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Methane emissions due to oil and natural gas operations in The Netherlands

Final report

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Summary

Methane is, after carbon dioxide, the most important greenhouse gas. On a global scale, the most important sources of methane are rice cultivation, termites, landfills and the exploitation, transport and use of coal, oil and gas. On the basis of atmospheric ^{14}C-measurements the contribution of the fossil methane sources is estimated to be about 20%.

In The Netherlands the most important methane sources are identified to be the agriculture (cattle and manure); landfills and the oil and gas system. Existing estimates of source strengths however, are inaccurate. Total Dutch methane emissions are estimated to be about 1200 ktonne.

In The Netherlands sources, effects and options for abatement of greenhouse gas emissions are studied within National Research Programme on Global Air Pollution and Climate Change. With respect to methane emissions, a number of studies are performed, in which emission estimates are further improved.

The Netherlands are the fourth largest producer of natural gas in the world. Besides that, significant amounts of oil are produced. Some information about the amounts of oil and natural gas produced are presented in table 1. For this reason it may be expected that significant amounts of methane are emitted as a result of the exploitation and exploration of natural gas and oil.

Table 1   Production figures in 1990 and 1993 [EZ, *1991*; EZ, *1994*]

	1990		1993	
On-shore gas	54,585	million m^3	66,154	million m^3
Off-shore gas	17,856	million m^3	17,851	million m^3
On-shore oil	1,247,900	m^3 (st)	1,303,000	m^3 (st)
Off-shore oil	2,744,500	m^3 (st)	1,709,800	m^3 (st)
Condensate[1]	588,600	m^3 (st)	764,000	m^3 (st)

[1]   Condensate is a liquid, which consists of the condensable hydrocarbons in the natural gas. The liquid is also referred to as natural gasoline or natural gas liquids (NLG).

In order to quantify emissions from natural gas and oil exploration and production and to identify options for emission reduction, this study was performed.

The quantification of the emissions is done in two ways.

In an engineering-study, the sources of methane in the exploration and production of oil and gas are identified and subsequently quantified. This quantification is performed in various ways, depending upon the nature of the specific source. Methods comprise the calculation material balances using process simulation programmes; application of emission factors, e.g. for estimating emissions due to incomplete combustion in flares and gas engines; the interpretation of emission measurements. This engineering-study is based on a number of emission studies, performed by the various natural gas and oil producing companies in The Netherlands. These emission studies and their interpretation by Stork-Protech [1993] were placed at our disposal.

The resulting emission estimate for the years 1990 is given in the tables 2 to 5. In these table it can be seen, that the largest part of the methane is emitted in the exploitation of natural gas off-shore and that emissions are connected to normal process operations (off-gases from various processes, purge gases. Another possible important source are the passing valve emissions, which are the result of leaking pressure safety valves. Emissions in the exploitation phase are negligible. Incidental emissions due to maintenance or accidents are relative small and the same goes for emissions from leakages (fugitive emissions).

Table 2   Methane emissions due to exploration of natural gas and oil (in ktonne)

Source	Off-shore		On-shore	
	Cont.	Discont.	Cont.	Discont.
- drilling operations		< 0.1		< 0.1
- well-tests		0.1		0.1
- cleaning of wells		0.1		0.1

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Table 3   Methane emissions due to exploitation of natural gas (in ktonne)

Source	Off-shore		On-shore	
	Cont.	Discont.	Cont.	Discont.
Emissions from vents:				
- process gases	30 - 55		6 - 11	
- purge gases				
- blanketing gases	< 0.1		< 0.1	
- passing valves	12 - 21		< 0.1	
- maintenance		6.6		0.6
- system upsets				
Emissions from flares:	< 0.1		1.5	
Emissions from energy use:				
- exhaust of gas engines	1.5		0.3	
- exhaust of gas turbines	< 0.1		< 0.1	
- non-exhaust		0.9		0.2
Compressors:				
- seal losses	1.7		0.1	
- non-exhaust		0.4		< 0.1
Pneumatic devices		0		0
Fugitive emissions:				
- wells	0 - 0.2		0 - 0.6	
- treatment	0 - 0.3		0 - 1.7	
- pipeline	0 - 3.8		0 - 0.4	
Total	45 - 83	8	8 - 16	0.8

Table 4   1990 methane emissions due to production of oil (in ktonne)

Source	Off-shore		On-shore	
	Cont.	Discont.	Cont.	Discont.
Emissions from vents:	7.0	0	4.7	0.2
Emissions from flares:	0.2	< 0.1	0.6	< 0.1
Emissions from energy use:				
- exhaust of gas engines	0.3		0.2	
- turbines	< 0.1		< 0.1	
- non-exhaust		0.2		0.1
Compressors:				
- seal losses	0.2		< 0.1	
- non-exhaust		< 0.1		< 0.1
Fugitive emissions:				
- wells	< 0.1		max. 0.2	
Total	8	0.2	6	0.3

Table 5   Summary of 1990 methane emissions (in ktonne)

Source	Off-shore	On-shore	Total
Natural gas			
• continuous	45 - 83	8 - 16	53 - 99
• non-continuous	8	0.8	9
Total gas	53 - 91	9 - 17	62 - 108
Oil			
• continuous	8	6	13
• non-continuous	0.2	0.3	0.5
Total oil	8	6	14
Total continuous	53 - 91	14 - 22	67 - 113
Total non-continuous	8	1	9
Total sector	61 - 99	15 - 23	76 - 122

The emission estimate of 1990 is extrapolated to 1993, taking into account a number of measures, that are implemented between 1990 and 1993, and that reduce the methane emissions. The resulting estimate is presented in table 6.

Table 6   Summary of 1993 methane emissions (in ktonne)

Source	Off-shore	On-shore	Total
Natural gas			
• continuous	45 - 83	2.5 - 5	48 - 88
• non-continuous	8	0.2	8
Total gas	53 - 91	3 - 5	56 - 96
Oil			
• continuous	2.5 - 5	1.5	4 - 6.5
• non-continuous	0.1	0.2	0.3
Total oil	2.5 - 5	1.7	4 - 7
Total continuous	48 - 88	4 - 7	52 - 95
Total non-continuous	8	0.4	8
Total sector	56 - 96	4 - 7	60 - 103

In the years 1990 to 1993 about 16 to 19 ktonne of methane emissions was mitigated, which equals 16 to 21% of the amount emitted in 1990. This emission reduction is notably obtained by reducing the amount of gases vented in the on-shore gas exploitation and in the on- and off-shore oil production. Besides this, a slight decrease of methane emissions is a result of reduced oil production off-shore.

An other way to quantify emissions is the use of methane concentration measurements combined with model calculations. This is typically useful for quantifying incidental methane emissions. Since July 1991 methane concentration measurements are performed in Kollumerwaard in the northern part of the Netherlands, near the Groningen gas field. These measurements are used in a dispersion model as input parameters to calculate emission estimates for on-shore drilling and production sites.

Concentration measurements and model calculations resulted in emission estimates for several drilling sites and production sites of natural gas in the north of the Netherlands. The calculated estimates were compared with the results from the engineering study and with emission figures published by NAM. Comparison of the three emission estimates shows a much larger emission estimate calculated by the model than the estimates published by NAM and quantified by the engineering study. A reason for the difference between the estimates is difficult to find.

The emission estimates calculated by the model are subject to inaccuracies. The parameters which have an important influence on the total methane emission are the emission factor of a production or drilling site and the occurrence of incidental emissions at such a site. The occurrence of incidental emissions was calculated from the measured methane concentrations in Kollumerwaard, assuming that all high methane concentrations were caused by emissions from the oil and gas industry. When this is not the case, the occurrence rate can be victim to an over estimation. The representativeness and accuracy of the average emission factor of a site is determined by the registration of high CH_4 concentrations in Kollumerwaard and by the quality of the model calculations. Due to missing meteorological parameters it is not possible to give an estimate for all the observed methane peaks. Furthermore it is not always possible to identify a drilling or production site in being responsible for an observed CH_4 peak.

The possibilities for further methane emissions reduction, are abundant. Minimisation of use of purge gas and stripping gas and improved control and maintenance with regards to passing valve emissions might be applied at existing platforms off-shore. New platforms off-shore might be designed in a way that process emissions become almost negligible. For example, reuse or recompression might be optimized, or even alternative dehydration processes might be applied.

Since the off-shore industry is renewing itself is a rather fast way, the striving for minimisation of emissions at new-to-build platforms will be an effective way for reducing methane emissions further. When this policy proves to be successful, methane emissions might even be reduced to about 10 to 20% of 1990 emissions within the next 10 to 20 years.

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1 Introduction

1.1 General

As a result of increasing concentrations of greenhouse gases in the atmosphere, the possibility of a global warming in the next century is generally accepted. Although methane is emitted in much smaller quantities than carbon dioxide, its contribution to the greenhouse effect is quite large. This is because the effect of methane on a weight basis is about 22 times the effect of carbon dioxide. Figure 1.1 gives the contribution of methane to the total greenhouse gas emissions, both worldwide as in The Netherlands [Greenpeace, **1990**; Van Amstel et al., **1994**].

Khalil and Rasmussen [**1994**] have constructed a record of atmospheric methane which indicate that atmospheric methane concentrations have more than doubled in the last two centuries. At this moment a slight decrease is observed in the rate of increase, which might be a first indication of successful methane abatement. But it is also possible that concentrations of OH radicals increase. OH is able to remove CH_4 from the atmosphere.
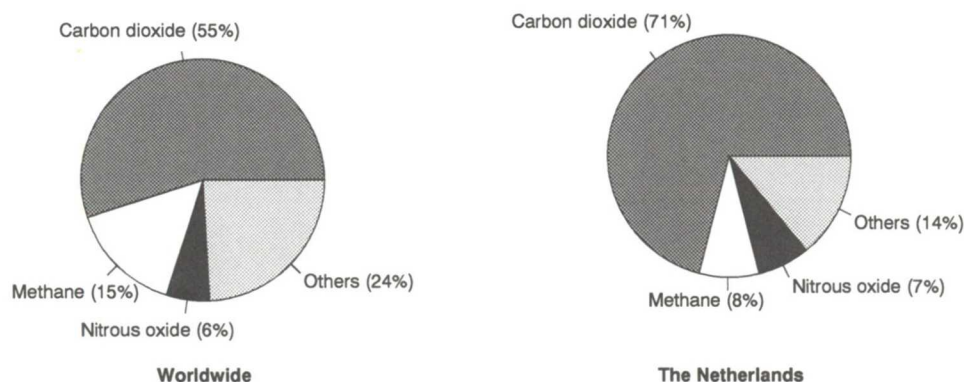
Figure 1   *Contribution of the various gases to the greenhouse effect, both worldwide (left) as in The Netherlands (right). Others are (H) CFC's, NO_x, CO and so on*

The main sources of methane are identified, but the strength of individual sources is not quantified accurately. Table 1.1 shows that worldwide methane emissions estimates range from 400 to 610 Tg[1]. Atmospheric ^{14}C-measurements indicate, that about 20% of this is of a fossil origin. Oil and gas systems are not the only fossil source; coal-mines are also identified as a significant methane emitter. The main contribution to this emission of fossil methane is most likely the natural gas production in Siberia and subsequently its transport. Estimates of emissions here range up to 10% of all Russian gas produced.

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[1] $Tg = 10^{12}$ g, 1000 kilo tonnes.

Table 1.1 *Global methane emissions [Watson et al., 1992]. The total emission including
natural sources is estimated to be 515 Mtonne per year*

	Annual global emission (Mtonne)	Range of estimate (Mtonne)
coal mining		25 - 47
natural gas system[1]	100	5 - 30
petroleum production		25 - 42
rice Paddies	60	20 - 150
enteric fermentation	80	65 - 100
animal wastes	25	20 - 30
wastewater treatment	25	?
landfills	30	20 - 70
biomass burning	40	20 -80

[1] Natural gas system refers to exploration, production, transport, distribution and end-use of
natural gas.

The Dutch methane emissions in 1991 are estimated to be 0.8 to 1.6 Tg, the main
contributors being landfills, cattle and manure and the oil and gas system, as shown
in table 1.2. This table is derived from Van Amstel [**1993**]. The emissions from the
natural gas system are the result of this study.

Table 1.2 *Methane emission estimation for The Netherlands
(in kilotonnes CH_4 per year, Van Amstel et al., [**1993**]; this study)*

	1990	
	Low	High
Natural gas production	56	96
Natural gas transport	6.5	6.5
Natural gas distribution	28	84
Oil production	4	7
Combustion[1]	16	31
Wetlands	40	120
Inland and coastal waters	24	60
Small water bodies	8	24
Animals	297	551
Animal waste	76	142
Landfills	178	576
Sewage treatment	3	3
Water production	2	2

[1] This concerns the combustion of end-use of oil and natural gas

The Dutch emissions from the petroleum and natural gas exploration and production
have been estimated several times. Nielen [**1991**] made a first quantification of

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emissions. At that time little was known about the Dutch situation, so his survey was more based on experiences abroad, as published in open literature. This study was at the basis of the emission estimate of Van Amstel et al. [1993]. Elzenga and Smit [1993] made an estimate of amounts of methane emitted from stacks, vents and flares. The producers association NOGEPA [Stork-Protech, 1991] made their own estimate, based on extensive research of the oil companies. This estimate however, has to be considered as an inventory of *known* sources, instead of an inventory of *all* sources. Sources of methane, that are hard to assess (e.g. fugitive emissions, exhaust gases, etc.) are neglected. Finally NAM [1993], The Netherlands largest oil & gas company, published an estimate of their own emissions. Through extrapolation of this NAM-estimate, a fourth estimate of Dutch methane emissions from the oil and gas production can be made. A comparison of these quantifications is presented in table 1.3.

In this context, it should be noted that NOGEPA will present in the autumn of 1995 an updated estimate of 1990 emissions, an estimate of the emissions in 1994 and a no-additonal policy scenario for emissions in the near future.

Table 1.3 Overview of the emission estimates (in kilo tonnes/year)

	Nielen[1]	Elzenga[2]	NOGEPA[2]	NAM[3]
Total on-shore			14	15
Total off-shore			69	99
Total natural gas	40 - 70			
Total oil	1 - 35			
Total	41 - 105	132	83	114

[1] refers to 1989, equals about Van Amstel [1993].
[2] refers to 1990
[3] refers to 1992

1.2   The National Research Programme

In order to improve our knowledge about the greenhouse effect, the National Research Programme on Global Air Pollution and Climate Change (NRP) was funded. In the NRP a large number of studies are conducted, for example:
— fundamental research on the way in which the earths climate system works;
— research and quantification of the sources of greenhouse gases;
— identification of possibilities for emission reduction.

An overview of studies that are performed in the NRP is presented in [NRP, 1993].

1.3   This study

The lack of insight of governmental organisations in the activities and processes in the oil and gas industry, the uncertainty in estimates of methane emissions from the oil and gas production, and the need for the identification of

options for emission reduction, urged the NRP to perform a study to methane emissions due to oil and natural gas operations in The Netherlands.

In order to do this, KEMA and TNO were asked to perform a joint research project, which consisted of both emission measurements and interpretation of ambient methane concentrations and an engineering-study.

In the engineering study the emissions were estimated starting from emission factors, material and energy balances, engineers rules and so on for two reference years: 1990 and 1993, this was done for a number of reasons:

— 1990 as a reference year makes the results fit for comparison with other estimates (Elzenga, NOGEPA);
— 1990 emissions are important for policy makers, since future targets for total Dutch methane emissions relate to reference year 1990;
— 1993 emissions give an overview of the situation to-date;
— comparison of 1990 and 1993 give an insight in emission reduction, that is already achieved by the sector.

For a large part, this emission estimate is based upon information provided by the oil and gas industry and collected by Stork-Protech [1993]. The way in which emissions were assessed comprise both measurements at several installations, as simulations of the processes.

Methane concentration measurements in Kollumerwaard, in the northern part of The Netherlands, near the Groningen gasfield, are used to detect incidental emissions. Such emissions result in a clear peak in the methane concentration. As a supplement to the stationary measurements, mobile measurements are carried out to provide information about the homogeneity of the methane concentration in the northern part of The Netherlands. Finally by using a dispersion model a link is made between measured concentrations and emissions. Calculations with this model provide emission estimates for on-shore drilling and production sites.

1.4   Structure of the report

The results of the study are presented in this report. A short historical and geographical overview of the industry is given in chapter 2. Besides that this chapter pays some attention the developments in the next twenty years. The industries activities, both in the exploration and in the exploitation phase are presented in chapter 3. This overview is that important, because insight in the nature of emissions starts with knowledge of processes.

The chapters 4 to 6 give the results of the engineering-study. Depending on the specific unit operation, methane may be emitted for a number of reasons, for example: as a normal process emission, due to fugitive leakages or due to various accidents. In chapter 4 these reasons are further explored. The way in which the emissions from such a source subsequently may be quantified is described in chapter 5, and based on these methods, an estimate of Dutch methane emissions from the oil and gas industry is described in chapter 6.

In chapter 7, both the stationary and mobile methane measurements are described, and their results are discussed and compared with the results of the engineering study. Options for emission reduction are discussed in chapter 8 and finally conclusions are drawn in chapter 9.

2 Oil and gas production in The Netherlands

2.1 General

The foundations for the Dutch oil and gas industry were laid in the second world war. The German occupying forces prospected for oil to fuel their war machine and discovered the oil field in Schoonebeek.
The industry achieved its present dimensions after the discovery of the Groningen gasfield in 1959 and the development of the off-shore activities after 1969.

Nowadays The Netherlands are the worlds 4th largest producer of natural gas. Besides that, significant amounts of oil are produced. The main exploitants are NAM (Shell/ Exxon), Amoco, Chevron, Clyde Petroleum, Continental, Elf Petroland, Mobil, Placid, Unocal and Wintershall.

Geographical overview
A geographical overview of Dutch gasfields is provided in figure 2.1. The Groningen field in the north-eastern part of The Netherlands is the largest gasfield in West-Europe. Smaller gasfields are present on-shore in Friesland, Drente and Twente, just south-west of Groningen, and in the Waddenzee (the coastal area just north of Groningen). Besides that, gas is produced from some small fields in the western part of The Netherlands.
Off-shore numerous gas fields are present, scattered mainly in the K and L-regions of the Dutch part of the continental shelf.

The natural gas produced in Groningen is relative low-calorific 'sweet'-gas. On-shore gas-fields in Twente en Drenthe produce H_2S-rich 'sour'-gas. Off-shore in general a high calorific 'sweet'-gas is produced.

Oil is produced in Schoonebeek (near Groningen), at several smaller fields in the western part of The Netherlands, and off-shore, mainly in the P-region. Recently oil is discovered in the most northern F-part of the continental shelf
The oil produced in the Western part of The Netherlands and on the continental shelf is of a relative light quality. The oil produced at the Schoonebeek concession, is rather heavy, steam injection is required in order to produce this oil.

Production
The production figures for The Netherlands for 1990 and 1993 are listed in table 2.1. The gas production exceeds the domestic demands, and about half of the production is exported to, amongst others, Germany and Belgium. The oil production covers about 20% of domestic oil consumption.

gasreservoir
oliereservoir
gasleiding
olieleiding
gesloten gebied
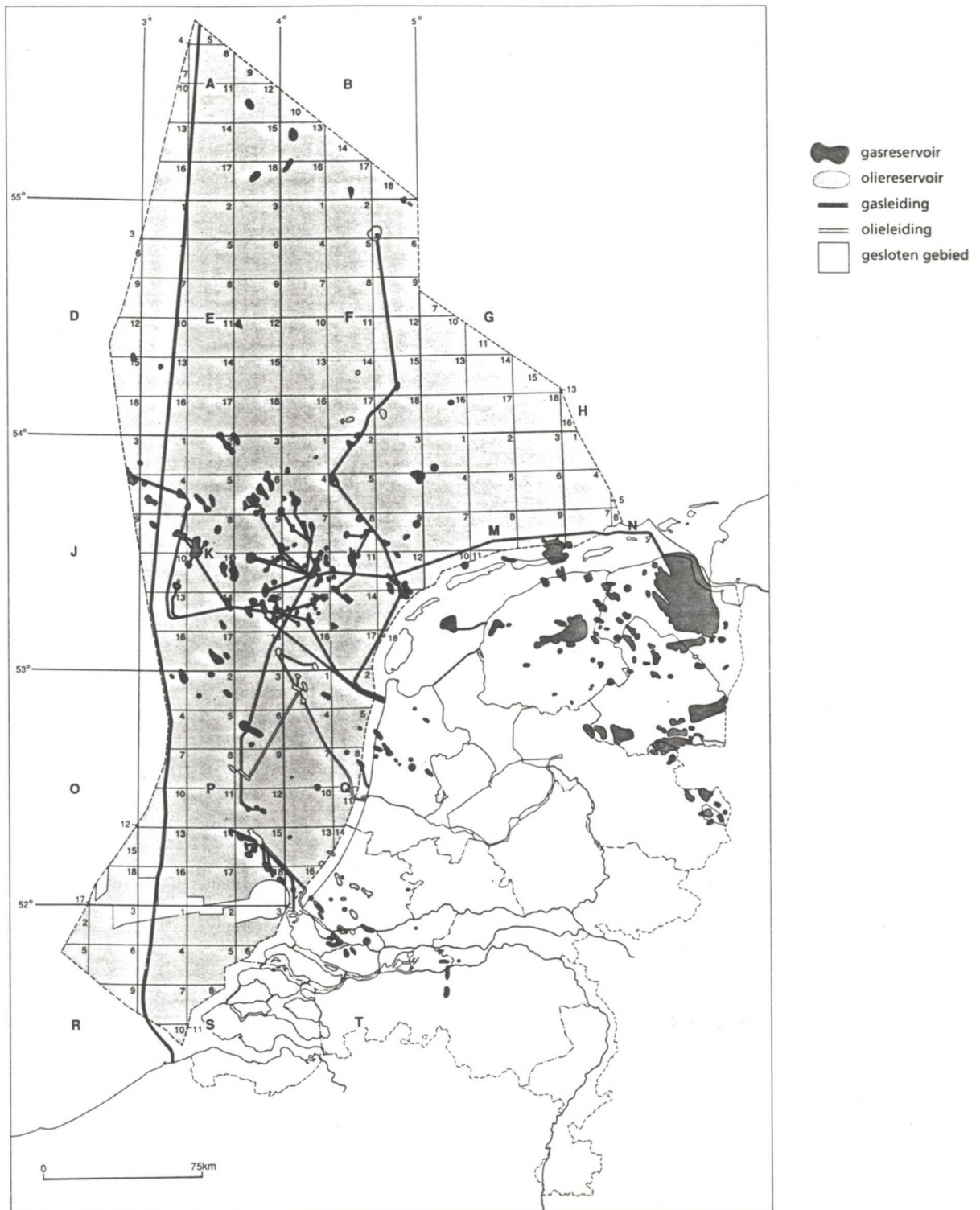
Figure 2.1   Oil and gas production in The Netherlands

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Table 2.1 Production figures in 1990 and 1993 [EZ, **1991**; EZ, **1994**]

	1990		1993	
On-shore gas	54,585	million m^3	66,154	million m^3
Off-shore gas	17,856	million m^3	17,851	million m^3
On-shore oil	1,247,900	m^3 (st)	1,303,000	m^3 (st)
Off-shore oil	2,744,500	m^3 (st)	1,709,800	m^3 (st)
Condensate[1]	588,600	m^3 (st)	764,000	m^3 (st)

[1] Condensate is a liquid, which consists of the condensable
hydrocarbons in the natural gas. The liquid is also referred to as
natural gasoline or natural gas liquids (NLG).

2.2   Future prospects

After a period of fast growth of activities in the seventies and early eighties,
the size of the Dutch oil and gas industry is at this moment slightly diminishing. The
development of further activities in future depends, apart from available reserves of
bitumina, on a number of factors:
— the development of prices and profits of oil and gas production. This is very
   important, since they determine whether gas fields and how long they are
   exploited;
— technological progress, which determines the feasibility to start or continue
   production from smaller and older fields;
— production and use of natural gas, which may be stimulated by international
   environmental policy with regards to global climatic change. This is a result of the
   decrease of specific greenhouse gas emissions, from using natural gas to oil and to
   coal (the 'fuel shift'), on the condition that gas and oil production and transport
   is not accompanied with large methane emissions;
— Dutch energy policy, which aimes to safeguard supply of domestic demands for as
   long as possible.
   The succes of this policy determines the attractiveness for further exploitation of
   the numerous smaller gasfields off-shore in future.

Decreasing exploration efforts
Except for parts of the F-field and the 'Waddenzee' (the coastal area north-west of
Groningen) most of the Dutch territory is explored at this moment. Netherlands is
considered a 'mature area' and exploration incentives decrease. It is generally
expected, that no large gasfields will be discovered anymore. NAM, however, still
hopes for discovery of larger gasfields in the most northern part of the Dutch
continental shelf. The size of a field in this remote area has to be of about 10 milliard
m^3, when exploitation has to be economically feasible.

Natural gas reserves

The Groningen gasfield produces natural gas since 1963. The most recent estimate of the initial amount of natural gas (the amount of natural gas, present in 1963) is about 2900 milliard m³. About 2680 milliard m³ is considered as the initial reserve. This estimate has been adapted several times in the past. For example in 1990, when the economically and technically feasibility was proven to produce gas untill a reservoir pressure of 20 bars, instead of 50 bars which was assumed before. As a result of this, the amount of exploitable gas increased with another 280 milliard m³.

At this moment, the Groningen gasfield has produced about half of its initial reserve; the remaining expected reserves[1] being about 1439 milliard m³.

Initial and remaining reserves of the other fields and futures, both well on-shore as off-shore are tabulated in 2.2. The future additions are mainly expected in the Waddenzee.

Table 2.2 Expected natural gas reserves in The Netherlands (in milliard m³ [EZ, 1994])

	Initial	Remaining
Groningen	2,680	1,439
Other on-shore	276	266
Off-shore	586	356
Futures	190 - 410	190 - 410
Total[1]	3,842	2,361

[1]   assuming 300 milliard m³ for futures

Underground storage

The Groningen gasfield is used a buffer: at low gas demands natural gas production in Groningen is almost neglegible; in winter at high gas demands Groningen produces at full capacity.

But due to the decreasing reservoir pressures, the production capacity of the Groningen field declines. As a result of this, it is expected that in the near future peak-demands cannot be met any longer.

In order to increase the buffer capacity, underground storage of natural gas is planned at two sites in Groningen and at one site in the western part of The Netherlands. On the longer term, when natural gas has to be imported, these facilities for underground storage will be used to secure matching gas demands and supplies.

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[1]   Initial reserves and remaining reserves are calculated starting from data with an intrinsic uncertainty. In this way the contents of a reservoirs are calculated as an expectation curve. The 'proven reserves' represent the 90% certainty value of the curve. The 'expected reserves' represent the middle of the curve. In practice these expected reserves are considered as the most realistic value. 'Future additions' or 'futures' are estimates of reserves, that are not explored yet.

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Future natural gas production

A scenario of amounts of natural gas sales in the future is drawn by Gasunie the Dutch natural transporting company and the sole purchaser of gas produced in The Netherlands (see figure 2.2). Most of this gas will be produced in The Netherlands; a small proportion will be imported from Norway. It is expected, that amounts of natural gas produced are maintained at current levels until about the year 2007. After this year, gas reserves will suffice to cover domestic use for a longer period of time, at least until the end of the current planning period: 2018.
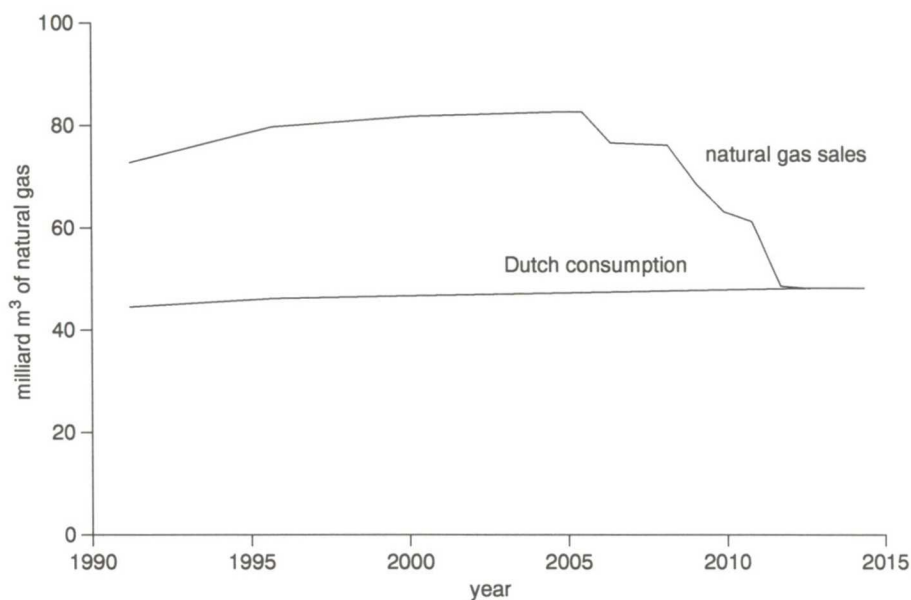
Figure 2.2 Natural gas sales and consumption in The Netherlands [Gasunie, 1991]

3   Activities in the natural gas and oil industry

3.1   Introduction

The activities of the oil and gas industry are divided in exploration and exploitation activities. In the exploitation phase activities are directed towards the identification of new oil and gas reservoirs, the determination of the amount and quality of the bitumina, and the determination of several field characteristics, such as field pressure, porosity and permeability of the reservoir. In the exploration phase the bitumina are extracted, treated, transported and finally sold.

3.2   Exploration

- *Seismic survey*

The search for natural gas or oil reservoirs starts with a seismic survey of the deeper geographic structures of the earth. This survey is performed by generating vibrations on the earth's surface, that are partially reflected at the border of two earth's layers. These reflections are subsequently measured and interpreted, resulting in geographic map of the region. From this map locations are identified that may contain natural gas or oil.

Seismic surveys and their interpretation have become more and more detailed throughout the years. As a result of this, the chance of success of a subsequent exploration drilling has increased to about 50%.

- *Exploration drillings*

After identification of a reservoir that may contain bitumina, an exploration drilling is performed. On-shore a drilling location is constructed. In the off-shore exploration platforms are used, which may also be used for well-testing.

The exploration drilling is performed as depicted in figure 3.1. 'Drilling mud' (a mixture of clay, water and chemical additives) is continuously circulated down through the hollow drilling string and subsequently back up through the annual space between drilling string and borehole wall. The static pressure of the drilling mud exceeds the reservoir pressure. As a result of this, the risk of uncontrolled gaseous or liquid emissions is reduced significantly. The cuttings, brought upwards in the mud, are analysed for the occurrence of bitumina.

Sometimes drillings are used to explore the extensiveness of a field, that already is identified. In such a case, it is called an appraisal drilling, but its procedure is comparable with an exploration drilling.

- *Well tests*

When the occurrence of gas or oil is proven in the exploration drilling, the feasibility of exploitation is investigated in a well test. In this test oil or gas is produced at varying production rates for some period of time. In order to assess the size of the reservoir and the ease of extraction, various parameters are monitored, such as amounts of bitumina withdrawn, the pressure drop in the reservoir. In recent years well-test procedures have been tightened and the duration of such a test is limited to about 20 to 70 hours.

kroonblok

takelblok

spoelkop/topdrive

spoelslang

boorkraan

trilzeef

veiligheids-
afsluiters

persleiding

spoelingspomp

accomodatie

conductor

boorstang

zeespiegel

zeebodem

bekledingsbuizen

beitel

NIET OP SCHAAL

De boorbeitel en een weergave
van de werking van de boor-
spoeling.

Figure 3.1 An exploration drilling off-shore
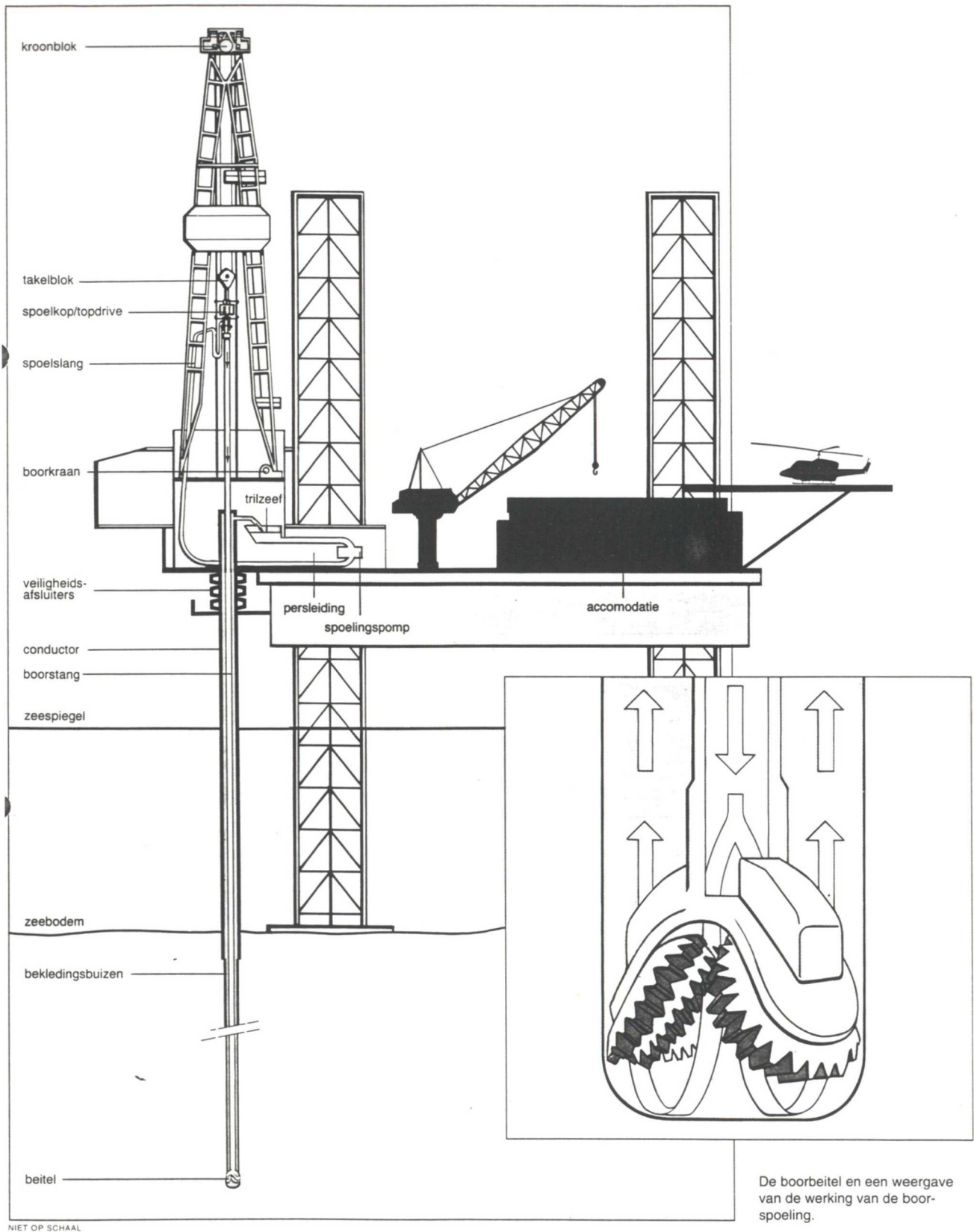
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Off-shore well tests are performed on platforms, that are specially designed for exploration purposes and are equipped with, amongst others, a flare. After the exploration period the platform is relocated to another exploration site, and replaced by e.g. a satellite platform.

• *Cleaning of the wells*
Before a well is taken into exploitation, the well is cleaned. This is done by adding a strong acid to the perforated bottom of the well. The acid removes all sorts of impurities from the reservoir in the direct neighbourhood roundabout the well, increasing the permeability of the rock and enabling oil or gas exploitation. The well are subsequently cleaned from acid by exploiting the well, catching the acid droplets before processing the natural gas.
Wells are normally cleaned before start of the exploitation, but also during exploitation when the production of bitumina declines faster as expected.

3.3   Natural gas production

3.3.1   Off-shore

Off-shore natural gas is produced and treated, according to figure 3.2. Wells are located both at satellite and production platforms. A satellite platform is a small, unmanned platform, where gas is produced and transported to a production platform, without any intensive treatment of the natural gas. A production platform is usually much larger. Natural gas is received from a number of wells or from one or more satellite platforms, after which the water is removed in a glycol-dehydrator[1] in order to avoid corrosion in the transport-pipes. Some times the field pressure is insufficient and the gas compressed before transport.
After this, the natural gas is transported ashore, where the condensate is removed, either in a low-temperature separator or in a silica-gel process.
After condensate removal, the natural gas is sold to Gasunie, which blends the gas in order to obtain a gas of a constant quality. Gasunie sells the natural gas to the larger consumers and the distribution companies, or exports the gas to countries such as Germany, Belgium or Italy.

3.3.2   On-shore

On-shore the natural gas is recovered at well locations and further treated, according to figure 3.3. In the Groningen field, the natural gas wells and treatment facilities are grouped together in so-called clusters. In some cases glycol-dehydration is applied before the gas is transported to another site, where the condensate is removed. In other clusters water and condensate are removed simultaneously in a low-temperature separator. In these cases glycol-dehydration is superfluous.
In the eastern part of the country, where sour gas is produced, the natural gas is subsequently transported and sweetened in a central desulphurisation facility in Emmen.

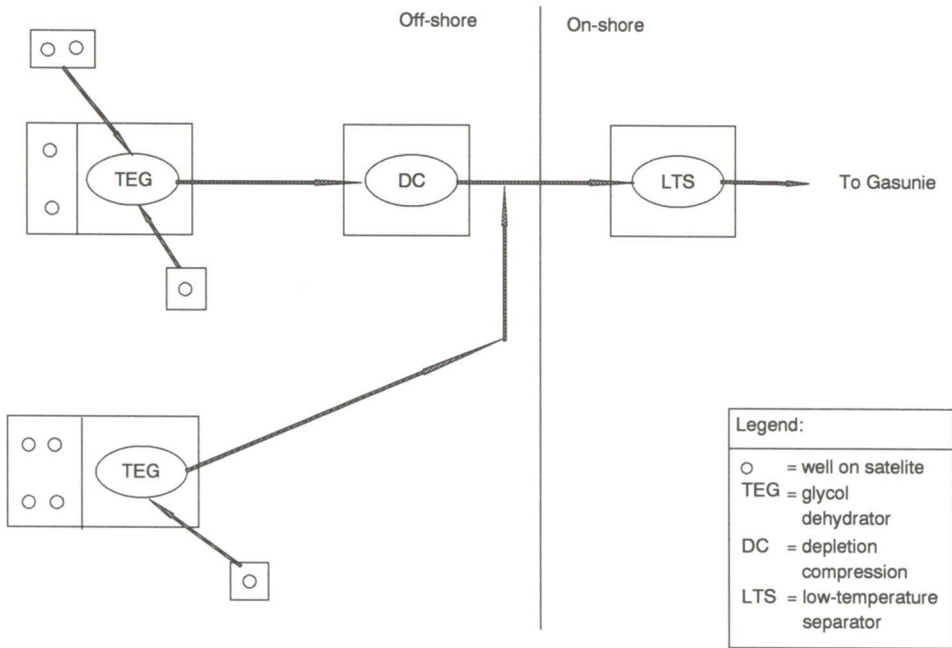[1]   All processes are described in more detail in chapter 3.3.

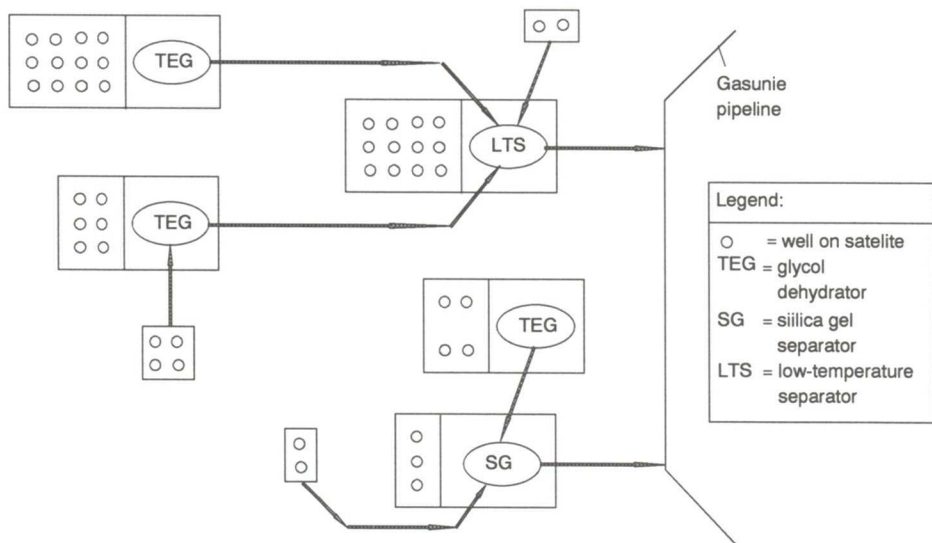Figure 3.2 Off-shore natural gas production

Figure 3.3 Inlet separation

3.3.3 Description of the equipment and processes

* *A well*

Figure 3.4 shows a typical gas well. The heart of the well consists of a tube, which is perforated at the lower part. Through these perforations, the natural gas flows from the reservoir into the tube upwards. The tube contains a hydraulic safety-valve, which closes itself when the gas-flow becomes too high. At the top of the well an 'X-mas tree' is applied, which controls the gas-flow from the wells.

* *Inlet separation*

Figure 3.5 shows a generalised flow-scheme of an inlet separation, which usually is placed immediately after a well on a satellite platform, on a production platform before glycol dehydration (see below), or in a cluster on-shore. The natural gas is produced at high pressure and elevated temperature. In an 'inlet separator' (1) a water-condensate mixture is separated from the natural gas main-stream. At some platforms cooling and further separation is applied in order to remove excess water (3). The volatile fraction (consisting of a mixture of methane, aromates, other hydrocarbons and water) is subsequently removed from the water-condensate mixture at a moderate pressure and a low temperature. Simultaneously the water is separated from the condensate. After this, the water is treated at atmospheric pressure, in order to remove the volatiles. Besides this other impurities are removed, and finally the water is drained into the sea.

Off-shore the condensate is recompressed, and recombined with the natural gas main-stream and the mixture is transported to a production platform or ashore. Off-shore the condensate is stored, loaded into tanker-cars and transported to refineries.

The volatiles from the water flash are usually vented or flared.
The hydrocarbon volatiles obtained from the condensate flash at moderate pressure may be used as a fuel gas in the glycol regeneration, or in gas-engines or turbines for power-supply. On-shore this gas may be recompressed and recombined with the natural gas main-stream. In all other cases these gases are vented or flared.

* *Glycol dehydration*

When the natural gas has to be transported along larger distances, the water vapour is removed in order to prevent pipeline corrosion. This is often done in a glycol dehydrator, which is depicted in figure 3.6.

After the natural gas is obtained from wells or from a satellite platform, water and condensate are separated and treated as described above (1-4). For a further reduction of the water content, the gas is treated in a glycol contactor (5). The glycol (usually triethyleneglycol) absorbs most of the water from the natural gas, along with amounts of hydrocarbons. Water and hydrocarbons are subsequently removed from the glycol in several different stages. Usually most of the hydrocarbons are removed in a first glycol flash (6). The remaining water is evaporated by heating the glycol at a temperature of about 200 °C in the glycol regenerator (7).
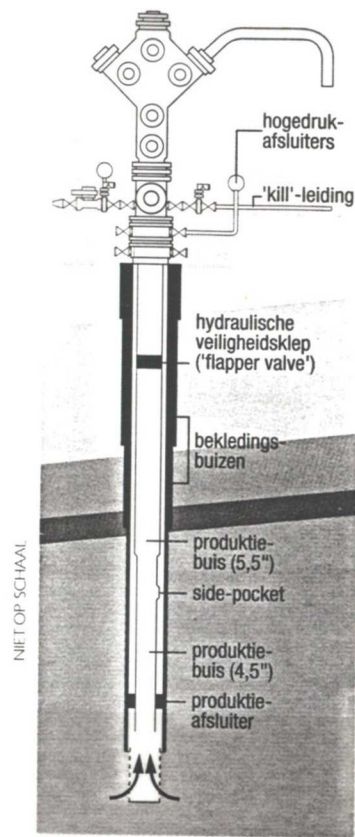In some cases no glycol flash exists, and all volatiles are released in the regenerator.

Figure 3.4 A typical gas-well

1. Inlet Sepator
2. Air Cooler (optional)
3. Inlet separator (optional))
4. Condensate flash
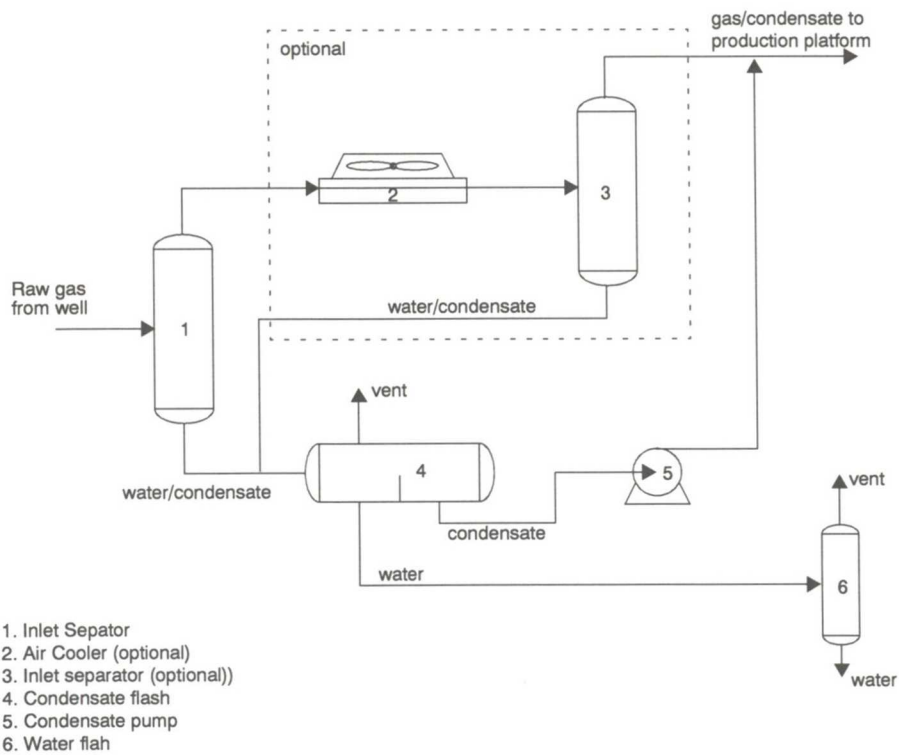5. Condensate pump
6. Water flah

Figure 3.5 Inlet separation

In some cases, natural gas is fed as a strip gas, just below the stills-column in the regenerator. This is done to improve the efficiency of glycol regeneration, for example, when the well-pressure of the natural gas is relative low and larger amounts of water have to be removed in order to obtain a lower dew-point of water in the product gas. Another reason for application of strip-gas is to obtain a sufficient dry glycol at a reduced regenerator temperature. This may be done to inhibit the degradation of the glycol and to increase its life-time.

The volatiles from the glycol regeneration are usually vented or flared.
The hydrocarbon volatiles obtained at moderate pressure from the glycol flash may be used as a fuel gas. At some locations (generally on-shore) this gas is recompressed and recombined with the natural gas main-stream. In other cases these gases are vented or flared.

- *Gas sweetening*

In the eastern part of The Netherlands, sour gas is produced. This gas is collected and sweetened centrally in a desulphurisation unit in Emmen. The gas is treated with Sulfinol, in which the hydrogen sulphate is solved. After this, the hydrogen sulphate is removed again from the Sulfinol and finally transformed into elementary sulfur in a Claus/SCOT-unit.

- *Low-temperature separator*

On-shore, the condensate is removed from the natural gas in a low-temperature separator, described in figure 3.7. Due to isenthalpic expansion of the gas, the gas is cooled to approximately -15 °C. When the gas-pressure is insufficient to obtain these low temperatures in this way, additional cooling is applied. To avoid formation of hydrates, mono- or diethyleneglycol is added to the gas. At the low temperature a condensate-glycol-water mixture is separated from the natural gas (5), and subsequently split in a condensate and a glycol-water mixture (6). After this the condensate is stabilised (7) and transported to refineries, while the glycol is regenerated and reused (8).

- *Silica-gel separation*

The silica-gel adsorption process can be applied as an alternative for the low-temperature separator. A simplified flow-scheme of this process is presented in figure 3.8. First the condensate and water are separated, in about the same way as described in the glycol-dehydration process (1 to 3), then the condensate is removed from the natural gas in a three-stage process. The gaseous condensate is adsorbed in column, filled with silica (4a), and the resulting natural gas is sold to Gasunie. When a column is saturated, the column is regenerated, using a hot natural gas stream in which the condensate is desorbed (4b). Finally the column is cooled down (4c), simultaneously warming up the natural gas-stream used in the regeneration step. A furnace (5) is used to provide additional heating of the regeneration gas. Normally three or four columns are present and at each time, one column is used as an adsorber, another column is regenerated and the third column is cooled down.
The condensate-gas stream is subsequently cooled (6) and the condensate is separated (7), stabilised (8) and transported to refineries. The natural gas, used to regenerate the silica, is recycled to the adsorbed column.
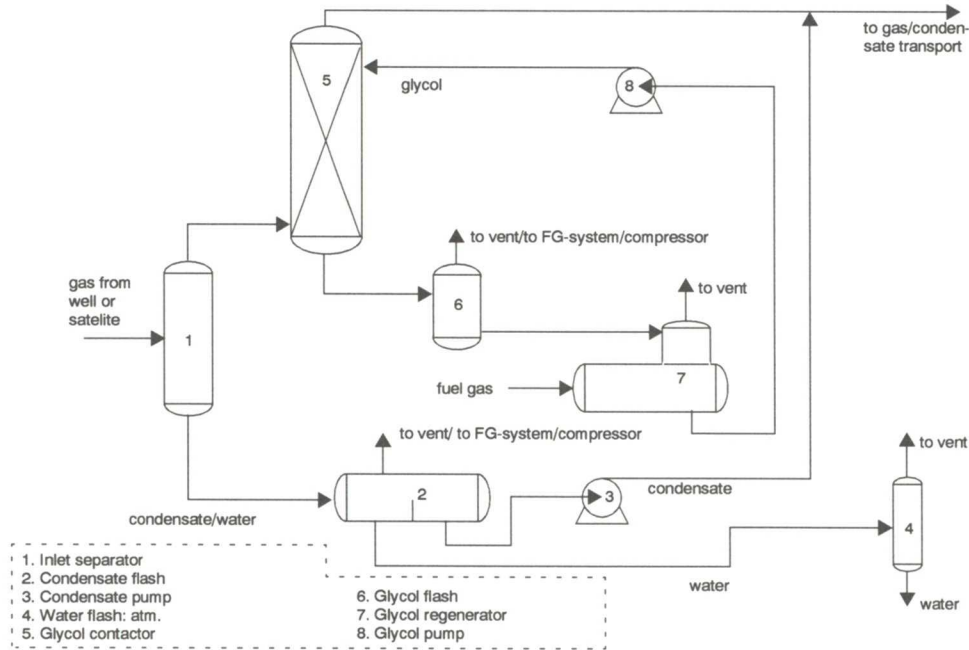
Figure 3.6 Glycol dehydration

1. Inlet separator
2. Condensate flash
3. Condensate pump
4. Water flash: atm.
5. Glycol contactor

6. Glycol flash
7. Glycol regenerator
8. Glycol pump
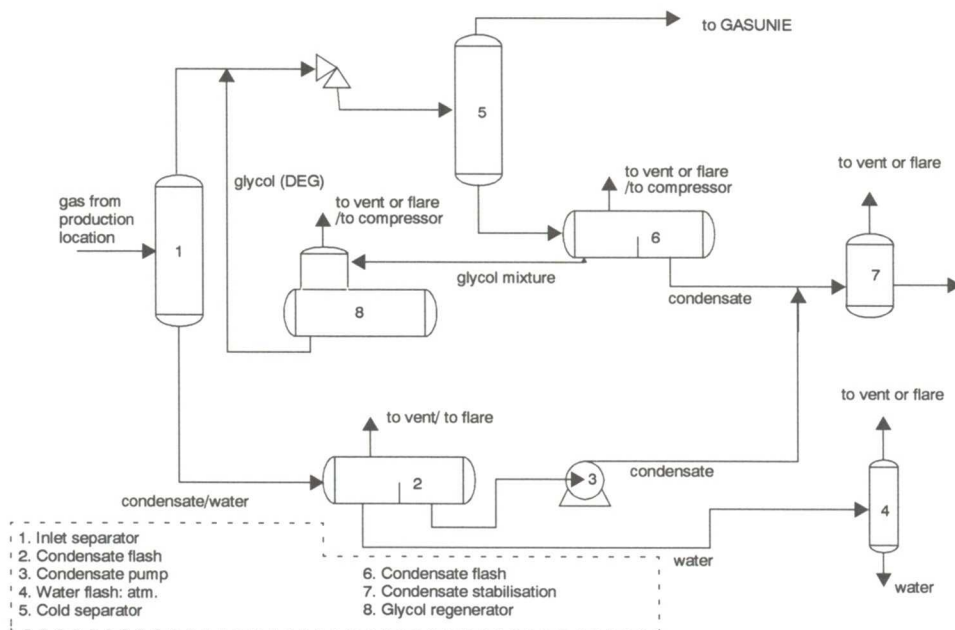
Figure 3.7 Low-temperature separation

1. Inlet separator
2. Condensate flash
3. Condensate pump
4. Water flash: atm.
5. Cold separator

6. Condensate flash
7. Condensate stabilisation
8. Glycol regenerator

1. Inlet separator
2. Condensate flash:
3. Water flash: atm.
4a. Silica-gel column in adsorption mode
4b. Silica-gel column in regeneration mode
4c. Silica-gel column in cooling mode
6. Air cooler
7. Condensate-gas separation
8. Condensate stabilisation
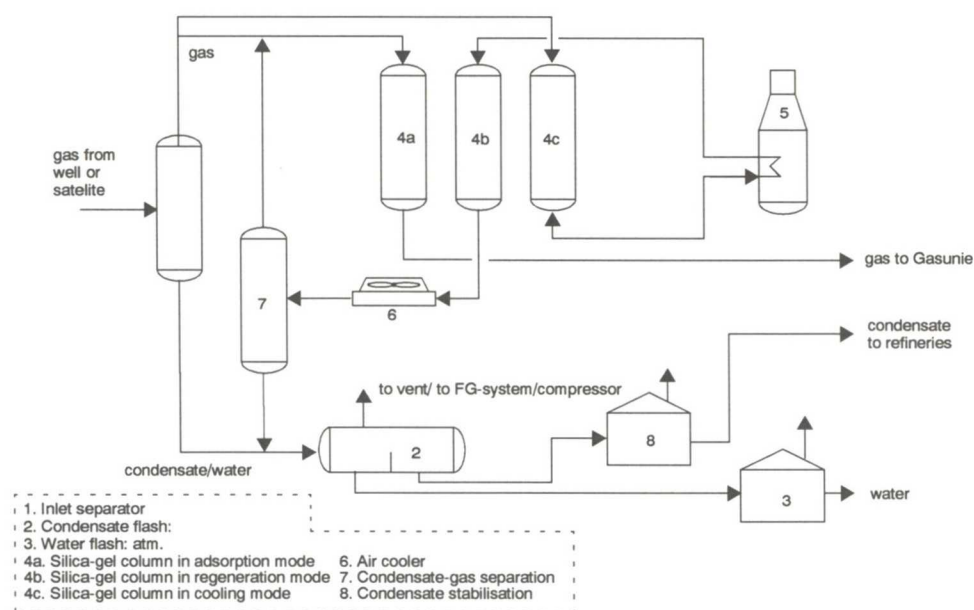
Figure 3.8 Silica-gel process

3.4   Oil production

Oil is recovered as an emulsion of formation water, oil and its associated gas. When an oil field is newly exploited, the amount of oil is relatively large. But when the amount of oil in the reservoir decreases, normally more and more water is produced. Exploitation of an oil-field remains economically attractive, even when the fluid contains up to 90% formation water. Ultimately the oil content of the produced fluid is too small, and further exploitation is not feasible.

The amount of associated gas varies also during the exploitation period. For example, when a combined gas-oil field is exploited, the oil in the bottom of the reservoir is extracted first. At prolonged oil recovery, the amount of natural gas increases steadily until ultimately oil production has shifted to gas production. Oil in The Netherlands typically contains about 30 m^3 per m^3 oil (st) .

Oil processing consists of separating the three components: water, oil and gas. This is done as represented in figure 3.9.

The oil is obtained from a well at a moderate. In some cases, the pressure of the oil suffices in order to cause a natural lift. In other cases an artificial lift has to be applied. This may be done by pumping the liquid from the reservoir. Another possibility is injecting natural gas, and using this as a lift gas for the oil-water emulsion.

After being produced, the gas phase (consisting of associated gas and lift gas) is separated in a first separator, operating at pressures of typically 8 bar. Remaining droplets of liquids are removed in a knock-out drum. After this there are several possibilities:
— the gas may compressed; dried in a glycol dehydration unit or in a low temperature separator; and ultimately reused as lift gas or sold to Gasunie;
— the gas may be used to generate electricity, using gas-engines and generators;
— the gas might be flared. This flaring of associated gas is only done when recompression and transport is economically not feasible.

The liquid phase from the first stage separator is treated in a second stage separator. Here the hydrocarbon mixture is separated from the formation water. In some cases, gas is used to improve this separation (gas flotation). The water mixture is reinjected in the oil reservoir or further treated and drained into the sea. The oil is stabilised and stored before transport.

The off-gases from the various unit-operations may be reused, recompressed flared or vented. In figure 3.10 a flow scheme is given of a Dutch on-shore oil-field, where reuse of gaseous effluents is optimised:
— the atmospheric off-gases from the glycol generator, the oil-stabilisation and the water flash are recompressed and recycled to the gas stream after the first separator;
— the off-gases from the second-stage separator are recompressed and recycled. After this the combined streams are compressed and subsequently dried.
A part of this gas is reused as lift gas; a second part is used for on-site energy generation; the remaining part is sold to Gasunie, who sells this gas to an industrial process. N.B., this gas has a different composition and calorific value, than the gas, that is usually sold in The Netherlands.

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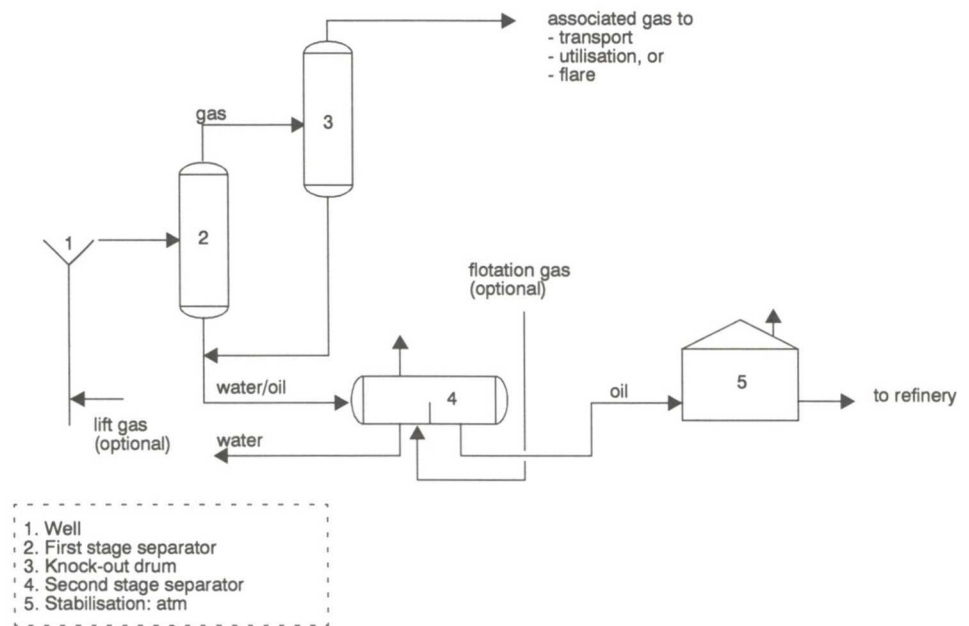
Figure 3.9 Oil production and treatment
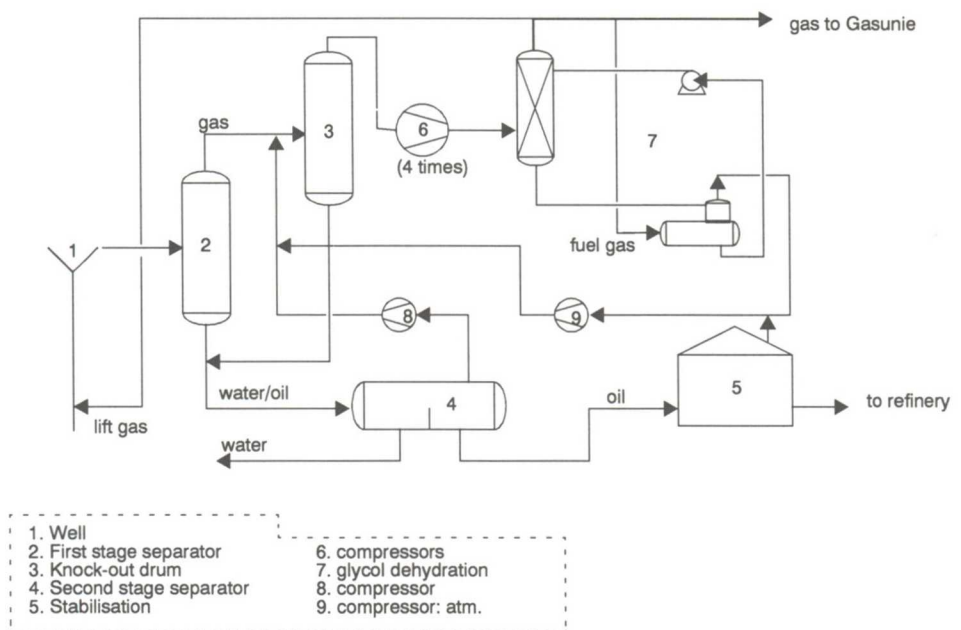
Figure 3.10   Oil production with maximum reuse and minimal methane emissions

4 Sources of methane emissions

4.1 Introduction

Emissions of methane may occur both in the exploration phase and during the exploitation of natural gas and oil. Relevant pathways, through which emissions may take place are described in this chapter in a qualitative way. Quantitative ways for estimating these emissions are described in chapter 5.

4.2 Sources in the exploration phase

In the exploration phase, methane may be emitted, during drilling operations, during well-tests and when cleaning the wells before production. Normally these streams are flared.

- *Exploration drillings*
The way in which exploration drillings are performed is described in chapter 3.2. Drilling mud is used to provide the static pressure to suppress uncontrolled release of bitumina. As a result of this the risk of emission of methane becomes neglegible.

- *Well tests*
During well-tests gas or oil is produced, at varying flow-rates for about 20 to 70 hours. Both on-shore as off-shore, the bitumina produced in a well-test are flared.

- *Cleaning of wells*
During the acid treatment and subsequent cleaning of a well, the natural gas that is produced is usually flared.

4.3 Sources in exploitation of gas

4.3.1 Vents and flares

During exploitation large amounts of methane are vented or flared. Most likely, this is one of the major sources of methane emissions in The Netherlands. Emissions from vent-stacks or flares are a result of:
- off-gases from various components of natural gas processing, e.g. condensate flashes, glycol regenerators;
- purge-gas, which prevents air from entering into the flare system;
- off-gases from pressure relieve valves, during system upsets;
- blanketing and breathing gas of various storage tanks;
- gases released during maintenance;
- passing-valves gas.

Generally, two types of off-gases are distinguished:
— Atmospheric gas streams;
— High pressure gas streams (from about 2 bars onwards).

Normally two flare or vent-systems are used to cope with these gas-streams as depicted in figure 4.1. This is done for safety reasons; e.g. to avoid the high pressure off-gases, that are released from a pressure safety valve, from entering the low-pressure glycol regenerator.

When gas streams are vented, all methane is directly emitted to the atmosphere. However, when the gas is flared, a significant reduction in emission is achieved. Flare efficiencies are determined by amongst others flare design, flare load compared to design capacity, and also by weather conditions. Under controlled conditions efficiencies over 99,5% may be achieved; at high load and bad weather conditions however, flare efficiencies may drop even below 95% (see also chapter 5.3).

- *Process emissions from inlet separation*
In chapter 3, figure 3.5, a simplified flowscheme of an inlet separation is presented. The condensate-water mixture that is removed, contains significant amounts of volatile hydrocarbons, including methane. This is partially a result of the high pressure in the inlet separator. When the pressure is reduced in the subsequent condensate flash and in the water flash, these hydrocarbons are released. The hydrocarbons from the condensate flash are removed via the high-pressure vent- or flare system; emissions from the water flash are removed through the atmospheric vent system.

The composition of the off-streams of these flashes do not represent the natural gas composition. Since the solubility of methane in the condensate water mixture is lower than the solubility of aromates or the C_2 to C_4-hydrocarbons, these off-gases contain relative much higher hydrocarbons. Besides that the off-gases from the flash contain much carbon dioxide and water vapour.

Off-shore off-gases from satellite platforms usually are vented. On-shore both high-pressure and atmospheric emissions usually are flared.

- *Process emissions from glycol dehydration*
A simplified flowscheme of a glycol dehydration on a production platform is shown in figure 3.6. On-shore glycol dehydration proceeds in about the same way. Analogous as described above, methane is solved in the condensate-water mixture, that is removed in the inlet separator. The methane is ultimately released in the condensate flash or water flashes.
The natural gas from the inlet separator is further dried in the glycol contactor. Nearly all the water, and a significant amount of hydrocarbons are solved in the glycol. The water and the hydrocarbons are subsequently released (to the high pressure system) at reduced pressure/low temperature in the glycol flash and (to the atmospheric system) at low pressure/high temperature in the glycol regenerator.

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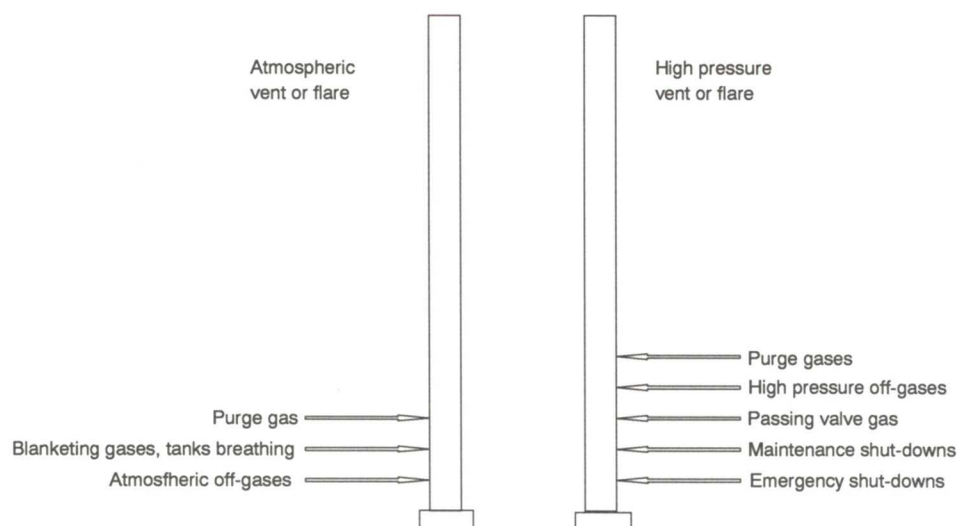
Figure 4.1 Fare or vent system

The composition of the emissions can not be compared with the composition of natural gas. Emissions from the glycol flash contain a lot of water vapour and consist of a relative high degree of higher hydrocarbons. As a result of the high affinity of glycol towards aromates, the off-gases of the glycol regenerator contain a lot of benzene, toluene and xylene.

As described in chapter 3.3, sometimes natural gas is used as a strip-gas to improve the regenerators efficiency. After passing through the regenerator column, this gas ends up in the atmospheric vent or flare system.

In many cases on-shore, high-pressure off-gases are recompressed, while off-gases on-shore usually are flared.
At several platforms part of the off-gases from the condensate and the glycol flashes is used as fuel gas in the glycol regenerator or as a fuel gas for electricity generation. At other platforms off-shore, off-gases are vented.

• *Emissions from low temperature separators*
A simplified flowscheme of a low-temperature was given in chapter 3, figure 3.7. Analogous as described above, methane is solved in condensate-water mixture, removed in the inlet separator, and is subsequently released in the condensate flash (to the high pressure system) and the water flash (to the atmospheric system).
A certain fraction of methane is solved in the condensate-glycol mixture, and is subsequently released either in the condensate flash (high pressure), the condensate stabilisation (high pressure) or in the glycol regeneration (atmospheric).

The composition of the emissions can not be compared with the composition of natural gas, since aromates and higher hydrocarbons are preferably solved in the glycol-condensate mixture.

Low-temperature separation is only applied on-shore. Off-gases from the low-temperature separators are normally flared or recompressed.

• *Emissions from the silica gel process*
A simplified flow-scheme of a silica-gel process is presented in chapter 3, figure 3.8. Methane emissions may occur from the condensate and water flash, in the same way as described above at the low temperature separator.

• *Purge gas*
In order to prevent air from entering the flare or vent system -which might result in the formation of an explosive mixture-, a gas flow is maintained in the vent-stack or at the flare tip. Normally natural gas is used for this purpose. At some platforms on the Dutch continental shelf however, off-streams of the process-equipment suffice as a purge, and no additional natural gas is used for this purpose.

• *Blanket gas emissions of storage vessels, vessel breathing*
Empty storage vessels of for example condensate, usually contain a gaseous hydrocarbon mixture. When such storage vessels are filled with condensate liquid, the gas content of the vessel is replaced with the liquid, and removed through the atmospheric vent or flare system.

As a result of ambient temperature fluctuations the gas and the liquid phase in the vessel is continuously expanding and shrinking. This breathing of the vessel, results also in emissions of hydrocarbons to the vent or flare system.

• *Maintenance*
In routine maintenance amounts of methane may be released to the vent or flare system. This occurs, for example, when process-equipment or a pipe-line is depressurised and flushed with air, before maintenance.
Examples of these maintenance activities include well workovers, orifice fitting replacement, maintenance blowdowns, maintenance of gathering pipelines, pipeline and compressor blowdowns.
In most cases, these off-gases are fed to the high pressure vent or flare system.

- *System upsets*

At system up-sets, the safety system of the production location comes into action. As a result of this, pressure relief valves may open, and the system is depressurised. The off-streams of a pressure safety valve are normally fed to the high pressure flare or vent-system system.

- *Passing valves emissions*

Pressure safety valves are used to release excess gas at system upsets. Block-valves are used to shut-off a certain part of the process and subsequently depressurise it, for example before maintenance. Both types of valves are connected to the flare or vent system, as illustrated in figure 4.2.

When, as a result of fouling or wear, these valves do not close completely, certain amounts of natural gas leak through. These passing valves emissions ultimately end-up in the high-pressure flare or vent-system.

4.3.2 On-site energy generation

- *Exhaust emissions*

On-site, a number of incineration processes are used for several purposes: reciprocating engines and turbines are used on location to supply the power to operate compressors and to generate electricity required; heaters are used, e.g. in the regeneration of glycol. In many cases these incineration processes are natural gas-fired, and due to incomplete combustion they are a source of methane.

- *Non-exhaust engine-emissions*

At shut-down of reciprocating engines, the engines are flushed with air for safety reasons. Before starting-up again, these engines are flushed several times with natural gas. Doing this amounts of methane are released to the atmosphere. So both start-up as shut down is normally accompanied by emissions of methane.

4.3.3 Compressor stations

- *Seal losses*

The compressors axis has to revolve in the compressor casing, so the connection between both parts cannot made gas-tight. As a result of this, the seals between the axis and the casing (see figure 4.4) are always leaking to some extent.

Most compressors are equipped with gas-seals, which consist of two discs. One of them is attached to the axis and rotates just opposite of the other disc, which is attached to the casing. The distance between both discs is about 3 μm.
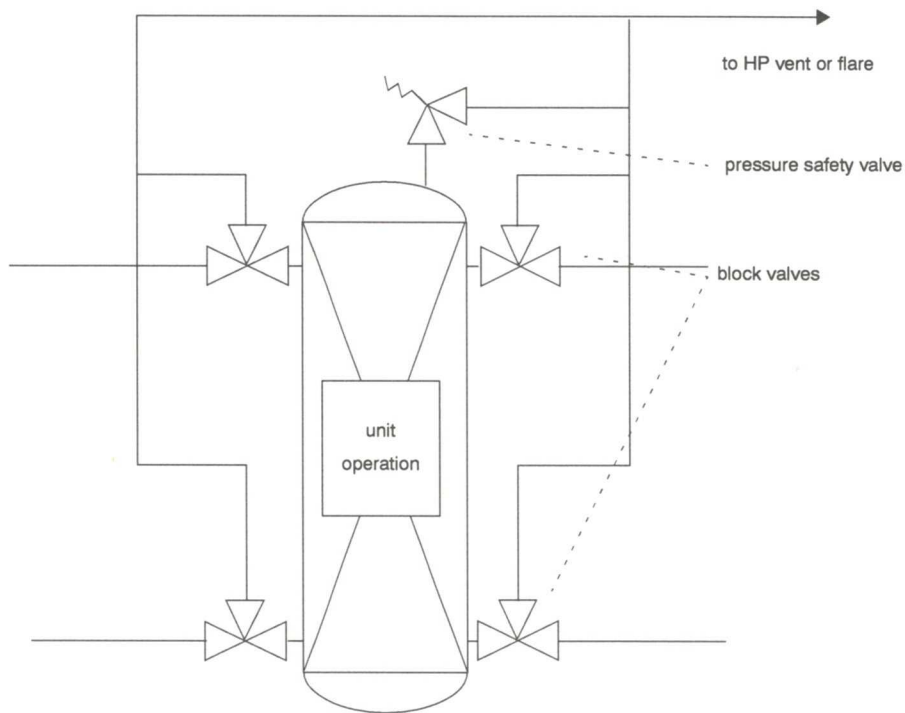
Figure 4.2 Block valves and pressure safety valves

Seal losses, may be disposed off in a controlled way through an atmospheric vent- or flare system, but in many cases, they are vented separately.

- *Start-up and shut-down*

At shut-down of compressors, the equipment is flushed with air. At start-up with natural gas. Normally this gas is vented, resulting in emissions of methane.

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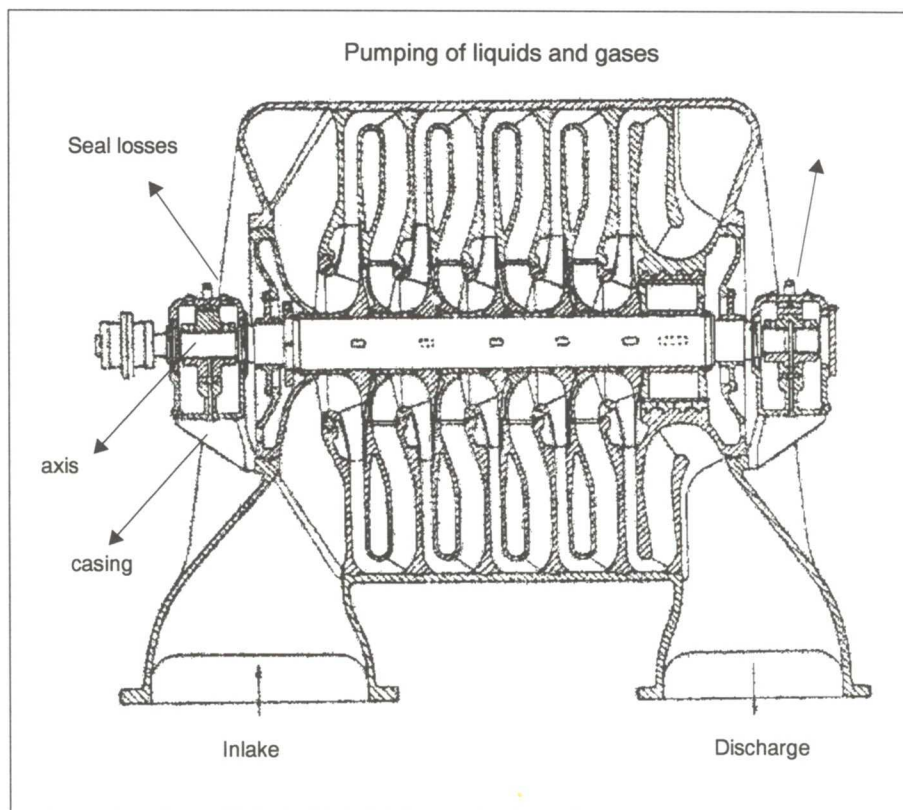
Figure 4.3 Seal losses of a compressor

- *Energy requirements*

Compression of natural gas to accelerate production and increase ultimate recovery is the main consumer of energy off-shore. This results in methane emission, both in the exhaust-gases and as a result of start-up and shut down of engines (see § 4.3.2).

4.3.4   Fugitive emissions

Chronic leaks occur throughout the natural gas system. Especially, joints, flanges and valves may leak to some extent. Most of these leakages are most likely limited to a few cc a day (10^{-6} m³), but considering the amount of this type of connections, the total sum of the fugitive leaks may contribute significantly to the total emissions.

Larger leakages are easily detected, since they will cause the formation of ice on the flanges outer surface. This ice is a result of a drop in temperature, due to the expansion of the gas from about 80 bar to atmospheric.

4.3.5   Pneumatic devices

Valves, actuators in the system are sometimes natural gas-operated. This means that the pressure of the natural gas is used to switch the valves. The natural gas is vented to the atmosphere, after being used.
These pneumatic devices may occur throughout the system: in wells, in gas-treating and along pipelines.

4.3.6   Chronic leaks from abandoned wells

Abandoned wells can be divided in two categories: wells, that are permanently abandoned and wells that are temporally out of production.

When wells are permanently abandoned, a very tight sealing is prescribed. The borehole is sealed with dozens of meters of concrete, followed by a plug of drilling mud, another seal of concrete, etcetera. Such a rigid sealing has a zero emission.

4.4   Sources in the oil production

4.4.1   Vents and flares

Just as it is the case in the natural gas production, gases vented or flared in the oil industry come from a range of sources in oil extraction and treatment. The most important ones are: purge gas, emissions due to maintenance, blanketing gases and process emissions and associated gas.
In most cases the flare or vent system is divided in a high pressure and an atmospheric system. Nearly all high pressure systems and most of the atmospheric systems are equipped with flares. This goes both for the on-shore as the off-shore oil extraction.

- *Process gases*
The origin of the off-gases from processes in the oil industry is depicted in figure 3.9. The off-gases from the second stage separator may be fed to a high pressure vent or flare system. The off-gases from the oil stabilisation tank or water the water flash may be fed to the atmospheric system. Furthermore emissions may occur in the treatment of the gas; either in the flaring of associated gas, or in its treatment, or in its use for energy generation.

The amount of process-gas that ultimately ends up in the flare-tip or vent-stacks depends upon the way in which the various gas-streams are used or recompressed. For example: the oil process, as described in chapter 3, figure 3.10, has in theory no process emissions.

- *Associated gas*
Most of the associated gas that remains unused, ends up in the high pressure flare system. In one case, a fraction of this gas is reinjected in an empty oil field.

- *Purge gas, off-gases from maintenance, blanketing gases*
The origin of these three types of off-gases is comparable with the off-gases in the production of natural gas, which are already described in chapter 4.3.1.

- *Passing valve emissions*
Due to the relative low gas pressures, the passing valve emissions in the production of natural gas will not occur to the same extent as in the exploitation of natural gas.

- *Lift gas and flotation gas*
As can be seen from figure 3.9, lift gas and flotation gas end up in the off-gases from the first stage and second stage separator, respectively. But the gases used for these purposes are usually provided by recompressing the off-gases from these separators. In a steady state situation both the lift gas as the flotation gas are in a closed circuit and the amount of gas coming from the system is equal to the amount of associated gas entering the loop. As a result of this, the overall contribution of lift-gas and flotation gas the to total off-gases is zero.

4.4.2 Emissions from on-site energy use

Emissions from on-site energy use are both exhaust emissions and incidental emissions at start-up and shut-down, as described in chapter 4.3.2.

4.4.3 Emissions from compressors

Emissions of compressors in the treatment of associated gas are seal losses and emissions due to start-up and shut down. Both types of emissions are described above in chapter 4.3.3.

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5 Estimating emissions

5.1 Introduction

In this chapter it is described, in what way emissions from certain activities in the system may be quantified. The methods presented here are more suited for determining emissions from a single platform or cluster, than for quantifying the national methane emission. A national emission is obtained, as the sum of the emissions from all installations in a country.

The methods, described in this chapter, are used to quantify the emissions of all oil and gas companies that are active on the Dutch territory. In chapter 6 a total emissions from the Dutch industry is derived from the companies emission inventories.

5.2 Emissions during exploration

* *Emissions due to drillings*
As described in chapter 4.2, **methane emissions as a result of drilling operation are negligible.**

* *Emissions due to well-tests*
The methane emissions from well-tests may be estimated from the length of a well-test and the amount of gas produced. A well tests typically lasts for 20 to 70 hours, with about 100.000 m³ of natural gas produced per day. Normally this gas is flared. But the flows, generated during a well-test are not easily predicted. For this reason, the capacity of a flare may be underestimated, which results in a relative low flare efficiency, maybe even as low as about 95%. From this information, the methane emission of a single well-test can be calculated as **10 tonne at maximum.**

* *Emissions due to cleaning of wells*
The methane emissions due to cleaning of wells may be estimated in the same way. A typical cleaning operation results in methane emissions of about the same order of magnitude as a well-test: **10 tonne at maximum.**

5.3 Emissions in the exploitation of natural gas

5.3.1 Emissions due to venting and flaring

The amounts of methane vented or flared may be estimated in two ways:

A first method is by measuring gas flows in the flare tip or in the vent-stack, along with the methane concentration. Gas-flows may be measured using some appropriate device, for example anemometers or pitot-tubes. Methane concentrations may be

obtained, using some appropriate sampling device and a GC/FID or IR detector. Measuring emissions may be rather difficult in various cases, since both gas-flows and methane concentrations may be highly variable. This goes especially for high-pressure vent-stacks, where gas velocities may range over a factor 10.000: from the minimum amount of purge gas of a few centimetres per second during regular operation, to just below the velocity of sound at system up-sets.

A second method for estimating emissions from vents and flares is by estimating the various contributions to the amount of methane vented or flared. This means that off-gases from processes, purge gases, passing valve emissions, and incidental emissions due to maintenance and system upsets are quantified separately.

- *Process emissions*

Process emissions may be calculated, using a suitable simulation programme. Stork-Protech calculated the process emissions from the Dutch natural gas industry, using the simulation programme PRO-II [Stork-Protech, **1993**], but other commercially available process simulation programmes such as ASPEN + or MAX may also be applied. Relevant input parameters are the composition of the raw gas (methane content, concentrations of other hydrocarbons, water content), the process conditions (pressures and temperatures), glycol recycle rate and amounts of gas recompressed or used as a fuel gas.

It should be stressed that methane/water and methane/condensate mixtures are hard to predict. The result depends heavily upon the thermodynamics that are used. Peng-Robinson or Predictive RKS are preferred.
Besides this it should be noted that these simulation programmes assume equilibrium, whereas in real situations this equilibrium may not be reached.

Emissions from the glycol regenerator are increased, when natural gas is used as a strip-gas. All natural gas, that is used as a strip-gas, ultimately ends up in the atmospheric vent- or flare system. When this amount is unknown, a first guess might be obtained from the recommended amount of stripgas: 6 m^3 strip-gas per m^3 TEG, which boils down to about **1 m^3 strip-gas per 3000 m^3 natural gas dehydrated** [Manning, **1993**].

The emissions from a low-temperature separator or a silica gel-process (see chapter 3.3) are calculated in a analogous way.

In table 5.1 and 5.2 the emissions from a satellite platform and a production platform, as calculated with PRO-II, are given. In case of the production platform, also the calorific content of the off-gases is given. Two conclusions may be drawn from these tables:
— most methane is released in the glycol cycle; the condensate and water treatment is relative small source of methane compared;
— the high-pressure off-gases are much larger than the low-pressure emissions, so at sites where these streams are used for energy purposes or are recompressed, emissions are significantly reduced.

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Table 5.1 Emissions from a satellite platform
(kg per 10^6 m³ natural gas produced)

| – Condensate-Gas Ratio: | | 8 |
| – Water-Gas Ratio: | | 25 |
Source	**Condensate flash**	**Water flash**
CH_4	42	1
BTX[1]	1	0.2
Other[2]	20	1.8

[1] Benzene, toluene and xylene
[2] Mainly H_2O and higher hydrocarbons

Table 5.2 Emissions from a production platform
(kg per 10^6 m³ natural gas produced)

| – Condensate-Gas Ratio: | 15 | | | |
| – Water-Gas Ratio: | 10 | | | |
Source	**Condensate flash**	**Water flash**	**Glycol flash**	**Glycol regenerator**
CH_4	72	0.1	284	33
BTX	0	-	-	84
Other HC	42	0.05	164	55
H_2O	25	0.25	182	101
Calorific value (GJ)	6.1	0.01	24.0	8.1

Short-cut methods for estimating process emissions
When simulation programmes aren't available, emissions from the condensate flash and from the water flash may be estimated from a methane material balance: The amount of methane solved in the water condensate mixture is calculated from the amount of condensate and water in the raw gas and the solubility of methane in the condensate or water at the temperatures in the inlet separator (see figures 5.1 and 5.2 which are calculated assuming Predictive RKS). The amounts of methane emitted in the condensate flash and the water flash are subsequently calculated from the amounts of methane that remain solved in the condensate flash and in the water flash. The methane emission has to be corrected for amounts of gas from the condensate flash, used as a fuel gas.

Such a short-cut method for estimating emissions from the glycol regenerator part is less easy defined. In literature emission factors of emissions from glycol dehydrators are given: based both on emission measurements and simulation of various types of dehydrators, Radian [1992] derived an glycol dehydrator emission factor of 5.57 tonne yr⁻¹ of methane, for dehydrators with a average capacity of 8.7 million m³ yr⁻¹ of natural gas. From this an emission factor is calculated of **0.64 g of methane per m³ natural gas treated.**

Another emission factor may be derived from table 5.2: **0,32 g of methane per m³ natural gas treated (0,29 g from the condensate flash; 0,03 g from the glycol regenerator).**

* *Purge gas*

When purge gas is used, the amount may be calculated from the diameter of the vent-stack and the minimum gas-flow. Vent-stacks typically are 12, 24 or 36 inch. Minimum gas-flows depend upon the stack diameter and the presence of seals on the stack, but a typical value is 2 - 4 cm s^{-1}.
Emissions from purge gas from a 24 inch stack, can be calculated in this way as **100-200 tonne of methane per year.**

* *Passing valves emissions*

NAM compared measurements of gas-flows in vent-stacks with calculated process emissions and amounts of purge gas. This was done for several representative satellite platforms and treatment facilities off-shore and clusters on-shore. From these measurements it was concluded that about 30% of the emissions off-shore could not be attributed to off-gases from processes or purge gas. This amount of 30% is believed to be caused by passing valves emissions, and equals about **1 g of methane per m³ of natural gas produced** [NAM, 1995]. However, both in the measurements as in the process calculations certain uncertainties exist. Because the estimate of the passing valve emissions is the difference of both, this estimate is also uncertain on-shore no passing valves emissions were observed.

The extent to which passing valve emissions occur, depends upon the control and maintenance programme of the valves. In theory it is possible to limit passing valve emissions to negligible, when a strict control and maintenance programme is applied [Stork-Protech, 1995].

* *Blanket gas emissions, breathing emissions*

Blanket gas emissions may be calculated from the volume of liquid stored. Since the pressure of the blanket gas is atmospheric, 1 m³ of liquid replaces about 1 m³ of gas. So blanket gas emissions are about **0.6 kg methane per m³ of liquid stored.**

* *Maintenance*

Emissions from maintenance may be calculated as the product of the volume of the equipment that is cleaned, the operating pressure and the amount of annual process shut-downs. Volumes of the equipment vary from about 3 m³ to about 50 m³, operating pressures are up to 80 bar. This results in emissions of about **150 to 2500 kg of methane per event**. Normally the equipment is blown-down once a year.

* *System upsets*

Methane emissions from system upsets may be estimated from the number of upsets per year, and the amount of methane released per upset. Amounts of methane that are released per event are comparable to the amounts as described at 'maintenance': about **150 to 2500 kg of methane per event**. Emergency shut-downs are very rare. Their frequency is much less than the frequency of maintenance blow-downs.

* *Emissions from flares/flare efficiencies*

When calculating the emissions from flares, a flare efficiency has to be estimated. This flare efficiency depends upon flare design, state of maintenance, flare load versus design load and meteorological conditions.
Bartelds [1977] gives in table 5.3 an indication of emission factors, for different classes of flares.

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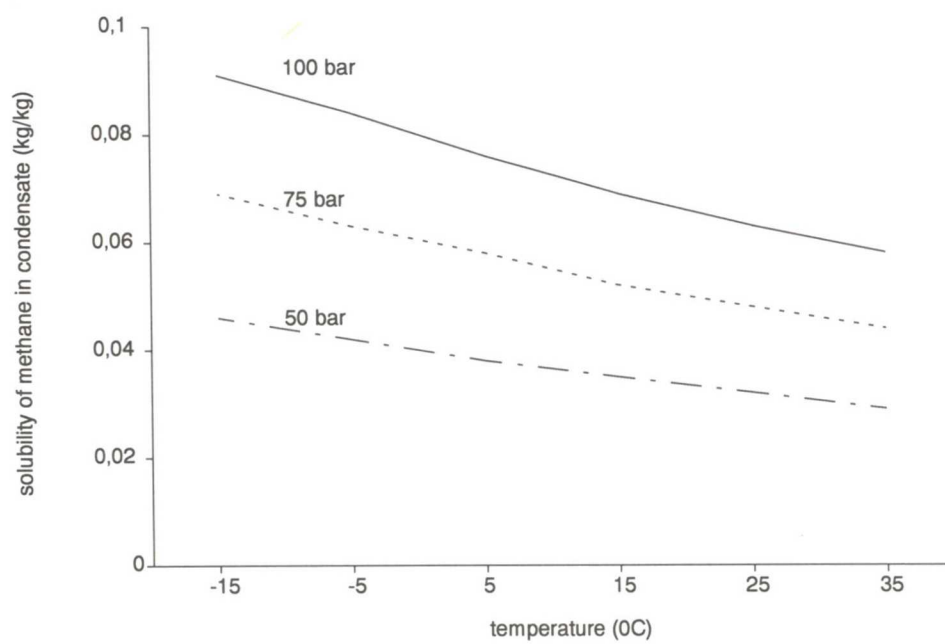
Figure 5.1 Solubility of methane in condensate
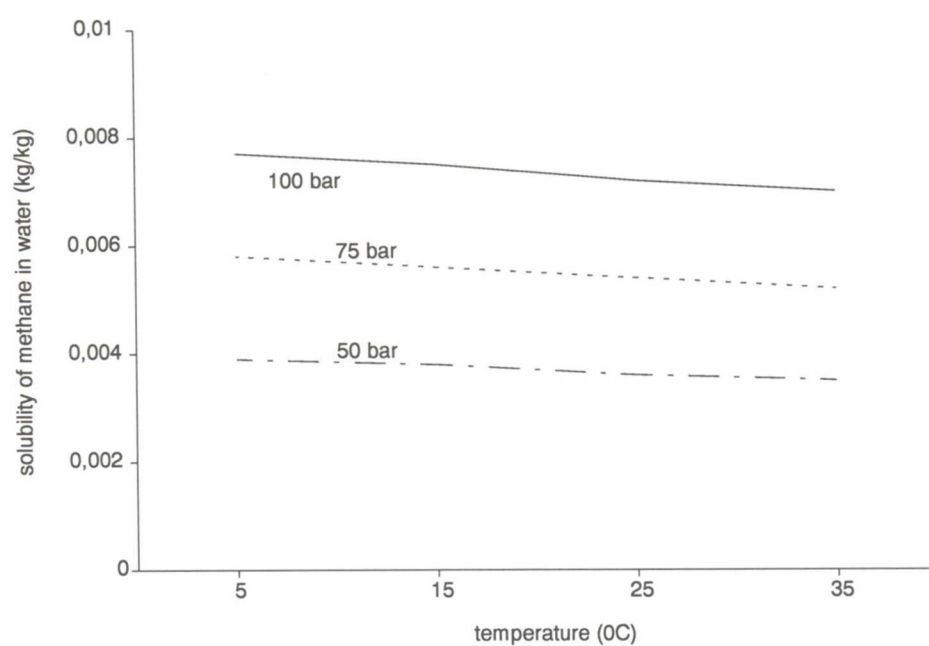
Figure 5.2 Solubility of methane in water

Table 5.3 Flare efficiencies [Bartelds, 1977]

Class[1]	Flare efficiency (%)	Unburnt hydrocarbons (%)
A	99.9	0.01
B	98	2
C	0	100

[1] - Class A are all flares, that do not belong to class B or C. In general, class A are those flares, operating at favourable meteorological conditions, flaring gases with sufficient heat load, with application of steam-injection.
   - Class B emission factors apply, when one of the following is true:
     - flare load 10% higher than the design load
     - heat content of the off-gases is between 6.000 and 10.000 kJ Nm^{-3} (about 20-30% of hydrocarbons in the gas).
     - wind-speed at the flare tip is between 20 and 40 m s^{-1} (wind-force 9 to 12 Beaufort).
     - steam injection does not work properly
   - Class C emission factors apply, when there is doubt about the efficacy of the flare and when one of the following is true:
     - heat content of the off-gases is less than 6000 kJ Nm^{-3} (less than about 20% of hydrocarbons in the gas).
     - wind-speed at the flare tip is higher than 40 m s^{-1} (wind-forces higher than 12 Beaufort).
     - pilot-flames do not work.

5.3.2 Emissions from energy generation

• *Exhaust emissions*
Although combustion characteristics are very different for e.g. different heaters and the range methane emissions is quite large, it is common practice to quantify emissions, using emission factors. Table 5.4 gives an overview of some factors, as obtained from literature.

Table 5.4 Methan emission factors of use of fuel gas

Reciprocating engines	18 g	per m^3 fuel used	US-EPA	[1993]
	6.3 g	per m^3 fuel used	Nielen	[1991]
Turbines	0.31 g	per fuel m^3 used	US-EPA	[1993]
	0.03 - 0.3 g	per fuel m^3 used[1]	Nielen	[1991]
Heaters	0.2 - 0.8 g	per fuel m^3 used[2]	Nielen	[1991]

[1] Depending in turbine load
[2] Depending on load and type of burner

- *Non-exhaust engine-emissions*

Annual emissions during shut-down and start-up of engines are calculated as the product of the number of stops and starts per year and the amount of methane released per start. An engine is typically shut-down and started-up about 12 to 24 times per year; the amount of methane released depends upon the type of engine, and is **about 15 to 200 kg per engine per start-up.**

5.3.3   Compressors

- *Seal leakages*

Seal leakages of a compressor are defined by the compressor manufacturer, and are about 1,5-5 m^3 hr^{-1} [Stork-Delaval, **1995**], which boils down to about **1 to 2,5 tonnes of methane per compressor per year.** Normally these seal losses are collected and transported to an atmospheric vent or flare system. When they are flared, the methane emissions are significantly reduced.

- *Start-up and shut down*

Annual emissions during shut-down and start-up of compressors may be calculated as the product of the number of stops and starts per year and the amount of methane released per start. An compressor is typically shut-down and started-up about 12 to 24 times per year; the amount of methane released depends upon the type of compressor, and might even be as high as **650 kg per compressor per start-up.**

5.3.4   Fugitive emissions

Chronic leaks are hard to address, since they may occur throughout the system. An accompanying problem is, that most flanges do not leak, and most emissions come from less than about 0,5% of all flanges [Countess and Browne, **1993**].

In this chapter three possible methods are described:
a. a very simple method, based on an American inventory of fugitive emissions in the system;
b. a more detailed method, based upon the use of emission factors per flange;
c. a very detailed method, based upon measurement of methane concentrations near possible fugitive sources.

Ad a)

In an analysis, performed by Tilkicioglu and Winters [**1990**], emission factors were derived for different parts in the natural gas system. The results are represented in table 5.5.

These emission factors were derived by estimating emissions from a number of representative oil and gas producing sites, assumins emission factors per flange, as described by Eaton et al. [**1980**]. Ultimately emissions were scaled down a factor four, due to technological progress. This decrease of emissions with about 75% is also affirmed by Countess and Browne [**1993**], as illustrated in table 5.6.

Table 5.5 *Methane emissions due to chronic leaks*
            [Tilkicioglu and Winters; 1990]

	Emission factor	
Gas wells	0.27	tonne yr^{-1} per well
Oil wells	0.07	tonne yr^{-1} per well
Treatment facilities	3.59	tonne yr^{-1} per facility
Storage & withdrawal	0.001	tonne per Mm^3
Gathering & transmission	0.957	tonne yr^{-1} per km pipeline

The drawbacks to this method are evident:
— the natural gas exploitation in the United States differs from the exploitation methods elsewhere, so application of these emission factors to e.g. The Netherlands results in uncertainties;
— since the emission factors described in table 6.6 are at the basis of this method, the draw-backs described at ad b) are also valid here.

Ad b)
A second method of estimating leaking amounts of methane is by estimating fugitive emissions per flange, connections, valves and so on. This is done by application of the emission factors as tabulated in 5.6. The emission factors in table 5.6 are obtained in an extensive survey, in which leakages were measured of about 200,000 connections, flanges valves, etc. in the U.S. petroleum industry.
The total emissions are finally obtained by summarizing the emissions from all these components.

Table 5.6 *Emissions factors for fugitive hydrocarbon emissions in gas services*
            (in kg y^{-1} per component)

Component	Reference Eaton et.al. [1980]	Reference Countess and Brown [1993]
Connection	2.48	0.86
Diaphragm	0.82	0.55
Valve	0.33	0.12
Other component	12.26	3.64
Mean per component	2.60	0.76

There are some major drawbacks to use of these emission factors:
— the emission factors are derived for petroleum production, at specific pressure and temperatures, probably completely differing from the circumstances in the system under study. So use of these emission factors results in uncertainties when applied to the Dutch natural gas industry;
— state of maintenance is not reckoned with, it makes no difference whether the system completely neglected or well kept. So the influence of improved control and maintenance can not be quantified in this method.

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Ad c)

Methane emissions per component may be obtained by measuring methane concentrations near the component and transforming the methane concentration into a leakage rate. There are several methods for this interpretation of concentrations. The method given by Coenen [1991], is the method, proposed by the Dutch government to assess fugitive emissions by hydrocarbons. The emission factors are described in table 5.7.

Table 5.7 Emission factors for measured values of hydrocarbons (in kg y^{-1}, per component)

Component	Measured value (in ppm)		
	0 - 1.000	1.001 - 10.000	> 10.000
Valve	1.22	14.4	395
Flanges, connections	0.18	76.6	328
Safety measures	126	2,600	14,800
Open end valves	1.14	76.7	105

Problem is, that this method is developed for hydrocarbon emissions. Application of this method to methane might lead to uncertainties.

5.3.5 Pneumatic devices

Valves and actuators in the system are sometimes natural gas-operated. This means that the hydraulic pressure of the natural gas is used to switch valves etc. The natural gas used is vented to the atmosphere.
Pneumatic devices occur all through the system, both in wells as along pipelines.

Emission factors for pneumatic systems, as tabulated in table 6.8, are given by US-EPA [1993].

Table 5.8 Methane emissions from pneumatic devices

	Emission factor	
Production	0.57 g	per m^3
Gathering & transmission	0.46 kg yr^{-1}	per m pipeline

5.4 Methane emissions due to oil production

5.4.1 Vents and flares

• *Off-gases from processes and associated gas*
Process emissions and emissions from associated gas may be calculated from material balances. This may be done, using the same simulation programmes as described in chapter 5.3.1, at process emissions in the production of natural gas. In order to assess the emissions, use and recompression of these gases have to be taken into consideration.

• *Other off-gases to flares or vents*
Emissions of methane due to use of purge gas, blanketing gas and maintenance may be calculated as described above in chapter 5.3.1.

• *Flare efficiencies*
Flare efficiencies are described in chapter 5.3.1.

5.4.2 Methane emissions due to energy generation

The way in which methane emissions from energy generation may be estimated is described above in chapter 5.3.2.

5.4.3 Methane emissions from compressors

The way in which methane emissions from compressors may be estimated is described above in chapter 5.3.2.

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6 Quantification of emissions

6.1 Activity data

6.1.1 Exploration

The number of exploration drillings and appraisal drillings in The Netherlands are presented in table 6.1.

Table 6.1 Exploration and appraisal drillings [EZ, 1991; EZ, 1994]

Year	On-shore number of drillings	Results			Off-shore number of drillings	Results		
		Oil	Gas	Both		Oil	Gas	Both
1990	13	0	6	2	35	0	14	6
1991	15	0	10	1	45	2	17	2
1992	12	0	6	2	20	0	8	0
1993	10	0	8	0	13	0	0	0

The number of well tests is unknown, but are most likely limited to about 10 per year.

The number of cleaning operations of wells is also unknown, and is limited to about 20 per year.

6.1.2 Natural gas production

The amounts of natural gas and condensate, produced in The Netherlands are presented in table 6.2.

Table 6.2 Natural gas production figures in 1990 and 1993
         [EZ, 1991; EZ, 1994]

	1990	1993
On-shore gas	54,585 million m^3	66,154 million m^3
Off-shore gas	17,856 million m^3	17,851 million m^3
Condensate[1]	588,600 m^3 (st)	764,000 m^3 (st)

[1] Condensate is a liquid, which consists of the condensable hydrocarbons
     in the natural gas. The liquid is also referred to as natural gasoline or
     natural gas liquids (NLG).

An estimation of the amounts of natural gas used for energy purposes, or flared are
presented in table 6.3. This estimate was made on basis of carbon dioxide emissions
from the sector, as obtained from Staatstoezicht op de Mijnen [1994].

Table 6.3 Energy use and amounts of natural gas flared in 1990 natural gas production
         (in million m^3)

	On-shore	Off-shore
Energy (except compressors)	90	110
Energy for compressors	15	250
Flared	150	6

An overview of equipment in the production of natural gas is given in table 6.4.

Table 6.4 Equipment in the production of natural gas in The Netherlands in 1990
         [Elzenga and Smit, 1993; EZ, 1991]

On-shore:	
Number of wells	600[1]
Number of treatment facilities	120
Off-shore:	
Satellite platforms, wellheads, risers	45
Production and integrated platforms	21
Compressor platforms	6
Length of the pipeline system (in km)	993

[1] Some of these wells were already abandoned in 1990.

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6.1.3   Production of oil

Relevant data about the production of oil are represented in the tables 6.5 to 6.7.

Table 6.5 *Production figures in 1990 and 1993 [EZ, **1991**; EZ, **1994**]*

	1990	1993
On-shore oil	1,247,900 m³ (st)	1,303,000 m³ (st)
Off-shore gas	2,744,500 m³ (st)	1,709,800 m³ (st)

Table 6.6 *Equipment in the production of oil in The Netherlands in 1990*
*[Elzenga and Smit, **1993**; EZ, **1990**]*

On-shore:	
Number of wells	626[1)
Number of treatment facilities	5
Off-shore:	
Satellite platforms, wellheads	6
Production platforms	4
Compressor platforms	6
Length of the pipeline system (in km)	993

[1)   Some of these wells were already abandoned in 1990.

Table 6.7 *Energy use and amounts of natural or associated gas flared in 1990*
oil production (in million m³) [Staatstoezicht op de mijnen, 1994])

	On-shore	Off-shore
Energy (except compressors)	37	34
Energy for compressors	20	30
Flared	58	20

6.2   Dutch methane emissions in 1990

In the tables 6.8 to 6.10 the 1990 methane emissions from exploration and exploitation of natural gas and petroleum in The Netherlands are described. This quantification is obtained by estimating emissions per company. The method which is used by these companies to estimate their emissions varies, but in general the methods that are used described in chapter 6. The companies information is gathered, validated and supplemented by Stork-Protech [**1993**].

In the exploration phase:
— emissions from well-tests and cleaning of wells are estimated, assuming the typical production and duration as described in chapter 6.1; 20 well-tests and 20 cleaning operations performed every year. As a flare efficiency 95% is assumed, which seems a worst case assumption.

Table 6.8 Methane emissions due to exploration of natural gas and oil (in ktonne)

Source	Off-shore		On-shore	
	Cont.	Discont.	Cont.	Discont.
- drilling operations		< 0.1		< 0.1
- well-tests		0.1		0.1
- cleaning of wells		0.1		0.1

With regards to the production of natural gas:
— emissions from venting of process gases, purge gases and emissions due to maintenance and process up-sets are obtained from the Stork-Protech study. Unfortunately no further information was available about the distribution between off-gases from processes and emissions due to purge gases;
— passing valve emissions are estimated, assuming the emission factor as described in chapter 6.3 valid for at least half the production of natural gas off-shore and about the whole production on-shore;
— emissions from flares are estimated from the amounts of gas flared as tabulated in 6.3, and assuming a flare efficiency of 98%. This mean value of 98% is a worst case, since flare efficiencies only drop below 98% at severe circumstances (see table 5.3);
— exhaust emissions from energy use are estimated, assuming the emission factors as given in table 5.4, the amount of natural gas used, as described in table 6.3 and assuming one third is used in engines and two thirds is used in turbines;
— non-exhaust emissions from energy and emissions from compressors are inventories by Stork-Protech;
— since pneumatic devices are not used, methane emissions from these devices are zero;
— fugitive emissions are estimated using the activity data as described in table 7,4, assuming the emission factors in table 5.5 and assuming an uncertainty of -100% to +300%.

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Table 6.9   Methane emissions due to exploitation of natural gas (in ktonne)

Source	Off-shore		On-shore	
	Cont.	Discont.	Cont.	Discont.
Emissions from vents:				
- process gases	30 - 55		6 - 11	
- purge gases				
- blanketing gases	< 0.1		< 0.1	
- passing valves	12 - 21		< 0.1	
- maintenance		6.6		0.6
- system upsets				
Emissions from flares:	< 0.1		1.5	
Emissions from energy use:				
- exhaust of gas engines	1.5		0.3	
- exhaust of gas turbines	< 0.1		< 0.1	
- non-exhaust		0.9		0.2
Compressors:				
- seal losses	1.7		0.1	
- non-exhaust		0.4		< 0.1
Pneumatic devices		0		0
Fugitive emissions:				
- wells	0 - 0.2		0 - 0.6	
- treatment	0 - 0.3		0 - 1.7	
- pipeline	0 - 3.8		0 - 0.4	
Total	45 - 83	8	8 - 16	0.8

Table 6.10   1990 methane emissions due to production of oil (in ktonne)

Source	Off-shore		On-shore	
	Cont.	Discont.	Cont.	Discont.
Emissions from vents:	7.0	0	4.7	0.2
Emissions from flares:	0.2	< 0.1	0.6	< 0.1
Emissions from energy use:				
- exhaust of gas engines	0.3		0.2	
- exhaust of gas turbines	< 0.1		< 0.1	
- non-exhaust		0.2		0.1
Compressors:				
- seal losses	0.2		< 0.1	
- non-exhaust		< 0.1		< 0.1
Fugitive emissions:				
- wells	< 0.1		max. 0.2	
Total	8	0.2	6	0.3

The 1990 emissions, as obtained in the tables 6.7 to 6.9 are summarised in table 6.11.

Table 6.11   Summary of 1990 methane emissions (in ktonne)

Source	Off-shore	On-shore	Total
Natural gas			
• continuous	45 - 83	8 - 16	53 - 99
• non-continuous	8	0.8	9
Total gas	53 - 91	9 - 17	62 - 108
Oil			
• continuous	8	6	13
• non-continuous	0.2	0.3	0.5
Total oil	8	6	14
Total continuous	53 - 91	14 - 22	67 - 113
Total non-continuous	8	1	9
Total sector	61 - 99	15 - 23	76 - 122

6.3 Dutch methane emissions in 1993

The 1990 emission estimate is extrapolated to 1993, using the amount of natural gas and oil produced as an indicator. Besides this, the effect of methane reducing measures by the industry are taken into account:
— in the on-shore gas industry all installations are equipped with flares, resulting in a significant reduction of methane emissions compared to 1990;
— in the on-shore oil industry reuse and recompression of amounts vented is further optimized;
— in the off-shore oil-industry, emissions are further reduced by the closure of elder platforms with vents, and the realisation of new platforms, equipped with flares.

The results of this extrapolation are presented in table 6.12.

Table 6.12 Summary of 1993 methane emissions (in ktonne)

Source	Off-shore	On-shore	Total
Natural gas			
• continuous	45 - 83	2.5 - 5	48 - 88
• non-continuous	8	0.2	8
Total gas	53 - 91	3 - 5	56 - 96
Oil			
• continuous	2.5 - 5	1.5	4 - 6.5
• non-continuous	0.1	0.2	0.3
Total oil	2.5 - 5	1.7	4 - 7
Total continuous	48 - 88	4 - 7	52 - 95
Total non-continuous	8	0.4	8
Total sector	56 - 96	4 - 7	60 - 103

6.4 1990-1993 emission reduction

From the quantifications of 1990 and 1993 emissions in tables 6.11 and 6.12 can be seen that an emission reduction is accomplished of about 16 to 21% of the 1990 emission level (16 -19 ktonne). About half of this amount is mitigated by minimising on-shore venting. Almost 20% of this amount is the result of optimizing on-shore oil producing processes; another 20% is the result of reduced venting of associated gas in the oil-production off-shore. The remaining 10% is a result of decreased activities in oil-production off-shore.

6.5 Other Dutch emissions from the natural gas system

6.5.1 Emissions from transport

Natural gas in The Netherlands is sold to Gasunie. Gasunie blends the natural gas in order to obtain a constant quality, and transports the gas to the distributing companies. Besides that Gasunie sells natural gas directly to the 400 largest gas consumers in The Netherlands. About half of the gas is exported.
In order to do this, Gasunie has a 11,500 km pipeline system, including 75 metering stations and 1100 city gate stations. The inlet pressure is 66,5 bar; the outlet pressure is 8 bar. In order to facilitate transport 10 compressor stations are operated by Gasunie.

The emissions from the Gasunie transport system are inventoried by Coors et al. [1993], and are tabulated in 6.5.

Table 6.13   1989 methane emissions due to transport of natural gas [Coors, 1993]

Source	Emission (million m³)	Emission (ktonne)
Compressor stations	5.3	
LNG-storage	2.1	
Metering units	2.9	
Pipelines	0.7	
Total	11.0	6.5

At this moment Gasunie is taking measures in order to reduce their emissions. Examples of measures that are implemented are:
— reducing the flushing of compressors before start-up;
— prevention of use of natural gas to start-up gas-turbines. Instead of this turbines are equipped with electric starting engines;
— modification of the drain-system of scrubbers and cyclone filters, by using non-bleeding level controllers;
— shift from gas-engines to gas-turbines, with relative less methane exhaust emissions;
— improving control and maintenance of the pipeline system;
— recompression of gas instead of venting, when the pressure is relieved from parts of the system.

6.5.2 Emissions from distribution

Households and smaller companies are provided with natural gas by the energy distribution companies. These companies exploit low pressure distribution

networks with a total length of about 93,000 km. Piping materials used are PVC (50%); PE (10%); steal (20%) nodular cast iron (5%) and grey cast iron (15%).

Leakages in the distribution network result in emissions. Natural gas losses during distribution are currently estimated as 0,4 to 0,5% of the amount of natural gas distributed [Pistorius, **1995**]. This estimate is based upon use of emission factors, as obtained by British Gas [**1993**].

Experiences of Dutch natural gas distributing companies, concerning the number of leakages encountered during routine control of pipelines and the size of an average leakage, indicate that these emission factors apply. The resulting estimate is about 50% accurate.

At this moment further research is performed by GASTEC, for making a more accurate estimate of emissions from distribution.

In 1990 21,000 million m³ was distributed. Assuming the emission factor as described above, methane emissions from distribution are calculated to be 56 ktonne (ranges 28-84 ktonne).

6.5.3   Emissions due to end-use

Emissions of methane during the end-use of natural gas are the result of incomplete combustion. 1990 emissions are estimated, based on the method, described by Nielen [**1991**]. The results are depicted in table 6.4. According to Nielen, the overall estimate is accurate to about 30%.

Table 6.14   Dutch methane emissions due to use of natural gas in 1990

Source	Consumption (million m³)	Emission (ktonne)
Energy companies	8,700	0.5
Industry	13,600	5.5
Households	10,400	10.4
Others (greenhouses, offices)	8,400	7.0
Total	41,000	23.4 (15 - 32)

7 Concentration measurements

7.1 Introduction

Within the NRP (National Research Program), methane has been measured, in addition to a number of other components and meteorological variables, at Kollumerwaard, located near Lauwersmeer on the border of Groningen and Friesland. Since the beginning of the measurements in July 1991, several times increased methane concentrations (up to 12 ppm) were observed which could not be ascribed to measurement failures. These high methane concentrations are used to study possible CH_4 sources in the neighbourhood of Kollumerwaard.

Because of the location of the Kollumerwaard measurement point, the effect of continuous emissions of CH_4 sources on the methane concentrations will be limited. To identify this effect, a distinction must be made between background levels and concentration levels, which are determined by local emissions. Combination of the measured trace gases at the site with the measured meteorological parameters will provide information about possible CH_4 source area's (Vosbeek, 1993a; 1994b).

Incidental emissions of a relative large size can be detected more easily. Such incidents result in a clear peak in the methane concentration. In conjunction with meteorological data an approximation can be given of the area of origin.

As a supplement to the stationary measurements in Kollumerwaard, a few campaigns were carried out to measure the distribution of the methane concentration. These measurements will provide information about the homogeneity of the CH_4 concentration in the northern part of The Netherlands, the emissions size of individual sources and the ratio of the CH_4 concentration to the values measured in Kollumerwaard.

In this chapter the results of the methane concentration measurements will be presented, first the stationary measurements in Kollumerwaard and then the mobile measurements in the north of The Netherlands. By using a dispersion model a link can be made between measured concentrations and emissions. This chapter will also present the results of these model calculations. In 1993 a preparatory study has been performed [Vosbeek, **1993a**] focused on a dispersion model called STACKS, developed by KEMA [Erbrink, **1992a**; Erbrink, **1992b**; Tieben, **1993**]. STACKS is the abbreviation for Short Term Air-pollutant Concentrations: KEMA modelling System. Application of this model will provide a quantification for incidental methane emissions.

7.2 Measurements

7.2.1 Stationary measurements

Since July 1991 in Kollumerwaard (figure 7.1), a couple of trace gases in the air are continuously measured. KEMA performs measurements for carbon dioxide (CO_2), methane (CH_4) and carbon monoxide (CO). Apart from measuring these trace gases, measurements are performed of several meteorological parameters, for example wind direction, wind speed, air pressure, temperature, global radiation and relative humidity.

Figure 7.1 Map showing the site of the Kollumerwaard station in northern Netherlands

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Measurement method

The concentration measurements in Kollumerwaard of the trace gases CH_4, CO_2 and CO in ambient air are performed continuously at 15 minutes intervals. Using the multi component capabilities of gas chromatography (GC) as an analytical technique, three real time comparable time series of concentrations are produced. The air inlet is at about 10 m above the ground (which is at sea level). There are several Quality Control and Quality Assurance procedures performed: every three hours (injection of standard gas mixtures), daily (modem communication), monthly (control of system parameters), semiannually (validation of control and calibration gas mixtures) and occasionally (participation in round robin tests). The inaccuracy of the measurements is less than 1%. This is confirmed by round robin tests, KEMA participates in with other institutes.

Measurements

The average methane concentration in Kollumerwaard is between 1,8 ppm and 2,0 ppm depending on season and wind direction [Vosbeek, **1994a**]. The measured concentrations at Kollumerwaard are somewhat higher then those observed by Khalil and Rasmussen (1994). The CH_4 concentration measurements by Khalil and Rasmussen are performed at sites with no dominant anthropogenic influences like Mauna Loa (Hawaii). Kollumerwaard is situated at the European continent and can therefore not be characterized as a background location. The site is characterized as a coastal site by Beck and Grennfelt [**1994**]. This means the site receives relatively clean air when the wind is directed from the sea towards land. Burdening of the measurement site with a variety of CH_4-sources at the European continent (for example landfills, ruminants, natural gas distribution networks, and also oil and natural gas production) contributes to a systematic increase of the global background concentration of methane in Kollumerwaard.

The dependency of the methane concentration with respect to the wind direction is presented in figure 7.2. This figure shows the wind direction dependency for Kollumerwaard as well as for Arnhem. Arnhem is also a site where stationary methane measurements are performed by KEMA. Wind sectors of 10 degrees are used to identify local sources. Arnhem and Kollumerwaard both show high concentrations in the south-east and low concentrations in the north-west. Concentrations are higher in Arnhem then in Kollumerwaard due to more anthropogenic sources (like the city of Arnhem).

Winddistributie
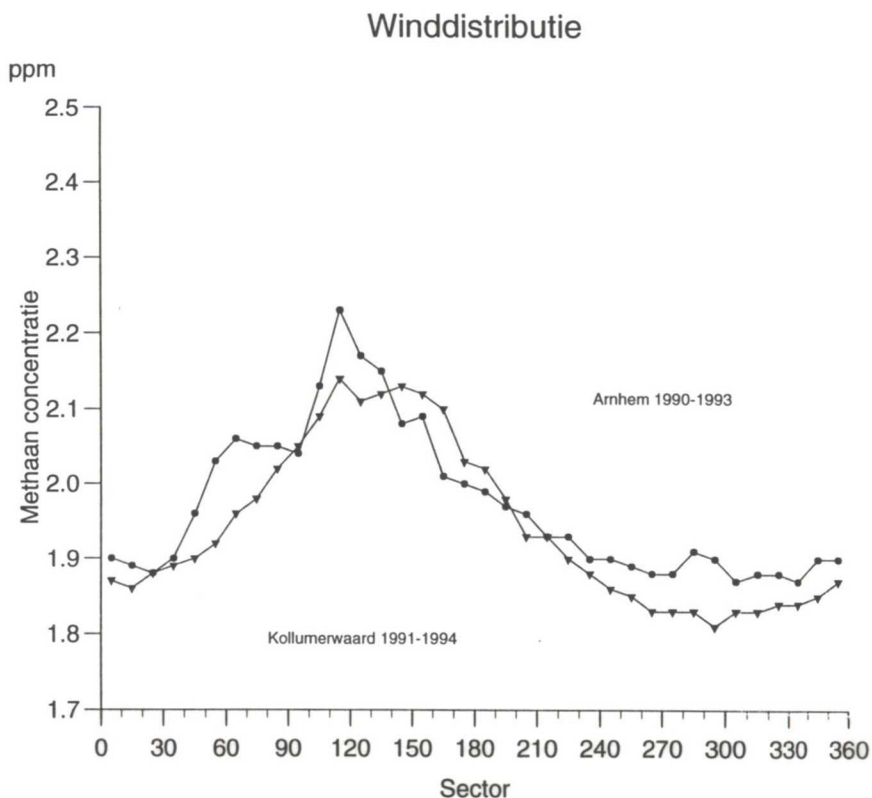
Figure 7.2 Wind direction dependency of methane concentrations in Arnhem and
Kollumerwaard

The measurements in Kollumerwaard show incidental high methane concentrations.
Figure 7.3 shows examples of incidental increases of the methane concentration in
1991, 1992 and 1993. The word 'incidental' already implies the small time scale at
which these events take place. Generally these very short extreme increases in the
methane concentration occur in less than 1% of the measurements which are
performed continuously at 15 minutes intervals. Depending on wind direction this
can vary between 0% in the north-west to north direction and 3% in the east to south-
west direction [Vosbeek, **1993b**].

There are several possible reasons for the observed incidental high methane
concentrations superimposed on the daily mean concentration at Kollumerwaard.
High methane concentrations observed during night time hours can be caused by
meteorological circumstances (inefficient mixing in the atmosphere, decreasing high
of the boundary layer in the evening results in increasing concentrations). However
these meteorological circumstances will not give rise to methane concentration
increases of more than 1 ppm. High methane concentrations observed during the day
are most likely the result of incidental emissions of a large CH_4 source, relatively close
to the measurement site. The nature of the most important CH_4 sources in The
Netherlands (landfills, ruminants, wetlands and continuous emissions in the oil and
gas industry) will 'only' give rise to a systematic increase of the CH_4 concentration.
Incidental emissions, will probably only occur in the oil and gas industry. This can be

the result of accidents and maintenance activities. Furthermore, the northern part of The Netherlands is powdered with natural gas exploration and exploitation sites. Therefore, it is plausible to consider incidental emissions during the production of natural gas as the major source of the observed incidental high methane concentrations in Kollumerwaard.
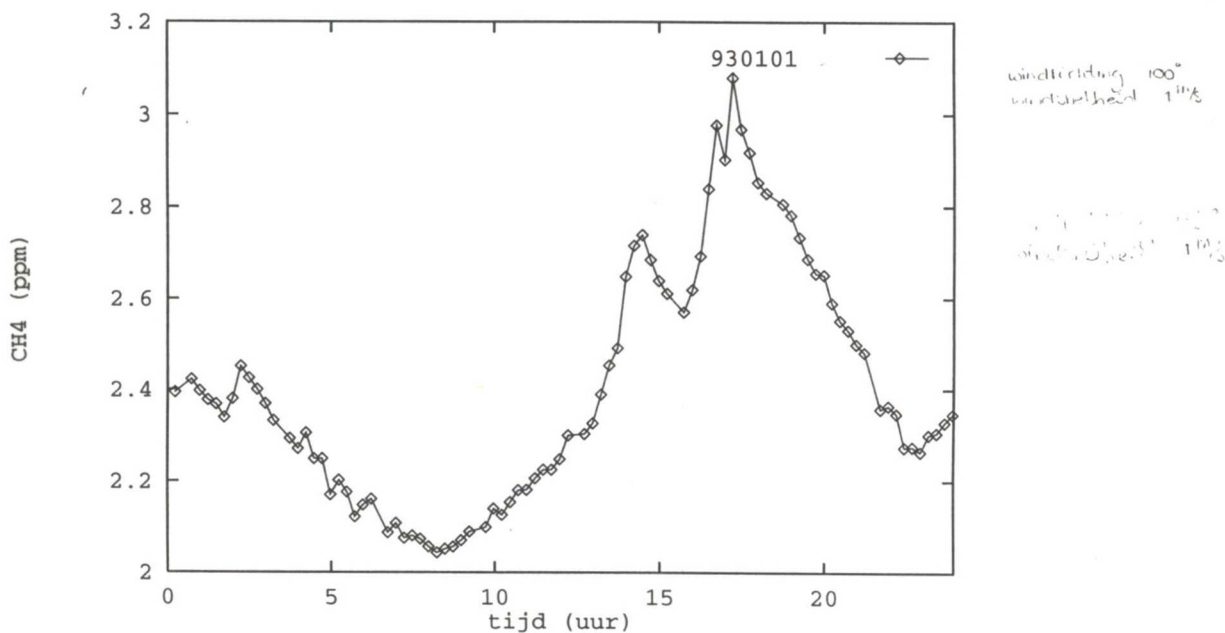
Figure 7.3 Examples of daily profiles of methane in 1991, 1992 and 1993.

Table 7.1 Dates with increased methane concentrations at Kollumerwaard
(CH₄ concentrations of 3 ppm or higher)

1991[1]	1992	1993	1994[2]
10-07-1991	05-03-1992	01-01-1993	03-02-1994
02-08-1991	08-03-1992	05-03-1993	07-04-1994
03-08-1991	04-05-1992	12-03-1993	19-04-1994
04-08-1991	21-05-1992	13-03-1993	24-04-1994
05-08-1991	24-05-1992	14-03-1993	10-05-1994
21-08-1991	14-06-1992	15-03-1993	
13-09-1991	30-06-1992	04-04-1993	
16-09-1991	08-07-1992	22-04-1993	
19-09-1991	09-07-1992	22-04-1993	
21-09-1991	17-07-1992	11-05-1993	
10-10-1991	29-07-1992	21-05-1993	
27-11-1991	07-08-1992	07-07-1993	
28-11-1991	20-08-1992	18-07-1993	
29-11-1991	24-09-1992	28-07-1993	
30-11-1991	10-12-1992	04-08-1993	
08-12-1991		12-08-1993	
09-12-1991		15-08-1993	
22-12-1991		18-08-1993	
31-12-1991		31-08-1993	
		12-09-1993	
		15-09-1993	
		23-09-1993	
		20-10-1993	
		01-11-1993	
		04-11-1993	
		12-11-1993	
		23-11-1993	
		01-12-1993	
		02-12-1993	

[1] Measurements since July 1991
[2] For 1994 data were available until June 3, 1994

Table 7.1 shows an overview of days with increased methane concentrations measured at Kollumerwaard (absolute concentrations of 3 ppm or higher). The point of times at which these concentration increases were observed are presented in paragraph 7.3 (table 7.4 for 1991; table 7.5 for 1992; table 7.6 for 1993).

7.2.2   Mobile measurements

A way of gaining additional information about the distribution of methane concentrations in the Groningen gas production area, is by performing a mobile measurement campaign. Furthermore, mobile measurements can play a role in the quantification of incidental emissions. In the preparatory study in 1993 [Vosbeek, 1993a] it was investigated what the boundary conditions are for the mobile measurement campaigns. Besides this, possible measurement equipment was studied. This preparatory study learned that for a success full mobile measurement

campaign foreknowledge of activities in the natural gas production area is essential. Without knowledge of exploration and exploitation activities and, therefore, of possible emissions, even mobile measurements are not able to measure elevated concentrations.

Several attempts have been made to obtain cooperation and thus information from the oil and gas industry. Consultation with the Dutch State Supervision on Mines (Staatstoezicht op de Mijnen (STOdM)) delivered information on drilling activities performed in the period July 1991 till August 1994. This information is presented in table 7.2. This information was however not available when the first mobile measurement campaign started. Table 7.2 only contains drilling sites, located within a radius of about 40 kilometres from Kollumerwaard [KEMA, **1994a**]. Furthermore table 7.2 also shows the type of drilling performed. When an exploration drilling starts, it is not clear whether gas will be found. An appraisal drilling affirms the presence of natural gas. Deviation drillings are performed when the production of natural gas is started.

Measurement method
The mobile measurements were performed by using a photo acoustic spectrometer of Bruel & Kjaer [Verhage *et al.*, **1992**; Vosbeek, **1993a**]. The accuracy of the spectrometer is not very high (0,1 ppm), but it is possible to measure methane background concentrations (1,8 ppm - 2,0 ppm). The detection limit of the photo acoustic spectrometer is 300 ppb.

As was already mentioned the information in table 7.2 was not available when the first mobile measurement campaign started. Information about the location of natural gas production sites was therefore obtained from the Dutch Topographical Atlas (1987). These locations were consolidated with information of the Dutch Photographic Service in Emmen. This service receives every year a new photographic update of The Netherlands. Several photographs have been studied to consolidate the locations found in the Topographical Atlas. The locations of the production sites were still the same, there was however no time to identify possible new sites (after 1987).

During the campaigns it was agreed upon measuring only production sites with burning flares. The fact that a flare is burning indicates towards production activities, since a flare is often used as a kind of a pilot-flame.

Table 7.2 Overview of on-shore drillings performed since June 1991
            (within a radius of about 40-50 kilometres of Kollumerwaard)

Location	Type	Period
Noordbroek-6	deviation	01-06-1991 / 04-08-1991
Kollumerland-2	exploration	25-06-1991 / 25-09-1991
Marum-3	appraisal	08-08-1991 / 01-10-1991
Surhuisterveen-1	exploration	03-10-1991 / 12-11-1991
Pasop-1	exploration	03-10-1991 / 12-12-1991
Dongjum-1	exploration	07-11-1991 / 20-01-1992
Ameland-oost (203)	deviation	14-11-1991 / 10-03-1992
Beerta-1	exploration	28-11-1991 / 01-02-1992
De Vries-1	deviation	08-01-1992/ ..-..-..
Harlingen-1	deviation	30-01-1992 / 20-02-1992
Vlagtwedde-3	....	13-02-1992 / ..-..-..
Grijpskerk-2	appraisal	01-03-1992 / 10-05-1992
Ameland-westgat	....	02-04-1992 / 11-06-1992
Ameland-oost (204)	....	08-06-1992 / 30-10-1992
Munnekezijl-1	exploration	25-06-1992 / 29-09-1992
De Pauwen-1	deviation	30-07-1992 / 05-10-1992
Anjum-1	exploration	01-10-1992 / 21-12-1992
Ameland-oost (203)	....	30-10-1992 / 17-12-1992
Terschelling-1	exploration	25-10-1992 / 04-12-1992
Ameland-westgat	....	24-12-1992 / 05-01-1993
Ureterp-202	deviation	31-12-1992 / 08-02-1993
Terschelling-2	exploration	31-12-1992 / 04-03-1993
Zevenhuizen-2	exploration	08-02-1993 / 24-03-1993
Pietersbierum-1	exploration	19-05-1993 / 08-07-1993
Saaksum-1	exploration	15-07-1993 / 14-09-1993
Vierhuizen-1	exploration	23-09-1993 / 10-04-1994
Harlingen-8	deviation	04-11-1993 / 04-12-1993
Oosterwolde-1	exploration	04-11-1993 / 31-12-1993
Nieuwe Schans	exploration	18-11-1993 / ..-..-..
Uiterburen-1b	deviation	13-11-1993 / 19-12-1993
Grijpskerk-3	appraisal	22-12-1993 / 23-04-1994
Engwierum-1	exploration	24-03-1994 / 05-06-1994
Anjum-2	exploration	21-04-1994 / drilling
Munnekezijl-2	deviation	29-04-1994 / completion

Campaign 28-06-1994
West from Veendam three natural gas production sites are situated. At all three the sites triple measurements were performed, first upwind and then downwind. The meteorological conditions for this day were sunny, with a weak south-east wind (3 m/s). In Veendam two sites had a burning flare, at the third site the flare was out. The measured concentrations at all three the sites did not differ significantly from background concentrations (Appendix A, page 1).

In the neighbourhood of Hoogezand at least 15 production sites are situated, however only few sites had burning flares. At two sites measurements were performed and again no differences were measured with respect to background concentrations (Appendix A, page 2).

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In the surroundings of Midwolde two natural gas production sites are located, but at only one a burning flare was observed. At this location measurements were performed but again with the same conclusion as at the other sites: no increased concentration levels of methane with respect to background concentrations (Appendix A, page 2).

Campaign 19-07-1994
The first measurement campaign learned that in the area of production sites similar CH_4 concentrations are measured as are measured at Kollumerwaard. Thus confirming the homogeneity of the CH_4 concentration in that particular area. Before a new measurement campaign was carried out information was obtained from STOdM concerning the drilling activities performed at that moment in the north of The Netherlands. Very close to the measuring site of Kollumerwaard two drilling activities were executed: in Munnekezijl and in Anjum. At both locations concentration measurements were carried out and the Kollumerwaard site was also measured twice.

Weather conditions were fair: sunny, clear weather at the beginning of the day and in the course of the day somewhat cloudier. Wind came from the north-east (5 m/s). During this campaign methane concentrations were measured similar for the drilling sites and the Kollumerwaard site. No indication of incidental emissions of CH_4 was found.

Campaign 26-07-1994
For the beginning of the third campaign again the Dutch State Supervision on Mines was consulted. The drilling at Anjum and Munnekezijl were still active and at the time a work-over (maintenance activities) took place at 't Zandt. The plan for this campaign was a visit to some of the production sites already visited in the first campaign, then a visit to the drilling sites of the second campaign and finally a visit to the work-over at 't Zandt.

The weather conditions were again sunny, the wind direction in Veendam, Scheemda and 't Zandt was stable south-west, with wind speeds of 3 to 5 m/s. During the measurements at Anjum and Munnekezijl there was almost no wind.

In Kollumerwaard the daily average concentration during this campaign was 1,9 ppm. The production sites as well as the drilling sites as the work over in 't Zandt showed no relevant increased CH_4 concentrations with respect to the concentration measured at Kollumerwaard.

Conclusion
The additional mobile measurements indicated that the methane concentrations in the north of The Netherlands are rather homogenous. Continuous emissions are probably to low to be detected. The detection limit of the Photo Acoustic spectrometer (300 ppb) already indicates this. Continues emissions like leakages from the used systems are better estimated with the use of an engineering study in stead of mobile measurements. Furthermore few information is gained about the emission size of the individual sources. Under normal circumstances (no maintenance or accidents) it is not possible to measure elevations of the methane concentration at production sites or at drilling sites of natural gas. The mobile measurements could have played an important role in the quantification of incidental emissions, 'unfortunately' they did nor occur during the planned measurement campaigns.

7.3   Model calculations

7.3.1   Introduction

By using a dispersion model a link can be made between measured concentrations and emissions. In 1993 a preparatory study was performed to give an overview of the dispersion model STACKS (Short Term Air-pollutant Concentrations: KEMA modelling System). This model was chosen to interpret the high 'peak' CH_4 concentrations observed in Kollumerwaard, with help of the measured methane concentrations in Kollumerwaard. Since the performed preparatory study STACKS has changed somewhat (KEMA, 1994b). For the calculations in this report STACKS version 2.2 was used.

In this paragraph model STACKS will be described briefly. For more details is referred to the publications of Erbrink [**1989, 1991, 1992a, 1992b, 1994**]. After the model description the results of the model calculations will be presented. First for known drilling locations and secondly for production (exploitation) sites.

7.3.2   STACKS

The contribution of industrial emissions from tall stacks to the air pollution levels is generally calculated with <u>dispersion models</u>. Models that are widely used include both the so-called *traditional* models and the *advanced* models. Traditional models make use of concepts, developed in the sixties and seventies and concentrate e.g. around the Pasquill stability classification and classified dispersion curves. Advanced models on the contrary make use of more recently developed concepts in which the atmosphere is described in a physically better way and in which dispersion is described as continuous functions of relevant meteorological parameters. Traditional models are e.g. the Dutch National Model (DNM). Advanced models are e.g. the model STACKS. STACKS has been developed by KEMA and is selected as the reference model to up-date the DNM. STACKS was developed to calculate the dispersion and deposition of air pollution from point sources (stacks). STACKS is able to simulate dispersion both short-term and long-term. The application of the model is limited to a radius of 40 kilometres from the source. Within this range wind and turbulence are considered constant.

STACKS is an advanced (Gaussian, see also figure 7.4) model in which the horizontal and vertical dispersion parameters are not derived from stability classes like in traditional models, but the dispersion parameters are a function of the measured turbulence parameters. The model needs turbulence parameters to describe the horizontal and vertical dispersion. These turbulence parameters are conducted from measurements of wind speed and wind direction at a height of 10 metres. A long time series of hourly mean values of the relevant meteorological parameters is thus used as input for the model. Hence, the model calculates basically hourly averaged concentrations.

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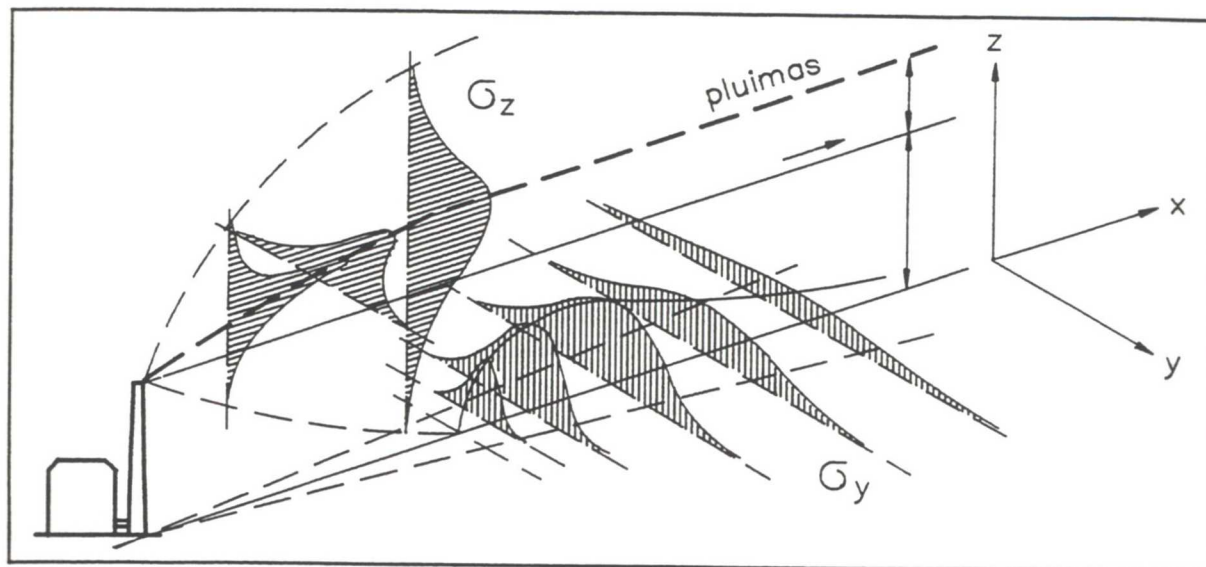
Figure 7.4 Gaussian dispersion model, with σ_y and σ_z the horizontal and vertical dispersion parameters.

The atmosphere in the model is described in layers of 100 metres up to a height of 1000 metres, in which both temperature as wind profile are given. Temperature and wind profile can be derived from balloon soundings. At Kollumerwaard these soundings are not available and therefore temperature and wind profile at Kollumerwaard are derived from wind speed, radiation and surface roughness length. With this information the growth of the boundary layer can be determined.

For the estimation of CH_4 emissions from natural gas exploration or exploitation activities the short-term model is used. In this version of the model no information of the boundary layer is necessary. The model then gives an approximation for wind and temperature profile.

Input parameters
Some input parameters have a direct influence on the calculated concentrations. In the study performed in 1993 [Vosbeek, **1993a**] this influence has been studied. The most important source parameters are:
— source strength;
— source position;
— emission height;
— surface roughness length (urban or rural area).

Furthermore the meteorological parameters also influence the concentrations:
— wind speed;
— wind direction;
— turbulence parameters.

The turbulence parameters provide information about the state of the atmosphere: stable, neutral or unstable and thus about the degree of dispersion.

Calculations

The dispersion of a certain amount of methane emitted by an imaginary methane source can be simulated by STACKS. The calculated hourly averaged methane concentrations in a certain grid point can be stored as a function of time. The calculated concentrations can then be compared with the measured concentrations for the day for which the meteorological data served as input variables. Comparison of calculated and measured concentrations will give an estimation of the strength of the possible responsible methane source. In this way all the in table 7.1 presented data with increased methane concentrations can be simulated and for each of these data a possible source strength can be estimated. The estimation of the source strength is strongly dependent on the distance from source to receptor point. Increasing distance of the source to the receptor point results in a quadratic decrease of the measured concentration at the receptor point.

The location of the drilling sites presented in table 7.2, and the period in which these drillings were performed were compared with the data when concentration peaks were observed in Kollumerwaard (table 7.1). Furthermore production sites may also be responsible for methane emissions observed in Kollumerwaard and therefore can also act as a methane source. For accurate calculations the source location in the model has to be within a radius of 40 kilometres of the receptor point [Vosbeek, **1993a**].

When variations in wind direction are to large or when the wind speed is smaller than 1 m/s, the model does not calculate hourly averaged concentrations.

7.3.3 Interpretation of peaks

Methodology

First of all, all possible CH_4 sources must be selected. For this purpose as a possible source was considered, every drilling or production location, located wind ward plus or minus 15 degrees of the major wind direction during an observed peak, at a maximum distance of 40 kilometre from Kollumerwaard. Secondly a relation must be found between days with observed methane peaks and periods of activity at the selected sources (schematically this is presented in Appendix B). After this for every possible source, the source strength was calculated by trial and error using model STACKS, assuming an emission duration of 1 hour (a larger emission duration will result in higher estimates).

Problems

There is a problem when the situation occurs that the axis of the plume is not in one line with the measurement site, due to the wind, and that the measurement site only measures the much lower concentration in one of the boundaries of the plume. The model misinterprets the concentration at the measurement site as the concentration in the axis of the plume. A small concentration registered in the receptor point can therefore result in an overestimation of the source strength. To anticipate this over-estimation of the emission strength an upper limit was put at 60.000 kilogram. This is 0,1% of the by NAM reported methane emission for 1991. Table 7.4 shows the emission estimates for the drilling sites of 1991.

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7.3.4   Model calculations for drilling sites

For the year 1991 combinations of possible CH_4 sources with CH_4 peaks are given (table 7.3). Drilling site Beerta is situated too far away from Kollumerwaard and therefore no calculations were performed for this site. For 1992, 1993 and 1994 fewer combinations were found. For 1992 only three days were found. For 1993 six days and for 1994 only one day.

1991
In 1991 about 20 combinations could be made of possible CH_4 sources with CH_4 peaks. Drilling sites in 1991 that could possibly be responsible for the increased methane concentrations observed in Kollumerwaard are Marum, Surhuisterveen, Kollumerland and Pasop. Beerta is not taken into account because of the distance with respect to the Kollumerwaard site.

Table 7.3 Combination of days with methane peaks and drilling sites for 1991

Peak dates	Drilling sites	Distance/Direction
02-08-1991	Marum	20 km/185 degrees
	Surhuisterveen	18 km/210 degrees
03-08-1991	Surhuisterveen	18 km/210 degrees
	Kollumerland	10 km/220 degrees
05-08-1991	Marum	20 km/185 degrees
	Surhuisterveen	18 km/210 degrees
21-08-1991	Marum	20 km/185 degrees
	Surhuisterveen	18 km/210 degrees
16-09-1991	Marum	20 km/185 degrees
	Surhuisterveen	18 km/210 degrees
	Kollumerland	10 km/220 degrees
19-09-1991	Marum	20 km/185 degrees
	Surhuisterveen	18 km/210 degrees
	Kollumerland	10 km/220 degrees
21-09-1991	Marum	20 km/185 degrees
27-11-1991	Beerta	55 km/105 degrees
	Pasop	15 km/160 degrees
28-11-1991	Pasop	15 km/160 degrees
29-11-1991	Beerta	55 km/105 degrees
30-11-1991	Beerta	55 km/105 degrees
08-12-1991	Pasop	15 km/160 degrees
09-12-1991	Pasop	15 km/160 degrees
31-12-1991	Pasop	15 km/160 degrees

Table 7.4 Methane emission estimate for drilling sites for 1991 (kg)

Date	Concentration increase	Locations	Emissions (kg)[3]
02-08-1991[1]	18.00 h: 1300 ppb	-	-
03-08-1991[1]	00.00 h: 1200 ppb	-	-
05-08-1991	01.00 h: 1300 ppb	Marum	7,560
		Surhuisterveen	> 60,000
21-08-1991	00.00 h: 1000 ppb	Marum	52,200
		Surhuisterveen	-
	05.00 h: 900 ppb	Marum	-
		Surhuisterveen	-
16-09-1991	01.00 h: 900 ppb	Marum	-
		Surhuisterveen	4,680
		Kollumerland	20,160
	03.00 h: 1200 ppb	Marum	> 60,000
		Surhuisterveen	8,280
		Kollumerland	16,920
19-09-1991	06.00 h: 800 ppb	Marum	18,720
		Surhuisterveen	18,720
		Kollumerland	-
	23.00 h: 1200 ppb	Marum	> 60,000
		Surhuisterveen	10,800
		Kollumerland	-
21-09-1991[1]	04.00 h: 1500 ppb	Marum	-
27-11-1991	17.00 h: 1000 ppb	Pasop	-
	20.00 h: 1400 ppb	Pasop	15,120
	22.00 h: 1500 ppb	Pasop	-
28-11-1991	00.00 h: 1100 ppb	Pasop	> 60,000
29-11-1991[2]	20.00 h: 5600 ppb	-	-
30-11-1991[2]	00.00 h: 2200 ppb	-	-
08-12-1991[1]	21.00 h: 1100 ppb	-	-
09-12-1991[1]	02.00 h: 1200 ppb	-	-
	07.00 h: 800 ppb	Pasop	-
31-12-1991	06.00 h: 1400 ppb	Pasop	32,400
	10.00 h: 1700 ppb	Pasop	2,800
	12.00 h: 1200 ppb	Pasop	> 60,000
Average emission factor F [kg/h][4]			30,000

[1] There is insufficient meteorological information to give an estimate for the emission strength
[2] Location Beerta is situated more than 40 km from Kollumerwaard
[3] Location Beerta is situated more than 40 km from Kollumerwaard
[4] Emission factor F is the average of the 17 calculated emission estimates in this table

1992

At March 8, 1992 the observed CH_4 peak, took place during drilling activities at Grijpskerk. At the other days the observed methane concentrations peaks could not be linked with drilling activities These peaks are possibly due to emissions from abandoned drilling sites. Although according to paragraph 4.3.6 permanently abandoned wells are no source of CH_4 emissions, calculations were made for abandoned drilling sites when located within a radius of 40 km from the measurement site. This might result in an overestimation. Possible locations in 1992 are: Grijpskerk, Marum, Surhuisterveen, Pasop, Munnekezijl and Kollumerland.

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Table 7.5 *Source emission estimate for 1992 for drilling sites (kg)*

Date	Concentration increase	Locations	Emissions (kg)[3]
08-03-1992	14.00 h: 1300 ppb	Grijpskerk[1]	> 60,000
		Marum	> 60,000
		Surhuisterveen	52,560
	15.00 h: 1100 ppb	Grijpskerk[1]	-
		Marum	> 60,000
		Grijpskerk	15,840
04-05-1992[2]	04.00 h: 1200 ppb	-	-
14-06-1992[2]	04.00 h: 1200 ppb	-	-
08-07-1992[2]	19.00 h: 2000 ppb	-	-
17-07-1992	22.00 h: 1000 ppb	-	-
	01.00 h: 1100 ppb	Grijpskerk	48,240
		Marum	-
		Pasop	2,160
	05.00 h: 700 ppb	Grijpskerk	5,760
		Marum	2,520
07-08-1992[2]		Pasop	> 60,000
10-12-1992	04.00 h: 1400 ppb	-	-
	19.00 h: 1500 ppb	Munnekezijl	864
		Kollumerland	> 60,000
		Surhuisterveen	25,200
Average emission factor F [kg/h][4]			35,000

[1] These are sites where drilling activities took place at the time of the observed concentration increases. The other sites were already abandoned at the time of the observed methane concentration increase.
[2] During these days no adequate meteorological information was available
[3] For the calculations an emission duration of one hour was used
[4] Emission factor F is the average of the 13 emission estimates in this table

1993
In 1993 meteorological data were only available for a limited period, calculations were performed only for the event of January 1, 1993. However, for this date no location was found with active drilling activities during the observed methane increase. Actually there is one abandoned drilling pit (de Pauwen) found that could be responsible for the measured increase in methane.

1994
For the observed methane increase on April 7, 1994 as a possible drilling site Grijpskerk was found. However for 1994 applies the same as for 1993: there are insufficient meteorological data available to perform the calculations.

Table 7.6 Methane emission estimate for a drilling site in 1993 (kg)

Date	Concentration increase	Locations	Emissions (kg)[2]
01-01-1993	17.00 h: 1100 ppb	de Pauwen[1]	> 60,000
Average emission factor F [kg/h]			60,000

[1] This site was already abandoned when the increase in methane was observed
[2] For the calculations an emission duration of one hour was used

7.3.5   Model calculations for natural gas production sites

Apart from drilling sites, production sites of natural gas may also be responsible for incidental emissions of methane. Most gas production sites are situated in the north-east part of The Netherlands. The sites located within a radius of 40 kilometres from Kollumerwaard were studied more closely. Seven sites were found (one production site can in this case also be a cluster of production sites, for example Slochteren). The location of these sites were all studied with respect to the wind direction during observed increases in the methane concentration in Kollumerwaard. During the period July 1991 until January 1993 ten methane peaks were found, which were possibly caused by several natural gas production sites. For these ten days emission estimates were calculated as described in paragraph 7.3.3.

1991
The production sites in 1991 that could possibly be responsible for the increased concentration for methane in Kollumerwaard are: Slochteren, Heidenschap, Ten Post, 't Zandt and the neighbourhood of Schildmeer. Table 7.7 shows the emission estimates for 1991 for the production sites.

1992
For 1992 possible production sites contributing to increased methane concentrations are: Slochteren (S), Heidenschap (H), de Pauwen, Ten Post, neighbourhood of Schildmeer, neighbourhood of Emma Polder, 't Zandt and Zeerijp. Unfortunately three days do not have the required meteorological data. On March 5, 1992 the model gives no increases of the concentration at the time of the observed methane peaks. Only for one day emission estimates were made for two separate locations. Table 7.8 shows emission estimates for 1992 for natural gas production sites.

1993
Again only calculations were performed for January 1, 1993. Six production sites could be marked as possible source of the methane peak for that day. Table 7.9 shows emission estimates for 1993 production sites of natural gas.

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Table 7.7 Source emission estimate for 1991 for production sites of natural gas (kg)

Date	Concentration increase	Locations	Emissions (kg)[1]
21-09-1991	04.00 h: 1500 ppb	Heidenschap	-
		Slochteren	-
10-10-1991	12.00 h: 1100 ppb	Ten Post	55,800
		Heidenschap	6,840
		't Zandt	-
		Schildmeer	> 60,000
		Slochteren	7,200
	15.00 h: 800 ppb	Ten Post	6,840
		Heidenschap	33,480
		't Zandt	17,640
		Schildmeer	7,920
		Slochteren	24,480
27-11-1991	22.00 h: 1500 ppb	Heidenschap	> 60,000
		Slochteren	> 60,000
29-11-1991	20.00 h: 5600 ppb	Ten Post	> 60,000
		Heidenschap	12,960
		Slochteren	20,880
	21.00 h: 3400 ppb	Ten Post	15,840
		Heidenschap	7,200
		Slochteren	> 60,000
	22.00 h: 2800 ppb	Ten Post	> 60,000
		Heidenschap	> 60,000
		Slochteren	10,440
	23.00 h: 4100 ppb	Ten Post	21,600
		Heidenschap	30,240
		Slochteren	28,800
30-11-1991	00.00 h: 2200 ppb	Ten Post	8,280
		Heidenschap	> 60,000
		Slochteren	> 60,000
	01.00 h: 1700 ppb	Ten Post	> 60,000
		Heidenschap	7,200
		Slochteren	10,800
	05.00 h: 1900 ppb	Ten Post	> 60,000
		Heidenschap	12,960
		Slochteren	27,000
	06.00 h: 1600 ppb	Ten Post	> 60,000
		Heidenschap	8,280
		Slochteren	20,160
Average emission factor F [kg/h][2]			32,000

[1] For the calculations an emission duration of one hour was used.
[2] Emission factor F is the average of the 35 emission estimates in this table.

Table 7.8 *Methane emission estimate for natural gas production sites for 1992 (kg)*

Date	Concentration increase	Locations	Emissions (kg)[2]
05-03-1992	16.00 h: 1000 ppb	Surhuisterveen	-
		Heidenschap	-
	19.00 h: 1400 ppb	Surhuisterveen	-
		Heidenschap	-
30-06-1992[1]	04.00 h: 1200 ppb	-	-
	05.00 h: 1300 ppb	-	-
09-07-1992[1]	02.00 h: 1400 ppb	-	-
29-07-1992	05.00 h: 1200 ppb	Surhuisterveen	> 60,000
		Heidenschap	54,000
07-08-1992[1]	04.00 h: 1400 ppb	-	-
Average emission factor F [kg/h][3]			57,000

[1] For these days no meteorological data are available
[2] For the calculations an emission duration of one hour was used
[3] Emission factor F is the average of 2 emission estimates

Table 7.9 *Methane emission estimate for natural gas production sites for 1993 (kg)*

Date	Concentration increase	Locations	Emissions (kg)[1]
01-01-1993	17.00 h: 1100 ppb	Heidenschap	8,460
		Slochteren	1,800
		Schildmeer	> 60,000
		Zeerijp	-
		't Zandt	-
		Ten Post	18,720
Average emission factor F [kg/h][2]			22,000

[1] For the calculations an emission duration of one hour was used
[2] Emission factor F is the average of 4 emission estimates

7.4 Results

With the use of the model calculations it is possible to give for 1991, 1992 and 1993 an estimation of the methane emissions during the production of oil and natural gas in The Netherlands. The result of this estimation can then be compared with the methane emission data published by the oil and gas companies. A first cautious extrapolation will be conducted to estimate the magnitude of incidental methane emissions. For this extrapolation four parameters are required:

1) an average emission factor per site: F [kg/h]
2) the occurrence rate of incidental emissions: V [percentage]
3) the duration of the active period of a site: T [h]
4) The number of sites active: n

The total emission (E) for a certain year is then: E [kg] = F * V * T * n

Ad 1) 'F', the average emission factor, is determined by the model calculations, which induces a certain uncertainty. The average emission factor is strongly dependent from the number of source-peak combinations found.

Ad 2) The occurrence rate of incidental emissions during the active period of a drilling or production site has to be estimated. Literature does not give any indication in this direction. The performed concentration measurements in Kollumerwaard are able to give more insight in the occurrence of incidentally high methane emissions. For 1991 CH_4 concentrations higher than 3 ppm occur in 0.8% of all the measured CH_4 concentrations. For 1992 this is 0.3% and for 1993 0.4%. In an earlier estimate [Vosbeek, **1994a**] a quantification was made with an occurrence rate of 1% for all the years. The occurrence rates used in the underlying study are more accurate.

Ad 3) The period during which a site is active is also required. Table 7.2 showed per drilling site the duration of the drilling activities. For the calculations an average active period of 30 days (720 hours) is used. For a production site the same period of 30 days will be used, although these sites probably have a longer period in which they are active.

Ad 4) To be able to give an estimation for all on-shore drilling activities all known sources have to be taken into account. Table 7.2 shows all the drilling sites within a radius of 40 kilometres from Kollumerwaard for 1991, 1992 and 1993. With respect to the production sites, the total of sites found in the Topographic Atlas are used, assuming constant over the three years. The Dutch Ministry of Economic Affairs [EZ, **1994**] shows an overview of all on-shore drillings performed in The Netherlands during the period 1991-1993. The total of drillings from table 7.10 is larger than obtained from STOdM (table 7.2).

Table 7.11 shows the parameters used for the calculations for each year and for each type of site.

Table 7.10   *On-shore drillings in The Netherlands [EZ, **1994**]*

	Exploration	Appraisal	Production (deviation)	Total
1991	11	4	11	26
1992	11	1	12	24
1993	10	-	11	21

Table 7.11   Calculated total methane emission for 1991, 1992 and 1993

	1991		1992		1993	
	Drilling	Production	Drilling	Production	Drilling	Production
V [%]	0.008	0.008	0.003	0.003	0.004	0.004
T [h]	720	720	720	720	720	720
n[1]	8	30	17	30	12	30
F [tonnes/h]	30	32	35	57	60	22
E [tonnes]	1,382	5,530	1,285	3,694	2,074	1,901
Total [tonnes]	6,912		4,979		3,975	

[1]   The number of drillings is derived from table 7.2. Using table 7.10 will result in a higher emission estimate.

To place the calculated total CH_4 emission for the several years in a clear perspective, they are compared with methane emission factors published by NAM [1994] and the engineering study (chapter 6). NAM is the biggest on-shore natural gas producer in The Netherlands. *Table 1.2* shows that onshore methane emissions are about 15% of the total methane emissions during the production of oil and natural gas.

The total emission estimate calculated with the dispersion model concerns only incidental emissions. The engineering study shows that incidental emissions are about 10% of all the emissions in the oil and gas industry. Table 7.12 shows the CH_4 emission estimates by NAM, for onshore incidental emissions. Furthermore the estimate made in the engineering study is given (using table 6.11 for 1990 and table 6.12 for 1993), also assuming that 10% of the onshore emissions are incidental emissions. The last column of table 7.12 gives the CH_4 emission estimate calculated with measurements and model.

Table 7.12   Comparison incidental onshore methane emission estimates of NAM,
the engineering study and the modelling study (in tonne)

	NAM (NAM, 1994)	Engineering Study	Model calculations
1990	915	1,500 - 2,300	-
1991	915	-	6,912
1992	818	-	4,979
1993	518	400 - 700	3,975

Comparing the three emission estimates it is very clear that the emission estimate calculated by the model is much larger than the estimates by NAM and the engineering study. A reason for the difference between the estimates is difficult to find. The emission estimates calculated by the model are subject to inaccuracies. The parameters which have an important influence on the total methane emission E (table 7.11) are emission factor, F and the occurrence of incidental emissions, V. The time for which a drilling site is active seems to be very reasonable and also the number of sites active in The Netherlands is not over estimated. The occurrence of incidental

emissions was calculated from the measured methane concentrations in Kollumerwaard, assuming that all high methane concentrations were caused by emissions in the oil and gas industry. When this is not the case, the occurrence rate can be victim to an over estimation. The representativeness and accuracy of the average emission factor (F) is determined by measuring high CH_4 concentrations and by the quality of the model calculations. Due to missing meteorological parameters it is not possible to give an estimate for all the observed methane peaks. Furthermore it is not always possible to point towards a drilling or production site in being responsible for an observed CH_4 peak.

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8 Options for emission reduction

8.1 Reduction of emissions during exploration

During exploration, methane emissions are almost negligible. The neglegible amounts of methane that are emitted, are a result of unburnt methane in flares during well-tests and during cleaning of the wells. Further reduction of the methane emissions may be possible by optimizing the flare efficiency. This may be done by avoiding that the flare design load is exceeded.

8.2 Reducing emissions during exploitation of oil and gas

• *Flaring instead of venting*
When off-gases are flared, methane emissions are reduced with about 95 to 99.8%, depending on the flare efficiency. When in a certain situation or at a certain platform flaring instead of venting is considered, three aspects have to be reckoned with:

— *Overall environmental effect*
A flare requires a continuous minimum load. For this reason a certain amount of natural gas is continuously flared. As a result of this emission reduction of methane and other hydrocarbons results in extra carbon dioxide emissions and also in the emissions of e.g. nitrogen oxide. The overall environmental impact differs from case to case, and depends amongst others on the continuity or discontinuity of the off-streams that have to be vented or flared.
For continuous off-streams, flaring is preferred. But when off-streams are of a very discontinuous nature venting might be preferred from an environmental point of view.
In this context should be noted, that when high pressure process emissions are increasingly recompressed or used as a fuel gas, the remaining high pressure off-gas becomes more discontinuous. So when off-streams from processes are increasingly reused, the overall environmental impact of flaring gradually diminishes and might even become negative.

— *Technological feasibility*
Flaring of off-gases results in a significant heat generation. For safety reasons, the flare should be positioned away from other process equipment. Depending on the flare size, the heat irradiation becomes tolerable at distances of about 30 to 100 meters.

On-shore, a flare is simply erected away from the other equipment, with connecting pipelines for supply of the off-gases. Off-shore however, flaring is not that easy. Here flares are usually constructed like a sprout from a tea-pot, directed diagonally away from the platform. Such a sprout consists of several pipelines for off-gases and flare-gas and a foot-bridge to enable maintenance of the tip.

Off-shore, the stability of the platform is another problem. All platforms are accurately balanced, each part of equipment being counterbalanced by another part

at the other side of a platform. When platform are newly built with a flare, the balance may be reckoned with in the design-phase; but when an existing plaform has to be retrofitted with a flare, disturbance of the balance will be one of the main obstacles for implementation.

This goes especially for satellite and production platforms for the production of natural gas. These platforms are in general very small; so such a distance is not easily achieved.

— *Economic feasibility*
Unlike the other possibilities for emission reduction, flaring of the gas is always associated with costs which are not accompanied by profits. The reason for this is that the valuable methane is destroyed instead of recovered or reused.
On-shore and when new platforms are built off-shore, flares may be installed at relative low costs. Off-shore retrofit of platforms will result in high costs. This is mainly due to the fact that both man-power and equipment have to be helicoptered in.

• *Minimisation of use of strip gas in glycol dehydration*
As described in chapter 4, in some cases natural gas is used as a strip-gas in the glycol regenerator. All stripgas is vented or flared, after being used, contributing to total methane emissions.

A first possibility for reducing the amount of strip gas used, is a thorough check, whether additional stripping is required in the specific situation. At some platforms stripping is only applied, just to be safe with respect to glycol quality and the water content of the gas that is produced, so a reduction of use of stripping gas may be accomplished without any problem.

A second option may be an increase of the temperature at which the glycol is regenerated. This temperature is limited to about 210 °C, due to the instability of glycol at higher temperatures. Besides that, the regeneration temperature is limited by the capacity of the glycol furnace. In some cases however, an increase of temperature may be possible, so stripping might be mitigated.

A third possibility is the use of other gases as a stripping gas. A prerequisite is, that this alternative stripping gas contains less water than the off-gases of the glycol regenerator. If this isn't the case, the stripper turns into an absorber, which has an adverse effect on the glycol quality after regeneration. One possibility is use of the off-gases from the condensate flash. These gases are normally vented, so use of these gases as a stripping gas doesn't result in increased methane emissions.

In the design phase of the platform, several options are more easily implemented: the capacity of the glycol dehydrator may be designed to dehydrate natural gas streams at reduced pressure; the capacity of the furnace may be designed in such a way, that stripping is prevented; the column efficiency may be improved by increasing the column height or the efficiency of the column packings; and finally use of alternative stripping gas may be reckoned with already in the design phase. The latter option is not to be preferred, since the possibility exists to recompress and reuse these off-gases.

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• *Increasing the pressure of the condensate flash*
Increase of the pressure of the condensate flash reduces the amount of methane that is desorbed from the condensate. This effect, however, is limited. For example, when the well pressure is 100 bar, and the pressure in the condensate flash 5 bar, about 95% of all methane is desorbed. When the pressure in the condensate flash is doubled to about 10 bar, 90% of the methane will still desorb in the condensate flash.
Increase of this pressure, however, may be important. The reason for this is that the feasibility of recompression or reuse of this gas improves, when this gas is released at higher pressures.

• *Using process emissions as a fuel gas*
Continuous emissions, that are released at higher pressures, may be used as a fuel gas for the furnace of the glycol regenerator or as a fuel-gas for electricity generation. At several platforms in the off-shore natural gas producing industry, this is already done.

Table 8.1 shows the energy demands in off-shore natural gas production. The energy required for compression, which also consumes a large amount of gas, is not incorporated in this table. Comparing this table with the amounts of off-gases in table 5.2, shows, that energy requirements clearly exceeds the energetic content of the off-gases from processes.

Table 8.1 Energy demands on a production platform

	Natural gas consumption	
	(m³/ million m³)	(GJ$_{th}$/million m³)[1]
Engines & turbines	3,000 - 10,000	100 - 330
Furnaces	500 - 1,000	16.5 - 33

[1] assuming 33 MJ/m³ for natural fas off-shore
[2] depending on load

One of the problems in utilising the energetic content of the off-gases is the quality of the fuel gas. The composition and energy-content of the off-gases from the glycol and condensate flash vary significantly in time. So if these off-gases have to be used, the way in which the energy is generated has to be able to cope with these variations. Since gas-engines are less sensitive towards changes in composition, than gas turbines, use of process-emissions as a fuel gas is more easily achieved when gas-engines are used.

— *Technological feasibility*
Utilisation of process emissions is at this moment applied at gas production sites both on as off-shore. So it may be considered a proven technology.

• *Recompression of process emissions*
Another option for use of process emissions is recompression of the gas, and subsequently recombining it with the dried natural gas stream. In the Dutch on-shore gas production, this is done for most off-gases from glycol flashes and condensate flashes.

Recompression is more easily achieved, when the off-gases are released at higher pressures. This reduces the amount of compression steps and energy required for compression, and improves its cost-effectiveness.

— *Technological feasibility*
The higher the pressure of the process gases, the more feasible is recompression. Recompression of off-gases at atmospheric pressures, may be impossible. In some cases, for example when the up-stream equipment at the suction-side of the compressor is sensitive for pressures under atmospheric. In such a case recompression for example may be the cause of tank-collapse.

• *Alternative dehydration processes*
Since the glycol dehydration makes a large contribution to total methane emissions, emission reduction might be accomplished by using alternative dehydration processes. An example of this is the pervaporation process. In this process, the gas is dried, using glycol, but the glycol is not regenerated by heating, but by vaporation. This vaporation process is applied, using a membrane unit, which is highly selective for water. In this way the methane remains solved in the glycol and is not emitted anymore in the regeneration step. It is technologically feasible to perform this vaporation process at higher pressures, decreasing the amount of methane emitted from the glycol flash and improving the options for reuse or recompression of the off-gases from the flash.

• *Reducing passing valves emissions*
Passing valves emissions are significantly reduced, by implementation of an improved inspection and maintenance programme of the valves. Leaking valves are detected, using ultra-sonoric equipment. Larger leaks may be indicated by the formation of ice on the outside of the low-pressure side of the valve: a result of adiabatic expansion of the gas.

In chapter 4 is described, that passing-valves emissions contribute to the amount of gas, that is flared or vented. The initiation of these emissions may be identified, when gas-flows in the vent-stacks are continuously measured. An increase in flows indicates an increase in passing valve emissions.

Another option for detecting passing valves emissions might be the application of flow-meters in the vent-stacks. An increasing trend in continuous emissions is most likely a result of increasing passing valves emissions. NAM is planning to install these flow-meters in their vent-stacks as a part of their methane- and VOC-emission control strategy.

Once a leaking valve is detected, emission is stopped by repair or replacement of the valve.

• *Reducing purge gas streams*
At several platforms the amount of purge gas used is higher than strictly required. At these platforms, emissions may be reduced, by simple adjusting the purge gas flow. But since safety is the first concern of a platform operator, such a measure will not be easily taken.

Another option for reduction of purge gas streams are the application of seals at the vent-tip, which reduce the required purge gas streams. Examples are the molecular seal and the fluatic seal (depicted in figure 8.1)

• *Recompression of gas during maintenance*
Before repair or maintenance, parts of the system are depressurised. These gases may be recompressed and rerouted to the system. This might be done, using a transportable compressor unit.

— *Economic feasibility*
Investigations of Gasunie indicate, that recompression is economically attractive, when the amounts of gas recompressed are larger than 65,000 m³ [Coors, **1993**]. On-shore recompression may be possible. In the off-shore it is harder to achieve, since all equipment has to be flown in per helicopter. This makes recompression off-shore an expensive option.

• *Reduced flushing of engines, before start-up*
Investigations of Gasunie indicate, that flushing compressors or engines before start-up is not required. Formation of an explosive mixture is prevented by the overpressure in the system. As a result of this, emissions during start-up and shut-down might be reduced, simply by altering start-up procedures. In this it has to be noted, that this option for emission reduction is of much more importance to gas-transport than to gas production, because the number of starts and stops in the transport sector is much larger than the number of starts and stops in the exploitation.

• *Use of electric starting engines*
During start-up of compressors or gas turbines methane emissions may occur, when gas-pressure is used to start the engines. Use of electric starting engines instead of these gas-driffer engines reduces the incidental methane emissions during start-up.

8.3   Discussion

In the paragraph above, many possibilities are described for reducing emissions. The economic and technological feasibility of these measures will differ for the various installations:
— when new installations are built on-shore, the technological and economic feasibilities will be very good: most of the off-gases may be recompressed, the remaining part may be flared. In this way it will be possible to create installation as with little or no methane emissions (except for possible fugitive leaks);
— the same goes for new platforms off-shore, with one main difference: on-site energy-use, may be a main off-gas consumer. Besides that, flaring of off-gases may not be possible, especially at smaller platforms;
— the possibilities for reducing emissions at existing installations are also very good: recompression of high-pressure off-gases is already implemented at most of the on-shore natural gas clusters. Besides this flaring has become common practice during the last ten years. As a result of both measures, methane emissions from the gas production off-shore has been considerably reduced in the last five years (see chapter 7.4);
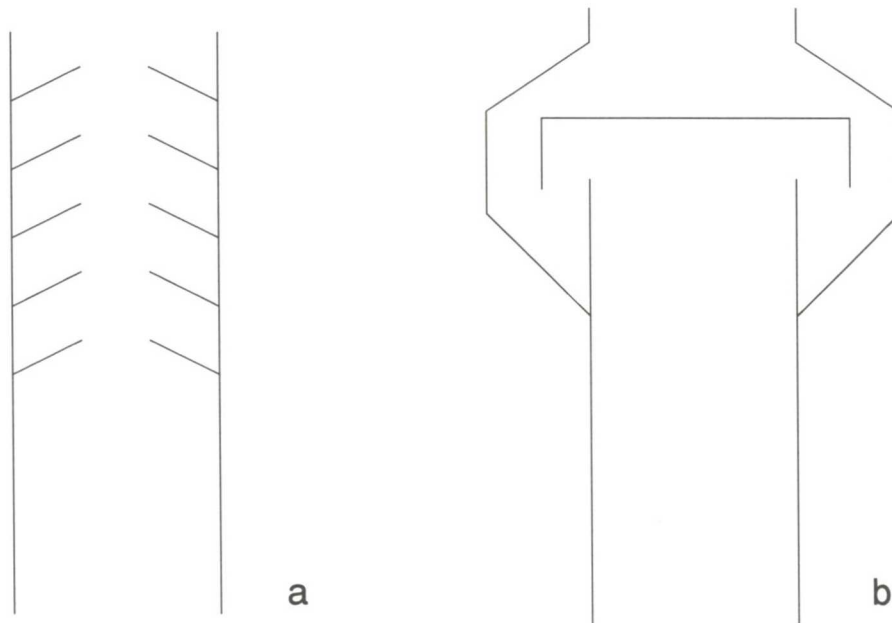
Figure 8.1   Fluatic seal (a) and molecular seal (b) for reducing purge gas emissions

— at existing off-shore platforms however, possibilities to reduce emissions will remain very limited. In some cases minimisation of use of natural gas a purge gas or as a strip gas may result in some reduction of methane emissions, in other cases passing valve emissions might be reduced. But the options that might reduce the bulk of the emissions (recompression or reuse of off-gases, flaring instead of venting) are very hard to implement on existing platforms. There are several obstacles for doing this. The limited space on a platform and the stability of a platform are two technological ones; equipment and man-power supply is another one, since all equipment and man-power has to be flown in by helicopter. This makes methane reducing measures off-shore very expensive.

But gas-fields off-shore are exploited in a relative short time (typically seven to ten years). As a result of this, most of the present generation of platforms will be abandoned in the next ten years. Gas production will be maintained at present levels, by taking other fields into production. These platforms are still to be build.

So the off-shore industry renewes itself very quickly. As a result of this, it will not be cost-effective to demand extreme measures for methane reduction at existing platforms. It makes more sense to strive for new platforms with optimized reuse and recompression and minimised emissions. In this way methane emissions from the oil and gas industry will be gradually phased out in the next decades. This policy is currently prepared by the Dutch Emission Guidelines in cooperations with the sector. If this policy is successfully implemented, off-shore methane emissions will be reduced with about 90% within the next 10 to 20 years, leaving only the fugitive emissions and exhaust emissions.

9   **Conclusions**

The 1990 emissions from the Dutch natural gas and oil industry are estimated to be 76-122 ktonne. Of this 15-23 ktonne was emitted on-shore; off-shore emissions were 61-99 ktonne.

The 1993 emissions are estimated to be 60-103 ktonne (4-7 on-shore; 56-96 ktonne off-shore).

In the years 1990 to 1993 about 16 to 19 ktonne of methane emissions was mitigated, which equals 16 to 21% of the amount emitted in 1990. This emission reduction is notably obtained by reducing the amount of gases vented in the on-shore gas exploitation and in the on- and off-shore oil production. Besides this, a slight decrease of methane emissions is a result of reduced oil production off-shore.

In the gas industry, most methane emissions are the result of venting during normal operations. Use of purge gas, emissions from glycol dehydration and most likely passing valve emissions are the main causes of this. Besides this, a significant part of the methane vented is released from the condensate treatment facilities. Non-vent emissions, such as methane in the exhaust of engines or flares, seal gas losses and fugitive emissions, contribute to at most 10% of the total. Emissions from exploration and emissions due to accidents are almost negligible.

Methane emissions in the oil industry may be due to the venting of associated gas. Besides this, associated gas is solved in the oil or in the formation water. This gas be released when these streams are treated at reduced pressure.

The quantification made by the concentration measurements and the model calculations resulted in estimates for the on-shore incidental CH_4 emissions. For 1991 the estimated incidental emissions were found to be about 7 ktonne, for 1992 this was 5 ktonne and for 1993 this was 4 ktonne. When incidental emissions are only about 10% of the total emissions, on-shore, the results are relatively high. The results show however emission reductions in 1993 compared to 1991 and 1992.

The results of this part of the study should be interpreted carefully. Combination of a receptor model and a dispersion model could possibly give better emission estimates (EPA, 1994). In a dispersion model a certain amount of gas is emitted from a stack, after which the dispersion over an area is calculated and thereby the emission at a certain point. In a receptor model the actual measured concentration of a gas is used to recalculate the strength of the emission source. The complementary use of both models can reduce the limitations that either model may have if used separately. However for both models enough meteorological data should be available.

The possibilities for further methane emissions reduction, are abundant. Minimisation of use of purge gas and stripping gas and improved control and maintenance with regards to passing valve emissions might be applied at existing platforms off-shore. New platforms off-shore might be designed in a way that process emissions become almost negligible. For example, reuse or recompression might be optimized, or even alternative dehydration processes might be applied.

Since the off-shore industry is renewing itself is a rather fast way, the striving for minimisation of emissions at new-to-build platforms will be an effective way for reducing methane emissions further. When this policy proves to be successful, methane emissions might even be reduced to about 10 to 20% of 1990 emissions within the next 10 to 20 years.

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11 Governmental organisations, companies and research institutions

CBS	Dutch central bureau for statistics - The Hague
EZ	Dutch Ministry of Economic Affairs - The Hague
Gastec	Dutch research organisation of gas distributors - Apeldoorn
Gasunie	Dutch gas transporting company - Groningen
KEMA	Dutch research organisation for energy distributors - Arnhem
NAM	Company, that accounts for about half of the Dutch natural gas production - Assen
Nogepa	Netherlands Oil and Gas Explorers and Producers Association - The Hague
NRP	National Research Programme - Bilthoven
RIVM	Dutch National Institute for Public health and Environment Protection - Bilthoven
OLF	Norwegian oil and natural gas producing company
STodM	State Supervision on the Mines - Rijswijk
Stork-Protech	Engineering consultants - Schiedam
TNO	Netherlands Organisation for Applied Scientific Research - Apeldoorn
US-EPA	United States Environmental Protection Agency
VROM	Dutch Ministry of the Environment - The Hague

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12   Authentication

Name and address of the principal
N.V. KEMA
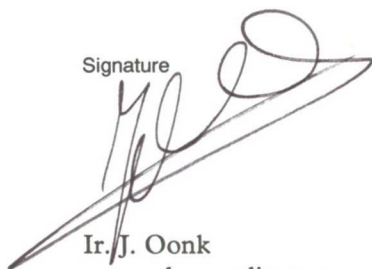Drs. M. Vosbeek
P.O. Box 9035
6800 ET Arnhem

Names and functions of the cooperators
Ir. J. Oonk

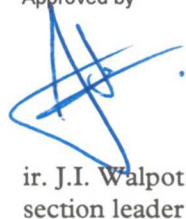Names of establishments to which part of the research was put out to contract

Date upon which, or period in which, the research took place

Signature
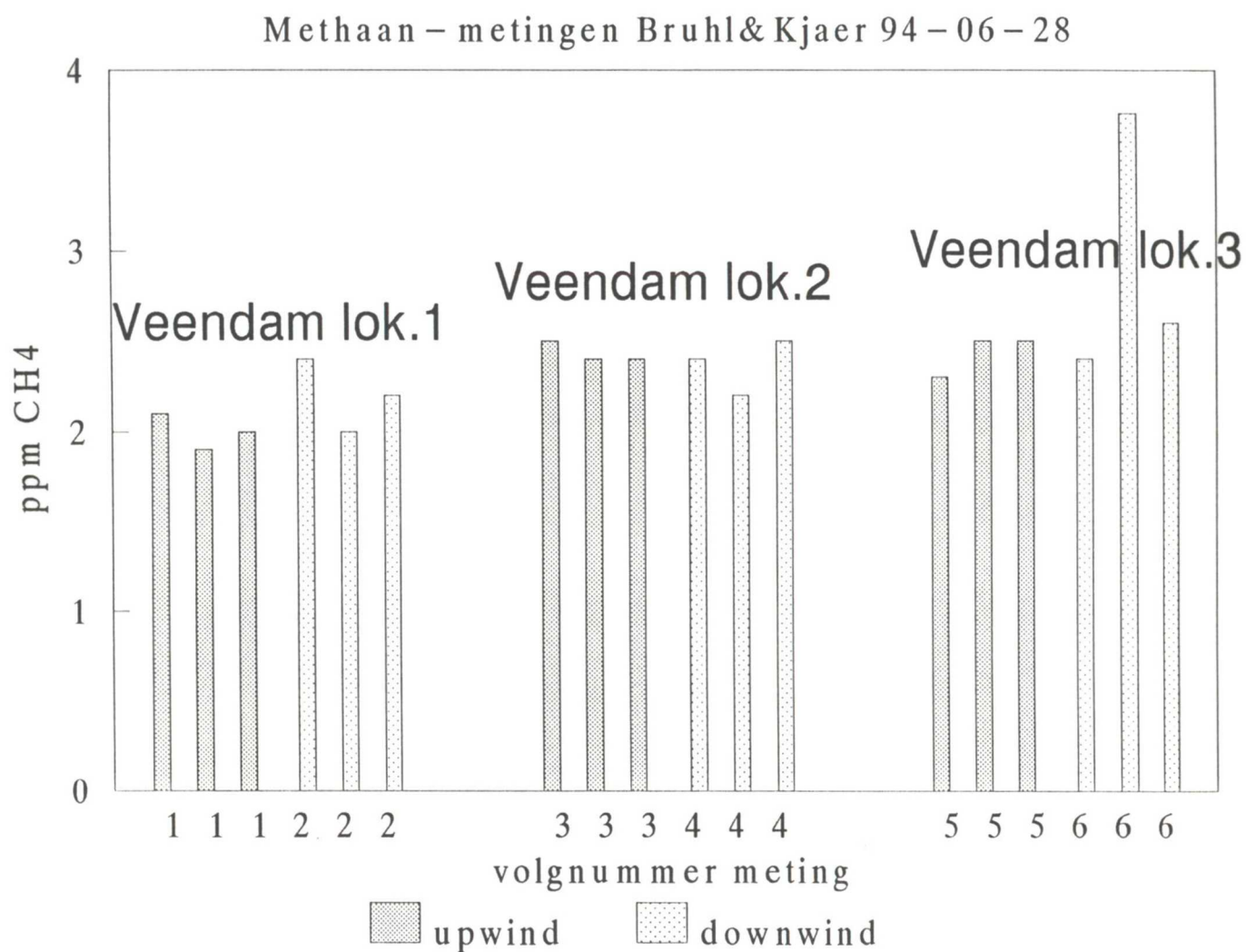
Ir. J. Oonk
research coordinator
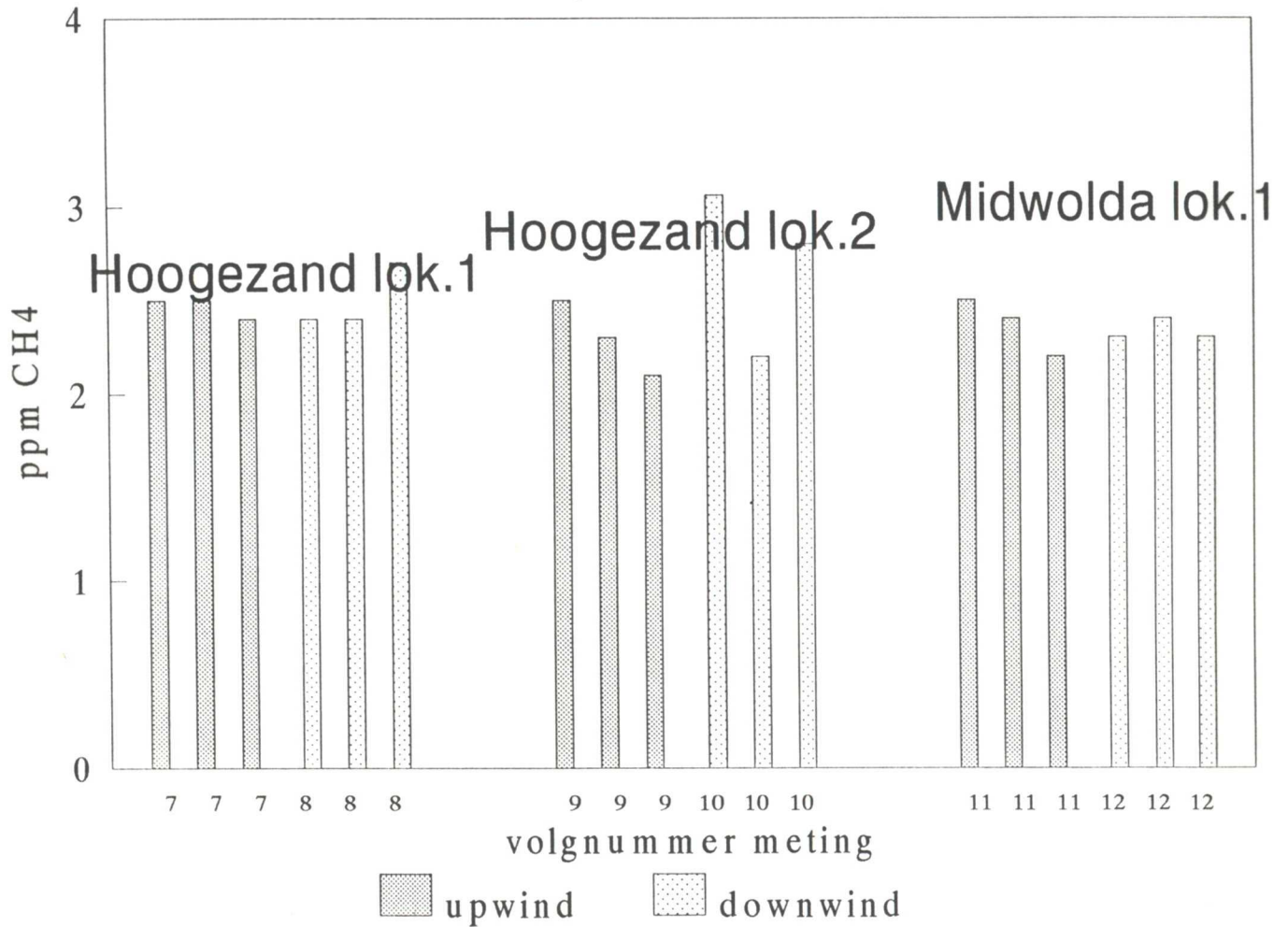
Approved by

ir. J.I. Walpot
section leader

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Appendix A   Mobile methane measurements at 06-28-1994, Veendam

Methaan − metingen Bruhl & Kjaer 94 − 06 − 28

Lokatie 1 fakkel uit; Lokatie 2 en 3 fakkel aan.

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Mobile methane measurements at 06-28-1994, Hoogezand and Midwolda

Methaan − metingen Bruhl& Kjaer 94 − 06 − 28

Hogezand lok.1 en lok.2 fakkel uit; Midwolda lok.1 fakkel aan.

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Appendix B

Figure 1 shows a methane peak at July, 10 1991. The major wind direction during the measured methane peak was 195 degrees. Figure 2 shows the Kollumerwaard site with the solid line the wind direction during the observed CH_4 peak at July 10, 1991. The broken lines show the boundaries of 15 degrees on either site of this wind direction. The figure shows that the two drilling Surhuisterveen and Marum are situated within this area. Table 7.2 showed the periods these drilling sites were active and unfortunately both sites became active after July the tenth, when the peak was observed.

For this incidental CH_4 peak it is thus not possible to point towards a drilling site and no emission estimate was calculated for this date.
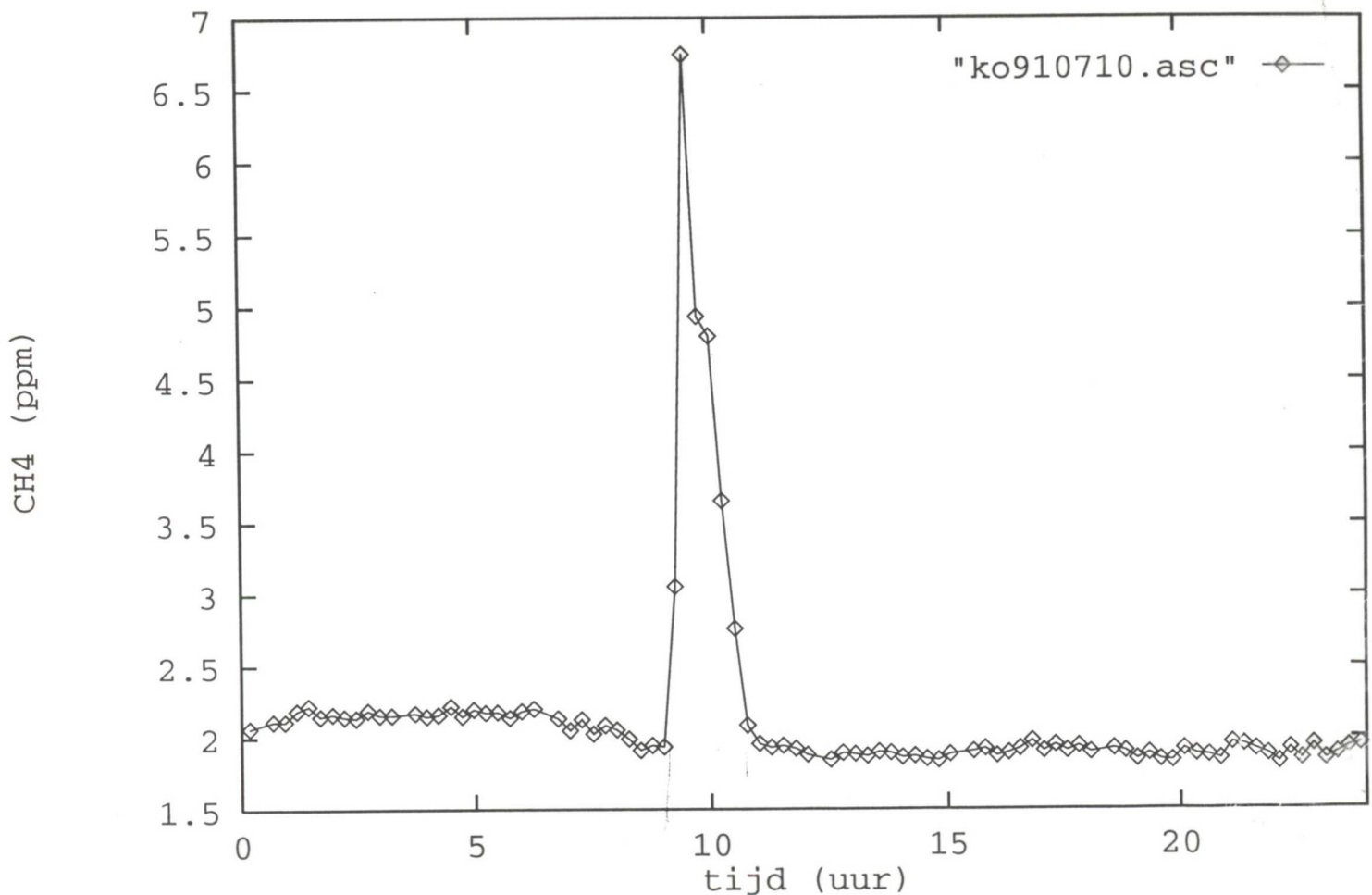

Figure 1   Daily methane profile of July 10, 1991

Methane emissions due to oil and natural gas operations in the Netherlands
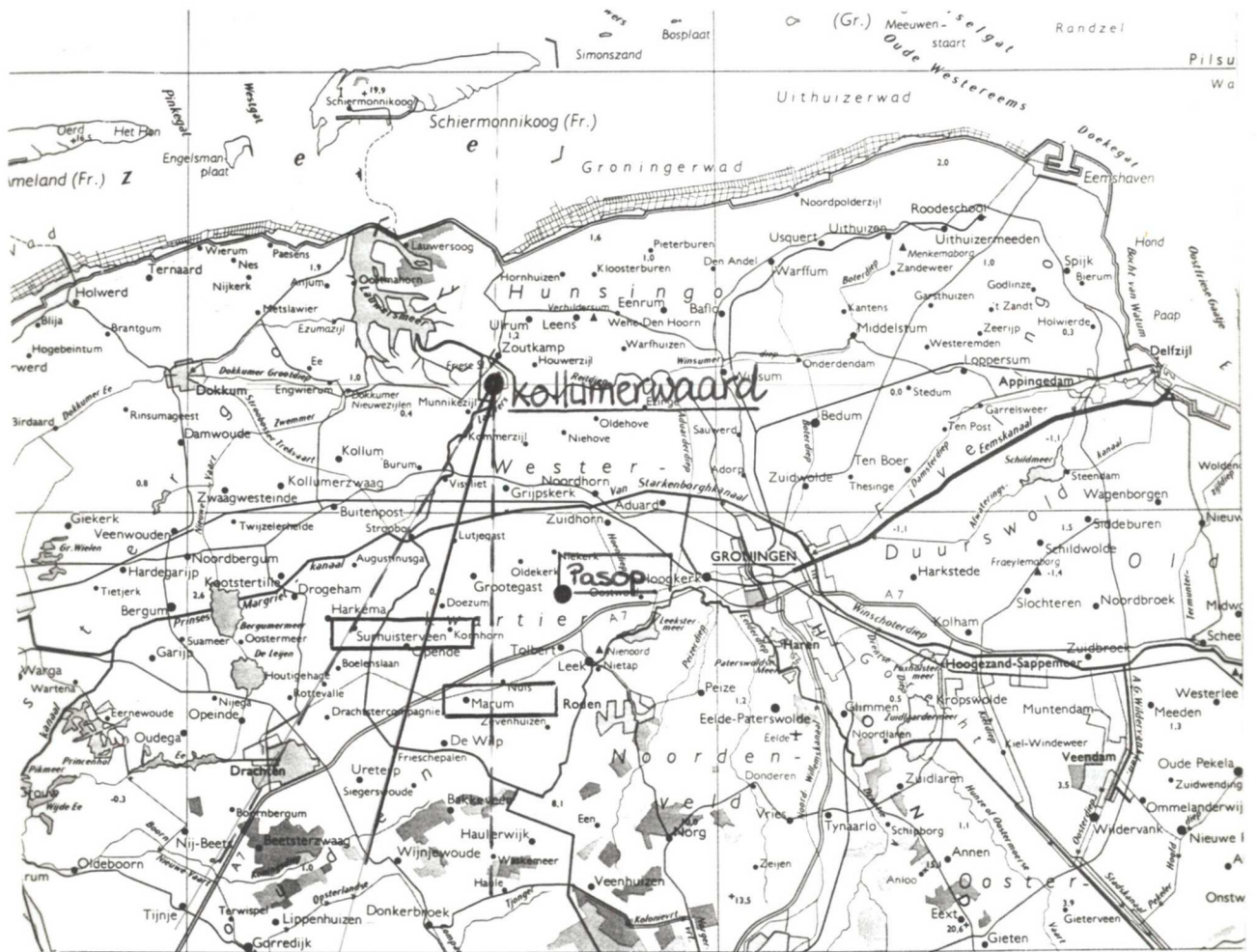*Final report*

Figure 2   Example of the determination of a methane source with help of the wind direction
during the measured methane peak