max A (Si)

If $MA \geq 85^{o}$ the well is classified as a horizontal well using the indicator variable HW:

$$HW = \begin{cases} 1, MA \geq 85^{\circ} \\ 0, \text{otherwise.} \end{cases}$$

If L(Si) denotes the length of well section Si, then the total length of the horizontal section of a well is denoted as HL:

$$HL = \left\{ \sum_{i=1}^{l} L(S_i) \middle| A(S_i) \geq 85^{\circ}, \quad i = 1, \ldots, l \right\}.$$

Oil and gas wells are drilled horizontally for a variety of reasons, but primarily to improve production and reach reserves that otherwise might not be developed. Horizontal drilling is less stable than drilling vertically, more difficult to log and complete, and often between 2 and 3 times the cost of a similar length vertical borehole. Directional wells with long horizontal departure are called extended reach wells and are often defined as wells with TD/ VD> 2.0.

- Casing geometry

Casing serves several important functions in drilling and completing a well, and is one of the most expensive parts of a drilling program, ranging from 10 to 20% of the total cost of a completed well. Casing prevents collapse of the borehole during drilling and isolates the wellbore fluids from the subsurface formations. Casing also provides a flow conduit for the drilling fluid and permits the safe control of formation pressure. A well that does not encounter abnormal formation pore pressure gradients, lost circulation zones, or salt sections usually require only conductor and surface casing to drill to target. Deeper wells that penetrate abnormally pressured formations, lost circulation zones, unstable shale sections, or salt sections generally will require one or more strings of intermediate casing to protect formations and to prevent problems.

Each casing section has a diameter Di= D(Si), radius Ri = R(Si), and length Li = L(Si) measured from the rotary table. If k =NS represents the number of strings associated with the well, then a finished well is characterized by the vectors D = (D_1, D_2,., Dk) and L= (L_1, L_2,., Lk). The number of casing strings provides an indirect measure of well complexity, since complex wells are frequently associated with multiple strings and narrow margins between pore pressure and fracture gradients. The incremental well casing length is denoted by L^*=(

$L_1^*, L_2^*,..,L_k^*$), where $L_i^* = L_i - L_{i-1}$ for i=1,…,k and $L_0^*=0$. If hole sections can be drilled without setting intermediate strings or liners then drilling can proceed quickly.
Operators generally prefer the production casing to be as large as possible to maximize production, but large production casing requires a large wellbore, which is more complicated and expensive to drill, since the rig has to be higher spec and more rock volume has to be removed. Average hole size and removed rock volume are numerical measures that characterize the geometry of the final drilled well. The average hole size HS is determined by the weighted average diameter of the casing string along the wellbore:

$$HS = \frac{\sum_{i=0}^{k} D_i L_i^*}{\sum_{i=0}^{k} L_i^*},$$

while the rock volume removed VR from the wellbore without washout is defined as

$$VR = \pi \sum_{i=0}^{k} R_i^2 L_i^*.$$

The cost of drilling should be larger the greater the average hole size and volume removed from the wellbore.

- Well complexity

A wide variety of well types and configurations exist, along with several notions of what constitutes a ‘‘complex’’ well, and it is unlikely that a single definition will ever be widely accepted since practices, opinions, and experiences among drilling contractors vary significantly. Complex wells arise from geologic formations, target depth and the size of the reservoir sands, wellbore trajectory, the experience of the contractor and application of technology, as well as numerous other factors. Conditions that create a complex well are often proxied through a description of the physical characteristics of the well, such as the water depth, vertical depth, maximum angle, and number of casing strings. High-pressure/high temperature HP/HT wells begin to exhibit high temperatures at depths around 18,000–20,000 feet, although in areas with geothermal activity, hot drilling conditions can occur at shallower depths. HP/HT wells are usually planned and drilled using significantly less formation data than shallower and cooler wells. The trajectory of a well, G, can also be used to describe complex wells. A well is often considered complex if its formation pressure FP exceeds 10,000 psi or temperature T is greater than 300 ^{o}F anywhere along the wellbore. A complexity index is used to identify complex drilling environments if any of these conditions occur:

$$CI = \begin{cases} 1, & FP > 10,000 \text{ psi}, \; T > 300\,^{\circ}\text{F}, \text{ or } \Gamma \text{ complex} \\ 0, & \text{otherwise.} \end{cases}$$

The ratio of the horizontal length to the total footage drilled describes the percentage of the well's footage drilled under horizontal conditions:

$$HR = \frac{HL}{DI};$$

e.g., for most exploratory wells HR≈0, while for development and extended reach wells, 0 < HR≤1. The aspect ratio AR,

$$AR = \frac{HD}{VI},$$

measures the aggregate curvature of the well trajectory, and the extended reach ratio, ER, is defined as the ratio of total depth to total vertical depth:

$$ER = \frac{TD}{VD}.$$

All three ratios provide metrics that quantify the wellbore trajectory.

Site characteristics(1)

The well site is characterized by its geographic location determined through its latitude/longitude coordinates, the distance from the well to the nearest onshore service station, and the water depth. Water depth and environmental conditions expected to be encountered are primary determinants in the selection of the rig required for drilling. As water depth increases, larger and more robust rigs are required, with extra hoisting capacity, mud circulation systems, mooring systems, etc. The region and country in which a well is located is an important consideration in obtaining government regulations and permits. The maturity of the infrastructure support services can play a significant role in determining drilling cost, and the knowledge and experience of the contractor, say as measured by the number of wells drilled in the region, can be important factors.

Operator preference

- Contract type

The operator decides not only where to drill, but also how to drill, and the manner in which to let the contract. The contract type (dayrate, turnkey), job specification (one well, multiple wells), market rate, and negotiating strategies are important factors in determining drilling time and cost.

- Rig selection

Many different rigs can be used to drill an offshore well. Rig selection depends upon factors such as the type of well being drilled, water depth and environmental criteria, the type and density of the seabed, expected drilling depth, load capacity, frequency of moves, ability to operate without support and availability. Before selecting a rig, a detailed site assessment is completed to identify water depth and bottom conditions, and expected weather, wind, tides, wave heights and current speeds. Water depth is an important factor since the rig must be rated to work in the depth required; e.g., a jackup must be able to jack up on location and withstand the normal environmental forces encountered. Seabed conditions determine if an independent-leg or mat-supported jackup can be employed. Independent-leg jackups are employed in firm soil, coral, or uneven seabeds; mat-supported jackups require low soil shear values and a flat seabed. The decision to use an anchored or dynamically positioned rig depends on the nature of the seafloor, the size of the rig, and the expected operating conditions.

Deepwaters characterized by strong currents create a need for high specification rigs capable of maintaining station, and in some instances, suppressing vortex induced vibrations. If weather and environmental conditions are expected to be a problem, then sophisticated all-weather semis can be used to hedge against weather downtime. The increase in availability is achieved through the higher capital cost of the equipment; which in turn is passed to the operator in higher dayrates. Jackups are cheaper but are more prone to weather delay. The choice is up to the operator: the trade-off is between drilling availability and dayrate. Rig availability also plays a role in the selection process, since if the regional demand exceeds supply, market rates will rise. In the past, dayrates were based on investment and depreciation schedules, but when a market has a capacity shortage, dayrates will be determined primarily by demand rather than cost recovery. If regional utilization rates are low, drillers may stack jackups and contract large rigs to shallow water projects to maintain the utilization of high cost equipment.

Drilling characteristics

- Bit size and type

Different types and sizes of bits are used according to the hardness of formations, pressure regime, and drilling plan. Bits are classified as roller bits, such as steel tooth and insert bits, and fixed cutter bits, such as polycrystalline diamond compact (PDC), thermally stable polycrystalline (TSP) and natural diamond bits. For hard and abrasive drilling conditions in deep wells drilled with mud, tricone bits are commonly used, but their susceptibility to wear and bearing failure limits their drilling time. In deep hole sections, where tripping times are longer, polycrystalline or natural diamond bits are competitive with the tricone bit. The final bit size employed in the well is denoted FBS.

- Drilling fluid

Drilling mud is applied to control the pressures that exist in the wellbore at different depths. Synthetic-based muds have downhole performance similar to OBMs and offer advantages over WBMs in certain circumstances; e.g., SBM have higher lubricity compared to WBMand can endure more hostile downhole conditions. The use of SBM is likely to enjoy faster penetration rates and is also less likely than WBM to interact with the production horizons because their physical and chemical makeup is similar to the hydrocarbon bearing zone. Other fluid-related issues involved in the choice of drilling fluid system include hole cleaning, lubricity, stability, barite sag, and fluid stability. In horizontal, multilateral and extended reach applications, fluid-related issues become more complicated, and the more complex the mud program, the greater the expected cost of drilling.

- Mud weight

Heavy mud is typically used to create an overbalance to prevent fluids from entering the well. The greater the hole pressure, the heavier the mud, and the slower the drilling. Mud weights vary over each well section. If the mud weight applied to drill out well section Li*, i¼

- Formation evaluation

Formation evaluation is a critical step in exploration since it is the stage in which information about the presence/absence of hydrocarbon bearing reservoirs is acquired. It is important to remember, however, that time spent coring, logging, reaming, and testing is ‘‘flat’’ time, and so for wells that require extensive formation evaluation data, normalization is required prior to performance comparison. Cutting a core requires separate round trips to install and remove the coring assembly, and because coring is slower than drilling, if the well is deep and the interval is large, coring can incur a significant amount of rig time. The number of days spent drilling out core samples, or trying to core, the well in any hole section is denoted by CD. The number of days spent logging, or trying to log, before or after total depth is reached, but excluding logging while drilling or formation evaluation drilling, is denoted LD. Coring and logging days include interrupt time and waiting on weather time.

Exogenous events(1)

Exogenous events cannot be predicted with any degree of accuracy, but their impact and duration needs to be considered to normalize for conditions beyond the control of the contractor.

- Weather

Offshore drilling may be subject to significant delays caused by the weather, and weather downtime can play an important factor in the total costs of the operation. Weather downtime can impact drilling operations in various ways; e.g., weather too severe for operations involving supply boats may lead to delay if stock levels on the rig decline to a critical level; weather may impact anchoring up and moving time; weather may be too severe for drilling to occur; and extreme weather may result in damaged or lost drill strings and risers. If operating limits are exceeded because wave heights, ocean currents, or eddies are too strong, drilling operations will be temporarily abandoned and resumed when conditions fall within the operating capabilities of the equipment. Waiting on weather WOW time needs to be considered separate from the drilling time and cost metrics.

- Interrupt time

Many problems can occur during drilling requiring suspension of the activity. Most contracts specify a certain amount of ‘‘free’’ downtime (24 h per month is typical), but outside this allowance, the contractor does not receive payment for the time the rig was inactive. Other delays that may occur not directly accountable to the driller are usually charged at a reduced rate. One of the most common problems in drilling a hole is that something breaks inside the well, such as a piece of bit or drill string, or something falls down into the wellbore, such as wrenches or other tools (see Appendix A). These pieces of metal are called ‘‘fish’’ or ‘‘junk,’’ and because the bit cannot drill through them, drilling must be suspended until they can be retrieved by ‘‘fishing’’ tools leased from a service company. The use of fishing tools cost the operation extra money and time spent fishing is flat time. If fishing is unsuccessful, the hole will either be sidetracked or whipstocked (drilled around the obstacle), and in the worst case, a new hole may need to be spudded. Rig equipment failure, lost circulation and stuck pipe are the main causes of downtime in the Gulf of Mexico, and in some cases have been reported to account for nearly 25% of drilling budgets. Interrupt time cannot be predicted with any degree of accuracy, and so an upper limit exists on the expected reliability of any cost prediction tool.

- Oil and gas prices

There is a correlation between hydrocarbon prices and drilling costs. When the price of crude oil increases, there is generally an increase in exploration and drilling activity, and a decrease in rig availability. Supply-and-demand lead to an increase in the costs of rig rental rates, material costs, and services. Natural gas prices impact rigs drilling for gas on a regional basis.

Unobservable variables

Many variables which influence drilling performance, such as well planning and preparation, project management, and technology are difficult (if not impossible) to quantify, and since the manner in which these variables impact the drilling program are essentially unobservable, it is usually not possible to directly incorporate these factors into modeling. The importance of these factors to performance cannot be overstated, however, and is commonly recognized as playing an important role in operations.

- Well planning

The first step in planning any well is to design the wellbore path to intersect a given target. Were adequate time and resources given to the operational team to develop an efficient and best practice well design, or was too little given too late for the team to succeed? Careful planning and evaluation are required to successfully complete a project whether drilling easy, normal pressure wells, in shallow water, shallow target, benign environments; or difficult wells with a complex geometry that have a combination of high temperature, high pressure, narrow pressure/formation gradient windows, salt, rafted shale, high angle, shallow hazards, deepwater, contaminated environments. A multi-disciplinary operational team is usually the most efficient to deal with drilling/well construction issues and objectives.

- Project management and leadership

Comprehensive, forward looking, integrated engineering planning, coordination, execution and management, including defined contingencies and options, helps the drilling program to be executed in the shortest possible time.

- Well quality

The timely delivery of logged, tested, and producible boreholes is important to the profitability of the field. What was the quality of the final wellbore? Was there skin damage?

- Technology

The impact of technology on drilling performance is pervasive but difficult to isolate. Technology may be ‘‘enabling’’ or ‘‘enhancing’’ or both, and will normally shift from enabling to enhancing over time. New technology is expensive, both in terms of cost and learning, but if the technology reduces drilling time or improves the efficiency or safety of the operation and becomes widely adopted, costs decline and the performance efficiencies will improve and become absorbed within the process. Trade-offs between competing technologies and processes are common but quantifying the differences in impact remains notoriously difficult to evaluate.

5. Wastes during Drilling and Production Operations(16)

In the upstream petroleum industry, there are two major operations that can potentially impact the environment: drilling and production. Both operations generate a significant volume of wastes. Environmentally responsible actions require an understanding of these wastes and how they are generated. From this understanding, improved operations that minimize or eliminate any adverse environmental impacts can be developed.

During both drilling and production activities, a variety of air pollutants are emitted. The primary source of air pollutants are the emissions from internal combustion engines, with lesser amounts from other operations, fugitive emissions, and site remediation activities.

Drilling

The process of drilling oil and gas wells generates a variety of different types of wastes. Some of these wastes are natural byproducts of drilling through the earth, e.g., drill cuttings, and some come from materials used to drill the well, e.g., drilling fluid and its associated additives. This section reviews the drilling process, the drilling fluid composition, methods to separate cuttings from the drilling fluid, the use of reserves pits, and site preparation.

Overview of the Drilling Process

Most oil and gas wells are drilled by pushing a drill bit against the rock and rotating it until the rock wears away. A drilling rig and system is designed to control how the drill bit pushes against the rock, how the resulting cuttings are removed from the well by the drilling fluid, and how the cuttings are then removed from the drilling fluid so the fluid can be reused.

The major way in which drilling activities can impact the environment is through the drill cuttings and the drill fluid used to lift the cuttings from the well. Secondary impacts can occur due to air emissions from the internal combustion engines used to power the drilling rig.

During drilling, fluid is injected down the drill string and though small holes in the drill bit. The drill bit and holes are designed to allow the fluid to clean the cuttings away from the bit. The fluid, with suspended cuttings, then flows back to the surface in the annulus between the drill string and formation. At the surface, the cuttings are separated from the fluid; the cuttings, with some retained fluid, are then placed in pits for later treatment and disposal. The separated fluid is then reinjected down the drill string to lift more cuttings.

The base fluid most commonly used in the drilling process is water, followed by oil, air, natural gas, and foam. When a liquid is used as the base fluid, either oil-based or water-based, it is called "mud."

Water-based drilling fluids are used in about 85% of the wells drilled worldwide. Oil-based fluids are used for virtually all of the remaining wells.
During the drilling process, some mud can be lost to permeable underground formations. To ensure that mud is always available to keep the well full, extra mud is always mixed at the surface and kept in reserves or mud pits for immediate use. Reserves pits vary in size, depending on the depth of the well. The pits can be up to an acre in area and be 5-10 feet deep. Steel tanks are also used for mud pits, especially in offshore operations. Pits are also used to store supplies of water, waste fluids, formation cuttings, rigwash, and rainwater runoff.

Drilling Fluids

Drilling fluids serve a number of purposes in drilling a well. In most cases, however, the base fluid does not have the proper physical or chemical properties to fulfil those purposes, and additives are required to alter its properties. The primary purpose of drilling fluid is to remove the cuttings from the hole as they are generated by the bit and carry them to the surface. Because solids are more dense than the fluid, they will tend to settle downward as they are carried up the annulus. Additives to increase the fluid viscosity are commonly used to lower the settling velocity.
Drilling fluids also help control the well and prevent blowouts. Blowouts occur when the fluid pressure in the wellbore is lower than the fluid pressure in the formation. Fluid in the formation then flows into the wellbore and up to the surface. If surface facilities are unable to handle this flow, uncontrolled production can occur. The primary fluid property required to control the well is the fluid's density.
Additives to increase fluid density are commonly used. Drilling fluids also keep the newly drilled well from collapsing before steel casing can be installed and cemented in the hole. The pressure of the fluid against the side of the formation inhibits the walls of the formation from caving in and filling the hole. Additives are often used to prevent the formation from reacting with the base fluid.
One common type of reaction is shale swelling. A final function of drilling fluids is to cool and lubricate the drill bit as it cuts the rock and lubricate the drill string as it spins against the formation. This extends the life of the drill bit and reduces the torque required at the rotary table to rotate the bit. Additives to increase the lubricity of the drilling fluid are commonly used, particularly in highly deviated or horizontal wells.
Many of the additives used in drilling fluids can be toxic and are now regulated. To comply with new regulations, many new additives have been formulated (Clark, 1994). These new

additives have a lower toxicity than those traditionally used, thus lowering the potential for environmental impact.

Water-based Drilling Fluids

Water is the most commonly used base for drilling fluids or muds. Because it does not have the physical and chemical properties needed to fulfil all of the requirements of a drilling mud, a number of additives are used to alter its properties. During drilling, formation materials get incorporated into the drilling fluid, further altering its composition and properties. A typical elemental composition of common constituents of water-based drilling muds is given in Table 2-1 (Deeley, 1990). These constituents are discussed in more detail below.

A variety of materials are available that can suppress flocculation of clay particles in drilling muds, although none are totally effective under all conditions. The most common deflocculants are phosphates, tannins, lignites, and lignosulfonates. Phosphate deflocculants can be used when the salt concentrations and temperatures are low. Tannins are effective in moderate concentrations of electrolyte concentration and moderate temperatures. Lignites and lignosulfonates can be effective at high temperatures, particularly if they are complexed with heavy metals like chromium.

Polymers, like xanthan gum, have also been developed to increase the viscosity of drilling mud. These polymers have the advantage of shear thinning, which lowers the viscosity and required pumping power during high pumping rates, when a high viscosity is not needed.

Unwanted Components

All drilling muds generally have a number of unwanted componentsthat can potentially harm the environment. The most common of these are heavy metals, salt, and hydrocarbons. The concentration of these materials varies significantly. The primary concern arises when the drilling fluid must be disposed of.

Heavy Metals

Heavy metals can enter drilling fluids in two ways: Many metals are naturally occurring in most formations and will be incorporated into the fluid during drilling; other metals are added to the drilling fluid as part of the additives used to alter the fluid properties. The most commonly found metals have traditionally been barium from barite weighting agents and chromium from chrome-lignosulfonate deflocculants. Heavy metals naturally occur in most rocks and soils, although at relatively low concentrations.

Drilling Fluid Separations

During the drilling process, a large volume of cuttings are generated and carried out of the well by the drilling fluid. These cuttings must be separated from the mud liquid so the liquid can be reinjected into the drill string to remove more cuttings. Cuttings contaminated with drilling mud are a major source of petroleum industry waste. The potential environmental impact of such cuttings can be significantly reduced by separating the solid cuttings from the more toxic mud.

The effectiveness of separating cuttings from the mud depends primarily on the cuttings size. Separations can be enhanced if the cuttings size is kept as large as possible. Cuttings size depends on a number of factors. The most important factor in keeping cuttings size large is to generate large cuttings at the bit during drilling. The initial cuttings size is controlled by the bit type, the weight on bit, and the formation type. A second factor in controlling the cuttings size is to minimize additional grinding of the cuttings in the well as they are lifted to the surface. Cuttings removal is controlled by the hydraulic design of the bit jets, the mud viscosity, the mud velocity, the well depth, the rotational speed of the drill string, and the mechanical strength of the cuttings. A third factor controlling cuttings size is whether the cuttings contain clays which can hydrate (deflocculate) in the mud before separation. Clay hydration can be controlled by the mud chemistry. Additives like polyacrylamides, polymers and salts, as well as oil-based muds, can help control formation reactivity and minimize degradation of solids.

One difficulty with using advanced technology for improved separations at a drill site is the high cost of equipment rental. The expenditure for this equipment can be easier to justify if a good economic model for their benefits is used. One such model has been proposed by Lai (1988) and was subsequently verified by field performance (Lai and Thurber, 1989).

Production

The production of oil and gas generates a variety of wastes. The largest waste stream is produced water, with its associated constituents.

This section reviews both the production process and the wastes that are generated during production.

- **Air emissions**

A wide variety of air pollutants are generated and emitted during the processes of finding and producing petroleum. These air pollutants include primarily oxides of nitrogen, volatile organic compounds, oxides of sulfur and partially burned hydrocarbons(like carbon monoxide and particulates). Volatile hydrocarbons, including aromatics, are emitted during the regeneration of glycol from natural gas dehydration (Grizzle, 1993; Thompson et al., 1993).

- **Combustion**

The largest source of air pollution in the petroleum industry is the operation of the internal combustion engines used to power drilling and production activities, such as drilling rigs, compressors, and pumps. These engines can be powered by either natural gas or diesel fuel. The two primary pollutants emitted from these engines are oxides of nitrogen, primarily NO and NO2, and partially burned hydrocarbons.

The nitrogen oxides are commonly referred to as NO. During combustion, about 3.5 pounds of NOx can be generated for each barrel of fuel burned. Emissions of NOx from petroleum industry operations in 1975 totaled 1.3 million U.S. tons. This level was about 11% of the total NO emissions from all stationary sources in the United States and 6% of the total emissions from all sources. About 46% of the NOx emitted by the petroleum industry was from gas processing activities, 21% from production activities, and 22% from refineries. Crude oil transport emitted 5.2% of the petroleum industry NOx, onshore drilling emitted 4.2%, and product transport emitted 0.9% (American Petroleum Institute, 1979).

NOx is formed at high combustion temperatures when molecular oxygen dissociates into individual oxygen atoms. Atomic oxygen readily reacts with atmospheric nitrogen to form NOx. Methods to limit the formation of NOx include combustion modifications to lower the flame temperature during combustion and flue gas treatment to remove any NOx that has formed. However, little can be done during drilling and production operations to lower NOx emission, other than to purchase low NOx generating equipment and operate it as recommended by the manufacturer.

Partially burned hydrocarbons are emitted during combustion when the fuel/air mixture is incorrect. The most common partially-burned hydrocarbons from internal combustion engines powered by natural gas are formaldehyde and benzene (Meeks, 1992). About 25 pounds of formaldehyde and 1.5 pounds of benzene can be generated per million cubic feet (MMcf) of fuel burned. For fuels containing benzene, ethylbenzene, toluene, or xylene (BETX), about 3% of those compounds will pass through the engine and be emitted.

Another major source of air pollutants is the operation of heater treaters, boilers, and steam generators. These types of equipment also emit NOx and partially burned hydrocarbons like carbon monoxide. If a sulfur-bearing fuel is used, sulfur oxides, primarily SO2 and SO3 (referred to as SOx), can also be emitted. For a crude oil having a sulfur content of 1.1%, about 7.5 pounds of sulfur will be released for every barrel of fuel burned. For reference, a steam generator operating at 50 million Btu/hr can inject steam into three to five wells. The data in this table were adjusted for 365 days of continuous operation.

- **Emissions from Operations**

A number of operations at production facilities emit volatile materials into the air. Operations that can cause emissions include the use of fixed roof tanks, wastewater tanks, loading racks, and casing gas from thermal recovery operations. During the operation of fixed roof tanks, volatile hydrocarbons can be emitted into the atmosphere. There are three major sources of emissions from these tanks: breathing losses, working losses, and flashing losses. Breathing losses arise from a change in vapor volume from changes in temperature and barometric pressure. Working losses are caused by changes in the tank's fluid level. Flashing losses occur when dissolved gas flashes to vapor from pressure drop changes between the tank and the production line.

Open tanks, sumps, and pits can be sources of emissions for volatile hydrocarbons. The emission rates depend on the ambient temperature, surface area of the fluid exposed to the atmosphere, and composition of the hydrocarbon.

- **Fugitive Emissions**

Another source of air pollutants are the fugitive emissions of volatile hydrocarbons. These are hydrocarbons that escape from production systems through leaking components like valves, flanges, pumps, compressors, connections, hatches, sight glasses, dump level arms, packing seals, fittings, and instrumentation. Valves are usually the most common components that leak. These emissions generally result from the improper fit, wear and tear, and corrosion of equipment.

Although the leak rate from individual components is normally small, the cumulative emissions from an oil field containing a large number of components can be significant.

The leak rate at offshore production facilities is significantlylower than at onshore facilities.

- **Emissions from Site Remediation**

Another source of air pollution is from the cleanup of petroleum contaminated sites. Many cleanup practices for hydrocarbons spilled on soil result in volatile hydrocarbons being emitted into the air and transported from the spill site. The most common hydrocarbon spilled that causes air pollution is gasoline.

6. Decision making on oil exploration with difficult environmental conditions such as Arctic(12)

Exploring new frontiers in the search for oil and gas resources

Since the start of the petroleum activities in Norway at the end of the 1960s, Norwegian industry has developed considerable resources and competence to explore, develop and produce oil and gas fields. Today, the Norwegian Continental Shelf is by and large a mature petroleum area. In 2006, only about 12% of the produced petroleum reserves were replaced by new findings (Norwegian Petroleum Directorate, 2007). The oil production peaked in year 2000 and has declined by 25% between 2000 and 2006. The gas production continues to increase.

This development will in the future have large impact on employment and value creation in the Norwegian oil industry. Both the Norwegian oil companies and the supplier industry have at an early stage identified this trend and are seeking business IOCs.

The US Geological Survey (USGS) expects 24% of the World's remaining undiscovered petroleum resources to be located in the Arctic (USGS, 2000). Petroleum activities in this area have, however, for decades been hampered by a high cost level and significant public resistance (USGS, 2000). This situation is about to change. The high oil prices during the last years and the increasing competition for new petroleum resources have evoked the IOCs' interest for especially the Arctic offshore. It has been a natural step for the Norwegian oil industry to expand into the Arctic offshore, as 30% of the undiscovered Norwegian petroleum resources are expected to be in the Barents Sea. The country's advanced offshore oil industry and location in the ''High North" are also expected to be competition advantages internationally.

Environmental and safety challenges

Oil and gas development in the offshore Arctic is controversial. The area is in the public perception an icon for clean and undisturbed nature, and the ''last wilderness". Fisheries and hunting of marine mammals are of great economic importance for the Arctic population, which includes indigenous people such as the Nenets in the Kara Sea and the Eskimos in Chukchi and Beaufort Seas. Environmental non-governmental organisations (NGO) challenge oil and gas development in the offshore Arctic, based on a claim that the Arctic is so valuable and vulnerable that it should not be put at risk.

In Norway, as for example in Alaska, one of the major controversies has been the risk of large oil spills from blow outs. The Exxon Valdez tanker wrecking in Alaska in 1988 plays a significant role in the public mind as a reminder of the vulnerability of the Arctic environment to petroleum activities. Extreme environmental conditions such as low temperatures, icing and sea ice, and long periods of darkness, as well as insufficient oil spill preparedness resources and long distances to infrastructure, represent operational challenges. Unless compensated for, these are likely to increase the frequency of accidents and their environmental consequences. It is feared that consequences to the environment and subsistence economy activities may be irreversible. It is also claimed that regular discharges from oil installations of produced water and drill cuttings will threaten food chains in the Arctic seas, which are often perceived as more sensitive than those in more temperate areas. Finally, emissions of climate gases from the consumption of extracted oil and gas will contribute to increased global warming and to climate change that is most visible in the Arctic. The NGOs also point to a general lack of knowledge about the ecosystems in the Arctic and their vulnerability to petroleum activities.

The Norwegian oil industry recognises the significance of the issues brought up by the environmental NGOs, but regards them in general as manageable. These issues do, however, represent economic and reputation risks, due to prolonged authority handling, the possibility of a moratorium on petroleum activities in specific areas, increased costs of remedial action, and large reputation impact also of minor incidents. Risk of litigation has so far not been an issue in Norway, but is highly relevant in the US.

Arctic environmental conditions such as sea ice and ice bergs and extreme combinations of low air temperatures and high wind speed (high wind chill effect on the human body) also represent considerable safety, health and emergency preparedness challenges. At present, proven technical solutions do not exist for exploration and production of petroleum resources in the most extreme conditions.

The decision by a Norwegian Oil Company to apply for permission for exploration and production (production licence) in the Norwegian part of the Barents Sea, with a committed exploration well, and the later preparations for the drilling program, is used as case. It addresses how decisions are made by the Oil Company involving economics and the assessment and handling of risks. The focus is on the environmental risks, since these have been determining for the feasibility of the project and are unique for the geographical area. In particular, the paper addresses the following questions:

1. How have risks and uncertainties in assessments of petroleum reserves, exploration and development costs, environmental and reputation risks, and possibilities and costs of mitigation been made explicit and balanced in the initial decision to enter into the license?

2. How have corresponding risks and uncertainties been handled in decisions on well concept, mitigation measures and costs?

3. To what extent has the decision making been structured in accordance with a pre-defined plan? To what extent have explicit economic and risk acceptance criteria been employed and how have they been balanced?
4. To what extent has the decision making process interacted with a stakeholder dialogue to ensure acceptance among the general public, authorities, politicians and NGOs that the oil and gas industry can operate safely in perceived environmentally sensitive areas?
5. What role have the license partners played in the acceptance of the Operator's decision proposals?
6. What role have the authorities played in the decision to explore and drill, through the public hearing and permission process?

Principles for decision making about entering into new areas and drilling exploration wells.

- Licensing round application and award

The Norwegian Government regularly invites oil companies to participate in applications for production licenses within a particular geographical area of the Norwegian Continental Shelf. The area in question must have been opened up for petroleum activity by the Norwegian Parliament, which requires an impact assessment of environmental, economic and social effects of such activities, carried out on behalf of the Government. Each company may within a deadline nominate blocks they want included in the licensing round, but the decision on which blocks to include in the licensing round is made by the Ministry of Petroleum and Energy (MPE), after consultation with the Ministries of Environment and Fisheries. The oil companies' nominations are confidential, but there are several known cases where nominated blocks have been initially approved by MPE and then excluded from the licensing round because of potential for conflict with fisheries or being too close to an environmentally vulnerable coastline.
The next step is that the MPE invites oil companies to apply for production licences for specified blocks. The announcement includes conditions related to environmental concerns and fishery interest, some of which are general for all blocks in the licensing round and some block specific. Examples are requirements to map coral reefs within the blocks. ''Zero-discharge" to sea requirements have been conditions in the last licensing rounds, see further below.
Oil companies may apply individually or in groups. Applications will include a proposed work obligation, such as seismic surveys covering a specified number of km or a specified number of exploration wells to explore the petroleum potential in the blocks. Based on the

applications, the MPE puts together a group of companies for each licence, and appoints an Operator for the partnership who is responsible for the activities under the terms of the licence.
The licence is awarded for a limited period, up to 10 years. It includes the specified work obligations to be carried out during this period (e.g. one exploration well to be drilled into a particular geological formation or to a total depth of 1500 m, or collection and processing of 500 km^2 of 3D seismic). The licence award confirms the conditions relative to environment and fisheries interests that were given already in the announcement of the licensing round.
The Oil Company's decision to participate in a licensing round and apply for a specific block is based on technical and economic evaluations, as well as strategic considerations. The former are based on expected petroleum reserves, estimated costs of exploration, development and production, and estimated income. Strategic issues may be securing access to additional resources and strengthening company presence in an area, access to a new province, or making the most of existing infrastructure. The environmental requirements to activities in the block are rarely challenged, nor is the feasibility of environmentally safe operations in the block questioned, once the area is opened by the authorities for exploration. Mitigation of environmental and safety risks are included as cost elements in the overall evaluation, and reputation risks become part of the strategic considerations.
The proposed work program is in reality the Company's bid for the license; by offering licenses for award the authorities have expressed their intention to have the petroleum reserve potential in an area mapped. The Company's bid shows how large resources the Company is prepared to spend on this mapping. It is in practice at this stage that the decision to drill one or more exploration wells in the block is made. The decisions that remain are where and how to drill, or possibly to apply for permission to relinquish the license if it turns out to be less promising than expected.

- Asset management, drilling assessment and approval

Once the licence has been awarded, the Oil Company with responsibility as Operator will ensure that the work obligation is met by establishing a work program for approval by the licence partners. The licence is organised as a ''company within the Company", with a Management Committee, an Exploration Committee, and later a Technical Committee, each with representatives from all partners and chaired by a manager from the Operator. Management of the licence is regulated by voting rules and commercial agreements between the partners that have been approved by the authorities. In the case discussed in this paper, the Norwegian Oil Company is the Operator for the licence. The Company's Business Area for Norway is Licence Owner. A manager from the Company's Exploration

Sector is Asset Manager during the exploration phase, and normally chairs the management committee. The Norwegian State is one of the licence partners through the State's Direct Financial Interest.

The Asset Manager seeks approval for activities, plans and capital expenditure with the Company's Licence Owner, and finally presents these to the licence Management Committee for approval. The Asset Manager is also responsible for carrying out the necessary geological interpretations based on seismic data. He may recommend acquisition of new seismic data, and commission drilling assessments. The decision on when, where and how to drill will be based on information regarding licence commitments, geological analyses of expected petroleum volumes and risks in drillable prospects within the licence area, and an evaluation of the value of information that the well can generate. The drilling of the well, cost and location must be approved by the licence committees. There is also a need for confirmation of well feasibility and information on cost and risks for the actual well, received from the well delivery process (see Figs. 6.1 and 6.2). This process is the responsibility of the Company's Drilling Department, and is linked to the Company's Exploration process when it comes to decisions on exploration wells.

The basis for a drilling decision will also include further technical and economic evaluations of how potential findings of oil and gas may be commercialised.

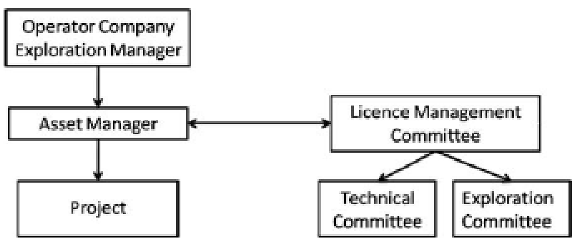


Fig 6.1.Organogram showing the organisation of a licence

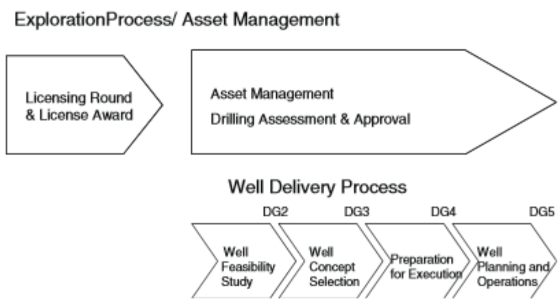


Fig 6.2. The exploration/asset management and well delivery processes

The Company's decision to recommend the drilling of a specific well to the Licence Management Committee is made by the Business Area manager, as the Company's Licence Owner. Apart from information on the actual well, this decision will be based on a ranking of the prospect relative to other drillable assets in the Company's portfolio, to make sure that Company's exploration budget is used optimally. The Company's decision could also be to recommend postponing of operations, or to relinquish the licence without fulfilling the work obligation. These may be options if information and analysis after licence award indicate significantly reduced volumes and/or reduced probability of finding these volumes, or if other risks have increased. Partners may interpret information differently, or have other interests leading to contradictory conclusions. In these cases, the licence decision in the Management Committee has to be resolved by voting. The company may also decide to seek a buyer for a part of its share in the licence, to reduce risk.

Should commercial discoveries be made, the licence will progress towards development of facilities to capture the petroleum resources (field development phase). If results on the other hand are negative, the Operator determines remaining probability of finding petroleum resources, and expected volumes, and may eventually propose relinquishment of the whole or parts of the license.

- The well delivery process

The Company's Drilling Department has the responsibility for the planning and execution of the actual drilling of the well. The Asset Manager informs the Drilling Department about well location, possible restrictions, and well objectives; the overall objective usually being to clarify the potential of oil and gas resources in the identified formation. The Drilling Department establishes a well project, which determines the feasibility of drilling the well and generates time and cost estimates. Subsequent steps in the well delivery process include well concept selection, well planning, preparation for execution, and operations. Assessments in the various phases are shown in Fig. 6.3.

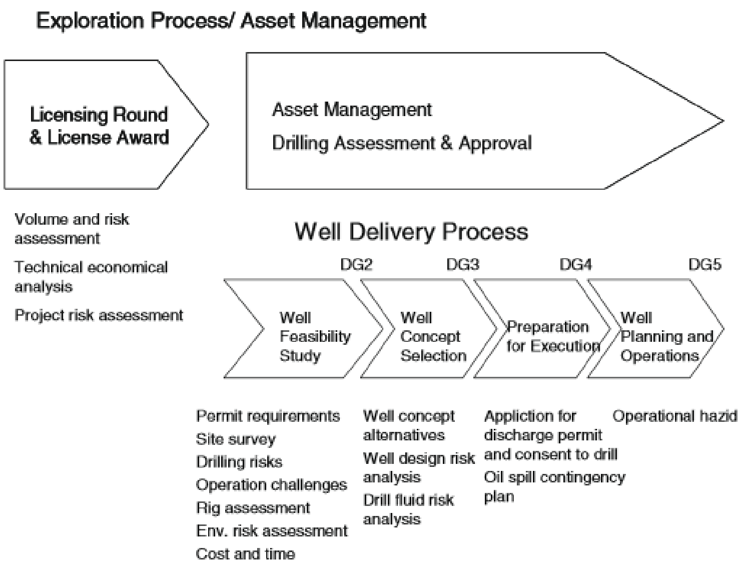


Fig 6.3. Assessment activities for licence application and well delivery.

Health, safety and environment (HSE) risks are systematically addressed in the feasibility phase. The well project carries out studies to determine whether these risks may represent ''show stoppers" or have significant cost and schedule consequences. Studies include a site survey to identify shallow gas, investigation of presence of corals and any other habitats that require special protection, and an environmental baseline survey of the proposed drilling location. An environmental risk assessment is performed, based on modelling of oil spill spreading and impacts. Special safety risks in drilling, such as shallow gas, large water depth, and high reservoir pressure, are assessed.

The well design and drilling fluid risk analyses address the risks of not meeting the well objectives, which are to prove commercial hydrocarbons, and fulfil the work commitment.

Rig availability is a particularly significant issue. This is critical in the Norwegian Barents Sea, where there is a requirement for a ‘‘sealed” rig with zero-discharge to sea and there may be a time- window of a few winter months when for environmental reasons drilling into potential oil containing reservoirs is allowed.

All identified risks are entered into a standardized risk register. The register is kept updated until completion of the well project. The information on well feasibility, cost and time, rig availability and risks is fed back to the Asset Manager, who makes his recommendation to the Licence Owner.

The aim of the well concept selection phase is to compare possible alternative solutions and to decide on a main well concept. Studies initiated in the feasibility phase are carried out to an increased level of detail. A well design risk analysis is performed to determine the likelihood of not meeting well objectives for the different well designs, and the alternatives are assessed based on economic criteria. Special environmental or safety requirements are assessed again at this stage, to ensure timely implementation. An example is the requirement for ‘‘sealed” drilling rigs in the Barents Sea, to avoid regular and minor accidental discharges to sea. The concept selection report is subject to an independent review before the Drilling Department decides on a well concept.

The preparation for execution phase is finalised when all studies are completed, applications are sent to the authorities and contracts are settled. Contracts are mainly based on frame agreements with pre-qualified suppliers. The quality of the suppliers’ HSE management systems and performance are important issues during pre-qualification. From an environmental point of view, the prequalification of rig and drilling contractors and chemicals suppliers are especially important.

The application for discharge permit is submitted to public hearing, and the final authority consent to start drilling may be appealed by stakeholders. This can represent a critical delay if the licence specifies a limited time-window for drilling and/or the appropriate drilling rig is only available for a limited period. Making sure that there are no outstanding environmental issues that can precipitate a serious delay of the drilling plans is one of the important mitigating actions in the licence management and well planning. This is particularly relevant for activities in areas where petroleum activity may be controversial, such as the offshore

Arctic. It has happened on the Norwegian Continental Shelf that the authorities have postponed their final decision following NGO appeal and in effect made drilling impossible, even if drilling was part of the licence commitments and it could be demonstrated that all requirements were met. Similarly, in 2007, exploration drilling in the Beaufort Sea was stopped by order of the Court following appeal by the local government, even though the Operator had obtained all the required authority permits.

- Petroleum activities in the Norwegian Barents Sea

The first licences in the Norwegian Barents Sea were awarded in 1979, and exploration drilling started in 1980. However, the environmental impact statement that formally opened the southern part of the Barents Sea for petroleum exploration came in 1988. So far approximately 70 exploration wells have been drilled in the area. Both exploration interest and stakeholder engagement regarding activities in the Barents Sea have varied greatly since 1980. So far the Sn0hvit field is the only field being developed, and Goliat is the only field at the planning stage.

There was a sudden halt in exploration activity in the Norwegian Arctic in 2001, triggered by the general elections. The halt came as the result of a scientific dispute on impacts on fish reproduction of hormone mimicking trace components in formation water that is discharged from petroleum installations. Stakeholders feared that if petroleum resources were found in the Lofoten area, there would be pressure to develop and produce them. It was envisaged that discharge of formation water from this production could threaten important fisheries in Lofoten, or rather: there was no scientific guarantee that it would not. The new government initiated a regional environmental and socio-economic impact assessment for petroleum activity in the Lofoten - Barents Sea area (Norwegian Ministry of Oil and Energy, 2003), as basis for a comprehensive management plan for the area Norwegian (Ministry of Environment, 2006). This process coincided with a significant increase in shipping of oil from the Russian Arctic along the coast of Northern Norway. This was perceived as a major threat of oil spills with consequences like the ‘‘Exxon Valdez”, adding to the perceived environmental threat from oil activity in the region.

The impact assessment reopened areas in the Barents Sea South for year round petroleum activity, with the exception of areas considered especially vulnerable to oil spills; see Fig. 6.4.

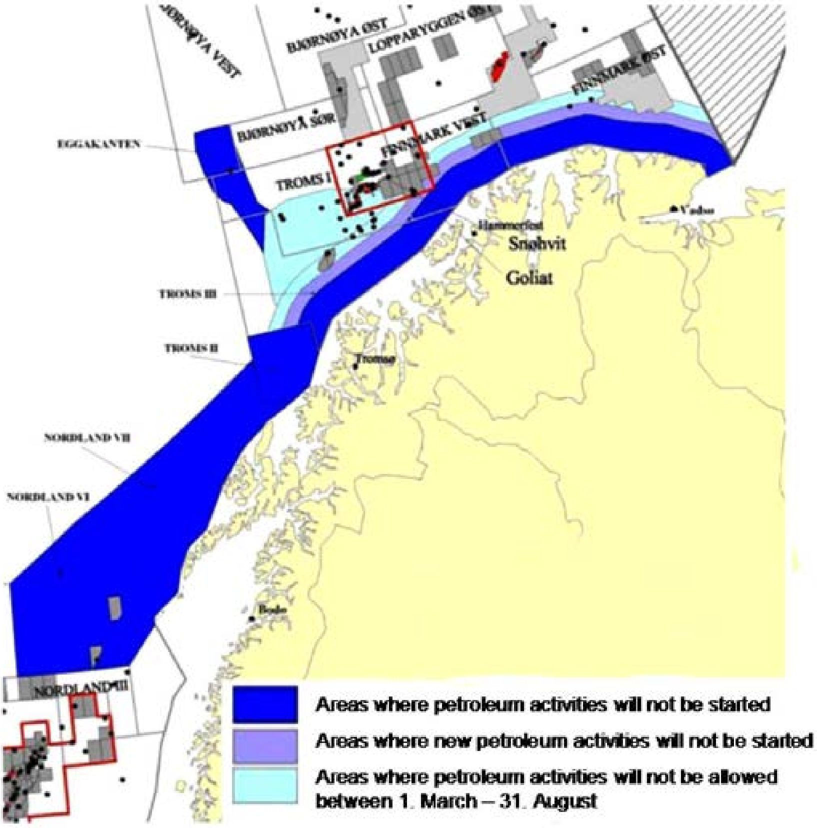


Fig 6.4. Geographic restrictions on petroleum activities in the Lofoten – Barents Sea management plan 2006

Amongst these are the polar front, the marginal ice zone, the coastal zone out to 35 km from shore, and the Lofoten area which is home to a seasonal cod fishery of national importance since medieval times. A decision to reopen areas off Lofoten was postponed until a revision of the plan in 2010.

The impact assessment was based on a ‘‘zero-discharge-to-sea” regime, which includes the following measures:

1. no discharge from drilling, except from the top section of the well,
2. minimal discharge of chemicals, and restricted to chemicals that are non-toxic, biodegradable and do not bio-accumulate,
3. closed drains on the rigs to avoid discharge of drainage water and minor spills,
4. no regular discharge of formation water during production.

The zero-discharge regime was seen as an ultimatum from the authorities to the oil industry and agreed prior to the impact assessment. Whether these measures have a net environmental benefit and are cost-effective have been questioned. They were at the time seen by both authorities and oil companies as the only way to make it politically feasible to carry out the impact assessment in time and get the region reopened for petroleum activity without too many years delay. The process from opening of an area for exploration to start of petroleum production normally will take about 15 years, and there was a general push from both government and companies to have new production in place before 2020.

The Management plan for this area, in 2006, generally confirmed the recommendations from the impact assessment in 2003 regarding areas opened and temporarily closed for petroleum activity. The plan shall be revised in 2010, in the period of the next Parliament.

Description of the case

- The licence and licence conditions

The licence with the well used as case in this paper, was awarded in the 19th licensing round in 2006. This round included 30 blocks in the parts of the Norwegian Barents Sea recommended for reopening in the strategic impact assessment. The potential petroleum containing structure in this block has been known since the 1980s, all the time seen as geologically interesting but environmentally challenging. The licence in question was controversial, as it was located close to shore within an area banned for new activities in the 2006 Management Plan. The plan had, however, made an exemption for 19th round licences.

The licence agreement states a work obligation consisting of one exploration well, to be drilled within 3 years, and the MPE reserves the right to request drilling within 12 months once all necessary background information has been collected. The following licence specific environmental tasks and requirements are given for the exploration activity in the licence agreement:

1. Fisheries and marine resources shall be given special consideration during the planning and execution.
2. The area shall be mapped for corals reefs that could be harmed by the petroleum activity.
3. A baseline environmental survey shall be performed prior to drilling.
4. The oil spill contingency plan shall be based on risk assessment, but the dimensioning of oil spill resources shall take additional account of how close the activity is to shore, to specially vulnerable environmental resources, and other interests that may be at risk.
5. Zero-discharge to sea. The only exception being drilling waste from the top section of the well, provided that the receiving environment has been carefully mapped and contains no resources or habitats that may be harmed by the discharge (e.g. fish spawning areas, coral reefs, sponge communities). The requirement generally means that drilling waste will have to be reinjected into the well, or collected and brought to shore for deposition.

The licence agreement includes no other mention of HSE requirements, but refers to laws and regulations that are in force at the given time. These would apply equally for all petroleum activities on the Norwegian Continental Shelf.

- Assessment activities in the exploration process
    - Project risk assessment

Fig. 6.4 shows an overview of the assessment activities in the exploration process. All assessments are characterised by risks and uncertainties. The results of these assessments and the project risk assessment are documented in a risk register. This is the Asset Manager's tool to keep track of and manage the risks in the project. It is based on input on risks and uncertainties from all involved disciplines including Drilling (cf. the well delivery process).

Fig 6.5 shows an overview of the risk themes addressed in this assessment. They are the result of accumulated experience.

1	**External uncontrollable risks**
1.1	Political
1.2	Legal
1.3	Authority approvals
1.4	Social/ cultural
1.5	External environment
1.6	Commercial
1.7	Conjectures/ market during project execution
1.8	Weather
1.9	Strike
1.10	Terror, NGO
2	**Project external, controllable risks**
2.1	Project strategy and financing
2.2	Partner/ joint venture relations
2.3	Decision timing
2.4	Sustainability
2.5	Rig consideration
3	**Project internal risks**
3.1	Project management
3.2	Resources available
3.3	Experienced personnel
3.4	Reserve base
3.5	Technical maturity
3.6	Startup and production level
3.7	Regularity/ productivity

4	**Location specific risks**
4.1	Extreme wind, currents, high waves
4.2	Temperature
4.3	Visibility
4.4	Seabed conditions
4.5	External environment
4.6	Deep water
4.7	Distance to land/ other installations
4.8	Close to ship fairway/ fishing activities
4.9	Multinational crew, crew rotation
4.10	Simultaneous operations
4.11	Large quantities of equipment
4.12	New operation/ procedures/ equipment
4.13	Shallow gas/ shallow water/ boulders
4.14	HTHP/ deep well
4.15	Unknown area, few reference wells, poor seismic quality
5	Well design risks
5.1	Well path
5.2	Casing
5.3	Cementing
5.4	Hole cleaning and stability
5.5	Completion
5.6	Intervention
5.7	Well control
5.8	Logging

Fig 6.5. General project risk themes.

The external uncontrollable risks have been addressed for petroleum activities in the Arctic in general, by:

1. Continuous work to improve the safety of operation.
2. Increasing environmental knowledge about environmental resources and impacts of petroleum activity, through cooperation with research institutions and own R&D.
3. Dissemination of information with focus on issues know to be contentious.
4. Dialogue with politicians, fishermen and other stakeholders.

- Volume and risk assessment

Petroleum volume estimates are represented as probabilistic distributions. Hydrocarbon column height (i.e. volume) distribution is calculated from geological information on distributions of sealing capacity, structure capacity and migrated hydrocarbon volume. Basic elements in the assessment are:

1. The probability of geological success (i.e. finding petroleum resources).
2. The volume distribution given geological success.
3. The minimum volume needed for commercial success.

- Technical economical (tech-ec) analysis

The tech-ec analysis uses the information on geographical area, fluid type, estimates on gas-to-oil ratio, volume estimates etc. to define production profiles, number of wells, assessing solutions and costs for drilling, development, production and export, and associated costs. The commercial analysis calculates income based on Company's decision requirements for return on invested capital and pre-defined product prices. Results are presented as net present value (NPV).

Threshold volume (lowest volume that can support a development solution at NPV = 0 at a defined product price) is used to truncate non-commercial outcomes from the distribution of possible discovery volumes.

An overall risk analysis of both input data and output is performed after the initial economic analysis. The risk analysis can result in updates of high/low scenarios and adjustment both to cash flow elements and discount rates used in the calculations.

Assessments in the well delivery process

- Risk register

The Drilling department manages its own risk register for the well delivery process. This is based on the various assessment activities in this process. Examples from the risk register for the case included the following ‘‘red” risks:

1. Damage to equipment and loss of time during mobilization; especially relevant because of much new and heavy equipment to be mobilized/ demobilized during changeover to new Operator, plus wintertime and short weather window for heavy lifts. Probability: Likely. Consequence to CTR: Serious.
2. Vessels on collision course with the rig; relevant because of winter darkness, high fishing activity, Russian oil tankers, possibly NGO vessels. Probability: Likely. Consequence to HSE: Serious.

3. Cuttings handling equipment fails; may lead to production of more cuttings slurry than the rig has capacity to store, coinciding with being unable to pump slurry from rig to supply vessel for off take. Probability: Likely. Consequence to CTR: Serious.
4. Incomplete data collection, caused by choice of drilling fluid, environmental restrictions to use of tracer, or quality of cores. Probability: Likely. Consequence to well objectives: Serious.

- Permit requirements

The environmental requirements for the case were more extensive than for petroleum activities in the North Sea, but known and accepted at the time of the license application.

- Site survey

The survey of the planned drilling site included investigations for shallow gas, sediment conditions, bathymetry (water depth and seabed

7. The role of project management(3)

It has been recognised over the last 30 years that project management is an efficient tool to handle novel or complex activities. Avots has suggested that it is more efficient than traditional methods of management, such as the practice of functional divisions in a formal hierarchical organisation, for handling such situations. The process of bringing new projects on stream and into the market imposes demands on established organisations and necessitates different management techniques from those required to maintain day-to-day operations.

In such circumstances, where companies have a finite, unique and unfamiliar undertaking, the techniques of project management can be successfully implemented. These undertakings would call for more and faster decision making techniques than possible in a normal operation and making the right choices will be critical to company success. The use of project management has become associated with such novel complex problems, which are inevitably called a project. Consequently the success of project management has often been associated with the final outcome of the project. Over time it has been shown that project management and project success are not necessarily directly related. The objectives of both project management and the project are different and the control of time, cost and progress, which are often the project management objectives, should not be confused with measuring project success. Also, experience has shown that it is possible to achieve a successful project even when management has failed and *vice versa*.

There are many examples of projects which were relatively successful despite not being completed on time, or being over budget, e.g. the Thames Barrier, the Fulmar North Sea oil project or Concorde, all of which turned out to be relative successes, even though the project control aspect of them failed. It can therefore be argued that the relationship between the two is less dependent than was first assumed, and in order to measure project success a distinction should be made between the success of a project and the success of the project management activity.

This chapter attempts to provide a logic for the distinction between project management and the project. Starting from a definition of the two terms, it will outline the factors which affect their success, the individuals involved and their respective orientations and the relationship between these elements. It also discusses the implications of the situation where the project fails but the project management process is perceived to have succeeded or *vice versa.*

Definitions

In order to distinguish between the project and project management it is necessary to develop distinct definitions for the two terms. A project can be considered to be the achievement of a specific objective, which involves a series of activities and tasks which consume resources. It has to be completed within a set specification, having definite start and end dates.

In contrast, project management can be defined as the process of controlling the achievement of the project objectives. Utilising the existing organisational structures and resources, it seeks to manage the project by applying a collection of tools and techniques, without adversely disturbing the routine operation of the company. The function of project management includes defining the requirement of work, establishing the extent of work, allocating the resources required, planning the execution of the work, monitoring the progress of the work and adjusting deviations from the plan. Initially these two definitions may appear to overlap.

Both are heavily orientated to the achievement of the project. The important distinction lies in the emphasis of both definitions. The project is concerned with defining and selecting a task which will be of overall benefit to the company. This benefit may be financial, marketing or technical, but this will tend to be of a long-term nature, oriented towards the expected total life span of the completed project. In the case of a construction project the benefits could be extended over 50-100 years, depending on the anticipated building life. In contrast, project management is orientated towards planning and control. It is concerned with on-time delivery, within-budget expenditures and appropriate performance standards. This is the context of the short-term life of the project development and delivery. Once delivery is achieved the management, as it relates to planning and control of the development and delivery, will cease. A new, or different form of management, will then establish the operation and control of the project use from this point on. The focus, therefore, of project management is distinct from that of the project because it is short term, until delivery of the project for use. In contrast the project itself is long term, based on the whole life rather than just the development cycle.

Having established this distinction between the project and project management it is possible to start to distinguish between success and failure of the two.

Project success or failure

The definition of a project has suggested that there is an orientation towards higher and long-term goals. Important parameters within the goals will be return on investment, profitability, competition and market ability. A range of variables and factors will affect the ability to achieve these goals, which have been identified by various authors. The following list has been derived from the writings of Cash and Fox , Baker *et al.,* Kerzner, Wit and Kumar: (a) objectives; (b) project administration; (c) third parties; (d) relations with client; (e) human parties; (f) contracting; (g) legal agreements; (h) politics; (i) efficiency; (j) conflicts and (k) profit. The current literature, for example, Morris and Hugh, would imply that the success of a project is dependent on having:

- a realistic goal;
- competition;
- client satisfaction;
- a definite goal;
- profitability;
- third parties;
- market availability;
- the implementation process;
- the perceived value of the project.

Only two of the items from this list would lie directly within the scope of project management as previously defined. These are the definitions of a goal and the implementation process. This would indicate that project management and its techniques are only a subset of the wider context of the project. Project management plays a role in project success but that role is affected by many other factors outside the direct control of the project manager. This would start to explain why projects can succeed or fail independently of the project management process.

Project management success or failure

The definition of project management suggests a shorter term and more specific context for success. The outcomes of project management success are many. They would include the obvious indicators of completion to budget, satisfying the project schedule, adequate quality standards, and meeting the project goal. The factors which may cause the project management to fail to achieve these would include:

- inadequate basis for project;
- wrong person as project manager;
- top management unsupportive;
- inadequately defined tasks;
- lack of project management techniques;
- management techniques mis-used;
- project closedown not planned;
- lack of commitment to project.

These factors would suggest that successful project management requires planning with a commitment to complete the project; careful appointment of a skilled project manager; spending time to define the project adequately; correctly planning the activities in the project; ensuring correct and adequate information flows; changing activities to accommodate frequent changes on dynamic; accommodating employees' personal goals with performance and rewards; and making a fresh start when mistakes in implementation have been identified. The narrow definition of tasks in successful project management provides an indicator of why project management success and project success are not directly correlated. A project may still be successful despite the failings of project management because it meets the higher and long-term objectives. At the point when the project management is completed the short-term orientation could be one of failure but the long-term outcome could be a success, because the larger set of objectives are satisfied instead of the narrow subset which constitutes project management. The majority of literature on project management stresses the importance of techniques in achieving project objectives.

They stress how successful implementation of techniques contributes to a successful project. Avots and Duncan and Gorsha both claim that project management is an important part in project success. Avots, in studying the reasons for project management failure, argued that failure could be avoided by paying careful attention to the project management factors which caused failure. Duncan and Gorsha identified three problem areas which indicate the success of a project. These are under-costing, overspending and late delivery. It is suggested that project planning is needed to overcome these problems.

Lackman has discussed the different tools available to a project manager to achieve success. These include work breakdown structures, client information sheets and project plans, among others. The early development of strategies, philosophies and methodologies of project implementation have been stressed by Kumar as the most important factor in achieving success. He suggested that by gathering sufficient site information and being aware of project considerations and constraints; it is possible to tailor strategies and methodologies which are specific to a certain situation. Such well-defined strategies will assist in providing a satisfying and successful implementation of a project. The concentration on techniques may be considered as the 'hard' issues in project management. They are the easily measured and quantified concepts of time and cost. Other writers have incorporated what might loosely be called people skills alongside these more administrative functions. These people skills are 'soft' issues in management. For example Randolph and Posner N, Posner and Jaafari stressed personal, technical and organizational skills as being necessary to help control projects and achieve successful results.

Implicit in all the above literature is the claim that projects end when they are delivered to the customer. That is the point at which project management ends. They do not consider the wider criteria which will affect the project once in use. Two writers who have made a distinction between these orientations are Wit and Nicholas TM. They make a distinction between project success and the success of project management, bearing in mind that good project management can contribute towards project success but is unlikely to be able to prevent failure. They also emphasise that a project can be a success despite a poor project management performance.

If, as this argument implies, project management is purely a subset of the project as a whole, then it is suggested that the broader decisions in selecting a suitable project in the first place are more likely to influence the overall success of the project than can be achieved merely through the techniques of project management. The techniques may help to ensure a successful implementation of the project, but if the project is fundamentally flawed from the start it would be unlikely that techniques alone could salvage it. The techniques may help to identify the unfeasible nature of the project, and indicate that it should be abandoned or changed.

Individual responsibilities

Given a clear distinction between the project and project management it would imply a requirement for a corresponding distinction between the individuals responsible for success in both areas. Kerzner states that "the major factor for the successful implementation of project management is that the project manager and team become the focal point of integrative responsibility". This would suggest that the focus for success in both spheres should lie with the project management team and would tend to exclude the client from any role in project success, contradicting the earlier assertion that the early decision making on a project dictates success. The client is responsible for these decisions and therefore has an important role in determining success.

The completion of a project requires input from a variety of groups including the client, the project team, the parent organisation, the producer and the end user. Each party has a role in defining and determining success. They all have specific tasks and responsibilities that they must fulfil in order to achieve success (Kumar).

The client is expected to be the main party concerned about the success of the project in the long term. In most cases, the project was instigated at the behest of the client, and the financial and other rewards for the client hinge on its successful implementation. The client cannot expect to abdicate responsibility by passing all duties to the project team. It has already been intimated that the team will be orientated towards objectives which are only a subset of the overall aims of the project. The client must ensure that an emphasis on the subset does not threaten the achievement of the wider aims from which it is drawn. Facilitating the team is important for the client, but in the final analysis the project was not instigated to facilitate the team. The project originates from a requirement to meet a need that exists for the client. That initial need must be kept in focus by all those involved on the project.

The user is the group or individual who makes use of the completed project or product. In some situations this might be the client, but for goods sold on the open market the end user and client may be two distinct groups. Project success will be considered by the users as the ability to satisfy their needs. These needs may take the form of practical requirements and be in vivid contrast to those of the client. Satisfying end users needs is one facet of quality assurance that has come to the fore recently. Oakland defines quality as "the satisfaction of users needs". Success for the user will be oriented towards long-term utilisation of the project outcome rather than project management techniques. As such, the project team concerned with the development, may have little or no direct contract with the user, who may remain unaware of the management processes and whether these have been successful or not.

The parent organisation will be involved in the project by providing resources. They may also exercise a controlling influence over the project in determining factors such as profitability, market share, quality and scope of service. Their responsibility towards the project is important and the commitment and support of a parent organisation is a vital requirement to project success. Unless the parent organization is willing to commit company resources and provide any necessary administrative support, project management can be very difficult. In this role they will have two differing interests in the project. In allocating resources they will have an interest in the efficient use of the resources during development. The project team will be responsible for the planning and control of the use of these resources, consequently the parent organisation will be interested in the success of the project management process. The team will be accountable for their use of these resources, and if they fail to be effective they must expect to give an account for their actions. The parent organisation will have a second concern, because they will want a return on their allocation of resources to the project. There will be an interest in the success of the project as a whole as well as the project management aspects.

The project team will shape the implementation of the project. It is important for the team to employ the correct management techniques to ensure that planning, controlling and communication systems are all in place. Without these systems the co-ordination and control of all individuals and resources within the team is difficult. The orientation of the project team will be towards the task rather than the people.

This will be particularly true as deadlines for achieving work are stressed and become paramount in people's thinking. The scope of interest here will be the completion of work and delivery of the project. Any rewards for the team will occur at the end of this management phase, therefore their primary concern will be to reach the end of this phase successfully.
The context of the producer can be viewed from two aspects. In the first instance the producer will have a task oriented view of the project similar to the rest of the project team. The producer's commitment to the project will end once it is handed over to the client. The commitment is therefore towards short-term rather than long-term goals.
In the second instance the producer is a user of the project in the sense that information generated by the project team is used to manufacture the end product. The producer will now be concerned with the ease of final assembly, but again in the short-term context of the project development and not the longer-term use.
This discussion has highlighted how the various individuals involved in a project will have different orientations towards the final project outcome. Success will be viewed differently by each group because their expectations for the project will vary. To return to the quote from Kerzner which opened this section, it would seem inappropriate to place all the responsibility for integration on the project team. Because the involvement of the project team is concerned with only a small subset of the total project it would seem more logical to make an individual who has a wider view responsible for the project. The client has the longer term and wider orientation and there is a logical argument for making the client responsible for the end project.

The overlap between project and project management

It was suggested earlier that there is an overlap between project management and projects, in that the former is a subset of the latter. Yet confusion does exist between the two in practice. This confusion could have arisen because of three factors:

1. *Time frame--project* success is often commented on at the end of the project management phase. At this time knowledge about the project management success will be known because the budget, schedule and quality criteria can be measured. Here each of the parties will be able to compare original data requirements to what is achieved. In terms of quality standards it could be monitored by the amount of rework or by the degree of client satisfaction. The long-term indicators will not have been realised yet and consequently they cannot be measured. Therefore, it is convenient to judge success at this time by whether the project management criteria have been

satisfied rather than the project criteria. So project management success becomes synonymous with project success, and the two are inseparable.

2. *Confusion of objectives--the* objectives of project success and project management success are often intertwined. Instead of clearly identifying the two as separate groups they are shown to be a single homogenous set. Because of this lack of distinction the two sets of objectives are seen to be correlated. For example 'completion to budget' might be placed alongside 'profitability' as objectives. Budget is primarily a project management issue, yet profitability is a project objective. To suggest that a client instigates a project just to see it completed to budget reduces the importance of the project objectives.
3. *Ease of measurement--two* of the objectives within project management are common across all projects and are easy to measure quantitatively. These are compliance with budget and schedule. Because of these readily identifiable measures it is easy to concentrate on project management and its success rather than the wider context of the project. Many of the project objectives will tend to be either qualitative and not easily measured in any objective manner, or longer-term and not measurable immediately. This makes it convenient to use measures of project management success as a means of determining overall project success. The confusion outlined above can be avoided by an improved appreciation of the role of project management within the project. The role of project management is to use the resources available effectively to accomplish a set goal within certain criteria. This role of project management needs to be placed within the context of a wider project.

Figure 7.1 shows a six stage model of the life of a project, the stages being as follows:

1. Conception phase--the idea for the project is birthed within the client organisation and its feasibility determined.
2. Planning phase--the method to achieve the original idea is planned and designed.
3. Production--the plans are converted into physical reality.
4. Handover--the finished project is handed over to the client for use.
5. Utilisation--the client makes use of the finished project.
6. Closedown--the project is dismantled and disposed of at the end of its useful life.

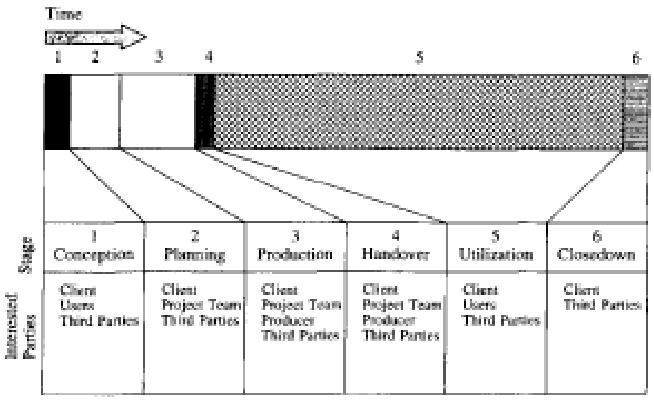


Fig 7.1: The stages in a project life cycle, and the parties interested in each stage

The diagram illustrates how each of the parties previously identified interact with the project during this life-cycle. It also highlights the role of a new group that of third parties. There are various third parties which could influence the development and use of a project. These include: statutory authorities, both local and national; the media; environmental groups and the general public.
The diagram illustrates where the distinction between success and failure differs between the project and project management view. The project team will be involved with stages 2-4, whereas the client is interested in stages 1-6.

As Figure 7.2 shows the team will be focused on the narrow task of successfully reaching the end of stage 4, at which point they will terminate their involvement and progress to the next project.

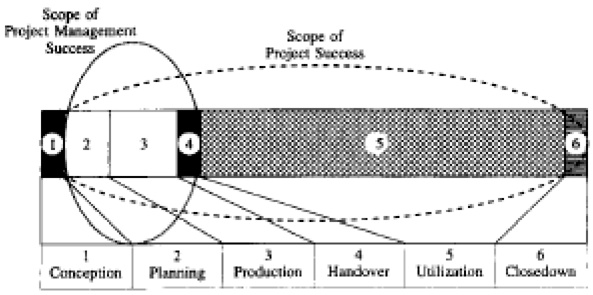


Fig 7.2: The scope of success within the project life cycle

The client is left to cope with the outcome, which must be effectively utilized until it reaches the last stage. Throughout this process the project performance can be assessed in one of three ways:

1. The implementation--this is completed in stages 2-4 and is concerned with the project management techniques and their implementation.
2. Perceived values--this is the view of users who will interact with the project during the utilisation phase.
3. Client satisfaction--at project closedown when the client can examine all influences on the project and an assessment can be made as to the satisfaction of the original goals.

The three assessment criteria illustrate the notion that project management techniques are not solely important for project success. There are other external criteria which are at least as important, if not more so, for the successful implementation of projects. Perceived values and client satisfaction will persist for a longer period than implementation.
Although at stage 4 the implementation is paramount because it is the only available criteria to judge the project, as the project progresses through stage 5 the significance of project management will decline. Consequently different criteria for judgement will come to the fore and their significance over implementation will increase with time.
The natural tendency for the project management team will be to concentrate on completing stage 4 within the set criteria. The resulting emphasis of project management techniques is towards achieving specific and short-term targets. Hence the interest in project management literature on issues such as project planning, estimating, quality and control, all of which are tools targeted at reaching stage 4 within the set criteria. There is less significance placed on satisfying stage 5 and 6 targets because the team will probably have little or no direct involvement with the project at this time. So parameters of return on investment, profitability, competition and marketability are likely to become secondary.
This leads to a reference to the link between project and project management success. Consider the situation where the project has failed whereas the project management process was perceived to be successful. In this situation the project has failed because it has not been used as it was initially intended, could not be marketed, or did not get its return on investment to the client; while its implementation process was produced on time, to budget and according to scope. The project management could not have prevented the failure of the project. This arises because of the project management criteria being a subset of all project criteria.
Although the subset has been satisfied, the wider set has not been. The only possible criticism of the project management is that the early processes of feasibility should have discovered the potential for the project to fail, and should have warned the client of the need to abandon or redefine the scope of the project.
In this case the importance of project management success will be of little or no value to any party except the project team, unless they are concerned with the utilization phase of the

final outcome. The implementation success is of no importance because the client is not able to use the investment, and the project team should have been more satisfied if the outcome of their efforts had been properly used. For example a new factory which is not occupied will lay empty and the client will spend extra money on upgrading, securing, servicing, making changes, or accepting lower offers. Obviously the investment will be a failure from their point of view even if the control aspects of it went according to plan.

The second scenario is where the project implementation was either delayed or cost more, but in the end the client was able to make profitable and good use of it. In this case the project management failure is of little significance in the longer term. In the short term the project management failure may be an inconvenience because use of the development was delayed by the schedule overrun. Alternatively, more finances have to be established to fund the budget overspend. Yet the inconvenience may only involve a brief embarrassment at the handover of the project. In both scenarios we see that project success and failure is not totally dependent on project management success and failure, the exception being when the project is too late or too expensive and can no longer be used. Then there will be a link between project management failure and the failure of the whole project, but here the breakdown in project management must be extreme.

The result is that three issues need to be addressed by all those involved in projects. These are the project definition, the client role, and the evaluation process. The project definition and early decision making is critical to overall success. The efforts of the project team will not redeem a project that is doomed to fail because of poor early decision making. There is, though, the possibility that poor project management could threaten a potentially good project. The client is responsible for the creative processes in identifying possible ideas for a project. The role of project management can help in this process by ensuring that the feasibility study identifies ideas which are unlikely to succeed and recommending to the client that they are abandoned. Feasibility should not be confined in this case to the feasibility of the development process, but should be extended to the subsequent use. Even in this situation the project team is not involved in the creative process of producing ideas, but with the checking of ideas generated by the client.

For the client role in projects two courses of action can be adopted. Either the client has to become actively involved in the planning and production phases, or the involvement of the project team has to be extended into the utilisation phase. Increased client involvement in planning and production will help to ensure that the wider set of objectives continues to be emphasised. Although there will be some additional cost to the client in terms of time and resources this should be small compared to the total cost of the project. To make the project team responsible for the project after handover and into the utilisation phase is not new. For example when the contract for the Tunnel Bridge was awarded in 1730, the contractor, who was in effect offering a turnkey package including design and production, was required to ensure that the bridge remained serviceable for the first 20 years of use. Any failure during this period was to be corrected at the contractor's expense.

Such a condition would force the project team and the producer to consider the longer-term project objectives, but this must be balanced against the costs associated with such a requirement. No team will accept such additional responsibility without adequate recompense. The likely cost of this extra requirement may far outweigh the cost to the client of increased involvement in the earlier stages.

An evaluation process which examines the whole project from conception to close down is required, to complement the project management evaluation process. Such a process will include issues of project economics and viability, at least, which are broader than merely how to accomplish the project on schedule, to budget and to scope. It will give less attention to the management and implementation aspects of projects and concentrate on the economic, financial and utilisation aspects. This technique will probably require more input from producers and the project team into the utilisation phase, which may form a closer partnership between two or more parties in a 'win-win' situation.

Consequently the term 'project management' may be replaced by the 'management of projects', the focus being not so much on the tools and techniques of bringing the project in on schedule, to budget and to technical performance, but on the wider phenomena of the project and of how it can be successfully managed throughout its life.

Start up project(6)

In a paper on project start-up it would be natural to go through all the motions of project initiation prescribed in the textbooks for the successful project. However, space has not been allowed for this nor is it what is intended. Instead some reflections will be made around factors which to me are essential, identifying experiences gained, some of which could be applicable to other areas.

To give some indication of a major task force engineering project let me briefly summarise some figures from the Gullfaks B project (Figure 7.3).

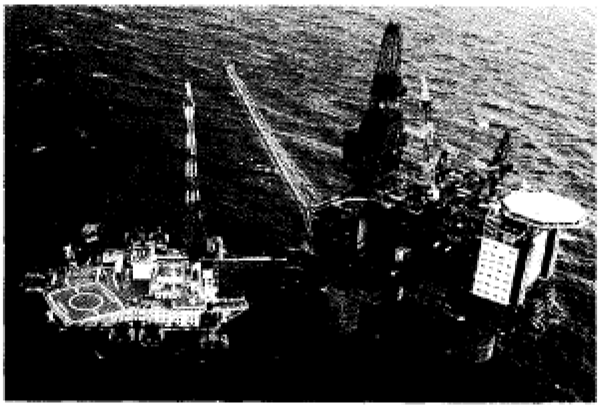


Fig 7.3 :The Gullfaks platform on location

- Main features:
  - 6 years from project initiation to start of oil production
  - Platform budget £1.1 billion
  - water depth: 142 m
  - production capacity: 150 000 bbl/day
  - topside tow-out weight 28 000 t, operating weight 34 500 t

- Topside pre- and detail engineering alone constituting:
  - 1,2 million man-hours over 2% years
  - 95 peak manning, 580 persons directly involved
  - 25 milestones where penalty clauses were applicable

- Resulting in
  - 14 major construction contracts
  - 230 equipment and material purchase orders
  - 15 000 drawings and documents (excluding supplier drawings)

The characteristics of such a major offshore engineering project are as follows:

- task force organization, many people, variety of experience, background and culture
- short and hectic execution periods, absolute time limits, requiring a rapid and hectic start
- enormous moneys involved
  - field development costs £0.5-2.5 billion with
  - large economic consequence of delays
- complex and tightly packed equipment arrangements

- high safety standards and stringent requirements from authorities
- large number of drawings and documents with great interdisciplinary dependencies

However, whatever the project size, small or large, the overall project objective will always be the provision of:

- deliverables to ‘quality’, i.e. in conformance with specified requirements, meaning delivery of the agreed product and service, on schedule and within budget. Out of this emerges two fundamental challenges, namely:
- establishment of an organization that can produce a fully coordinated and technically adequate documentation
- establishment of plans and budgets and managing accordingly.

Project Start-Up

Everyone will agree that the basis for a successful project is established during the start-up phase. This phase normally is the most hectic period of any project, in the midst of which the client is expecting drawings and documents to be produced. It could, however, be postulated that a successful project is more dependent on what preparations are made by the company and contractor prior to project initiation than on what is done during start-up.

One of the factors special to the Gullfaks B project was that Statoil had already realized at an early stage the importance of detailed plans being available prior to project initiation, as well as of ensuring conclusion of major conceptual issues. Thus Statoil, prior to project start-up, initiated three technical pre-studies, plus (and not least important) a planning study, drawing up the detailed project plans, all studies involving personnel subsequently engaged in the project execution.

An important aspect of the planning study was that the engineers themselves were responsible for definition of SOW, activities and dependencies, thereby, with assistance from planning, in fact themselves establishing the plans they later would be working to, a principle subsequently adopted to all project execution within Aker Engineering (AE).

As detailed-plans for project execution were available at project start, mobilizing personnel could immediately be assigned to planned and productive work, resulting in increased confidence in project approach and plans and thereby increased motivation.

Further, there was time and opportunity for project management to give full priority to achieving progress, especially in the early phases, as well as focusing on organizational development and concluding the many outstanding administrative start-up activities.

A simple but effective tool in the latter context was the 90-day start-up schedule (see Figure 7.4), established for each organizational unit being followed up on a weekly basis, listing all important administrative activities.

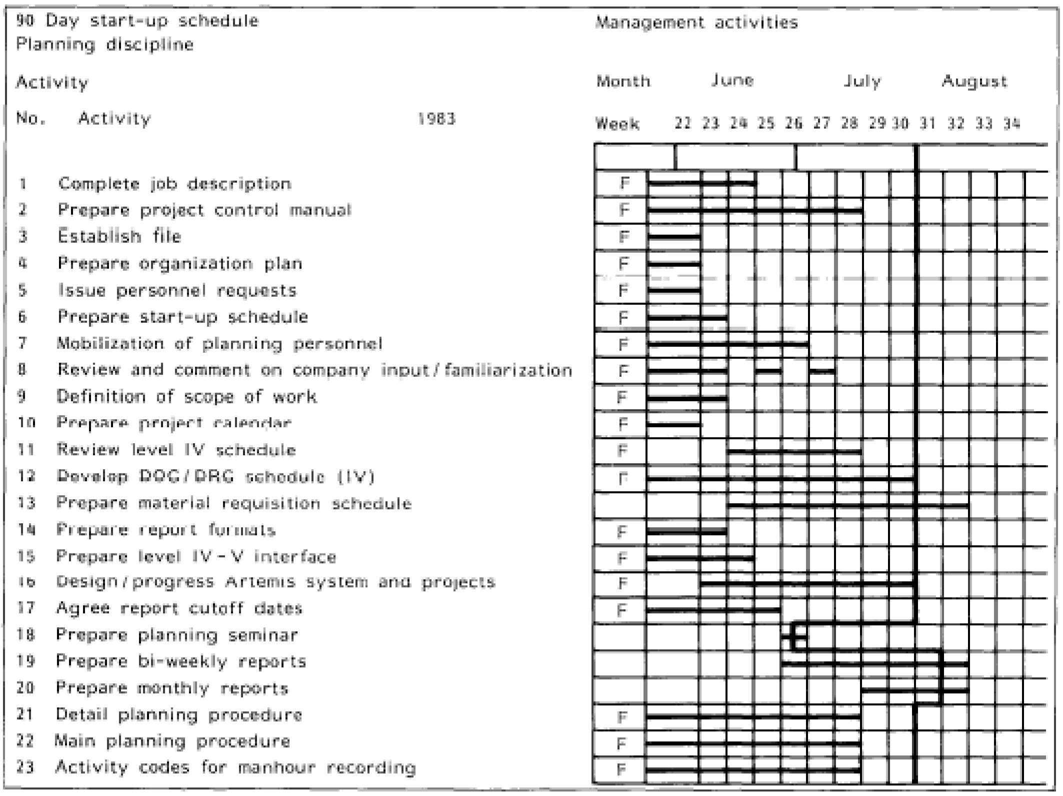


Fig 7.4: 90-days start-up schedule

However, it must be said that the start-up of the Gullfaks B project was special. Looking at other projects, the everyday reality is different, and a series of problems could be listed normally ending up with project management drowning in start-up activities, using their time putting out fires and forgetting that their main task is to establish an organization with one joint goal, the achievement of the project objectives. Balancing these problems, however, there always seems to be a team of people with great motivation and the ability to manage the impossible by means of hard work.

Summarizing our experience from the Gullfaks projects and Veslefrikk and our present projects Snorre & Sleipner the way to come from today's reality to a preferred future must be by

- planning start-up activities in advance
- performing essential studies and priority start-up activities prior to start-up, especially project plans concept definition and resolution of conceptual issues
- using start-up schedules

- on all levels
- with weekly follow-up

In summary:

- well prepared is nearly 'half complete'.

Organizational Development in Project Start-Up

As previously mentioned there are two main challenges:

- execution in accordance with agreed plans and budgets
- establishing an organization which can produce a fully coordinated and technically sound documentation.

The manning of a project itself is not necessarily a complicated task, and in general, though there are great challenges, technical problems rarely exist, only problems relating to the organization and the lack of communication. The real challenge is, therefore, to create the right organization and organizational spirit to face the considerable coordination task and challenges in the project and not least to bring all those individuals with varying background and experience into one team with the common goal of providing the agreed product and service on schedule and within budget.

However, there hardly exists a single key to what type of organization is right, however small or large the project may be. Consequently there is a large probability that a number of varying organizations can be successful, provided that the individuals in that organization agree that their organization is right for the task that they are about to solve and, especially, that each project participant fully understands that it is only the organization as one entity striving towards one common goal that can achieve the project's objective and thereby secure success.

In addition, it is important not to underestimate the considerable challenge faced by any individual thrown into a hectic project especially knowing that insecurity often leads to uncertainty, frustration and negative attitudes, while mutual trust and a secure environment will promote cooperation, communication and problem-solving.

What, then is, the objective of team-building activities? For Gullfaks B it served several purposes, primarily

- establishing the right ‘attitude' to project objectives and a project identity
- that the individuals in the organization should reach agreement on organizational principles, agree the details of operation, coordination and communication, and agree management style and management principles

- creating a safe environment through project personnel getting to know each other
- offering personal development to project participants

Experience from the Gullfaks B team-building process was positive and likewise unique, identifying that:

- Clear project objective is necessary.
- Several sessions are necessary, preferably with over-night stay and with the number of topics limited.
- Use of short concise introductions and simple statements are a 'must', allowing plenty of time for group and plenary discussions and ‘workshops’.
- Only the main organizational principles should be highlighted, with details being left to those experiencing and living with them.
- Team-building must be performed at all levels.

Another lesson learned is that it is easy to fall into the trap of thinking that information meetings are team-building meetings. This is not the case, even though such meetings serve an important purpose in providing information on quality assurance, planning, contact and so on; and as such are part of the overall organizational development effort.

The involvement of the client in project teambuilding is also greatly underestimated. Without client involvement in team-building no common platform will be established for understanding the necessity of early conclusions, simplicity of solutions reducing preferential engineering, and informal communication and problem-solving.

The conclusion must therefore be that team-building is an essential ingredient in any project start-up process. Therefore more emphasis should be placed on project team-building especially in early phases of the project. Further, there must be team-building on all levels, and the client should be involved.

Visions for the future

Looking back at some of the project experience from the 1970s, much experience has been gained in project organization and management. Effective tools, methods and systems have been developed which will more than adequately serve organizations in controlling start-up and management of major projects. Hence, there is little need for major advancement in this area, beyond the constant refinement of systems, tools and methods as well as adaptation to varying sized projects. However, with the problems we so often experience in project start-up and management of projects, major advancement is called for. This is all the more evident when apprehending the full consequences of the industry’s recent development towards cost-effective development concepts, and lump-sum engineering and management contracts where bonuses or penalties are payable when the quality of the engineering and management product has been verified towards actual platform completion.

Therefore as long as we are dependent on the human brain and the innovative resources of individual human beings, the most effective way of meeting this new and challenging future must be by ensuring and allowing for pre-project preparations and by creating the effective and inspiring team where each individual can fully utilize and develop his or her resources.

For the Gullfaks B project, Statoil realized the importance of this. When the platform was put into production the spring of 1988 the following was evident:

- A schedule acceleration of 11 months had been achieved.
- The platform cost was reduced by 25% (£300 million) against budget.
- The number of man-hours for offshore completion were reduced by 40%.

As they say in the UK: 'The proof of the pudding is in the eating.'

8. Stress, fatigue, situation awareness and safety in offshore drilling crews(15)

Critical factors in the prevention of industrial accidents include the ability of workers to maintain awareness of the work environment, understand the information it holds, and predict how situations will develop (Jones and Endsley, 2000; Stanton et al., 2001). The term used in industry for this cognitive skill is situation awareness (SA), defined by Endsley (1988, p. 97) as ‘‘... the perception of the elements in the environment within a volume of space and time, the comprehension of their meaning, and the projection of their status in the near future’’.

Cognitive skills such as situation awareness are known to be susceptible to the effects of work-related conditions such as fatigue and stress (Endsley, 1999; Sexton et al., 2000; Tucker et al., 2010) which are common in many high-risk industries, for example in offshore oil and gas exploration, where personnel work on remote installations, often in time-pressured, dangerous conditions (Flin and Slaven, 1996). The recent Deepwater Horizon drilling rig disaster in the Gulf of Mexico which killed 11 men and caused the worst oil spill in US history is testimony to the very hazardous nature of this industry's activities. Ongoing examination of the causal events indicates failures in situation awareness and risk assessment (Report to the President, 2011). Analysis of earlier drilling industry accidents, such as the Montara blowout in 2009 off Australia (Hayes, 2012), and on the UK Continental Shelf (UKCS) also identified failures to attend to relevant information in the work environment as a common contributory factor (Sneddon et al., 2006).

Drilling activity is a critical and challenging process in hydrocarbon exploration and production, especially for the increasingly hazardous deepwater wells (Skogdalen et al., 2011). Drillers have to maintain control of the well, lead work on the drill floor (sometimes involving heavy, physically demanding work), but also deal with advanced technological equipment and monitoring facilities. They may be based in the drill cabin, using advanced computer systems to provide them with a clear view of the task and real time data logging. The drill crew have to manually handle heavy equipment since the process is not entirely automated. The ‘well’ is drilled into the sub-sea oil reservoir or gas field, which involves carefully positioning the drill bit, collar and drill pipe into the well. This assembly is then attached to the kelly and rotary table which rotates, lowers and raises the drill pipe in order to carry out drilling activities. Drilling mud is introduced into the centre pipe in order to counterbalance internal pressures and to float the rock cuttings back to the surface where they are extracted from the hole, making the process slippery. Additional sections of drill pipe are added as the well gets deeper forming the ‘drill string'. The drill bit often needs to be replaced due to different rock compositions and in order to do this, the entire drill string has to be removed from the well and the pipes stacked in order to reach the drill bit. This is a hazardous process due to the slippery mud from the cuttings. Once this process has been completed, oil or gas flows up through well by placing a smaller-diameter pipe (tubing) into the casing and a packer down the outside to form a seal round the tubing. A device known as a 'Christmas tree' is attached at the top of the tubing allowing the drill crew to control the flow from the well. Due to the pressures at the depths where hydrocarbons are found, 'blow-outs' are possible and are an added risk to the process (Skogdalen et al., 2011). Blow-out valves are placed on the seabed in order to stabilize the pressure and control the well when necessary but the potential for a catastrophic situation is very real for the drill crew. It is apparent from the description above that SA is a critical issue influencing safety in the drilling industry but little research has been undertaken focusing on SA in this area. In particular, there is a lack of offshore specific SA models and measures available and there is also limited evidence of the role of stress and fatigue in affecting global SA. The current study was designed to first develop a measure of global SA in offshore drilling crews and secondly to use it to measure the relationships between stress, fatigue and situation awareness in offshore drilling personnel on the UKCS, and to determine whether situation awareness (SA) is associated with safety outcomes such as unsafe behaviour, near misses and accident history.

Measuring SA

Several methods for measuring SA have been developed, usually as a task-based, state characteristic, often using simulators (see Salmon et al., 2006 for a review). Several of these were considered for the current study, including the Situation Awareness Rating Technique (SART) (Taylor, 1990) where after task completion, respondents rate factors affecting their performance and understanding to give a global measure of SA. This method was deemed unsuitable as it measures SA for a specific task, while the aim of this research was to assess a more global estimate of SA. The Situation Awareness Global Assessment Technique (SAGAT) (Endsley,1988) is used to assess a participant's SA when a simulated task is interrupted. This was also rejected as no drilling simulator facilities were available to the researchers at the time this study was conducted. We appreciate that there have been further developments in SA theoretical underpinnings and measurement in recent years (see Salmon et al., 2008) however at the time this study was conducted, this literature was not available for consideration.

We therefore decided to develop a self-report measure which could be used with workers in the high risk drilling environment without the presence of an observer, or the interruption of tasks. This measure was intended to indicate an individual's level of SA as a general measure, rather than a transient, task-dependent, state measure. Individual differences in situation awareness have been documented (Gugerty and Tirre, 2000) and this is an emerging interest, as two trait-based, self-report measures have recently been developed. The Workplace Cognitive Failures Scale (Wallace and Chen, 2005), is a 22-item scale developed to assess cognitive failures in the workplace. The Factors Affecting Situation Awareness (FASA) (Banbury et al., 2007) is a measure of a pilot's acquisition and maintenance of SA. These scales were not available for consideration during the design stage of the present study but they could be useful in the future as measures of SA or to provide a source for testing concurrent validity with the current measurement instrument if future work was being conducted in the offshore drilling sector.

Several general (i.e. not workplace) trait measures of attention and cognitive disposition were scrutinised, such as the Short Inventory of Minor Lapses (Reason and Lucas, 1984), the Everyday Attention Questionnaire (Martin, 1983), and the Mindfulness Attention Awareness Scale (Brown and Ryan, 2003). They were rejected because of limited validity and reliability data and/or items were not appropriate for assessing awareness in a work environment. The Cognitive Failures Questionnaire (CFQ - Broadbent et al., 1982) was also reviewed. The CFQ provides a robust measure of everyday attention and lapses but is not work specific and did not cover issues that would be relevant to a drilling industry situation. It was therefore decided to develop a new trait SA measurement technique, the 'work situation awareness' (WSA) scale specifically aimed at measuring general awareness of the drilling work environment, based on an adaptation of the CFQ.

Factors affecting SA and attentiveness

There is limited empirical evidence regarding the factors affecting general levels of SA: many studies focus only on specific attentional processes such as vigilance, and do not consider awareness in a broader sense. Two workplace-related conditions that have been more widely reported in the literature as impacting SA are stress and fatigue.

Stress and SA

Increasing levels of stress can result in reduced working memory capacity and diminished attention (Hockey, 1986; Hancock and Szalma, 2008). Stress can result in poor concentration/alertness due to an overload on the individual's cognitive resources, and this can interfere with the primary perception of the situation, causing inattention to the available information. Consequently, there may be a narrowing of the individual's attentional field to incorporate only a restricted number of core aspects, resulting in peripheral information receiving little or no attention. While this 'cognitive tunnel vision' (Tversky and Kahneman, 1974) may be a valuable adaptive strategy in a safety critical environment by preventing overload, factors outside the central focus of attention may be those that have most potential to be harmful. Relatively high levels of occupational stress have been measured in offshore studies, (Mearns and Hope, 2005; Parkes, 1998) and associations between stress and offshore accident rates have also been established (Sutherland and Cooper, 1986, 1996).

Fatigue, sleep disruption and SA

Fatigue also causes detriments to alertness levels and consequently increases the risk of accident involvement (HSE, 2006), as the cognitive resources required are depleted due to physical exertion or sleep deprivation (Rosekind et al., 1994). Dawson and Reid (1997) found that deficits in cognitive processing in individuals with only moderate sleep deprivation were akin to those experienced when blood alcohol levels are over the legal limit for driving. The effects of fatigue are to generally decrease the speed of cognitive processing, and thus increase reaction times, tunnel vision, inattentiveness, and lower vigilance and concentration (Helmreich et al., 2004). These effects have been reported in the maritime industry (Smith, 2001; Wadsworth et al., 2008), transportation (Fletcher and Dawson, 2001), and power generation (Ognianova et al., 1998) and have also been reported for the offshore oil and gas industry as outlined below.

The working environment in the offshore drilling industry

Managers in the offshore oil and gas industry report that lack of care and attention is one of the main causes of accidents (O'Dea and Flin, 2001). This has particular relevance for drilling personnel, who are involved in one of the most dangerous activities, running long, heavy pipes into hydrocarbon reservoirs under the sea bed in a fast operation. They must be able to continuously monitor and understand the drill floor environment if they are to keep their accident risk to a minimum. Occupational stress is a feature of offshore life, originating from the usual sources, the offshore living environment, helicopter travel, and the interface between job and family (Parkes, 1998; Sutherland and Cooper, 1986, 1996; Sutherland and Flin,1989) .

Fatigue and sleep disruption are common. Drilling crews often work 12-h shifts for 14 or more days with no rest days. Many locations work a shift pattern (known as 'short change' or 'midhitch roll over') which involves personnel changing half-way through their stint offshore from day-shift to night-shift or vice versa), disrupting sleeping patterns (Gibbs et al., 2005). Conditions generally tend to be noisy due to machinery. There are high numbers of personnel living and working in a limited area, and personnel also may share an accommodation cabin, which can disturb relaxation time and sleep (Mearns and Hope, 2005).

Relationships between performance shaping factors, work SA and accidents

Examining the relationships between performance shaping factors such as stress and fatigue and work SA (WSA) may identify their relative contribution to accident involvement. The relationships being examined in the study are illustrated in Fig. 1 and explained below.

N.B. Only volitional non-compliance was measured, due to the difficulty of measuring non-volitional non-compliance (e.g. forgetting), as by their very nature, individuals may not be aware of them.

Fig. 8.1 proposes that fatigue and stress will have a detrimental impact upon WSA, and that as a result workers with lower WSA will have more accidents and near-misses, and report more unsafe behaviours, due to their attention and alertness being reduced. It is proposed that WSA is a key part of the explanatory mechanism for why stress and fatigue are related to workplace accidents.

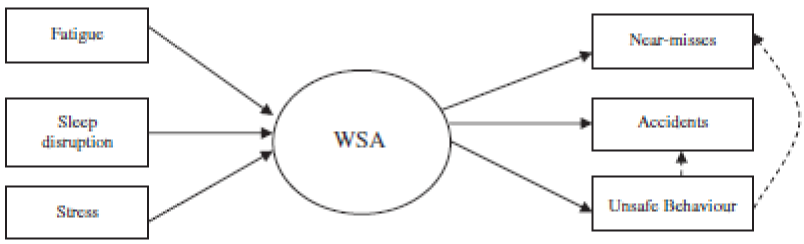


Fig 8.1:Proposed relationships between fatigue, sleep disruption, stress with WSA and unsafe behaviour, accident/near miss involvement

Hypotheses

As part of the validation process (see above) it was predicted that the Cognitive Failure Questionnaire (CFQ) scores would correlate negatively with WSA scores. The nature of the scoring on the scales means that higher WSA scores represent better SA whereas higher CFQ scores represent more cognitive failures. This validation was conducted before a series of hypotheses were tested.

Hypothesis 1a. Stress will be negatively associated with WSA.

Hypothesis 1b. Sleep disruption will be negatively associated with WSA.

Hypothesis 1c. Fatigue will be negatively associated with WSA.

It is proposed that WSA will have a subsequent effect upon personal safety outcomes such as unsafe behaviour, accidents and near-misses. Wallace and Vodanovich (2003a,b) found that cognitive failures were a predictor of occupational safety behaviour, in that individuals reporting more cognitive failures also reported increased safety non-compliance and more accidents, and Wads-worth et al. (2003) showed that occupational accidents were associated with increased cognitive failures.

Hypothesis 2a. WSA will be negatively associated with unsafe behaviour.
Hypothesis 2b. WSA will be negatively associated with rates of accident involvement.
Hypothesis 2c. WSA will be negatively associated with rates of near-miss occurrence.

It is also proposed from the above that WSA mediates the relationship between performance shaping factors (fatigue, sleep disruption, stress) on unsafe behaviour.

Hypothesis 4. WSA mediates the relationship between the performance shaping factors and unsafe behaviour.

Method

- Sample

The sample consisted of drilling personnel (n = 378) based on eight drilling rigs and platforms on the UKCS. All locations were contracted to operate for one multi-national operating company at the time of the survey. A total of 185 (49%) questionnaires returned were viable for analysis. This is an acceptable response rate for this remote sector, and is comparable to that found in other studies (e.g. Mearns et al., 2006). Respondents included all levels within the drilling hierarchy, from roustabout to drilling supervisor. Respondents indicated which age group they belonged to, rather than giving their actual age so that anonymity would not be compromised. The mean age group of respondents was 35-44 years. Of the sample, 77% were employed directly by the drilling company - the remainder were employed by the operating oil company or another contracting company. A total of 44% were supervisors, and 74% had worked at their present location (rig) for 5 years or less. Of the respondents, 66% worked a 2-week trip rotation pattern (2 weeks offshore then 2 weeks leave onshore), 44% worked a rolling shift pattern of one trip of day shift followed by one trip of night shift and 34% had ‘on-call’ duties.

- Procedure

A self-report questionnaire survey was used to collect data on cognitive failures, WSA, stress, sleep disruption, fatigue, unsafe behaviour and accident history. Two modes of distribution were used: personal offshore site visits by one of the research team and (due to logistical limitations for offshore trips), postal distribution. Respondents were given envelopes in which to return the completed questionnaires to the research team. No significant differences were found on any measure between the samples surveyed using the two methods.

- Measures

The questionnaire consisted of five sections: WSA, cognitive failures, fatigue and sleep disruption, safety behaviour, and accident history.

- Work SA (WSA)

This scale was developed to measure specific awareness of the work environment on the drilling rig. It was adapted from the Cognitive Failures Questionnaire (Broadbent et al., 1982) and drew on our previous work on situation awareness in drilling, which involved interviews with experienced drillers (Sneddon et al.,2006). It contained 20 items (Appendix A), and was scored on a 5-point scale (0 = very often to 4 = never; i.e. the higher the score, the better the individual's awareness of the work environment). Items were customised for the offshore drilling environment. They included 5 positively worded statements such as '7 take note of objects/events on the rig even if they are not directly related to my work'', '7 think ahead of my work to plan for different possible out-comes'' and 15 negatively worded (reverse scored) statements '7 am easily distracted by my thoughts and feelings". A final question asked at what time of the shift/rotation respondents felt least aware.

- Cognitive failures

The CFQ (Broadbent et al., 1982) was included for validation purposes, as it is an established measure for assessing slips of attention in everyday life. It has been shown to have high internal reliability, i.e. the items group together to measure the same underlying construct (e.g. Larson et al., 1997; Vom Hofe et al., 1998; Wallace, 2004), is well validated with other scales and has been found to be a significant predictor of accidents (Wallace and Vodanovich, 2003a,b). It contains 25 items, with responses indicating how often particular situations indicating failures of attention and cognition have happened to the respondent within the last 6 months, and is answered on a 5-point scale (4 = very often to 0 = never).

- Fatigue

To measure levels of fatigue, a scale developed by the Australian Maritime Safety Authority (AMSA; Parker et al., 1998) was selected since it had been developed for a marine environment, similar to that experienced by the offshore oil and gas industry both with regard to the physical environment and the shift patterns. The fatigue scale was modified to make the 13 items more suitable for the offshore work domain. They assessed to what extent boredom, number of days into the trip, working with a crew who are not fully competent, and working a night shift contributed to respondents' feelings of tiredness, fatigue or decreased alertness. The items were rated on a 5-point scale (ranging from 1 = never to 5 = always).

- Sleep disruption

The sleep disruption scale also came from the AMSA set of marine measures and contained 14 items, assessing how often sleep was disrupted offshore (or the onset of sleep delayed). As above these items were listed on a 5-point scale (ranging from 1 = never to 5 = always). For both these scales, a higher score indicated greater sleep disruption and fatigue.

- Stress

Standard occupational stress scales were rejected due to their length, or the unsuitability of the items. Instead the measure of stress was derived from offshore stress scales (Parkes, 1998; Sutherland, 1994; Sutherland and Cooper, 1996) into a list of 32 items customised for the drilling industry. The stressors included work overload, threat of job loss, demands of work on private life, and making mistakes. Respondents rated how much stress they perceived from each of the items on a 6-point scale (ranging from 0 = no stress to 5 = extreme stress).

- Unsafe behavior

This measure was the safety behaviour scale of the Offshore Safety Questionnaire (OSQ) (Mearns et al., 1997), which assesses to what extent respondents participate in short-cuts and violating behaviours. It has been used in a number of offshore oil industry studies (e.g. Mearns et al., 2003, 2010) and has acceptable internal reliability. The Cronbach's alpha of the scale in the current study was 0.88. The 11 items were rated on a 5-point scale (1 = never to 5 = always), modified from the three-point scale used in the OSQ, as this was felt to limit respondents' answers. Higher scores represented more unsafe behaviour.

- History of accidents and near-misses

The final section recorded respondents' accident history while working offshore. They were asked if they had been involved in an accident at any time in their offshore career; if they had experienced an accident on board the rig within the last 12 months that required a trip to the medic; and if they had experienced a near- miss on board the rig in the last 12 months. Four final items asked for: (a) very brief details of the accident or near-miss; and (b) the time of day/period of trip the accident or near-miss. We acknowledge that the respondents may have been unwilling to report such incidents due to the possibility of reprisal but by assuring confidentiality of the results we hoped that this unwillingness would be counteracted to some extent.

Analyses

The structure of the WSA was examined with a principal components analysis. To test relationships between stress, fatigue and WSA levels, correlations (Pearson's Product Moment) and regression analyses were used. The Sobel test was run to test for mediation effects of WSA between stress and safety noncompliance.

Results

- Principal components analysis

Principal components analysis (using the Varimax technique, which results in a rotated, orthogonal solution for the matrix) of the WSA scale was conducted, in order to test the factor structure. A loading level of 0.4 was set, as suggested by Field (2005). A four- factor structure (see Table 8.1) emerged, accounting for 53.6% of the variance. They were labelled as follows: concentration; attention; anticipation and distraction.

Table 8.1

Principal components analysis of the WSA scale.

Factor one		Concentration
Loading	.72	I am not able to keep my mind focused on work and it has a tendency to 'wander'
	.69	I find it difficult to concentrate for long periods of time
	.69	I 'tune out' during routine work, or when work is boring
	.62	My work area is often cluttered or disorganised
	.60	I have trouble getting back into work after an interruption
	.59	I become bored with my work quickly
	.55	I am easily distracted by visual stimulation (i.e. movement)
	.52	I often find I have carried out work on 'auto-pilot', without being aware of it
	.47	I find it difficult to pay attention to someone, even if I am being spoken to directly
Cronbach's alpha	.83	
Factor two		Anticipation
Loading	.72	I ensure I know most rig activities that are ongoing so I can 'keep an eye' on things
	.72	I think ahead of my work to plan for different possible outcomes
	.69	I take note of objects/events on the rig even if they are not immediately related to my work
	.64	I find it easy to keep track of everything that is going on around me
	.54	I find it easy to remember work instructions
Cronbach's alpha	.69	
Factor three		Attention
Loading	.82	I often speak or act without thinking
	.62	I often have difficulty paying close attention to details, which often results in careless errors
	.60	When I finish reading or being told instructions, I often have to re-read them or ask for them to be repeated as I don't remember them
Cronbach's alpha	.65	
Factor four		Distraction
Loading	.66	I am easily distracted by background noise
	.63	I often daydream during work
	.50	I am easily distracted by my thoughts or feelings
Cronbach's alpha	.73	

- Hypotheses results

The total WSA scale was found to have a Cronbach's alpha of 0.86, and was highly correlated with the total CFQ ($r = -.70$, $p < 0.01$), confirming Hypothesis 1 that the scales are measuring similar underlying constructs. The four sub-scales also had alphas ranging from 0.65 to 0.83. It is acknowledged that an alpha of 0.65 is rather low (Nunnaly, 1978) but given that we were developing a new scale, we believed it was acceptable to retain this scale for current purposes.

Table 8.2 displays the bivariate correlations between the four extracted factors and the other test variables, while Table 8.3 shows the accident history of the group.

Table 8.2

Means, standard deviations and pearson correlation coefficients between the measured variables.

Variable	Mean	SD	1	2	3	4	5	7	8	9	10
1. Overall WSA	53.42	7.95	–								
2. WSA – concentration	22.98	4.79	.89**	–							
3. WSA – anticipation	15.05	2.57	.53**	.18*	–						
4. WSA – attention	8.26	1.44	.61**	.47**	.23**	–					
5. WSA – distraction	7.30	1.93	.75**	.63**	.19*	.36**	–				
6. Sleep disruption	30.66	7.11	−.32**	−.28**	−.08	−.22**	−.33**	–			
7. Fatigue	31.03	7.49	−.40**	−.36**	−.14	−.26**	−.36**	.67**	–		
8. Stress	57.23	26.24	−.44**	−.40**	−.24**	−.28**	−.32**	.49**	.67**	–	
9. Unsafe behaviour	17.45	5.32	−.51**	−.51**	−.21**	−.37**	−.35**	.17*	.33**	.39**	–

* $p < 0.05$.
** $p < 0.01$.

Table 8.3

Table 3
Self-reported accident and near-miss involvement.

	Yes	%	No	%	n
Accident history at any time in career	92	51	90	49	182
Accident in past 12 months	3	2	112	98	115
Near-miss in past 12 months	24	14	149	86	173

It was found that higher levels of stress had a negative relationship with WSA (Hypothesis 2b), as did higher levels of sleep disruption (Hypothesis 2c) and fatigue (Hypothesis 2d). Consistent with expectations, lower levels of WSA were significantly related to increased unsafe behaviour in the workplace (Hypothesis 3a), ($r = -.51$). This could be because the people who admit to having lower WSA are also the people who are willing to admit to non-compliance. Table 7.3 shows the self-reported frequency of involvement in an accident or near-miss. Hypothesis 3b was supported: those who had previously experienced an accident were found to have significantly lower WSA than those who had never experienced an accident ($t(166) = -2.33$, $p < 0.05$). In contrast, no support was found for the hypothesis that individuals with lower levels of self-report WSA are more likely to have been involved in a near-miss than those with higher levels, ($t(158) = -1.44$, $p = ns$). This could be due to the fact that the participants did not want to report near misses, although reporting near misses could be seen as less threatening than reporting accidents. Individuals who had experienced an accident had significantly higher unsafe behaviour scores than individuals who had not (t(171) = 2.07, p <0.05). Those who had experienced a near-miss in the last 12- months reported that they engaged in significantly more unsafe behaviour than those who had not (t(163) = 3.76, p < 0.01).

In addition to the above analyses, a linear multiple regression analysis (Field, 2005) was carried out to determine what combination of workplace variables predicted global WSA (see Table 8.4).

Table 8.4

Table 4
Multiple regression model predicting global WSA.

Predictor variables	β	t	SE
Stress	−.34	−3.74**	.03
Fatigue	−.14	−1.30	.11
Sleep disruption	−.06	−0.64	.10
$F(3,173) = 12.77$, $p < 0.001$, $_{adj}R^2 = 0.22$			

** $p < 0.01$.

Stress was the only factor to make a significant contribution to the model, indicating that those who report higher stress levels also report poorer WSA. The model explains 22% of the variance in the global WSA scores.

Regression analyses for each of the four WSA factors were also conducted (see Table 8.5). Similar to the regression conducted for global WSA, the only significant predictor was stress, explaining 17%, 5% and 8% of the variance in the WSA factors ‘concentration’, ‘anticipation’ and ‘attention’, respectively (those who report higher stress also report poorer concentration, projection and attention levels). When the variables were entered to predict ‘distraction’, sleep disruption was the only significant predictor, explaining 17% of variance.

Table 8.5

Multiple regression models predicting factors 'concentration', 'anticipation', 'attention' and 'distraction' from the WSA scale.

	β	t	SE
Concentration predictor variables			
Stress	−.31	−3.34**	.17
Fatigue	−.13	−1.17	.07
Sleep disruption	−.04	−.41	.06
$F(3,173) = 13.83$, $p < 0.001$, ${}_{adj}R^2 = 0.17$			
Anticipation predictor variables			
Stress	−.29	−2.92**	.01
Sleep disruption	−.06	.64	.04
Fatigue	−.01	.07	.04
$F(3,172) = 4.12$, $p < 0.01$, ${}_{adj}R^2 = 0.05$			
Attention predictor variables			
Stress	−.19	−1.98*	.01
Sleep disruption	−.07	−.73	.02
Fatigue	−.08	−.71	.02
$F(3,176) = 5.76$, $p < 0.001$, ${}_{adj}R^2 = 0.08$			
Distraction predictor variables			
Sleep disruption	−.15	−1.65**	.03
Stress	−.15	−1.60	.01
Fatigue	−.16	−1.36	.03
$F(3,174) = 10.51$, $p < 0.001$, ${}_{adj}R^2 = 0.14$			

* $p < 0.05$.
** $p < 0.01$.

Earlier analyses indicated that stress was a significant predictor of unsafe behaviour at work, and so the next step was to test whether WSA was a mediator of the relationship between stress and unsafe behaviour. Baron and Kenny (1986) recommend using the Sobel test (Sobel, 1982) to identify the percentage of the total effect that is mediated, and the ratio of the indirect to the direct effect (see Preacher and Hayes, 2004). Tables 8.6 and 8.7 display the results.

Table 8.6

Summary of regression analysis results for WSA between stress and unsafe behaviour.

Variables	Regression coefficient	SE
Stress and unsafe behaviour	0.08**	0.14
Stress and WSA	−0.14**	0.02
WSA and stress on unsafe behaviour	−0.26**	0.05

** $p < 0.01$.

Table 8.7

Sobel test results for WSA between stress and unsafe behaviour.

Sobel test	Percentage of the total effect that is mediated	Ratio of the indirect to direct effect
3.76**	47.82	0.92

** $p < 0.01$.

The results show that WSA mediates 47.82% of the relationship between stress and unsafe behaviour, therefore accounting for almost half of the effect this study aimed to discover how different occupational factors inherent to the offshore drilling industry can affect attentiveness, and subsequent accident risk.

Regarding Hypothesis 1, a significant negative association was found between the Cognitive Failures Questionnaire and WSA, indicating that the more mishaps and lapses of attention an individual reported, the less workplace awareness he/she reported. This suggests that the skills required to maintain attention in everyday life are similar to the abilities that control attentiveness in the offshore drilling environment, as it is only the context that changes, and not the mental activities. Reason (1988) suggested that some people are more likely to experience cognitive failures due to their more rigid style of cognitive management and attentional focus. This could be an area for further investigation, particularly in high hazard domains where more flexible styles of cognitive management and attentional focus may be necessary to keep the appropriate perspective on ongoing operations. Such styles could either be selected for or trained for, but only if the WSA scale can be shown to have predictive validity for performance in the drilling sector. The development of more realistic simulators since this study was conducted, provides the opportunity to test the measure in such controlled environments.

Individuals reporting higher levels of stress were found to have poorer WSA. The literature on indicates that stress has a tendency to cause individuals to narrow their field of attention (Endsley, 1995) and can impair cognitive resources by undermining working memory (Hockey, 1986). Higher levels of sleep disruption and fatigue also correlated with decreased WSA. This corroborates Wallace et al.'s (2003) finding that individuals who scored higher on daytime sleepiness also experienced more cognitive failures. Sleep disruption is part of working offshore and these findings suggest that this is detrimental to employees by decreasing their WSA levels. Companies may wish to consider altering the shift patterns that are in place to make them more stable, for example, allow workers to always work a day or night shift rather than switch shift patterns in the middle (split/swing shift), or installing extra sound proofing in cabins to allow personnel to enjoy more undisrupted sleep.

Stress and fatigue were correlated but the multiple regression analysis showed that stress was the only significant predictor of WSA. When the component factors of WSA were examined in more detail, stress was also found to be the only significant predictor for concentration, projection and attention. Although the effect of fatigue appears to have been diminished in these analyses, sleep disruption was still a predictor of 'distraction'. Wallace et al. (2003) found that scores on the daytime sleepiness scale correlated significantly with their 'distractions' factor in samples of undergraduate students and military personnel, thus corroborating the results found in this study.

The hypothesis that individuals who report poorer WSA will participate more frequently in unsafe work behaviours was supported. In a study on production workers, Wallace and Vodanovich (2003a) also found that cognitive failure scores were positively related to safety non-compliance. Wickens et al. found that driving errors, lapses and violations were predicted by cognitive failure and the loss of SA through use of mobile phones has been found to be associated with traffic violations, e.g. speeding (Kass et al.,2007).

These findings suggest that unsafe work behaviours such as taking short-cuts and breaking rules could be due to lapses of attention or awareness, rather than deliberate violations. On the other hand, perhaps those who violate simply do not bother to pay attention. It may be that this is an issue with the projection stage of WSA, in that an individual is more likely to take a shortcut as he/she cannot (or is poor at) predicting the possible negative outcomes of this action. Conversely, those with better quality WSA may be more able to accurately predict what may happen and are more aware of the risks, and so consequently are less likely to carry out the unsafe behaviour.

Support was found for the hypothesis that individuals who had been involved in an accident at some point during their offshore career would have significantly poorer WSA scores. Likewise, Wallace and Vodanovich (2003b) reported that in military electrical workers, cognitive failures were positively correlated with both automobile accidents and workplace accidents. Larson et al. (1997) also found that accidents and scores on the cognitive failures scale were associated. These results confirm the importance of maintaining good quality SA in an attempt to successfully prevent accidents. There was no support for the hypothesis that individuals with poorer WSA would be more likely to have been involved in a near-miss within the last 12 months. However, this is most likely due to the fact that only 14% of the sample was in this category, and therefore the calculation had very little power. It was found that individuals who had been involved in an accident at any point during their offshore career were significantly more likely to engage in non-compliance at work than their colleagues who had never experienced an accident, as were those who had experienced a near-miss in the last 12-months (compared to those who had not).

Stress, WSA and safety

The results of a mediation test showed that 48% of the relationship between stress and unsafe behaviour was mediated by WSA, suggesting that WSA is an important construct when investigating workplace safety. High hazard/high reliability organisations should note the results of this and similar studies and either use further validated WSA scales in their selection processes or incorporate SA into their training programmes. It also important to note the impact stress has on human performance and measures to reduce the impact of stress in the workplace should be implemented by all organizations.

The WSA scale

The principal components analysis of the WSA scale produced a four-factor model (concentration, attention, anticipation and distraction). The CFQ is characterized by three components - perception, memory and motor function (Broadbent et al., 1982) and Wallace and Chen (2005) also identified a three-factor model (memory, attention and action) as the best fit for their Work Cognitive Failures Scale using confirmatory factor analysis. One possible reason for the four factors emerging in the current study is that they are an artefact of the hazardous and fast moving drilling environment. Furthermore, distraction can affect all three stages of perception, comprehension, or anticipation, which could explain why these distractive items clustered into a single factor.

9. Evaluating accidents in the offshore drilling of petroleum(16)

Introduction

The petroleum industry has effective industrial and environmental safety practices. However, whenever an accident happens the impacts are so devastating that the memory lingers for decades and the event is cited time and again. The key to good industrial and environmental safety lies from a demonstrated management commitment that treats industrial and environmental safety as having equal priority to other organizational goals. Employees are involved in, and know that they have the ownership of the industrial and environmental safety process. Realistic and achievable industrial and environmental safety targets are set for all work groups to achieve. Employees are adequately trained in industrial and environmental safety skills. Incident investigations are carried out not so much as to apportion blame but to minimize and prevent future occurrences. Positive steps are taken to improve employee behaviors, attitudes and values. Ahern pointed out that these include employee involvement and ownership of the industrial and environmental safety process; developing teamwork and supporting leadership within workgroups; recognizing and valuing individual contributions to industrial and environmental safety; and fostering a situation where employees genuinely care about the industrial and environmental safety of their co-workers. Monitoring techniques can be introduced to assist in assessing the general industrial and environmental safety conditions of the organization. In order to reduce risks associated with production facilities, one approach is to provide real time and risk-based accident forecasting mechanisms and tools that can enable the early understanding of process deviations and link them with possible accident scenarios. A forecasting algorithm was developed by Gabbar which can identify and estimate industrial and environmental safety measures for each operation step and process model element and validated with actual process conditions.

The industrial and environmental safety management has to be aware and recognize the business hazard, and therefore be proactive to it. The attitudes throughout the organization on the application of the industrial and environmental safety management systems must be honest and sincere as shown by the commitment of senior managers, and that the actions taken are not just because of the threat of legal sanctions. The handling of commercial pressure must demonstrate knowledge that industrial and environmental safety is one of the important overall business priorities. The state of being informed and ready is also important to ensure that incidents do not escalate into worse accidents; and accident investigations and analyses do uncover the underlying factors and any managerial failings that may have led to the accidents. Human factors play an important role in the completion of emergency procedures. Human factor analysis is rooted in the concept that humans make errors, and the frequency and consequences of these errors are related to work environment, work habits, and procedures.

An accident could have occurred repeatedly and has become of a routine nature or it can be a unique event. While there are lessons to learn from the experience of routine accidents since the impacts are somewhat similar, a once- off accident or a surprise event is more difficult to manage. Sensible responses to routine accidents can be developed, reviewed every now and again and further improved. These may include disaster warning systems, emergency management schemes, and disaster recovery programs including clean-up activities there are available methods to cleanup for on-land cases but for offshore cases the recovery has to depend on natural forces. For a surprise event there is not much to draw from experience and the preparedness to face such an occurrence is usually lacking. Each industry and each player in the industry has an approach towards industrial and environmental safety for that industry or that particular organization.

The petroleum industry involves activities like exploration and production (E&P), transportation, processing and refining, product distribution and storage with their own nature of incidents. Each activity is different from another with different general degree of risks involved. The focus of E&P would be drilling activities with the associated blowouts. Contributing factors include human error, equipment and control failure, weak operating systems and procedures and hazardous materials and environmental conditions. Short-comings from one or any combination of the above factors may result in an accident. Human error results from weak leadership, low levels of skills and knowledge, low reliability and poor discipline. Accidents may occur due to failure of equipment through poor state of maintenance and repair, control and emergency shut-down (ESD) system failure, materials of construction, improper design and technology utilization and operability. Technical support needs to be adequate and up-to-date. The ability to trace the drill-string by making a precise 3-dimensional underground survey is helpful. By using inertial technology an anti-disturbance and high accurate positioning can be achieved. Near-bit force measurement and drill-string acoustic transmission of bottom-hole assembly (BHA) can investigate down-hole dynamic behaviors of BHA and to monitor and control the forces acting on the drill assembly which would assist in preventing accidents. Application of industrial and environmental safety systems like hazard and operability (HAZOP), hazard analysis (HAZAN), technical audit and inspection, passive protection and inherent industrial and environmental safety affects the industrial and environmental safety performance. Effective procedures like operating instructions, shift change, start-up and shut-down, isolation and use of blind plates, hot-work permits, check lists, training of contractors' workers, limits of authority and lines of command can all reduce the number and impact of accidents. Escape routes, emergency response and evacuation, use of personal protective equipment (PPE), survival training, fire-fighting and First Aid are also important factors. Natural disasters contribute to the occurrence of accidents. Awareness and state of preparedness to handle the potential hazards of harsh environmental conditions from events like hurricanes, rain-storms and earth-quakes and volcanic activities can also lessen the ultimate impact of such incidents.

Accidents produce external pressures on companies leading to new regulations and renegotiation of enforcement of regulations. Structural characteristics of both the industries and the regulatory regime determine the interactions between the regulated and the regulator. In the industrial sectors where hazards and risks are visible and of public interest, it is easier to implement regulations through outside pressure.

Accidents drain resources. They result in loss of human lives and property. They interrupt production and negatively affect market goodwill and the environment. Effective remedial steps must be taken to reduce the frequency and consequence of accidents. The main objective of this study is to examine the situation in relation to jack-ups, drill ships, semi-submersible and platforms and determine the critical areas and have a better awareness and understanding for each activity, which may re-duce the number of accidents. These were identified from selected examples based on absolute numbers of these events and the perceived environmental effects they had caused. Remedial steps are proposed.

The main objectives of this study are do the following by region:

- Determine the cumulative number of offshore drilling accidents.
- Determine the cumulative number of fatalities resulting from these accidents.
- Determine the frequency and percentage of various types of accidents.
- Observe for any trends or cycles in the occurrences of these accidents.

Material and methods

Data were collected from public records and reports dating back to 1956. In order to lessen the effect of location factor differences, some of which may be hidden, the events are listed by region: North America, Europe, Middle East, South America, Asia and Australia, and Africa. The facilities were classified under jack-ups, drill ships, semi- submersible and platforms. In this chapter, no attempt is made to relate frequency of incidents or fatality to water depth, so no data on the water depths are presented. For each region the cumulative frequency of accidents and number of fatalities involving drilling was recorded and plotted against weeks after the starting date on a regional basis. The frequency of occurrence for any year can be obtained from this plot. A regular slope indicates that the situation is steady, while an increasing slope indicates a deteriorating condition and a decreasing slope indicates an improving situation. Changes in slopes would indicate the beginning and the end of a possible cycle. Figures for fatality for each region were also recorded and classified under different ranges of 0, 1-10, 11-20, 21-50, 51-100, 101-200 and more than 200. The common basic causes were classified under blowouts, storms, structural failures, towing accidents, gas leaks, soil failures running aground or capsize and miscellaneous causes taken from outstanding examples. The summary of the frequency as percentages of the total global figure for each type of accident were also presented on a regional basis. In the current study no corresponding analysis was done based on facility type Steps were suggested to improve the situation.

- **North America**

Fig. 9.1a shows that over the study period there were a total of 98 recorded accidents. There is an indication of a regular changing slope every about 8-10 years. Fig. 9.1b shows a cumulative number of fatalities of 188 with a maximum of 84 recorded by the semi-submersible Ocean Ranger flooding. Fig. 9.1c shows that out of 98 accidents, 38 or 38.8% were due to blowouts followed by 25 or 23.4% caused by storms. Structural failures made up 10.2% and towing accidents made up 6.1%. Fig. 9.1d is the pie-chart showing the percentage distribution of the basic causes.

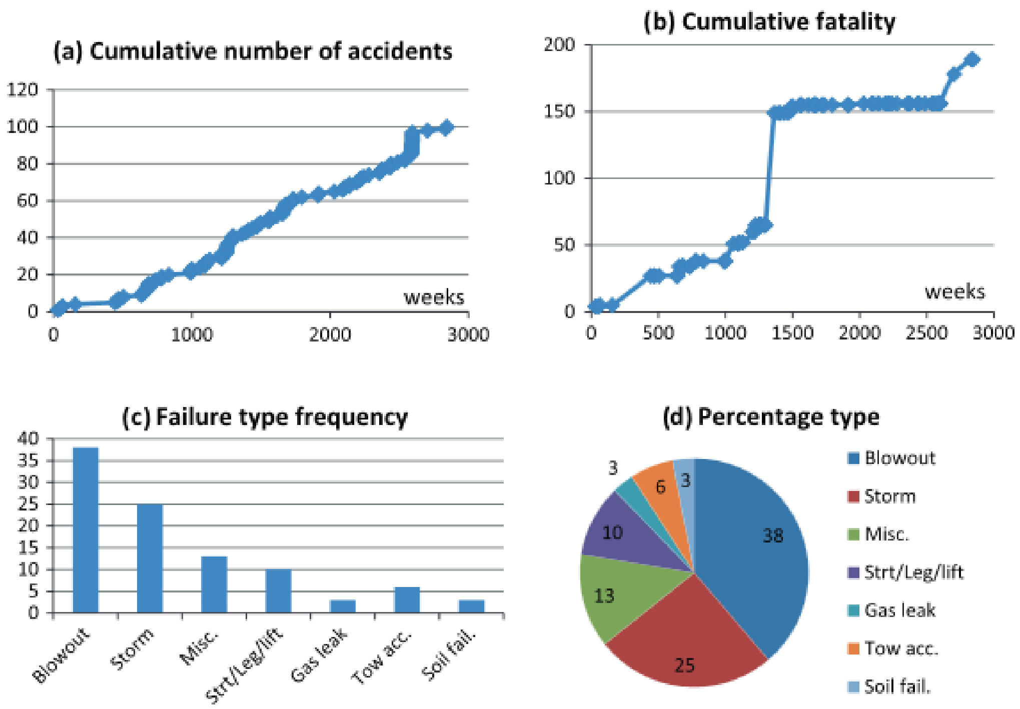


Fig 9.1. Accidents type and frequency and fatality (N America)

There is a slight indication of a presence of cycles in the frequency of accidents over the study period as indicated by periods of fairly constant slopes.

On Valentine’s Day, 1982 a terrible storm rages off the coast of Newfoundland some 315 km east of St. John’s on the Grand Banks and the Ocean Ranger, the world’s mightiest self-propelled drilling rig, was pounded by waves more than 20 m high. At the height of the storm, the “indestructible” rig began to tip over, and then capsized. All 84 men on board perished. It was Canada’s worst tragedy at sea since the Second World War. The Ocean Ranger was the largest and most advanced oil rig of its kind, built to withstand the world’s stormiest seas. It was learned that design flaws could have started the Ocean Ranger’s problems but poor training turned it into a catastrophe. The blame was squarely on the rig’s owners and operators. With proper training the crew could have overcome the ballast control problems. With proper survival suits, many of them would be alive today. The mighty Titanic was designed to slice through ice; the mightier Ocean Ranger was designed to tame the hurricane. But the elements might be mightier than one might think.

In October 2007, the Usumacinta was contracted to drill at PEMEX’s Kab-101 platform in the Bay of Campeche. The Kab-101 platform was a light production Sea Pony type platform, installed by PEMEX in 1994, which had two wells. The Usumacinta was contracted to complete drilling work on a third well, named Kab-103. The Usumacinta was brought into position alongside the Kab-101 platform to finish drilling the Kab-103 well. A cold weather passed through the Gulf of Mexico bringing storm winds of 130 km/h with waves of 6–8 m. The adverse weather conditions caused oscillating movements of Usumacinta. These movements caused the cantilever deck of the Usumacinta to strike the top of the production valve tree on the Kab-101 platform, resulting in a leak of oil and gas.

The subsurface safety valves of wells 101 and 121 were closed by PEMEX personnel, but the valves were unable to seal completely. The 81 personnel on the Usumacinta were evacuated by lifeboat. Rough seas hampered the rescue operation and caused the break-up of at least one life raft. Fires and bad weather delayed operations. There were 21 reported deaths during the evacuation of the Usumacinta, with one worker missing, presumed dead. There were some criticisms over the use of dispersants causing the oil to sink to the seabed easily. There was also been speculation that the rig suffered some structural or jacking failure.

Deepwater Horizon was an ultra-deepwater, dynamically positioned, semi-submersible offshore oil drilling rig with a crew of 146. In September 2009, the rig drilled the deepest oil well in history at a depth of 10,685 m in the Tiber Oil Field at Keathley Canyon block 102, approximately 400 km southeast of Houston, in 1259 m of water. On 20 April 2010, while drilling at the Macondo Prospect, an explosion on the rig caused by a blowout killed 11 crewmen and ignited a fireball visible from 56 km away. The resulting fire could not be extinguished and on 22 April 2010 Deepwater Horizon sank, leaving the well gushing at the seabed and causing the largest offshore oil spill in US history. An important factor in the rapid escalation of the Macondo blowout was failure by drill floor personnel to use the diverter, which is designed for just such a situation.

- **Europe and North Sea**

Fig. 9.2a shows that over the study period there were a total of 32 recorded accidents. There is an indication of a regular changing slope every about 9-11 years. Fig. 9.2b shows a cumulative number of fatalities of 330 with a maximum of 167 recorded by the platform Piper Alpha fire and explosion in the North Sea. The figure shows that there is a clear change in the trend in both the numbers of accidents and fatalities recorded after the Piper Alpha disaster. This could be due to positive developments in Regulations following the Cullen Report. Fig. 9.2c shows that out of 32 accidents, 9 or 28% were due to blowouts followed by 6 each or 18.8% caused by gas leaks and structural failures. Storms and towing accidents made up 3 each or 9.4%. Fig. 9.2d is the pie-chart showing the percent-age distribution of the basic causes.

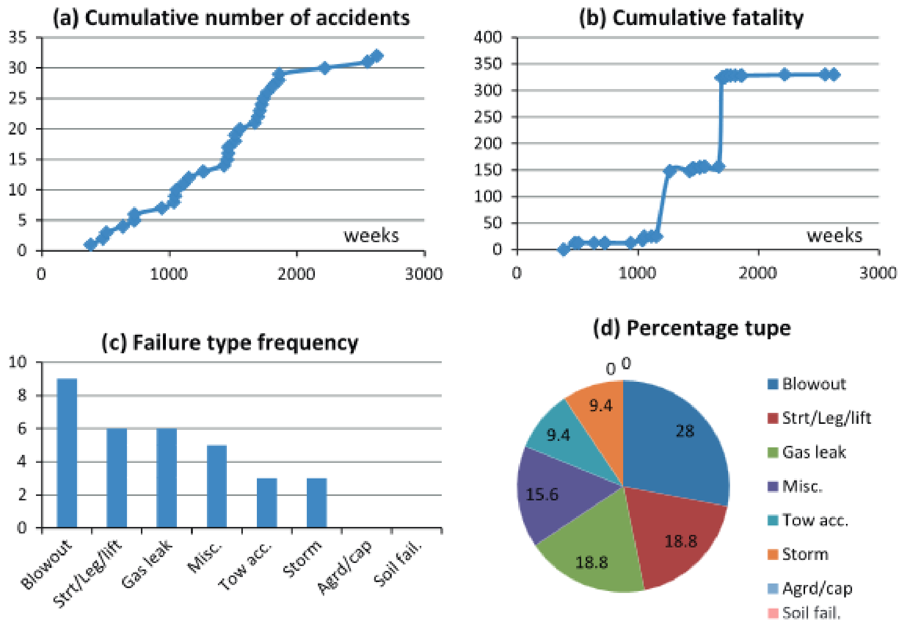


Fig. 9.2. Accidents type and frequency and fatality (Europe)

There is an indication of a presence of cycles in the frequency of accidents over the study period as indicated by periods of fairly constant slopes. On 27 February 1965 the Sea Gem, a ten legged jack-up, became the first rig to break up and sink in the North Sea while attempting to move to a new location. The disaster claimed 13 lives and 5 serious injuries.

The Ocean Prince was built from a Gulf of Mexico semi- submersible template and it was reasoned that if this design had operated successfully in the Gulf it would also operate successfully in the North Sea. This was a gravely wrong assumption. The rig design was probably adequate to withstand the rigors of the North Sea weather, however, only in a floating mode and not sitting on bottom. The rig was not equipped with a motion compensator, as this piece of machinery had not yet been invented. To compensate for the rig vertical heave, bumper subs were utilized in the drill string. This proved to be extremely inefficient. The rig was fitted with Gulf of Mexico type anchors designed for the soft mud bottom in the Gulf. They were not designed for the hard sand bottom of the North Sea. These anchors would not seat and constantly slipped causing the rig to go off location on many occasions. The work boat captains were inexperienced in drilling support operations. They would constantly run their vessels into the rig causing serious damage to both the boat and the rig. The rig was drilling in a bottom setting position which had caused very severe scouring. In high wave conditions the rig could be lifted off the bottom and smashed back down causing visible structural cracks. The weather was miserable on the morning of 6 March 1968. The rig collapsed due to unattended structural cracks and eventually sank.

The Alexander L. Kielland was a semi-submersible located in the Ekofisk Field for Phillips Petroleum. It was supporting the Edda rig for workers who travelled between the two rigs via a bridge. On 27 March 1980, one of the main horizontal braces supporting one of the five legs failed due to a fracture. The remaining five braces attached to the leg failed in quick succession and the rig almost immediately listed partially submerging the main deck and accommodation block.

Attempts were made to launch lifeboats, with only two of the seven lifeboats launched successfully. Three of the lifeboats were smashed against the rig’s legs as result of the storm winds and waves whilst being lowered, leading to a number of casualties. There were 212 men aboard and only 89 survived the accident. On top of the high winds and waves, the men also faced near freezing waters with little protection.

On 6 July 1988 at about 2200 h an explosion occurred on the Piper Alpha platform facility in the North Sea. The subsequent fire escalation was swift and dramatic with the first of three gas risers failing catastrophically after 20 min. In the disaster 167 persons out of 229 lost their lives. Available evidence has been examined to explain the rapid fire escalation and fire dynamics are now being considered in the design and operation of UK offshore installations. At the height of the blaze on the platform, flames could be seen 100 km away. Survivors slid down pipes and jumped into the icy sea to escape the flames. The UK Offshore Operators’ Association said accidents have fallen by 50% since the Piper Alpha disaster and workers and unions are consulted on matters of industrial and environmental safety. Cullen stated that the company operating the rig was not prepared for a major emergency and adopted a superficial attitude to the assessment of the risks of a major hazard.

The Piper platform represented a major step in both the development of the UK offshore resources and technology. The basic design of the topsides was based on those used in the Gulf of Mexico. The oil production from the Piper Alpha platform represented some 10% of the UK production from the UK sector of the North Sea.

The disaster remained as the worst ever oil rig disaster costing billions of dollars in property damage. It was caused by a massive fire which was the result of an accumulation of errors and questionable decisions. A key lesson from Piper Alpha in 1988 was that the OIM had no realistic training in emergency response. Since then major emergency response (MEM) training, competence development and assessment for OIMs and deputies has become standard practice in the UK sector.

Aspects of design can be important. Design of fire and explosion barriers fits well with the current engineering skills and work-processes in investment projects. The perception on industrial and environmental safety by operators on the platforms had been gauged by some researchers. Industrial and environmental safety climate surveys on 13 platforms had also been conducted to assess the confidence of off-shore workers after an incident. The type of approaches towards industrial and environmental safety can also differ from one installation to another which can affect overall morale and confidence and state of mind of the workers. In conjunction with forecasting techniques indicators can also be introduced to monitor the general trend of the conditions on the platform in relation to industrial and environmental safety habits and practices. There are individual indicators for active fire protection and mustering of personnel.

- **Middle East**

In the current chapter the accident types (or causes) are grouped into blowouts, towing accidents, running aground, structural failures, gas leaks, storms, soil failures, and others. Fig. 9.3a shows that over the study period there were a total of 14 recorded accidents. There is an indication of a regular changing slope every about 7-8 years. Fig. 9.3b shows a cumulative number of fatalities of 69 with a maximum of 20 recorded by the Nowruz platform fire in the Persian Gulf. Despite the fatalities from the Hasbah Platform blowout the trend in the frequency of accidents does not seem to change. Fig. 9.3c shows that out of 14 accidents, 5 or 35.7% were due to blowouts followed by 3 each or 21.4% each caused by towing accidents and storms. There were 2 gas leaks or 14.3% and 1 structural failure or 7.1%. Fig. 9.3d is the pie-chart showing the percentage distribution of the basic causes.

There is an indication of a presence of cycles in the frequency of accidents over the study period as indicated by periods of fairly constant slopes.

In December 1956 the Qatar 1 had a towing accident and sank in the Arabian Gulf. On 2 October 1980 the Hasbah Platform drilled by the Ron Tappmeyer jack-up, exploratory well No. 6 blew out in the Persian Gulf for 8 days and cost the lives of 19 men. In 1983, the Nowruz Oil Field in the Persian Gulf, Iran, was involved in a number of oil pollution incidents from war hostilities resulting with 20 deaths.

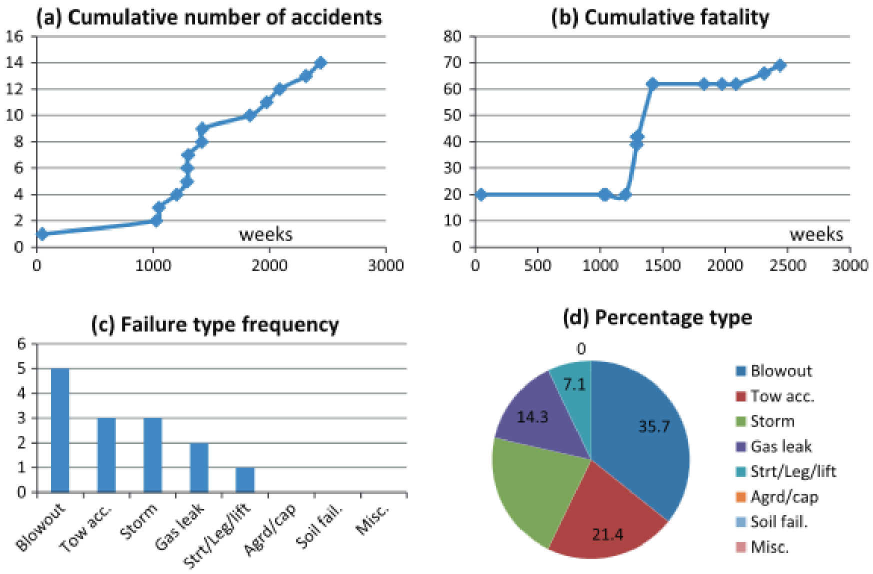


Fig. 9.3. Accidents type and frequency and fatality (Middle East)

- **South America**

In the current chapter the accident types (or causes) are grouped into blowouts, towing accidents, running aground, structural failures, gas leaks, storms, soil failures, and others. Fig. 9.4a shows that over the study period there were a total of 35 recorded accidents. There is no indication of any regular changing slopes. Fig. 9.4b shows a cumulative number of fatalities of 61 with a maximum of 42 recorded by the Enchova platform explosion. The figure shows that the trends for both the frequency of accidents and the number of fatalities decrease dramatically around the end of the eighties. These correspond to the positive change of E&P operating regimes in Brazil which dominated the oil and gas upstream activities of South America following the Enchova disasters. Fig. 9.4c shows that out of 35 accidents, 29 or 82.8% were due to blowouts followed by 4 or 11.4% caused by structural failure. There was one accident caused by a gas leak and one due to a storm or 2.9% each. Fig. 9.4d is the pie-chart showing the percentage distribution of the basic causes.

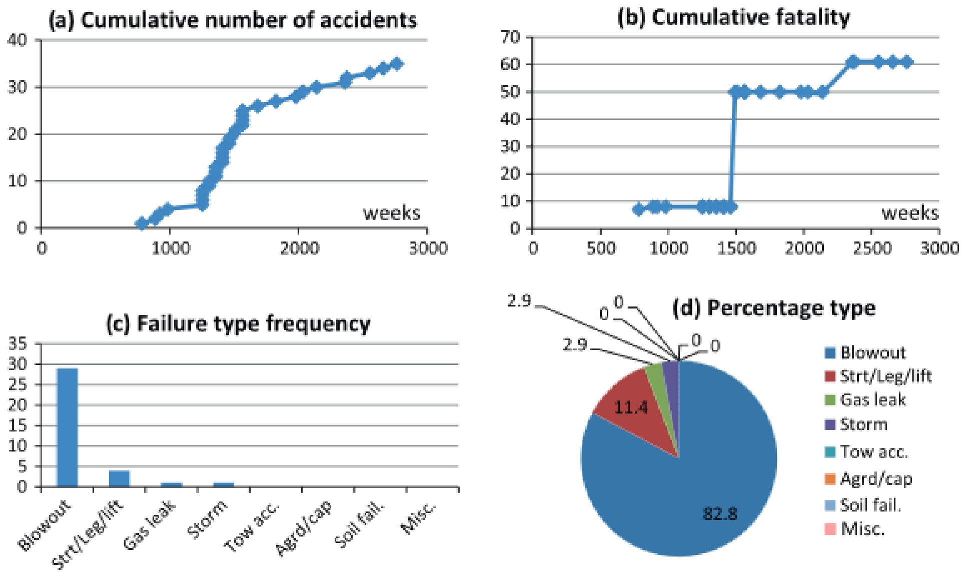


Fig. 9.4.Accidents type and frequency and fatality (South America)

There is an indication of a presence of cycles in the frequency of accidents over the study period as indicated by periods of fairly constant slopes.

The Enchova Central platform was the location of two major incidents. In the first, on 16 August 1984, a blowout occurred followed by explosion and fire. The majority of the workers were evacuated but 42 personnel died during the evacuation of the platform. The most serious incident occurred when the lowering mechanism of a lifeboat malfunctioned, causing the bow hook to fail. The lifeboat was then left suspended vertically until the stern support broke and the lifeboat fell 10-20 m to the sea, killing 36 occupants. Six other workers were killed when they jumped 30 or 40 m from the platform to the sea.

The second incident occurred four years later on 24 April 1988 and resulted in the destruction of the platform. The well suffered a gas blowout. The blowout preventer (BOP) did not shut the well in and attempts to kill the well failed. A drill pipe was forced out of the well and struck one of the platform legs, causing sparks which ignited gas from the blowout. The fire burned for 31 days, resulting in extensive damage to the topside structure. Fortunately, a floating hotel was alongside the Enchova Central at the time and the platform was evacuated with no loss of life.

The P-36 was brought into operation in the Roncador Field off the coast of Brazil in May 2000. The unit was capable of processing 180,000 bopd and 7.2 million cubic meters of gas per day. In May 2001, the P-36 was producing around 84,000 barrels of oil and 1.3 million cubic meters of gas per day when it became destabilized by two explosions and subsequently sank.

On 15 March 2001, an explosion was recorded in the starboard aft column, thought to have been the mechanical rupturing of the starboard emergency drain tank (EDT). This caused the release of gas-saturated water and oil into the aft starboard column and caused the platform to list.

A second larger gas explosion which killed 10 members followed causing a progressive list that led to the subsequent loss of the platform.

The main causal factors were listed as alignment of the port EDT permitting entry of hydrocarbons; delay in the activation of the port EDT drainage pump, allowing the reverse flow of hydrocarbons; inadequate contingency plans and inadequate training.

- **Asia and Australia**

Fig. 9.5a shows that over the study period there were a total of 26 recorded accidents. There is an indication of a regular changing slope every 8-9 years. Fig. 9.5b shows a cumulative number of fatalities of 348 with a maximum of 91 recorded by the sinking of the drill ship Seacrest in a hurricane off Thailand. Despite high fatality figures in several accidents across the region over the study period, the trend in the frequency of accidents does not seem to change.

Fig. 9.5c shows that out of 26 accidents, 12 or 46.2% were due to blowouts and 3 or 11.5% caused by storms. There were 2 accidents caused by structural failure, towing activities and soil failures or 7.7% each. There was 1 or 3.8% accident caused by a gas leak. Fig. 9.5d is the pie-chart showing the percentage distribution of the basic causes.

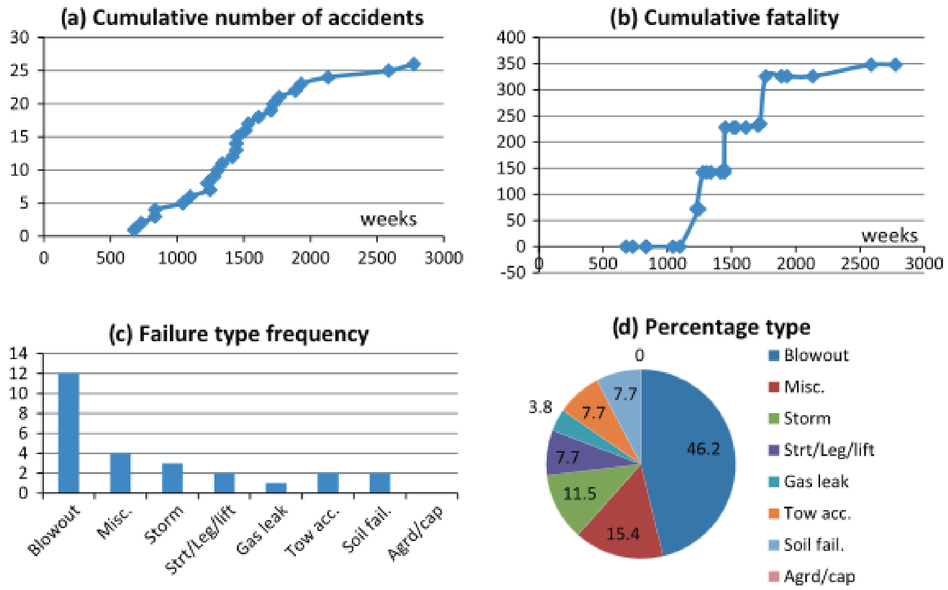


Fig.9.5.Accidents type and frequency and fatality (Asia/Australia).

There is an indication of a presence of cycles in the frequency of accidents over the study period as indicated by periods of fairly constant slopes.

The Montara oil spill was an oil and gas leak and subsequent slick that took place in the Montara oil field in the Timor Sea, off the northern coast of Western Australia.

The slick was released following a blowout from the Montara wellhead platform on 21 August 2009, and continued leaking for 74 days. Halliburton was involved in cementing the well. Sixty-nine workers were safely evacuated.

There was an ignition at surface, even though the whole installation was 'dead' and unmanned but there was insufficient mud available. The intense fire caused the cantilevered rig to collapse onto the platform below it and both platform and rig were extensively damaged.

The cement barrier was faulty. It was learned that not one of the Montara wells had been constructed in strict compliance with PTT's well manual.

The accommodation barge at Montara was poorly prepared for a blowout situation, though the initial emergency response to pull off station was effective. It is apparent that no party, including the regulators who reviewed the installation safety case, believed that a significant continuing hydrocarbon release was a realistic event which should be considered.

Emergency response arrangements and equipment were fundamentally sound, and the calm weather was undoubtedly another key factor in ensuring rescue after abandonment. Investigations revealed many organizational deficiencies, primarily involving clear communications and risk-based decision making. There was lack of adequate foresight on local organizational systems and procedures. It was judged that the associated risks were not so significant that work should stop until they were corrected.

On 25 November 1979 the Bohai 2 jack-up rig had a towing accident in a storm and sank. There were 72 deaths. The following year on 15 June the Bohai 3 had a fire as a result of blowout killing 70 crewmembers. The Seacrest drillship capsized in 1989 during Typhoon Gay, with the loss of 91 crew members. Another storm fatality, the Glomar Java Sea capsized and sank during Typhoon Lex in 1983 with the loss of all on board. A support vessel collided with Mumbai High North in 2005, rupturing a riser and causing a major fire that destroyed the platform.

- **Africa**

In the current chapter the accident types (or causes) are grouped into blowouts, towing accidents, running aground, structural failures, gas leaks, storms, soil failures, and others. Fig. 9.6a shows that over the study period there were a total of 14 recorded accidents. There is an indication of a regular changing slope every 8-9 years. Fig. 9.6b shows a cumulative number of fatalities of 271 with a maximum of 230 recorded by the Funiwa 5 platform blowout and forest fire.

There was no indication of any trend in the frequency of accidents. Fig. 9.6c shows that out of 14 accidents, 8 or 57.2% were due to blowouts followed by 3 or 21.4% due to towing accidents. There were 2 or 14.3% accidents caused by structural failure and 1 or 7.1% accident due to a gas leak. Fig. 9.6d is the pie-chart showing the percentage distribution of the basic causes.

There is an indication of a presence of cycles in the frequency of accidents over the study period as indicated by periods of fairly constant slopes.

On 9 October 1995 in West Africa the Gemini jack-up collapsed due to leg failure and killed 18 people. Oil from the 1980 Funiwa 5 blowout polluted the Niger Delta for 2 weeks, followed by fire and the eventual bridging of the well. Santa Fe's Al Baz jack-up burned and sank after a blowout in 1989 with the loss of 5 lives. A fire on the Ubit platform in Nigeria in 1996 killed 18 people.

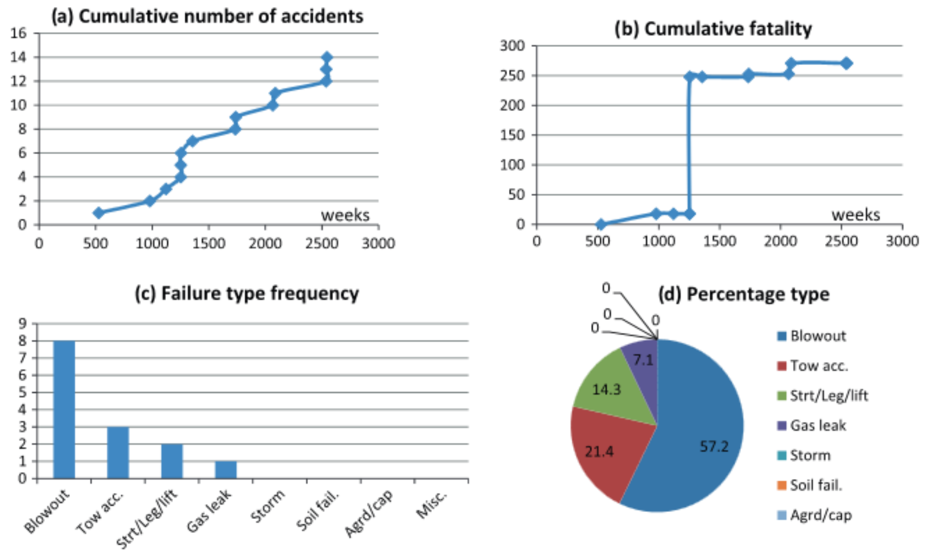


Fig. 9.6.Accidents type and frequency and fatality (N America).

Overall summary of failures

Basically all the stated accidents were due to human error and incompetence and equipment and instrument failures. There is no one factor that solely contributes to the accident but a host of other contributory failures that together ultimately make it happen. From the examples above it can be observed that almost all the accidents cited were routine accidents. Similar accidents have happened elsewhere sometime in the past. The question is whether people really learn from history or not. Or maybe even an apparently routine incident is unique and there are no two exactly similar ones that there is nothing much to learn from past incidents.

Fig. 9.7a shows the summary of the number of operating facilities as from 1991 to date and the number of accidents recorded in this study. Jack-ups represent the biggest number of operating facility type followed by platforms, semi-submersibles and drill ships. There is a corresponding trend in the frequency of accidents in relation to the numbers of facility types in operation. Fig. 9.7b shows the percentage of the various types of facilities in operation and the percentage of those types involved in incidents. It is apparent that jack-ups have a disproportionately higher rate of failures compared to platforms and semi- submersibles. This could be due to the less stable operating conditions for the jack-ups. Fig. 9.7c shows the total frequency of incidents for each type of facility involved in this study. Fig. 9.7d shows the frequency for various fatality ranges. The majority of accidents involved no fatalities. The trend shows the higher the range of fatality, the less the frequency, which is to be expected. The concern is more on the double and triple fatality figures recorded by some accidents. This will be elaborated further in subsequent sections. Fig. 9.7e shows the overall failure type frequencies classified under blowouts, storms, structural failures, towing accidents, gas leaks, soil failures, running aground, and others. It can be observed from the figure that the most frequent accident type is a blowout followed by storm and structural failure. Fig. 9.7f is a pie-chart showing the percentages of the various basic causes for the accidents with blowouts representing the highest with 46.1%.

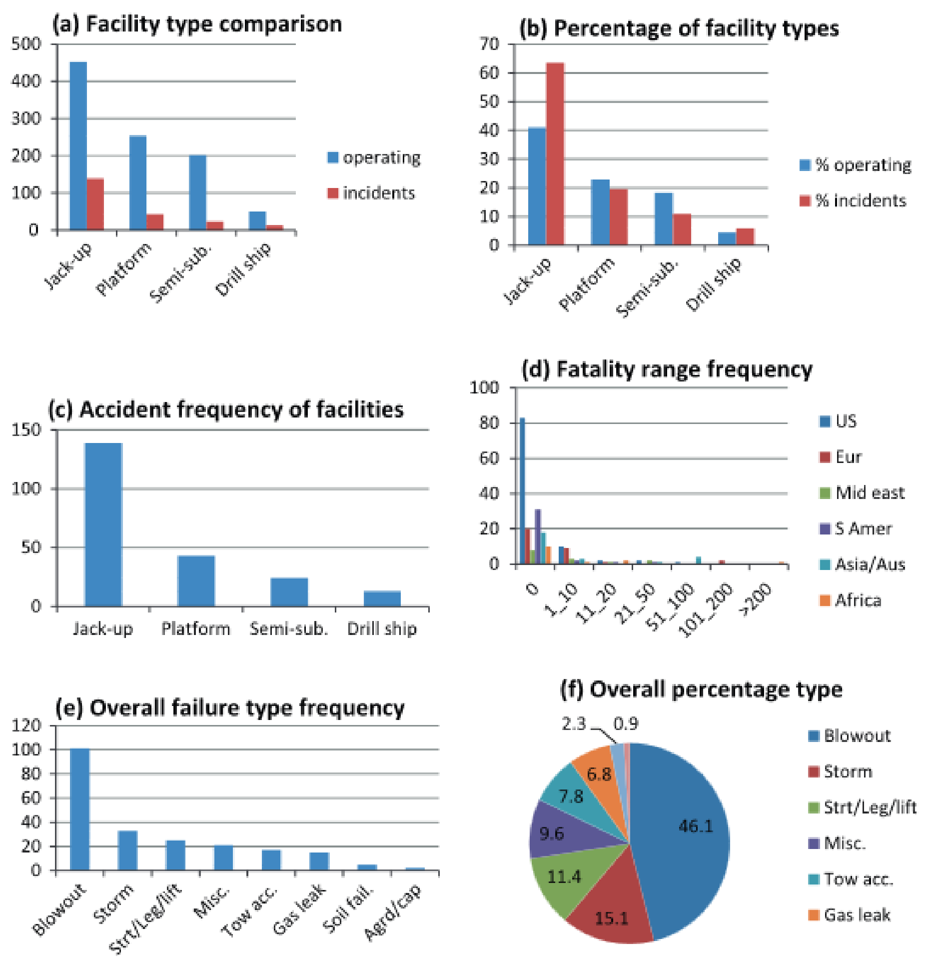


Fig. 9.7.Summary of overall frequencies, failure types and fatalities

Fig. 9.8 shows the

summary of the frequencies as percentages of the total global figure of the various types of accidents on a regional basis. The figure shows that N America is top in all types of accidents. The plots are consistent to the number of operating facilities in the various regions.

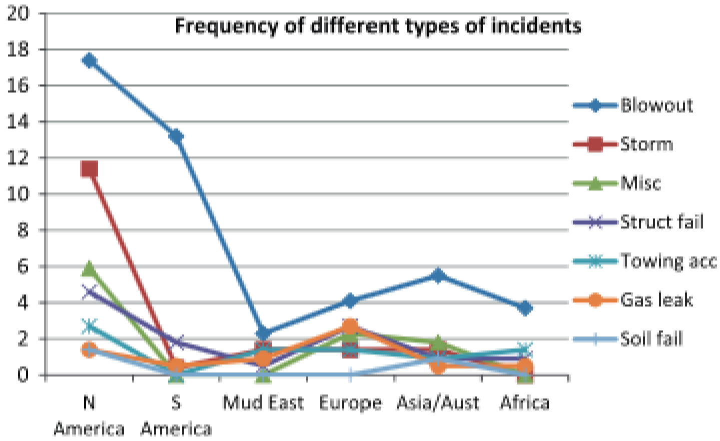


Fig 9.8. Frequencies as percent of total global figure of accidents: by region

Remedial measures

Accidents drain the human and other resources. Lives, reserves and equipment are lost; production is discontinued and market goodwill is negatively affected production, while there could be untold damage to the environment. It is to the interest of all stakeholders to ensure that accidents are reduced or eliminated. Remedial measures have to be found and implemented. Responsibility, authority and accountability must be properly assigned.

- Human factor

DeCola and Fletcher stated that human factors - either individual errors or organizational failures - have been reported to cause as much as 80% of accidents. Accidents in the oil and gas industry can be reduced through healthy industrial and environmental safety practices. Leadership who can maintain a level head during crises must be properly selected. An open, trusting work environment has to be developed. Adequate resources must be provided for industrial and environmental safety training. Training and emergency preparedness, safety equipment, evacuation procedures, availability and effectiveness of rescue parties all have an influence on the overall impact of accidents. The industrial and environmental safety conditions can be improved through positive efforts. This was demonstrated in Brazil. Prior to 1988 Brazil E&P activities were experiencing about three blowouts per year. The major reasons were identified as inattention to operations, inadequate supervision, improper maintenance, improper installation and inspection, improper planning, improper procedures and improper documentation. A program was then introduced which proposed the promotion of better well controlled industrial and environmental safety through training and certification, monitoring operational activities, elaborating standards and operational procedures, and doing research. This resulted in an almost ten-year period without a blowout event in drilling operations. Advances in technology play an important role in enhancing the skills of the operators to be more prepared to carry-out the functions of operating, maintaining and surveillance of facilities through simulator training, better graphics and animation and other aids.

Managers are important figures in an organization. Their job organization, attitudes and accident prevention approaches are vital in ensuring a safe work place and a satisfied workforce. Studies have been conducted among presidents, vice-presidents and managers in the industrial company Norsk Hydro to analyze the associations between attitudes, behavioral intentions and behavior. The sample consisted of 210 respondents and the data were collected in 1997 and 1998 among participants at the Hydro Management safety Training Workshops, which is a safety course for the managers employed by the company. Managers' attitudes are interesting because they may affect behavioral intentions and the managers' behavior related to the achievement of safe working practices. Eight attitudinal dimensions explained up to nearly 40% of the variance in behavior. The study shows that industrial and environmental safety attitudes may be an important causal factor for managers' behavioral intentions as well as behavior. High management commitment, low fatalism, high industrial and environmental safety priority, and high risk awareness were found to be particularly important attitudes for managers. Human reliability index based on 64 API-770 performance factors could be effectively employed to best suit the man to the job.

- Equipment and instruments

In the Piper Alpha accident the compressor header pipe gave way because of overpressure giving rise to a rupture and release of the flammable and explosive contents. One out of two vital compressors producing power for the entire complex was down for overhaul. A single safety valve on the header was taken out for repair and a blind plate fixed in its place rendering the system unsafe to operate. Repair work was simultaneously carried out on the deluge pump for automatic fire-fighting system. Shutdown procedures and limits of operational authority were also unclear to operators.

Technology is available to prevent over-pressure through relief valves and thus prevent disastrous rupture, Inspection and to a limited extent, repair, is possible while the equipment is running. This reduces the need to overhaul. Unfortunately it is the human urge to take chances oftentimes becomes the cruxial weakness.

- Systems and procedures

Communication failure is another contributory cause of accidents. Breaks in the chain-of-command e.g. waiting for instructions which never come because the ones to issue the command are dead and replacements are not appointed. Interface problems like shift changeover duty and missing vital safety documents are common. Language problems where several workers come from different nationalities have also been known to contribute to accidents. There is often inadequate training on procedures not only for the on-site workers but also the casual contractor's workers. New recruits combined with inadequate supervision by inexperienced supervisors and replacements are other contributory causes to accidents. Safety management systems need to be implemented. Systems for performance evaluation and corrective action cannot be overlooked by management.

Procedures need to be continually reviewed, and operators well- trained in carrying them out. However, systems involving hardware can be improved through technology development. Monitoring systems, emergency shut-down systems and fail-dafe systems are examples of these.

- Design

In several cases victims are placed in what can be referred to as getting 'from the frying pan into the fire' or entrapment. People are trapped between the raging fire and the icy cold waters. They just jump several hundred feet into the icy waters of the sea just to perish in order to escape the raging fire on the platform. In other cases people seek shelter in gas-filled confined spaces like poorly designed control rooms waiting for disaster to strike because there are no other places to run to. Fail-safe, redundant and idiot-proof designs must be adopted. A design which works perfectly in one region need not always be suitable for other regions. Soil conditions could be different, environmental conditions could be different and the workers attitudes could also be different. System design must be site specific. Opt for safer processing alternatives and utilize concept of greener technology through materials reduction, replacement and less use of hazardous materials. The number of workers required to be within the explosive limits at any one time must be minimized through proper design.

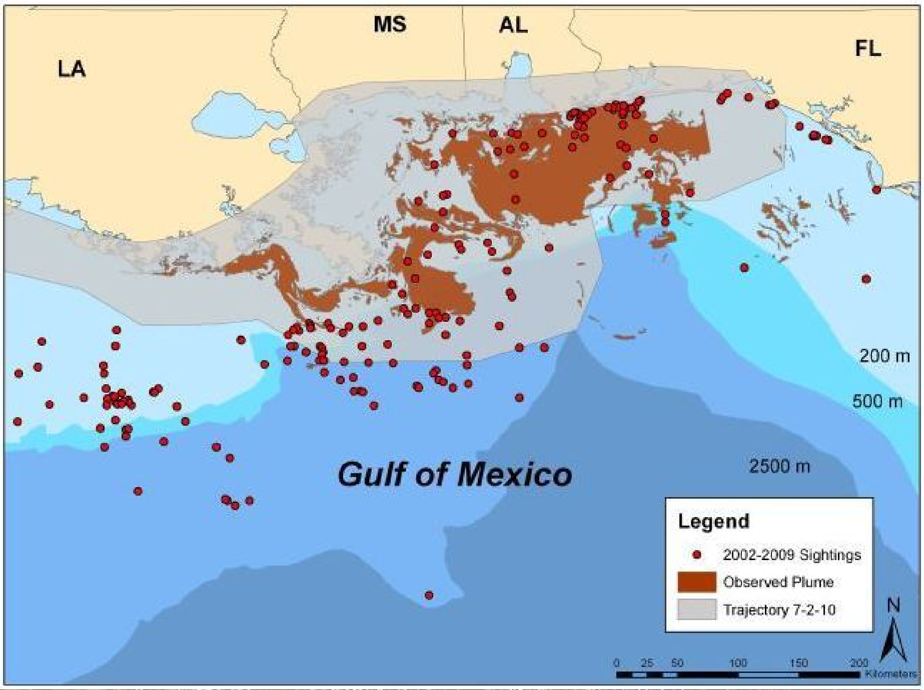
It may be possible to design facilities and systems approaching 100% safe, but the cost would be prohibitive. The normal approach is to design to as high a level of safety as possible taking into consideration the cost. This is backed-up with effective operating procedures. As a last measure, 'fire-fighting' approach is adopted where operators are trained to handle the incident when it happens.

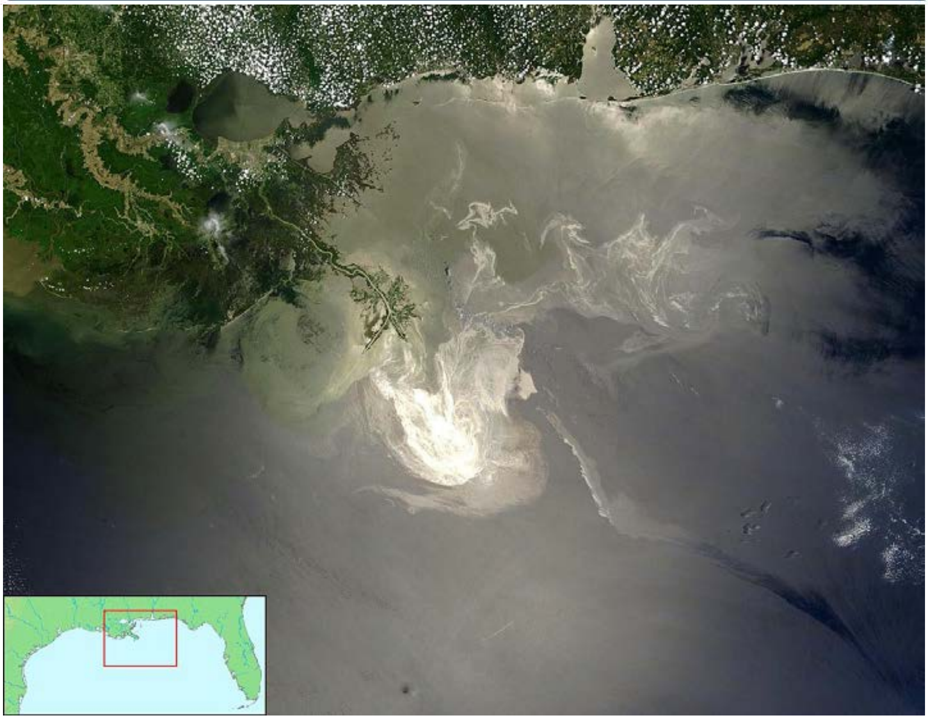
- Environment

Several notable accidents are caused by natural episodes like rain-storms and hurricanes, volcanic activities and lava-flows and mud-flows, earth-quakes and tsunamis which are beyond anybody’s control. In these cases the sensible things to do are to heed the warnings, avoid them if possible, and reduce the impact through better awareness and state of readiness. Technology advances in weather forecasting by satellites, monitoring of volcanic activities and others can assist to achieve this state of readiness.

10. Environmental Consequences-Gulf of Mexico Accident

The Gulf oil spill is recognized as the worst oil spill in U.S. history. Within days of the April 20, 2010 explosion and sinking of the Deepwater Horizon oil rig in the Gulf of Mexico that killed 11 people, underwater cameras revealed the BP pipe was leaking oil and gas on the ocean floor about 42 miles off the coast of Louisiana. 87 days later, an estimated 3.19 million barrels of oil had leaked into the Gulf.





The well was located over 5,000 feet beneath the water's surface in the vast frontier of the deep sea—a permanently dark environment, marked by constantly cold temperatures just above freezing and extremely high pressures. Scientists divide the ocean into at least three zones, and the deep ocean accounts for about three-quarters of Earth's total ocean volume.

Immediately after the explosion, workers from BP and Transocean (owner of the Deepwater Horizon rig), and many government agencies tried to control the spread of the oil to beaches and other coastal ecosystems using floating booms to contain surface oil and chemical oil dispersants to break it down underwater. Additionally, numerous scientists and researchers descended upon the Gulf region to gather data. Researchers tried to understand the spill and its impact on marine life, the Gulf coast, and human communities.

Fig 10.1 Gulf of Mexico BP Accident

The eight failures that caused the Gulf oil spill (22)

Eight catastrophic failures led to the explosion that destroyed the Deepwater Horizon drilling rig in the Gulf of Mexico, killing 11 people and leading to one of the biggest oil leaks in history, according to BP's long-awaited investigation into the accident.

BP accepts its role in the disaster but also points the finger at two of its contractors.

The accident occurred on 20 April as the team aboard Deepwater Horizon was preparing to temporarily abandon a well it had drilled some 70 kilometres from the US coast.

The day before the accident, the crew had pumped cement to the bottom of the borehole, a standard procedure intended to prevent oil leaking out. On the day of the accident, the team were conducting checks to determine that that the well had been properly sealed.

BP says the accident was caused by the failure of eight different safety systems that were meant to prevent this kind of incident:

1. **<u>Dodgy cement</u>**

The cement at the bottom of the borehole did not create a seal, and oil and gas began to leak through it into the pipe leading to the surface. BP says the cement formulation seems not to have been up to the job.

2. **<u>Valve failure</u>**

The bottom of the pipe to the surface was sealed in two ways. It too was filled with cement, and it also contained two mechanical valves designed to stop the flow of oil and gas. All of these failed, allowing oil and gas to travel up the pipe towards the surface.

3. **<u>Pressure test misinterpreted</u>**

The crew carried out various pressure tests to determine whether the well was sealed or not. The results of these tests were misinterpreted, so they thought the well was under control.

4. **<u>Leak not spotted soon enough</u>**

Whether a well is under control or not, the crew at the surface should be able to detect a flow of oil and gas towards the surface by looking for unexpected increases in pressure in the well. Exactly this kind of increase occurred about 50 minutes before the rig exploded, but it was not interpreted as a leak.

5. **<u>Valve failure no. 2</u>**

About 8 minutes before the explosion, a mixture of mud and gas began pouring onto the floor of the rig. The crew immediately attempted to close a valve in a device called the blowout preventer, which sits on the ocean floor over the top of the well borehole. It did not work properly.

6. **<u>Overwhelmed separator</u>**

The crew had the option of diverting the mud and gas away from the rig, venting it safely through pipes over the side. Instead, the flow was diverted to a device on board the rig designed to separate small amounts of gas from a flow of mud. The so-called mud-gas separator was quickly overwhelmed and flammable gas began to engulf the rig.

7. **No gas alarm**

The rig had an onboard gas detection system that should have sounded the alarm and triggered the closure of ventilation fans to prevent the gas reaching potential causes of ignition, such as the rig's engines. This system failed.

8. **No battery for BOP**

The explosion destroyed the control lines the crew were using to attempt to close safety valves in the blowout preventer. However, the blowout preventer has its own safety mechanism in which two separate systems should have shut the valves automatically when it lost contact with the surface. One system seems to have had a flat battery and the other a defective switch. Consequently, the blowout preventer did not close.

"It is evident that a series of complex events, rather than a single mistake or failure, led to the tragedy. Multiple parties, including BP, [oilfield services company] Halliburton and [offshore drilling company] Transocean, were involved," said Tony Hayward, BP's chief executive.

Anatomy of an Oil Spill(21):

- The accident

On April 20, 2010, the *Deepwater Horizon* oil rig exploded, killing eleven people and setting off the largest marine oil spill in world history. A few days later, underwater cameras revealed that oil and gas were leaking from the ocean floor about 42 miles off the coast of Louisiana. The oil well leaked 4.9 million barrels of oil before it was capped nearly 3 months later on July 15, 2010. (Fig10.2)

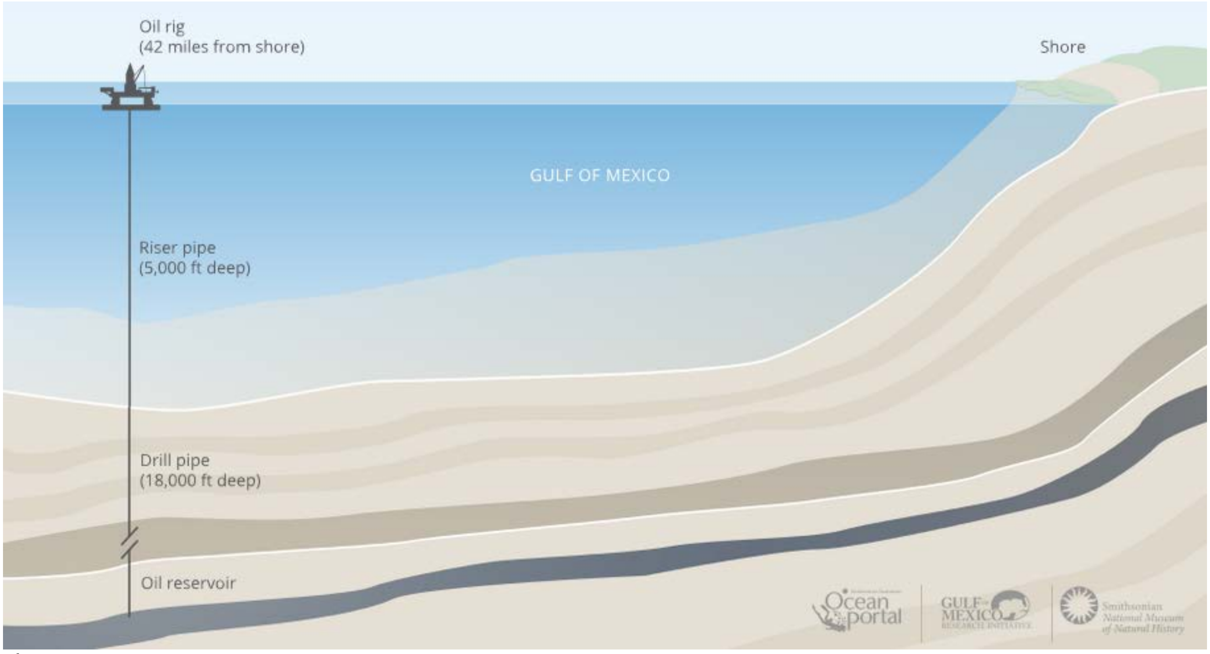


Fig 10.2

- The Disaster

The *Deepwater Horizon* rig sat 42 miles off the Louisiana shore, pumping oil up from deep beneath the seafloor. On the night of April 20, a bubble of methane gas escaped from the well and shot up the pipe towards the surface, causing an explosion and fire. This tragically took the lives of 11 rig workers, while 115 others were successfully evacuated. Crude oil and gases, buried deep beneath the seafloor, began leaking from the oil well 5,000 feet down. Wind, waves and currents spread the oil across the ocean's surface to form a slick, which eventually covered around 5,000 square miles—about the size of Connecticut.

Fig 10.3

- The Cleanup

The rig sank on April 22 after burning for more than a day. Workers did their best to stop the oil from washing up on the Gulf shore, where it would be even more difficult to remove from fragile coastal ecosystems. Some wildlife, such as birds and sea turtles, got stuck in the surface slick during cleanup, endangering their lives.

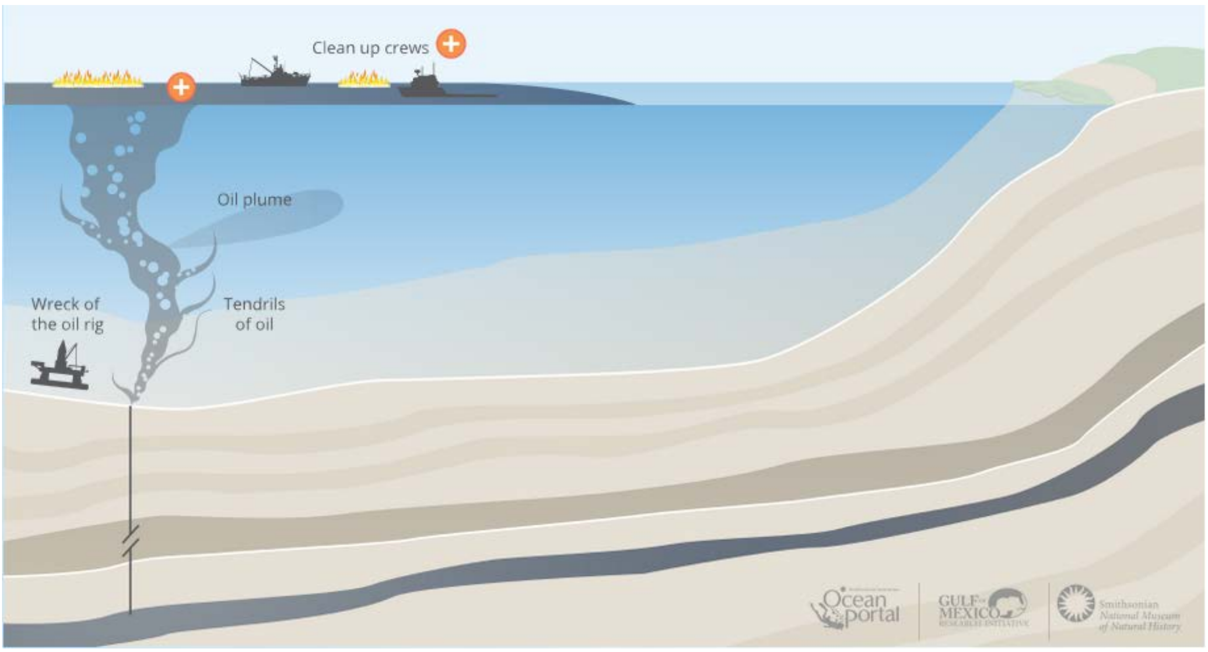


Fig 10.4

- Dispersants

On April 26, BP began adding dispersants to the oil. Dispersants are like strong soaps, which cause the oil to break down and mix with water more easily to speed up its natural biodegradation. As they combined, the oil became less buoyant, forming additional underwater plumes while preventing the droplets from floating to the surface and spreading to the coasts. But dispersants can also enter the food chain and potentially harm wildlife.

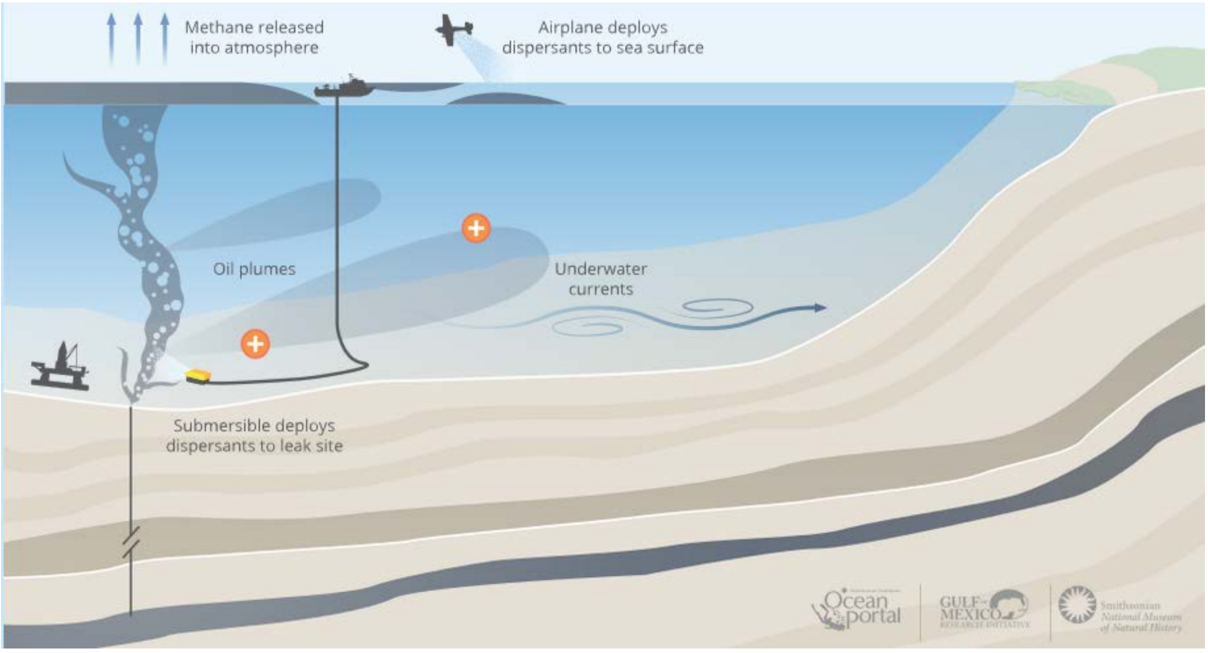


Fig 10.5

- The Open Ocean

The oil spill occurred more than 40 miles offshore, which was lucky in some ways, as less oil was able to reach fragile coastal ecosystems. But it still interacted with wildlife in the open ocean. It was eaten by organisms big and small, some of which are better able to clear it from their bodies than others. And out in the open, it ran into any developing eggs or larvae carried by the waves—the effects of which we won't know for years to come.

Fig 10.6

- The Deep Sea

As much as 20 percent of the spilled oil may have ended up on and buried beneath the seafloor, where it interacted with wildlife such as deep-sea corals, fish, mollusks and microscopic foraminifera. When the buried oil is brought back to the surface, it can expose animals to dangerous chemicals again. In addition to the oil and dispersants that fell to the seafloor, sediment was left behind during attempts to plug the leaking well. Understanding how the oil spill affected the seafloor may take many years because it's difficult to access and observe.

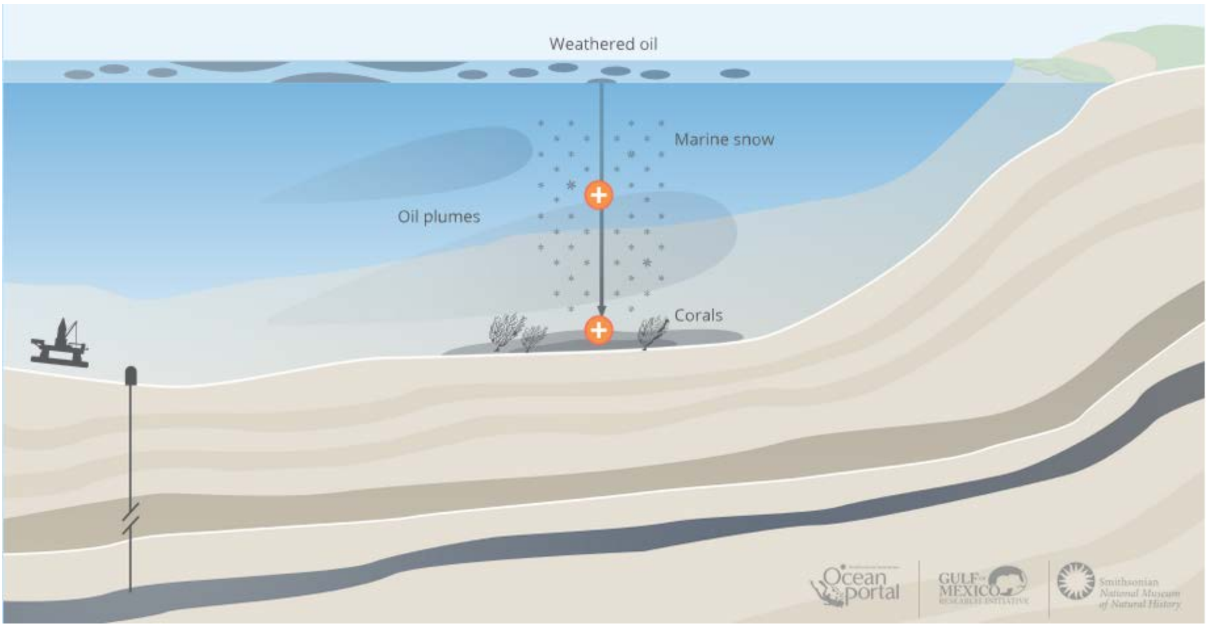


Fig 10.7

- The Coast

Thirty days after the leak, oil began washing up on the shores of Louisiana. Marshes and estuaries are the worst places that oil can end up. They are difficult to clean without killing the marsh grass itself, and serve as nurseries for young ocean animals. Sometimes the oil becomes buried beneath the mud, where it is slowly released back into the water over decades. In heavily oiled areas of marsh, erosion rates doubled in the years after the spill and little recovery has been observed since. We won't know the full effects of oil in the marshes for years after the spill, when the larvae that would have been exposed to oil are grown up and caught in fisheries.

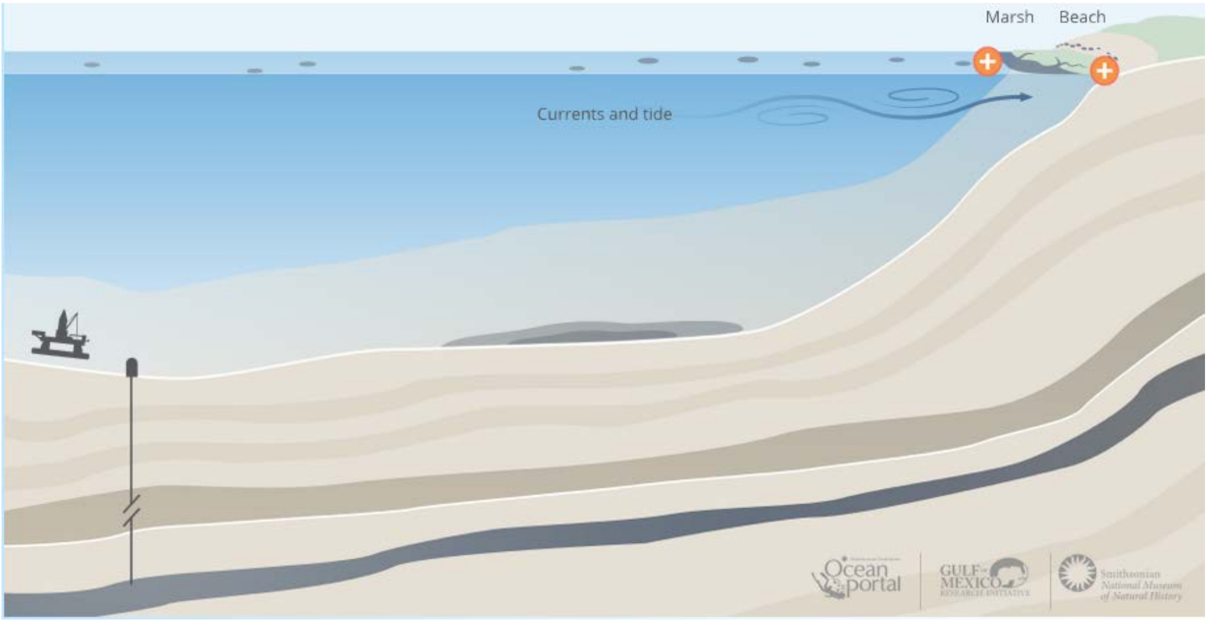


Fig 10.8

- Today

The *Deepwater Horizon* oil spill leaked oil and gas into the Gulf of Mexico for 87 days until the well was capped on July 15, 2010. Today, Gulf seafood is safe to eat and the Gulf is recovering better than expected. Scientists continue to study the effects of the spill and develop technologies to improve upon the cleanup methods and response for any future spills that occur.

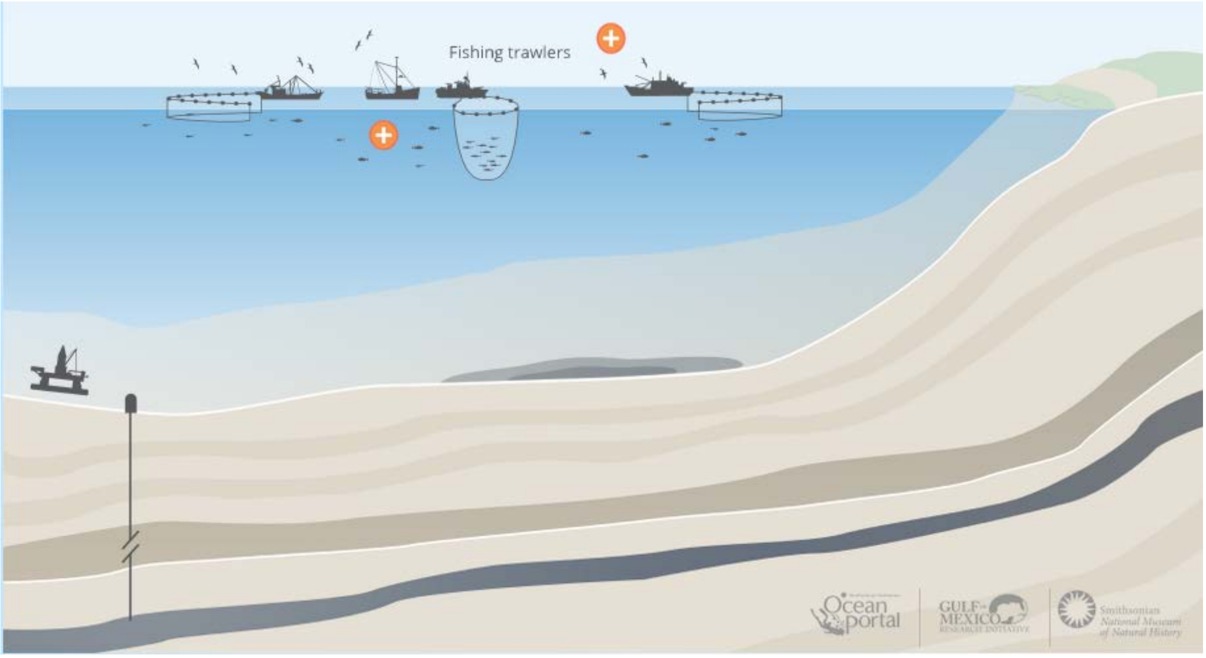


Fig 10.8

Once the oil left the well, it spread throughout the water column. Some floated to the ocean's surface to form oil slicks, which can spread more quickly by being pushed by winds. Some hovered suspended in the midwater after rising from the wellhead like a chimney and forming several layers of oil, dispersant and seawater mixtures drifting down current; during the spill a 22-mile long oil plume was reported. This plume formed because chemical dispersants, released into the water to break up the oil so it could wash away, allowed the oil to mix with seawater and stay suspended below the surface. And some oil sunk to the seafloor by gluing together falling particles in the water such as bacteria and phytoplankton to form marine snow. As much as 20 percent of the spilled oil may have ended up on top of and in the seafloor, damaging deep sea corals and potentially damaging other ecosystems that are unseen at the surface.

Fig10.9

Clean-up Methods

Fig 10.10 Brown pelicans congregate on containment boom that surrounds Queen Bess Island, a few miles north of Grand Isle, La. August 25, 2010. The island is a sensitive nesting area for brown pelicans. More about the Gulf oil spill can be found in our Gulf oil spill featured story.

- Physical Methods

When oil spills into the ocean, it is difficult to clean up. When you have 3.19 million barrels to clean up, it is even harder.

Part of the difficulty is that no two spills are alike. The amount and type of oil (whether crude or refined) affects how it spreads, and a spill in seawater spreads differently than freshwater. Local environmental conditions also play a huge role: currents, tides, weather, wind speed and direction, air temperature, water temperature and presence of ice all affect how the oil spreads and how well cleanup workers can access the spill area. This variability makes it difficult to plan for spills ahead of time.

The most basic method of clean up

is to control the spread of the oil using physical barriers. When oil spills in water, it tends to float to the surface and spread out, forming a thin slick just a few millimeters thick. (A very thin slick is called a sheen, which often looks like a rainbow and can be seen in parking lots after a rainstorm.) Cleanup workers first surround the slick with floating booms to keep it from spreading to harbors, beaches or biologically important areas like marshes. Then they can use different tools to remove the collected oil. Often they will drive skimmers, boats that skim spilled water from the water's surface, through the slick.

After most of the oil is removed by skimmers, workers use sorbents to mop up the trace amounts left behind. Sorbents either absorb oil like a sponge or adsorb oil, which means that oil sticks to its surface. They come in three main types: natural organic materials like peat moss, straw, hay and sawdust; natural inorganic materials like clay, volcanic ash, sand, or vermiculite; and synthetic sorbents made of materials similar to plastic like polyurethane, polypropylene, and polyethylene. Which type is used will depend on the particular spill, as some types of sorbents work best on different types of oil and under different weather conditions.

Another option is to speed up the oil's natural biodegradation using dispersants.

Fig 10.11 U.S. Air Force, Tech. Sgt. Adrian Cadiz, A C-130 Hercules from the Air Force Reserve Command deploys dispersant into the Gulf of Mexico May 5, 2010, as part of the Deepwater Horizon/BP oil spill response effort.

- Dispersants

Removing spilled oil from the environment is a difficult task. Because oil is hydrophobic (doesn't mix with water), it floats to the surface when it spills into the ocean and forms large slicks. These slicks can wreak havoc on coastal ecosystems and animals, so cleanup workers use dispersants—chemicals that break down the oil into smaller particles that mix with water more easily—to prevent them from forming. Evaporation and bacteria can then degrade these tiny droplets more quickly than if they were in a large slick, or waves can wash them away from the spill site.

Dispersants are often used when workers want to stop the slick from spreading to a protected area like a harbor or marsh. This can be a boon for animals found on the surface and coast, such as seabirds, marine mammals and those found in the Gulf's mangroves, because the oil is moved out of their habitat. But dispersants can also enter the food chain and potentially harm wildlife.

In the case of the Deepwater Horizon oil spill, clean-up workers treated the oil with over 1.4 million gallons of various chemical dispersants. Typically such large amounts are sprayed over the open ocean from an airplane or helicopter. But during the BP oil spill, they were also injected straight into the Macondo wellhead, the source of the leak, in order to reduce the amount of oil that reached the ocean surface. Five years after the spill some scientists believe that injecting dispersants directly at the wellhead may not have done much to help reduce the size of the oil droplets.

Just because the oil and dispersants are out of human sight and mind in the deep sea doesn't mean they're gone. It's possible that life in the deep sea was exposed to the dispersant-oil mixture. Scientists have found that the dispersant-oil mixture was rapidly colonized and broken down by bacteria that sunk towards the bottom. Any bits of the mixture that didn't get broken down would then get buried in coastal and deep-sea sediments, where its breakdown slows.

While the dispersant helps expose more of the oil to bacteria and waves which help to break it down, it also makes the oil more available to wildlife. One 2012 study showed that the combination of oil and the dispersant Corexit is 3 to 52-times more toxic to rotifers (microscopic animals) than oil by itself. This isn't because of anything inherently dangerous in the mixture of the two; the rotifers are more able to ingest oil once it's made accessible by the dispersant. Furthermore, the dispersants may not have been necessary. A modeling effort supported by the Gulf of Mexico Research Initiative offered evidence that the dispersants injected into the Macondo wellhead may not have helped to lessen the amount of oil reaching the surface after all.

A lot of research is still needed to fully understand the long-term effects of dispersants on the region and its inhabitants—not to mention how they move through the food chain to impact larger predators, such as people. Researchers are developing new dispersants that cause less environmental damage for the next spill.

Ecosystem Effects- Effects on Wildlife

Fig:10.12 NOAA, Striped dolphins swim among emulsified oil patches on April 29, 2010 in the Gulf of Mexico, a few days after the Deepwater Horizon oil spill.

There were some immediate impacts to the animals of the Gulf of Mexico that could be seen with the naked eye: pelicans black with oil, fish belly-up in brown sludge, smothered turtles washed up on beaches. But not much time has passed since the spill, and it will take many more years of monitoring and research to understand what happened.

Strandings of both dolphins and sea turtles increased significantly in the years following the spill. "From 2002 to 2009, the Gulf averaged 63 dolphin deaths a year. That rose to 125 in the seven months after the spill in 2010 and 335 in all of 2011, averaging more than 200 a year since April 2010," reported *Reuters* in 2015. Since then, dolphin deaths have declined, and long-term impacts on the population are not yet known. Kemp's ridley sea turtle nests have gone down in the years since the spill, and long-term effects are not yet known.

Seabirds were initially harmed by crude surface oil—even a small bit of oil on their feathers impeded their ability to fly, swim and find food by diving. Seabird losses may have numbered in the hundreds of thousands, but reliable estimates are hard to come by. Looking beyond the sea, researchers are currently studying how oil may have affected land birds that live in the marshes along the Gulf coast.

Invertebrates in the Gulf were hard hit by the Deepwater Horizon spill—both in coastal areas and in the deep. Shrimp fisheries were closed for much of the year following the spill, but these commercially-important species now seem to have recovered. Deep-water corals grow very slowly and can live for many centuries. Found as deep as 4,000 feet below the surface, corals near the blowout showed signs of tissue damage and were covered by an unknown brown substance, later identified as oil from the spill. Laboratory studies conducted with coral species showed that baby coral exposed to oil and dispersant had lower survival rates and difficulty settling on a hard surface to grow.

The impact of the spill on fish communities is still largely unknown. Lab studies have shown that oil can cause heart defects in the developing larvae of bluefin tuna and other fish, but we won't know if this occurred in the wild until after those larvae would have grown up. Some fish larvae populations actually grew after the spill, as they had more food in the form of oil-eating microbes.

There were some reports of deformed wildlife after the spill. For years following the spill there were reports of fish with lesions and deformities, and some reports of eyeless and deformed shrimp after the spill. However, consuming Gulf seafood is now completely safe.

Over 1,000 miles of shoreline on the Gulf of Mexico, from Texas to Florida, was impacted by oil from the Deepwater Horizon blowout. Much of this area has been cleaned, but eroded shorelines are taking longer to recover and erosion rates have accelerated in these areas.

Fig 10.13: Yanwu Zhang 2010MBARI,An autonomous underwater vehicle from the Monterey Bay Aquarium Research Institute (MBARI) being launched from the NOAA Ship Gordon Gunter in the Gulf of Mexico.

- Underwater Robot

In May 2010, the Monterey Bay Aquarium Research Institute (MBARI) sent a high-tech robotic submersible to the oily waters of the Gulf of Mexico. Like other autonomous underwater vehicles (AUV), the robotic sub was programmed at the surface to navigate through the water on its own, collecting information on deep oil plumes from the Deepwater Horizon spill as it traveled. Although satellites and aircraft helped show the extent of the spill at the surface, researchers hoped that the AUV would allow them understand what was happening farther down in the water column.

During the NOAA-sponsored expedition, MBARI's AUV mapped part of a plume 1,000 meters (3,300 feet) below the surface, and collected water samples at various depths. The resulting data helped the researchers identify a persistent deep oil plume and link the oil in this plume to its source: the Deepwater Horizon blowout.

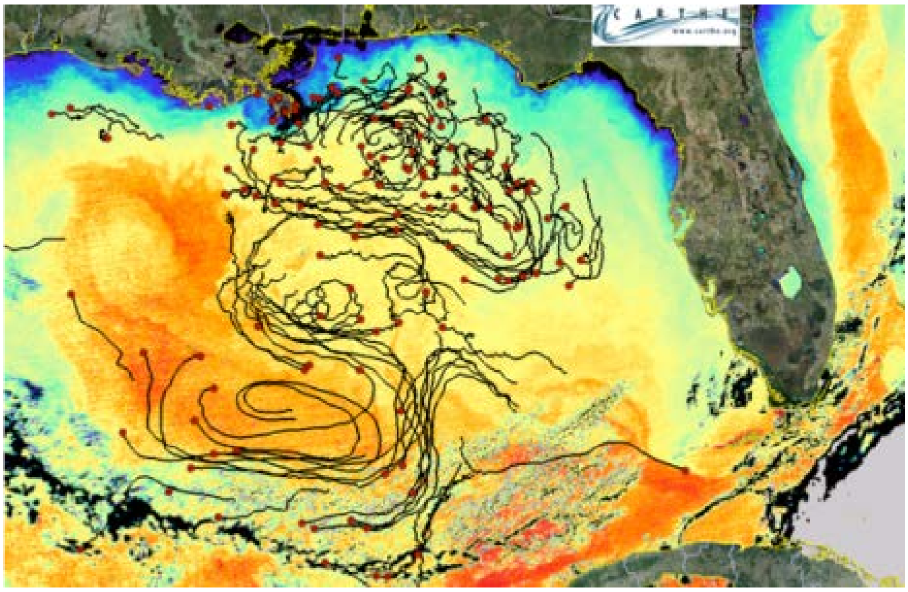


Fig 10.14 Photo courtesy of CARTHE, Drifters deployed into the Gulf of Mexico sent location information back to scientists through a GPS satellite. Some of the 5.7 million data points about the drifters locations are seen in this map of the Gulf.

Where it did go?

- Modelling the Movement

Once the over 200 million gallons of oil began spewing out of the damaged wellhead—where did it go? Keeping track of that much oil—especially as it sinks into the deep sea—is a difficult task that can't be done with eyes alone. Along with visual tracking, computer models of the oil's movement helped researchers get a better sense of what path it took and where it ended up.

To build the models, researchers first had to understand where ocean eddies, currents and waves carried the tiny oil particles. To understand surface water movement better, researchers set small, yellow boards made of wood afloat on the ocean's surface and asked beachgoers to report where they found these “drift cards” when they washed up on shore. This citizen scientist endeavor provided general information about how far the waves can carry a floating object and specific data points that can be used to improve models of where the oil disperses.

Further data collection has been ongoing since the spill by the Consortium for Advanced Research on Transport of Hydrocarbon in the Environment (CARTHE). CARTHE has more high-tech "drift cards:" their “drifters” are small buoy-like instruments with GPS, which ping their locations to satellites as they drift on ocean currents. Their location gets tracked for weeks or months at a time and provide an unprecedented amount of location-based data for modeling. This information can be used to better predict oil movement in case of future spills.

Fig 10.15: J. Short, Oceana, and S. Senner, Ocean Conservancy An environmental chemist collects samples of oil in the Gulf of Mexico from the Deepwater Horizon spill. The resulting chemical “fingerprint” of the oil will help determine the origin of other samples.

- Threats & Solutions

Fig 10.16: U.S. Coast Guard photo by Petty Officer 3rd Class Patrick Kelley

Workers contracted by BP load oily waste onto a trailer on Elmer's Island, just west of Grand Isle, La., May 21, 2010.

- Human Health Risks

In the immediate aftermath of the Deepwater Horizon oil spill, concerns about public health focused on people coming into direct contact with the oil and dispersants. The Centers for Disease Control and Prevention offered safety advice to Gulf Coast residents and relief workers and the EPA conducted toxicity tests on dispersants. However, long-term questions about oil spills and their impact on human health remain. The National Institutes of Health began to address these in a study that is tracking 33,000 cleanup workers and volunteers for a decade. The research will assess whether exposure to crude oil and dispersants has an effect on physical and mental health.

Fig 10.17**:** New England Aquarium. One of many Kemp's ridley sea turtles (Lepidochelys kempii) recovering at the Audubon Aquarium of the Americas, after the 2010 Gulf of Mexico oil spill. Turtles were cleaned and nursed back to health with the help of New England Aquarium staff.

As the days, weeks, and months progressed the indirect impacts related to seafood consumption also gained attention. The chemicals in oil that are of most concern to humans are called polycyclic aromatic hydrocarbons (PAHs). Some of these are known to cause cancer. The U.S. Food and Drug Administration is charged with monitoring the levels of PAHs in Gulf Coast seafood. It works in conjunction with NOAA, the EPA, and state agencies to determine which fisheries are safe to open and which ones should be closed. In order for a fishery to be reopened, it must pass both a "smell" test and a chemical analysis. Seafood cannot go to market if it contains harmful levels of PAHs or if it emits an odor associated with petroleum or dispersants. Fishing area closures peaked on June 2, 2010, when 88,522 square miles of the Gulf of Mexico were off-limits. On April 19, 2011, NOAA announced that commercial and recreational fishing could resume in all of the federal waters that were affected by the spill.

- Rescuing Animals in the Oil Spill

Pictures of pelicans, sea turtles, and other Gulf of Mexico wildlife struggling in oil were among some of the most disturbing images of the Deepwater Horizon oil spill disaster in 2010. According to the U.S. Fish and Wildlife Service, thousands of “visibly” oiled animals (pdf) —which include birds, sea turtles, and marine mammals—were collected by authorities in the vicinity of the Deepwater Horizon oil spill. Many of the animals were already dead, but for those found alive, dozens of organizations, including the Smithsonian’s National Zoological Park and the New England Aquarium (NEA), were mobilized to rescue, rehabilitate, and later release animals affected by the spill. National Zoo personnel were dispatched to the Gulf largely to assist with the process of relocating animals affected by the spill and helping to identify future release sites for those rescued. Dr. Luis Padilla, a Zoo veterinarian who helped with a pelican release in Texas, and Dr. Judilee Marrow were among those who assisted in the Gulf.

NEA staff who helped to rehabilitate sea turtles rescued from the Gulf oil spill offered a behind-the-scenes view on the aquarium’s Marine Animal Rescue Team Blog. The blog described how rescuers in boats and spotter planes were “looking for rounded mounds on the surface of the oil, which usually means that there is a turtle floating under the surface of the oil." The rescue team, based at the Audubon Aquarium of the Americas in New Orleans, treated dozens of endangered sea turtles, such as Kemp's ridley, loggerheads, green sea turtles, and hawksbills. To learn more about how oil affects marine life, watch this video from the Pew Environment Group that explains the impact of oil on marine life throughout the water column and check out this fact sheet from U.S. Fish and Wildlife which summarizes

“Effects of Oil on Wildlife and Habitat.” (pdf) We may not know the full effects of the spill on animals - both big and small - for years to come.

11. Conclusions

The evidence presented has demonstrated the continuing evolution of the offshore oil and gas industry into a global phenomenon. While the heartlands of the Gulf of Mexico and the North Sea retain leadership positions, more than 40 countries are now known to possess hydrocarbon resources, and developing and newly industrialising countries figure prominently on the resource map. Similarly, although offshore hydrocarbons as yet account for only a minority of total oil and gas production, and although offshore output growth has in fact been slower than anticipated by the International Energy Agency in 1996, the trend is rising and is likely to continue to do so as the limited infrastructures found in newly proven resource regions are enhanced. But it has also been shown that improved understanding of the extent and scale of offshore hydrocarbon resources is not simply a consequence of the industry's extension to new global regions and countries. Additional key factors are the rapid progress made with respect to operations in deep and ultradeep waters, together with accumulating resource knowledge in well-established production provinces. Known resources in these provinces increase partly through deeper insights into the scale of proven fields, and partly through the discovery of new deposits as the provinces are reworked.

Moreover, the industry's history gives every indication that this will continue to occur.

As was emphasised at the outset, the momentum of progress with respect to resource knowledge and exploitation is closely interwoven with state policies and with the basic economics of energy prices. Thus the recent dramatic rise in Opecbasket oil prices (from$12 a barrel in mid-1998, to almost $19 a barrel in mid-1999 and nearly $30 a barrel in 2000 and 2001) is likely to stimulate exploration and development in many costly offshore regions. Conversely, if major producing countries allow output to be boosted in response to the West's argument that high oil prices risk destabilising the global economy, this stimulus will be muted. While these politico-economic factors cannot be ignored, however, the paper has clearly demonstrated the need to add to them the crucial contribution made by technological change to offshore exploration and exploitation activity. In addition it has revealed the importance of probing beyond the umbrella term 'technological change' to gain insights into the exceptionally broad spectrum of advances on which progress is dependent. Interpretations offered throughout the paper suggest that, to rationalise this complex spectrum, offshore innovations can generally be related to four overriding industry objectives:

- to improve, through exploration, knowledge of the location and scale of resources (as exemplified by the evolution of mobile drilling rig design);
- to achieve affordable access to those resources (e.g. through floating production systems);

- to ensure cost reductions in exploration and production (e.g. through minimal rig designs or improved data analysis and interpretation);
- and to boost recovery rates (e.g. through advanced drilling techniques).

For two reasons, however, this classification should not be allowed to oversimplify the picture. First, individual advances are commonly related to more than one of the industry's objectives. The evolution of drilling rig design, for example, has not simply made a fundamental contribution to exploration, but also to resource accessibility.

Second, it is important to recognise the degree to which the maximisation of benefits 596 D. Pinder / Ocean & Coastal Management 44 (2001) 579–600 is a function of the interdependence of innovations. Thus directional drilling and computer imaging must be integrated operationally if the full potential of either is to be realised. In the innovative offshore world, outcomes are frequently more than the sum of the individual parts.

Partly because of this interdependence, but also because of commercial confidentiality and variations in conditions from one oil or gas field to another, it is impossible to quantify the gains associated with specific technological advances.

However, there is no doubt that their combined effects are impressive, as a range of North Sea resource experiences demonstrate. Initial estimates were that total reserves in the first 13 fields to be developed in the UK sector amounted to 1072 mt, far less than half of which would have been recoverable using the technologies of the day. But by 1997 these fields had already produced 1385 million tonnes, and at least another 200 million tonnes were known to be recoverable. Similarly, although production from the Statfjord field between 1988 and 1998 was equivalent to the total reserve estimate made at the start of the period, this field is now expected to remain productive until at least 2020. Recent reappraisal in the Troll field, meanwhile, has raised its estimated recoverable reserves by almost 8% as a result of enhanced recovery technologies. More generally, whereas in the 1970s the proportion of oil reserves that could actually be recovered was typically only 30% or less, by the mid-1990s the average recovery rates for North Sea oil and gas were 43% and 70%, respectively. Moreover, EU estimates at this time were that the eventual impact of R & D would be to increase recoverable North Sea oil reserves from 21 to 57 billion barrels, and more than double the volume of recoverable gas. In the process, >400 marginal fields might well become developable.

Finally it must be stressed that the paper has by no means exhausted the under researched issues requiring investigation in connection with offshore oil and gas. A start has been made with respect to the relationships between technological progress and offshore developments. But most of the technologies considered would justify much fuller investigation and evaluation in their own right and, as was indicated at the outset, space limitations have prevented consideration of important additional themes. Virtual reality technologies, for example, are not simply impacting on reservoir analysis, but also on the construction costs and ergonomics of drilling rig and production platform design. While the technological focus must remain a priority, however, there is also scope for extensive research into industry strategies which suggest that technological solutions are not universally viewed as the sole way forward in the resource procurement arena. This is particularly true with respect to companies' efforts to reduce costs and risk. One strand of evidence strongly suggests growing interest in the externalisation of risk to 'turnkey' drillers while a second highlights the increasing importance attached to the cost-reduction potential of new corporate organisational structures, characterised by one operator as 'smarter management rather than smarter technology'. What is also important is to ensure that a new research focus on technologies and organisational practices designed to benefit the oil and gas industry does not eclipse concern for other neglected issues. In the environmental arena, for example, the impact of noise pollution on sensitive and endangered species such as cetaceans is now a matter of D. Pinder / Ocean & Coastal Management 44 (2001) 579–600 597 debate; this raises major questions as to the acceptability of progress with marine seismic survey techniques. And, while it is always tempting to dwell on the forces driving an industry's growth, the other end of the life cycle must be remembered: decommissioning strategies, as yet barely studied systematically, will ultimately provide a yardstick by which the industry's environmental credentials are judged. In short, therefore, a range of major neglected research issues associated with offshore oil gas is readily identifiable, and offers the prospect of achieving far more balanced understanding of the forces driving this increasingly vital global industry than has hitherto been possible.

Environmental decision-making in OOG operations is usually a complicated process due to conflicting objectives or criteria, imprecise data, and interdependency between groups of decision-makers.

From economical view, over time, economists have greatly improved our understanding of the role of technological change in economic growth and of the constituents of technological change. Technological progress has offset resource depletion in this important industry, and thereby the potential for technological change to fuel continued economic growth in the face of fixed stocks of non-renewable resources. Unique data set also allows us to decompose productivity change into various constituents, which provides a more detailed understanding of the interplay of various factors that together comprise productivity change in this important industry.

The results show that increases in productivity have offset depletion effects in the Gulf of Mexico offshore oil and gas industry over 49 year period from 1947–1996. However, the nature of the effect differs significantly from what is typically assumed for non-renewable resource industries. During the first 30 years of the time horizon, productivity is found declines in offshore oil and gas production. But in more recent years, productivity increased rapidly, offsetting depletion effects. Productivity change has been highest in the past 5 years, indicating that we may still be along the increasing portion of a hypothetical ‘‘S’’-shaped technological time path. However, extrapolating trends into the future is risky, especially over longer time periods. It could well be that the pace of technological advance could slow in the near future, and depletion effects could lead to declines in productivity in this important non-renewable resource industry.

Depletion effects are decomposed into effects associated with changes in field size, water depth, porosity and a residual that measures aggregate resource extraction in the Gulf of Mexico. Each of these effects is roughly similar in magnitude, and that interesting shifts occur over time. For example, initially field size appeared to be more important than water depth in explaining depletion. However, as new technologies allowed us to find larger fields by moving to ever deeper waters, water depth tended to have a stronger effect on reducing TFP than did field size. Again, it remains to be seen whether this trend will continue, or whether we will quickly deplete the stock of large, deep water fields. The contribution of technological change is analyzed and efficiency change in sector total factor productivity (TFP). An index for decomposing is developed technological change into that associated with specifically identifiable new technologies and a residual. The former we call ‘‘technological innovation’’, and the latter we call ‘‘learning-by-doing’’. Similarly, we isolated technology diffusion from the residual factors that impact on efficiency change. We then compare the relative importance of technological innovation, learning-by-doing and technology diffusion on TFP in the industry.

The results indicate that both learning-by-doing and diffusion of technological had a significantly larger impact on TFP than technological innovation. This implies that although technological innovation is crucial for improving TFP, there is a larger productivity gains associated with learning-by-doing (e.g., experience of engineers and managers) and the diffusion of technology through the industry. This suggests the importance of developing policies that provide flexibility in implementing and adapting existing technologies.

Conserning the project management, this paper has highlighted the overlap that exists between projects and project management and the confusion that can arise from the common use of these terms. It has also attempted to highlight how the objectives of a project and project management are different and how the emphasis of project management is towards achieving specific and short-term targets compared to the wider aims of a project.

The conclusion is that to make the project management team totally responsible for success would appear to be inappropriate and that the client should take an increased interest in the development and use of the project.

There also needs to be an improved distinction between success and failure for the project and project management interests. Project success could be assessed using three assessment criteria based not only on project management techniques but on other external criteria which are important for the successful implementation of projects, from conception through development and use, to the final closedown.

Thus, for a project to be successful there must, first, be an improved appreciation of the role of project management within projects, and this role must be placed within the context of a wider project alongside other outside criteria and long-term expectations. Second, the project manager must allow the client to contribute actively in the planning and production phases and at the same time the project team involvement has to be extended into the utilisation phase.

This would be accommodated properly in a project evaluation technique that examines not only the implementation processes but also the economic and financial performance.

Finally, one must always bear in mind that successful project management techniques will contribute to the achievement of projects, but project management will not stop a project from failing to succeed. The right project will succeed almost without the success of project management, but successful project management could enhance its success. Selecting the right project at the outset and screening out potentially unsuccessful projects, will be more important to ensuring total project success.

Also in this study has developed a measure of situation awareness (WSA) specifically for use with offshore drilling crews. The WSA scale shows evidence of content, construct and concurrent validity however more work is required to establish discriminant and predictive validity. This study has shown that higher levels of stress and fatigue are linked to lower levels of WSA, which in turn are indicative of increased participation in unsafe work behaviours, and higher accident risk. These results need to be replicated by testing in drilling simulators or even in longitudinal studies. Social desirability and presentation bias could have affected the results, despite the assurances of anonymity and confidentiality and these biases should be controlled for, for example by using the Marlowe- Crown Social Desirability Scale (Crowne and Marlowe, 1960). Situation awareness training is not generally used in the oil industry although it is provided in other high risk sectors (aviation, maritime, nuclear) Crew Resource Management (CRM) (Kanki et al., 2010) and in many of these domains, non-technical skills, such as SA, are regularly checked as part of licence revalidation (Flin et al., 2008). Following the *Deepwater Horizon* accident, the offshore oil and gas industry is beginning to develop CRM syllabi for drill crew and the above results suggest that SA, as well as fatigue and stress management will need to be key components.

Given these findings, and with recent accidents highlighting that offshore drilling crews are employed in one of the most hazardous maritime occupations, it seems justifiable to suggest that offshore companies may also benefit from reviewing their working patterns and conditions to ensure that their impact on cognitive skills is fully understood as part of their risk mitigation strategy.

The oil and gas industry has moved from a reactive approach to a proactive approach to safety. The modelling of the frequency of events, their effects and mitigating circumstances can be carried out with some accuracy. However, while the understanding of the causes and their effects are better, there is still scope for enhancement of the performance of Safety Management Systems. The industry has made significant improvements in hardware, design and protection and in this respect has much to tell other industries.

The overall trend of the new regime cannot yet be judged with any confidence; there appears to be a reduction in fatalities and general improvement in safety standards. The benefits of the modern designs are still out-weighed by older (first and second generation) installations, and a cultural change takes some time to produce its benefits, so it may be a few more years before clear trends can be established with confidence.

All the accidents examined showed that basically they were due to human error and incompetence and equipment and instrument failures. It is apparent that jack-ups have a disproportionately higher rate of failures compared to platforms and semi-submersibles. There is a corresponding trend in the frequency of accidents in relation to the numbers of facility types in operation. The frequency for various fatality ranges with the majority of accidents involving no fatalities.

In the preparation of guidelines related to industrial and environmental safety there is a need to maintain good coordination and understanding between Federal and State agencies and the private sector in order to avoid discrepancies in implementation. Good communication across all levels must be maintained with special emphasis at the interfaces. Full scale drill exercises must be conducted regularly to assess the logistics and essential supply requirements. Potential problems in the systems and procedures like evacuation procedures could be debugged. Safety training and refresher courses designed and implemented. In cases of shared common facilities there must be more cooperation across company lines to maintain and repair these facilities. For each region there is an indication of a presence of cycles in the frequency of accidents over the study period as indicated by periods of fairly constant slopes. The recurring pattern of accidents cycles may be used as a guide to anticipate incidents and to be better prepared for them.

In case of **Gulf of Mexico accident** was an avoidable accident caused by a series of failures and blunders by the companies involved in drilling the well and the government regulators assigned to police them, the presidential panel named to study the accident has concluded.

The companies — BP, Transocean and Halliburton, and several subcontractors working for them — took a series of hazardous and time-saving steps without adequate consideration of the risks involved, the commission reports in a chapter of its final findings, released on Wednesday in advance of the full report, to be published early next week.

The panel also found that company officials had failed to consult with one another on critical decisions and that senior management had paid insufficient attention to the troubled well, which was being drilled a mile under the gulf's surface.

The commission warned that without major changes, another such accident was likely. "The blowout was not the product of a series of aberrational decisions made by rogue industry or government officials that could not have been anticipated or expected to occur again," it concluded. "Rather, the root causes are systemic and, absent significant reform in both industry practices and government policies, might well recur."

BP's Macondo well erupted on April 20, causing an explosion aboard the drilling rig that killed 11 men and led to the spill of nearly five million barrels of oil, some of which still befouls the gulf shoreline.

BP noted that the commission had found fault with a number of companies, not only BP, the main owner of the well. BP added that it was taking steps to deal with problems identified by the panel. "Even prior to the conclusion of the commission's investigation, BP instituted significant changes designed to further strengthen safety and risk management," the statement said.

The findings will come as no surprise to the companies or to federal regulators, who say they have already taken steps to address the problems identified by the commission.

“The report released today reflects areas the Interior Department has already identified, acknowledged and spent months working aggressively to reform,” said Kendra Barkoff, the department’s press secretary.

“The most significant failure at Macondo — and the clear root cause of the blowout — was a failure of industry management,” the study concluded. “Better management of decision-making processes within BP and other companies, better communication within and between BP and its contractors and effective training of key engineering and rig personnel would have prevented the Macondo incident.”

Offshore oil exploration is by nature risky, the commission concluded. “Notwithstanding these inherent risks, the accident of April 20 was avoidable,” the panel wrote. “It resulted from clear mistakes made in the first instance by BP, Halliburton and Transocean, and by government officials who, relying too much on industry’s assertions of the safety of their operations, failed to create and apply a program of regulatory oversight that would have properly minimized the risk of deepwater drilling.”

From all above we could result to follows. Environmental protection has a key role in the success of such a project and follows the project from the initial exploration stages until the implementation and transfer stages. Although, according to the scientific literature, a key role in causing accidents plays the human factor, in the case of the Gulf of Mexico the causes gathered in the supervision of the authorities, in project, risk and judgment management and to education of engineers.

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