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TNO Report

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Inventory of technologies and developments for reducing (residual) risks in shale gas extraction

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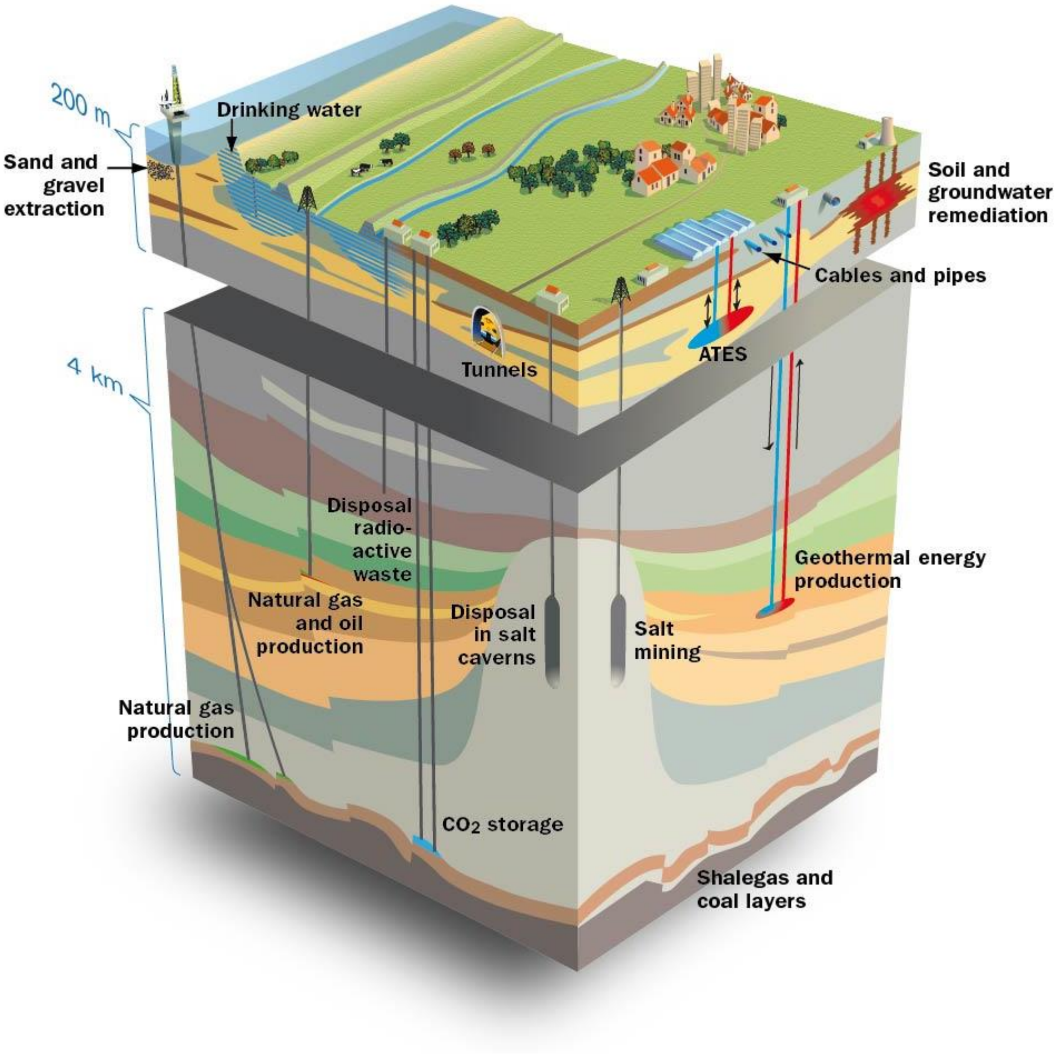

Management summary

Title :	Inventory of technologies and developments for reducing (residual) risks in shale gas extraction
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Note:

This report is composed of 3 parts:

1. Management summary in table form
2. Main report
3. Background information (appendices)

The management summary gives a quick overview of the topics researched, the results of the research of TNO/Deltares relating to this topic and the technologies and developments that can be used in the short and long term. The table always includes successively: the sub-question as formulated by the Ministry of Economic Affairs, a short presentation of the significance of this question in the Dutch context, the measures that can relatively easily or in the short term lead to a reduction in the relevant risks, and the measures that are expected to become available in the longer term.

Category 1: *These innovations have a TRL 1-3 and this is hence a technology proven to an experimental phase to “Proof of Concept”. These technologies are not expected to come onto the market in the next 10 years.*

Category 2: *These innovations have a TRL 4-6 and this is a technology that has been validated to demonstrated in a relevant environment. These technologies should appear on the market within 10 years.*

Category 3: *An innovation/development with TRL 7-9 (green) is a technology that that is from prototype to actually proven in an operational environment. These technologies will be available in the near future.*

Section	Question	Interpretation TNO/Deltares	Current practice/ Short term	Longer term	Category
1	*In shale gas extraction is there a risk of contamination of ground- and surface water due to the spillage of chemicals, fracking water or flowback water, how can this risk be limited?*	Incidents in the form of spillage, leaks, etc. are unavoidable and may occur both at the extraction site and outside it. For Dutch mining sites, including mobile installations, according to the existing regulations provisions must be taken to protect the soil from contamination. Should soil contamination still occur, the soil will be decontaminated according to the existing legislation and regulations.	At present the statutory framework in particular is of essential importance, which helps to limit incidents. In addition tanks and piping have improved protection from leaks due to the use of different materials and application of coatings.	If the current legislation changes, the following matters may be included: Extra protection of the soil can be achieved by use of geotextile and geosynthetics on surfaces. Geotextile and geosynthetics are already available, but are not yet widely used.	3
2	*What are the most recent findings in the area of migration of methane or other components from the fracked shale stratum to the overlying aquifer? And in particular for the Netherlands. Are new techniques known with which measurements can be carried out on site, in detail, and underground to identify any leaks and/or migration of methane or other components to aquifers?*	Risks of direct migration of methane or other components from the fracked shale stratum to the overlying aquifers are limited in virtually all situations, and only significant if fracking affects the insulating qualities of wells. This risk is limited in the Netherlands by stringent legislation and regulations for the design of wells, but, in view of the scale of fracking in shale gas extraction, are a point of concern.	Before starting fracking and shale gas extraction site-specific analysis of the geological and geomechanical conditions of the subsoil and the dimensions of fracks, and extra attention to fracking activities in the planning and design of wells help to limit migration risks. During fracking micro-seismic monitoring and monitoring of composition and contamination in the groundwater and/or deeper aquifers is used.	In the longer term (3-5 years) improvements in design of seismic monitoring networks, further development of high resolution sensors for monitoring, and the combination of different monitoring techniques may help further limit migration risks	2

3	*Various chemicals are used for drilling and fracking. Can the use of these chemicals be avoided? Are there alternatives? What are the developments relating to new more sustainable chemicals? Can the chemicals be replaced by substances that are biodegradable (in the deep subsoil or in any wastewater treatment plant) and/or non-environmentally harmful substances?*	In most cases the same fluids are used for drilling and fracking in shale gas extraction as for drilling for conventional gas (see also Witteveen+Bos 2013), although the optimum composition of the chemicals in a fracking fluid may differ depending on the local geology and properties of the reservoir rock. The risk that chemicals may have a harmful effect on the earth's surface is mainly determined by the chance of spillage or leaks, the quantity, concentration and toxicity of the leaked chemicals, and the site-specific interaction with the environment which leaked chemicals may reach.	There are possibilities in the Netherlands of replacing chemicals used for fracking by substances with the same functionality that are less environmentally harmful in case of possible incidents. There is a lot of development in the area of alternative, more sustainable, biodegradable and less harmful chemicals in fracking fluids, but they are still not widely used.	Over a period of five to ten years the practical usability and added value of innovative alternatives for chemicals in fracking fluids will be better known. Most alternative chemicals have still only been tested under experimental conditions (such as in laboratories). In addition special fracking and drilling techniques may make fracking more efficient or replace it, so that the use of chemicals can be reduced or avoided.	2

4	*A large quantity of water is injected into the ground and returned to the surface. The flowback water contains harmful substances that are naturally present in the earth. The processing of flowback water is a known problem in the conventional gas industry. In particular the scale of the quantities of flowback water for shale gas requires new solutions in the area of treatment. Are conventional wastewater treatment plants available to treat the produced water? Can this be done on site? Can this water be discharged or reused without additional risks to the surface water?*	Two types of wastewater streams can be distinguished in shale gas extraction: the flowback water, or the water that is produced immediately after fracking, and the production water, or the water that is also produced during the exploitation of shale gas. The former concerns a relatively large volume within a short time and the latter small volumes during the whole exploitation period of the well. Both cases involve water of poor quality: the production water will be brine with concentrations above that of seawater and in which among other things hydrocarbons such as benzene are produced at the same time. In the case of flowback water the salt concentrations may be somewhat lower but the additives to the fracking water also partly flow back. For both streams it is undesirable for them to get into the surface water, soil and associated groundwater layers.	Three scenarios or combinations of these are feasible for processing these water streams: 1. treatment until the water can be returned (back) to the environment, 2. injection of the water into an empty gas field, 3. reuse in subsequent fracking activities. For the second and third scenario treatment of part of the (non-natural) substances is possibly necessary, partly depending on the regulations. Flowback and production water contain contaminants, but treatment to any required level is in principle possible. This is both possible at an extraction site with mobile units or as a central facility. Most techniques are in a very advanced stage of development. The desalination of the very salty brine water is the most intensive treatment stage in terms of energy and costs.	The current development is at a very advanced stage of development. Apart from optimising treatment activities, specifically in shale gas extraction, there are no critical technologies or developments that further minimise the risks A crystallisation plant was recently commissioned in Pennsylvania (US) that is able to convert the wastewater, after chemical pretreatment, into water that meets the current specifications in the US for water discharge and salt that is suitable as road salt. This is the first plant of its kind and has proved itself economically and environmentally as regards feasibility. At present the recovery of other valuable products from the wastewater is being investigated further.	3

5	*Are there alternatives for the use of water in fracking? For example by liquefied gases such as propane, butane and carbon dioxide. Do these techniques have (or are they expected to have) a higher or a lower risk for the soil, groundwater, environment? What is the expectation as regards the risk for new techniques?*	The major risk in the use of water is that the water supply for example for drinking water supply or agriculture will suffer from shale gas extraction. In the Dutch situation it is unlikely that a water shortage will occur in case of shale gas extraction, provided sound planning is carried out beforehand for the supply and disposal of water used in fracking.	There are alternatives for water in fracking fluids, of which carbon dioxide, LPG or propane are most commonly used in the US and Canada. For most alternative fracking fluids the added value as regards the reduction of risks in shale gas extraction, it has not been demonstrated whether the fluids are more harmful, more dangerous or more difficult to manage than conventional fracking fluids.	It is not expected that the alternatives will play a major part in fracking in shale gas extraction in the near future.	1 to 2
6	*Are there new techniques that reduce the chances of failure of well integrity? Are there new methods for monitoring well integrity? In case of a loss of well integrity are there new methods or developments for restoring well integrity?*	Ensuring well integrity is in the first place a question of the right use of the technology and procedures. The knowledge and technology for this are present and tested in conventional oil and gas extraction. The biggest risks of leaks to groundwater can be expected when in the long term the integrity of the well after leaving and sealing the well (abandonment) is adversely affected. To date there is very little experience with long term monitoring of the integrity of large numbers of (shale gas) wells after abandonment.	A significant reduction in risks will be achieved by using monitoring technology. Upon abandonment of wells regularly recurring measurement of the pressure in the well or sampling groundwater on the surface or in shallow aquifers may help to identify any leaks in good time, so that remedial measures can be taken at an early stage.	New and improved monitoring technologies, for example using optic sensors, may be operational within a few years.	2

7	*Are new techniques or developments known with which the result of fracking can be established with greater certainty?*	Better control of the result of fracking helps in particular to reduce the risks of migration of substances from the fracked shale stratum to the overlying strata and to reduce seismic risks. The most important techniques that can be used before starting fracking and gas extraction focus on better characterisation of the subsoil using models, seismic profiling or laboratory scale experiments. The most important techniques that can be used during or after fracking and gas extraction focus on different types of monitoring.	The most important technological developments that can help control the result of fracking better are (1) improvement of sensors to monitor fracks, (2) improvement of the design of monitoring networks to use real time monitoring, and (3) better integration of geological and geomechanical models of subsoil and micro-seismic data. New data from wells, analyses of new sample material, and (laboratory) tests on new sample material from Dutch shales can help fill the most important knowledge gaps in the area of the result of fracking.	Better control of the result of fracking can in future be achieved with alternative methods of monitoring, for example using (combinations of) electrical, thermal, of magnetotelluric monitoring, or combinations of different monitoring techniques, for example micro-seismic and tiltmeter monitoring or 4D seismic profiling and micro-seismic data.	1 to 2

8	*With what techniques can the risk of methane emission be prevented? Are these techniques used and are there any new developments?*	There are possibilities of limiting CH4 emission to the atmosphere in shale gas extraction. This is more a financial consideration, than a question of innovation. The question in the United States is in particular whether it is economically profitable to prevent the emission. High leakage losses then are therefore a choice and not a given. Based on the Dutch regulations for conventional gas extraction a considerably lower emission can be expected for any shale gas extraction than in the American situation.	The most important thing in the Dutch situation is as far as possible to avoid venting gas to the atmosphere and in addition as far as possible to carry out transport and fracking in sealed systems. Venting can be avoided by capture and reuse. Technologies for doing this already exist. In addition monitoring and identification of CH_4 leaks with the current measurement techniques is very possible.	Innovative developments relating to monitoring are focussed at present above all on (much) cheaper sensors that can till measure methane with the necessary accuracy. Note that accuracy is necessary because methane emission to the atmosphere virtually disappears against the background noise.	3
9	*Have new insights recently been developed relating to seismic risks due to fracking and the extraction of shale gas?*	Seismic risks due to fracking and the extraction of shale gas are generally small. Significant seismic risks may occur if bigger faults are reactivated due to fracking and the extraction of shale gas. These risks occur in the United States and elsewhere above all in areas with significant natural seismicity and upon injection of large quantities of fluids in a relatively small area.	Before starting fracking and shale gas extraction site-specific analysis of the geological and geomechanical conditions of the subsoil, planning of wells and fracking, and limiting the quantity of injected fracking fluid can help limit seismic risks. During fracking (micro-) seismic monitoring can be used to stop or limit fluid injection in good time. At present this is one of the existing requirements of the Dutch State Supervision of Mines	Seismic risks can be further minimised by better (real time) integration of geological and geomechanical models of the subsoil and micro-seismic data.	3
				Innovative monitoring techniques	2
				Also alternative methods for stimulation that can replace fracking (for example innovative drilling techniques) can reduce risks further. These technologies are still under development in the Netherlands.	1

10	*Are there innovative ways of organising, new ideas about minimising the complex logistics movements in order to reduce the risks associated with transport? To what extent can an infrastructure for the supply and disposal of water offer a solution?*	Shale gas development is associated with more transport movements. This relates above all to the supply of clean water and disposal of contaminated water. These are known risks specific to big industrial processes, such as noise nuisance and the emission of gasses and particulates	By means of supply chain management and ICT resources transport streams can as far as possible be combined and the transport capacity used to the optimum. This can reduce the risks associated with transport movements. The placement of a pipeline for the transport of water reduces the risk related to transport.	Supply chain management and ICT resources are available, but only being used very gradually.	3
11	*Are new methods and new procedures known that lead to less risk for the environment and lower emissions of substances to the environment?*	The emissions other than methane associated with the extraction of shale gas in the Netherlands for the most part consist of the emission and resuspension of NOx and particulates. Although these are not greenhouse gases per se, these emissions also involve a certain health risk.	Tightening up the requirements laid down for the emission of among other things trucks and other equipment with an internal combustion engine, as well as changing over to an all-electric scenario, tackles the current emission level. Above all the possible saving that can be made in the area of scale factors can in addition contribute to lower environmental pollution.	Apart from implementation of emission limiting transport scenarios there are no major technologies or developments that further minimise the risks. Please, also see topic 8 on page 11 which describes monitoring technologies	3
12	*The risks of shale gas extraction and production are partly influenced by the greater scale of activities. For each site more wells, resources, water and equipment are necessary which leads to more emissions to the environment and more transport movements compared with conventional local gas extraction. Are new methods and new procedures known which make less wells, resources, water and materials necessary?*	Shale gas extraction is an intensive process, that compared with conventional gas extraction is associated with possibly more nuisance. In the densely populated Netherlands this applies even more so than in the US for example. The risks can be reduced by using supply chain management over the whole production chain in shale gas extraction.	Optimisation of a development plan in shale gas extraction can be carried out with techniques that are present. Optimisation of a development plan, due to the use of continuous real-time data input can make the development of shale gas much more efficient and reduce the environmental impact.,.	Optimisation by closed loop reservoir management[1] can lead to 1) the smarter positioning of fracks, 2) possibly also less fracks and 3) a reduction in the number of drilling sites. This method is hence a major factor in the possible reduction of the scale of shale gas extraction and the associated risks.	2

[1] *NB: Definition of 'closed loop reservoir management' is different here to what is referred to in the report of W+B. For the definition applicable here see section 12.2 on Scale factors*

13	*Is it possible to use a well or part of a well for the extraction of geothermal energy after the extraction of shale gas? Are extra risks associated with this?* *and* *Is it possible to reuse infrastructure that was built for the extraction of shale gas after the production phase for other (sustainable) energy projects?*	It is in principle possible to reuse a shale gas well for extraction of geothermal energy. Shale gas wells differ greatly in a number of respects (depth, materials used, width, required site) from geothermal wells, so combined use requires extensive adjustment and suboptimal properties of the individual applications.	The conversion of two shale gas wells to a conventional, low enthalpy geothermal doublet probably cannot be achieved economically. Reuse of the infrastructure in shale gas extraction may be attractive particularly for underground energy storage to buffer irregular energy supply from renewable energy sources.	What may be possible is the combination of the geothermal system from more than two converted shale gas wells, that pump relatively low flow rates, and in which narrow pumps can be fitted. The question is however very much whether this is economically feasible. A site-specific cost-benefit analysis should show this.	1

Summary

Section	Question	Interpretation TNO/Deltares	Measures that help reduce the (residual) risk	Category
14	*What are the most important - very generally applicable - results of the inventory, summarised and with a view to reinforcing aspects?*	A summary focussing on available measures that can be used in the short term (virtually immediately) after licensing (Cat. 3) and research into what may in the (medium) long term contribute to reducing (residual) risks	– In case of changes to regulations relating to setting up the extraction site, the risk of spillage and leaks can be taken into account for example by fitting geotextile, and appropriate maintenance and inspection in the light of existing legislation and regulations – Geological and geomechanical modelling of the reaction of the underground system to extraction activities, and the interaction of extraction activities with existing geological structures such as faults. – Determination and use of the optimum composition of fracking fluids, both with a view to the risks of using chemicals and the efficiency of fracking. – Implementation of an optimum development plan for extraction sites in combination with closed loop reservoir management. – Implementation of appropriate monitoring of ground- and drinking water and methane emissions. – Suitable monitoring strategy (for example real time monitoring) in the subsoil that focuses both on the extent of fracks, detection of migration and maintenance of well integrity and on improving the efficacy of fracking and gas extraction. **NB:** In particular the combination of the above-mentioned research and measures has important added value.	3
			– Before starting extraction research and innovations are important that focus on knowledge gaps in the area of control of the result of fracking, alternative methods of reservoir stimulation, the interaction of Dutch shale strata with fracking fluids, or improving cement that is used in wells with a view to improved well integrity when using a multitude of frack stages. – The optimalisation by closed loop reservoir management may lead to 1) smart frack placement, 2) potentially less fracks, and 3) a decrease of the number of drilling locations. This method is therefore an important factor in the potential reduction of the scale of operations and the associated risks.	1 and 2

			– During extraction in particular research and innovations in the area of monitoring are important. A lot of research and innovations focus on new monitoring techniques and improved sensors. But innovations in the area of above-ground monitoring can also be used to appropriately handle methane emissions, drinking and groundwater contamination and complex logistics movements. – After the extraction site has been abandoned in particular the abandonment of the well is important. The Netherlands has a great deal of experience in this area with conventional gas extraction, but there is little experience with the long term monitoring of large numbers of abandoned wells. Risks can be reduced here by carrying out regular (or real-time) pressure measurements in the well, or monitoring the groundwater composition on the surface or in shallow aquifers.	
			– After extraction the infrastructure can possibly be reused for geothermal energy. Additional research is necessary to assess possibilities for reusing shale gas wells for geothermal energy better. In each case before starting any extraction is the time to prepare a consideration/plan relating to the reuse of shale gas wells for geothermal energy since an adapted well design is necessary. This technology can probably only be used in the longer term.	1

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Introduction

The Netherlands has a long history as far as conventional oil and gas exploration and production are concerned. Many oil and gas fields have already been found and reserves have largely been produced. New reserves are increasingly difficult to find. In addition the demand for energy is growing worldwide. As a result the worldwide focus is increasingly on producing oil and gas from shale rocks.

Shale gas extraction has really taken off in recent decades, particularly in the United States. In addition unconventional technologies such as horizontal drilling and hydraulic fracking have played an important part. In the United States tens of thousands of wells have been drilled, gaining a lot of experience in the production of shale gas.

It is uncertain whether shale gas will have such a big impact in the Netherlands. The shale strata that could be attractive in shale gas extraction in the Netherlands are the shales in the Jurassic Posidonia Formation and the shales in the Carboniferous (Namurian) Epen Formation. From a technical point of view, according to the latest estimates these shales could produce between 200-500 billion m^3 of gas[2], but there is considerable uncertainty about these estimates because of the lack of data from well tests.

At present a number of exploration licences have been granted to explore the prospects of shale gas reserves in the Netherlands, but no drilling into the shale is yet being carried out. Activity is on hold because more clarity is needed about the safety of shale gas extraction, and in particular about the impact on people, nature and the environment. This concern has arisen mainly because of possible adverse effects of shale gas extraction on (drinking) water quality, water consumption, soil quality, air quality and land use. Such effects have been observed in some extraction sites in the United States.

In 2013 Witteveen+Bos, Arcadis and Fugro were commissioned by the Dutch government to carry out a study into the possible risks and consequences of the exploration for and extraction of shale and coal gas in the Netherlands. The following conclusions emerge in their study:

- Compared with conventional gas extraction, shale gas extraction has a bigger footprint and there are more industrial activities on each drilling site
- Methane may be released during various phases of exploration and extraction and due to the intensive logistics, longer drilling and fracking more CO_2 is emitted compared with conventional gas extraction
- Due to the high pressure injection of fracking fluid in or near an active fault zone, earthquakes may possibly occur during shale or coal gas extraction.
- The fracking fluid consists mainly of water containing proppants and additives (approx. 2%). A number of these additives may be harmful in high concentrations .

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[2] Zijp and Heege, Shale gas in the Netherlands: current state of play, International Shale Gas and Oil Journal, issue February 2014

- One possible risk of shale and coal gas extraction is the contamination of the groundwater due to the failure of well integrity, migration of fluid or methane directly from the shale or coal stratum either via the well or due to spillages and leaks on the drilling site

Witteveen+Bos states that these possible consequences and risks for nature, people and the environment are manageable and that the current legal frameworks offer sufficient options for addressing the risks. In addition the execution of site specific research is recommended with the aim for each potential extraction site of evaluating the effects of shale gas extraction on people, nature and the environment and minimising the risks.

The M.E.R. commission has stated that the risks at well or extraction site level are comparable with those for conventional gas extraction, but that above all the scale on which the whole drilling and fracking process is carried out possibly introduces extra risks. The M.E.R. commission als indicated that Witteveen+Bos mainly looked at the subsurface aspects and to a lesser extent to the surface effects In response to these statements the Minister of Economic Affeirs decided to develop a PlanMER Shale Gas.

This study evaluates the existence and development of new technologies that may reduce the risks of shale gas extraction for people, environment and habitat with a focus on ground- and drinking water, emissions, earth movements and footprint.

Text box 1: Central Research Question

> ***Central research question:***
> *Are there developments and technologies with which the (residual) risks of the extraction of shale gas (drilling, fracking, production of gas, water and drilling muds) can be reduced?*

Definition

This study focuses on the inventory of new developments and technologies that reduce (residual) risks of the extraction of shale gas, but then only on those topics laid down by the client, the Ministry of Economic Affairs.

(Residual) risks are understood to mean the risk of an unwanted event that remains after taking measures, as proposed in the Witteveen+Bos report published in 2013.

The risk of an activity is seen as the chance of an (unwanted) event multiplied by the effect of this event (risk = chance x effect). Risks can therefore be minimised by using measures to reduce the chance of something happening and/or by reducing the effect. Risks may be of a technical nature and relate to the extraction activity itself, or constitute a threat to people, nature and the environment. Although for some parts both types of risks are identified the report has a strong focus on the last category.

This study looks at new technologies and other developments that limit the chance of an incident or can reduce adverse effects of that incident. The study is of a qualitative nature and gives an overview of technologies and other management measures that are becoming available now, or in the near future (the coming 5-10 years). A condition is that they are now already in development or described as niche technology in available literature. Quantification of chances and possible effects can in many cases only be carried out by additional site-specific research and therefore falls outside the scope of this research.

TNO and Deltares are both active as scientific research institutes in the relevant areas. Together they understand the whole knowledge portfolio required here. Building on their existing expertise the partners are able to put the risks and proposed measures in perspective and create a clear overview, in which as far as possible they refer to scientific literature. In line with the question of the Ministry of Economic Affairs and in keeping with the independent role of TNO and Deltares, *no* position is taken with respect to the desirability of the different measures identified. The aim is to give as complete as possible an overview of methods for reducing the residual risks. The weighing, desirability and importance of using these methods forms part of the political debate, and must ultimately be adopted by bodies which are responsible for legislation and regulations regarding oil and gas extraction in the Netherlands.

For further information as regards our vision of honest research please refer to:
- TNO: The TNO Code – *How we are working on a better future (De TNO Code – Zó werken wij aan een betere toekomst)*[3]
- Deltares: Corporate Social Responsibility (Maatschappelijk Verantwoord Ondernemen)[4]

Guide

The main report describes for each sub-topic the relevant aspects of the risks and the developments and technologies available (in the long term), after which attention is paid to general conclusions relating to reducing risks relating to shale gas extraction in the Netherlands. Each section, which is always linked to one of the questions asked by the Ministry of Economic Affairs, is set out in the same way. First the Ministry's question is presented and put into context: the risks relating to the question are stated and put in the perspective of the anticipated Dutch situation. This is very different on several points from the practice for example in the United States, where to date most experience has been gained internationally. The relevant developments and available technologies for reducing these residual risks are then discussed. Each section concludes with an answer to the sub-question, with specific attention being paid to the so-called low-hanging fruit: the measures that can ensure a reduction in the residual risks relatively easily or in the short term. The main report concludes with an overall conclusion section, which as far as possible incorporates the insights from the different sub-conclusions.

Within the research that has led to the report, a great deal of knowledge has been collected that gives a good overview of current practice in the area of shale gas extraction and risk reduction as well. This knowledge base can be found in the appendices, classified by sub-question.

[3] https://www.tno.nl/en/about-tno/mission-and-strategy/tno-code/
[4] http://deltares.nl/xmlpages/tan/files?p_file_id=23114

Approach & Accountability

To arrive at an adequate response to the questions asked by the Ministry of Economic Affairs, the answers were prepared by a multidisciplinary team from TNO and Deltares including experts who have been involved in recent shale gas issues, who have relevant expertise from a different field of work, or who have a strong track record in research into the extraction of shale gas and/or environmental, health, and safety risks of industrial activities in general. To arrive at an overall response, all the sub-questions have been approached systematically in the same way.

A draft version of the report has been reviewed by external experts. This review was carried out by representatives of the Ministry of Economic Affairs, the Ministry of Infrastructure and Environment, KWR Watercycle Research Institute, the Association of Water Companies in the Netherlands (VEWIN), EBN BV, the Netherlands Oil and Gas Exploration and Production Association (NOGEPA), the Dutch State Supervision of Mines (SodM) and ARCADIS. Where possible and available their comments in response to the review are included in the final report.

Approach

The work includes firstly a study of relevant literature, available expert reports and identification of gaps. These gaps were then filled in by interviews with experts and additional literature research. This first phase was followed by a phase of knowledge integration not only to answer the questions in themselves, but also to indicate the relationship between them.

As stated above, a fixed format is used for each sub-question to evaluate technologies and developments:

1. Presentation of the question asked
2. Description of the relevant risks that are considered as they are known in current practice.
3. Description of the Dutch situation, to translate the knowledge developed abroad into a knowledge base relevant for the Netherlands
4. Presentation of the relevant developments and technologies that may help reduce the risks relating to shale gas extraction in the Netherlands.
5. Thematic conclusion that interprets the inventory

Technologies from other industries that could be relevant for minimising the (residual) risks of shale gas were also looked at. Promising technologies are being developed in other industries, but their use for the extraction of shale gas is mostly a question of the longer term.

Great care has been taken to clearly indicate sources when describing the different technologies, developments and other relevant knowledge. To ensure independence in this report, it was decided only to include knowledge and technology if their use has been proven and can be verified in scientific publications. As far as possible, peer-reviewed publications have been used here. To make the link between information and reference as clear as possible and to avoid duplication the references are mainly included in the background information (appendices), and not in the main report. The references in this report focus on the most recent literature (roughly the last 5 years) and specific insights for the Netherlands. The report of Witteveen+Bos (2013) is an important basis for this report. Another important starting point is the study of Tyndall (2011) which has looked at the impact of shale gas extraction from an English perspective and in its description of the base case uses a distribution relevant for Europe as regards quantitative assumptions on scale. This base case is more in line with the Dutch situation than knowledge and experience from the American context. In addition the EBN Notional Field Development Plan of Halliburton (2011) has been used, because this is aimed specifically at the Dutch situation. These studies give quantitative insights into the operations involved in shale gas extraction for possible Dutch situations. Companies from virtually the whole chain were consulted by means of interviews or review sessions for input and the completeness of this report. The precise details and added value of new developments and technologies for service companies often form part of confidential corporate information. Also this knowledge, that may possibly become available within a few years, is only included in the report if its use is proven and can be verified in scientific publications.

To give an indication of the maturity of the innovative technology or development, work is being carried out in many sectors with the ‘Technology Readiness Levels’, or TRL[5] for short derived from aerospace engineering:

- **TRL 1** – basic principles observed
- **TRL 2** – technology concept formulated (proof of principle)
- **TRL 3** – experimental proof of concept
- **TRL 4** – technology validated in lab environment
- **TRL 5** – technology validated in relevant environment
- **TRL 6** – technology demonstrated in relevant environment
- **TRL 7** – system prototype demonstration in operational environment
- **TRL 8** – system complete and qualified
- **TRL 9** – actual system proven in operational environment

We have also used this in this report as an indicative tool, but we distinguish between 3 categories, which we want to link as far as possible to the PlanMER Shale gas. These categories give the maturity of innovations related again to the TRLs, with an expected period until they can be considered ready for market.

Category 1: These innovations have a TRL of 1-3 and this is hence a technology proven to an experimental phase to Proof of Concept. These technologies are not expected to be on the market in the coming 10 years.

Category 2: These innovations have a TRL of 4-6 and this is a technology that is validated to demonstrated in a relevant environment. These technologies should appear on the market within 10 years.

[5] Based on the TRL appendix G used by the European Union in the new work programme for research and development Horizon 2020

Category 3: An innovation/development with a TRL of 7-9 (green) is a technology that is from prototype to actually proven in an operational environment . These technologies will be available in the short term.

Accountability

The overview presented here clusters knowledge from various disciplines and is hence a knowledge base of technologies and developments that can reduce the risks of shale gas extraction. The purpose of the knowledge base is to be an important information source for all stakeholders, and it aims to provide technical-scientific support for decision-making on the development of shale gas in the Netherlands.

The variety of expertise requested is wide and requires a highly multidisciplinary team, which represents a high degree of seniority. Set out below are the different departments from TNO & Deltares that have contributed to this research.

- TNO Climate, Air and Sustainability
- TNO Petroleum Geosciences
- TNO Risk Analysis for Products In Development
- TNO Sustainable Geo-Energy
- TNO Sustainable Transport & Logistics
- TNO Water Treatment
- Deltares Soil and Groundwater Systems

MAIN REPORT

1 Ground- and Surface water

1.1 Introduction

1.1.1 Question:

In shale gas extraction is there a risk of contamination of ground- and surface water due to the spillage of chemicals, fracking water or flowback water, how can this risk be limited?

1.1.2 Overview of relevant risks and processes

The extraction of shale gas is an intensive process in which a lot of chemicals and process water is used. Furthermore a large number of waste streams are produced during drilling of the wells, fracking and gas production. The principal waste consists of wastewater (flowback water from fracking and production water) and drilling muds. On the extraction sites the chemicals will have to be supplied and stored. The wastewater is also stored in storage tanks. This wastewater can be treated on site or transported to a wastewater treatment plant. The supply, transfer, storage and disposal of the chemicals and wastewater may involve spillage and leaks where the soil and groundwater are contaminated. Incidents in the form of spillage, leaks, etc. cannot be prevented entirely and regularly occur in conventional and unconventional gas or oil extraction.

1.1.3 Relevant aspects for the Dutch situation

On Dutch mining sites measures and provisions are taken to protect the soil from contamination that are also specified in the form of outcome-oriented regulations in the environmental permit from the underlying Environmental Law Decree. The 2012 Netherlands Soil Protection Directive (Nederlandse Richtlijn Bodembescherming – NRB) is for the present the statutory framework for this. For above-ground storage of fluids such as chemicals and wastewater the Soil Protection Directive for Above-ground Atmospheric Storage Tanks applies. Soil protection measures must also be taken for mobile installations on mining sites (Decree on general rules governing the environment in mining (Besluit algemene regels milieu mijnbouw), Official Gazette 2008 125). The Netherlands Soil Protection Directive (NRB) offers a further, general development of this.
The term '"negligible risk" (verwaarloosbar risico) is at the heart of the NRB: a situation in which by a combination of provisions and measures the occurrence of or increase in contamination of the soil measured between zero and final situation research is as far as possible prevented and where remediation of the soil is reasonably possible. Via the so-called customised route non-traditional measures can be implemented with which a negligible risk is also achieved, offering an opportunity for innovation. Traditionally impermeable floors and paving are used as a soil-protection provision but in principle other effective physical provisions are also permitted.

Incidents also occur in the Netherlands on mining sites with soil contaminants. It can be concluded from the annual reports of the Dutch State Supervision of Mines that from 2007 to 2012 there were 150 incidents with substances contaminating the soil and of these 30 took place outside the mining site (Hartog & Cirkel, 2013). The risk of soil and groundwater contamination therefore not only exists on the extraction site but also outside it. According to the annual reports in all cases of soil contamination the soil was decontaminated according to the existing legislation and regulations.

1.2 Technologies and developments that reduce the (residual) risks in shale gas extraction

Various techniques are available that focus on soil protection and prevention of leaks from storage tanks and associated piping. These relate above all to techniques that should 1. prevent penetration of fluids and other materials into the soil and 2. prevent leaks from storage tanks and piping. Many of these techniques have been developed in recent decades and new developments are coming into being more by evolution than by revolution.

In case of any future change in the legislation, new techniques may also be included. A potentially attractive new technique is the use of geotextile and geosynthetics as a preventive measure to prevent contamination of the soil and ground- and surface water. This involves liner systems of impermeable material which contains a drainage layer. This can incorporate a shock absorbing layer so that trucks can drive over it. This measure is probably particularly attractive for use in places where activities representing a threat to the soil either take place over a relatively short time or there are less frequent risks of soil contamination.

Developments that are underway for storage tanks such as those also used in the American oil industry, relate in particular to the material of which the tanks are made and the coatings that are used. New material from which the tanks are made includes glass fibres or steel tanks covered in glass fibre or durable coatings. New developments for storage tanks made of synthetic materials, plastics and epoxy are also taking place in the Netherlands (Jong et al. 2009).

It is also important that 1. when an incident occurs action can quickly be taken to limit its scope as far as possible, 2. incidents are not only limited to extraction sites but may also occur outside these sites through accidents during road transport and faults in pipeline infrastructure. Appropriate maintenance and inspection are essential elements that help limit incidents.

1.3 Conclusions

Incidents in the form of spillage, leaks, etc., as reported[6] by SodM, occur on mining sites or during transport from and to the sites (by pipelines or by road). In recent decades much has been achieved to limit the effects on the soil by means of measures and provisions. This applies both as regards regulations and technologies. Appropriate maintenance and inspection also play an important role here.

Technical developments relating to soil protection or prevention of leaks from tanks and piping are occurring at present more by evolution. An attractive, new and preventive technique is the use of geotextile and geosynthetics on surfaces (*Category 3*).

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[6] From Annual Reports of the Dutch State Supervision of Mines

2 Methane Migration

2.1 Introduction

2.1.1 Question:

What are the most recent findings in the area of migration of methane or other components from the fracked shale stratum to the overlying aquifer? And in particular for the Netherlands. Are new techniques known with which measurements can be carried out on site, in detail, and underground to identify any leaks and/or migration of methane or other components to aquifers?

2.1.2 Overview of relevant risks and processes

The most important risk of migration of chemical components from the fracked shale stratum to the overlying aquifer is that shallow aquifers are contaminated. This risk is determined by the chance that due to fracking a migration path is created between the fracks and shallow aquifers, and the effect of any contamination. Because of the specific rock properties of shales (among other things low permeability) it is very unlikely that methane migration will cause contamination of shallow aquifers – and therefore this must be investigated for each situation – as (1) the extraction occurs at a sufficient depth so that no direct link is formed between the fracks and aquifers, (2) there are no big natural faults present that form a link between fracks and aquifers along which methane or other components can migrate, and (3) fracking is not affected by the insulating action of cemented wells.

2.1.3 Relevant aspects for the Dutch situation

Micro-seismic monitoring of the vertical extent of fracks in the US and Canada shows (1) that none of the fracks extend as far as aquifers, (2) that the distance between the top of the frack and aquifers in more than 99% of the cases is more than 1000 metres and the associated fracks extend less than 350 metres from the horizontal strands to overlying strata, and (3) that the vertical extent of fracks depends very much on site-specific factors (such as local stress state) and the method of fracking (above all the quantity of fracking fluid injected.

For shale gas extraction in the Netherlands it is assumed that extraction will be at depths of more than 1500 metres. At present there is still no practical experience with fracking the Dutch shales (see also Witteveen+Bos 2013 for experience in the Netherlands with fracking for conventional gas extraction). Modelling studies for the Posidonia Formation show that the vertical extent of fracks is less than ~200 metres from strands (depending on injection volume). A direct link between the fracks and aquifers is therefore virtually excluded. No examples are known from the US and Canada where fracking in shale gas extraction has caused a link between fracks and aquifers along natural faults. There are no indications from conventional gas extraction in the Netherlands that migration of methane or other components along natural faults constitutes a risk on a short (non-geological) time scale. In the US and Canada migration of methane or other components from the fracked shale stratum to the overlying aquifer along the well is seen as an important possible cause of contamination of ground- or surface water. The risk is present if the design, positioning or cementing of the well is not carried out properly. This risk is limited in the Netherlands by stringent legislation and regulations for the design of wells.

Because of the greater scale on which fracking is carried out in shale gas extraction, the effect of fracking on the insulating action of wells may be a point of concern (see also section 6).

2.2 Technologies and developments that reduce the (residual) risks in shale gas extraction

The most important analyses and measures that can be used *before* starting fracking and shale gas extraction to limit risks of migration are (TRL8-9):

1. An analysis of the existing composition and where applicable contamination already present in the groundwater (“baseline”).
2. Site-specific analysis of the geological and geomechanical conditions of the subsoil as regards the presence of large scale permeable faults.
3. Design, positioning and cementing of the wells in accordance with Dutch legislation, taking into account the planned fracking activities, presence of large scale faults and nearby wells.
4. An estimate of the dimensions of fracks in the subsoil using models for the site-specific execution of fracking.

The most important analyses and measures that can be used *during* the pilot phase/initial phase of fracking and gas extraction are (TRL8-9):

1. Monitoring the composition and contamination in the groundwater, so that it can be established whether migration occurs.
2. (Micro-)seismic monitoring to determine the extent of fracks and the dimensions of the stimulated reservoir volume (see also sections 7, 9).
3. Implementing a “traffic light” or “hand on the valve” method (among others, Bommer et al. 2006), where extraction activities are temporarily stopped or suspended if migration is observed.

The most important new techniques for limiting migration risks in shale gas extraction are aimed at improving underground monitoring of leaks by (1) improving the design of seismic monitoring networks and methods for processing and interpreting (micro-)seismic data so that migration paths that may occur due to fracking can be better mapped, (2) development of sensors that at high resolution can detect changes in chemical composition in deep aquifers above the shale stratum, and (3) the combination of different monitoring techniques for example based on tracers, temperature, electrical conductivity, or acoustic signals (TRL1-4).

In the short term (1-3 years) additional research in the area of the interaction of fracks with geological structures and wells may have added value for the Dutch situation. In the longer term (3-5 years) it is the above all important to eliminate the knowledge gaps regarding the use of (micro-seismic and chemical) monitoring to detect and mitigate vertical migration through wells.

2.3 Conclusion

Micro-seismic monitoring of the vertical extent of fracks in the US and Canada shows that none of the fracks extend as far as aquifers and that the distance between the top of the frack and aquifers in virtually all cases is over 1000 metres.

Modelling studies for the Posidonia Formation show that a direct link between the fracks and aquifers can also be virtually excluded for the Netherlands. Risks of migration of methane or other components from the fracked shale stratum to the overlying aquifers are limited in virtually all situations, and only significant if fracking affects the insulating action of wells. This risk is limited in the Netherlands by stringent legislation and regulations for the design of wells, but may be a point of concern, in view of the scale of fracking in shale gas extraction.

Before starting fracking and shale gas extraction site-specific analysis of the geological and geomechanical conditions of the subsoil, modelling of expected dimensions of fracks, and extra attention to fracking activities in the planning and design of wells can help limit migration risks (*Category 3*).

During fracking micro-seismic monitoring and monitoring of composition and contamination in the groundwater and/or deeper aquifers can be used to temporarily suspend or limit fracking or gas extraction (*Category 2*).

In the medium to long term (3-5 years – *Category 2*) improvements in the design of seismic monitoring networks, further development of high resolution sensors for monitoring, and the combination of different monitoring techniques can help further limit migration risks.

3 Chemicals for drilling and fracking

3.1 Introduction

3.1.1 Question:

Various chemicals are used for drilling and fracking. Can the use of these chemicals be avoided? Are there alternatives? What are the developments relating to new more sustainable chemicals? Can the chemicals be replaced by substances that are biodegradable (in the deep subsoil or in any wastewater treatment plant) and/or non-environmentally harmful substances?

3.1.2 Overview of relevant risks and processes

The risk of using chemicals for fracking is determined by the chance that the chemicals will have a harmful effect on the earth's surface or in the subsoil and the impact of the harmful effect on the environment. The risk that chemicals have a harmful effect on the earth's surface is mainly determined by the chance of-spillage or leaks (see section 1), the quantity, concentration and toxicity of the leaked chemicals, and the site-specific interaction with the environment which leaked chemicals can reach. For the risk in the subsoil depth and spread are also important factors. For the effect in the subsoil it is furthermore important how the chemicals behave at higher temperature and pressure. Some chemicals break down quickly in the subsoil and are therefore less or not harmful in the subsoil. The toxic effect of pure substances says little about the possible effects of dilute substances on the environment in shale gas extraction. The optimum composition for gas extraction of the chemicals in a fracking fluid may differ for each fracking activity, and among other things depends on the depth, thickness, composition and properties of the reservoir rock.

Fracking fluids *may* contain the following chemicals:

1) water is the main component and serves as a solvent or means of transport for the other components,
2) proppants consisting of screened sand or ceramic granules of a certain size to keep fracks open after fracking so that gas can flow to the well,
3) acids and acidity stabilisers to prevent silicates in the stratified rocks swelling or dissolving some minerals from the rock,
4) iron control additives to prevent deposition of iron or metal oxides in the well,
5) gel polymers, gel stabilisers, viscosifiers and crosslinkers to increase the viscosity and carrying capacity of the fracking fluid so that the proppants are carried to the fracks and crosslinkers to form gels with high viscosity and carrying capacity,
6) friction reducers to reduce the friction in the well during pumping,
7) surfactants to reduce surface tension between the rock and fluid to promote the inflow and outflow of the fracking fluid,
8) corrosion inhibitors to prevent corrosion of the well,
9) clay stabilisers are intended to prevent swelling and migration of water-sensitive clay,
10) gel breakers to break down gels after formation so that after their action they can flowback out of the well,

11) oxygen scavengers to prevent the polymers breaking down too quickly, precipitation of iron or metal oxides in the well and to prevent oxidation,
12) scale inhibitors can be used to prevent precipitation of some poorly soluble carbonate and sulphate salts,
13) biocides to prevent the growth of bacteria,
14) fluid-loss additives to limit the uptake of fracking fluid by the rock so that it can largely be recovered, and
15) anti-surfactants and defoamers to reverse the effect of surfactants and prevent foaming.

In addition to this analysis of functionality in the report the toxicity of the most commonly used chemicals is analysed based on existing guidelines, classifications and recordings, and trends in the development of possible alternatives identified (see appendix C1).

3.1.3 Relevant aspects for the Dutch situation

In most cases the same fluids are used for drilling and fracking in shale gas extraction as for drilling for conventional gas (see also Witteveen+Bos 2013), although the optimum composition of the chemicals in a fracking fluid may differ depending on the properties of the reservoir rock.

The *Netherlands Oil and Gas Exploration and Production Association* (NOGEPA) has prepared a fact sheet of *all products* that have been used in the last 5 years for the extraction of oil and gas in the Netherlands (NOGEPA, 2013). There is no practical experience in the Netherlands with fracking in shale gas extraction. The products in the NOGEPA fact sheet (2013) have therefore been used to date for fracking for gas extraction from so-called ‘tight gas’ sandstones, or other less permeable conventional gas reservoirs.

As regards the toxicity of chemicals used in the NOGEPA fact sheet (2013) hazard-classifications and risk phrases are set out for both the individual components (based on Directive 67/548/EEC) and the products as a whole (based on Directive 99/45/EC). For the use of hazardous chemicals during gas extraction activities on onshore sites information must be provided that demonstrates that the activities comply with the REACH, CLP and Biocides EU Regulations. In addition it must be noted that additives that are included in REACH, must in addition also be approved for use as a fracking fluid (see appendix C2).

3.2 Technologies and developments that reduce the (residual) risks in shale gas extraction

Most knowledge development in the area of fracking fluids takes place in the service industry that plans and carries out fracking operations for the E&P industry. Extensive information about fracking techniques and fracking fluids can be found on various websites of the service industry. The most recent developments from the service industry are mainly aimed at more efficient fracking so that less fracking fluid is necessary and at less harmful and more environmentally friendly fracking fluids. Screening of the toxicity of the most frequently used chemicals can be used to limit the risk of using chemicals in fracking by (1) determining the *substance-specific* function in fracking, (2) replacing chemicals with unwanted classification(s) by chemicals with no classification or with a lower classification, and (3) using classified chemicals in lower concentrations or not using them if that does not adversely affect the efficiency of fracking and gas extraction too much.

In addition there is a lot of development in the area of alternative, more sustainable, biodegradable and non-environmentally harmful chemicals in fracking fluids. The added value and technical usability of these chemicals has often not yet been tested and must be looked at on a case by case basis to arrive at a more environmentally friendly fracking fluid. It is also important here to determine the actual toxic effect of the chemicals under the relevant conditions. Special techniques can also be used so that fracking can be better controlled or be carried out more efficiently. By better control of fracking, or by other stimulation techniques work can be carried out with less fracking fluid and/or chemicals. A promising technique that is in line with this is so-called zipper fracking, where fracking is carried out simultaneously from two parallel horizontal shale gas wells and is hence better controlled. This technique is already being used in the US and Canada.

There are also special drilling techniques that could replace fracking in the longer term (5-10 years), among other things radial wells where parts of the reservoir are drilled from a central well or needle/fishbone wells where a large number of short, thin wells are jetted from a central well with hydro-jetting.

Other techniques (such as thermal, pneumatic, electrical or exothermal fracking, or fracking with explosives or pressure pulses) are exotic or in the experimental phase (at most used once or a few times in a controlled environment), and it is unclear whether these techniques have added value and in what short term they can be used.

3.3 Conclusions

The risk of using chemicals in fracking is determined by the chance that chemicals will have a harmful effect on the earth's surface or in the subsoil and the impact of the harmful effect on the environment. The optimum composition for gas extraction of the chemicals in a fracking fluid may differ per fracking activity, and among other things depends on the depth, thickness, composition and properties of the reservoir rock. Although the toxic effect of pure substances says *only* a little about the possible effects of diluted substances on the environment in shale gas extraction, these can be used to limit the risk of using chemicals in fracking fluids (*Category 3*).

An inventory of chemicals that are used for fracking in the Netherlands (see appendix C2), makes it clear that there are opportunities for choosing safer substances with the same functionality as less safe substances. There is a lot of development in the area of alternative, more sustainable, biodegradable and non-environmentally harmful chemicals in fracking fluids.

In addition to developments in using chemicals for drilling of fracking fluids, there are also (niche) techniques such as zipper fracking and special drilling techniques that can make fracking more efficient or even replace them so that the use of chemicals can be used or prevented. The added value and technical usability of most other techniques is unclear and it is unlikely that they will be in use in the short term (< 5 years).

It is not known what the ideal composition of fracking fluids is for the shales in the Netherlands. This gap can be reduced in the short term (1-2 years) by analysing the rock properties and effects of different fracking fluids for shales from the US and Canada. The complete filling of this gap can only be carried out by acquiring practical experience with fracking of Dutch shales. Other gaps lie above all in the usability and added value of more exotic alternatives for chemicals in fracking fluids that have at present only been tested in laboratories (period of use application 5-10 years – *Category 2*).

4 Treatment of flowback and production water

4.1 Introduction

4.1.1 Question:

A large quantity of water is injected into the ground and returned to the surface. The flowback water contains harmful substances that are naturally present in the earth. The processing of flowback water is a known problem in the conventional gas industry. In particular the scale of the quantities of flowback water for shale gas requires new solutions in the area of treatment. Are conventional wastewater treatment plants available to treat the produced water? Can this be done on site? Can this water be discharged or reused without additional risks to the surface water?

4.1.2 Overview of relevant risks and processes

Two types of water streams to be produced can be distinguished in shale gas extraction: the flowback water that is produced immediately after fracking, and the production water, that is also produced when exploiting shale gas. The first – based on Tyndall (2011) (see appendix d) concerns a relatively large volume within a short time and the latter category concerns small volumes during the exploitation period of the well. In both cases this is poor quality water: the production water will be brine with concentrations above those of seawater, in which among other things hydrocarbons such as benzene are produced at the same time. In the case of flowback water the salt concentrations may be somewhat lower but the additives to the fracking water also partly flow back. It is undesirable for these water streams to get into the surface water, soil or associated groundwater layers.

Three scenarios or combinations of these are feasible for processing these water streams: 1. treatment until the water can be returned (back) into the environment, 2. injection of the water into an abandoned gas field (which is possible under strict conditions for the production water in conventional gas extraction in the Netherlands), 3. reuse in subsequent fracking activities. For the second and third scenario treatment may possibly be necessary for some of the (non-natural) substances, which will partly depend on the regulations.

4.1.3 Relevant aspects for the Dutch situation

In conventional onshore gas extraction the production water is injected into an (empty) gas field. In the Netherlands there is therefore experience with processing production water. It is relevant that in a well inspection campaign in 2008 three of the five injection wells had problems with well integrity, defects or uncertainty in this respect (Vignes, 2011). This number of 60% is significantly higher than the number of production wells that showed comparable defects in the same campaign, namely 1 of the 26.

|In the extraction of shale gas water is released that may be saltier than seawater, or a brine. For comparison: in conventional gas extraction up to 200 g Cl^-/L gets into the production water while seawater contains 19 g Cl^-/L. In the Netherlands there are not yet any plants operational that desalinate seawater or even saltier water on a commercial scale. In the recent past there was such a plant on Texel, but this closed in 1994. In other parts of the world including the Arab world plants of this

type are however operational. In the Netherlands there is a lot of experience with treatment of all sorts of wastewater, where consideration can be given to the fact that the Netherlands also has an extensive petrochemical industry. Practical experience in the area of water treatment is therefore widely present and knowledge development is also being carried out in different research groups.

4.2 Technologies and developments for water treatment

Water treatment in shale gas extraction is still in its infancy compared with water treatment in other industries. For the treatment of flowback water it is natural to use technologies that are already used in the oil and gas industry or which are already used in other sectors for water treatment for the specific substances that are present in the flowback water. Relevant treatment stages, as also found from the experience in the United States, that can be undergone to treat flowback water and production water, are:

- Removal of suspended solids: SS and sand;
- Oil removal;
- Removal of dissolved organic matter (aromatics, fracking chemicals, natural organic materials NOM);
- Removal of heavy metals and scale formers (divalent ions);
- Removal of salt;
- Disinfection.

The degree to which the stages must be gone through (the intensity, quality requirements and required treatment chain) depends on the quality that is required for discharge, injection or reuse. The more treatment stages, the better the quality of the water of course becomes.

Innovative technologies seem above all necessary for desalination, because this is the most expensive and most energy-demanding stage. It should after further development be possible to use technologies such as membrane distillation, membrane distillation/crystallisation and freeze crystallisation, but also existing thermal desalination methods must be further tested for the use of flowback water. At present there is one desalination plant in operation in Pennsylvania (US) that has demonstrated the economic and environmental feasibility and wastewater converted into water that meets the local discharge requirements and in salt which is used for spreading on ice (road salt) (Hirsch, 2014).

Table 1 lists different technologies that are considered able to carry out the required treatment stage, with the associated TRL. The TRL (see Approach & Accountability for an explanation) is used for the situation generally arising in all sectors. A description of the technologies can be found in Appendix D2: Brief description of water treatment technologies

Table 1. Technologies for the removal of different substance groups in flowback water.

Suspended solids and sand		**Dispersed oil**		**Desalination**	
Technology	TRL	Technology	TRL	Technology	TRL
CPI/PPI	9	CPI/PPI	9	Crystallisation	9
Hydrocyclone	9	Hydrocyclone	9	Freeze crystallisation	4
(Bag) filtration	9	Candle filtration	9	RO	9
Media filtration	9	Media filtration	9	Forward osmosis	9
Microfiltration/ Ultrafiltration	9	Electrocoagulation	9	Membrane distillation	7
Flocculation/ coagulation	9	Dissolved air flotation (DAF)	9	Membrane distillation/ crystallisation	3
Dissolved organic matter		**Divalent ions/heavy metals**		Multi Stage Flash (thermal desalination)	9
Electrocoagulation	9	Precipitation	9	Multi Effect Distillation (thermal desalination)	9
Activated carbon filtration	9	Media filtration	9	Mechanical vapour recompression (thermal desalination)	9
Fluid-fluid extraction	9	Crystallisation	9	**Disinfection**	
Pertraction	9	NF	9	UV	9
MPPE	9	Ion exchange	9	Chlorine, chlorine dioxide, sodium hypochlorite	9
$UV/H_2O_2/O_3$ (AOP)	9				
RO	9				

CPI/PPI: corrugated plate interceptor/parallel plate interceptor
AOP: advanced oxidation processes

4.2.1 *Capacity of conventional wastewater treatment plants*

In principle wastewater treatment plants are available to remove any contamination in the flowback/produced water. However, due to the complex composition of the mixture it cannot be stated with certainty in advance how good these technologies work for the given conditions.
Removal of particles, oil, (natural) organic material, scale formers (e.g. Ca, Mg) is usually possible with conventional technologies that are also in part already used in the oil and gas industry. Desalination of the production water is the most challenging stage in the treatment. If the salty water may not or cannot be discharged or injected, it must be largely desalinated. Reverse osmosis (RO) is a conventional desalination stage. This can be used for TDS (total dissolved solids) concentrations up to around 50 g/l. In the production water however TDS concentrations may occur of 100 g/l, 200 g/l or even more. In that case thermal desalination methods are necessary to remove the salt from the water, such as membrane distillation, multi stage flash and mechanical vapour recompression. These are technologies that are already used in other sectors, but not yet much in shale gas extraction. The costs of these technologies are high, particular the energy

costs. The energy consumption and the costs do however increase for each additional treatment stage and if a higher treatment output is required. Further research will have to establish whether these desalination technologies can be used at acceptable costs and whether they are also suitable in practice for the flowback/production water stream that is released in shale gas extraction.

4.2.2 Water treatment on the extraction site

Treatment of flowback water on site is in principle possible. Based on the scenario where on an extraction site with ten wells with in addition four different treatment stages, a wastewater treatment plant is necessary of the size of around 8 sea containers. Treatment plants with the dimensions of a sea container are available. Produced waste, sludge, and concentrate will have to be removed to be treated elsewhere. The costs for treatment on site will have to be compared with the costs for full disposal and treatment elsewhere in a large central treatment plant.

4.2.3 Reuse and discharge

Reuse for fracking or discharge to surface water can be undergone without additional risks as sufficient treatment stages. In principle very pure water can be produced from the flowback and production water that is suitable for high quality purposes. If there is the possibility or reusing the flowback water largely for fracking purposes without extensive desalination, then this contributes positively to the financial feasibility of shale gas extraction because of relatively easy treatment and limitation of water transport.

4.3 Conclusions

Flowback and production water contain a wide range of contaminants. Treatment to any required level is in principle possible. This is both possible on an extraction site with mobile units and at a central facility. Most techniques are in a very advanced stage of development (*Category 3*).

The required treatment will depend on where the water goes to: reinjection into an empty gas field, discharge to surface water or shallow groundwater or reuse in subsequent fracking activities. The desalination of the very salty brine water is the most intensive treatment stage in terms of energy and costs.

An interesting question remain: at what scale does an optimised treatment process from one shale gas extraction site become profitable? For example can an estimate be made of the number of wells per extraction site at which the tipping point lies between central (generic) treatment and treatment at the extraction site itself.

5 Alternatives for the use of water in fracking

5.1 Introduction

5.1.1 Question:

Are there alternatives for the use of water in fracking? For example by liquefied gases such as propane, butane and carbon dioxide. Do these techniques have (or are they expected to have) a higher or a lower risk for the soil, groundwater, environment? What is the expectation as regards the risk for new techniques?

5.1.2 Overview of relevant risks and processes

In the vast majority of fracking fluids water is the main component. In view of the large quantities of fracking fluids needed for large scale shale gas extraction the use of water may constitute a risk for local water resources. The major risk in the use of water is that the water supply for example for drinking water supply or agriculture will suffer from the shale gas extraction. This mainly plays a part in areas with a water shortage or areas with other industry or activities for which a lot of water is necessary. For this reason, among other places in the US and Canada, a great deal of attention is paid to the water use for fracking, and there are companies operating that have specialised in fracking for shale gas extraction using alternative fluids. There are a range of possible alternatives for water in fracking fluids. It is important to report that most of these alternatives, because of their still early stage of development, are not (yet) used on a large scale. For some other alternative fracking fluids the added value as regards the reduction of risks in shale gas extraction, it has not been demonstrated whether the fluids are more harmful, more dangerous or more difficult to handle than conventional fracking fluids.

5.1.3 Relevant aspects for the Dutch situation

In the Dutch situation it is the unlikely that a water shortage will occur in case of shale gas extraction, provided sound planning is carried out beforehand for the supply of water used in fracking. In addition the load on the existing local water supply infrastructure plays an important role (see also section 10 on transport).

As regards alternative fluids that can replace water in fracking – based on Article 42 of the Decree on general rules governing the environment in mining[7] – when using chemicals during gas extraction activities on onshore sites information must be supplied that shows that the activities meet the REACH, CLP and Biocide EU Regulations (see also section 3 on the use of chemicals). All operators use the NOGEPA chemical tool for this, see Figure 1.

[7] News report 13 May 2014 on Dutch State Supervision of Mines website (www.sodm.nl)

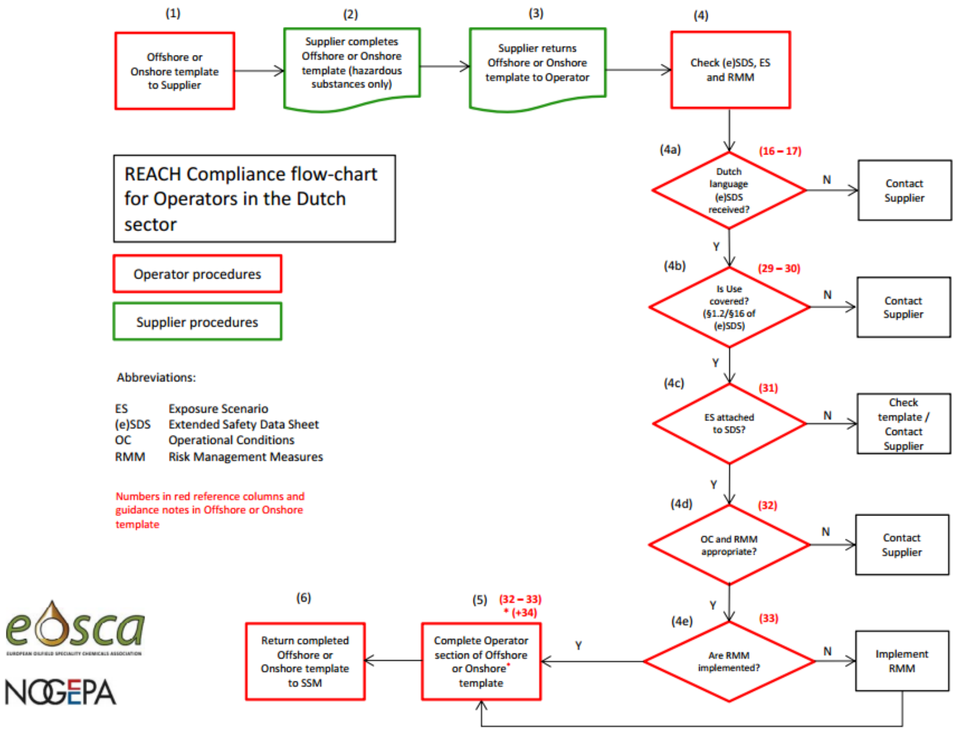


Figure 1: Flowchart from NOGEPA chemical tool, which must be followed and which has already been implemented by every operator (SodM - 13-05-2014)

5.2 Technologies and developments that reduce the (residual) risks in shale gas extraction

There are various alternatives so in fracking water can be entirely or partly replaced by oil-based substances (among othersLPG, propane, diesel), carbon dioxide, nitrogen, helium, foam, acids, alcohols, emulsions. Alternatives for the use of water as a fracking fluid that are already in use are carbon dioxide, LPG and propane. For carbon dioxide an additional advantage is that more gas can possibly be extracted because absorbed methane in the shales is released, and at the same time carbon dioxide is ‘fixed’ in the shale rock. The risk for soil, groundwater and environment very much depends on the method of use, environment, availability, transport and costs of alternative substances and is therefore different for each project. Generally the alternatives have the advantage (as regards risks for the soil, groundwater, environment), that few or no other chemicals are needed.

Table 2: Advantages and disadvantages of alternatives as identified by Gandossi (2013)

Advantages	Disadvantages
Seem to give better results as regards the effect of fracking on gas production	Are themselves often harmful or hazardous (LPG, diesel, foam, acids, alcohols)
Flow back more easily (LPG, propane, diesel, foam, nitrogen, helium)	In virtually all cases are hardly used or only under experimental conditions, so their effect and risk is insufficiently known
After *working* in the shale the risk for the environment is lower (acids)	In virtually all cases special installations or infrastructure are necessary to use the alternatives
Are readily biodegradable (alcohols)	In some cases seem to give worse results as regards the effect of fracking on shales
Are less harmful for the environment (CO_2, nitrogen, helium)	In virtually all cases are more expensive

In particular carbon dioxide, LPG and propane are used in the US and Canada but each bring their own problems and risks for large scale use. Most other techniques are in the experimental phase and not fully developed.

5.3 Conclusions

In the vast majority of fracking fluids water is the main component. The most important risk of the use of water-based fracking fluids is that large scale shale gas extraction can affect local water resources. This is probably not an issue in the Netherlands, provided it is well planned.

There are a range of possible alternatives for water in fracking fluids, of which carbon dioxide, LPG or propane are used most in the US and Canada (*Category 2*). Most alternative fracking fluids are not used on a large scale (in relative terms), the added value as regards reducing risks in shale gas extraction has not been demonstrated, or the fluids are more harmful, more hazardous or more difficult to handle than conventional fracking fluids.

The most important knowledge gaps are therefore related to the technical usability, practical feasibility of wide use, and the added value for risk management. Because of the disadvantages (see Table 2) it is not expected that the alternatives will play a major role in the near future (5-10 years – *Category 2*) in fracking for shale gas extraction. As a result their risk for the soil, groundwater, environment for large scale use are for the present insufficiently known for reducing the risks of shale gas extraction in the Netherlands.

6 Well integrity

6.1 Introduction

6.1.1 Question:

Are there new techniques that reduce the chances of failure of well integrity? Are there new methods for monitoring well integrity? In the case of a loss of well integrity are there new methods or developments for restoring well integrity?

6.1.2 Overview of relevant risks and processes

Possible risks of loss of well integrity relating to shale gas extraction are discussed in evaluations and policy and technology exploration such as the UK Shale Gas review, the review of the Canadian Academy of Sciences, and a number of recent panorama publications in scientific literature; recent technical-scientific literature focuses in particular on the inventory of possible problems with well integrity and the frequency with which this type of problem could occur in shale gas extraction (Davies et al, 2014; Bachu and Valencia, 2014; Ingraffea et al., 2014). Risks relating to well integrity that are specific to shale gas, are (DNV, 2013; Bachu and Valencia 2014):

- The great number of wells, located close to one another, with possible leakage paths via fracks or adjacent wells;
- Risks of leaks of fluid to rock aquifers due to drilling work and wells;
- Fracking carries a risk of induced seismicity with it, with the possible consequence of damaging well integrity.

In addition issues that are specific to the integrity of horizontal wells play a part (Bachu and Valencia, 2014):

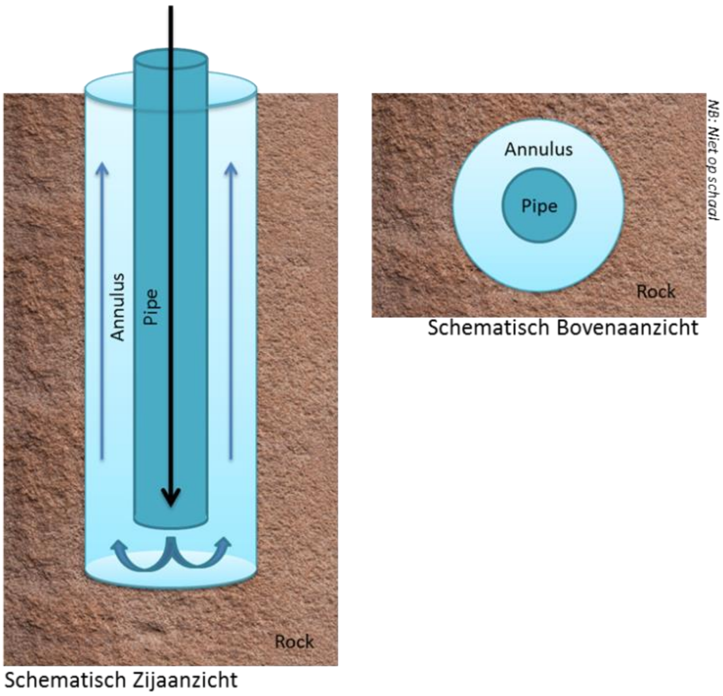
- Forces on the horizontal part of the casing make it difficult to centre the casing properly for the horizontal part of a well with the possible consequence of inadequate cementing
- Repeated pressure changes along the horizontal part lead to extra stress on the casing and cement

Research in shale gas wells in the United States indicates that in 3 to 6 % of wells problems have possibly occurred with well integrity (Davies et al, 2014). How these problems must be translated into an increased (long term) risk is however unclear, because the inventories do not elaborate on the result of intervention to restore integrity.

6.1.3 Relevant aspects for the Dutch situation

The Mining Decree (Mijnbouwbesluit) and the Mining Regulations (Mijnbouwregeling) specify rules that, in addition to safety requirements for well design, also relate to monitoring of the well during construction and use.

In the first instance the integrity of a well is tested by means of so-called Formation Pressure Tests (FPT), which look at how the pressure at the top of the well responds to a pressure load that is higher than the rock pressure in the deeper section. When the pressure applied partly ceases this may mean that somewhere along the well there is a leak. The most commonly used methods for well inspection are the Cement Bond Log (CBL). A CBL gives a relatively rough estimate of the local thickness and quality of the cement adhesion. A video camera can also be used or a so-called Multifinger Caliper Log (MCP) to detect damage to the casing. Possible damage to the integrity may also be detected on the surface by monitoring the pressure at the top of the well (the pressure in the annulus: see Figure 2 in light blue (Annulus Pressure)). A continuous high pressure on the casing may indicate that the seal of the well is not adequate. Changes occurring in pressure, both plots rising, and a steadily increasing pressure, on the surface may indicate acute leakage along the well. Monitoring of possible leakage can also be carried out by regular sampling and determination of methane concentrations on the surface or in shallow aquifers. The deviation in the concentrations and composition of the gas from expected values or previous measurements is then an indication of leakage.



Schematic side view Schematic top view

Figure 2: Schematic diagram of a well and the annulus (light blue)

In 2010 the Dutch State Supervision of Mines (SodM) carried out research (news report 29 November 2010 on the Dutch State Supervision of Mines website (www.sodm.nl[8])) into well integrity in the Netherlands. It concluded the following from this:

- No alarming insights arise regarding well integrity. In cases where there were problems, these were reported to SodM and the monitoring and hence prompt repair of the well is working well;
- It is reported that there are no indications of problems with well integrity for (conventional) gas wells and severe corrosion problems in water injection wells.
- The principle of double barriers is used everywhere in the Netherlands. True this is according to the executing party's own interpretation, but there is no reason to change anything either in well design, or to introduce detailed, statutory regulations.
- The numbers of wells considered were not representative and the same applied for the associated conclusions.
- The procedures relating to well integrity can be improved in the Netherlands

This study was also an input for the above-mentioned study by Vignes (2011).

In addition the Witteveen+Bos report states that for individual wells the occurrence of leakage flows is virtually the same as the risk for conventional gas extraction and that the chance of 'blowouts' is lower, because for shale gas the gas does not flow of its own accord. Due to the higher number of wells on one extraction site, the cumulative risk is however greater than for conventional gas extraction.

6.2 Technologies and developments that reduce the (residual) risks in shale gas extraction

Integrity of a well means that the different parts that are fitted in a well function properly so that no leaks of fluids or gasses can occur from deep rock formations to shallower rocks of the earth's surface. Cement and the adhesion of cement to the casing and the rock is generally seen as the most important factor for the integrity of a well. Good cementing ensures that the well and the reservoir rocks remain insulated from the overlying rock formations.

Well integrity depends in particular on applying the cement correctly. The methods for this are based on decades of experience in oil and gas extraction. Recent developments have led to improvements on four fronts:

- Procedures for applying the cement suited to the local conditions in the well and determining the optimum cement composition by detailed modelling of the conditions in the well and the dynamics of the cementing process (McDaniel et al., 2014; Yadav et al., 2014).
- The planned rotation and movement of the casing to influence the dynamics of applying and setting of cement so as to improve the filling and adhesion of the cement (Holt and Lahoti, 2012).
- The use of specially composed flushing fluids that reduce the risk of leaving behind drilling muds and drilling fluid (Benkley and Brenneis, 2013).
- The use of improved formulae for the ingredients of the cement or the addition of substances that lead to an improved adhesion to the casing and

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[8] SodM Presentation for Nogepa on 'integrity of wellbores and wells' & SodM Presentation for Nogepa on 'integrity of mining installations'

rocks. An example of this is the use of special synthetic resins that ensure better adhesion between the cement column and sheath.
- The use of cement with plastic properties that ensure that any (hairline) cracks are sealed in the long term (self-healing cement). (Taoutaou et al., 2011)

In addition much new technology development is taking place in the area of well inspection and monitoring. As regards monitoring of well integrity a distinction can be made between inspection methods, usually based on logging tools, and sensors that are installed in the well permanently or in the long term.

More recent techniques for inspecting the quality of cement and casing are generally improved versions of the acoustic CBL tools or new methods for using these tools in horizontal wells (Nurhayati and Foianini, 2013). For example there are tools that can give a more detailed picture of the cement thickness due to a greater resolution around the well. Also combinations of electromagnetic and high-resolution acoustic observation give a better indication of cement thickness and adhesion to the casing.

The most important new development is the use of sensors based on glass fibre technology (fibre optics) for permanent monitoring in wells (Pearce et al., 2009, Rassenfoss, 2013). Glass fibre in principle offers the facility of measuring the temperature (Distributed Temperature Sensing, DTS), displacement due to stretching and shrinkage (Distributed Strain Sensing, DSS), and the pressure (Distributed Pressure Sensing, DPS) over the whole length of the well with high resolution and accuracy. Locally occurring changes in pressure or temperature may be an indication that a link has occurred between the deeper rock strata and overlying part of the well and therefore possible damage to the integrity. Severe stretching or shrinkage indicates deformation of the cement column or casing and hence an increased chance of damage to the integrity.

Glass fibre as a technology for permanent acoustic measurements has been tested under operating conditions (Distributed Acoustic Sensing, DAS). With DAS technology the sound of fluid flow, and therefore leaks, can be detected locally with great sensitivity.

Use of glass fibre technology offers prospects for a great improvement in monitoring well integrity (Hull et al., 2010). At present the technology is available, but is not yet often used. The technology is relatively expensive and not yet fully developed. In addition the great quantity of data that has to be processed and analysed requires specific knowledge and a great use of computer capacity.

To date there is very little experience with long term monitoring of well integrity after abandonment. In particular monitoring after abandonment of large numbers of (shale gas) wells is a knowledge gap. Regularly recurring measurement of the pressure in the well or the sampling of gas reserves on the surface may help detect any leaks promptly, so that remedial measures can be taken at an early stage (*Category 3*).

6.3 Conclusions

Ensuring well integrity is firstly a question of the correct use of existing technology and procedures. The knowledge and technology for this are present and proven in conventional oil and gas extraction. However, the extent of and a focussed approach to specific aspects related to shale gas extraction have still only been researched to a very limited degree, particularly in view of the intensity of drilling and fracking.

A significant reduction in risks will be achieved by using monitoring technology (*Category 3*). Maintenance of well integrity is high on the agenda of the industry and new and improved monitoring technology, which for example uses fibre optic sensors will be operational in a few years (*Category 3*).

The greatest risks for leaks to groundwater can be expected when in the long term the integrity of the well deteriorates after abandonment and sealing of a well (regulated by the Mining Decree and Mining Regulations).

7 Establishing the result of fracking

7.1 Introduction

7.1.1 Question:
Are new techniques or developments known with which the result of fracking can be established with greater certainty?

7.1.2 Overview of relevant risks and processes
It is important for both the optimum extraction of shale gas and the reduction of risks in shale gas extraction to have a good picture of the disturbance in the subsoil resulting from fracking. Better control and management of the result of fracking helps in particular to reduce the risks of migration of chemical components from the fracked shale stratum to the overlying strata (see section 7) and to reduce seismic risks (see section 9). A distinction can be made between techniques and analyses that can be used *before starting* or *during and after* fracking to check the result of fracking better.

7.1.3 Relevant aspects for the Dutch situation
In the Netherlands there is a great deal of knowledge about the use of seismic data for exploration and production of conventional oil and gas. There are different areas in the Netherlands for which 2D or 3D seismic profiling is available. The repeated gathering of seismic data for the same area is for example used for oil extraction in Schoonebeek. Because of the importance for optimising fracking and the extraction of shale gas micro-seismic monitoring is regularly used in the US and Canada. Micro-seismic monitoring *during fracking* is not yet used in the Netherlands. Long term seismic monitoring is however used in the Netherlands for monitoring induced seismicity (see section 9).

7.2 Technologies and developments that reduce the (residual) risks in shale gas extraction

The most important techniques required *before starting* fracking and gas extraction are (*Category 3*):

1. Site-specific analysis of the geological and geomechanical conditions of the subsoil in combination with models that predict the dimensions of fracks in the subsoil.
2. Multicomponent seismic data, for determining (geomechanical) rock properties.
3. The execution of laboratory scale frack experiments, to determine the effect of fluid injection on the shales and to calibrate frack models.

The most important development and techniques that can be used *during or after* fracking and gas extraction are (*Category 3*):

1. Micro-seismic data, for assessing individual fracks or stimulated reservoir volume *during fracking*.
2. Tiltmeters on the earth’s surface or in monitoring wells to map fracks.
3. Monitoring of gas or fluid flow from the fracks to the well using temperature variations or based on acoustic signals, to characterise fracks better.

4. Time-lapse seismic monitoring *before starting* and *after execution* of fracking, to determine changes in the subsoil as a result of fracking.

7.3 Conclusions

The new techniques and developments for establishing the result of fracking can be broken down into specific analyses that can be used *before starting* or *during or after* fracking or the extraction of shale gas.

The most important techniques that are used *before starting* fracking and gas extraction focus on better characterisation of the subsoil using models, seismic profiling or laboratory scale experiments.

The most important techniques that can be used *during or after* fracking and gas extraction focus on different types of monitoring. The most important technological developments that can contribute to better control of the result of fracking are (1) improvement in sensors, (2) improvement in the design of monitoring networks to use real time monitoring, and (3) better integration of geological and geomechanical models of the subsoil and micro-seismic data.

In the future alternative methods of monitoring, for example using (combinations of) electrical, thermal, or magnetotelluric monitoring may also have a part to play (*Category 1-2*). The combination of different monitoring techniques, for example micro-seismic and tiltmeter monitoring or 4D seismic profiling and micro-seismic data can help considerably in the better control of the result of fracking.

New data from wells, analyses of new sample material, and (laboratory) tests on new sample material are necessary to fill the most important knowledge gaps in the area of the effects of fracking in the subsoil and control of the result of fracking (period 1-3 years – *Category 3*).

For monitoring *during fracking* experience from the US and Canada can be used.

8 Methane emissions

8.1 Introduction

8.1.1 Question:

With what techniques can the risk of methane emission be prevented? Are these techniques used and are there new developments.

8.1.2 Overview of relevant risks and processes

In 2013 Royal HaskoningDHV (RHDHV) carried out a study into the carbon footprint[9] of shale gas from a Dutch perspective, where it is assumed that the gas is used to generate electricity for a meaningful comparison. RHDHV bases this on the Global Warming Potential (GWP) which is a relative measure of the potential of a greenhouse gas to warm the earth: the effect of 1 kg of greenhouse gas (where methane is one of them) over a period of 100 years compared with 1 kg of CO2 over the same period. The GWP for methane is 25 – 28, determined by the IPCC. RHDHV standardises this in their report to the GWP per kWh. In shale gas extraction this amounts to 4.5 g CO_2eq/kWh of which the majority of the methane emissions are associated with transport (~69%). For conventional gas extraction the emission load is 4.0 g CO_2eq/kWh. This is slightly lower, because the same quantity of methane emission is attributed to a smaller quantity of produced gas, because the production per well in shale gas extraction is lower. 100% reduction in methane emissions in shale gas extraction leads to ~1% reduction in the total carbon footprint (for comparison, a 100% reduction in Methane emissions in the United States can lead to ~10% reduction in the total carbon footprint).

Shale gas is in fact natural gas that sits in shale rocks and consists largely of methane. Methane (CH_4) occurs naturally in the atmosphere and, in outside air concentrations, is not harmful to people. However, methane is a powerful greenhouse gas. For this reason the leakage losses of methane in the complete chain from extraction to use partly determine the carbon footprint of shale gas extraction. Extraction of fossil fuels such as coal, oil and gas is accompanied by emissions of methane. The question is therefore not whether CH4 emission will take place in shale gas extraction, but whether there are techniques for reducing this emission as far as possible.

Non-methane volatile organic hydrocarbons (NMVOC) can also be emitted in shale gas extraction including possibly the BTEX components (benzene, toluene, ethylbenzene and xylenes) if these are present in the crude gas. Emissions of NMVOC falls outside the scope of our commission and are not further investigated here. It can however be stated in advance that any CH_4 reduction technique and/or leakage loss limitation will also reduce the emission of these substances.

8.1.3 Relevant aspects for the Dutch situation

In the Netherlands the emission requirements for “Installations for natural gas and oil extraction” given in the special Regulation E11 of the Netherlands Emission

[9] The extent to which the climate is impacted by carbon dioxide emissions (or the converted equivalent) per generated kilowatt hour (kWh)

Guidelines (Nederlandse Emissie Richtlijnen – NeR, 1996)[10]. This Regulation relates to natural gas and oil extraction installations with their associated treatment processes. For point sources flare or other vapour removal installations are specified that must minimise the VOC and CH_4 emission. In addition there is the (more sustainable) option of recompressing the gas and feeding it back into the main production gas stream or recovering it as a fuel. For all emissions not specifically mentioned in the special regulation the general provisions of the NeR (1996) on emission requirements and associated measurement obligations apply.

Set out below are a few examples of important conditions that lead to high emissions in the United States, but which will be considerably different under Dutch regulations, leading to fewer leakage losses compared with the American situation:

- **Pneumatically powered equipment:**
  In the United States it is the practice to operate pneumatic equipment on gas pressure, in the Netherlands this is not the case. Pneumatic equipment is operated here by air pressure. As a result gas emissions are entirely avoided.
- **Compressor packing losses:**
  In the BR NER (Special Regulations in Dutch Air Emissions Guideline) measures are specified that are applied and compulsory within conventional gas extraction. These techniques also apply to shale gas extraction.
- **Losses related to the gas distribution network:**
  The Netherlands has a dense and well controlled gas distribution network, the same networks will be used for shale gas extraction as for conventional extraction. This infrastructure is more extensive and better than in the United States.
- **Abandoned gas wells:**
  In the United States in some states wells are sometimes abandoned without or with minimal sealing. As an illustration, in New York State alone there are 3500 abandoned or inactive gas wells that were drilled and exploited before the recent regulations on well sealing came into force (New York State Dept. of Environmental Conservation, 2012). In the Netherlands the Mining Regulations include rules for abandoning wells that will also apply to shale gas wells.

8.2 Technologies and developments that reduce the (residual) risks in shale gas extraction

In the United States large scale programmes focus on the (further) development of technologies for preventing methane leakage losses. It can however be basically stated that these are not new technologies that are unknown to date. The decisive argument in the United States relating to emission limitation is economic profitability and cost minimisation. Previous investments are higher for emission limitation. Extra costs and investment for the capture and reuse of shale gas during drilling and preparation of a well relate among other thing to extra equipment to capture sand and separate the water, mud and gas. This equipment has to function reliably at very different and variable flow rates and pressures. Although the gas or oil captured represents an economic value this is not by definition more than the investment required to prevent leaks. An important point in the current development

[10] http://www.infomil.nl/onderwerpen/klimaat-lucht/ner/digitale-ner/3-eisen-en/3-3-bijzondere/e11-installaties/#page-body

of emission limiting technologies is therefore cost reduction and the demonstration of profitability.

For monitoring CH_4 concentrations in and around an extraction site with which leaks can be demonstrated and detected, validated techniques also already exist.

8.3 Conclusions

The issue relating to methane emissions in the United States is primarily whether it is economically profitable to prevent the emission. High leakage losses there are therefore a choice and not a given. In the Netherlands everything has to be done to prevent methane emissions. These resources are available.

The most important thing in the Dutch situation is as far as possible to avoid venting gas to the atmosphere and in addition to carry out transport and fracking as far as possible in sealed systems. Venting can be prevented by capture and reuse. Flaring can still always be used as a last resort. Technologies to do this already exist.

By following the Dutch regulations for conventional gas extraction for any shale gas extraction, a considerably lower emission can already be expected compared with the American situation. It is also important that monitoring and identification of CH_4 leaks is very possible with the current measurement techniques. There is experience with this in the Netherlands for example for measurements around old landfill sites (*Category 3*).

9 Earth movements

9.1 Introduction

9.1.1 Question:

Have new insights recently been developed relating to seismic risks due to fracking and the extraction of shale gas?

9.1.2 Overview of relevant risks and processes

Seismic risks are determined by the risk that earth movements will occur as a result of seismicity, and the consequences of this on the earth's surface (i.e. the damage that an earthquake causes). The earth movement that occurs at ground level depends among other things on the magnitude and depth of the earthquake, the damping of the vibration by the *deeper* subsoil, and the (often local) amplification or damping of the vibration in the *shallow* soft subsoil. Factors such as population density and buildings are also decisive for the consequences of earth movements and therefore the risk of seismicity. The most important possible consequences of seismicity are: (1) damage to the well (casing and/or cement), (2) damage to buildings, infrastructure or nature on the earth's surface, and (3) damage to underground infrastructure or facilities in the immediate vicinity of the epicentre. These consequences may constitute risks for people, nature and the environment, among other things due to an increase in risks of contamination or due to unstable infrastructure or buildings.

Seismicity that is a direct the consequence of gas extraction or well stimulation (improving the permeability of the rock for example by hydraulic fracking) is called induced seismicity. The occurrence of seismicity is determined by the combination of (1) natural stress state as a result of local geological conditions such as the properties of faults and the stress state of the subsoil, and (2) the local disturbance of the subsoil (as regards reservoir pressure and local stress state) as a result of gas extraction activities.

9.1.3 Relevant aspects for the Dutch situation

For risks of earth movements a distinction is made between risks as a result of subsidence and as a result of ground accelerations caused by induced seismicity. Subsidence plays an important part in conventional gas extraction in the Netherlands, but, as a result of differences in mechanical rock properties, is much lower in shale gas extraction (see also Witteveen+Bos 2013). Induced seismicity plays an important part in both conventional gas extraction and in shale gas extraction. However, the mechanism that induced seismicity can cause is different: for shale gas extraction (mainly reactivation of natural faults as a result of local *pressure increase* during fracking) and for conventional gas extraction (mainly reactivation of natural faults as a result of compaction and *pressure reduction* of reservoir strata during extraction).

An extensive analysis of risks as a result of induced seismicity in shale gas extraction can be found in Witteveen+Bos (2013). For the Netherlands relevant new insights relating to this analysis are that (1) there are examples from Canada (Horn River Basin) where during fracking for shale gas extraction an earthquake occurred with a magnitude of M_L = 3.8, and (2) there is more knowledge about the relationship between injection volume and magnitudes of induced seismicity (i.e. better knowledge about the effect of limiting fracking fluid injected or wastewater on induced seismicity, Wolhart et al., 2006; Maxwell et al., 2009; Downie et al., 2010; BC Oil and Gas Commission, 2012; Keranen et al. 2013).

9.2 Technologies and developments that reduce the (residual) risks in shale gas extraction

The most important analyses and measures that can be used *before* starting fracking and shale gas extraction to limit seismic risks, area:

1. Site-specific analysis of the geological and geomechanical conditions of the subsoil, particularly as regards natural seismicity and the presence and (possible critical) stress state of faults, and of the shallow subsoil and above-ground as regards soil conditions, population density and vulnerability of buildings (*Category 3*).
2. Planning of wells and fracking in the subsoil at a safe distance from big natural faults using a geological model and models that predict the dimensions of fracks in the subsoil, taking into account above-ground infrastructure and spatial planning (*Category 2*).
3. Limiting the quantity of fracking fluid injected (*Category 2*).

These are all methods that are mentioned in many analyses and studies, but in practice are far from being used everywhere. In addition there is also still a lot of technological progress to be made in this area.

The most important method that can be used *during* fracking and gas extraction to limit seismic risks, is (micro-)seismic monitoring (*Category 3*), in particular in combination with a “traffic light” or “hand on the valve” method.

The most important added value for minimising the seismic risks of shale gas extraction can be obtained from better integration of geological and geomechanical models of the subsoil and micro-seismic data (TRL6-7), particularly as regards continuous and real time improvement of predictive models and adaptation of fracking activities in the light of micro-seismic data (history matching, *Category 2*). The most important new developments are focussed on improving networks of geophones (on the earth’s surface or in monitoring wells), the design of seismic monitoring networks, and processing and interpreting (micro-)seismic data (*Category 3* for different techniques). There is also a role for alternative methods of monitoring (for example electrical or thermal, and monitoring *in* the well, *Category 1*), alternative methods for stimulation that can replace (for example innovative drilling techniques), or more efficient fracking fluids so smaller volumes are necessary. Because of the occurrence of seismicity with relatively high magnitudes there is a lot of knowledge from geothermal energy (for example from the FP7 GEISER project on “*Geothermal Engineering Integrating Mitigation of Induced Seismicity in Reservoirs*”, see www.geiser-fp7.fr) on measures to limit seismic risks, particularly on the “traffic light” system and statistical models that can be used.

In the short term (1-3 years) additional research into the site-specific properties of Dutch shales and predictive geomechanical modelling of the effects of fracking in the subsoil in the light of existing data have added value. For filling knowledge gaps as regards site-specific disturbance of the subsoil by shale gas extraction data from new wells, from analyses of new sample material, and from (laboratory) tests on new sample material are necessary (period 3-5 years).

9.3 Conclusions

Seismic risks due to fracking and the extraction of shale gas are generally small since in most cases in the US and Canada maximum earthquake magnitudes as a result of fracking are small (M < 1, only measurable, not perceptible or harmful). Significant seismic risks may occur if bigger faults are reactivated by fracking and the extraction of shale gas.

Before starting fracking and shale gas extraction site-specific analysis of the geological and geomechanical conditions of the subsoil, planning of wells and fracking, and limiting the quantity of fracking fluid injected may help to limit seismic risks (*Category 3*).

During fracking (micro-)seismic monitoring can be used to suspend or limit fluid injection promptly.

In addition to innovative monitoring techniques the seismic risks can be further minimised by better (real time) integration of geological and geomechanical models of the subsoil and micro-seismic data, and alternative methods for stimulation that can replace fracking (for example innovative drilling techniques). These technologies are still in development and will only be usable in the longer term (*Category 2*).

10 Complex logistics movements

10.1 Introduction

10.1.1 Question:

Are there innovative ways of organising, new ideas about minimising the complex logistics movements in order to reduce the risks associated with transport? To what extent can an infrastructure for the supply and disposal of water offer a solution?

10.1.2 Overview of relevant risks and processes

In the area of complex logistics relating to shale gas extraction sites there are virtually no specific risks. Particulars relating to other complex logistics projects lie possibly in the volume flows of supply and disposal of water. Risks of a lot of logistics movements include noise nuisance, emission of gasses and particulates, and the pressure on public roads. The reduction of risks and emissions related to the logistics of shale gas extraction is mainly focussed on the two biggest transport streams: the supply of clean water and the processing and disposal of contaminated water. These risks are of course known and familiar risks relating to such industrial logistics processes, but in view of the extent of the quantities of contaminated water this requires extra attention on designing and setting up the extraction site.

10.1.3 Relevant aspects for the Dutch situation

The Dutch situation differs in this respect from the known American situation. In the Dutch situation this involves short(er) distances and a very good coverage of water-infrastructure.

The goods moved during the installation phase for the drilling process relate to: drilling fluids and drilling materials for horizontal and vertical drilling. The source of these goods is from EU industry or importation via the Port of Rotterdam. Transport via rail is not an option within the Netherlands, because this is not viable for distances over 500 km (Economic Impact Study Goods Transport by Rail). There are no specific risks for shale gas extraction associated with transport by rail (container) and by road for these goods. The construction of pipelines is a possibility that can replace a lot of fluid and gas related transport.

10.2 Technologies and developments that reduce the (residual) risks in shale gas extraction

During the design phase of a shale gas extraction site materials and equipment are needed to set up the site. The transport of equipment and materials (this does NOT therefore involve the transport of large quantities of water whether contaminated or not) for the setting up and dismantlement of a shale gas extraction site appears to be very similar to the transport process corresponding to road building projects. The logistics solutions for minimising these transport streams (and hence the associated risks and emissions) lie in supply chain management and ICT resources to combine the transport streams as far as possible and to utilise the transport capacity to the optimum. The trend in ICT technology is to make real-time data available from all the chain partners and to link these data (big data applications). By applying smart algorithms to these data a quicker insight is obtained of the state of the chain processes, the possibilities of combining goods flows and the consequences of disruptions. In case of adequate anticipation based on this improved insight, this may result in fewer transport movements and less impact on the environment. The IT technology required for this to facilitate supply chain management is proven technology in its current form, but is only used to a limited extent so far. This technology may still benefit greatly from innovation.

The biggest movement of goods is carried out directly relating to and during the process of hydraulic fracturing. The equipment (pumps and tanks) and the materials for hydraulic fracturing are transported to the extraction site from the Netherlands, or Europe by road. The same considerations apply for this as for the transport of construction equipment and materials during the design phase: supply chain management and ICT technology to achieve combination of goods flows.

The supply of clean water for the hydraulic fracturing process and the disposal of the contaminated water (depending on local reuse or not) are of considerable size. In the Dutch situation it should in principle be possible for each extraction site to drill a groundwater source to supply the required quantities of clean water (which depending on the geographic location may be fresh, brackish or salt water). However, in the Netherlands we only extract water for high quality uses and at present it is still unclear how shale gas extraction will be evaluated in this respect. This means that the transport mentioned in the Tyndall (2011) study related to this may cease to apply for the Dutch situation. If a local groundwater source is not available, the construction of a pipeline network is a consideration on the one hand for supply and on the other hand for disposal instead of local extraction or transport via trucks. However, the dense distribution over the shale gas extraction area and the relatively short period and repetitive way in which the water is processed, means that this involves high investment costs. A piping infrastructure should reasonably be constructed to dispose of the shale gas extracted and the infrastructure for the water and gas can upon construction be combined which will benefit cost effectiveness.

Reuse of wastewater from previous fracking processes (after water treatment), can cover the requirement for a large part of the total clean water (see section 4), but not all of it. This provides in particular a logistics challenge in the timing of the logistics process. In addition to large quantities of clean water chemicals and sand are also necessary for the hydraulic fracturing process. There are no specific risks associated with this other than for other transport with (hazardous) chemicals or sand. Central processing results in large quantities of contaminated water to be transported.

The contaminated water that is released during production (production water) is very salty water (a brine with up to 200 g Cl^-/L). There are at present no treatment plants for this in the Netherlands. Contaminated water can only be injected into empty gas fields. The immediate availability of empty gas fields is crucial here, and is therefore not an overall option. Re-injection cannot be carried out into a shale gas field. In addition re-injection requires separate permits. The (temporary) capture and storage of contaminated water forms a considerable logistics challenge since according to Dutch legislation this may not be done in an open basin. Reuse or discharge therefore requires a considerable investment in waste water treatment plants.

Ideally during the production phase the shale gas extracted will be immediately processed into Dutch quality natural gas and connected via a conventional pipeline to the Dutch natural gas grid. Extra transport infrastructure (in particular pipelines) is necessary to make the connection of the extraction site to the Dutch natural gas grid possible. It is however quite feasible that the pressure in the well head (the installation on the surface that seals the well), the gas quality and low inflow of gas will not make it profitable to compress shale gas in the high pressure Gasunie network. For this reason options must be researched for regional/local sale as an alternative.

Gasterra should according to the current regulations buy gas offered at market price, provided for example it does not contain too much CO_2.

In the dismantlement phase the wells are sealed and the nature and extent of the transport is comparable with the construction phase of the drilling installation (30 transports, according to Tyndall (2011)).

10.3 Conclusions

As regards the transport the majority of the transport movements relating to shale gas extraction sites are no different from those relating for example to road building projects. Where the difference lies is in the supply and disposal of water. The supply can be carried out in the Dutch situation using pipelines, so the risks are negligible. The disposal (using pipelines) of the – contaminated –flowback water is more complicated, but is no different from transports of hazardous fluids within the current legislation and regulations. However the streams are of a greater volume and have the biggest impact for the required transport logistics.

Where the gain can be made is in the planning of the flows and the use of ICT resources. Making available real-time data from all the chain partners, the smart combination of these data and the application of smart algorithms to these data will in the first instance give a quicker insight into the state of the chain processes, but goods flows can also be combined more quickly and a quick and appropriate response made to disruptions in the transport network. A proven technology that is still only used on a very small scale (*Category 3*).

11 Environmental risks and emissions

11.1 Introduction

11.1.1 Question:

Are new methods and new procedures known that lead to less risk for the environment and lower emissions of substances to the environment?

11.1.2 Overview of relevant risks and processes

In addition to methane emission in shale gas extraction in the widest sense (that is at all stages) emissions of (air) pollutants also occur that are harmful to health. It is important here to make a distinction for methane. This is above all a greenhouse gas and in the concentrations at which it currently occurs in the atmosphere are not harmful to health. The main expected emissions of air pollutants are NOx and particulates (PM_{10} and $PM_{2.5}$)[11] due internal combustion engines or (heavy) road traffic and mobile machines not intended for the road such as pumps, generating units, excavation machines, cranes, etc.

Particulates are not included in the Witteveen+Bos report because, as described in appendix 1, the question was about the carbon footprint. Since particulates are not a greenhouse gas, these were not taken into account.

11.1.3 Relevant aspects for the Dutch situation

Unlike the Witteveen+Bos report, in the report of Royal HaskoningDHV on the carbon footprint of shale gas in the Netherlands the emissions of NOx and particulates are included for a significant part in the total emissions during production of shale gas. If the whole life cycle of a well is considered, the energy supply from diesel amounts to 44% (rounded), where this works out as much as 78% (rounded) when only fracking is considered.

11.2 Technologies and developments that reduce the (residual) risks in shale gas extraction

In Europe and the Netherlands there is already a long tradition of the progressive reduction of the environmental risks of internal combustion engines by means of the European emission standards, also known as the EURO standards (EC, 1997; 1998). These EURO standards determine the acceptable upper limit of exhaust gas emissions of new vehicles and/or machines as sold in Member States of the European Union. The increasingly further tightened emission standards were introduced progressively (see section 8) This does not therefore concern new innovative technologies but technologies already available on the market.

[11] PM_{10} = particulate matter < 10 micrometre & $PM_{2.5}$ = particulate matter < 2.5 micrometre

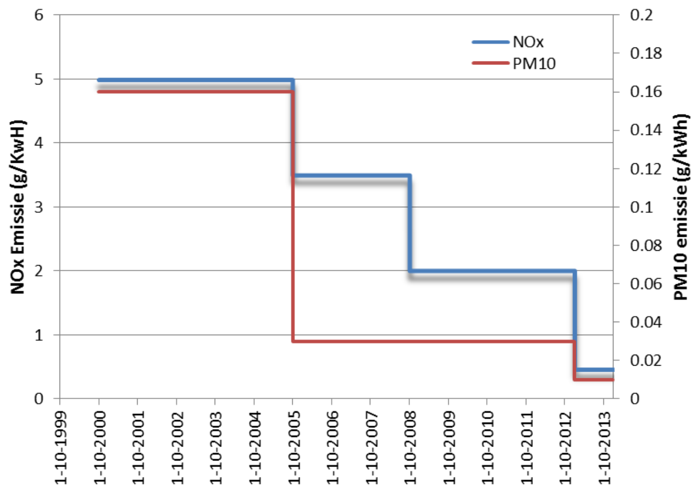

Figure 3: Progression of European NOx (left axis) and PM10 (right axis) emission standards for new trucks (EURO III to EURO VI)

emissie = emission

The most recent EURO standard for heavy freight traffic is the EURO VI standard which has been in force since December 2013. For mobile machines “Stage IV” is the most recent emission requirement, in force since 1 January 2014. In view of the very recent introduction date these technologies can be regarded as new but commercial availability and use have already been proven.

Within the current report it is important to realise that such emission requirements only apply for new vehicles or machines and there is no ban on the use of older machines or trucks. As the life cycle of machines and trucks can be 10-20 years, it takes a long time before a new technology has fully penetrated the market. This means that, if one wants these technologies to be used to limit environmental risks, this must be explicitly required. The use of biodiesel gives a reduction of almost 4 g CO_2eq/kWh (RHDHV 2013).

Another important measure to limit emission to air as far as possible is to avoid the use of internal combustion engines as far as possible by changing over to the use of electrical equipment, machines and possibly also transport. This is also to a significant degree already existing technology. Examples here are electric pumps, compressors etc. Drilling towers can also be fully electrically powered at present (which therefore also means without a (diesel) generating unit).

No new innovative technologies are known to limit the emission of resuspended dust. Smart supply and disposal of water and above all limiting this for example by means of piping can make an important contribution to reducing emissions. For this consideration a sound life cycle analysis study is necessary. This is not included in the study of RHDHV (2013), because the database used does not predict the modelling of a temporary water pipeline.

11.3 Conclusions

Emissions other than methane associated with the extraction of shale gas in the Netherlands consist for the major part of the emission and resuspension of NOx and particulates. Although these are not in themselves greenhouse gases, these emissions also involve a certain risk.

There are no ground-breaking innovations or developments that reduce these risks. The tightening up of the requirements laid down for the emission of among other things trucks and other equipment with an internal combustion engine (*Category 3, but note continued use/depreciation of current equipment)*, as well as the changeover to an all-electric scenario (NB: all-electric includes transport) (*Category 1*), to a large extent approaches the current emission level. In addition these developments do not specifically apply to shale gas extraction, but are relevant for all transport with trucks and (big) construction activities.

12 Scale factors

12.1 Introduction

12.1.1 Question:
The risks of shale gas extraction and production are partly influenced by the greater scale of activities. For each site more wells, resources, water and equipment are necessary which leads to more emissions to the environment and more transport movements compared with conventional local gas extraction. Are new methods and new procedures known which make less wells, resources, water and materials necessary?

12.1.2 Overview of relevant risks and processes
The process of shale gas extraction is more intensive than extraction of conventional gas: due to greater footprint and transport movements, this increases the chance that more people will suffer nuisance, such as air pollution, noise nuisance and visual intrusion, compared with conventional extraction.

12.1.3 Relevant aspects for the Dutch situation
The Netherlands is a densely populated country with extensive infrastructure. These properties mean that the risks that shale gas extraction involves may have a greater impact in the Netherlands. By using supply chain management over the whole production chain of shale gas extraction the risks can be reduced. In the W+B (6.2/A3.2) report this is called the closed loop system. The use of this system may result in a more efficient development plan with fewer safety risks. Closed loop systems can also be greatly optimised using real time data, this is hardly used yet and is accompanied by many technological developments. This is called *closed loop reservoir management*'.

12.2 Technologies and developments that reduce the (residual) risks in shale gas extraction

It is known that not all existing shale gas wells produce commercially and that in many cases not all fracture stages (possibly only 30-40%)[12] contribute to producing wells. This means that the same production result could in principle be achieved with much fewer wells and hydraulic fracturing, and with a proportionate reduction in risky activities.

To increase the success most big operating and service companies have developed formalised roadmaps, usually supported by their own software, to reduce the failure percentage of shale gas development (the asset as a whole, but also individual wells and fracture stages). The essence here is the introduction of a system into the use of information (measurements by e.g. logging tools) and a progressive development with verifiable criteria.

In the development of oil reservoirs in particular it is normal for different development scenarios to be calculated beforehand using numerical models. The reliability of these models is increased by conditioning them to measurements using

[12] EIA 2012 Golden Age of Gas Rules

numerical algorithms. The availability and quality of measurements is hence decisive for the reliability of a model-based scenario calculation. It is pointed out in the literature that horizontal wells (in the US) are not always logged and that 3D seismic profiling is not always used. Both sources of information potentially contribute greatly to a better understanding of the reservoir and hence a better identification of so-called 'sweet spots' and can thus have a positive effect on the scale of any extraction.

Since very many possible development scenarios can potentially be achieved, numeric optimisation algorithms are also used so that, based on these models, a systematic search can be made within all the achievable scenarios for the optimum scenario. Optimality is typically assessed here from an economic perspective (e.g. net present value expected), but also minimisation of uncertainty and risks can form part of the (robust[13]) optimisation aims.

The systematic and iterative following of the two stages described above is well known in the oil industry as closed-loop reservoir management, and is the subject of much recent research & development, in particular relating to the efficiency and efficacy of algorithms for model conditioning and optimisation.

A few attempts have already been made to check the value of this system on shale gas developments. In particular the determination of optimum numbers and sites of wells and fracture stages was the purpose here, but also limitations or conditions for permitted development plans, e.g. on footprint or volume of fracturing fluid, should in principle be considered.

12.3 Conclusions

The development of a development plan is a technique that is used as standard in the world of conventional extraction. Closed loop reservoir management is a development plan and describes an extraction project, and shows what developments could have occurred. Often a development plan therefore has a phased character with decision points along the way. This applies above all for the extraction of (heavy) oil, water flooding[14] and enhanced oil recovery[15].

For shale gas there is rather an Area Development Plan (as in the EBN-Halliburton study: 'Area Development Plan'); such a plan will also have to include the necessary flexibility to be able to make the exploration and exploitation respond to new information or conditions as it goes along.

A development plan is highly beneficial for continuous input of data from logs from horizontal wells and/or seismic data. From a development plan that uses closed loop reservoir management many possible development scenarios emerge, where model based decisions play a central part. This means that plans and models are adjusted in real time during drilling and/or fracking, so as to optimise the activities

[13] Robust = the resulting strategy is given to the optimum (taking into account) the uncertainty in the underlying model
[14] For water flooding an attempt is made by water injection to increase oil production. This technique is known as secondary extraction
[15] Enhanced Oil Recovery falls under tertiary extraction and indicates a number of techniques that increase the oil extraction. A known example of this is the stimulation of oil extraction by CO_2 injection

(*Category 3*). This does not alter the fact that the initial drilling and fracking plan must naturally meet all the prevailing safety requirements. The closed loop reservoir management focuses on optimisation, where a choice can be made of optimisation purposes; economic, uncertainties and risks.

Optimisation by closed loop reservoir management can lead to the smart positioning of fracks and possibly also fewer fracks, or drilling fewer wells and hence a reduction in the number of drilling sites. This approach is therefore promising and an important factor in the possible reduction in the scale of shale gas extraction and the associated risks.

13 Combination of shale gas extraction and geothermal energy

13.1 Introduction

13.1.1 Question:
Is it possible to use a well or part of a well for the extraction of geothermal energy after the extraction of shale gas? Are extra risks associated with this?

and

Is it possible to reuse infrastructure that was built for the extraction of shale gas after the production phase for other (sustainable) energy projects?

13.1.2 Overview of relevant risks and processes
At present are there no relevant risks known that are associated with an anticipated use of the shale gas well for geothermal purposes (so-called double-play concept).

13.1.3 Relevant aspects for the Dutch situation
In the RHDHV study into the carbon footprint of shale gas from a Dutch perspective a comparison is made between shale gas extraction with and without synergy with geothermal energy, both conventional (heat utilisation) and ultra-deep (electricity production). In that case they start from the advantages of the well sites and equipment already present. In the case of direct heat utilisation from a depth of 1800 metres there is an emission reduction in 15 g CO_2eq/kWh and for electricity production 96 g CO_2eq/kWh. This study only focusses on associated emissions by carrying out a Life Cycle Analysis and has not looked at the technical feasibility.

The combination of shale gas extraction and electricity generation by using geothermal energy so-called Enhanced Geothermal Systems (EGS)) is not taken into consideration at present because the predicted capacity (Dumas et al. 2014) in the Netherlands only seems economically profitable between 2030 and 2050 (based on the European resource assessment with a levelized cost of energy (LCOE) that is less than 100 Euro per generated megawatt hour (MWh)). In the long term this could be an option, but the well diameter remains the bottleneck.

13.2 Technologies and developments that reduce the (residual) risks in shale gas extraction

It is in principle possible to reuse a shale gas well for extraction of geothermal energy. The target reservoir for geothermal energy is never the same as the reservoir for shale gas. The well will therefore have to be deepened (if the geothermal energy reservoir lies below the shale gas reservoir), or completed in the case of a shallower geothermal energy reservoir. For this it may be necessary to drill a sidetrack to be able to fit the right well completion (gravel pack, perforation or slotted liner). A geothermal energy well has no production casing, unlike a shale gas well. This will therefore have to be removed. Because of the high flow rate of a geothermal energy well the diameter of the casing is greater than the production casing of the shale gas well. It will therefore be necessary to remove this, or to use a narrow production casing in combination with a small diameter pump, possibly in a configuration with several production and injection wells instead of a classic doublet. Electric Submersible Pumps (ESPs – the electric pumps that are suspended in the well) exist in small diameters, but to date these are not used in doublets in the Netherlands. The question is very much whether this can be economic, because of the costs of the pump and the relatively great friction losses that occur in narrow production casings.

A shale gas well has a limited planned life cycle. In the construction of the well the possible reuse over a period of a few decades must be taken into account, in the choice of both cement and steel. The steel used in shale gas wells has a high strength, because these wells are always fracked. Geothermal wells are not fracked to date in the Netherlands (although this is not impossible) but have to do with a greater corrosion risk than shale gas wells[16]. The steel thickness must be sufficiently great to remain intact through the whole production period, given the expected corrosion rate.

For most doublets the heat demand is present on the same site as the wells. Virtually no transport of geothermal energy is carried out. If a shale gas well is to be reused, it is therefore necessary that there is a heat demand on the drilling site, or a short distance away of a maximum of a few kilometres.

When an abandoned shale gas extraction site is converted for heat extraction by means of geothermal energy, the infrastructure already constructed can be used. The area covered by individual extraction sites (1 – 1.5 ha according to the Notional field development plan, EBN 2011-2012) is too small for profitable positioning of wind turbines or solar panels and these applications benefit too little from the present infrastructure to be regarded as an opportunity.

13.3 Conclusions

The conversion of two shale gas wells into a conventional, low enthalpy geothermal doublet probably cannot be achieved economically because a shale gas well has too small a diameter to make a big flow rate possible, and the pulling of the narrow casing(s) and possible fitting of a wider casing is expensive (*Category 1*).

What may be possible, is to put together the geothermal system from more than two converted shale gas wells, that pump relatively low flow rates, and in which narrow pumps can be fitted (*Category 1*). As a result one or more of the existing narrow casings can be maintained. It is however very much the question whether this is economically feasible. A clear answer cannot be given to this. A site-specific cost-benefit analysis must show this.

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[16] Due to the higher acidity as a result of degassing of the formation water as upon lifting, the pressure is lower, in combination with salt and casing

14 Integration of the different topics

This section summarises the most important, very generally applicable, results of the inventory carried out of technologies and developments to reduce (residual) risks in shale gas extraction. The summary is laid out based on (1) available measures that can be used in the short term (i.e. virtually immediately after licensing, *Category 3, see Approach & Accountability*), (2) research in the longer term (3-10 years ff. – *Category 1&2*) that help reduce (residual) risks, (3) most important developments per sub-question, (4) a short comment concerning the comparison of shale gas with respect to shale oil and (5) brief comment on the comparison with conventional gas extraction.

14.1 Measures that can reduce (residual) risks in shale gas extraction *in the short term*

The most important, very generally applicable, result of the inventory carried out of technologies and developments to reduce (residual) risks in shale gas extraction is that the most important gain can be obtained by carrying out the following site-specific research or taking measures *before starting large scale extraction*:

- In case of changes to regulations relating to setting up the extraction site the risk of spillage and leaks can be taken into account for example by fitting geotextile, and appropriate maintenance and inspection in the light of existing legislation and regulations.
- Geological and geomechanical modelling of the reaction of the underground system to extraction activities, and the interaction of extraction activities with existing geological structures such as faults. This research helps to reduce the chance of underground methane migration, gives the range of the result of fracking, and can be used to determine the optimum positioning of fracking to reduce the chance of induced seismicity by reactivation of large scale faults. A detailed characterisation of subsoil and rock properties using indirect geophysical methods such as seismic profiling, testing the behaviour of shales in pilot wells, or laboratory tests on samples from pilot wells contribute to an important degree to the accuracy of the modelling.
- Determination and use of the optimum composition of fracking fluids, both with a view to risks of using chemicals and the efficiency of fracking. This measure helps to reduce risks of possible contamination of soil and ground- and drinking water, and to reduce the scale of fracking and water use.
- Implementation of an *optimum* development plan for extraction sites in combination with closed loop reservoir management. This measure helps to reduce the scale of operations; fewer fracks or even fewer wells, fewer extraction sites, less water and therefore also fewer transport movements.
- Implementation of appropriate monitoring of ground- and drinking water and methane emissions. Particularly important is the determination of site-specific baselines before starting shale gas extraction and implementation of a strategy for adjusting or stopping operations if risks are exceeded.
- Suitable monitoring strategy (for example real time monitoring) in the subsoil that focusses both on the extent of fracks, detection of migration and maintenance of well integrity and on improving the efficacy of fracking and gas extraction.

In particular the combination of the above-mentioned research and measures has significant added value.

14.2 Research and innovations that *in the longer term* help to reduce (residual) risks in shale gas extraction

Innovations and developments in shale gas extraction can be broken down into different phases: before starting extraction, during extraction, after extraction, and after the extraction site has been abandoned.

Before starting extraction: Research and innovations are important that focus on knowledge gaps in the area of control of the result of fracking, alternative methods of reservoir stimulation, the interaction of Dutch shale strata with fracking fluids, or improving cement that is used in wells with a view to improved well integrity when using a multiplicity of frack stages.

During extraction: In particular research and innovations in the area of monitoring are important. A lot of research and innovations focus on new monitoring techniques and improved sensors. Examples are real time monitoring with fibre optics, (combinations of) electrical, thermal or magneto-telluric monitoring, monitoring based on micro-seismicity and improved monitoring networks. But innovations in the area of above-ground monitoring can also be used to handle methane emissions, drinking and groundwater contamination and complex logistics movements appropriately.

After extraction the infrastructure can possibly be reused for geothermal energy. Additional research is necessary to assess the possibilities for reusing shale gas wells for geothermal energy better. In each case before starting any extraction is the time to prepare a consideration/plan relating to the reuse of shale gas wells for geothermal energy since an adapted well design is necessary. This technology can probably only be used in the longer term.

After the extraction site has been abandoned: After completing the shale gas extraction in particular the abandonment of the well is important. The Netherlands has a great deal of experience in this area with conventional gas extraction, but there is little experience with the long term monitoring of large numbers of abandoned wells. Risk can be reduced here by carrying out regular (or real time) pressure measurements in the well, or monitoring the groundwater composition on the surface or in shallow aquifers.

14.3 Most important developments as regards (residual) risks in shale gas extraction per sub-question

For the different sub-questions (see sections 1-13) the most important developments are:

- Contamination of ground- and drinking water during transport and on site are known and no different than for other activities for which extensive legislation and regulations are in place
- Direct methane migration to aquifers is very unlikely, and not yet observed in shale gas extraction in the United States and Canada. The distance

between the fracks and aquifers which in the Netherlands is more than 1000 metres is important, and in virtually all cases sufficient to prevent a direct link between fracks and aquifers. Migration along wells is a point of concern.

- More is increasingly known relating to the chemicals that are used during fracking and it is possible to choose the safest substances for the Dutch shale strata. It is expected that alternative (so-called greener) chemicals in water-based fracking fluids will not play a decisive part for the coming 5-10 years. Alternatives without water are used, but are for the time being not better, because they are often more difficult to handle, and in some cases even more dangerous or more harmful than conventional fracking fluids.
- The flowback and production water can technically be treated to any required level, both on site and decentrally in a wastewater treatment plant.
- The Netherlands has a great deal of knowledge relating to well integrity from its long history of conventional gas extraction. However, in shale gas extraction the long horizontal wells, the multiplicity of frac stages, and the abandonment of the large numbers of wells require attention.
- The result of the planned fracks should be estimated before starting by geomechanical models in combination with characterisation of the subsoil, and be determined by appropriate monitoring during the activity. Underground monitoring gives the best options for adjusting fracking activities.
- Reduction in methane emissions is in many cases technically possible, for example by preventing venting/flaring, by capture and reuse, and by using sealed systems. In combination with monitoring the methane emissions can be greatly reduced, but financial considerations play a part.
- The risk of earth movements is mainly limited to the risk of induced seismicity. The risk is only significant if bigger faults are reactivated, if significant *natural* seismicity has occurred on the extraction site, or if there are large quantities of fluid in a relative area, and can therefore be limited by staying away from big faults when developing fields and by limiting the volume of injected (waste) fluid. Real time monitoring based on micro-seismicity and limiting the volume of fracking fluid injected can further help to limit seismic risks.
- As regards logistics, shale gas extraction is very similar to a road building project. These complex logistics can be set up much smarter using real time supply chain management with the help of innovative ICT applications (combining and interpreting large quantities of data). As regards required water volumes shale gas extraction is unique. Risks can be avoided by handling the supply and disposal of water with pipelines.
- Most environmental risks and emissions are not specific to shale gas extraction. As regards these risks in particular a gain can be made by using cleaner alternatives for internal combustion engines (trucks and other equipment) or implementing an all-electric scenario.
- A development plan for shale gas sites with clearer optimisation objectives that can be predetermined not only contributes to successful and optimum extraction, but also to safety, risks and scale factors due to possibly fewer sites, wells and/or fracks.
- A combination of shale gas extraction and geothermal energy seems very unlikely for the time being, although additional site specific research and

research into the use of different well designs may give more clarity about the possibilities.

14.4 Comparison between extraction of shale gas and oil

It should be determined beforehand (that means before exploration wells have been positioned) using models with only considerable uncertainty whether shales contain oil, condensates or dry gas (or a combination of these). This report has a strong focus on extraction of dry gas from shales. Although extraction of oil and condensates from shales may differ considerably, above all as regards the specific application and planning of drilling and fracking and as regards optimum field development, virtually all the results to reduce (residual) risks, described in sections 14.1-14.3, also apply for extraction of shale oil or condensates.

14.5 Comparison with conventional gas extraction

In the inventory of technologies and developments to reduce (residual) risks in shale gas extraction, a good distinction can often not be made between techniques that are specific to shale gas extraction and techniques that are used in conventional gas extraction or in other industrial activities such as road building projects and transport by road. In particular for techniques that are also used in conventional gas extraction and for risks that also play a part in conventional gas extraction, because of its long history of conventional gas extraction there is much knowledge and appropriate legislation and regulations have been implemented in the Netherlands. For *exploration wells* that aim to test whether and how much gas can be extracted from the shales, the risks are not therefore essentially different from conventional gas extraction. The *most important* differences in risks between conventional gas extraction and *large scale shale gas extraction* arise from differences in type of wells (*mainly* a few vertical wells for conventional gas extraction and *mainly* multi-lateral horizontal wells in shale gas extraction), and from differences in the scale (intensity) of drilling, fracking and transport.

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APPENDICES - Background information

Appendix A: Ground- and Drinking water

The extraction of shale gas is an intensive process in which a lot of chemicals and process water are used. In addition large quantities of waste streams are produced during drilling of the wells, fracking and gas production. The principal waste consists of wastewater (flowback water from fracking, production water) and drilling muds. The chemicals will have to be supplied to and stored on the extraction sites. The wastewater is also stored in storage tanks. This wastewater can be treated locally on site or transported to a wastewater treatment plant.

The supply, transfer, storage and disposal of the chemicals and wastewater may involve spillage and leaks where the soil and groundwater are contaminated. Studies carried out in the US show that there are regular incidents in shale gas extraction with spillage and leaks where soil and groundwater contamination occurs. In Colorado between July 2010 and July 2011 above-ground leaks occurred in 0.4% of wells, where on average 200 m^3 of soil was contaminated to an average depth of 2 m (Gross, et al. 2013). In the Netherlands too incidents regularly occur with soil contaminants. It can be deduced from annual reports of the Dutch State Supervision of Mines that from 2007 to 2012 there were 150 incidents with substances that contaminate the soil and that of these 30 took place outside the mining site (Hartog & Cirkel, 2013). The risk of contamination of soil and groundwater therefore exists not only on the extraction site but also outside it. According to the annual reports, in all cases of soil contamination the soil was decontaminated in accordance with the existing legislation and regulations.

The quantity of wastewater depends on the quantity of water that flows back during the fracking process (flowback water), the quantity of production water and the quantity of wastewater that can be reused. The water is contaminated among other things with potassium chloride, mineral oil, polyacrylamide, various acids such as citric acid, ammonium persulphate, borate salts and ammonium bisulphite (see also paragraph 3.3). The drilling muds may be slightly radioactive (see Schmidt, 2000), depending on the rock and may among other things contain heavy metals and sulphate. If the drilling muds come into contact with water it may contaminate the water, for example by oxidation of Fe sulphides present as pyrite, FeS_2. Witteveen+Bos (2013), in partnership with Arcadis and Fugro, has been commissioned by the Ministry of Economic Affairs (EZ – Energy Market Directorate) to carry out research into the risks of extraction of shale and coal gas in the Netherlands. This research finds the following quantities of wastewater for the extraction of shale gas in the Netherlands for the North-Brabant development scenario (Table 3). These figures are based on assumptions for a base case from the Notional Field Development Plan of Halliburton (2011) that corresponds to a 500,000 mcf/day[17] gas treatment plant.

[17] Million Cubic Feet per day

Table 3. Waste for the Base Case location as formulated by Halliburton (2011) with 3100 m deep well and 1500 m long horizontal wells (source Witteveen+Bos, 2013)

	value	unit
Wastewater		
well development scenarios (max)	130	number
fracs per well	22	number
water required per frac stage	477	m^3/frac
water quantity for fracking per well	$10.5 \cdot 10^3$	m^3/well
total quantity of water required for fracking (without reuse of wastewater) per site	1.36	million m^3
flowback fraction of fracking water	15	%
flowback per well	$1.6 \cdot 10^3$	m3/well
Total wastewater flowback after fracking	$20.4 \cdot 10^4$	m^3
production water per well (5 m^3/day and for 7 years)	$12.8 \cdot 10^3$	m3/well
total production water per site	31.55	million m^3
total wastewater (flowback+production water)	31.80	million m^3
exploitation period site	25	year
Average total wastewater per year (without reuse)	1.27	million m^3/year
total wastewater per year (with 13 to 67% reuse)	0.42 to 1.11	million m^3/year
Drilling muds		
Drilling muds per well	200	m^3
Total volume of drilling muds	$26 \cdot 10^3$	m^3

Soil protection measures at extraction site

The soil at the extraction site may be contaminated in various ways:

- Spillage of drilling muds, flowback water and brine.
- Spillage of chemicals near storage tanks.
- Leaks from above-ground storage tanks or wastewater piping.

In addition it is also possible that contamination may occur outside the extraction site due to spillage and/or leaks during transport.

The Netherlands Soil Contamination Directive(Nederlandse Bodemrichtlijn Bodem – NRB) lists measures and provisions that can be taken to achieve a negligible soil risk (NRB 2012, Netherlands Soil Directive Soil+, NL Agency, Ministry of Infrastructure and Environment). There are source-directed measures that prevent fluids getting into the soil. For above-ground storage of fluids such as chemicals and wastewater the Soil Protection Directive on Above-ground atmospheric Storage tanks (Bodembescherming Bovengrondse atmosferische Opslagtanks – B04 Soil, InfoMil March 2000). Soil protection measures must also be taken for mobile installations (Decree of 3 April 2008, concerning rules on the environment relating to mobile installations and submarine installation (Decree on general rules governing the environment in mining, Decree 125 – Besluit algemene regels milieu mijnbouw, Besluit 125)).

Below is a brief description of the measures that must be taken relating to the tanks themselves and the soil under storage tanks, as included in the current regulations. Table 4 lists the techniques that are available to take the measures.

Depending on the fluids that are stored the tanks must meet one or more of the following requirements:

- be fitted with a shutdown system that shuts the system down if the system fails;
- consist of a double-walled system fitted with leak detection for both the tanks and piping;
- be coated internally and externally (to protect from internal and external corrosion);
- be fitted with cathodic protection to prevent corrosion of the tank bottom (this may possibly also apply for the various (underground) piping;
- leak detection to detect leaks, spillage or any other failure of the storage system before the fluid released penetrates the soil.
- overfill protection systems;
- drive away protection system .

Table 4. Available techniques for measures to prevent fluids stored in tanks getting onto and into the soil

Measure	Available technique
Soil under storage tank	
sealing structure	- plastic membranes, such as HDPE, VLDPE, LLDPE, PP, EDPM; - mineral sealing layers, such as natural clay, sand bentonite (polymer), bentonite mats; - hard surfacings, such as concrete and asphalt
protection from penetration of rain- and groundwater	- limitation of entry of rainwater: rain edge, slab membrane, skirt membrane, (bitumen) sealings, impermeable mound shoulder; - limitation of entry of (capillary) groundwater: ring wall of stone chips or gravel, capillary-interrupting layers, sufficient mound/foundation height, control of groundwater level.
Storage tanks	
internal and external coating	• paint systems, such as based on zinc silicate and epoxy; • fibre-reinforced cladding (linings, plastic bottoms); • elastomers, such as polyurethane
cathodic protection	• sacrificial anodes under or next to the tank bottom • anode strips under the tank bottom • active protection with printed flow systems (inert anodes supplied with direct current)
leak detection	• inspection drains; • detection anodes (anode strips); • (cable) sensors; • soil air detection with extraction lances or piping.

There are many types of tanks available and the most suitable tank depends on the type of fluid. In the Knowledge Inventory Document “Vloeibare bulk op- en overslag” (Fluid bulk storage and transfer) drawn up on behalf of the Interprovincial Consultative Committee (IPO) an extensive overview is given of what techniques are available and what is the best way for safe storage of substances (Jong et al. 2009). This overview lists for different types of fluids what type of a tank is most suitable and what requirements it must meet.

In the DNV report (DNV-RP-U301) with recommendations among other things to protect the environment when carrying out shale gas extractions it is recommended that triple protection be used for the storage of chemicals. The chemicals themselves must be stored in suitable storage tanks. These tanks must be enclosed by a double containment facility. The volume of both the secondary and tertiary containment facility must be at least big enough to contain the capacity of the biggest tank in case of leaks (DNV 2013). A membrane can be laid in the foundation under a storage tank. This is then the secondary protection. The tertiary protection can be achieved with the installation of a fluid-proof tank pit.
There are also double-walled tanks. These could be used as double protection instead of using a membrane in the foundation. However, for tanks with a double

bottom there is the chance that cracks and therefore leaks will occur. This is therefore less safe than using a membrane in the foundation (Jong et al. 2009).

To limit the quantity of fluid stored on an extraction site and therefore the risk of leaks, DNV recommends only preparing the frac fluids as they are used. Large quantities are involved that also have to be stored responsibly.

Tank foundation and pits

Tank foundations and tank pits also have to meet various requirements. In the Knowledge Inventory Document this is described at length: The soil under new tanks to be built must be fitted with a sealing structure on or above the subsoil with the aim of detecting emissions (ed. leaks) of stored fluids and preventing the spread of the leaked product to the soil (Figure 4). The tank foundation must be located higher than the ground- and surface water. In addition the water or another fluid must be quickly conducted away from the tank wall and bottom. Settlement must be prevented, as well as washing away due to bottom leakage or penetration of rainwater and erosion due to wind and water. The sealing structure must also be protected from penetration of rain- and groundwater.

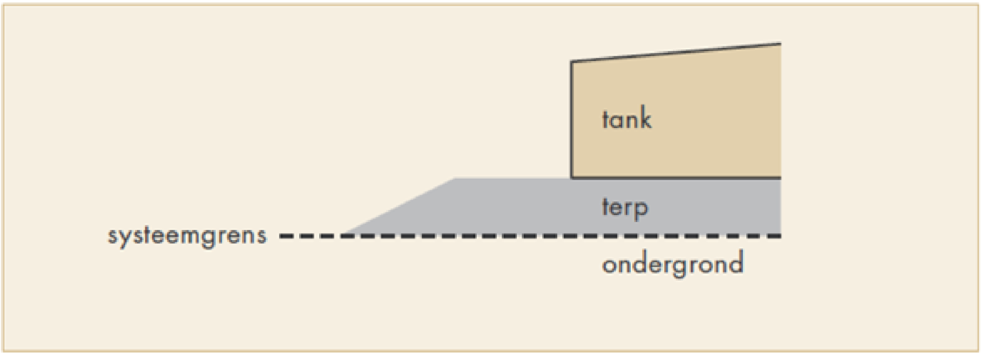


Figure 4 Schematic diagram of sealing structure under an above-ground storage tank.

terp = mound; systeemgrens = system boundary; ondergrond = subsoil

A good tank foundation is very important and this must be designed carefully. Supervision during the construction of the tank foundation is very important to ensure that no settlement occurs later and increases the risk of leaks from the tanks. Several tanks can be placed in a common tank pit. If a fluid is hazardous to the soil, and that is the case with many of the chemicals used and the wastewater produced, the tank pit must at least be fluid-proof. Fluid-proof tank pits should preferably be made entirely of compacted river/ sea clay for example with a layer of fine gravel or lavalite. The bottom must have a slope of 1: 100 in the drainage direction so that in case of leaks the fluid can quickly drain away. The bottom of a tank pit may also be made of impermeable concrete. This is however only suitable for small tank pits because of shrinkage cracks that may occur in concrete and adversely affect its impermeability (Jong et al. 2009).

Sealing the extraction site

Not only tanks but also piping can leak. To protect the soil of the extraction site properly the whole extraction site must be fitted with an impermeable hard surface that is also regularly checked for cracks. This hard surface is best to slope to one side so that leaked fluids can be captured easily (DNV, 2013).

Transferring of fluids

To prevent spillage when transferring fluids bottom transfer is preferable. Here the fluids are transferred into the tank via the bottom via a sealed coupling. Vapours formed in the tank are in this way not released during transfer (Jong et al. 2009).

Risks of contamination outside the site

The report of Hartog & Cirkel (2013) states that it can be deduced from the annual reports of the Dutch State Supervision of Mines that from 2007 to 2012 there were 150 incidents with soil contaminants and that 30 of these took place outside the mining site. Outside the extraction site the soil and the surface water may also be contaminated by:

- accidents with tankers filled with wastewater;
- spillage upon transfer of wastewater;
- leaks from discharge pipelines outside the mining site.

Measures must also be taken outside the extraction sites, for example at transfer sites to prevent soil contamination. In addition truck traffic carrying contaminated wastewater should be limited as far as possible. An accident with a truck may in fact cause contamination of the topsoil outside the extraction sites.

Measures in case of incidents

To get an idea of the measures that are taken in the Rotterdam Port area in case of an incident the Rijnmond Environmental Protection Agency, DCMR Milieudienst Rijnmond, was contacted. If an incident occurs in the port in which pollutants get onto the soil contaminated gravel and soil is often removed using vacuum trucks. This is a sort of rough excavation. Big companies have this type of vacuum truck ready to take immediate action. If no vacuum truck is available or it cannot be used due to the local conditions, proper excavation is carried out where that is possible. In that case alternative excavation facilities would be desirable. In all cases all the installations and safety rules that are necessary are applied.

Immediately after excavation samples are taken to check whether the contamination has been removed sufficiently. Should too much residual contamination remain or there have been technical obstacles to removing the contamination properly then advice is prepared and in-situ decontamination is often carried out.

Ultimately the faster the contaminated soil is removed the smaller the chance of further spread of the fluid into the top soil and/or the groundwater. The ability to remove the soil quickly for example with a vacuum truck reduces the risk of soil contamination. The availability of such an installation in the near vicinity of an extraction site is a measure that can be taken to reduce the risk.

Leaks/spillage of volatile fluids are regularly covered with extinguishing foam for safety and odour reasons. This does however promote the vertical spread of fluids into the soil and involves all sorts of extra contamination in the soil such as the fluorosurfactants from this foam. The presence of a retaining tank pit under a storage tank prevents the fluids getting into the soil after covering.

In case of spread to surface water oil booms are used/set out. This is helpful in particular if there is leakage of oil-based fluid into the surface water. This will not however limit the spread of substances such as metals dissolved in the water.

Techniques for tank inspection

Corrosion is the most common form of deterioration of a tank. A few suitable techniques are available that on big plate surfaces such as the bottom and wall of a tank can detect a reduction in the material thickness due to corrosion where the tank is not damaged (Niet Destructief Onderzoek (Non-Destructive Testing): Jong et al. 2009). These techniques are:

- Magnetic Flux Leakage. By magnetising the metal surface thickness-reduction defects are detected by the leakage of magnetic fields.
- Ultrasonic testing: sound waves are generated and the material thickness can be determined with the time between transmission and reflection.
- Saturation Low-Frequency Eddy Current testing. The thickness of the material can be determined with deformation of the Eddy current that occurs on generation of a magnetic field.
- Acoustic emission. By measuring sound any deterioration in the material can be measured.

Special techniques are available to measure corrosion of the annular part of the tank (Jong et al. 2009):

- Long Range Ultrasonic testing. The reflection of sound waves gives an indication of whether corroded spots are present in the material.
- Pulse Eddy Current testing. Magnetism is used to determine the residual thickness under the tank bottom and foundation. A space between bottom and foundation may for example occur due to uneven settlement.

Weld seams must also be regularly inspected (Jong et al. 2009). This can be done by:

- Magnetic particle testing. Measurements are taken with magnetic fields to see whether there are any defects in the weld seam.
- Dye penetrant testing. Tests are carried out with penetration and staining of fluid to see whether cracks are present in the weld seams.
- X-ray testing. Weld defects are detected by X-rays that penetrate the material.
- Time of flight Diffraction testing. Defects in weld seams are detected by ultrasound diffraction.
- Vacuum box testing. By means of a water/soap solution and vacuum you look to see if soap bubbles occur by the weld seam and this is therefore leaking.

Available sensor techniques for leaks in storage tanks of production water and drilling muds are (gems sensors, 2014):

- buoyancy (float) sensors: These types of sensors are lighter than the fluid and float on the fluid surface. Movement of the fluid surface is transferred with a mechanical coupling to a valve or transmitted to the control room.
- optical sensors: These sensors measure the change in the transfer of infrared light.
- capillary sensors.
- capacitive sensors: These sensors work based on an electrical field that is not broken by conductive or non-conductive fluids.
- ultrasound sensors: These sensors emit sound waves at high frequencies that are reflected and detected.
- magnetorestrictive continuous level transmitters. With an electric pulse or an iron-magnetic wire the position of a float with a magnet is determined. When crossing the pulse with the magnetic field of the float a second pulse is reflected to an electrical circuit that determines the fluid level (Maclennan and Nutt, 2010).

These sensors can also be used in combination.

Maintenance as a measure

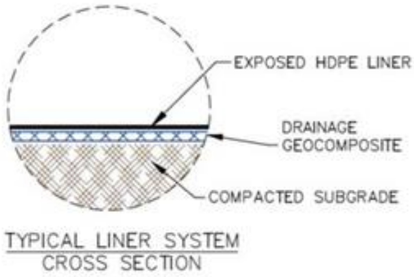
In the US the lack of maintenance is regarded as a serious problem by the EPA and others (Wood et al. 2011; Eaton, 2013). Research into contamination occurring due to spillage and leaks in Colorado in the US (Gross et al. 2013) showed that storage tank systems were a big source of leaks. These were often leaks caused among other things by corrosion of the tank or other technical failure of the system. Human error was only the cause in a few cases (Gross et al. 2013). To reduce risks of contamination of the top soil and surface water the systems installed must be regularly inspected and maintained. Muehlenbachs et al. (2011) carried out an analysis of the performance indicators relating to incidents on oil and gas platforms in the Gulf of Mexico. They found statistically significant differences between the companies in the numbers of self-reported incidents and cases of non-compliance. This suggests considerable differences in the work culture between companies with more and less diligence in handling incidents. Good maintenance and inspection by the authorities is therefore important. It is important to realise that well-functioning maintenance also creates support among residents and other stakeholders (Eaton, 2013).

In the Netherlands the competent authority for licensing lies with the Ministry of Economic Affairs. Overall supervision for mining installations lies with the Dutch State Supervision of Mines (SodM). The Dutch State Supervision of Mines supervises compliance with statutory regulations that apply for the exploration and extraction of minerals and for the storage of substances underground, as well as for the extraction of geothermal energy and for the transport and the distribution of natural gas (from the Dutch State Supervision of Mines: Strategy & Programme for 2012 – 2016).

New techniques

Soil protection

In the US developments are underway in particular in the area of geotextile and geosynthetics to prevent contamination due to spillage and leaks. The company Geosynthetic Lining Systems (http://www.gseworld.com) makes liner systems of impermeable material which include a drainage layer. It can also incorporate a shock absorbing layer so that trucks can drive over it. This design of the material can be laid in the well pad to prevent contamination of the subsoil.



Another company that develops geosynthetic solutions to protect the soil from spillage and leaks is Geosynthetics (geosyntheticsmagazine.com).

These are techniques that are used in practice and we think that this technique can be used in particular on sites where a lot of storage and transfer takes place for shorter periods (say less than a year).

Storage tanks

Developments that are underway for storage tanks as also used in the American oil industry, are in particular the material of which the tanks are made and the coatings used. New materials from which the tanks are made are glass fibres or steel tanks clad in glass fibre or durable coatings. There are also new developments in the Netherlands for storage tanks made of synthetics, plastics and epoxy (Jong et al. 2009). When using new types of material it is of course important that these meet the applicable standards.

Appendix B: Methane migration to aquifers

Conditions for migration of methane and other components

Migration of methane and other components from deeper shale strata to overlying strata may be caused both by natural processes and shale gas extraction. Shales and other formations with a high clay content are characterised by very low permeability and, without stimulation, methane migration only occurs on a geological time scale (among others King 2012). As long as sufficient *undisturbed* (low-permeability) rock is present between the fracks and potential migration paths, migration of methane or other components to the overlying aquifer will not be significant. It is therefore unlikely that methane migration causes contamination of shallow aquifers, provided (1) the extraction is carried out at a sufficient depth so that no direct link between the fracks and aquifers is formed, (2) there are no large natural faults present that form a link between fracks and aquifers along which methane or other components can migrate, and (3) fracking does not affect the insulating action of cemented wells (King 2012; Davies et al. 2012, 2014). When assessing techniques to limit risks of migration it is important to make a distinction between these three conditions and associated migration mechanisms.

<u>Possibility of direct link between the fracks and aquifers</u>
The extent of the fracks and the dimensions of the stimulated reservoir volume are central to the question of whether a link between fracks and aquifers is possible, and therefore what depth is sufficient to prevent methane migration from shales to groundwater aquifers.

The growth of the frack from the well to shallow strata is limited by the presence of natural barriers, such as local variations in stress state, in strength of rock and contact between strata, and in permeability (among others Davies et al. 2012). Because in the United States and Canada (micro-)seismic monitoring is increasingly used during fracking for shale gas extraction, a lot of data about the possible extent of fracks is determined by the occurrence of micro-seismicity. Although it is possible that fracks are bigger because part of the fracking process is aseismic, this approach is at present the best available.

Recent studies have been carried out that in the light of micro-seismic data assess the extent of fracks for the extraction of shale gas in the US and Canada (Fisher and Warpinski 2012; Davies et al. 2012; Warpinski 2014). Because of the relevance for migration to shallower strata, these studies focus mainly on inventory of the measured *vertical* extent of fracks, and less on the stimulated reservoir volume. The most important new insights that these studies have provided with regard to the vertical extent of *stimulated* fracks are (Figure 5):

1. None of the fracks mapped with (micro-)seismic data extend as far as aquifers. For most (>99%) of the fracks the distance between the top of the frack and aquifers is more than 1000 metres. In exceptional cases fracking has been carried out at a depth of less than 1000 metres and the minimum distance between the top of the frack and aquifers is around 500 metres.

2. Site-specific factors play an important part in the growth of fracks, particularly as regards the depth of fracking, the degree to which fracking fluid flows from the frack into the shale, the local stress field and the presence of natural faults.
3. Factors that can be adjusted in the execution of fracking play an essential role in the growth of fracks. The extent of fracks mainly depends on the quantity of fracking fluid injected, and the type and composition of the fracking fluid (particularly the viscosity).
4. By far the majority of fracks (~99%) extend less than 350 metres from the well to overlying strata. The maximum vertical extent is 536 metres for the Marcellus Shale and 588 metres for the Barnett Shale (Davies et al. 2012). It is significant that this statistical analysis does not take into account differences in execution of the fracking process; greater maximum vertical extent may for example be caused by greater injection volumes.

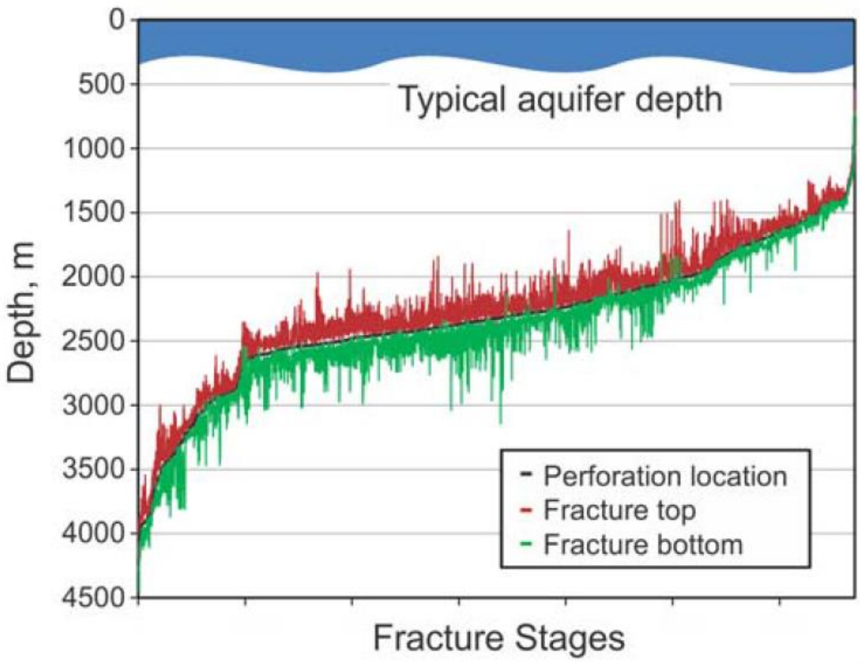


Figure 5 Compilation of the vertical extent (Fracture top *in red* and Fracture bottom *in green*) of fracks for wells at different depths (Perforation location) and typical depth of wells for drinking water supplies (*in blue*). Data for 6 big shale gas reserves in the US (Warpinski 2014, see Fisher and Warpinski 2009 for data per shale gas reserve)

Since site-specific factors are decisive for the extent of fracks the dimensions of fracks for shales in the Netherlands may differ from the trends in the US and Canada. At present there is still no experience with the fracking of Dutch shales. It is however possible to predict the frack dimensions with models (EBN 2011-2012; Ter Heege et al. 2014). Although the model predictions have considerable uncertainty (in particular as regards the occurrence of natural faults), sensitivity analyses suggest that the vertical extent of fracks for the Posidonia Shale Formation to a depth of 2 - 3.5 km for realistic scenarios is less than 200 metres. It is therefore unlikely that a direct connection is possible between the fracks and aquifers in shale gas extraction at this depth.

Possibility of connection between fracks and aquifers along natural faults
Examples are known of fracking fluid that during fracking migrates along natural faults so that fracks occur in shallow strata (Sharma et al. 2004). In this example fracking is used for gas extraction from low-porosity sandstone reservoirs, and the fluid at a depth of ~4 km migrated around 200 metres along a natural fault. The migration is demonstrated with (micro-)seismic monitoring. It is also known that *natural* migration of oil to the earth's surface can take place along natural faults (among others, Leifer et al. 2010). Migration of fluids along natural faults to the earth's surface is therefore possible. There are however no known examples where *fracking for shale gas extraction* has caused a connection between fracks and aquifers along natural faults. The two most important reasons for this are (1) that fracking for shale gas extraction in the vast majority of cases takes place at depths of more than 1000 metres (Fisher and Warpinski 2012) and (2) that the clay-content of shales results in a reduction in the permeability of faults that cut through the shales (among others Ter Heege & Hoedeman 2013).

Possibility that fracking can affect the insulating action of cemented wells
Migration of methane or other components from the fracked shale stratum to the overlying aquifer along the well is possible if the design, positioning or cementing of the well is not carried out properly (EPA 2011; Green et al. 2012; Davies et al. 2014). Since a well is an artificial connection between the shale stratum and the earth's surface, methane or other components can migrate up along poorly insulated wells. This is seen as one of the major possible causes of contamination of ground- or surface water (among others, EPA 2011; Davies et al. 2014). It is therefore important that fracking near the well does not affect the insulating action (see examples in Dusseault et al. 2001). This applies in particular for vertical wells where the maximum vertical extent of the fracks is usually achieved along the well. The design, positioning or cementing of the well must therefore take into account the effect of fracking.

Experience with migration of methane or other components in fracking in the Netherlands
Fracking is carried out in the Netherlands on a much smaller scale than in the US and Canada (EPA 2011; EBN 2011-2012). Fracking is mainly carried out in the Netherlands to stimulate low-porosity sandstone reservoirs, and has not been carried out for shale gas extraction. The Netherlands Oil and Gas Exploration and Production Association (NOGEPA) has evaluated the experience with fracking in the Netherlands (NOGEPA 2013). They conclude that since the start of gas extraction in the 1950s fracking has been carried out in over 170 wells. Recently, over the period from 2007-2011, fracking was carried 9 times onshore and 13 times offshore. No negative consequences of these fracking activities are known.

Measures to limit risks of migration of methane or other components.

The risks of migration of methane or other components from the fracked shale stratum to the overlying aquifer are determined by the combination of the chance of migration occurring and the effect of the migration. The chance of migration is determined by the extent of fracks, the presence of permeable natural faults and the well integrity. The effect of migration depends on site-specific factors such as groundwater flows, drinking water supplies and population density.

The most important analyses and measures that can be used *before starting* fracking and gas extraction are:

1. An analysis of the existing composition and contamination already present in the groundwater (baseline), so that with monitoring during extraction activities it can be determined whether new migration occurs (among others, Lafortune et al. 2013).
2. A good design, positioning or cementing of the wells, taking into account the planned fracking activities. It can be determined with site-specific geomechanical models *whether* and *in what way* fracking may affect the insulating action of the wells

Site-specific analysis of the geological and geomechanical conditions of the subsoil. It is above all important to determine whether large scale permeable faults are present along which migration to overlying strata is possible. Planning of wells and fracking in the subsoil at a safe distance from large scale permeable faults (see also Analyses and measures to limit seismic risks).

3. An estimate of the dimensions of fracks in the subsoil can be made using models. If necessary, the quantity of fracking fluid injected can be reduced to limit the vertical extent of fracks

The most important analyses and measures that can be used *during* fracking and gas extraction are:

1. Monitoring the composition and contamination in the groundwater and/or deeper aquifers during extraction activities, so that it can be determined whether migration occurs.
2. (Micro-)seismic monitoring to determine the extent of fracks and the dimensions of the stimulated reservoir volume. Migration risks can be limited using monitoring by implementing a “traffic light” or “hand on the valve method (among others, Bommer et al. 2006), where extraction activities are temporarily stopped or suspended if migration is observed.

Monitoring techniques to detect the risk of vertical migration

This section gives an overview of the technologies and a number of specific analyses and technology that can be used *before starting* and *during* fracking or the extraction of shale gas to analyse and limit migration risks with an indication of use in the United States, Canada and the Netherlands and “Technology Readiness Level” (TRL). In most cases these technologies are also used to limit other (for example seismic) risks and relevant sections in the report are referred to.

<u>(Conventional) technology in current practice (international and in particular in the United States and Canada)</u>
Monitoring of composition and contamination in groundwater, the design and positioning of insulating wells, site-specific analysis of the geological and geomechanical conditions of the subsoil, and the modelling of fracks in the subsoil are conventional technologies (TRL8-9) that are used in current practice. There are also different methods for determining the flow of fluid with measurements in wells (wireline logging), such as pulsed neutron logging, oxygen activation logging and carbon oxygen logging that can be used to determine flow of water in and around a well and potential problems with the insulating action of wells can be detected.

(Niche) technologies that are still rarely used, but are already available on the market and their possible impact on minimising the (residual) risks of shale gas
Planning of wells and fracking in the subsoil at a safe distance from large scale permeable faults and limiting the quantity of fracking fluid injected are niches that are rarely or never used in current practice in the United States and Canada (TRL6-7). The most important new developments of (niche) technologies that can be used for limiting migration risks are aimed at improving (underground) monitoring of leaks (among others Haas 2013). For migration as a result of fracking itself development is aimed primarily at improving the design of seismic monitoring networks, processing and interpreting (micro-) seismic data to map migration paths that may occur due to fracking better (TRL1-4). Other monitoring techniques based on temperature variations (distributed temperature sensing), based on acoustic signals (distributed acoustic sensing), or using chemical or other tracers can be used to map the growth of fracks or the interaction of fracks with wells better. The combination of these techniques with micro-seismic monitoring are important niches.

Inventory of current technologies from other industries that may be relevant for minimising the (residual) risks of shale gas
There is a lot of knowledge about monitoring or migration in case of underground CO_2 storage (TRL4-7). Since fracking does not usually play a part in CO_2 storage the focus lies in particular on migration along wells and natural migration. For the development of sensors that can detect changes in chemical composition at high resolution, one can look at developments in the area of monitoring of contamination on the surface. It must however be taken into account here that the temperature and pressures in the deeper subsoil are different from normal conditions on the earth's surface.

Developments and technologies that will become available in the (near) future and their effect on minimising the (residual) risks of shale gas
A development that may possibly be important in the future is monitoring methane and other components at a depth, for example in deep aquifers above the shale stratum. This can be done in separate wells for monitoring or using underground sensors that detect leaks in the light for example of tracers, chemical components, temperature changes, electrical conductivity, or acoustic signals (Haas 2013). The advantage of deeper underground monitoring is that migrations can be detected sooner, but the technology is still under development (TRL depending on type of monitoring) and uses are still limited.

Gaps in knowledge and technology specific to the Netherlands and taking into account (period of) possible usability
One of the major gaps in knowledge specific to the Netherlands is the lack of experience with (micro-)seismic monitoring during fracking. To identify and prevent leaks good data are necessary on the effect of fracking in the subsoil. The experience with micro-seismic monitoring from the US and Canada can be used immediately after licensing in the Netherlands. After licensing it will take 3-5 years to eliminate knowledge gaps regarding the efficiency of the detection of vertical migration along wells with micro-seismic monitoring, and regarding underground monitoring of leaks in aquifers.

Appendix C1: Chemicals used for drilling and fracking

The use of chemicals in current practice

In most cases the same fluids are used for drilling for shale gas as for drilling for conventional gas (see also Witteveen+Bos 2013). As for drilling for conventional gas, most drilling fluids used in the US and Canada for drilling for shale gas contain mainly water (water-based drilling mud) to which various chemicals can be added (among others King 2012). The exact composition of drilling fluids varies depending on the depth to which drilling is carried out and the composition of the rock drilled through. Specifically for horizontal wells, in some types of shales the quantity and type of clays that are present in the shale is an important factor. The most commonly used chemicals (Table 5) have the function of (1) increasing the specific gravity of the drilling fluid (weighting agents), (2) increasing the carrying capacity of the drilling fluid for sand grains (viscosifiers), (3) reducing the viscosity of the drilling fluid and preventing the particles adhering to one another (diluents or deflocculants), (4) reducing the surface tension between rock and fluid (surfactants), and (5) preventing the swelling of clays (clay stabilisers). In some cases in the US and Canada shallow wells are drilled with compressed air. Deeper wells are sometimes drilled with (synthetic) oil (for example diesel oil) instead of water (oil-based mud or synthetic oil based mud), among other things to reduce friction along the drill wall or to prevent clay swelling (among others King 2012).

The optimum composition of the chemicals in a fracking fluid for gas extraction may differ for each fracking activity, and among other things depends on the depth, thickness, composition and properties of the reservoir rock. A detailed description of the technology used in fracking for conventional gas can be found in the report of Witteveen+Bos (2013). The *Netherlands Oil and Gas Exploration and Production Association* NOGEPA has prepared a fact sheet of all the products that have been used in the last 5 years in the extraction of oil and gas in the Netherlands (NOGEPA, 2013). Outside the Netherlands chemicals with the same functions are used in fracking fluids that we find for the Netherlands (among others, FracFocus, 2013; Bergmann et al, 2014). The purpose of these inventories is to give a full overview of *all* the chemicals used for fracking. No distinction is made between the different applications of fracking, for example for conventional gas or shale gas. It is also not stated to what extent these chemicals are still used in the current practice of shale gas extraction in the US and Canada.
For the analysis of the need for the use of different chemicals and possible alternatives it is important to cluster the chemicals used based on their function in fracking. Substances in fracking fluids may be classified according to the following function groups. The substances used, roughly in order of their concentrations in fracking fluids, with their most commonly used name (English), and with a rough indication of their use in fracking in the US and Canada (rare, common, or virtually always, based on Kaufman et al. 2008; Paktinat et al. 2011; King 2012; Gandossi 2013), are:

1. Water (virtually always) is the main component of virtually all fracking fluids (usually much more than 90% of the total volume). In exceptional cases alternative fluids are sometimes used (see section 5).

2. Proppants (virtually always) consist of screened sand or ceramic granules of a certain size that are usually necessary to keep fracks open (permeable) after fracking so that gas continues to flow to the well.
3. Acids (often) and acidity stabilisers (rarely) may be necessary to prevent silicates in the stratified rocks swelling and hence silting the pores up again. Acids can ensure that some minerals dissolve from the rock (for example carbonates preacidify as HCl), so the well is freed from cement residues and the permeability of rocks is increased. For treatment with acid, corrosion inhibitors are often necessary to prevent corrosion of equipment. Acidity stabilisers can be used to maintain the action of some other additives (including crosslinkers).
4. Iron control additives (rare) may be necessary to prevent precipitation of iron of metal oxides in the well.
5. Gel polymers, gel stabilisers, viscosifiers and crosslinkers (rare) may be necessary to increase the viscosity and carrying capacity of the fracking fluid so that the proppants do not sediment during pumping but are transported and end up in the fracks. Crosslinkers react to certain conditions in the well with polymers so that gels with high viscosity and carrying capacity are produced.
6. Friction reducers (virtually always) are used to reduce the friction in the well during pumping.
7. Surfactants (often) are used to reduce surface tension between rock and the fluid so that inflow and outflow of the fracking fluid is promoted.
8. Corrosion inhibitors (often) may be necessary to prevent corrosion of the well.
9. Clay stabilisers (often) are intended to prevent swelling and migration of water-sensitive clay. Clay swelling may for example result in reduced gas production.
10. Gel breakers (rarely) can be used to break down gels again after formation so that after their action they can be produced back from the well.
11. Oxygen scavengers (often) are sometimes added to prevent too fast breakdown of polymers or precipitation of iron or metal oxides in the well (see also iron control additives).
12. Scale inhibitors (rarely) can be used to prevent precipitation of some poorly soluble carbonate and sulphate salts.
13. Biocides (virtually always) prevent the growth of bacteria that, by feeding on polymers, can cause corrosive and toxic H_2S to arise.
14. Fluid-loss additives (often) are substances that ensure that the uptake of fracking fluid is limited by the rock so that it can largely be recovered.
15. Anti-surfactants and defoamers (rarely) eliminate the action of surfactants and prevent foaming.

Table 5. Products and functions of chemicals that are used in drilling and fracking fluids with an indication of the individual compounds commonly used for this.

Product name	Component / chemical
Friction reducers	Polymers; Hydrotreated distillates - light fraction; Petroleum distillate; Polyacrylamide; Ethylene glycol
Proppants	Quartz sand; Ceramic material; Bauxite
Biocides	Glutaraldehyde; tetrakis hydroxymethyl phosphonium sulphate; 2-Bromo-2-nitro-1,2-propanediol; Quaternary ammonium chloride
Gel polymers	Guar gum; Polysaccharide; Petroleum distillate
Gel stabilisers	Sodium thiosulphate pentahydrate; Sodium chloride;
Gel breakers	Ammonium persulphate; Magnesium peroxide; Diammonium peroxodisulphate; Sodium bromate
Crosslinkers	Sodium tetraborate; 2,2,2’”-Nitrilotriethanol; Potassium metaborate; Potassium hydroxide;
Viscosifiers	Clays such as bentonite
Acids	Citric acid; Formic acid; Hydrochloric acid; Hydrogen fluoride
Fluid-loss additives	Sand, Clay
Surfactants	2-Butoxyethanol; Methanol; Isopropanol; Isopropyl alcohol; Nonyl phenol ethoxylate;
Acidity stabilisers	Sodium carbonate; Potassium carbonate; Potassium hydroxide; Sodium hydroxide
Clay stabilisers	Tetramethyl ammonium chloride; Potassium chloride
Corrosion inhibitors	Methanol; N,N-Dimethylformamide; Acetaldehyde
Iron control additives	Thioglycolic acid; Citric acid; Acetic acid
Oxygen scavengers	Ammonium bisulphide
Scale inhibitors	Ethylene glycol; Ammonium chloride; Polyacrylate; Sodium polycarbonate
Anti-surfactants and defoamers	Paraffins; Vegetable oils;
Weighting agents	Barium sulphate (only for drilling)

As in the above description there is a connection between some added chemicals: if chemicals are added for a particular purpose, it may also be necessary to add other chemicals necessary to support this functionality (temporarily), to prevent unwanted side effects.

Table 5 lists typical chemicals that are used for the function groups. The fact sheet shows that some chemicals occur in more than one function group and may therefore as an individual chemical substance possibly also perform more than one function.

Toxicity of chemicals used and the relation to risk of their use
The NOGEPA (2013) fact sheet gives hazard classifications and risk phrases for both the individual components (based on Directive 67/548/EEC)[18] and the products as a whole (based on Directive 99/45/EC)[19]. This fact sheet is based on information available via safety data sheets (veiligheids-informatiebladen - VIB's) or material safety data sheets (MSDS) of products/preparations. It is not compulsory to indicate on safety data sheets substances that are not classified or to indicate substances that are classified but do not contribute to the classification of the product (see for more detail the relevant regulation 99/45/EC). Table 6 of Appendix C2 gives an overview of chemical substances that *are (or have been)* used in the Netherlands for fracking, together with their classification and annotation according to Directive 67/548/EC, their REACH registration status, REACH PBT/vPvB qualification if a substance is registered in REACH (including individual P/vP and B/vB information if available) and other available information relating to persistence and bioaccumulation.

Finally the substances appearing in the Candidate list of Substances of Very High Concern (SVHC) are looked at. In this first phase only data screening is carried out based on the available classification and annotation, and on the data released by ECHA if a substance is registered for REACH. The substances list is based on the above-mentioned summary table of chemicals that are used in fracking in the Netherlands, put together by NOGEPA (2013), on data from the KWR (2012), and on the fracking fluid that is indicated on the website of the NAM. The substances indicated relate only to the function of the whole *product*; the function of the chemical substance as such is often less clear. Since there is also an overlap of chemical substances in products both within a single list and between the different lists, the substances in Table 2 are set out singly, separately from the list in which they are indicated and separately from the product function to which they relate.

Based on the information collected in Appendix C2 it can be deduced that:

- 74 of a total of 118 known chemicals are classified.
- 6 substances are classified as Carcinogenic, Mutagenic of Reprotoxic (CMR)
- 12 substances are possibly persistent or bioaccumulative (based on annotation R53).
- no substance is both CMR and possibly persistent/bioaccumulative
- 53 substances are REACH registered
- none of the REACH registered substances is qualified as PBT/vPvB or individual P/vP of B/vB.

In addition none of the substances appears on the candidate list of substances of very high concern (this is not shown separately in Appendix C2).

[18] Directive 67/548/EEC regulates the classification, packaging and labelling of hazardous substances. This Directive is also called the Dangerous Substances Directive.
[19] Directive 99/45/EC gives legal provisions on the classification, packaging and labelling of dangerous preparations. This Directive is also called the Dangerous Preparations Directive.

The risk of using chemicals in fracking is not only determined by the toxicity of the chemicals used. It is determined by the chance that chemicals have a harmful effect on the earth's surface or in the subsoil and the effect of the harmful action on the environment. The risk that chemicals have a harmful action on the earth's surface is mainly determined by the chance of spillage or leaks (see section 1), the quantity, concentration and toxicity of the leaked chemicals (this section), and the site-specific interaction with the environment which leaked chemicals can reach. Depth and spread are also important factors for the risk in the subsoil. For the effect in the subsoil it is furthermore important how the chemicals behave at higher temperature and pressure. Some chemicals decompose quickly in the subsoil and are as a result less or not harmful in the subsoil. This report limits itself to the screening of toxicity and identification of possible alternatives because the optimum composition of the chemicals in a fracking fluid for gas extraction may differ for each fracking activity and the interaction with the above- or underground environment differs for each chemical composition of the fracking fluid. Screening the toxicity of different chemicals based on existing guidelines, classifications and recordings *only* as in the above summary is not sufficient for a good indication of the risks of using fracking fluids. The toxicity data can however be used to reduce the risks of using fracking fluids (see Appendix B) and to identify possible alternatives (see Appendix E).

Knowledge and developments of fracking and fracking fluids by the service industry
Most knowledge and developments in the area of fracking fluids is carried out in the service industry that plans and carries out fracking operations for the E&P industry. A lot of useful information about better and less harmful fracking fluids can be obtained from flyers and information sheets from the service industry. The biggest three companies with activities in the area of shale gas extraction in the US are Schlumberger (www.slb.com), Halliburton (www.halliburton.com) and Baker Hughes (www.bakerhughes.com). Detailed information on fracking techniques and fracking fluids can be found on these websites. Although helpful and important, this information also has the purpose of marketing new technology and knowledge. Examples of recent developments that may help limit risks of fracking and chemicals in fracking fluids are (1) Schlumberger's HiWAY Flow-Channel Fracturing Technique where the combination of gels, special fibres and high frequency pulses gives better fracks, (2) Halliburton's RapidSuite systems where multistage fracking proceeds more efficiently by using systems that seal parts of the well during fracking, and (3) Baker Hughes's FracPoint systems where multistage fracking proceeds more efficiently by using special systems that seal part of the well during fracking. For all these techniques the service industry claims that fracking can be carried out more efficiently so less fracking fluid is necessary. On the websites you can also find information on compositions of fracking fluids that can help limit possible risks of chemicals in fracking fluids. It has also been decided in this report only to include the knowledge and technology of the service industry if its use has been proven and can be verified by means of scientific publications.

Possibilities for avoiding chemicals in fracking fluids and the use of alternative chemicals
<u>(Conventional) technology in current practice (international and in particular in the United States and Canada)</u>

An important trend from the US and Canada is that fracking for shale gas is carried out to an increasing degree by injecting low viscosity fluids (slickwater) at high speeds with smaller quantities of proppants (TRL9, King 2012; Gandossi 2013).

Slickwater fracking gives good results as regards opening natural structures and as regards the complexity of reactivated faults in the stimulated reservoir volume in certain types of shales. Slickwater consists mainly of water with a smaller quantity of chemicals added than in many other types of fracking fluid. The most important chemicals added have the function of reducing the friction between fluid and bore wall (friction reducers), or preventing the growth of bacteria (biocides). The optimum composition of the chemicals in a fracking fluid for gas extraction differs depending on the composition and properties of the shale. For this reason slickwater is not suitable for all shales, and for some (more ductile, or oil-containing) shales (for example the Bakken) fracking fluids is used with gel polymers. The trend in the use of slickwater described in King (2012) may be affected because the focus in shale gas extraction in the US has in the first instance been on the less ductile shales (for example the Barnett).

There is no practical experience with fracking for shale gas extraction in the Netherlands. The products in the NOGEPA summary table (2013) are to date therefore used in fracking for gas extraction from tight gas sandstones, or other less permeable conventional gas reservoirs. Cuadrilla (2011) states that *for test drillings* it uses a fracking fluid that only has glutaraldehyde (a biocide) and polyacrylamide (a friction reducer) added. It is unclear how far fracking with this fluid is optimum *for gas extraction* from Dutch shales. From information from companies that carry out fracking (service industry) it is known that fluids that are used for the fracking of shales in Europe contain biocides, gel polymers, clay stabilisers, crosslinkers, gel breakers, surfactants and corrosion inhibitors.
The overview in Appendix C2 can be used to make the fracking fluids safer by following the following procedure:

1) determine the *substance-specific* function for fracking and group substances based on their function
2) replace chemicals with unwanted classification(s) by chemicals without a classification or with a lower classification.

If a substance cannot simply be replaced,

3) use chemicals classified in lower concentrations, or even
4) do not use classified chemicals.

In the last case the effects on the efficiency of fracking and gas extraction play an important part.

In the first instance the focus could be laid for example on the CMR substances and substances that are potentially persistent or bioaccumulative (“R53”), since these are the “more severe” classifications within the human and environment classification.

In the documentation referred to it cannot be found why particular chemicals within a function group have been specifically chosen. Only based on the classifications from Table 5 can it be deduced that there are possibilities for choosing safer substances with the same functionality as less safe substances. This conclusion was also drawn by Bergmann et al. (2014). It is of course unclear how far different substances within the same function category differ in efficacy, which can also be an important choice criterion. This efficacy also depends on the properties of the shale. It is often not explicitly indicated what concentration of chemicals is actually necessary. There are often big differences in concentrations of chemicals in the different fracking fluids. Reduction or removal of chemicals in a fracking fluid can give a reduction of risks in preparation and use for people and environment.

Developments in applicable chemicals
<u>(Niche) technologies that are still rarely used, but are already available on the market and their possible impact on minimising the (residual) risks of shale gas</u>
There is a lot of development in the area of alternative, more sustainable, biodegradable and non-environmentally harmful chemicals in fracking fluids. The added value and technical usability of these chemicals has often not yet been tested and can be looked at per individual case so as to arrive at more environmentally friendly fracking fluids. It is also important here to determine the actual toxic effect of the chemicals under the relevant conditions. The toxic effect of pure substances says little about the possible effects of diluted substances on the environment in shale gas extraction. The most important trends and findings for different functions of chemicals (see above text) that are used are (among others King, 2012):

1. <u>Water</u> is not harmful. Alternatives for water use (with a view to availability and treatment) are described in section 5. Research focuses among other things on possibilities of fracking fluids with a higher salt content so that produced water can be (re-)used instead of fresh water (among others Kakadjian et al. 2013).
2. <u>Proppants</u> usually consist of screened sand or other non-harmful substances. Some types of ceramic granules clump together in the fracks or prevent compression of the rock around the granules, but no harmful effects are known.
3. <u>Acids (often) and acidity stabilisers and iron controllers</u>. Most of these chemicals lose their action by interacting with the rock (King 2012).
4. <u>Gel polymers, gel stabilisers, viscosifiers, crosslinkers and gel breakers</u>. These chemicals are used less often used in fracking for shale gas extraction in less ductile shales because of the better results with slickwater fracking (King 2010).
5. <u>Friction reducers</u>. Research focuses among other things on development of chemicals that break down polyacrylamide safely (Carman & Carwiezel 2007).
6. <u>Corrosion inhibitors</u>. Most corrosion inhibitors lose their action by interacting with the well or rock (King 2012). Research focuses among other things on development of biodegradable substances (see references in Choudhary et al. 2013).
7. <u>Clay stabilisers</u>. In many cases it is sufficient to add salts such as KCl for which no harmful effects are known.
8. <u>Scale inhibitors</u>. Biodegradable scale inhibitors are successfully used for oil and gas extraction in the North Sea (Patel 2009; Holt et al. 2009; Dickinson et al. 2011)
9. <u>Biocides</u>. Combinations of the much used glutaraldehyde and tetrakis hydroxymethyl phosphonium sulphate give a better result as regards preventing bacterial growth so lower concentrations can be used (Enzien & Yin 2011). Alternatives are the use of UV light, ozone, or chlorine dioxide in low concentrations (King 2012).

10. Surfactants, fluid-loss additives, oxygen scavengers, anti-surfactants and defoamers represent a wide range of chemicals. The need for the use and technical usability of alternative chemicals can be looked at for each individual case to arrive at more environmentally friendly fracking fluids.

Improved methods and alternatives for hydraulic fracking
There are special techniques that can be used so that fracking can be better controlled or be carried out more efficiently. Due to the better control of fracking, or other stimulation techniques it is possible to work with less fracking fluid and/or chemicals. In some cases a greater quantity of fracking fluid can also be extracted from both wells. For some techniques however other chemicals are necessary so the added value is not clearly proven. Some techniques are exotic or in the experimental phase (used a maximum of once or few times in a controlled environment), and it is unclear whether the technique can be used in the short term. Roughly in order of development (TRL level) or usability the most commonly used techniques are (among others Gandossi 2013):

1. Zipper fracking, where fracking is carried out simultaneously of two parallel horizontal shale gas wells (among others Sierra and Mayerhofer 2014). Here it is expected that the fracks will propagate towards one another. The advantage is better control of the extent of fracks (TRL7-9).

2. Special drilling techniques. Drilling techniques are being developed that can possibly (partly) replace fracking in the future. Known techniques are radial wells, needle wells, or fishbone wells. For radial wells parts of the reservoir are drilled from a central well. For needle wells or fishbone wells a large number of short, thin wells (usually some 5 cm in diameter and 1-10 metres long) are injected from a central well with hydro-jetting. Some techniques combine hydra-jet fracturing of material (Loyd 2004). Vertical cuts can also be made along a horizontal well with a sort of wire saw around the well. The length of the cuts may extend to some 30 m into the formation and be made over a length of 700 metres (Carter 2009). All these techniques are at present in the concept phase for shale gas extraction (TRL2-6). The greatest uncertainty in these techniques is the effect of the limited penetration depth and drainage area.

3. Thermal (cryogenic) fracking (see also section 5), where liquid CO_2 is used and the fracks occur due to stress changes as a result of cooling. By injecting liquid CO_2 an area around the well can cool by 50-100 °C. After injection conventional fracking is then also carried out. For this possibly less fracking fluid and chemicals are necessary. The disadvantage is that liquid CO_2 has to be injected for a lengthy period so that the fracks are of a sufficient extent (Mueller 2012). The technology has already been used for a while (Yost II et al. 1993), but is not widely used (TRL6-8).

4. "Cavitation hydro-vibration fracturing", which can be used for fracking a formation uses pressure pulses (Dzerko 2008, TRL1-5).

5. Pneumatic fracking, where air or another gas is injected under high pressure as a result of which fracks occur (Suthersan 1999). The technique is normally used for shallow formations. Often no proppant is used because it is assumed that the fractures remain open on their own (self-propped

fractures). On average the pressure must be two to three times higher than in normal fracking. Disadvantages are that it can only be used to a certain depth and that no proppant is used so that the permeability after fracking is not guaranteed.
A known technique is offered under the name “Grand Canyon” (TRL4-6).

6. Electric fracking is at present carried out by two methods. In the first method a pressure wave is created by an electrical discharge between two electrodes in a well filled with water. The pressure wave ensures the creation of fracks (Chen 2012). The second method uses a rapidly expanding plasma that is produced by pulses of high energy electrical discharge. Fractures that could occur here would be 1-15 metres. The disadvantage is that the penetration in the formation is smaller and that no proppant is left behind in the fracks so the permeability may be low. Known techniques are among other things PAED (“Pulsed Arc Electrohydraulic Discharges”) and PSF (“Plasma Stimulation and Fracturing Technology”). Techniques are in the concept phase (TRL2-4).

7. “Exothermal fracking”, where chemical reactions between the injected chemicals generate heat and gas. This then ensures thermal and mechanical fracking (Al-ajwad et. al. 2013, TRL1-4).

8. Fracking with explosives, where a pressure wave is created with (gel) explosives which results in new fracks. The fracks are then enlarged by injecting fracking fluid. Work is usually carried out with special explosives that work without oxygen and ensure rapid ignition with high energy, where the ignition is propagated at subsonic speeds by the gas created (deflagration). The occurrence of gas under high pressure ensures the formation of fracks. The fractures occurring are usually short (some 1-10 metres) with minimal vertical growth of fractures outside the formation, and form a complex network. The disadvantage is that the penetration in the formation is smaller and that no proppant is left behind in the fracks so the permeability may be low. Known techniques include among others Stimgun, StimTube, Gasgun, Pulsefrac (Rogala 2013, TRL1-5).

9. Bacterial methanogenesis (production of methane by anaerobic bacteria) is strictly speaking not an alternative technique for fracking, but can lead to local stimulation of methane generation so that fracking has to be carried out less extensively. This technique can probably only be used in shallow formations (<1500 m), since at greater depths no or much fewer bacteria occur. This technique is at present in the concept phase, in laboratories it is used successfully on rock samples (TRL1-4).

10. Fracking with seawater is not an alternative for fracking, but it is mentioned here because of the possibly lower or different use of chemicals, and because of the implications for water use and treatment (TRL4-6).

Other technologies and knowledge gaps
Inventory of current technologies from other industries that may be relevant for minimising the (residual) risks of shale gas
A large number of chemicals are known that, although in different concentrations, are also used in other industries, for example in the food industry or chemical

industry (among others King 2012). One can look for each type of chemical substance whether alternative chemicals are known from these industries that are more sustainable, biodegradable and less environmentally harmful, taking into account the relevant conditions in shale gas extraction.

Appendix C2: Summary of Toxicology

General comments on Table 6:

- For REACH registered substances no distinction is made between substances that are registered as a "full substance" or "intermediate". For intermediates as a rule less information is present and in most cases no PBT/vPvB qualification will be assigned.
- A substance is PBT if both the criteria for P and B and T are met. A substance is vPvB if both the criteria for vP and vB are met (for more information please refer to the REACH legal text and REACH guidance R. 11). The individual P, vP, B, vB or T qualification is not indicated in all cases for a REACH registered substance in the data released by ECHA (disseminated dossier on the ECHA website).
- N.a. = not applicable. In all the above-mentioned cases PBT/vPvB does not apply since *"the PBT and vPvB criteria of appendix XIII to the Regulation do not apply to inorganic substances*"
- An "X" is indicated if labelling R53 ("may cause long-term effects in the environment") is used in combination with R50 ("Very toxic in the aquatic environment") or R51 ("Toxic in the aquatic environment") which means that a substance is either not readily degradable or has a log Kow ≥ 3. Which of these two applies cannot be deduced based only on C&L. Labelling R53 in combination with R52 ("Harmful to aquatic organisms") in principle means that a substance is not readily degradable (separately from log Kow).

A full list of R-phrases is readily accessible via Wikipedia (http://en.wikipedia.org/wiki/List_of_R-phrases)

Table 6: Overview of chemical substances used in the Netherlands in fracking for gas extraction

Fracking substance	**CAS #**	**Classification**	**Substance Labelling** (R-phrases)	**REACH Regstr.**	**REACH PBT/vPvB**	**Persistent**		**Bioaccumulation**	
						ECHA	other	ECHA	other
1,2,4-Trimethylbenzene	95-63-6	Xn, N	R10, R20, R36, R37, R38, R51, R53	Y	N	N	X	N	X
1,2-Ethanediamine, N,N,N',N'-tetramethyl-, polymer with 1,1'-oxybis(2-chloroethane)	31075-24-8	N	R50, R53	-			X		X
1-Propanaminium, 3- amino-N-(carboxymethyl)-N,Ndimethyl-, N-coco acyl derivs., hydroxides, inner salts	61789-40-0	Xi	R36	-					
2-(2-butoxyethoxy)ethanol	112-34-5	Xn, Xi	R36, R65	Y	N	N		N	
2,2',2''-nitrilotriethanol	102-71-6			Y	N	N		N	
2-butoxyethanol	111-76-2	Xn, Xi	R20, R22, R36, R38	Y	N	N		N	

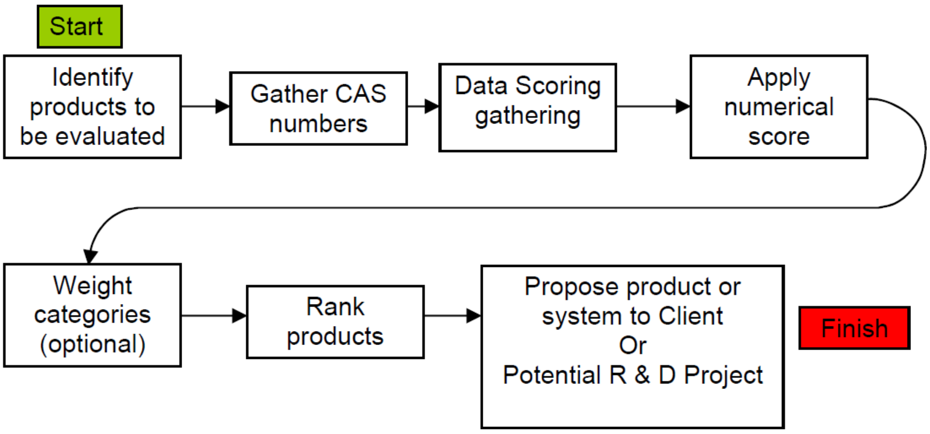
2-ethyl hexanol	104-76-7	Xi	R36, R38	Y	N	N		N	
2-methyl-2 H -isothiazol-3-one (MI)	2682-20-4			-					
3,6,9,12,15,18,21,24-Octaoxatetratriacontan-1-ol	24233-81-6	Xn, Xi	R22, R41	-					
5-Chloro-2-methyl-4-isothiazolin-3-one	26172-55-4			-					
5-chloro-2-methyl-2 H -isothiazol-3-one (CMI)	26172-55-1			-					
5-Chloro-2-Methyl-2H-Isithiazol-3-One and 2-Methyl-2H-Isothiazol-3-One (3:1)	55965-84-9	T, C, N	R23, R24, R25, R34, R50, R53	-			X		X
Acetic Acid	64-19-7	C	R10/R35	Y	n.a.*				
Alcohol, C11 linear, ethoxylated	34398-01-1	Xn, Xi, N	R22, R36, R38, R51, R53	-			X		X
Alcohol, C9-C11, Ethoxylated	68439-46-3	Xn, Xi	R22, R41	Y	N				
alkanes C10-14	93924-07-3	Xn	R65	-					
alkenes C>8	98526-58-9	Xn	R65	-					
Alkenes, C>8	68411-00-7	Xn	R65	-					
Alkyl hydroxy ethyl benzyl ammonium chloride	61789-68-2	F, Xn, C, N	R11, R22, R34, R50	-					
Aluminium chloride	7446-70-0	C	R34	Y	n.a.				
Aluminium oxide	1344-28-1	Xi	R36/38	Y	n.a.				
Aluminium silicate	1304-76-7								
Aluminium stearate	637-12-7			-					
Amine derivative	-	Xi, N	R38, R41, R50	-					
Amine derivative	-	Xi, N	R38, R41, R50	-					
Ammonium acetate	631-61-8	C	R34	Y	n.a.				
Aromatic ammonium compound	-	Xn, C, N	R34, R22, R50	-					
Ascorbic acid	50-81-7			-					
Acetic anhydride	108-24-7			Y	N	N		N	
Boric acid	10043-35-3			Y	n.a.				
Borate salts	-			-					
C10-16 ethoxylated alcohol - 9 moles ethoxylation	68002-97-1	Xn, Xi, N	R22, R41, R38, R50	-					
Calcined bauxite	66402-68-4			Y	n.a.				
Calcium Carbonate	1317-65-3			-	n.a.				
Calcium fluoride	7789-75-5			Y	n.a.				

Calcium hydroxide	1305-62-0	Xi	R41	Y	n.a.				
Calcium peroxide	1305-79-9	O, C	R8, R38, R41	-	n.a.				
Carbonhydrated Polymer	-			-					
Chlorous acid, sodium salt	7758-19-2	O, T, C	R9, R22, R23, R24,R32, R34	Y	n.a.				
Cholinium chloride	67-48-1			Y	N	N		N	
Citric Acid	77-92-9	Xi	R36	Y	n.a.				
Corundum	1302-74-5			-					
Crystalline silica, quartz	14808-60-7	Xn	R20, R22, R36, R48	-					
Distillates (Petroleum) light fraction treated with hydrogen	64742-47-8	Xn	R65	Y	N	N		N	
Diammonium peroxodisulphate	7727-54-0	O, Xn, Xi	R8, R22, R36, R37, R8, R42, R43	Y	n.a.				
Diesel	68476-34-6			Y	N				
Disodium tetraborate decahydrate	1303-96-4	**Repr Cat 2**	R60, R61	-					
Disodium octaborate tetrahydrate	12008-41-2	**Repr Cat 2**	R6, R60	Y	n.a.				
Dodecyl-pentadecyl alcohol ethoxylate	106232-83-1	Xn, Xi	R22, R41	-					
Epichlorohydrin	25085-99-8			-					
Ethanol	64-17-5	F	R11	Y	N	N		N	
Ethoxylated Alcohol	-	Xn, Xi	R22, R41	-					
Ethoxylated Alcohol	-	Xi	R38, R41	-					
Ethoxylated alcohol linear (1)	-	Xn, Xi, N	R22, R36, R38, R51, R53	-			X		X
Ethoxylated alcohol linear (2)	-	Xn, Xi	R22, R41	-					
Ethoxylated alcohol linear (3)	-	Xn, Xi	R22, R36, R38	-					
Ethoxylated C11 linear/branched alcohols (5eo)	34398-01-1c	Xn, Xi	R22, R41	-					
Ethoxylated C11 linear/branched alcohols (7eo)	34398-01-1b	Xn, Xi	R22, R41	-					
Ethoxylated fatty alcohol	-	Xn	R22, R41	-					
Glutaraldehyde	111-30-8	T, C, N	R23, R25, R34, R42, R43, R50	Y	N	N		N	
Glycerine	200-289-5			-					
Glyoxal	107-22-2	Xn, Xi, **Mut Cat 3**	R20, R36, R38, R43, R68	Y	N	N		N	
Guar gum	9000-30-0			-					
Guar Gum derivative	-			-					

Heavy Aromatic Naphtha	64742-94-5	Xn, N	R51, R53, R65, R66, R67	Y	N		X		X
Hemicellulase enzyme concentrate	9025-56-3	Xn	R42	-					
Hemicellulase-enzyme (cellulase)	9012-54-8			Y	N	N		N	
Hexamethylenetetramine	1009-7-0			-					
Iron oxide	1309-37-1			Y	n.a.				
Isoascorbic acid, sodium salt	6381-77-7			Y	N			N	
Potassium carbonate	584-08-7	Xn, Xi	R22, R36/37/38	Y	n.a.				
Potassium chloride	7447-40-7			Y	n.a.				
Kaolin	1332-58-7			-					
Crystalline silica, cristobalite	14464-46-1			-					
l-(+)-lactic acid	79-33-4	Xi	R41/, R38	Y	-	N*		n.a.	
Magnesium nitrate	10377-60-3	O, Xi	R8, R36, R38	Y					
Methanol	67-56-1	F, T	R11, R23, R24, R25, R39/23/24/25	Y	N				
Formic acid	64-18-6	C	R35	Y	N	N		N	
Mullite	-								
N,N-Methylene bis (5-methyloxazolidine)	66204-44-2	C, Xn	R34, R21, R22	-					
Naphthalene	91-20-3		R22, R40, R50, R53	Y	N	N	X	N	X
Sodium acetate	127-09-3			Y	n.a.				
Sodium bromate	7789-38-0	O, Xi, **Carc Cat 1**	R9, R20, R36, R37, R45, R48	-	n.a.				
Sodium carbonate	497-19-8	Xi	R36	Y	n.a.				
Sodium chloride	7647-14-5			Y	n.a.				
Sodium hydroxide	1310-73-2	C	R35	Y	n.a.				
Sodium persulphate	7775-27-1	O, Xn, Xi	R8, R22, R36, R37, R38, R42, R43	Y	n.a.				
Sodium thiosulphate, pentahydrate	10102-17-7			-					
Sodium hydrogen carbonate	144-55-8			Y	n.a.				
Olefins	68991-52-6	Xn	R65	-					
Oxyalkylated alcohol	-	Xi, N	R38, R41, R51, R53	-			X		X
Oxyalkylated alkyl alcohol	-	Xi, N	R38, R41, R50, R53	-			X		X

P/F novolac resin - hexamethylenetetramine complex	1302-93-8	Xn	R20/22	Y	n.a.				
Paraffin	90622-52-9	Xn	R65	-					
Paraffins (petroleum), normal C5-20	64771-72-8	Xn	R65, R66	-					
Phenol-Formaldehyde Novolak Resin	9003-35-4	Xn	R20/R22	-					
Polyethylene glycol monohexyl ether	31726-34-8	Xi	R38, R41	-					
Polyquaternary Amine	-		R52, R53	-			Y		
Polysaccharide derivative	-			-					
Potassium persulphate	7727-21-1			Y	N	N		N	
Propane-2-ol	67-63-0	F, Xi	R11, R36, R67	Y	N	N		N	
Propylene carbonate	108-32-7			Y	N	N		N	
Quaternary ammonium compound (modified)	-	F, Xn, C, N	R10, R11, R22, R34, R50	-					
Quaternary ammonium chloride	-	T, Xi	R21, R25, R36, R37, R38	-					
Quaternary Ammonium Salts	68989-00-4	Xn, C, N	R22, R34, R50	-					
Silicium dioxide	7631-86-9			Y	n.a.				
Silicon dioxide	60676-86-0			-					
Sodium hypochlorite	7681-52-9	C	R31, R34	Y	N	N		N	
Sodium tetraborate	1330-43-4	**Repr Cat 2**	R60, R61	Y	n.a.				
Sodium thiosulfate	7772-98-7			Y	n.a.				
Terpenes and Terpenoids, sweet orange-oil	68647-72-3	Xn, Xi, N	R10, R65, R38, R43, R50, R53	-			X		X
Tetraethylenepentamine	112-57-2	Xn, C, N	R21, R22, R34, R43, R51, R53	-			X		X
Tetrakis (hydroxymethyl) Phosphonium Sulphate	55566-30-8	T, Xn, Xi, **Repr Cat 2**, N	R22, R23, R41, R43, R50, R61	-					
Tetramethylammonium chloride	75-57-0	T, Xi	R21, R25, R36, R37, R38, R50	Y	N	N		N	
Titanium oxide	13463-67-7			Y	n.a.				
Vegetable oil	-			-					
Zirconium dichloride oxide	7699-43-6	C	R34, R52	Y	n.a.				
Salt of aliphatic acid	-			-					

Table 7: Example of the procedure for classifying chemical products as regards their potential environmental damage, toxicity and danger in case of incidents (Jordan et al. 2010). Top: procedure, middle: example of calculated scores for a surfactant, bottom: comparison of scores for different surfactants A-H that can be used to identify the least (H) and most (C) harmful surfactants.



Component	Methanol	Component A	Component B	Water	Total Score	Weight Score
CAS Number	67-56-1	CAS# A	CAS# B	7732-18-5		
%	x	x	x	x		
Environmental Criteria						
Acute Aquatic Toxicity	1	3	2	0		
Air Pollutants (VOCs)	3	0	0	0		
Priority Water Pollutants	0	0	0	0		
Bioaccumulation	0	0	0	0		
Biodegradation	0	1	1	0		
total score/component	x	x	x	x	176	4.4
Toxicological Criteria						
Acute Mammalian Toxicity	0	0	0	0		
Carcinogenicity	0	0	0	0		
Genetic Toxicity	1	1	0	0		
Reproductive and Developmental	3	3	3	0		
Corrosive/Irritant	1	1	1	0		
total score/component	x	x	x	x	223	5.6
Physical Hazards						
%					100	
Explosive					0	
Flammable					1	
Oxidizer					0	
Corrosive					0	
total score					100	2.5
Product Score (Environmental, Toxicological and Physical Hazard Criteria)					499.0	**12.5**
						(out of 100)
Data gap = 1						

Surfactant Product	A	C	D	E	F	G	H
Environmental Criteria	4.4	4.1	2.9	4.4	3.7	3.1	1.4
Toxicological Criteria	5.6	6.6	4.1	6.8	2.2	3.7	3.9
Physical Hazards	2.5	5.0	0.0	2.5	0.0	2.5	0.0
Product Score	**12.5**	**15.7**	**7.0**	**13.7**	**5.9**	**9.3**	**5.3**

worst case
best case

Appendix D1: Water treatment

Important factors for the choice of the treatment technology are 1) the quantity of water that must be treated, 2) the composition of the water and 3) the quality that is required after treatment.

The quantity of flowback and production water after fracking operations for shale gas extraction and its composition is addressed in the report of Witteveen+Bos (2013) and Olsthoorn (2014). This will be recapped briefly here to determine the starting point for the rest of this paragraph. After this, where known, the water quality requirements are discussed for reuse of flowback water, discharge to surface water and reinjection into an available gas or oil reservoir by means of an injection well.

The heart of this paragraph is the overview of different treatment technologies that can be used for treating flowback water and production water. Depending on what requirements are laid down for the treated water, more or fewer treatment stages will be necessary. Conventional technologies and technologies that will be coming onto the market in the (near) future are compared with one another and current practice abroad (in particular the United States) is looked at.
Then the overall scope (dimensions) of the treatment plants are checked and whether treatment can be carried out on site (decentral or central treatment). Finally the question whether the water can be discharged into the surface water without additional risks is answered (and if so, under what conditions) and the conclusions then follow.

Water use and flowback water in shale gas extraction

To arrive at an informed choice for the treatment technology of the flowback water in shale gas extraction it is necessary to know how big the water streams are. Averages for these are given in Witteveen+Bos (2013).

Flowback water is water that flows back to the surface after completing the hydraulic fracking. This water flows back to the surface during a period of three to four weeks, most intensively during the first seven to ten days after fracking. New York State (2009) gives a period of 2 to 8 weeks.

Starting with a scenario with 10 wells per site based on average water use and flowback water volumes per well an overview is given of the total volumes for this scenario (Witteveen+Bos, 2013, (Table 8). This assumes drilling to a depth of 3,500 m and strands of 1,500 m per well.

Table 8. Average water use and flowback water per well and site (source Witteveen+Bos, 2013).

scenario 10 wells per site, 7 years production	Use per well (m3)	Flowback per well (m3)	Use per site, 10 wells (m3)	Flowback per site, 10 wells (m3)
Fracking	18,500	9,250*	185,000	92,500*
Production water	-	244 thousand		2.4 million

* ultimately 30 - 70% flowback. Initially this is 15-35% (first 3-4 weeks)

On average 15-35 % of fracking fluid returns immediately after fracking as flowback. Later in the process in total approx. 50 % flows back. Around half of the fracking fluid is left behind in the subsoil. These estimates do however vary considerably.

As time goes on, less water will be produced. If it is assumed that the flowback water flows back in two weeks and production water after that over the 7 years production (according to the scenario in Witteveen+Bos, 2013) the flow rate of flowback water is 138 m^3/hour and of production water (maximum) 40 m^3/hour (Table 9).

Table 9. Estimate of flow rate of flowback water and production water on 1 site with 10 wells.

	Water volume 1 site (10 wells) (m^3)	1 site (10 wells) 2 weeks flowback water (m^3/hour)	1 site (10 wells) for 7 year (m^3/hour)
Flowback water	46,250*	138*	N/A
Production water	2,437,470**	N/A	40

* based on 25% flowback of the frack water in the first two weeks.
** based on 7 years production

Tyndall (2011) in Olsthoorn (2014) gives a range for flowback volumes for a site with 6 wells of 2000 m deep with strands of 1200 m (Table 10)

Table 10. Estimate of flowback water flow rate on 1 site with 6 wells (source Tyndall, 2011).

	Water volume 1 site (6 wells) (m^3)	1 site (6 wells) 2 weeks flowback water (m^3/hour)
Fracking water	54,000-174,000	N/A
Flowback water	7,920 – 137,280*	24 - 409

* based on 15% flowback of the fracking water

Based on Table 9 and Table 10 it is clear that if on a site with 6 to 10 wells the flowback water were to be treated on site, treatment plants are necessary that can cope with flow rates of 138 m^3/hour or even more during the first 2-8 weeks after fracking. After this it is expected that production water will be released at a lower flow rate (approx. 40 m^3/hour). The reduction in the flow rate does occur gradually however. It is not unusual here for the production water flow rate to fall continuously during the first year after fracking (King, 2010).

If the flowback water is stored temporarily, it is possible to work with smaller treatment plants, in this case for example with a maximum capacity of 100 m^3/hour. The wells are often fracked directly after one the other and as a result the flowback water is often produced simultaneously from the wells. Should this not be the case, the flow rates of the flowback water from the total site, given in Table 9 and Table 10, will be lower.

Composition of flowback water and production water in shale gas extraction

This paragraph gives an indication of what the composition of the flowback water and production water may be in shale gas extraction. It does not aim to give a precise composition of these water streams. This will have to be found from measurements. With the data in this paragraph it is however possible to indicate which components must be removed from the water, depending on the purpose of the treatment and the standards.

The flowback water during the first days/weeks after fracking consists mainly of fracking fluid with added chemicals and proppants. Due to reactions of the rock with chemical additives in the fracking fluid substances may also be released from the shale formation. These substances therefore also get into the flowback water. After this the produced water is primarily formation water.

Section 3 discusses the different fracking chemicals and possible alternatives in detail. A conservative scenario for the composition of the flowback water during the first days/weeks after fracking is that it has the same concentrations of fracking chemicals as the fracking fluid. To get an idea of these concentrations Table 11 gives a typical concentration for many of the substances used. In practice these concentrations in the flowback water will be lower due among other things to dilution, breakdown and the leaving behind of these components in the formation.

Table 11. Overview of normal substances in fracking water (US DOE, 2009 and Witteveen+Bos, 2013). For explanation see Table 5

Product name	Example of concentration (mg/L)
Friction reducers	880
Proppants	
Biocides (Glutaraldehyde)	10
Gel polymers (Guar gum or hydroxyethyl cellulose)	600
Gel stabilisers (NaCl)	
Gel breakers (Acids and/or oxidizers, ammonium persulphate)	100
Crosslinkers (Boric acid salts)	70
Viscosifiers	
Acids (Hydrochloric acid, citric acid, formic acid)	1.5%
Fluid-loss additives (Sand/Loam)	
Surfactants": Alcohol ethoxylates, naphthalene)	850
Acidity stabilisers (Sodium carbonate / Potassium carbonate)	110
Clay stabilisers	600
Corrosion inhibitors (N,N-dimethyl formamide)	20
Iron control additives (Citric acid)	40
Oxygen scavengers (Ammonium bisulphite)	
Scale inhibitors (Ethylene glycol)	400
Anti-surfactants and defoamers	
Weighting agents	

After around 50% of the fracking water has flowed back, the production water consists in particular of formation water. The result of this is that the production water is generally much saltier than the flowback water.

Table 12 gives an overview of the composition of wastewater that is released on the extraction of shale gas (Alley et al. 2011). These are concentration ranges measured in the United States. The overview is not complete. For example, organic compounds are not mentioned.

Table 12. Substances in production water from shale gas extraction (source Alley et al., 2011; Nd means not determined).

Parameter	Concentration in production water from shale gas extraction (mg/L)	
	Minimum	*Maximum*
pH	1.21	8.36
Alkalinity	160	188
Nitrate	Nd	2670
Phosphate	Nd	5.3
Sulphate	Nd	3663
Ra^{226} (pCi/g)	0.65	1.031
HCO_3	Nd	4000
Al	Nd	5290
B	0.12	24
Ba	Nd	4370
Br	Nd	10600
Ca	0.65	83950
Cl	48.9	212700
Cu	Nd	15
F	Nd	33
Fe	Nd	2838
K	0.21	5490
Li	Nd	611
Mg	1.08	25340
Mn	Nd	96.5
Na	10.04	204302
Sr	0.03	1310
Zn	Nd	20

Table 12 shows that among other things the slightly radioactive Radium-226 is released, various heavy metals, trace elements and also a lot of salt such as sodium chloride. The pH varies considerably between pH 1 and 8. The substances occur in production water, which means that the substances in principle occur naturally in the formation.

New York State DEC (2009) includes tables of the quality of flowback water. Flowback water contains the additives from the fracking fluid and components from the formation water in the shale rock, including substances mobilised from the rock. Apart from high concentrations of salts and heavy metals among other things oil-based substances and organic contamination are mentioned here (Table 13). This shows that a treatment effort is also necessary for mineral oil, BTEX and organic (micro-)contamination prior to reuse or discharge of the flowback of production water.

Table 13. A few additional contaminants in the flowback water (New York State DEC, 2009).

	Concentration			Unit
	Minimum	*On average*	*Maximum*	
Benzene	16	480	1950	µg/l
Toluene	2.3	833	3190	µg/l
Xylenes	15	444	2670	µg/l
Mineral oil	5	17	1470	mg/l
Naphthalene	11	11	11	µg/l
Phenols	0.05	0.2	0.4	mg/l
Total organic carbon	69	449	1080	mg/l

Table 14 includes maximum concentrations of the components in the production water after fracking for the extraction of conventional gas in the Netherlands by two operators (Van Leerdam and Koeman-Stein, 2014). Table 14 shows that the flowback water contains among other things high concentrations of sodium (81 g/l), calcium (42 g/l) and chloride (174 g/L). No analyses of flowback of fracking chemicals, total organic carbon (TOC) or chemical oxygen demand (COD) were carried out here. These are however parameters that must be known if reuse, injection or discharge to surface water is considered.

Table 14. Maximum concentrations in flowback water in the Netherlands (Van Leerdam and Koeman-Stein, 2014).

Component	Maximum concentration (mg/L)
Ammonium (NH_4)	270
Bicarbonate (HCO_3)	220
Chloride (Cl)	173,650
Bromide (Br)	400
Nitrate (NO_3)	310
Ortho-phosphate (P)	1,420
Sulphate (SO_4)	960
Iodide (I)	630
Sodium (Na)	80,930
Potassium (K)	7,200
Calcium (Ca)	41,680
Magnesium (Mg)	2,340
Barium (Ba)	80
Strontium (Sr)	1,840
Total iron (Fe)	1,400
Manganese (Mn)	80
Boron (B)	10
Lead (Pb)	30
Zinc (Zn)	130
Methanoic acid	2
Ethanoic acid	100
Propanoic acid	10

During the production of flowback water the sulphate concentration often falls, while calcium, strontium and barium concentrations increase. This happens because usually more sulphate is present in the fracking fluid than in the formation water (King, 2010).

No naturally occurring radioactive materials (NORM) are detected in the flowback water of Dutch operators. Measurement results in Germany and the United States show that during flowback among other things the slightly radioactive Radium-226 may be released and various heavy metals and trace elements. Since few measurement data are available, no statement can be made about the presence or absence of radioactive materials in shale gas extraction in the Netherlands. Experience with drilling through shale rock in the Netherlands is that a degree of radioactivity has virtually never been found above the standard of the Decree on radiation protection (Besluit stralingesbescherming - Bs) (Witteveen+Bos, 2013). If it is not above the standard, it is by definition not radioactive. Specific research will have to show how far the occurrence of radioactive material actually plays a part in the extraction of shale gas in the Netherlands and in the treatment of flowback/production water. Production of radioactive material is however a relevant subject for the Dutch oil and gas industry (Schmidt, 2000).

Required water quality before reuse, injection and discharge to surface water

Required water quality for reuse of flowback and production water for fracking
The typical water quality requirements for preparing the fracking fluid are given in Table 15 (Sun et al., 2012). Water quality requirements for crosslink fracking are more stringent than for slick water fracking.

Table 15. Typical water quality requirements for preparing fracking fluid (Sun et al., 2012).

Parameter	Crosslinked water	Slick water
pH	6-8	no
Fe (mg/l)	< 20	no
Total hardness (mg/l $CaCO_3$)	< 500 [1]	no
Bicarbonate (mg/l)	< 1000	no
Boron (mg/l)	< 15	no
Silica (mg/l)	< 20	no
Sulphate (mg/l)	< 50	no
TDS (mg/l)	< 40,000 or 70,000 [2]	Up to 280,000
Microbial count (number/ml)	< 100	no

1 may be higher due to addition of anti-scalant chemicals
2 depends on zirconium or borate crosslinking

The suspended solids (SS) concentration in the fracking water must be low, but to the best of our knowledge there is no guide value for this. Upon reinjection (Table 16) a guide value of 100 mg/l TSS (total suspended solids) is given. Suspended solids can block the pores of the fractured shale. If the flowback water contains a high suspended solids content, filtration is a logical first stage before the flowback water can be reused for fracking.
In some cases it will be necessary to remove TDS (total dissolved solids) to reuse flowback water for fracking purposes if the value lies above 40,000 mg/l. This does not however always have to be the case. Part of this is the removal of scale-forming ions, such as barium, calcium, magnesium and strontium. This can cause scaling in the well casing and in the above-ground installations. This results in higher energy requirements and pumping costs. To prevent scaling during hydraulic fracking

scaling inhibitors are often used. A large quantity of NaCl must possibly also be removed. For slickwater fracking this is probably not necessary.

There is limited information available relating to the effect of natural organic matter (NOM) on the hydraulic fracking process. The presence of NOM may in any case result in unwanted biological activity in the fracking water. To limit/control this, biocides can generally be added to the fracking fluid. A disinfection step (for example UV treatment) to reduce the microbial count can also be used.

Various fracking chemicals can also be used at present in brines with a TDS of 75 g/L or more (King, 2010). By mixing flowback water with fresh water not all the TDS has to be removed to be able to reuse it as fracking water. Since a maximum of around 50% of the fracking water flows back, another water source will always have to be used as fracking water in a subsequent fracking job.

Water quality before injection
In the Netherlands injection of wastewater in the soil is prohibited, except as part of active oil and gas extraction (Witteveen+Bos, 2013). Injection of flowback water with some of the fracking chemicals still present in an empty gas or oil well is not permitted in the Netherlands. This must be checked against the LAP. During the production phase of a gas well the production water could be injected. The most important operational requirements against which the water must be measured are indicated in Table 16. Possibly iron, TSS (total suspended solids) and H_2S must be removed before injection can be carried out.

Table 16. Quality requirements for injection of production water in a gas or oil reservoir with an injection well (source: NAM).

Parameter	Value
pH	4-7
Fe (mg/l)	<150
H_2S (mg/l)	≤ 0.5
TSS (mg/l)	< 100

Water quality before discharge to surface water
Water extraction and use and water discharge related to shale gas extraction is the subject of MER studies. This approach is used in regions where unconventional gas is extracted on a big scale, as in the US and Canada. The same approach will be used in the Netherlands. In the Netherlands the current legislation relating to water discharge is stringently and very consistently applied. It is expected that this will have a stimulating effect for the reuse of fracking water during shale gas extraction.

The processing and disposal of flowback water and production water is regulated in the Decree on general rules governing the environment in mining (Besluit algemene regels milieu mijnbouw – Barmm) and, if applicable, the Wabo environmental permit (Permit granted on the basis of Article 2.1 (1) sub-section e of the Environmental Permitting (General Provisions) Act (Wet algemene bepalingen omgevingsrecht) of the relevant production site. The processing and disposal of flowback water and production water is regulated in the Barmm. Flowback water and production water are waste(water) streams that fall under the normal rules for disposal of waste materials. For discharge into surface water a permit is required on the basis of the Water Act (Waterwet). Water boards are often the competent authority for this. For discharge into the sewer it is important that a sewage treatment plant must be able to process it. Discharge requirements also apply for this (see also Activities Decree - Activiteitenbesluit).

It is clear from the above that there are (still) no standards for discharge of flowback water and production water into surface water. (Local) authorities will have to give permits for this. Options for reasonable discharge requirements into surface water, may be:

- discharge requirements for chemical industry;
- comparison with effluent requirements and effluent composition of Dutch sewage treatment plants;
- list of maximum concentrations of priority substances in surface water in the Framework Water Directive (Kaderrichtlijn Water), some of which have a discharge standard (Table 17).

However, this does not cover all the substances in the flowback and production water.

If the standards in Table 17 are used, it is necessary to carry out extensive desalination and softening (TDS < 500 mg/l). In addition among other things oil and BTEX (benzene < 10 µg/l) must also be removed, organic compounds from the fracking water and from the formation and perhaps nutrients (Nitrate and Phosphor).

Table 17. Water quality standards before discharge to surface water.

Parameter	Concentration for discharge to surface water (WFD/ IPPC; USEPA)
pH	6.5-9
Ca, Mg (mg/l)	Alkalinity: 200
Fe (mg/l)	1,0
P (mg/l)	0.025 (Phosphate)
Sulphate (mg/l)	250
Benzene (µg/l)	10
Chloride (mg/l)	200
TDS (mg/l)	< 500

Treatment technology for the treatment of flowback and production water

Introduction
Flowback water is first collected in big sealed tanks a series of which are installed on the drilling site. The American method of water storage in open basins is not permitted in the Netherlands because of more stringent environmental requirements. The majority of the storage tanks can be removed after fracking

because they serve as storage for fracking water. One or two tanks usually remain on site during production. These tanks can be used as a buffer for periodic disposal with tankers (no treatment on site) to waste processing companies or serve as storage and buffer for the treatment of a continuous and more or less constant wastewater stream on site.
Before there can be any question of reuse, discharge or injection of the wastewater stream, a number of treatment stages must be undergone, or on a relatively small scale on site (decentral) or at a big central treatment plant after transport.

First of all the experience in the United States is briefly discussed. After this a wider overview is given of technologies that are available or will become available in the near future.

Experience in the United States
In the United States the flowback and production water is treated for different purposes with different technologies. An overview is given in Table 18. This shows that more or less intensive treatment is necessary depending on the purpose of the treatment. A description of the technologies mentioned can be found in appendix 2.

Table 18. Overview of treatment technology used in the US for the treatment of flowback and production water for different purposes (Stark, 2014).

	Pre-treatment		Desalination		Post-treatment	
Treatment for:	*Filtration*	*Chemical precipitation*	*Thermal*	*Membranes*	*Electrocoagulation*	*Other (e.g. biocide, UV)*
Reuse as fracking fluid	X					X
Drilling fluid	X	X	X	X	X	
Discharge to surface water (rarely permitted)	X	X	X	X	X	X
Use in agriculture	X	X	X	X		
Preparation of fresh water	X	X	X	X	X	X
Transport to discharge site or empty gas/oil well	X					
Example of basin	Barnett, Fayette-ville, Marcellus	Marcellus	Barnett Fayette-ville, Marcellus	Barnett, Marcellus, Woodford	Haynes-ville, Utah	Barnett, Haynesville, Marcellus

Table 19 shows which specific components are removed by the different technologies, that are used in the United States and in which shale gas basins they are used.

Table 19. Overview of the technologies that are used in the US for the treatment of flowback and production water and the components that are removed (Stark, 2014).

	Technology	Components removed	Example basin

Pre-treatment	Filtration	TSS	Barnett, Fayetteville, Marcellus
		MF: TSS, micoorganisms UF: viruses, colour	
	Chemical Precipitation	Precipitation-forming chemicals (Ca, Mg, Fe)	Barnett, Marcellus
Desalination	Thermal technologies	TDS (to approx. 200,000 mg/l)	Barnett, Marcellus
	Membranes: RO	TDS (to approx. 50,000 mg/l), microorganisms	Barnett, Woodford
Post-treatment	Electrocoagulation	TSS, metal ions, mineral oil	Haynesville, Utah
	Biocide/UV	Microorganisms	Haynesville

TSS: total suspended solids; MF: microfiltration; UF: ultrafiltration; TDS: total dissolved solids; RO: reverse osmosis

On site water treatment and discharge is carried out increasingly often in the United States, so less water has to be transported. For each site however one will have to look at what mobile water treatment units are available for each technology, as according to Stark (2014) mobile water treatment units are not available not for all technologies. Also reinjection into geological formations is a site-specific option.

Alleman (2011) indicates that thermal distillation/evaporation and reverse osmosis (RO) are effective technologies for treatment before discharge. Thermal distillation/ evaporation takes a lot of energy. Desalination by distillation takes approx. 70 litres of diesel or 70 m^3 gas per m^3 water. According to All Consulting (2009) cited in Tyndall (2011)/Olsthoorn (2014) on site distillation is nevertheless carried out in a number of places in the US.
Table 20 shows which suppliers are involved in this in the United States per shale gas basin.

Table 20. Suppliers of thermal distillation/evaporation and reverse osmosis used for water treatment in shale gas extraction in the United States (Alleman, 2011).

Supplier Treatment		Shale gas systems in the US				
	Thermal distillation/ evaporation	Marcellus	Barnett	Haynesville	Fayetteville	Woodford
	212 Resources	X	X			
	Fountain Quail	X	X		X	
	Aquatech	X	X		X	
	Veolia	X				
	INTEVRAS	X	X			
	GE Water & Process Technology		X		X	
	Total Separation Solutions			X		

Supplier Treatment		Shale gas systems in the US				
	Reverse osmosis	Marcellus	Barnett	Haynesville	Fayetteville	Woodford
	212 Resources	X	X			
	Fountain Quail	X	X		X	
	Aquatech	X	X		X	
	Veolia	X				
	INTEVRAS	X	X			
	GE Water & Process Technology		X		X	
	Total Separation Solutions			X		

Overview of available technologies and future available technologies

Relevant treatment stages, as also already found from the experience in the United States, that can be undergone for the treatment of flowback water and production water, are:

- Removal of suspended solids (SS) and sand;
- Oil removal;
- Removal of dissolved organic matter (aromatics, fracking chemicals, NOM);
- Removal of heavy metals and scale formers (divalent ions);
- Removal of salt;
- Disinfection.

The degree in which the stages must be followed depends on the quality required for discharge, injection or reuse. The more treatment stages, the better the quality of the water of course.

In the following tables different technologies are mentioned that are considered for carrying out the required treatment stage. A description of the technologies can be found in Appendix 2. An indication is given for each technology of how far there is experience in the oil and gas sector or in other sectors:

- conventional in oil and gas sector;
- still rarely used, but already on the market;
- in use in other industries;
- available in the near future + technology readiness level (TRL).

The TRL (see Approach & Accountability for an explanation) is used for a general situation for use in all sectors.

Removal of suspended solids and sand
If a storage tank is used before starting the treatment, part of the suspended solids and sand will already have settled in the storage tank. The following two tables indicate which technologies are available for the removal of solids and dispersed (not dissolved) oil. Sometimes both components can be removed from the water at the same time with one type of technology. A description of the technologies can be found in Appendix D2.

Table 21. Technologies for the removal of suspended solids and sand.

Technology	Conventional in oil and gas sector	Still little used, but already on the market	In use for water treatment in other sectors	Available in the (near) future or now already available
CPI/PPI	X		X	TRL 9
Hydrocyclone	X		X	TRL 9
(Bag) filtration	X		X	TRL 9
Media filtration	X		X	TRL 9
Microfiltration/ Ultrafiltration	X		X	TRL 9
Flocculation/ coagulation	X		X	TRL 9

The removal of suspended solids is necessary for both reinjection, reuse for fracking and for discharge to surface water. Removal of dispersed oil is perhaps not necessary for reuse for fracking and reinjection, but for discharge to surface water it is. This first treatment stage can be carried out with conventional technology, with which a lot of experience has already been acquired in the oil and gas sector and in other sectors.

Table 22. Technologies for the removal of dispersed oil.

Technology	Conventional in oil and gas sector	Still little used in oil and gas sector, but already on the market	In use for water treatment in other sectors	Available in the (near) future + TRL
CPI/PPI	X		X	TRL 9
Hydrocyclone	X		X	TRL 9
Candle filtration	X		X	TRL 9
Media filtration	X		X	TRL 9
Electrocoagulation		X	X	TRL 9
Dissolved air flotation (DAF)	X		X	TRL 9

The removal of dissolved organic matter, such as aromatics, fracking chemicals, NOM and organic microcontamination, is probably not necessary or only to a limited extent for reinjection and reuse for fracking, but it is for discharge to surface water. Table 23 gives an overview of which technologies can be considered for this. A description of these technologies can be found in Appendix D2. Many of these technologies are already used in the oil and gas sector for the removal of dissolved or dispersed oil.

Table 23. Technologies for the removal of dissolved organic matter.

Technology	Conventional in oil and gas sector	Still little used, but already on the market	In use for water treatment in other sectors	Available in the (near) future + TRL
Electrocoagulation	X		X	TRL 9
Activated carbon filtration	X		X	TRL 9
Fluid-fluid extraction	X		X	TRL 9
Pertraction		X	X	TRL 9
MPPE	X		X	TRL 9
$UV/H_2O_2/O_3$ (AOP)		X	X	TRL 9
RO	X		X	TRL 9

AOP: advanced oxidation processes

Removal of divalent ions (among others Ca, Mg, Sr) and heavy metals is important for discharge to surface water, reuse for fracking and probably also for injection, to prevent precipitation formation in installations, tubes, or at the bottom of the well. There are different conventional technologies available for achieving this (
Table 24). A description of the different technologies is given in Appendix D2.

Table 24. Technologies for the removal of metals and scale formers (divalent ions).

Technology	Conventional in oil and gas sector	Still little used, but already on the market	In use for water treatment in other sectors	Available in the (near) future + TRL
Precipitation	X		X	TRL 9
Media filtration	X		X	TRL 9
Crystallisation	?	X	X	TRL 9
NF	X		X	TRL 9
Ion exchange	?		X	TRL 9

The most challenging and probably also most expensive stage for the treatment of flowback and production water for shale gas production is desalination, the removal of TDS. There are a large number of desalination technologies on the market, such as pressure-based membrane processes (reverse osmosis, RO), thermal desalination and crystallisation (Table 25).

For the discharge to inland surface water it is probably necessary to desalinate water that may have a TDS of 100-200 g/l to 0.5 g/L (Table 17) or even lower.

With a few conventional and innovative technologies it is in principle possible to achieve this treatment stage. A description of the technologies is given in Appendix D2.

Table 25. Technologies for the removal of monovalent salts.

Technology	Conventional in oil and gas sector	Still little used, but already on the market	In use for water treatment in other sectors	Available in the (near) future + TRL
Crystallisation	?	X	X	TRL 9
RO	X		X	TRL 9
Forward osmosis	?		X	TRL 9
Membrane distillation		X		TRL 7
Membrane distillation and crystallisation				TRL 3
Multi Stage Flash (thermal desalination)			X	TRL 9
Multi Effect Distillation (thermal desalination)			X	TRL 9
Mechanical vapour recompression (thermal desalination)			X	TRL 9

TDS concentrations of up to around 200,000 mg/L can be treated with the thermal desalination methods mentioned. Corrosion and precipitation formation is a general point of concern for these technologies. Alleman (2011) indicates that the recovery lies between 50 and 90%. This means that 10% to 50 % of the flowback water still has to be removed if it is to be treated on the spot.

Brant (no year given) compares the thermal desalination methods Multi Stage Flash (MSF), Multi Effect Distillation (MED) and Mechanical Vapour Compression (MVC) with Reverse Osmosis (RO) (Table 26). This shows that the thermal desalination methods use big quantities of energy. RO uses less energy, but can only be used up to a TDS concentration of 50,000 mg/l. The recovery is not always good. For a recovery of less than 50% from an installation on site, more than half of the flowback water still has to be removed.

Table 26. Comparison of thermal desalination and reverse osmosis (Brant, no year given).

Process	Energy consumption[a] (kWh/1000 gal)	Operation based on	System recovery (%)	Relative Capital Costs
MSF	58	Steam (heat)	10 – 20	High
MED	29	Steam (heat)	20 – 60	Average to High
MVC	30 – 53	Compression (heat)	35 – 99	High
RO	8 – 23	Pressure	35 – 55[b]	Low to Average

Notes:
a– Combined electrical and equivalent thermal energy
b – Recovery ratios are a function of the TDS concentrations in injected water. Recovery ratios increase from 50%, where the TDS in the water supplied falls to below around 36,000 mg/L

If extra disinfection is necessary, UV treatment is used, or a (chlorine-containing) disinfectant can be used (Table 27). It is possible that this will not be necessary if previous stages also have the side effect of disinfection, such as distillation and evaporation processes and membrane processes (UF, NF, RO). For reuse as fracking fluid disinfection is a duplication, because during fracking a biocide is often already added to the water.

Table 27. Technologies for disinfection.

Technology	Conventional in oil and gas sector	Still little used, but already on the market	In use for water treatment in other sectors	Available in the (near) future + TRL
UV	?		X	TRL 9
Chlorine, chlorine dioxide, sodium hypochlorite	?		X	TRL 9

<u>Treatment before reuse as fracking water</u>
Table 18 (Overview of treatment technology used in the US) shows that for reuse of flowback water as fracking fluid only one filtration step and disinfection is necessary. In the report of Witteveen+Bos (2013) oil separation, sedimentation and filtration are mentioned as limited treatment.
Table 15 states what the water quality requirements are for preparing fracking fluid. For slick water fracking hardly any water quality requirements are laid down, but for crosslinked fracking there are. In addition to the requirements in Table 15 suspended solids will also have to be removed because of blocking of the pores in the well. Based on the composition of the flowback water as discussed above the following parameters will probably have to be removed or adjusted before flowback water can be reused as fracking water:

- Solids and suspended solids/oil;
- Iron;
- Possibly pH correction;
- Disinfection.

The removal of TDS may possibly be avoided by mixing flowback water with fresh water. Because not all the fracking water flows back, it will always have to be topped up with new water. By diluting sufficiently with fresh water the TDS concentration from Table 15 can be achieved. It may possibly not be necessary to dilute (as regards TDS concentration) as only during the first weeks after fracking is the flowback water reused.

A possible treatment process for this removal stages is:

- Plate interceptor (PPI/CPI) for simultaneous separation of solids and suspended solids (sedimentation) and dispersed oil (floating);
- Deferrization and further particle removal using (multi)media filtration;
- By acid or base dosing the pH can be adjusted to the right value if necessary;
- Disinfection can be carried out by UV radiation or with chlorine-containing disinfectants.

As a waste stream a quantity of sludge (settled particles) and floating oil is produced in the plate interceptor. The media filter must be periodically backwashed, which a gives a concentrated waste stream of a few percent of the treated water stream. This water probably has to be taken away for off-site treatment. After this treatment probably (over) 95% of the water can be reused for fracking.

Treatment before injection

An example of pipeline transport for injection is the NAM pipeline from Schoonebeek to Twente. Not many water quality requirements are laid down for reinjection via an existing oil or gas well, where permitted (Table 16). There is probably an aeration stage, followed by media filtration sufficient to obtain iron and H_2S below the standard for injection. If after this the total quantity of suspended solids is still above 100 mg/l, an extra filtration stage is used (for example bag filters).
Here too the media filter must be periodically backwashed, which gives a concentrated waste stream of a few percent of the treated water stream. This water must probably be taken away for off-site treatment.

Treatment before discharge to surface water

If the flowback water is discharged to fresh surface water, in addition to the treatment for reuse for fracking purposes salts, metals, organic matter and organic microcontamination must also be removed. Based on the composition of the flowback water the following parameters will probably have to be removed or adjusted before discharge to fresh surface water:

- Removal of solids and suspended solids;
- Iron removal;
- Softening (Ca, Mg);
- Removal of heavy metals;
- Sulphate removal;
- Salts and nutrients (N, P);
- Removal of organic matter and organic microcontamination;
- Possibly pH correction;
- Disinfection.

A possible treatment process for these removal stages is:

- Plate interceptor (PPI/CPI) for simultaneous separation of solids and suspended solids (sedimentation) and dispersed oil (floating).
- Aeration and deferrization using (multi)media filtration. By adding coagulant/ flocculant before filtration part of the organic matter is also already removed in this filtration stage.
- Softening and sulphate removal with nanofiltration. With this part of the TDS is also already removed. Crystallisation of among other things $CaSO_4$, $MgSO_4$ and $BaSO_4$ may be an alternative.
- RO for desalination is possible for a TDS < 50,000 mg/l. With this the majority of the organic matter and organic microcontamination is also removed. Thermal desalination can be used for high TDS contents of 50,000-200,000 mg/l (vapour recompression, multistage distillation techniques, such as MSF-Multi Stage Flash and MED-Multi Effect Distillation). It is possible that the flowback water will still have a TDS of below 50,000 mg/l during the first few weeks after

fracking. For treatment of production water in the long term (years) RO will probably not be an option.
- An advanced oxidation method (UV/H_2O_2 or UV/O_3) can be used to convert any organic microcontamination still present. This stage is also a disinfection stage.
- By acid or base dosing the pH can be adjusted to the right value if necessary.

As a waste stream a quantity of sludge (settled particles) and floating oil occurs in the plate interceptor. The media filter must be periodically backwashed, which gives a concentrated waste stream of a few percent of the treated water stream. This water must probably be taken away for off-site treatment.

For both NF and RO a maximum of 80% recovery can probably be achieved. If these two membrane filtration stages are used after one another a minimum of 40% of the flowback water will still have to be removed.

Alleman (2011) gives as treatment for discharge:
- Pre-treatment/conditioning: remove suspended matter and organic matter, pH correction.
- Then:
  - Thermal distillation, or
  - Reverse osmosis, or
  - Thermal evaporation.

If there is a possibility of discharging offshore, a lower level of desalination will be required.

<u>Treatment before high quality reuse</u>
High quality demineralised or distillate water can be obtained by extensive desalination with the techniques mentioned in above paragraph (discharge to surface water). That means that desalination does not stop at 0.5 g/l but that it is completely demineralised. The end product can then be reused for high quality purposes, such as for example generating high pressure steam.

Inventory of gaps in knowledge and technology

The treatment of flowback water in shale gas extraction is still in its infancy. In countries like the United States and Canada this is however starting to happen. There are many suppliers on the market for (small-scale) water treatment technology, but they often also have little or no experience with the treatment of flowback water from shale gas.

To gain more knowledge about the removal of specific components in the mixture of the flowback water experiments will have to be carried out on a laboratory scale. The most suitable technologies can then be tested on a pilot scale.

Specific research questions relating to the treatment of flowback water are:

- What removal yields for among other things suspended solids, mineral oil, salts, heavy metals, precipitation, fracking chemicals and organic microcontamination can be achieved in laboratory and pilot setups? The biggest research questions

probably lie in the area of extensive (thermal) desalination and the effect of (added) substances present in the flowback water.
- What operational problems arise and how can these be solved?
- What is the effect of the increased temperature of the water (up to maximum approx. 90°C, depending on the depth) on the treatment performance?
- For crosslinked fracking the viscosity of the flowback water (in particular during the first days) is higher than for normal salty groundwater. What is the effect of this on the treatment performance?

In addition it is important to know before water treatment whether an above-standard NORM is expected in the water. It is also essential to know the discharge requirements for discharge to inland surface water in order to choose an on-site wastewater treatment plant.

Finally the costs of on-site treatment of flowback and production water compared with removal and central treatment of the water or removal as chemical waste must also be calculated. The quantity of solid and fluid waste that arises during local treatment and that still has to be taken away, must be considered here.

Water quality of treated water

One of the sub-questions of this section is: “*Can this (flowback) water be discharged or reused without additional risks to the surface water*?” Reuse for fracking or discharge to surface water is possible without additional risks if sufficient treatment stages are followed. In principle very pure water can be produced from flowback and production water that is suitable for high quality purposes such as the generation of high-pressure steam.
The energy consumption and costs do however increase for each additional treatment stage and if a higher treatment output is required. It is an open question whether the extensive treatment to be able to discharge to inland surface water (removal of among other things mineral oil, (natural) organic material, fracking chemicals, heavy metals, scale formers, salts, micro-organisms) does not become so expensive that it makes the extraction of shale gas unprofitable. This requires further research. In particular the extensive desalination is a big cost item.

Dimensioning of the plants

Paragraph 0 gives the expected flowback rates after fracking for a site of 6 or 10 wells. This varied from 24 to 409 m^3/hour.
Table 28 gives an indication of the size of a few plants for different flow rates, where data were available.

Table 28. Indication of the size (L x B x H, in metres) of a few plants for different flow rates (CIW, 2002).

Treatment plant	Flow rate 6 m^3/hour	Flow rate 175 m^3/hour
MPPE, including steam generator	2 x 3 x 3	-
MF/UF	2 x 4 x 2.5	1-2 sea containers
Flotation unit	2 x 1.5 x 2	10 x 2.5 x 3
PPI/CPI	2.5 x 1.2 x 2.1	2.3 x 5 x 3.5
Hydrocyclone	1 x 3 x 1.2	3 x 4 x 1.7
NF/RO		1-2 sea containers

For a UF installation for the treatment of 175 m^3/hour approx. 60 to 140 membrane modules one metre long and approx. 10 cm in diameter are necessary. These can probably be fitted into 1 or 2 sea containers. For an NF or RO installation for the treatment of 175 m^3/hour approx. 50 to 100 membrane modules are necessary. These can probably also be fitted into 1 or 2 sea containers.

Plants for the treatment of flowback water can be fitted into sea containers or supplied by suppliers themselves in container form. Probably for each treatment stage a plant is necessary of a size of 1 or 2 sea containers if local treatment is necessary for one site with 10 wells.

By storing the flowback water in buffer tanks a constant flow rate can be supplied to the treatment plant. If after a period of days/weeks the production water flow rate begins to fall, the flow rate can be gradually reduced.

It is not unusual for the production water flow rate to fall continuously during the first year after fracking (King, 2010). For production water less (and perhaps different) treatment is necessary than for flowback water. Therefore for flowback water mobile treatment could be installed (for a few months) and permanent treatment for the treatment of production water. A system can possibly be installed that can be slowly switched off at a lower supply rate.

Decentral or central treatment

One of the research questions is whether flowback water can be treated on site. Treatment of flowback water is in principle possible on site. It is expected that on an extraction site with ten wells with for example four different treatment stages a wastewater treatment plant is necessary of a size of approx. 8 sea containers. Treatment plants on the scale of one sea container are available. Produced waste, sludge, and concentrate will have to be taken away to be treated elsewhere.

The costs for treatment on site will have to be compared with the costs for full disposal and treatment elsewhere at a big central treatment plant. Disposal and treatment on a central site for processing as chemical waste is current practice for flowback water in conventional gas extraction. To make a treatment plant on site more profitable it is important that the treatment after the flowback water has flowed back can also be used for production water during the active production phase of the wells.

The treatment plant for the production water will be of a smaller size, because the flow rate is lower. But more desalination may possibly have to be carried out, since the TDS concentration of the flowback/production water increases over time. The fracking water tanks can possibly be reused as storage for flowback water.

Appendix D2: Brief description of water treatment technologies

Technologies for the removal of solids and dispersed oil

PPI/CPI (gravitation separation)
To reduce the aliphatic content and solids and suspended solids in the flowback and produced water, a parallel plate interceptor (PPI) or corrugated plate interceptor (CPI) can be used. The separation takes place by the difference in density between oil, solids and water and by coalescence of oil droplets on the plates. Due to the short distance between the plates the small oil droplets only have to rise a short distance so they are still separated within the relatively short residence time. The small droplets merge on the plates into bigger droplets, which can rise more easily and faster to the surface. For the CPI, where the corrugated plates are almost horizontal, the bigger oil droplets flow through holes in the plates to the overlying plates. When the oil layer becomes thicker, the oil overflows. This technique is only suitable for non-dissolved components, such as dispersed aliphatics with sufficient droplet size (CIW, 2002).

Estimated footprint (LxBxH)
6 m^3/hour water: 2.5 x 1.2 x 2.1 m
175 m^3/hour water: 2.3 x 5 x 3.5 m

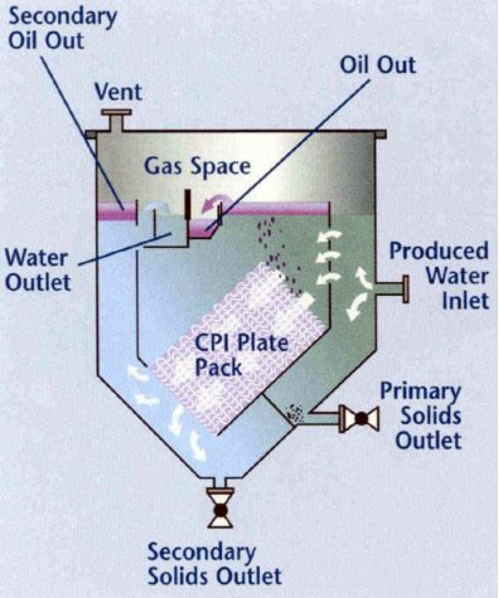


Figure 6. Example of a corrugated plate interceptor (National Energy Technology Laboratory).

Bag filter installation

A bag filter works according to the principle of microfiltration. The fluid is treated in bags by passing it through permeable pores. The contamination is left behind in the bags. The pore size varies between 1 and 1000 µm. A typical area of a bag filter is 0.50 m^2 with a maximum capacity of 10-50 m^3/h per bag. More than one bag filter can be present in one module, so that bigger streams can be treated.
Bag filters are made of polyester, polypropylene, nylon or other materials. The maximum temperature for use is 95°C to 135°C, depending on the material. A bag filter usually works via the principle of surface filtration (www.lenntech.com; product information for Twin Filter). In addition to bag filters there are also candle filters. These are intended for the removal of smaller particles. Neither type of filter can be regenerated. Bag filters and candle filters can be fitted with several filters in one module.
A typical size of a module with more than one bag is 1 x 1 x 2 m (LxBxH). Two or three of these modules are sufficient to treat the flowback water on one site with approx. 6-10 wells.
Bag filters are among other things often used in geothermal installations.

Figure 7. Examples of bag filters.

Figure 8:Modules for candle or bag filters (www.twinfilter.com)

Hydrocyclone
Oil-water separation using hydrocyclones is based on centrifugal forces and the difference in specific gravity between oil and water. In a hydrocyclone the fluids are fed in tangentially under pressure. The speed increases due to the shape of the cyclone, so very high centrifugal forces are produced and the water is separated from the oil. The heavier production water will move in a vortex through the cyclone to the outlet, while the lighter oil in the centre of the cyclone flows in a secondary vortex in the opposite direction to the side of the inlet. Solids can also be separated from water in this way. Dissolved components cannot be removed with a hydrocyclone (CIW, 2002).

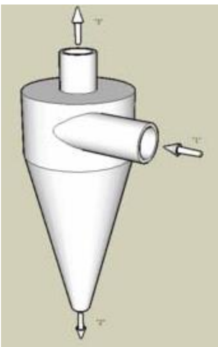


Figure 9. Schematic diagram of a hydrocyclone.

Estimated footprint (LxBxH)
6 m^3/hour water: 1 x 3 x 1.2 m
175 m^3/hour water: 3 x 4 x 1.7 m

Flotation
For gas flotation finely distributed gas is injected into the production water, whereupon oil droplets or suspended solids are stripped from the production water by the rising gas. The gas bubbles with oil or solids form a foam layer on the water that is then often skimmed off using a paddle wheel that skims the foam layer with part of the water into an overflow channel. The gas can be injected under pressure (dissolved gas flotation) or using an impeller or pump (induced gas flotation). Dissolved organic matter and heavy metals are not removed. However, by injecting gas volatile components can be stripped to a small extent. Sometimes air is injected instead of gas, so a large proportion of dissolved BTEX is also removed.

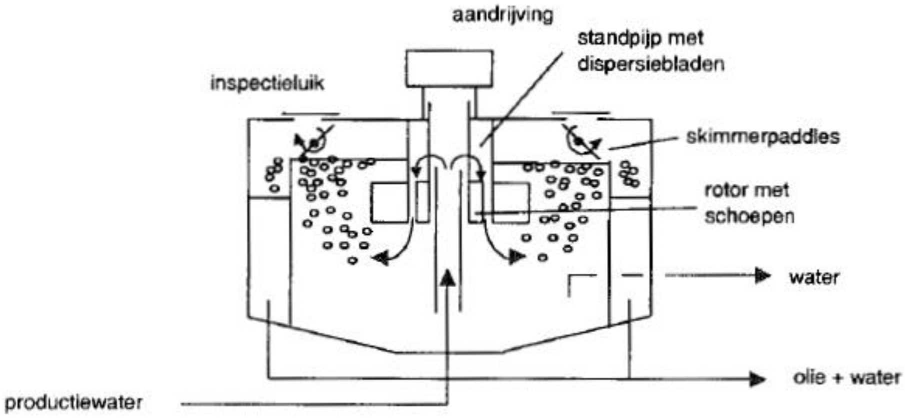


Figure 10. Process flow diagram of a flotation installation (CIW, 2002).

Inspectieluik = inspection hatch; aandrijving = drive; standpijp met dispersiebladen = standpipe with dispersion blades; skimmerpaddles = skimmer paddles; rotor met schoepen = rotor with blades; productiewater = production water; olie + water = oil + water

Estimated footprint (LxBxH)
6 m^3/hour water: 2 x 1.5 x2 m
175 m^3/hour water: 3 x 4 x 1.7 m

Sand filtration (media filtration)

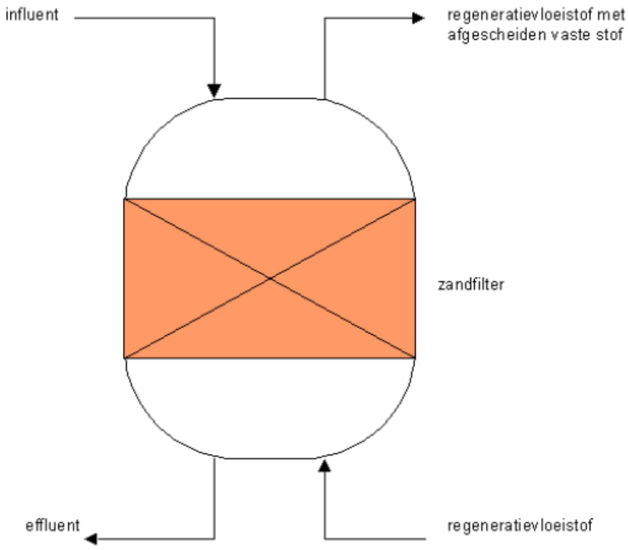


Figure 11. Schematic diagram sand filtration (Emis-Vito, a)

Influent = influent; regeneratievloiestof met afgescheiden vaste stof = regeneration fluid with separated solid; zandfilter = sand filter; effluent = effluent; regeneratievloiestof = regeneration fluid

Sand filtration is used for the removal of suspended solids, as well as floating and settleable solids. The wastewater flows vertically through a bed of fine sand and/or gravel. Solids present are removed by adsorption or physical encapsulation. If the pressure drop over the filter is too great, backwashing must be carried out.

A distinction can be made between continuous and discontinuous filters. In the case of continuous filters (often filters flowing upwards) the contaminated sand is continually removed, washed and reused without interrupting the filtration process. Discontinuous filters (often filters flowing downwards) interrupt their operation and carry out countercurrent flushing. Air bubbles are blown into the sand bed so that this is loosened. Then filtered water flows in a countercurrent through the filter bed. The contaminated material is released and flows away with the flushing water. The filtration process can then be resumed.

The yield of a sand filter is determined by two ways of operating sand filters, namely surface filtration and deep filtration. In surface filtration the particles to be captured are already captured on top of the filter bed. These particles together form a macroporous cake that can capture new particles very effectively. In deep filtration this generally involves finer particles that are more difficult to capture and which adhere to the sand particles by adsorption. Fouling from surface filtration is easier to remove during backwashing compared with fouling from deep filtration (Emis-Vito, a).

Coagulation/flocculation
This technique focuses on water streams in which very fine particles are found. These colloidal particles have a diameter of 1-1000 nm. These particles have a negative charge and do not settle in the water by themselves, they remain suspended. To be able to remove these particles, among other things, coagulation can be used. Here a coagulant (often based on iron or aluminium) is added to the water. Polymers are also used. The coagulant ensures a reduction in the repulsion between the different colloidal particles. Small flakes will then be created which by gently stirring can clump further together.
Flocculants can be added to support the process. Flocculants are high-molecular substances (polymers) with different functional groups. The charged particles and/or small flakes are attracted to the charge groups of the polymer, so a bigger flake is created. These can be separated more easily by flotation or sedimentation. Because the particles do not all have the same charge different charge groups are necessary for the polymer structure. There are both anionic, cationic and non-ionic polymers. Very important for good flocculation is the right bonding between the polymer and the particles. This means that in addition to the nature of the charge the distribution of the charge over the molecule is also important, as well as the length of the polymer. In addition the degree of crosslinking of the polymer, the forming of bonds with itself, is important. Due to the operation of these elements there are a few hundred different polymers each with their specific area of action. In a number cases it may be enough to add a flocculant to obtain good separation. Usually the combination of coagulant and flocculant will be required.

The flakes are then captured in a post-treatment stage and form a quantity of contaminated sludge that must be further processed (evaporation, landfill, burning,…).”[Emis-Vito, b]

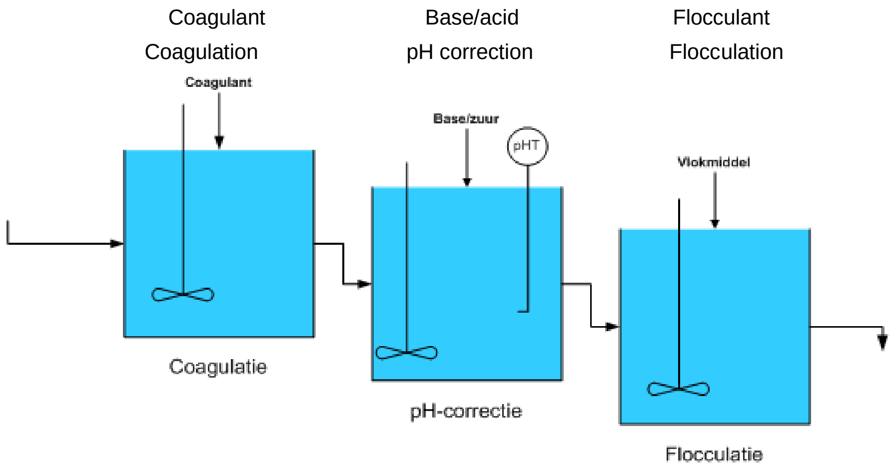


Figure 12. Schematic diagram of coagulation/flocculation process [Emis-Vito, b].

Electrocoagulation/flotation

Electrocoagulation uses the dissolving of an electrode (anode, often made of Fe or Al) by means of an oxidation reaction so as to release coagulant. Upon dissolving the electrode gas is also released (O_2, H_2) as a result of the splitting of water, which creates a flotation action. An auxiliary flocculant can be added to intensify the flotation. [Emis-Vito, c]

The following figure shows the structure of a cross-section through an electrocoagulation reactor. This consists of an electrolytic cell with an anode and a cathode. When this is connected to a direct voltage source an oxidation reaction will take place on the anode (positive), on the cathode (negative) a reduction reaction. [Emis-Vito, c]

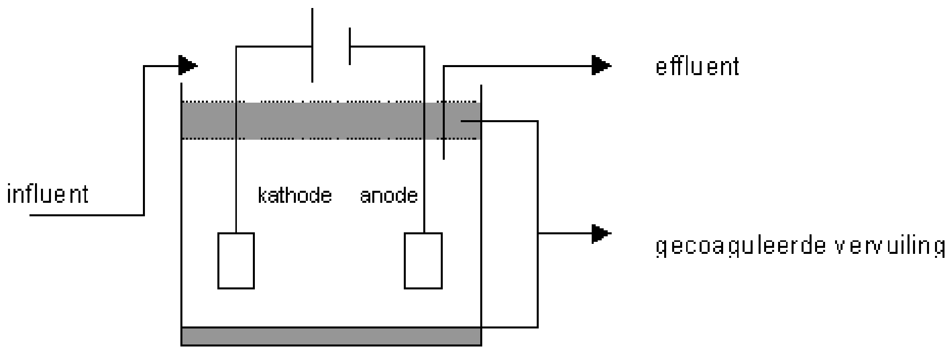


Figure 13. Schematic diagram of structure of electrocoagulation reactor [Emis-Vito, c].

kathode = cathode; gecoaguleerde vervuiling = coagulated contamination

Electrocoagulation/flotation can be used to remove solids, dispersed (partly also dissolved) oil and heavy metals. It is also a disinfection stage. In the US the technique is already used to treat flowback water from shale gas (Stark, 2014).

Microfiltration (MF)
Microfiltration (MF) is one of the pressure-based membrane processes from the series microfiltration, ultrafiltration, nanofiltration and reverse osmosis (Figure 14). The microfiltration process uses a membrane, a semi-permeable material, which in the case of microfiltration only particles smaller than 0.1 micron can pass through. The microfiltration membrane may consist of different materials such as for example polysulfone, polyvinyldifluoride (PVDF), polyethersulfone (PES), ZrO_2 and carbon. The pore size is between 0.1 and 5 micron. Because the pores are large in comparison with the other filtration techniques mentioned the pressure, necessary to pass a fluid through an MF membrane, is limited (0.1 to 3 bar). MF membranes are offered in various configurations by the suppliers. Possible membrane configurations are:

- tubular membranes: capillary, hollow fibre or tubular;
- plate-like membranes: flat sheet or spiral-wound.

Apart from the specific membrane configuration one can also distinguish between a few operation types. The 2 most commonly used methods are dead-end and cross-flow operation. The names refer to the way in which the feed is offered to the membrane. In dead-end MF the feed is passed vertically onto the membrane. On the feed side of the membrane a contamination layer is deposited here on the membrane surface. This layer contains all the particles that have been separated based on their size (screen action). This layer is periodically washed away by passing the produced fluid (permeate) back through the membrane for a short time in the opposite direct to the flow during production. The cake layer is hence loosened and can be removed. This is called semi dead-end operation. If the cake layer is compressed too firmly or sticks too firmly to the membrane it may be that this backwashing is no longer sufficient to remove the layer from the surface. Chemical cleaning must then be carried out, for example with peroxide, acid and base or detergent. [Emis-Vito, d]

Ultrafiltration (UF)
Ultrafiltration (UF) is a pressure-based membrane process. The UF process uses a membrane, a semi-permeable material, where in the case of ultrafiltration only particles smaller than 20 nm can pass through. The pore size is between 20 nm and 0.1 micron. UF can be used for the removal of particles and for the removal of dispersed oil (aliphatics).
UF membranes are offered in various configurations by the suppliers. Possible membrane configurations are:

- Tubular membranes: capillary, hollow fibre or tubular
- Plate-like membranes: flat plate or spiral-wound

Apart from the specific membrane configuration one can also distinguish between a few types of operation. The 2 most commonly used methods dead-end and cross-flow operation. The names refer to the way in which the feed is offered to the membrane. For dead-end UF the feed is passed vertically onto the membrane. On the feed side of the membrane a contamination layer is deposited here on the membrane surface. This layer contains all the particles that have been separated based on their size (screen action).This layer is periodically backwashed by passing the produced fluid (permeate) back through the membrane for a short time in the opposite direction to the flow during production. The cake layer is hence loosened and can be removed. This is called semi dead-end operation.

If the cake layer is compressed too greatly or sticks too firmly to the membrane it may be that this backwashing is no longer sufficient to remove the layer from the surface. Chemical cleaning must then be carried out, for example with peroxide, acid and base or detergent. [Emis-Vito, d]

A typical flux for a UF membrane is 50 l m^{-2} $hour^{-1}$ at a pressure of 0.3-1 bar. For a flow rate of 175 m^3/hour approx. 60 to 140 a membrane modules one metre long and 10 cm in diameter are necessary (surface membrane module is approx. 25-60 m^2) . This can probably be fitted into 1 or 2 sea containers.

Estimated footprint (LxBxH)
6 m^3/hour water: 2 x 4 x 2.5 m (CIW, 2002)
175 m^3/hour water: it is estimated that this can be fitted into 1 to 2 sea containers.

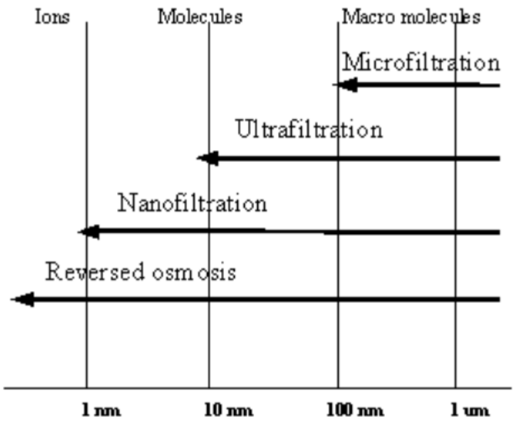


Figure 14. Separation level for different membrane filtration systems (www.lench.nl).

Technologies for the removal of dissolved organic matter

Fluid extraction

Fluid extraction is a process that separates substances based on their chemical properties. During fluid extraction the feed stream (water) with contamination is brought into contact with extraction fluid. The extraction fluid is selected such that it does not mix with the supply flow and dissolves the contamination well. During the extraction process the contamination in the supply flow (partly) passes into the extraction fluid, until equilibrium in concentration is reached. This equilibrium depends on the affinity that the contamination has for the extraction fluid. If several substances are present, the equilibrium will be substance-dependent. In an additional stage the contamination is separated from the extraction fluid so this can be reused.

Extraction can also be used to separate a valuable substance from the feed stream. Fluid extraction has different possible industrial scale designs. A distinction is made here between two main categories: the first category consists of mixers-settlers, where the extraction process consists of two separate stages (Figure 15). In the first stage the two fluids are mixed to permit substance transfer. In the second stage the two fluids are separated. The two stages can take place in separate reactors. The second category uses columns in which the two fluids are continuously in contact with one another. Typical special measures are taken here to increase the contact area between the feed and extraction stream (e.g. dispersion of one fluid, the use of trays or packing material) [Emis-Vito, f].

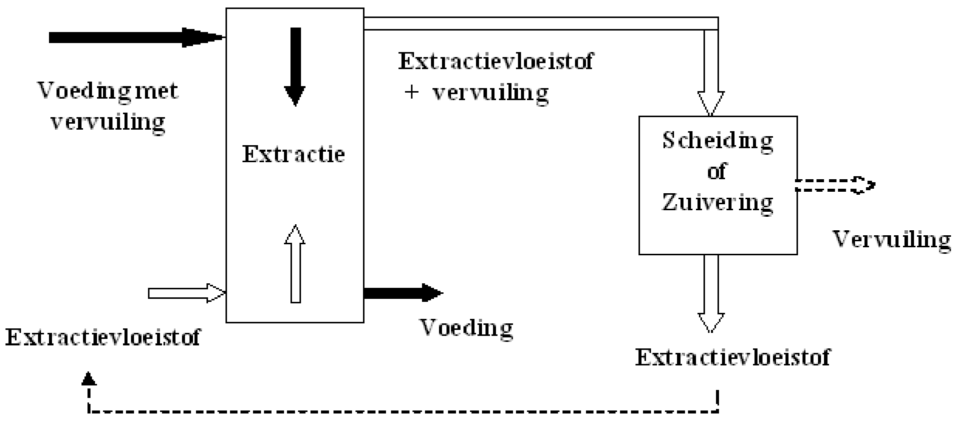


Figure 15. Schematic diagram liquid extraction process [Emis-Vito, f].

Voeding met vervuiling = Feed with contamination; Extractie = Extraction;
Extractievloeistof + vervuiling = Extraction fluid + contamination; Extractievloeistof = Extraction fluid;
Voeding = Feed; Scheiding of Zuivering = Separation or Treatment; Vervuiling = Contamination;
Extractievloeistof = Extraction fluid

MPPE

Dissolved hydrocarbons and other organic compounds can be removed from flowback and produced water using Macro Porous Polymer Extraction. In this technique the water is passed through a column with a packed bed of MPPE material. An extraction fluid, that is immobilised in the MPP matrix, removes the hydrocarbons from the water, after which the treated water may if applicable undergo a further treatment stage. Before the required effluent concentration has been reached, the supply is transferred to the second column and the first column is regenerated with low pressure steam. After the second column is charged, it switches back to the first column. A characteristic cycle takes 1-2 hours. The steam and hydrocarbon vapours are condensed, after which they are easy to separate, partly due to the high hydrocarbon / organic matter content. This technique is sometimes used on offshore gas production platforms to remove mineral oil.

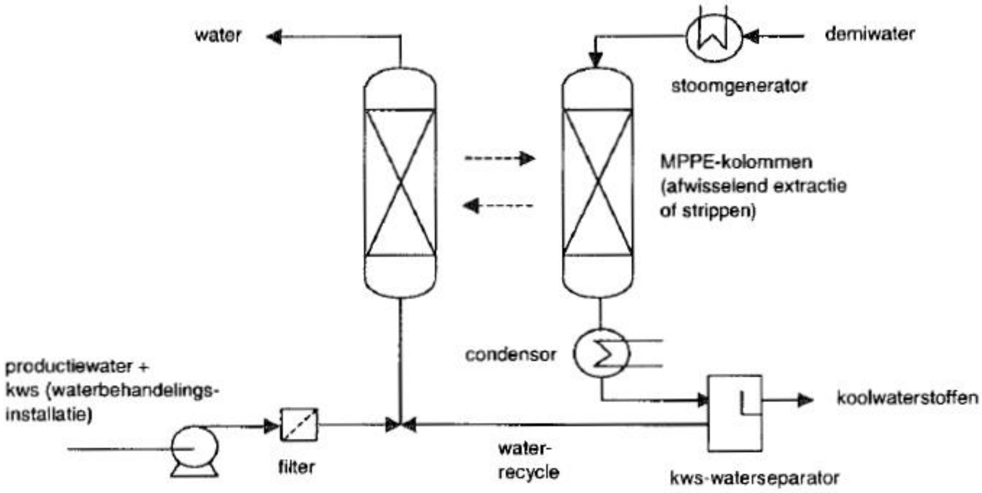


Figure 16. Process flow diagram for MPPE (CIW, 2002).

demiwater = demineralised water; stoomgenerator = steam generator; MPPE-kolommen (afwisselend extractie of strippen) MPPE column (alternating extraction or stripping); productiewater + kws (waterbehandelingsinstallatie) = production water + HC (wastewater treatment plant); koolwaterstoffen = hydrocarbons; water-recycle = water recycle; kws-waterseparator = HC-water separator

Estimated footprint, including steam generator (LxBxH)
6 m^3/hour water: 2 x 3 x 3 m

Activated carbon filtration

Activated carbon is thermally treated carbon with a very large internal surface area. As a result it is very highly adsorbent and able to remove a very wide range of organic molecules from the water.

Adsorption of components on the activated carbon can be predicted from their KOW coefficient (partition coefficient in octanol/water). If the log KOW value is less than zero, the substance in question will not be adsorbed. Measurements of the KOW value of organic compounds in flowback water can give an idea of the extent to which they can be adsorbed.

Use of activated carbon is among other things possible in the following forms: in a granular activated carbon (GAC) filter, using in-line addition of powdered activated carbon (PAC), in a membrane assisted affinity separator (MAAS) or in a continuous moving bed adsorption system (MBA/BBA).
The activated carbon particles in a GAC filter have a diameter of 0.25-3 mm. Once the column is fully saturated with a particular substance it will break through. At this point the filter must be regenerated and reactivated. The breakthrough time differs for each substance and depends among other things on the polarity of the substance in question. [Stowa, 2005]

Pertraction

Pertraction is based on the extraction of organic compounds (volatile and non-volatile) from fluids (among others water) using membranes. The membrane has no selectivity at all here. It is a hydrophobic MF membrane that ensures a high contact area between the organic extraction solvent and the treatment fluid. Furthermore it prevents the mixing of the two phases.

By using pertraction no separation of the fluid and the extraction solvent is necessary, which saves time and money. The membrane also makes flexible, independent regulation of the streams of both phases possible so the process is easy to optimise. As a result it is also possible to bring small quantities of extractant into contact with large quantities of water to be treated. This keeps the installations compact.

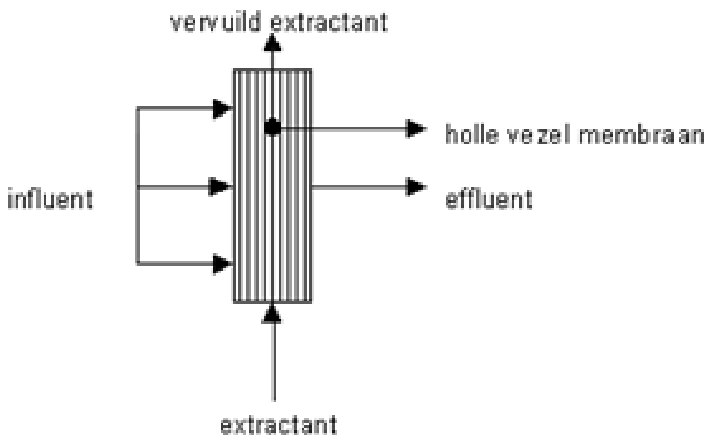


Figure 17. Schematic diagram pertraction process [Emis-Vito, g].

vervuild extractant = contaminated extractant; holle vezel membraan = hollow fibre membrane

A pertraction installation consists of one or more membrane modules in series (membranes are usually in a hollow fibre configuration for as high as possible a membrane area per volume). Here the extraction fluid flows along one side of the membrane (inside hollow fibre). The wastewater is passed along the other side of the membrane (outside hollow fibre). The pores of the membrane are then filled with the organic extraction solvent. The contaminants diffuse from the wastewater through the membrane to the extractant. Regeneration of the extractant can be carried out using among other things a vacuum film evaporator. Reuse of extractant is possible.

The selectivity may be affected by the choice of extraction solvent. In a number of cases the partition coefficients of different substances to be removed do not or hardly differ so selective separation is difficult or expensive, because several stages must be used. However, for removal of organic matter from wastewater, for example, selective separation is generally not necessary.

When selecting the extraction solvent in addition to the standard criteria for extraction (affinity for components to be removed, chemical stability and toxicity) account is also taken of the membrane system, that is chemical resistance of the membrane and viscosity. Due to the low quantity of extraction solvent required other more expensive extractants may possibly also be considered. In addition it is not necessary for a density difference to exist between the stream to be treated and extractant, which for conventional extraction is desirable because of the separation required afterwards." [Emis-Vito, g]

Pertraction installations are already used in the chemical industry, for example for the removal of chlorinated hydrocarbons. Pertraction is not yet used in the oil and gas industry.

Advanced oxidation processes (AOP)

Advanced oxidation processes (AOP) are used for the oxidation of complex organic constituents (that are poorly biodegradable) to simpler end products. An AOP is a greatly accelerated oxidation reaction which uses a free hydroxyl radical (OH·) which acts as a strong oxidant. The radical destroys substances that cannot be oxidised with conventional oxidants (such as oxygen, ozone and chlorine). The free radicals can be obtained from ozone (O_3) or hydrogen peroxide (H_2O_2) by direct reaction with one another or by reaction with UV light (photolysis) [Stowa, 2005]. To date UV/O_3, O_3/H_2O_2 and UV/H_2O_2 are the most commonly used systems for wastewater treatment.

The free radicals react with contamination and initiate a series of oxidative degradation reactions. When UV light is used a large part of the organic breakdown occurs as a result of photolysis of organic components. AOPs are to date used mainly for drinking water and specific industrial wastewater streams (e.g. textiles). The main purpose of this technique is to remove synthetic organic chemicals, pesticides and odour components. The chemistry of AOP is complex because of the great variety of reactions that may occur. One disadvantage of AOP is that the toxicity of possible by-products is not always lower than the original substances in the water. Also the consumption of chemicals may be high because of the non-specific nature of the technique. Another disadvantage is the reduced efficacy when components are present that remove these radicals. One big advantage of AOP is that complete oxidation to CO_2 and water is possible and that no sludge/concentrate is produced [Stowa, 2005]. Usually AOP is used to treat organic microcontamination. To treat high concentrations of organic matter with AOP too many chemicals are necessary, or the energy consumption is too high.

Technologies for the removal of heavy metals and scale formers (divalent ions)

Precipitation

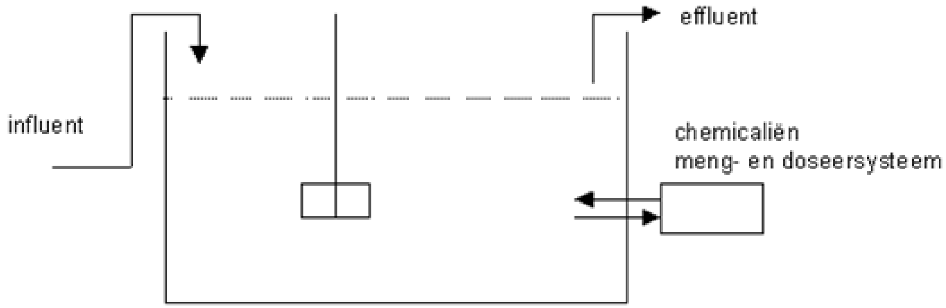


Figure 18. Schematic diagram precipitation process [Emis-Vito, h].

chemicaliën meng- en doseersystem = chemical mixing and dosing system

The purpose of precipitation is the chemical deposition of dissolved matter in the wastewater by adding a reagent that forms an unbreakable bond with the matter to be separated. Positive ions such as (heavy) metals but also negative ions such as phosphates and sulphates can be removed by precipitation. The deposition is generally carried out in a 1 to 1 molar ratio, this means that a molecule of dissolved matter (for example SO_4^{2}- present in the form of readily soluble sodium sulphate) forms an insoluble precipitate (in this case barium sulphate) with 1 molecule of reagent (for example barium from soluble barium chloride). Often however a limited overdose is required for complete removal.

Other examples are the softening of water with lime water (removal of Ca and Mg), the dephosphatation of wastewater using iron chloride to form poorly soluble iron phosphate and the removal of heavy metals such as chromium and nickel using sodium sulphide (formation of metal sulphides).
Other heavy metals can be precipitated as hydroxide by increasing the pH. After a substance has been precipitated, it can be separated from the main stream by filtration, flotation or sedimentation. Often a polymer is added to improve sludge separation.

Nanofiltration (NF)

Nanofiltration is a pressure-based membrane process that as regards its separation level lies between ultrafiltration and reverse osmosis. The pore size of an NF membrane is characterised by a cut-off value. This cut-off value is consistent with the molecular weight of the smallest molecule 90% of which can be retained by the top layer of the membrane. The cut-off value is expressed in Dalton (Dalton = weight in gram of 1 mol of the molecule). A typical NF membrane lies in the range of 150 – 500 Dalton, depending on the molecular structure.

NF membranes have pores with a size of approx. 1 nm. The salt retention for a typical NF membrane is considerably lower than for example for reverse osmosis. With NF divalent ions are virtually fully retained, while monovalent ions can partly pass through the membrane. As a result NF is for example suitable for softening groundwater.
An NF membrane is also ion-selective. This is the ability to distinguish different ions from one another. Because an NF membrane collects solid loaded groups in its membrane structure, electrostatic repulsion / attraction forces may arise between the components in the fluid and the (nanofiltration) membrane surface which results in a certain degree of ion-selectivity.
An NF membrane may consist of a tubular, spiral-wound, or flat plate form. A spiral-wound module is composed of spiral-wound polyamide membrane layers. At the end of the membrane the spiral-wound layers are sealed by an end cap. In the middle of the spiral-wound module is the permeate collection tube. All the pure water passes through the spiral windings and collects in this tube. [Emis-Vito, i]

A typical flux for an NF membrane is 30-50 l m^{-2} $hour^{-1}$. For a flow rate of 175 m^3/hour approx. 50 to 100 membrane modules of one metre long and 10 cm in diameter are needed (surface membrane module is approx. 40-67 m^2). This can probably be fitted into 1 or 2 sea containers.

Ion exchange

Ion exchange is based on the exchange of ions from the water streams with ions from a non-soluble material (resin). For the exchange mainly electromagnetic forces and/or adsorption are important. The ion exchange resins may have a natural origin or be produced. The natural materials are better known as zeolites, these are complex aluminosilicates with sodium as a mobile ion. The produced materials may be synthetic aluminosilicates, that are therefore called zeolites, but are usually often resins (styrene and divinylbenzene copolymers) or phenol-based polymers.

Five types of synthetic ion exchange resins are now in circulation: (1) strong acid cation, (2) weak acid cation, (3) strong base anion, (4) weak base anion and (5) heavy metal selective chelating resins. Resins may also have a macro-porous structure for the adsorption of organic material.

Relevant properties for the ion-exchange resins are:

- Exchange capacity (eq/L or eq/kg): quantity of exchangeable ions that the resin can adsorb. For preference the “ideal” value is higher than the capacity found during operation;
- Particle size: important factor relating to the flow behaviour and the kinetics of ion exchange;
- Stability: chemical/physical resistance in the long term;

- Selectivity: the ion exchange process is an equilibrium process between the ions in the water and the ions in the resin. A high selectivity for a particular ion means that this specific ion is exchanged to a considerable degree. An example here is the development of selective chelating resins. These resins have been specially developed for the very selective removal of heavy metals and as a result reach a very high removal efficiency.

As soon as the resin has been used up it is separated, regenerated and reused. For the regeneration salts, bases or acids are often necessary [Stowa, 2005; DOW]. Ion exchange can be used for example for softening or removal of sulphate and phosphate from the flowback water.

Technologies for desalination

Reverse osmosis (RO)
Reverse osmosis is a pressure-based membrane process that has a separation range of between 0.1 and 1 nm. Reverse osmosis membranes can largely remove divalent and monovalent ions (approx. 99%). The majority of organic compounds are also removed. The removal efficiency is not only determined by the size of the substances to be removed, but also by the polarity and charge of the substances, water and membrane.

Because reverse osmosis membranes are able to achieve these high retention rates an osmotic differential pressure occurs over the membrane. On the feed side there is a high salt concentration and on the other side of the membrane (permeate side) there is a low salt concentration. The water will naturally flow to the concentrate side to restore the thermodynamic equilibrium (osmosis).

By using a higher pressure on the concentrate side this osmotic pressure can be overcome and the pure water will be pushed through the membrane. Because the flow here goes against the osmotic pressure this is called reverse osmosis. The size of the required pressure depends on the concentration of ions on the concentrate side (from 2 to 17 bar for fresh and brackish water treatment and approx. 40 to 80 bar for seawater desalination).
A reverse osmosis membrane is composed of spiral-wound polyamide membrane layers (figure xxx). At the end of the membrane the spiral-wound layers are sealed by an end cap. In the middle of the spiral-wound module is the permeate collection tube. All the pure water passes through the spiral windings and collects in this tube [Emis-Vito, k].

A TDS up to approx. 50 g/L is feasible for RO. Above this the osmotic pressure is too great. The recovery at this high TDS concentration can often not be higher than 50% so the 50% concentrate must be removed or treated further (Brant, no year given).

Reverse osmosis is among other things also used in drinking water preparation, glasshouse horticulture and the chemical industry.

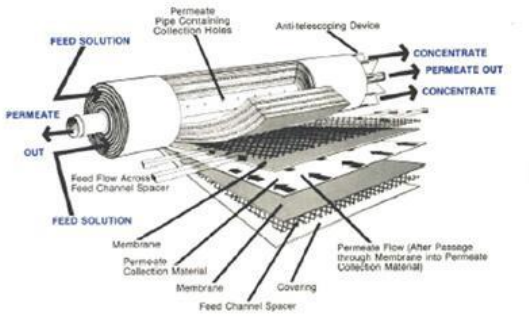


Figure 19. Spiral-wound membrane module.

<u>Multi stage flash (MSF)</u>

A multistage flash evaporator consists of a number successive evaporation chambers where the first chamber is operated at the highest pressure and each subsequent chamber has a lower pressure than the previous one. Salt water (for example seawater or in this case flowback water) is passed through tubular heat exchangers where it is heated by condensation of the vapour that is produced in each chamber. It is then heated in a separate heat exchanger to the required process temperature. After this heating the salty water is superheated with respect to the temperature and pressure in the first chamber. As a result part of the seawater will immediately evaporate so as to reach equilibrium between vapour and fluid corresponding to the conditions present. The vapour formed condenses on the tubular heat exchangers where the distillate (clean water) is collected. The remaining water is then passed to the next evaporation chamber where part is again evaporated. In this way in a number of successive stages a distillate is obtained which consists of pure water. The salty water is concentrated at each stage and ultimately forms the brine stream that is extracted in the last stage. [Sidem]

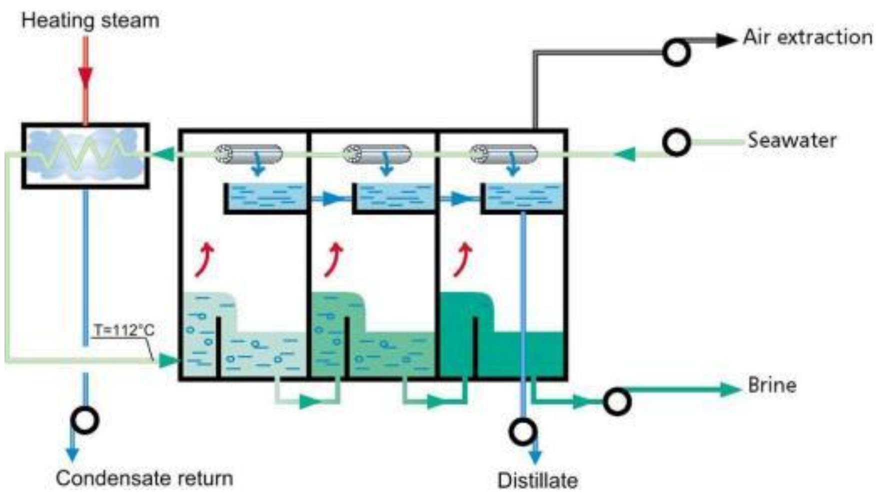


Figure 20. Schematic diagram of an MSF process (without brine flowback) [Sidem].

Mechanical vapour recompression (MDR or MVC)

“The purpose of evaporation is to concentrate dissolved contamination and distil purified water from wastewater. The technique described here is based on the principle of mechanical vapour recompression where applicable combined with falling film evaporation. A circulation pump conveys the influent to the top section of the vessel where the water is distributed over the heat elements. Part of the wastewater evaporated on the outer surface of the heat element. The vapour produced is passed through a compressor to increase the pressure a little and is then passed to the internal surface of the heat element where it condenses. Condensation energy is conveyed to the wastewater side of the heat element and the clean condensate is collected.

The concentrated wastewater flows to the bottom of the vessel where it is removed by the concentrate pump. The material of the heat element consists of a thin, non-corrosive elastic film of polymers or of rigid metals.” [Emis-Vito, j] A recovery of 72.5% or more is possible for treatment of concentrated shale gas brines. There is experience with this in the Barnett shale region (Hayes, 2012).

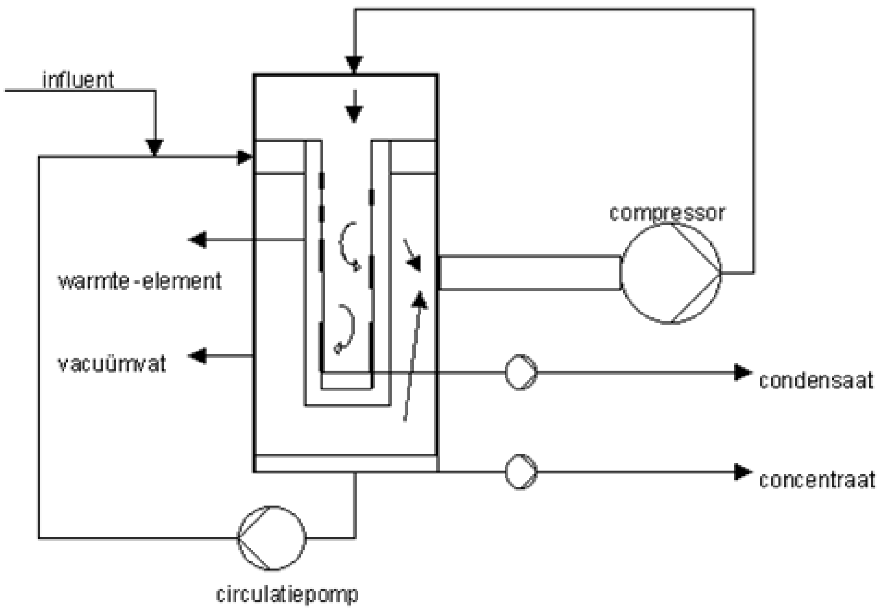


Figure 21. Schematic diagram of MDR process [Emis-Vito, j].

warmte-element = heat element; vacuümvat = vacuum vessel; condensaat = condensate; concentraat = concentrate; circulatiepomp = circulation pump

Multi-stage evaporation/Multiple effect evaporation (MEE)

Multi-stage evaporation focuses on the efficient evaporation of water. In a multi-stage evaporator the water is brought to boiling in a series of vessels, where each vessel is operated at a lower pressure with respect to the previous one. Because the boiling point of water falls as the pressure falls the vapour from a vessel can be used to heat the next vessel to boiling point. In this way a large part of the heat required for evaporation can be reused. Then only external heat is necessary for the first vessel (which is at the highest pressure).

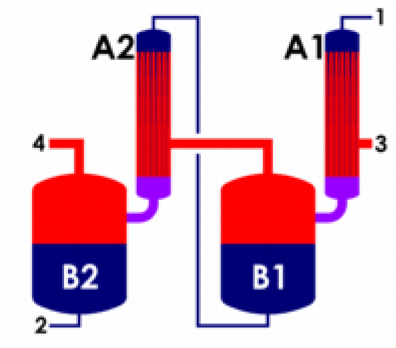


Figure 22. Schematic diagram of a two-stage evaporator (the vapour from B1 heats B2).

Membrane distillation

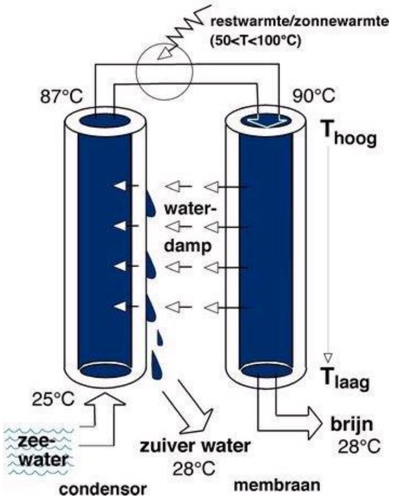


Figure 23. Schematic diagram of membrane distillation process [Hanemaaijer et al. 2007]

restwarmte/zonnewarmte = residual heat/solar heat; waterdamp = water vapour; hoog = high
laag = low; zeewater = seawater; zuiver water = pure water; brijn = brine; membraan = membrane

Membrane distillation combines membrane filtration with distillation. Salt or contaminated water can be processed into clean distilled water using heat. The clean water evaporates through the membrane to the outside and in this way is separated from the contaminated and salty residual moisture. This water can then be used in industry or made suitable as drinking water. Membrane distillation was originally developed for seawater desalination. In a module heated salty or contaminated water flows through a membrane. The membrane only allows the water vapour released through. The water vapour then condenses on the condenser opposite the membrane, from where it is removed. Here the water vapour gives off the heat to the salty water that is flowing through the membrane. Thanks to countercurrent exchange the heat utilisation is maximised. Because this operating principle is used here in a compact module only a small temperature difference and little energy supply is necessary. A membrane distillation module is composed of hundreds of layers of three elements: condenser-array, an intermediate layer, and a membrane-array. The distance between membrane and condenser-array is less than one millimetre so the water supplied only has to be heated a few degrees to create sufficient vapour pressure for effective distillation. [Appelman and Creusen, 2010]

The temperature of the flowback water can rise to 60 ºC with maxima of up to 90 ºC. This depends on the depth of the well. This heat can be used for membrane distillation.

An important point of concern in the use of membrane distillation for treatment of flowback water is the effect of surfactants (soaps, oils). These can disrupt the treatment process, because this can wet the pores of the membranes and lead to penetration.

General Electrics is at present using MD to treat flowback water from shale gas in the US.

Membrane distillation and crystallisation (MDC)
For the longer term one can look at technologies that cannot yet be used immediately because they are still in the development phase.
MDC is a technology under development by TNO and consists of a combination of membrane distillation and crystallisation. Parts of the knowledge obtained during the development of Memstill (including seawater desalination) and FACT (including water softening using crystallisation and precipitation) form the basis of the MDC concept.

In an MDC module the different salts are removed from the water stream in different stages. Evaporation and crystallisation occur here in a hybrid unit. No additives/ chemicals are used. Continuous crystallisation and precipitation are, as far as possible, initiated by the removal of water and under the influence of temperature changes. Crystallisation and precipitation are improved by dosing seed crystals.

In the following a schematic diagram of the MDC process is given. The development of MDC is in the laboratory phase.

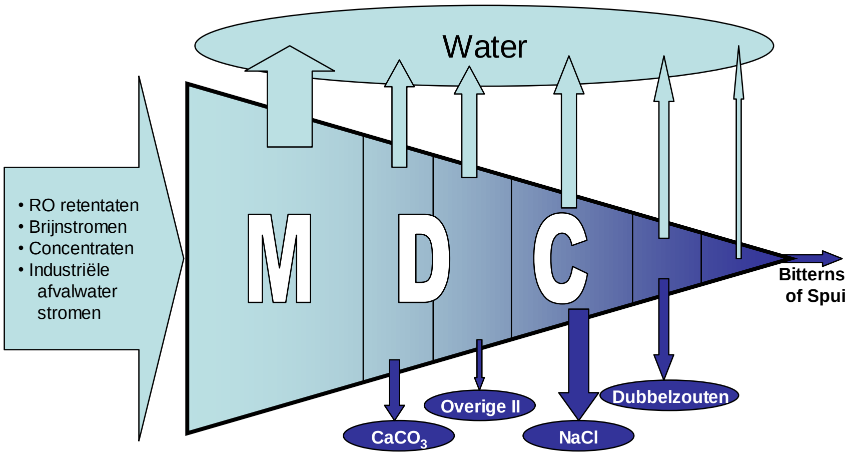


Figure 24. MDC concept. Water is removed while (mixed) salts are recovered stage by stage

- RO retentates
- Brine streams
- Concentrates
- Industrial wastewater streams Bitterns or sluice

Overige II = Other II; Dubbelzouten = Double salts

Forward osmosis (FO)

In forward osmosis the same membranes are used as for reverse osmosis. These retain (virtually) all dissolved solids and allow water through.

Due to the difference in concentration of the substances in the incoming water and permeate an osmotic pressure is created. This pressure ensures that water flows in the direction of the solution with the higher concentration of contamination. In reverse osmosis high pressure is therefore used to overcome the osmotic pressure.

Unlike reverse osmosis forward osmosis uses the osmotic pressure. In forward osmosis a draw solution is used to draw the water from the salt. Because the concentration of the components in the draw solution on the permeate side is higher this will lead to an osmotic pressure. As a result the water flows in the direction of the permeate side. The dissolved particles in the water are hereby retained by the membrane.

The water is then separated from the draw solution by a downstream separation stage.

The operating principle of FO makes it possible to separate the water from the stream to be treated at low pressures and therefore with relatively little energy. It is however important here to select a draw solution that permits easy separation of water.

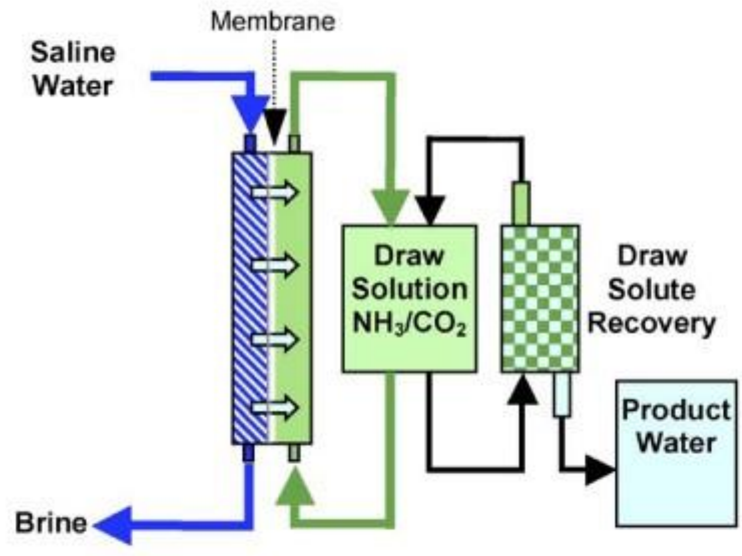


Figure 25. Schematic diagram of parts of forward osmosis installation (using NH_3-CO_2) (http://www.freedrinkingwater.com/Images-news/forward_osmosis_image001.gif)

<u>UV disinfection</u>
Ultra violet (UV) light forms part of the electromagnetic spectrum and has a wavelength between 100 – 400 nm. The range between 200-280 nm (UV C) has a bactericidal effect. By using the right dose UV is able to kill microorganisms, without the formation of toxic by-products.

The efficacy of UV radiation depends on the UV absorption of the material to be broken down. Nucleic acids (among other things building blocks of DNA) and proteins are effective in absorbing UV radiation. For this reason UV is an effective physical disinfection method. Radiation of microorganisms with UV results in non-reversible photo-biochemical changes in the DNA structure so the organisms are no longer able to multiply.

Appendix E: Alternatives for the use of water in fracking

There are a range of possible alternatives for water in fracking fluids. It is important to report that most of these alternatives are only used in exceptional cases, usually under experimental conditions (TRL5-7).

(Conventional) technology in current practice (international and in particular in the United States and Canada)

Examples of alternative fluids that are already used are fracking with carbon dioxide (Yost et al. 1993), LPG (Soni 2014) or propane (LeBlanc et al. 2011; EPA 2011; Gandossi 2013). In view of the often experimental nature of most other alternatives and lack of clarity about the added value as regards reducing risks they are described under (niche) technologies.

(Niche) technologies that are still rarely used, but are already available on the market and their possible impact on minimising the (residual) risks of shale gas and developments that will be available in the (near) future and their effect on minimising the (residual) risks of shale gas

Gandossi (2013) has identified a number of alternatives for water in fracking fluids. In addition to reduced water use and fewer problems with swelling clays, these substances have a number of advantages and disadvantages compared with water-based fluids, in particular as regards the use of chemicals (see also paragraph 3.3). The most important alternatives are:

1. <u>Carbon dioxide (liquid or supercritical CO_2)</u>. For supercritical CO_2 the temperature must be above 31.1 °C and pressure above 7.39 MPa. One advantage is good penetration into the formation. After the operations the CO_2 rises as a gas. Additional advantages are possible extraction of more gas because absorbed methane in the shales is released, and possible synergies with underground CO_2 storage. Disadvantages are that because of the low carrying capacity lower concentrations and smaller proppants are possible, that CO_2 is more difficult to transport and store, that CO_2 is corrosive in vicinity of water, possible high treatment costs.
2. <u>Liquefied Petroleum Gas (LPG), propane or diesel</u>. During fracking the LPG is in the liquefied state, after this it dissolves in the gas from the formation. Sometimes a gel is first made with chemicals so that the proppant can be transported into the rock better. In addition to LPG diesel is also used as a fracking fluid. The advantages are that fewer or no other chemicals are necessary and that LPG after fracking is easier to produce back. The big disadvantage is that these types of fluids are themselves harmful and furthermore readily inflammable. Cryogenically treated, liquid LPG (also called VRGE, or ‘dry fracking’) is a niche (Vandor 2012).
3. <u>Foam</u>. Foam often has a high viscosity and low density, and undergoes little or no chemical reaction with the shale formations, so it is easier to pump back and treat. Disadvantages are that some types of foam can only carry low concentrations of proppant, that the flow behaviour is more difficult to predict, and that often a higher pump pressure is required.

4. Acids. Acids are used to dissolve (part of) the rock so that flow of gas is improved. The method usually only works well if the shales have a high carbonate content. The technique is therefore mainly used for carbonate-rich reservoirs. Acids are used in shales in particular to reduce the required pump pressure, and less to serve as an alternative for water in the fracking fluid.
5. Alcohols, such as methanol. This technique in particular gives advantages in formations for which flow of water is blocked (liquid trapping or irreducible water). Methanol is naturally degradable, dissolves readily in water, has a low surface tension and high evaporation pressure. A lower pump pressure is also often necessary because of the lower viscosity compared with water. The big disadvantage is that methanol is readily inflammable and explosive, and that it is considerably more expensive than water.
6. Emulsions. In this technique an emulsion of two of more fluids is used. For example part of the water in CO_2 foam can be replaced by methanol to reduce the water use. Advantages and disadvantages of the use of emulsions depend on the components used. One disadvantage is the higher costs compared with water.
7. Nitrogen is often used in fracking fluids. Often foam or other types of fluids are also used in addition to nitrogen. Liquid nitrogen is used less often. Due to the extremely low temperature thermal fractures may arise. Fracks may possibly also occur that remain open by themselves (self-propping fractures, Grundmann et. al. 1998). Disadvantages are that due to the extremely low temperature (-197 °C), the equipment on the surface must be made of stainless steel. Sometimes special glass fibres must also be used in the well to protect against the low temperatures.
8. Liquid helium can be injected into a formation at high pressure. Fracks occur here and existing fracks are filled with helium. Then a phase transition takes place in which helium is converted from a liquid to a gas phase and expands drastically (> 700x). This has a favourable effect on fracking. Another favourable property of helium is it has a high diffusion rate into rocks, so no solvents are necessary. The use of the technique is not well known (possibly still only used by one company). Disadvantages are also the costs and availability of sufficient liquid helium. Also no proppant can be used which may adversely affect the flow of gas through the fracks.

Inventory of current technologies from other industries that may be relevant for minimising the (residual) risks of shale gas

Relevant current technologies from other industries are mainly important for alternative chemicals in fracking fluids (see paragraph 3.3).

Gaps in knowledge and technology specific to the Netherlands and taking into account (period of) possible usability

The most important gaps in knowledge are the technical usability and feasibility of (niche) technologies for fracking that have been described above. Some techniques are in the experimental phase and not fully developed. For other techniques the added value as regards reducing risks in shale gas extraction have not been demonstrated, or the alternative fluids are more harmful or more dangerous than conventional fracking fluids. It will generally only be possible to use the techniques in the long term (> 10 years).

Appendix F: Control of the result of fracking

This paragraph gives an overview of the technologies and a number of specific analyses that can be used *before starting* and *during* fracking or the extraction of shale gas to control the result of fracking better with an indication of the use in the United States, Canada and the Netherlands and also the “Technology Readiness Level” (TRL, see appendix 1).

(Conventional) technology in current practice (international and in particular in the United States and Canada)

The most important techniques that can be used *before starting* fracking and gas **extraction** are (TRL7-9):

1. Site-specific analysis of the geological and geomechanical conditions of the subsoil in combination with models that predict the dimensions of fracks in the subsoil. The models can be used to optimise the fracking process *beforehand* (among other things as regards the fluid volume, type of fluid, and number of frack stages through the well), and hence to limit the risks of fracking (see also sections 0 and 0).
2. Multicomponent seismic data can be used to determine (geomechanical) rock properties. In combination with fracking models these data can be used to make statements *beforehand* on the dimensions of fracks and stimulated reservoir volume (Figure 26).
3. The execution of laboratory scale fracking experiments. Experiments on samples of shales can be used to determine the effect of fluid injection on the shales and to calibrate fracking models (Reinicke et al. 2010; Meng & De Pater 2010).

The most important techniques that are used *during or after* fracking and gas extraction to determine the result of fracking are:

1. Micro-seismic monitoring (among others, Warpinski 2014, Figure 26). Micro-seismic data can be used to map out individual fracks or stimulated reservoir volume *during fracking* so that a good picture is given of the effect of fracking in the subsoil.
2. Monitoring using tiltmeters (among others, Astakhov et al. 2012). The mapping of fracks can also be carried out on the earth’s surface using tiltmeters or by means of monitoring wells in which small earth movements can be measured. The measurements can be related to deformation as a result of the occurrence of fracks.
3. Monitoring of flow of gas or fluids from the fracks to the well using temperature variations (distributed temperature sensing) or based on acoustic signals (distributed acoustic sensing). In this way the effects of fracking on the flow of gas or fluids in the subsoil can be better determined.
4. Time-lapse seismic monitoring (among others, Atkinson & Davis 2011). In time-lapse seismic monitoring *before starting* and *after carrying out* fracking seismic data (for example 2D or 3D seismic profiling, or vertical seismic profiling) are (repeatedly) gathered. From differences in the data *before starting* and *after carrying out* fracking changes in the subsoil as a result of fracking can be determined.

In micro-seismic monitoring it is assumed that the formation of fracks or reactivation of small natural faults is associated with measurable micro-seismicity. It is possible that fracks or stimulated reservoir volume are greater because part of the fracking process is carried out aseismically or because the magnitudes of the seismicity lie below the detection limit of micro-seismic monitoring. This technique is at present the best that is available for determining the result of fracking. The micro-seismic data can also be used to calibrate the fracking models, so that the predictive value of the models is greater, and optimisation of the fracking process is better, for successive fracking operations in the same formation. The micro-seismic data can also be used to limit risks of migration of fluids, or seismic risks. The resolution of the data relating to locating epicentres (and therefore fracks) very much depends on the design of the monitoring network and the distance from the epicentres to the monitoring network. The accuracy is usually greater in the horizontal than in the vertical direction. For networks on the earth's surface the uncertainty of the depth is usually of the order of 50-100 metres (and increases considerably with the depth). For networks in monitoring wells the uncertainty may be less than 1 metre (among others Eisner et al. 2009). Because of its importance for optimising fracking and shale gas extraction, micro-seismic monitoring is regularly used in the US and Canada (TRL9). Micro-seismic monitoring is not used in the Netherlands *during fracking* (TRL7-8). Long term seismic monitoring is however used in the Netherlands for monitoring induced seismicity (see section 9).

The mapping out of fracks can also be carried out using tiltmeters which has the advantage that the total deformation of the reservoir rock as a result of fracking is measured. Compared with micro-seismic monitoring tiltmeters therefore give additional information, among other things about the opening of fracks and deformation of the surrounding rock. Complex arrays in monitoring wells are necessary to locate individual fracks and distinguish between deformation of different fracks. Tiltmeter monitoring is however used in the US and Canada (TRL9), but much less than micro-seismic monitoring.

Time-lapse seismic monitoring gives a full picture (in the case of 3D seismic profiling) of the changes in the subsoil as a result of fracking or gas extraction. The interpretation of the seismic data for mapping fracks is time consuming and data gathering is expensive, especially in the case of 3D seismic profiling. It is therefore only used in a few cases in the US and Canada. There are different areas in the Netherlands for which 2D of 3D seismic profiling is available. The repeated gathering of seismic data for the same area is for example used for oil extraction in Schoonebeek.

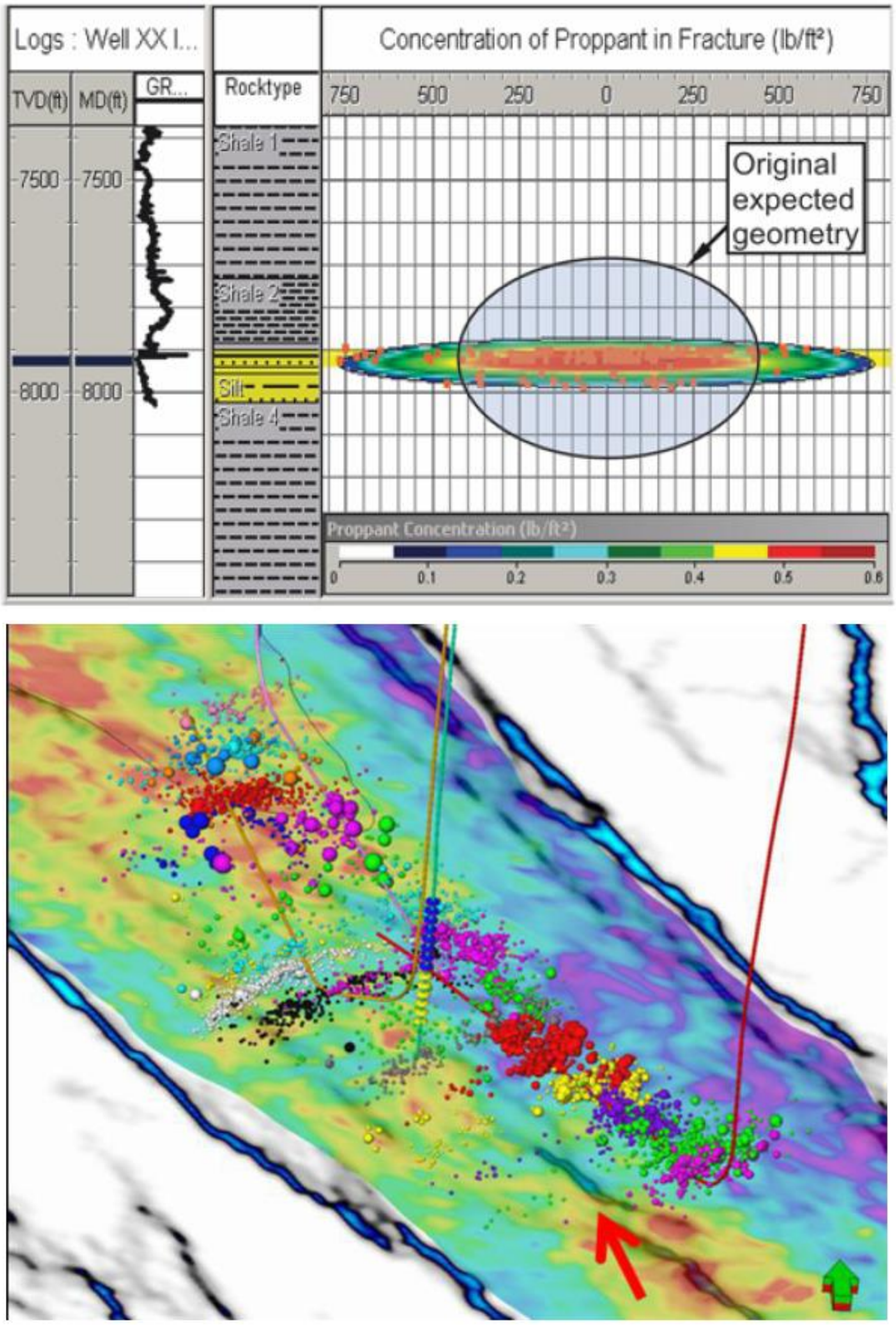


Figure 26 *Top figure*: Ideal example of a calibrated fracking model where the length and height of the frack are calibrated in the light of micro-seismic data (Warpinski 2014). *Bottom figure*: Example of mapping fracks along a horizontal well (*in red*) with micro-seismic data (*coloured circles*) for the Montney Shale in NE British Columbia, Canada. The size of the circles indicates the seismic magnitude and the different colours the different frac stages. The background colours are geomechanical rock properties (minimal Poisson's ratio) that can be determined from 3D seismic profiling. The black and blue lines in the background are faults (Norton et al., 2010).

(Niche) technologies that are still rarely used, but are already available on the market and their possible impact on minimising the (residual) risks of shale gas

Because of the importance of optimising fracking and shale gas extraction micro-seismic monitoring is the most important technological development in this area. Developments are being made in particular relating to improvement of sensors, improvement of the design of monitoring networks, and better integration of geological and geomechanical models of the subsoil and micro-seismic data (TRL6-7). Continuous and real time improvement of predictive models and adjustment of fracking activities in the light of micro-seismic data (history matching, TRL1-4) are niche technologies.

Inventory of current technologies from industries that may be relevant for minimising the (residual) risks of shale gas

The determination of stimulated reservoir volume with micro-seismic monitoring is also used outside the Netherlands for geothermal energy. The technologies that are used or proposed for geothermal energy are only different in the way they are used. Use of micro-seismic monitoring for geothermal energy focusses more on optimising fracking to increase flow rates for injection and extraction of water over a longer period, or on limiting seismic risks. The technology itself is not essentially different, or further developed than for the extraction of shale gas.

Developments and technologies that will be available in the (near) future and their effect on minimising the (residual) risks of shale gas

There may be a part to play in the future for alternative methods of monitoring, for example using (combinations of) electrical, thermal, or magnetotelluric monitoring, TRL3-5, among others He et al. 2012). The combination of different monitoring techniques, for example micro-seismic and tiltmeter monitoring (House et al. 2005) or 4D seismic profiling and micro-seismic data (Goodway et al. 2012).

Gaps in knowledge and technology specific to the Netherlands and taking into account (period of) possible usability

Just as for seismic risks, a lack of site-specific knowledge of the subsoil relating to shale gas reserves (Posidonia Formation and in particular the Geverik Member) is one of the most important knowledge gaps for the Netherlands. This applies above all as regards (geomechanical) rock properties of the shales, local stress state, and properties of faults. Although there is still scope for additional research into the site-specific properties of Dutch shales and predictive geomechanical modelling of the effects of fracking in the subsoil in the light of existing data (period 1-3 years), data from new wells, from analyses of new sample material, and from (laboratory) tests on new sample material are needed to fill this knowledge gap (period 3-5 years, depending on licensing). Although there is no experience in the Netherlands with (micro-seismic) monitoring *during fracking*, this can be done using experience from the US and Canada.

Appendix G: Methane emissions

Extraction of fossil fuels such as coal, oil and gas is accompanied by emissions of methane. In the Netherlands these emissions are calculated and reported under the Kyoto protocol in the National Inventory Report (NIR; Coenen et al., 2014). For example the IPCC category 1B2 Fugitive emissions venting/flaring is regarded by the Netherlands as a key source for CH4.
The emissions reported in the NIR relate to the emissions on Dutch territory including the Dutch Continental Shelf. This means that for example CH4 emissions for coal extraction outside the Netherlands for coal-fired Dutch installations are not reported in the Dutch NIR. These emissions must be reported by the country where the extraction takes place. In 2012 (most recent year) the Dutch CH4 emission resulting from extraction of energy sources was 34.67 kton CH4 (Coenen et al., 2014). The question is therefore not whether CH4 emission will be carried out in shale gas extraction (the answer is yes) but how this emission relates to extraction from other energy sources, in particular natural gas and coal, and whether there are techniques for minimising this emission.

<u>The carbon footprint of fuels in electricity generation</u>
Greenhouse gas emissions related to energy generation and supply are a major cause of climate change. The recent IPCC report focuses on the use of renewable energy sources and climate mitigation (IPCC, 2011) gives an extensive review and methodology description for comparing electricity generation with different energy sources. In their most aggregate form the data are summarised in Figure 27 for solar, wind and nuclear energy as well as the fossil fuels gas, oil and coal. The important message from Figure 27 for this study is the difference of approx. a factor of two for electricity generation based on gas compared with coal. There is no difference between the use of shale gas or ordinary (conventional) natural gas once it has been extracted and is in the gas grid. However an important point of discussion is the quantity of methane that leaks and is released in shale gas extraction compared with conventional gas or coal and due to the high GWP of CH4 (see above) the advantage could possibly be cancelled out.

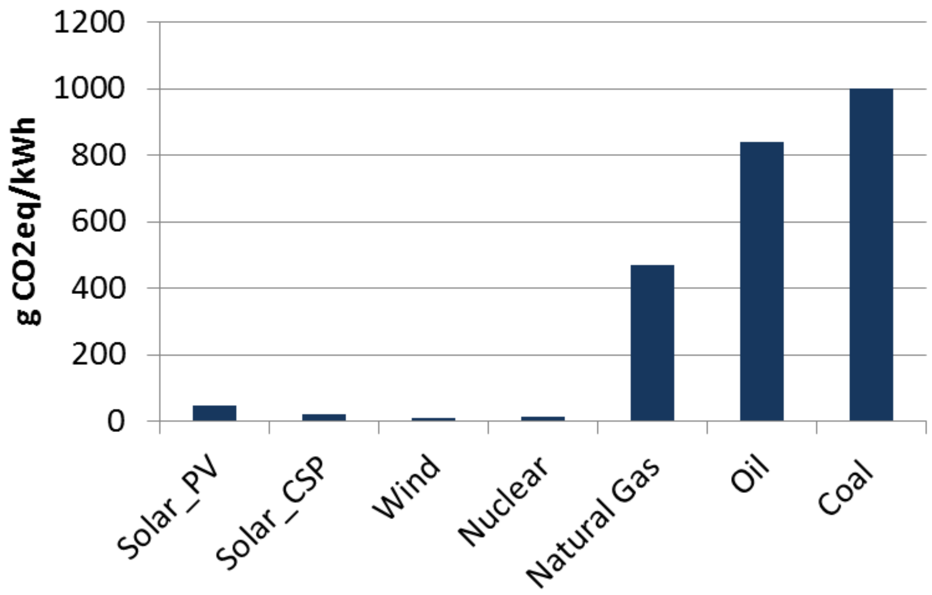


Figure 27 The average CO2 intensity of electricity generation based on an extensive greenhouse gas life cycle analysis literature review by the IPCC (Moomaw et al. 2011, IPCC SRRES appendix II, 2011)

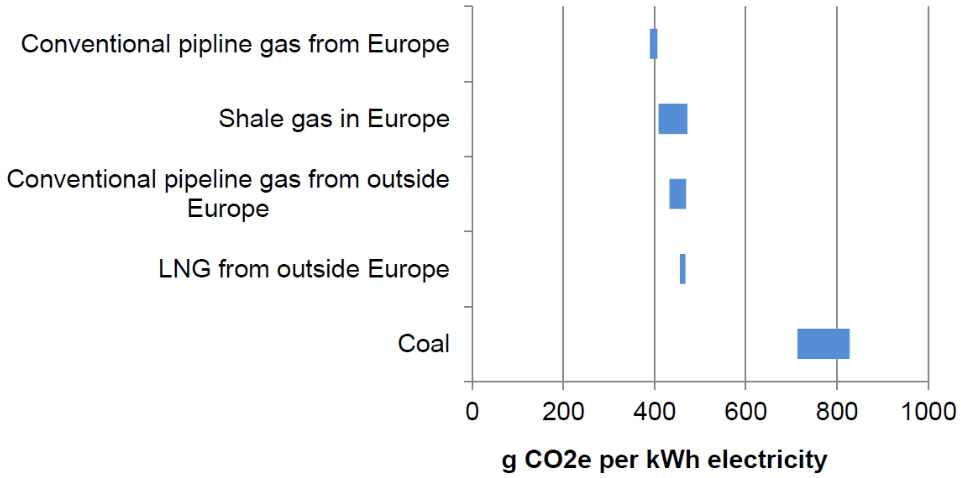


Figure 28 The CO2 intensity of electricity generation for different forms of natural gas and coal (AEA, 2012)

In a recent report for the European Commission (AEA, 2012; Climate impact of potential shale gas production in the EU) a comparison is made for Europe where the CO2 intensity of electricity generation with natural gas (with different origin) is compared with shale gas in Europe and coal. The CO2 intensities, both for coal and gas, as presented in Figure 28 are slightly lower than in Figure 27, which is caused by higher efficiency in Europe compared with the global average from Moomaw et al. (2011). The most important message of both figures is however the big difference with coal. For a comprehensive description of the assumptions please refer to Moomaw et al (2011) and AEA (2012). The bulk of the available literature supports the picture sketched by Figure 28 but the variation is considerable. There is also one study (Howarth et al., 2011) that claims that the CO2 intensity when using shale gas does not differ significantly from that of coal. The reason for this according to Howarth et al. lies in high leakage losses of methane in shale gas production. According to Cathles et al. (2012), in a response to Howarth et al. (2011), these assumptions for leaks are a big overestimate and the impact of emission limiting measures is underestimated. Other investigations support the picture that overall electricity generation with coal has a considerably higher carbon footprint (among others Jiang et al., 2011; Burnham et al., 2011, Stephenson, et al., 2011, Hultman, et al., 2011; NETL, 2011).

Ultimately the CH4 leakage losses determine the “carbon footprint” of shale gas compared with other fossil fuels such as natural gas, oil or coal. The difference between conventional natural gas and shale gas lies only in the upstream footprint: that is everything to do with exploration and extraction. It should also be noted here that transmission, distribution and storage for shale gas also do not differ from conventional natural gas. This upstream part of the carbon footprint is only a small part of the total footprint (indication 15-25%), the greater part is the CO2 that is released when burning the gas, as can be clearly seen in Figure 27 as this causes in particular the difference between the fossil sources on the one hand and the other energy sources (such as solar and wind energy) on the other. As stated the difference between conventional natural gas and shale gas as regards carbon footprint lies mainly in the upstream leakage losses of methane. Several studies including the AEA review report (2012); and very recently Weber and Clavin (2012), Dale et al. (2013) argue that this difference is very limited because leaks also occur in conventional natural gas extraction and transport over long distances also requires energy (e.g. from Russia or Algeria to the Netherlands; AEA (2012; see Figure 28)). This does not alter the fact that every study shows that reducing upstream leakage losses in case of any shale gas extraction must be a priority on the one hand to minimise the carbon footprint and on the other to optimise the usable and saleable quantity of gas.

Measurement and estimate of CH4 leakage losses in the US

In the US to an increasing degree detailed studies have been carried out into CH4 leakage losses in the whole chain from exploration to production of shale gas. There are two essentially different ways of quantifying this. One is bottom-up by deducing or measuring an emission factor for each activity and then calculating the total emission. This is the approach of the US EPA (among others US EPA, 2011; 2014; Allen et al. 2013) and by analogy how the Dutch national emissions registration works (see e.g. www.emissieregistratie.nl). The advantage of this approach is that it is known what specific activity contributes how much and specific measures can be targeted at this. The other method is top-down by integral measurement of the flux over the whole area where all the activities take place (see among others Petron et al. 2012, Miller et al. 2013, Karion et al. 2013, Petron et al, 2014). An example of such a measurement using an aircraft is given in Figure 29. The increase in the methane concentration downwind of the gas field is clearly visible. Based on these types of measurements a methane flux can be calculated for the whole area and using isotope analysis it can be demonstrated whether the CH4 measured is of fossil origin (in this example virtually all fossil) or of biogenic origin. The disadvantage of this approach is that the processes that are most responsible for the emission are not known. However the occurrence of leakage losses is incontrovertibly demonstrated. At present based on several studies the US EPA uses a leakage loss of 2.4% for shale gas from well to city. These overall leakage loss estimates are important because in a very complete analysis comparing different fuel use for electricity generation Alvarez et al.(2012) concluded that for the use of shale gas as a relatively climate friendly alternative for coal the tipping point lies at 3.2% CH4 leakage loss. The variation in the top-down estimates for different gas fields is moreover considerable and sometimes lies below and sometimes above this 3.2% (see also the discussion). The bottom line is that each study recognises and pleads that more measurements are needed to reduce the uncertainty and that limiting leakage losses deserves great attention to minimise the climate impact of shale gas extraction.

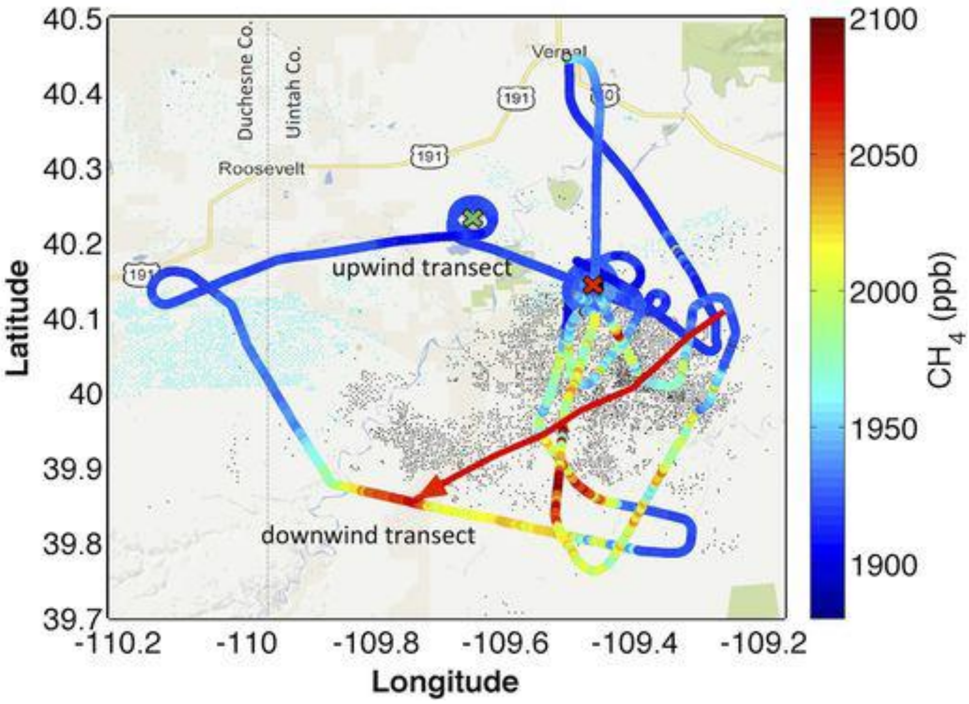


Figure 29 Example of aircraft measurements of CH4 concentrations on 3 February 2012 above the Uinta Basin gas field (Karion et al., 2013). Small black dots are the individual gas wells. The thick red arrow indicates the 3 hour trajectory of the air mass.

Alternative technologies for minimising methane emission

Leaks may occur in many stages of shale gas exploration, exploitation and distribution (among other things boring, fracking, venting, but also from all sorts of connections and equipment such as compressors, valves, pumps, piping and housings, old wells). An impression of the relative importance of the different processes can be obtained from the example in Figure 30. In an absolute sense Figure 30 and the report of NETL (2012) is an underestimate. Other literature clearly shows that both drilling of the wells and sealing or abandonment of the wells are important emission sources (among others Dale et al., 2013, Moore et al., 2014; New York State Dept. of Environmental Conservation, 2012). These sources are not or only under-represented in Figure 30. However the figure for the upstream part that is covered is illustrative and clearly indicates that 1) the leakage of CH4 is dominant as a causer of GHG emissions even with a 100 year GWP and that 2) within this above all the workovers (fracking again to keep production going), the pneumatic equipment operated on gas pressure (valves) and leakage losses during transport are important.

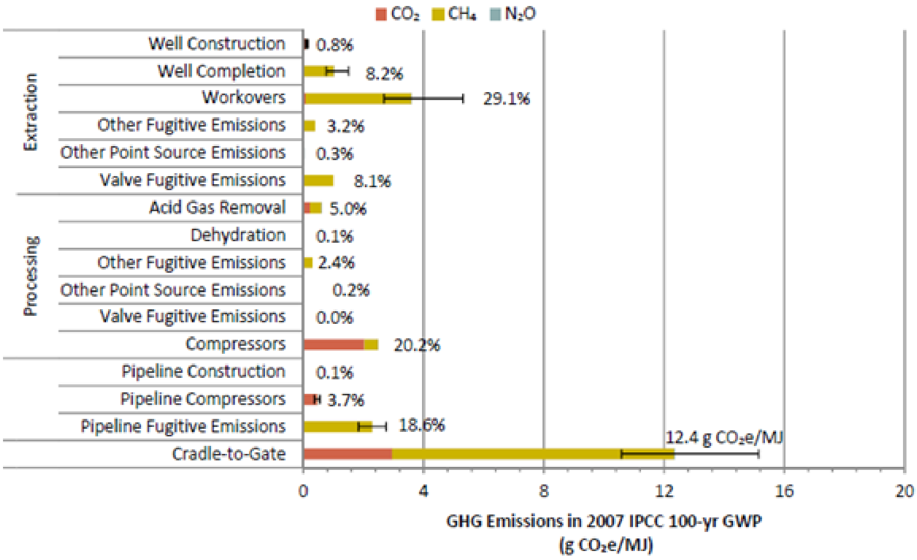


Figure 30 Detailed estimate of the upstream greenhouse gas emissions (expressed in CO2 equivalents on a 100 year horizon) for Barnett Shale shale gas (NETL, 2012).

In the United States different programmes focus actively on reducing emissions in the extraction of shale gas. These programmes partly overlap with one another in a technical sense. For new installations in the oil and gas sector the US EPA “New Source Performance Standards (NSPS)” apply which include a series of specific emission limit values for stationary sources. Since 2012 the NSPS also specifically covers shale gas extraction (US EPA, 2012). US EPA anticipates an ultimate (NMVOC) emission reduction of up to 95% for new shale gas sources, in particular by better capture of leaking natural gas. In 2015 the NSPS comes into force for shale gas extraction. (US EPA, 2012; more information can be found on http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf and http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf). Whether the policy of the US EPA will also actually lead to such high reduction percentages, will remain to be seen. This is probably feasible for specific cases but in total this seems unlikely due to the complex situation and the enormous number of wells (see also discussion).

In addition to the compulsory emission limit values such as those in the NSPS, since 1993 the EPA Natural Gas STAR programme has been active (http://www.epa.gov/gasstar/). Natural Gas STAR is a voluntary partnership between the EPA and oil and gas companies that has the purpose of promoting technologies and measures focussed on increasing operational efficiency and reducing methane emission. Within this framework US EPA has drawn up an extensive list of technical information on proven and cost effective methane emission mitigation technologies and practices that have already been successfully implemented by partner companies. Taking into account the whole industry (from extraction to distribution) Natural Gas STAR in the United States has led to a reduction in methane emission of just under 20% in 2010.

An overview of the measures in the EPA Natural Gas STAR programme is available on the website http://www.epa.gov/gasstar/ under the heading “Reduce your Methane Emissions” (Table 29). Under each of the main categories in Table 29 a sub-level is available. Table 29 gives as an example the breakdown of this sub-level for the section “oil and gas extraction onshore”. Then for each point at sub-level a detailed description of several options including costs and any payback time is available. An example of this for pneumatic equipment is the 1st subsection (http://epa.gov/gasstar/documents/ll_pneumatics.pdf) (US EPA, 2006). These are live documents that are regularly updated. These then include several reduction options with differing levels of efficiency and ancillary costs. Of course these measures and in particular the costs are specific to the current American situation. To determine which measures are specifically suitable and applicable in shale gas extraction in the Netherlands, an extensive further study is necessary including a detailed overview of all the equipment to be used as a starting situation. This falls outside the scope of the current study.

Table 29. Overview of the categories for which emission reduction measures (including hyperlink) were published on the website of the US EPA Natural Gas STAR programme

Reduce your Methane Emissions	
Main categories	Sub level
Onshore Petroleum and Natural Gas Production |	Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry Reduced Emission Completions for Hydraulically Fractured Natural Gas Wells Installing Vapor Recovery Units on Storage Tanks Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators Installing Plunger Lift System in Gas Wells Reducing Methane Emissions from Reciprocating Compressor Rod Packing Replacing Wet Seals with Dry Seals in Centrifugal Compressors
Offshore Petroleum and Natural Gas Production	
Onshore Natural Gas Gathering and Boosting	
Onshore Natural Gas Transmission and Underground Natural Gas Storage	
Onshore Natural Gas Processing	
Liquefied Natural Gas (LNG) Storage, Import and Export	
Natural Gas Distribution	

In view of the relatively high methane emissions during the well completion phase of shale gas extraction in the US within the framework of Natural Gas STAR part of the industry voluntarily applies Reduced Emission Completion (REC) techniques in the extraction of shale gas (estimated at approx. 50% of all sources). An important example of these techniques is to extend the Flowback period (time in which the fluid injected into the well flows back again due to the gas pressure created). The quantity of methane released during Flowback increases because of this with the result that its capture becomes profitable and it is not flared or worse still has to be blown off or vented. Use of REC reduces the leakage losses during well completion by 95% according to the EPA (US EPA, 2012). Overall REC has led to a reduction of approx. 5% in the total methane emission from oil and gas extraction in 2011 (this is approx. 20% for only shale gas extraction and approx. 2% of the whole oil and gas industry from extraction to distribution). More information about REC can be found on
http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf.

An interesting example and justification for the reduction in emissions during the well completion stage is given in the study for the Marcellus Shale by Dale et al. (2013) (Figure 31). Here the most recent period for which there are data (2011-2012) is compared with the previous years from 2007-2010 (= 100%). It can be clearly seen that the contribution to GHG emissions from well completion and waste management per well has reduced by a factor of 2 from together approx. 50% to 25%. This is a considerable improvement. It is expected that this will increase still further when in 2015 the US EPA “New Source Performance Standards (NSPS)” come into force for shale gas extraction (US EPA, 2012). However the ultimate efficacy will also depend on the monitoring and enforcement policy and the resources that will become available for this; with many thousands of gas wells there is a big challenge here for the US EPA. Figure 31 also clearly shows that in this specific case in particular the emissions during the drilling process require great attention. The reason for high emissions here is among other things that during drilling for example one drills through small gas bubbles or carbon layers containing fire damp which can create sudden pulses of pressurised gas. In normal practice these are blown off as quickly as possible to keep safety risks such as explosion as low as possible. Flaring could perhaps offer a solution here and (better still) capture. This must also be looked at in detail and site-specifically.

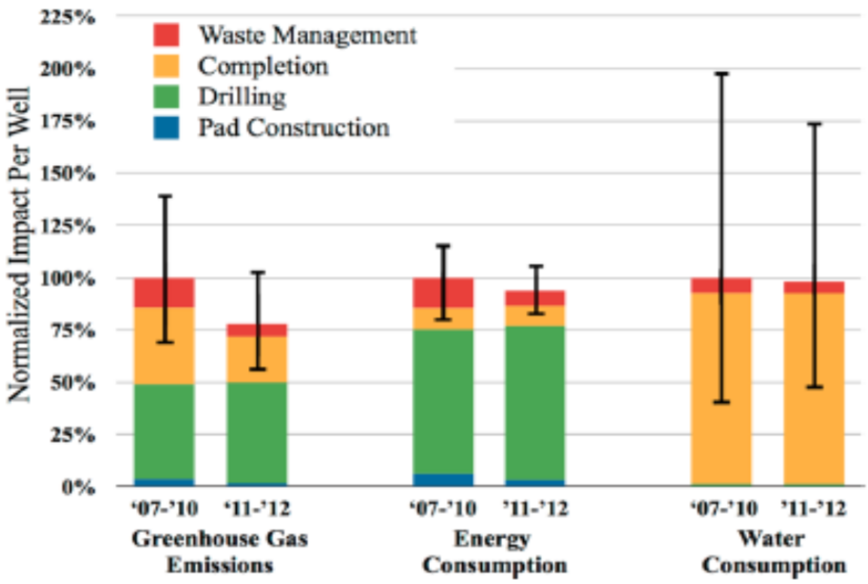


Figure 31 Greenhouse gas emission, energy consumption and water consumption based on a life cycle assessment per shale gas well for the Marcellus Shale, normalised for the period 2007-2010 (= 100%) (Dale et al., 2013)

Netherlands Emission Guidelines (Nederlandse emissie Richtlijnen - NeR)

Measurement data and an estimate of the potential methane emission in (large scale) shale gas extraction and production is at present based on the American situation and data because of a lack of data for other locations such as Europe. However it is important to establish that in the US there are often different emission requirements depending on the State where the operations are carried out. In general it can be said that the emission regulations in the US are less stringent and structured than in the Dutch situation.

In the Netherlands the emission requirements for “Installations for natural gas and oil extraction” are given in the special regulation E11 of the Netherlands Emission Guidelines (NeR, 1996)[20]. This regulation relates to natural gas and petroleum extraction installations with associated treatment processes. The important potential stationary emission sources in shale gas extraction are included by this special regulation. Specific attention is required to limit VOC (including CH4), both channelled emissions (point sources) and diffuse emissions. According to the regulation diffuse emissions must be limited by the use of fittings, valves, compressors and control valves with minimum leakage losses. In addition to this regulation the special regulation also specifies a measurement and maintenance programme to be carried out annually among other things with a view to minimising leakage losses. Of course maintenance and monitoring of the regulations followed is essential.

For the point sources flare or other vapour removal installations are specified that must minimise VOC and CH4 emission. For all emissions not specifically named in the special regulation the general provisions of the NeR (1996) apply with regard to emission requirements and associated measurement obligations. The NeR (1996) already offers support for limiting methane emission in shale gas production and extraction. For example the abandonment of an old gas well without sealing, as regularly happens in the US and where only recently plans of approach are being prepared for this (New York State Dept. of Environmental Conservation, 2012; PA DEP, 2000) would not be permitted in the Netherlands under the current regulations. As an illustration, in New York State alone there are 3500 abandoned or inactive gas wells that were drilled and operated before the recent regulations came into force (New York State Dept. of Environmental Conservation, 2012).

That does not alter the fact that it is recommended, if shale gas extraction is permitted, that the NeR also be specifically looked at for this practice and where appropriate adjusted. A further analysis of the NeR and possible points of adjustment falls outside the scope of this commission.

Discussion

Methane leakage losses in shale gas extraction determine to a high degree the carbon footprint of shale gas compared with other fossil fuels. It is quite irrelevant for comparison with renewable energy sources (see Figure 27), because for all fossil energy sources the bulk of the CO2 emission (75% or more) takes place in the burning phase. Data for operational shale gas extraction and measurement of leakage losses are at present only available for North America and this report, as well as all other known literature, can therefore only be based on this. The American literature is limited, although rapidly growing and all studies emphasise the need for more research, measurement data and monitoring.

The determination of the carbon footprint of shale gas extraction is receiving a lot of attention and is largely dominated by discussion about CH4 leakage losses. The

[20] http://www.infomil.nl/onderwerpen/klimaat-lucht/ner/digitale-ner/3-eisen-en/3-3-bijzondere/e11-installaties/#page-body

carbon footprint is an important point because (shale) gas is sometimes seen as a bridging fuel to a low-carbon economy. When comparing the carbon footprint of shale gas compared with other fossil fuels in life cycle analysis (LCA) studies it is crucial to look carefully at the assumptions. Although certain assumptions are not wrong in themselves, they may not be comparable. Examples of this are the use of a 100 or 20 year horizon for the GWP, the use as fuel for electricity or heat, and whether or not to include the burning phase in the determination of the total CO2 equivalent emission.

As stated earlier we can only use American data as a basis for this. The transferability of the data to the Dutch situation remains a big uncertainty. This can be convincingly illustrated with the top-down measurements of the leakage losses in the US. For the different gas fields total different net overall leakage losses are measured varying from 0.3% to 9% (Petron et al., 2012; Karion et al., 2013; Peischl et al, 2014). This distribution is not caused by difference in measurement techniques, because the same team (e.g. Peischl et al 2014) measures very different leakage losses for different gas fields. There is little idea about the causes; difference in implementation of REC (Reduced Emission Completion) techniques, more or less abandoned gas wells in the area that may or may not have been completed and oil and gas extraction, whether mixed or not. The latter is important because gas is a by-product when one focusses on oil extraction, and is sometimes seen as a nuisance. Then blow off instead of capture is already an attractive option with high emission as a result. These are hypotheses about the underlying causes that seem likely but there is above all a need for more and detailed measurements to increase understanding and can indicate cause and consequence. The importance of the distribution in the top-down leakage losses for the current study is above all that it cannot be stated in advance which of the gas fields is most representative for Europe or for the Netherlands. Apart from this a high leakage does not mean that no measures are possible and indeed the chance, that the measures are also cost-effective, is greater. The more gas there is to capture, the more it is worth doing this both economically and from an environmental view point.

For the development and sharing of knowledge relating to the reduction of methane leakage losses the US EPA has set up a considerable number of programmes. Implementation of these measures (REC, green completion etc.) has already led to considerable emission limitation and it is expected that this trend will continue when in 2015 compulsory emission limit values for certain aspects of shale gas extraction in the US comes into force. The problems are hence however far from solved. The determination and calculation of CH4 leakage losses in the oil and gas industry in the US is a very dynamic research field where the insights may differ considerably from year to year. A good example of this are the emission estimates of the US EPA for the gas industry that is at present undergoing big changes from year to year due to methodical development and the more detailed determination of emission factors (US EPA, 2013; Moore et al, 2014). Illustrative too is the fact that based on a large number of measurements Allen et al. (2013) arrived at a total emission that was comparable with the most recent estimate of the US EPA but had very different ratios in the underlying emission causes.

An important point for research and attention is that the bottom-up and top-down methods for the time being in no way match up. In a recent article in Science Brandt et al. (2014) conclude: “*National-scale top-down studies suggest that total U.S.* CH_4

emissions are 50% higher than EPA estimates (uncertainty range = 25 – 75% higher)" An important point according to Brandt et al (2014) is on the one hand leaks in the (outdated) gas distribution networks in the US (that are kept considerably lower in the Netherlands by good maintenance) but also that real bottom-up measurements on individual sources show an enormous spread where the majority hardly show any leaks while a small fraction is responsible for the bulk of the emission – this makes deduction of representative emission factors very difficult and makes detection and maintenance very time consuming. The distributions that Brandt et al. present are extremely skewed. As an illustration 50 of the 75000 emission points (0.06% of the total) were responsible for 60% of the emission.

Appendix H: Earth movements

Earth movement and seismicity

Seismic risks are determined by the chance of earth movements occurring with a certain speed or acceleration as a result of seismicity, and the consequences of this on the earth's surface (i.e. the damage that an earthquake causes). The chance that, or frequency with which, seismicity of a certain magnitude occurs, can be described with frequency-magnitude relations ("Gutenberg-Richter" relations; Gutenberg and Richter 1944; 1956; 2010). The effect of seismicity on the earth's surface or the intensity of seismicity is mainly determined by the ground movement (peak ground acceleration, frequency content and duration). The earth movement that occurs at ground level depends among other things on the magnitude and depth of the earthquake, the damping of the vibration by the *deeper* subsoil, and the (often local) amplification or damping of the vibration in the *shallow* soft subsoil. Factors such as population density and buildings also determine the consequences of earth movements and therefore the risk of seismicity.

Seismicity that is a direct consequence of gas extraction or stimulation is called induced seismicity. Induced seismicity can occur in areas that show natural seismicity, but also in areas that before gas extraction showed no natural seismicity. The occurrence of seismicity is determined by the combination of (1) natural seismicity as a result of local geological conditions such as the properties of faults and the stress state of the subsoil, and (2) the local disturbance of the subsoil (as regards reservoir pressure and local stress state) as a result of activities for gas extraction (Figure 32). The occurrence of natural seismicity is different for different regions in the Netherlands (Figure 33). For the local disturbance of the subsoil in particular changes in the stress state, pressure and temperature in and around the reservoir are important.

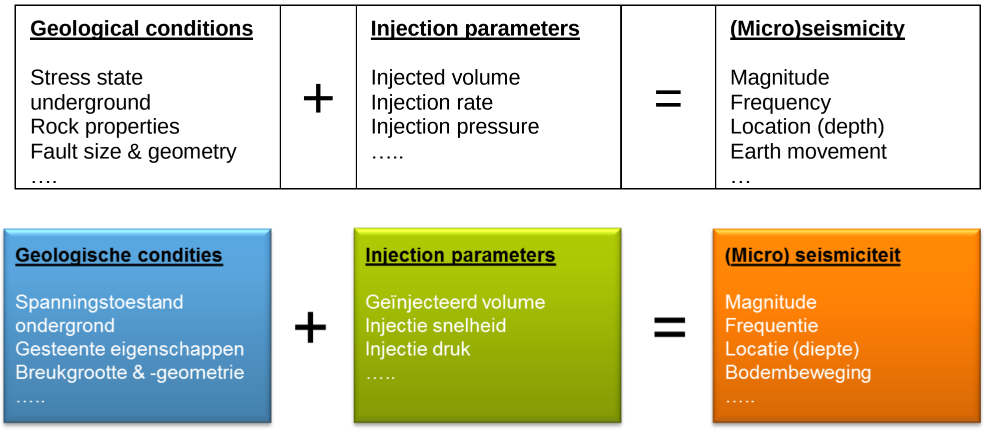


Figure 32 Schematic diagram of the combination of factors that determine occurrence of induced seismicity (Buijze et al. 2012).

Induced seismicity plays an important part in both conventional gas extraction from porous reservoir rock and in shale gas extraction (Van Wees et al. 2014). In gas extraction from porous reservoir rock compaction of reservoir strata may cause induced seismicity because existing natural faults are reactivated. The occurrence of seismicity is mainly determined by the degree of local *pressure reduction* and accompanying stress changes, due to the local geometry of reservoir strata and faults, and due to the degree to which compaction of reservoir strata translates into movement along faults. In shale gas extraction the local disturbance of the underground stress state occurs mainly as a result of the injection of fluids for the hydraulic fracking of shales (stimulation). In this case the seismicity is caused because existing natural faults are reactivated as a result of a local *pressure increase*.

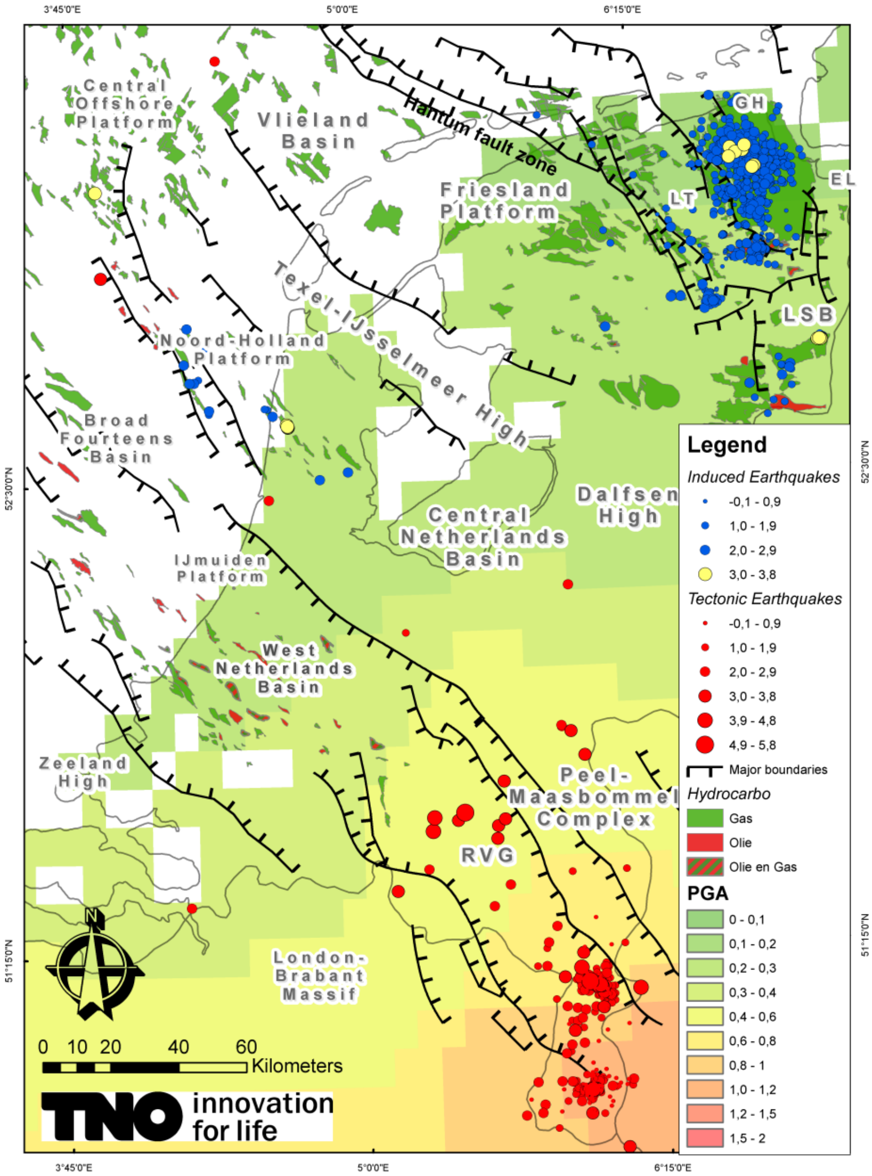


Figure 33 Induced and natural (tectonic) earthquakes in the Netherlands (Buijze et al. 2012). The black lines show the big structures that bound the different geological basins. The background colours show the peak ground accelerations (PGA) with a 10% chance of exceedance in 50 years for stiff soil conditions (seismic hazard, Giardini et al. 2003)

In carrying out an inventory of regional seismic risks (with local differentiation according to buildings, infrastructure, etc.) as a result of fracking and the extraction of shale gas it is important to take into account the local natural seismicity *and* the different mechanisms that cause seismicity.

The most important consequences of seismicity are: (1) damage to the well (casing and/or cement), (2) damage to buildings, infrastructure or nature on the earth's surface, and (3) damage to underground infrastructure or facilities in the immediate vicinity of the epicentre. In some cases these effects may be accompanied by an increased chance of contamination of ground or surface water (see section 1) or with an increase in instability of buildings, and hence constitute a risk for people, environment and habitat.

In the Mining Act for earth movements a distinction is made between risks of subsidence and of induced seismicity. Subsidence plays an important part in conventional gas extraction in the Netherlands (among other things in the Slochteren gas field near Groningen). Conventional gas reservoirs in the Netherlands often consist of porous sandstone or limestone. The hydraulic and mechanical properties of these types of reservoirs differ a lot from those of shale gas reservoirs. Due to the relatively high porosity, porous reservoir rock compacts during gas extraction as a result of the reduction in the pressure in the reservoir. Since the porosity (and hence the compaction-coefficient) of shales is much less than that of porous sandstone, the risk of subsidence in shale gas extraction is much lower (DECC, 2013).

Although seismic risks are therefore determined by several site-specific factors, the discussion often focusses on an inventory of earthquake magnitudes (Figure 34, Maxwell et al, 2009; Downie et al, 2010; Warpinski, 2012). Earthquake magnitudes (M) can be expressed in various ways (scale). The two most important logarithmic scales are (Haak and Goutbeek 2005, Davies et al. 2013): (1) The Richter scale (or local magnitude, M_L), that is often used and is based on the maximum result in the short periodic seismogram, and (2) the moment magnitude (M_w), which is seen as the most reliable and is a logarithmic presentation of the seismic moment ($M_0=\mu AD$, with μ the elastic slip modulus, A the area of the fault that is moved and D the displacement along the fault during an earthquake). (Regional) maps of so-called seismic hazards can also be made that are based on a probabilistic analysis of peak ground accelerations (Figure 33).

Aardbevingen voelbaar aan oppervlakte = Earthquakes that can be felt on surface

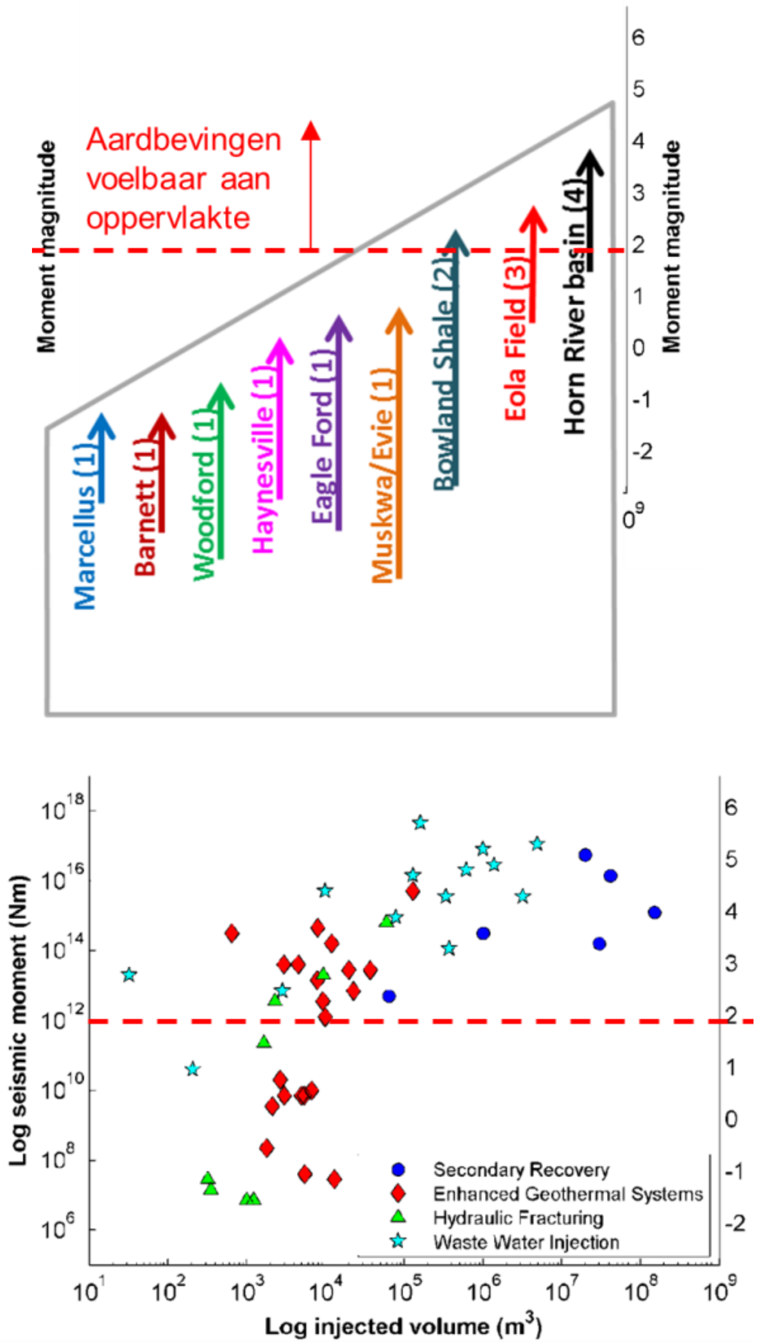


Figure 34 *Bottom figure*: relation between earthquake magnitudes (seismic moment M_0 and moment magnitude M_w) and injected volume for different types of fluid injection. *Top figure*: distribution in earthquake magnitude for different shale gas reserves in the US and Canada, 1- Warpinski 2012, 2- De Pater and Baisch 2011, 3- Holland 2011, 4- BC Oil and Gas Commission 2012 (Buijze et al. 2012).

The occurrence of induced seismicity in shale gas extraction

New insights relating to induced seismicity

Because in the United States and Canada to an increasing degree monitoring of seismicity with small magnitudes (M<1, hereinafter called micro-seismic monitoring) is used during fracking for shale gas extraction, a lot of data are available on induced seismicity. Recently a number of studies have been carried out that evaluate the occurrence of seismicity due to fracking and the extraction of shale gas (Maxwell et al, 2009; Downie et al, 2010; Warpinski, 2012; Davies et al. 2013; McGarr 2014). These studies focus mainly on evaluating earthquake magnitudes and the most important factors that determine the magnitude.

The most important new insights that these studies have provided relating to induced seismicity due to fracking and the extraction of shale gas are (see also Figure 34):

1. Seismicity in shale gas extraction in particular is measured during fracking.
2. For the vast majority of seismicity during fracking for shale gas $-3 < M_w < 1$ applies (data for 6 big shale gas reserves in the US, Warpinski, 2012; Davies et al. 2013).
3. The frequency and magnitude of induced seismicity vary considerably between different shale gas fields (and are therefore site-dependent).
4. Examples are known where fracking for shale gas extraction has given a maximum earthquake magnitude $M > 2$. The best documented are: (i) Horn River Basin in Canada ($M_L = 3.8$, BC Oil and Gas Commission 2012), (ii) Eola field in Oklahoma ($M = 2.8$, Holland 2011), (iii) Bowland shale near Blackpool, Lancashire in the United Kingdom ($M_w = 2.3$, De Pater and Baisch 2011).
5. The maximum earthquake magnitude increases with injection volume.
6. Because of the greater quantity of injected (frack) fluid earthquakes with higher magnitudes occur in particular in case of water injection for oil extraction (secondary recovery), when injecting used fracking fluid (waste water disposal), and when fracking for deep geothermal energy.
7. There are indicators in micro-seismic data that indicate whether earthquake magnitudes $M > 1$ can be expected: (i) a sudden increase in earthquake magnitudes (Wolhart et al. 2006), (ii) the lining up of hypocentres of earthquakes in orientations that deviate from the anticipated orientation of fracks (Norton et al. 2010), (iii) changes in frequency-magnitude relations (i.e. the b-value in Gutenberg-Richter relations; Kratz et al. 2012), (iv) changes in seismic efficiency (i.e. the ratio between the energy released by earthquakes and the energy added by fluid injection), (v) the seismogenic index that is a measure of the “sensitivity” of a particular site to the occurrence of induced seismicity (Shapiro et al. 2010). Indicators (i)-(iv) show that bigger fault structures are reactivated, and can be observed during fracking (real time monitoring). Indicator (v) describes the site-specific sensitivity to the occurrence of seismicity, and can be determined from existing shale gas extraction data from the same formations (the seismogenic index indicates how much of the theoretical potential seismic moment that is added to the geological system due to fluid injection also actually occurs as induced seismicity).

The effects of induced seismicity caused by the well, or the construction of underground or above-ground facilities are limited or not observed. The fact that shale gas extraction in the US or Canada often takes place in remote, sparsely populated areas, may play a part in the interpretation of the observations. Of the three well documented examples where fracking for shale gas extraction *itself* has caused a maximum earthquake magnitude $M > 2$, only for the $M_w = 2.3$ earthquake near Blackpool was deformation of the casing tube observed as a result of displacement along shale strata. This deformation did not cause problems with the well integrity or leaks (Green et al. 2010). The $M_L = 3.8$ earthquake in the Horn River Basin in Canada was felt, but, probably partly because of the lack of buildings in the region, did not lead to damage (BC Oil and Gas Commission 2012). The risk of deformation of the casing tube can be reduced by avoiding drilling near big natural faults, or by adjustments to the design of wells in problematic areas (Dusseault et al. 2001).

Seismic risks do however play an increasingly important part in the injection of large quantities of fluid into empty oil and gas fields using only new wells for disposing of flowback wastewater (Figure 34). Important examples of induced seismicity related to injection of wastewater are the earthquakes in the US related to injection of wastewater into an empty oil field near Prague (Oklahoma, US, Keranen et al. 2013). Another important example is the earthquakes related to injection of wastewater in an empty gas field near Zigong (SW Sichuan Basin, China, Lei et al. 2013). In both cases the occurrence of the earthquake seems among other things to do with the fact that the volume of injected fluid exceeded the maximum volume of oil produced, and that hence the critical pressure for large scale faults was exceeded. The injection of wastewater into aquifers or into empty oil or gas fields above the original reservoir pressure (from before the extraction) is not permitted in the Netherlands, therefore seismic risks as in Oklahoma or Zigong are not relevant for the current Dutch situation. In the Netherlands an earthquake of M_L=2.8 occurred near Weststellingwerf (De Hoeve) in the vicinity of injection of production water into an empty gas field. Seismic risks as a result of injection of wastewater can be entirely avoided by not injecting wastewater but discharging it above ground. Knowledge of experiences with the injection of wastewater from the US and Canada is important for reducing residual risks in shale gas extraction since it is responsible for the biggest earthquake magnitude related to fluid injection and it provides important information about the relation between injection volume and earthquake magnitude (Figure 34).

Analyses and measures to limit seismic risks

The most important analyses and measures that can be used *before* starting fracking and shale gas extraction to limit seismic risks are:

1. Site-specific analysis of the geological and geomechanical conditions of the subsoil. It is particularly important to determine whether it is likely that faults in the subsoil will reach a critical stress state and will move (reactivate) as a result of fracking and gas extraction. To determine this among other things analysis of the presence and properties of faults, local natural stress state in the subsoil, and properties of the shale and surrounding rock is needed. Also in some cases in the light of analyses of the natural seismicity an estimate can be made of the local seismic risks and the location of faults with a critical stress state.
2. Site-specific analysis of the shallow subsoil and top soil as regards soil conditions, population density and vulnerability of buildings. This analysis can be used to determine the possible effects of induced seismicity at different sites. The seismic risks can be limited by selecting extraction sites where these possible effects are minimal.
3. Planning of wells and fracking in the subsoil at a safe distance from big natural faults. Induced seismicity with $M > 2$ is caused by the reactivation of natural faults with a length of approximately one hundred metres (which does greatly depend on the section of the fault that moves). The cause of the reactivation of these faults is that the fluid pressure in the fracture zone or stress state of the fault changes due to the injection of fluid. The change in fluid pressure or stress may take place directly due to connection between fracks and the faults) or indirectly (due to changes in the vicinity of the fracture zone). An estimate of the safe distance can be made beforehand using a geological model and models that predict the dimensions of fracks in the subsoil. From geological models the location and displacement of the fault, and hence the dimensions of the fracture zone, can be determined. For these analyses one must take into account assumptions and uncertainties in the models.
4. Limiting the quantity of fracking fluid injected. The maximum earthquake magnitude increases with the injection volume (Figure 34). This is caused because by increasing injection volumes the disturbance of the pressure and stress in the subsoil increases, and because the chance that big natural faults are affected is greater. Limiting the quantity of fracking fluid injected can have a negative effect on gas production because the stimulated reservoir volume is reduced. It is therefore important before using geological models and models that predict the dimensions of fracks in the subsoil, to determine the optimum quantity of fracking fluid injected.

The most important method that can be used *during* fracking and gas extraction to limit seismic risks, is (micro-)seismic monitoring. As described above micro-seismic data can be used to determine indicators that indicate whether bigger fracture structures are reactivated. Seismic risks can be limited using seismic monitoring by implementing a “traffic light” or “hand on the valve” method (among others, Bommer et al. 2006), where extraction activities are temporarily stopped or suspended if seismicity exceeds a certain magnitude of intensity (Green et al. 2010). Also if there is a threat of it being exceeded mitigating measures can be carried out such as the recovery of fluids.

Status of technologies and knowledge gaps

This section gives an overview of the technologies and a number of specific methods that can be used *before* and *during* fracking or the extraction of shale gas to analyse and where necessary to limit seismic risks. An indication is given of possible uses in the United States, Canada and the Netherlands, linked to Technology Readiness Level (TRL, see Approach & Accountability).

(Conventional) technology in current practice (international and in particular in the United States and Canada)
Site-specific analysis of the geological and geomechanical conditions of the subsoil are often used both in the United States and Canada and in the Netherlands to determine seismic risks in (shale) gas extraction, gas storage, or geothermal energy (Wassing et al. 2012; Orlic et al. 2014). Different types of techniques can be used for this, including (1) geological mapping and modelling, (2) analyses of seismic surveys (2D or 3D), drilling data and stress state, and (3) geomechanical models of fracking and fault movement (all TRL9).

Micro-seismic monitoring *during fracking* is a much used technology in the United States and Canada (TRL9), but is not used in conventional gas extraction in the Netherlands. Long term seismic monitoring is however used in the Netherlands, among other things for gas storage in Bergermeer and gas extraction in Groningen. Furthermore in current practice micro-seismic monitoring in the United States and Canada is used in particular for optimising fracking and the extraction of shale gas, and rarely or never for actual intervention to limit these seismic risks. The micro-seismic data are however much studied to explain the occurrence of induced seismicity and hence to increase knowledge about the effect of fracking in the subsoil (among others, Maxwell et al. 2009; Warpinski 2012).

In the US and Canada protocols are recommended for managing seismic risks (Majer et al. 2008, NRC 2014). These protocols consist of the different combination of analyses and measures that are described in the section on “*Analyses and measures to* limit seismic risks ”. Seismic risks can best be limited with a combination of the site-specific analyses mentioned, a shale gas development plan that for planning wells and fracking takes into account the prevention of induced seismicity, minimising the quantity of fracking fluid, monitoring micro-seismicity during fracking and shale gas extraction, and implementing a “traffic light” or “hand on the valve” method.

(Niche) technologies that are still rarely used, but are already available on the market and their possible impact on minimising the (residual) risks of shale gas
Other measures such as planning of wells and fracking in the subsoil at a safe distance from big natural faults and limiting the quantity of fracking fluid injected are rarely used in current practice in the United States and Canada (TRL6-7). In addition to legislation and regulations the principal reasons for this seem to be that there are still only a limited number of well documented examples where fracking for shale gas extraction has *itself* caused a maximum earthquake magnitude of $M > 2$, and that shale gas extraction often takes place in remote areas. Among other things because of the population density planning of wells and fracking in the Netherlands will play a more important part (EBN 2011-2012).

The most important developments of (niche) technologies that can be used for analysing and limiting seismic risks focus on improving monitoring technology (on the earth's surface or in monitoring wells), the design of seismic monitoring networks, and the processing and interpretation of (micro-)seismic data (TRL1-4 for different techniques). These developments are particularly important for improving the seismic resolution during fracking so that the site of hypocentres, the growth of fracks and reactivation of small natural faults, and possible leaks along wells can be detected better.

<u>Inventory of current technologies from other industries that may be relevant for minimising the (residual) risks of shale gas</u>
Because of the occurrence of seismicity with relatively high magnitudes (see Figure 34) there is a lot of knowledge from geothermal energy about measures for limiting seismic risks, above all about the "traffic light" system (Bommer et al. 2006) and statistical models that can be used (Bachmann et al. 2011; Shapiro et al. 2010; Gischig and Wiemer 2013). Good examples have for example been investigated in the FP7 project GEISER about "*Geothermal Engineering Integrating Mitigation of Induced Seismicity in Reservoirs*" (see www.geiser-fp7.fr). Limiting seismic risks in some cases also plays an important part in conventional gas extraction, and in underground storage of gas or CO_2 (Figure 34; Davies et al. 2012; McGarr 2014; Orlic et al. 2013). The technologies used or proposed for this are not appreciably different, or less developed than for extraction of shale gas.

<u>Developments and technologies that will be available in the (near) future and their effect on minimising the (residual) risks of shale gas</u>
Apart from technological development in the area of micro-seismic monitoring, the most important added value for minimising the (residual) risks of shale gas is to be achieved from better integration of geological and geomechanical models of the subsoil with micro-seismic data (TRL6-7). In particular continuous and real time improvement of predictive models and adjustment of fracking activities in the light of micro-seismic data (history matching, TRL1-4) can be used to increase the knowledge of the disturbance in the subsoil and to limit seismic risks. There may also be a role for alternative methods of monitoring (for example electrical or thermal, and monitoring *in* the well, TRL3-5), alternative methods for stimulation that can replace fracking (for example innovative drilling techniques; see section 5), or more efficient fracking fluids so smaller volumes are necessary. Seismic risks can be further minimised with these methods.

<u>Gaps in knowledge and technology specific to the Netherlands and taking into account (period of) possible usability</u>
The most important gap in knowledge specific to the Netherlands is site-specific knowledge of the subsoil relating to shale gas reserves (Posidonia Formation and in particular the Geverik Member), particularly as regards (geomechanical) rock properties of the shales, local stress state, and properties of faults. Although there is still scope for additional research into the site-specific properties of Dutch shales and predictive geomechanical modelling of the effects of fracking in the subsoil in the light of existing data (period 1-3 years), data from new wells, analyses of new sample material, and (laboratory) tests on new sample material are needed to fill this knowledge gap (period 3-5 years, depending on licensing).

Appendix I: Combination with Geothermal energy

1.1 Configuration of a conventional geothermal well

Figure 35 shows the design of a typical geothermal well, in this case the Den Haag doublet. A doublet consists of two wells into the same geological formation. A second well (minimum) is therefore always necessary. The hot water namely flows into the production well (so the hot water is raised) via the screen at the bottom of the well (wire wrapped screen or gravel pack). The water then flows through the casing to the surface. Vice versa the cooled water flow is injected through the casing into the second well, the so-called injection well, via the screen or gravel pack into the reservoir. An electric submersible pump (ESP) is necessary to transport the water upwards into the production well (U.S. Department of Energy, 2007). The cross-section of the well varies in stages from approx. 34 cm (13 3/8") at ground level (the conductor tube) to approx. 14 cm (5½") by the screen at the bottom of the well (in the Netherlands) at a depth of approx. 2 to 3 kilometres. The big diameter of the well at the top is necessary to fit the ESP. This is in general suspended so deep that the pressure is above bubble point pressure. This is done to prevent bubbles occurring in the fluid so the efficiency of the pump is reduced. The depth in the Dutch situation is approx. around 500 to 700 metres. The exact choice of diameter of the well at reservoir level may differ based on the required size of the flow rate, in combination with the reservoir properties. A bigger diameter at the bottom the well facilitates inflow into the well. Other well configurations are also possible.

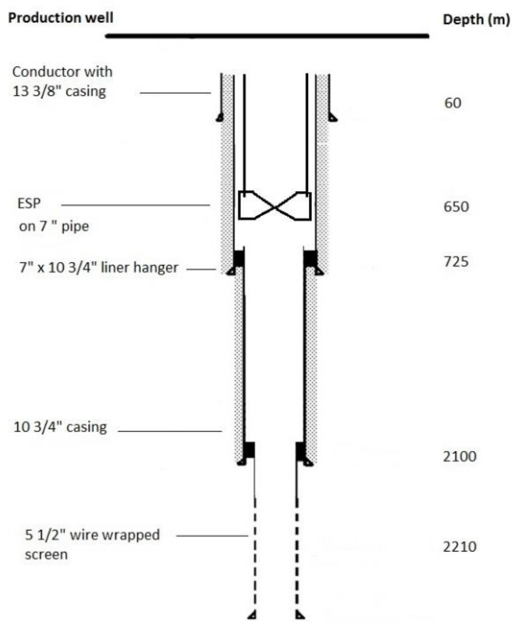


Figure 35 Geothermal energy production well of the Den Haag doublet (according to DWA, E.ON Benelux & IF Technology (2008) and Schoof (2013).

Differences between shale gas and geothermal wells
Geothermal wells have a bigger diameter than shale gas wells. This is because a geothermal well needs a big flow rate (in volume) to generate sufficient energy in order to be economic (U.S. Department of Energy, 2007). In addition in a geothermal well an ESP is necessary to bring up the water, while (shale) gas is so light that it requires no artificial lift (U.S. Department of Energy, 2007; Devold, 2006). The ESP is at a depth of approx. 500 to 700 metres, and is hung from a production tube that is lowered from the surface. Shale gas wells are drilled horizontally at reservoir level to make the contact area with the reservoir rock as great as possible. Geothermal wells are at present drilled vertically or deviated. Plans exist to drill the reservoir section for a geothermal well horizontally (if the reservoir is very thin) but have not yet been carried out. Finally the water flows into a geothermal well through the (wide) casing while in a gas well the gas flows through a (thin) production tube, that is located in a production casing (11.4 (4½") or 14.0 cm (5½") wide).

Conversion of a shale gas well to a geothermal well
In a shale gas well the gas flows via a relatively thin production tube to the surface. In principle it is possible to use the production tube for geothermal energy, but generally a gas production casing is too narrow to carry the big volume of water without big friction losses. Furthermore in each case part of the production tube must be removed in order to fit the ESP at a depth. The ESPs used in geothermal energy fit and function best in a wide casing (40 cm or 13 3/8", Polsky et al., 2008). This therefore means that not only must the production tube be removed, but probably also the production casing and one or more wider casings. ESPs exist in diameters of 8.9 cm (3.5”) to 25.4 cm (10”: source: Wikipedia). This means that the narrowest pumps in principle also fit in the production casing but these are probably also the pumps with a relatively small capacity. Finally all the equipment used for gas production must be removed, as normally happens when abandoning a gas well.

A geothermal doublet in the Netherlands generally consists of two or three wells, through which a large flow rate is pumped. A shale gas extraction comprises a large number of wells that are all geared to a low flow rate. In principle it is possible to design a system that consists of more than three wells with a small diameter. An ESP must then be inserted in all producers. This is probably not economically feasible because of the greater number of (expensive) pumps required, and the big friction losses.
It must be determined for each project whether the small diameter of the gas production tube and the hence associated negative effect on the production of the water (friction losses) must be offset against the costs of the removal of the production tube.

Aquifer is located above the shale gas reservoir
If this is done, only the well remains with its tubing which is perforated at the bottom. The perforations must be cemented and the non-cased section of the formation (the open hole) must be plugged with cement (Jahn et al., 2008). The geothermal energy reservoir can then be perforated. The target aquifers in the Netherlands are sometimes moderately or poorly consolidated. Production of water with a large flow rate can then lead to the production of sediment granules (fines). In such a case it is better to drill a sidetrack and fit this with a screen of the right pore size, as can be seen in Figure 36 (Jahn et al., 2008). Finally the pump is installed at the required depth.

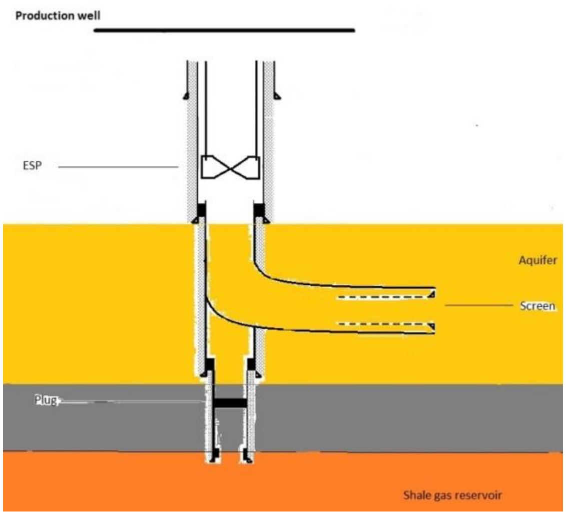


Figure 36 Conversion of a shale gas to a geothermal well for unconsolidated aquifers (adapted based on DWA, E.ON Benelux & IF Technology (2008) and Schoof (2013).

Aquifer is located under the shale gas reservoir
Where the target aquifer is located under the shale gas reservoir, first the reservoir section of the shale gas well no longer to be used must be completed as described above. Then the well must be deepened into the aquifer by drilling a sidetrack. The depth of the kickoff point of the sidetrack is partly determined by the minimum required diameter for the geothermal well (which again depends on the required flow rate). Then the well can be completed like a conventional geothermal well.

Risk
The risk of all the changes in the well configuration mentioned (deepening or drilling a sidetrack, cementing or plugging, perforation, fitting / removal of the production tube, fitting an ESP) are the same as for regular workovers in the oil and gas industry, and can lead to the jamming or breaking off of the drilling equipment, and ultimately the loss of the well. As long as the integrity of the casing is ensured, there is no risk of contamination of groundwater.

Shale gas wells generally have a relatively short planned life cycle. The steel used must meet stringent (strength) requirements, because the wells are fracked. Geothermal doublets are, to date and in the Netherlands, not fracked, but have a longer planned life cycle (both economic and technical) of approx. 30 to 50 years.

When it is planned to convert a shale gas well to a geothermal well, the construction must take into account the fact that the cement and steel have to last longer. Another factor is that the produced formation water in the geothermal well is often corrosive, which is an extra load on both the casing and the cement used – possibly both the casing steel and cement used in a geothermal well must meet different requirements to those in a shale gas well (where the steel in a shale gas well must in particular be strong, in a geothermal well it must be corrosion resistant and/or thick-walled). The corrosion risk depends on the composition of the formation water, which differs considerably from one place to another, in combination with the type of steel that is used in the installation. Alternatively corrosion protection or preventive measures can be taken, such as the use of inhibitors or coating, sacrificial anodes, etc.

Use of infrastructure for other purposes

On the site of shale gas extraction little infrastructure is present during the production phase. At the time of the construction of the extraction a transport pipeline may possibly be laid for the water that is necessary for fracking, to prevent nuisance from heavy traffic. At the time of extraction the gas extracted is transported with a pipeline to the gas distribution network or to a gas treatment plant. On the surface in addition only the wellheads and possibly a gas separation installation (for separating gas and produced water) are present.

The current doublets in the Netherlands are all built on the site where the heat demand is. In most cases this is a greenhouse or greenhouse complex, in the case of the Den Haag doublet this had to be an urban area to be heated. The above-ground infrastructure therefore consists of the local hot water distribution network. In some cases so much gas is produced with the hot water that this is removed from the water with a gas separation installation.

Transport of hot water over long distances is undesirable because of cooling. A gas pipeline to transport hot water to another site is therefore not worthwhile. A geothermal doublet on the site of shale gas extraction needs a local heat demand (greenhouses or industry).

A gas separation installation for shale gas extraction assumes a mixture of a lot of gas and little water. Most geothermal doublets in the Netherlands have a GWR (Gas Water Ratio) of approx. 1, which means that, under atmospheric conditions, approx. 1 cubic metre of water is produced per 1 cubic metre of gas. It is also true that it is sometimes desirable not to degas the water, because in this way the chemistry of the formation water changes less, so the water is less corrosive. In this latter case a gas separation installation is not necessary.