# The Oil and Gas Law Review

Second Edition

Editor
Christopher B Strong

Law Business Research

# The Oil and Gas Law Review

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# The Oil and Gas Law Review

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Christopher B Strong

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# EDITOR'S PREFACE

It is a privilege to have been able to participate in the second edition of *The Oil and Gas Law Review*. As with all the titles in this series, this volume is intended to serve as a practical reference for attorneys working in the oil and gas field, whether they are in private practice, in-house at energy companies, in government service or in academia. I would like to thank all of the contributing authors for providing excellent articles describing the legal regime for oil and gas within their respective jurisdictions, together with updates of notable recent developments.

*The Oil and Gas Law Review* is divided into 29 chapters, each covering a different jurisdiction. The authors of the chapters have been chosen on the basis of their demonstrated expertise within their jurisdiction. In selecting the jurisdictions to be covered by this volume, we have tried to ensure that our coverage is as broad as possible, with representation across most of the major producing regions.

Some of the most exciting legal developments in the oil and gas space in recent years relate to jurisdictions that have newly opened up to foreign investment, whether through the discovery of new producing basins in regions that previously had no significant oil and gas activity or through legal changes in jurisdictions that had previously been closed to foreign investment. Mexico is a prime example. Although its hydrocarbon industry is well established, since the late 1930s it had been closed to foreign investment and monopolised by state-owned producer PEMEX. All of that changed with the reforms that were passed late in 2013 and implemented over the course of 2014, with a carefully crafted legal regime designed to attract foreign investment while safeguarding the interests of the people of Mexico. For those readers interested in developments in Mexico or industry regulation in general, I would highly recommend the excellent chapter contributed by Carlos Ramos Miranda and Miguel Ángel Mateo Simón.

Among the jurisdictions with newly discovered petroleum reserves, I should mention Israel and Mozambique. Hardly on the radar a few years ago, recent offshore discoveries in those jurisdictions promise to be transformational, and each of these jurisdictions continues to develop its legal regime in order to adapt to fast-moving developments. Of particular note is Mozambique's new Petroleum Law, which came into effect shortly before publication of this volume and will no doubt be of significant interest to practitioners advising clients there.

Established jurisdictions have seen significant developments as well. For example, Norway had new tax rates come into effect, while the implementation of the recommendations of the UK's Wood Review promises to have a significant impact on operators in the UK's North Sea. On the other hand, Nigeria's long-awaited Petroleum Industry Bill still awaits passage. Perhaps it can be covered in a future edition of this volume.

Developments like those mentioned above are precisely what make international oil and gas law so challenging. We hope that by summarising developments in as many jurisdictions as possible, we can provide a useful resource for practitioners.

**Christopher B Strong**
Vinson & Elkins LLP
November 2014

# Chapter 20

# NETHERLANDS

*Roland de Vlam and Rogier Sterk*[1]

## I INTRODUCTION

### i Reserves and production levels overview

***Reserves***[2]

With onshore oil and gas production having started in the late 1950s and offshore production in the 1960s, the Netherlands has a mature hydrocarbon economy supported by a stable regulatory environment supportive of foreign and domestic investments alike. It is among the largest gas producers in Europe.[3]

In 1959 the huge onshore Groningen gas field, consisting of low calorific natural gas,[4] was discovered. The Groningen field is the largest gas field in Europe and among the 10 largest in the world. Down to approximately one-third of its original levels, it is estimated to have remaining recoverable reserves of around 774 billion standard cubic metres ($Sm^3$).[5] Total remaining recoverable amounts in developed and undeveloped fields are estimated at around 1,044 billion $Sm^3$. The non-Groningen reserves, consisting of high calorific gas, used in gas-fired power plants and in installations of (57) large industrial consumers, are dispersed over onshore and nearshore fields on Dutch territory (139 billion $Sm^3$)[6] and offshore fields on the Dutch part of the continental shelf (131

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1 Roland de Vlam is an attorney-at-law and Rogier Sterk is a tax advisor at Loyens & Loeff NV. The authors wish to thank Elisabetta Aarts and Yu An Chan for their work on this chapter.

2 As at 1 January 2014. Source: www.nlog.nl (annual report 2013).

3 Together with Russia, Europe's largest producer, and Norway.

4 Due to its relatively high (14 per cent) nitrogen content, the content of carbon hydrates in Groningen gas is relatively low, reducing its calorific value.

5 'Standard' refers to natural gas at 15 degrees centigrade and a pressure of 101,325 kiloPascal (kPa).

6 Exclusive of residual gas in fields converted to UGS at time of conversion.

billion $Sm^3$). The non-Groningen gas fields are commonly referred to as 'small fields', discussed in more detail below.

Oil reserves are estimated at a relatively minor 47.1 million $Sm^3$, predominantly in fields on Dutch territory, close to 50 per cent of which are as yet undeveloped.

The total area available for hydrocarbon licensing on Dutch territory (including territorial waters extending 12 nautical miles from the coastline) is just under 42,000km². On the Dutch part of the continental shelf this is close to 57,000km².

***Production levels***[7]

Total natural gas production on Dutch territory amounted to a little under 67 billion $Sm^3$ in 2013, with the Groningen field accounting for 57 billion $Sm^3$. Production from territorial small fields was up 5 per cent from 2012 levels. On the Dutch part of the continental shelf production approached 18 billion $Sm^3$.

Oilfield production in 2013 amounted to 1.3 million $Sm^3$, with 710,000 $Sm^3$ produced on the Dutch part of the continental shelf.

### ii Infrastructure

***Offshore gas pipeline infrastructure***

The Dutch offshore sector boasts a well-developed infrastructure to evacuate North Sea gas to shore. The 1970s saw the construction of the major Noord Gas Transport (NGT) and West Gas Transport (WGT) systems. The Northern Offshore Gas Transport (NOGAT) trunk line was constructed in the early 1990s and interconnects with Danish and German continental shelf pipeline systems. GDF Suez divested its interest in NOGAT to Dutch pension provider PGGM in September 2013. TAQA sold its 40 per cent interest in NGT to PensionDanmark in November 2013.

***Onshore gas pipeline infrastructure***

The Netherlands has a highly meshed onshore gas network for distributing gas to household consumers, industry and gas-fired power stations. The backbone high-pressure transmission network is owned by NV Nederlandse Gasunie (Gasunie) and operated by national gas transmission system operator Gasunie Transport Services BV (GTS). It is interconnected with neighbouring Belgian and German gas networks as well as with the UK through a 235 kilometre pipeline (BBL), running between Balgzand (Netherlands) and Bacton (UK).[8]

The transmission network comprises two separate systems: a system for transportation of Groningen (low-calorific) gas and a system for transportation of high-calorific gas, such as that originating from domestic small fields, LNG, Norway and Russia, servicing large-scale power stations and large industries.

---

7 As at 1 January 2014. Source: www.nlog.nl.

8 The pipeline is owned and operated by BBL Company, which is an incorporated joint venture of Gasunie (60 per cent), E.ON Ruhrgas (Germany) (20 per cent) and Fluxys (Belgium) (20 per cent).

The regional networks are owned and operated by regional distribution system operators (whose ownership is by law retained to public bodies). Both GTS and regional operators are unbundled from production, trade and supply, and manage the network subject to a fully regulated third-party access regime, on the basis of *ex ante* access and tariff regulation by the Netherlands Authority for Consumers and Markets (ACM), the designated national regulatory authority to oversee the functioning of the gas and electricity markets against the backdrop of the EU liberalisation framework.[9]

*Liquefied natural gas (LNG)*

To date, the Gate LNG facility at the Maasvlakte in Rotterdam with throughput capacity of 12 billion $m^3$, expandable to 16 billion $m^3$, developed by Gasunie and Vopak, is the only LNG terminal in the Netherlands. No plans for additional LNG processing capacity have been disclosed to the market. At the time of the Gate terminal development, two other initiatives were called off due to a lacklustre appetite in the market for LNG throughput capacity.

*Gas storage*

The Netherlands has operational underground gas storage in depleted fields at Norg and Grijpskerk, owned by NAM. A peak gas installation is operated at a depleted high calorific gas field near Alkmaar, now storing low-calorific gas to accommodate peak demand in household consumption.

Four recently built gas storage facilities are operated in salt caverns near Zuidwending, with three additional caverns in the process of being prepared for storage.

Designed to process a working gas volume of 4.1 billion $Sm^3$, the fully licensed gas storage at Bergermeer will be the largest open-access gas storage facility in Europe. Partial operational commercial operations have started since April 2014. The facility is scheduled to be fully completed in 2015.

Certain underground gas storage facilities in salt caverns in Epe, Germany, service the Dutch market and are directly connected across the Dutch–German border to the Dutch transmission system.

*Onshore oil pipelines*

A pipeline with a capacity of 15.8 tons[10] runs from Rotterdam Europoort eastward to Venlo on the Dutch–German border. Divided into two branches, it services refineries in Germany at Gelsenkirchen on one branch and Godorf and Wesseling on the other.

9 ACM is also the Dutch competition authority, formerly known by its Dutch acronym NMa. With effect from 1 April 2013 NMa, the telecommunications authority OPTA and the consumer protection authority merged to form the ACM.

10 The pipeline is owned by NV Rotterdam-Rijn Pijpleiding, which is jointly held by Shell (45.6 per cent), Shell Deutschland (10 per cent), Ruhr Öl (22.2 per cent), andBP Olex (22.2 per cent).

Another pipeline with a capacity of 28 million tons[11] transports crude oil imported at Rotterdam to refineries at Antwerp in Belgium.

A pipeline from Rotterdam to Vlissingen on the south-west coast supplies crude oil imported at Europoort to the Dow/Total refinery at Vlissingen.

*Offshore oil pipelines*

A Chevron-operated pipeline carries crude produced offshore to IJmuiden on the Dutch coast. A TAQA-operated pipeline carries condensate produced offshore to Europoort, Rotterdam.

*Refineries*

The Netherlands is the most important refining centre in Europe. It has six refineries. Four refineries, two of which count among the largest in Europe, are situated in the Port of Rotterdam area.

### iii Government policies

*Historic overview*

Gasunie, starting out as a single integrated company responsible for the purchase of all indigenously produced gas, its distribution within the Netherlands and its export to neighbouring countries, was established on 6 April 1963, with shares owned by the Dutch state (10 per cent), Dutch State Mines (now EBN) (40 per cent), ExxonMobil (25 per cent) and Shell (25 per cent). In that same year a concession still in force to produce the Groningen field was granted to the Groningen Partnership, a joint venture of Nederlandse Aardolie Maatschappij BV (NAM) (60 per cent) and EBN (40 per cent, non-operated). NAM is currently jointly owned in equal shares by Exxon Mobil and Shell.

*Market liberalisation*

In the wake of EU-driven gas market liberalisation and infrastructure unbundling, within Gasunie different organisations were formed followed by a functional split in January 2002. In 2005 Gasunie, converting to a holding company, split off its trading business to Gasunie Trade & Supply BV, renamed GasTerra BV in 2006, and its transmission business to GTS, which was appointed as transmission system operator under the Gas Act of 2000. GasTerra was hived off to ExxonMobil and Shell, which both hold a 25 per cent stake, and the state, which holds 10 per cent of the shares directly and 40 per cent through EBN.

GasTerra, as successor to Gasunie's trade and supply business, through its supply to retailers and large industries, continues to dominate the domestic gas market, as is reflected in certain provisions in the Dutch Gas Act, discussed below. At the same time it is a significant player on the European stage. GTS has remained a fully owned subsidiary of Gasunie, which itself became wholly owned by the Dutch state following

11 The pipeline is owned through Rotterdam Antwerpen-Pijpleiding NV by Total, as the majority shareholder, and ExxonMobil.

the aforementioned split-off and GasTerra hive-off. Gasunie has retained legal and beneficial ownership of the transmission network, operated by GTS.

In the previous edition of this book we reported on the study by the previous government on a minority privatisation of Gasunie and the electricity transmission grid operator TenneT. The current administration, however, has abandoned the idea of a privatisation and has proposed the possibility for TenneT and Gasunie to enter into strategic joint ventures with other TSOs that are in compliance with the EU Directives.[12]

*Small fields*

To extend the life of the Groningen field the government decided as early as 1974[13] that it would encourage exploration and development of smaller gas fields (the Small Fields Policy). The policy, which comprises (financial) incentives for small field development and marketability of small field production on the one hand and government-controlled depletion of the Groningen field on the other, has been consolidated in the Gas Act and is discussed in more detail in Section II.i, *infra*.

*Gas transportation hub (gas roundabout)*

With the Groningen field depleted to about one-third of original levels and small fields on average in decline since the turn of the century, government policies with respect to natural gas have since 2005 shifted to positioning the Netherlands as north-west Europe's 'gas roundabout' (i.e., a gas infrastructure hub offering transport, transit and storage for the north-west European gas region).[14] The overarching goals of this policy, which builds on the favourable geographic characteristics of the Netherlands, its well-developed gas transportation and storage infrastructure, gas trading expertise and centres of expertise throughout the value chain, are described as enhancing security of supply and fostering economic growth. The government informs the Second Chamber of Dutch Parliament of developments in bi-annual progress reports.[15] At the time of writing, the report had not yet been published. Committed gas-roundabout investment between 2005 and 2014 amounts to €8.3 billion: €7.9 billion through Gasunie and €0.4 billion through EBN. In 2010 investments totalled €7.2 billion.[16]

12 Second Chamber, 2013-2014, 28 165, No. 176.

13 Second Chamber, 1974–1975, 13 122, Nos. 1-2. The Small Fields Policy is not indicated as such or by that name. It was embedded in the first Energy Paper (Energienota), setting out an integral energy policy for the first time.

14 Cf. letter of the Minister of Economic Affairs to the Second Chamber, Second Chamber, 2005–2006, 29 023, No. 22.

15 Second Chamber 2009–2010, 29 023, No. 73, Second Chamber, 2011-2012, 29 023, No. 112.

16 Cf. Netherlands Court of Audit report of 11 June 2012, Second Chamber, 2011–2012, 33 292, Nos. 1-2, p. 40 et seq.

### iv Current issues

The pros and cons of shale gas initiatives and concerns over subsidence and earthquakes in Groningen as a result of production activities have dominated the public debate in the past year and further examinations and political positioning on these subjects are expected for the coming years. See Section IX, *infra*.

## II LEGAL AND REGULATORY FRAMEWORK

### i Domestic oil and gas regulation

*Mining Act (2003)*[17]

*General*

The current Mining Act became effective on 1 January 2003 and has since been changed to include additional provisions on fallow acreage (2010) and carbon dioxide storage (2011). Article 2(2) of the Mining Act applies to minerals[18] to the extent these occur at a depth of more than 100 metres beneath the earth's surface.

*Licensing*

The current Mining Act has introduced a uniform licensing regime for onshore and offshore licensing. The Act distinguishes licences for various onshore and offshore activities:

*a* exploration of minerals (including hydrocarbons) and geothermal energy;
*b* production of minerals (including hydrocarbons) and geothermal energy;
*c* underground storage;
*d* underground carbon dioxide storage suitability appraisals; and
*e* underground carbon dioxide storage.

Hydrocarbon exploration and production licensing will be discussed in more detail in Section III, *infra*.

*State participation*

The Mining Act and its predecessors charge the Dutch state with the task of participating directly in hydrocarbons exploration and production activities through EBN (40 per cent under the Mining Act, 50 per cent in a number of older licences, issued between 1976 and 1995). If requested by the holder of an exploration permit, EBN must collaborate in the establishment of an exploration agreement. Following discovery of economically

17 The term 'onshore' in paragraphs referring to the Mining Act and subordinate mining regulations generally includes the land-side of the Dutch territorial seabed. The term 'offshore' generally refers to the sea-side, of the Dutch territorial seabed, in addition to the Dutch part of the North Sea continental shelf.

18 Defined as subsoil minerals or substances of organic origin, in solid, liquid or gaseous form present in naturally grown concentrations or deposits, with the exception of marsh gas, limestone, gravel, sand, clay, shells and mixtures thereof.

recoverable reserves and the ensuing issuance of a production licence, the licensee must enter into a cooperation agreement with EBN within one year from the issuance of the licence. The Minister of Economic Affairs (MEA) may grant an exemption to this obligation only if by EBN's entering into an agreement the state could reasonably be estimated to suffer financial loss. The MEA may extend the one-year term for a further year. The cooperation agreement is subject to approval from the MEA. EBN thus acts as an independent (non-operating) partner in the majority of Dutch fields. Upon the acquisition of its participating interest, EBN must reimburse licence holders at a percentage equal to the interest, for the expenditures they incurred in exploration for and appraisal of the prospect, and any further capital investment in production facilities. As a rule the consideration includes investments in business assets, exploration expenses and an interest component.

*Fallow acreage*

To stimulate activity on licensed offshore fallow acreage, a change to the Mining Act empowered the MEA to review the delineation and decrease a licence area where no significant activities have taken place for two consecutive years. In the run-up to this legislative change the industry entered into a fallow acreage covenant with the MEA. The covenant provides for a step-by-step procedural approach to the use of the Minister's statutory powers and a new marginal fields tax incentive (see Section VI.iii, *infra*) in exchange for the Minister's new powers. The legislative changes entered into force on 1 January 2010 (acreage revision) and 16 September 2010 (tax incentive).

*Mining Act financial provisions*

The Mining Act applies a rental fee based on square kilometres for hydrocarbons exploration and production offshore, as well as for production onshore. Fees are indexed (commensurate with wage index as defined by royal decree). Applying to onshore production, a one-time fee, increasing with the size of the area in use for production installations (i.e., not the production licence area), is due to the province where production takes place.

Of considerably greater import is the state profit share (SPS), applying to profits made on onshore and offshore hydrocarbons production (both on Dutch territory and on the Dutch continental shelf), and turnover-based royalty rates, both of which are discussed in Section VI, *infra*.

*Mining Damage Guarantee Fund*

Mining companies active in onshore mining activities must annually contribute to the Mining Damage Guarantee Fund. The fund pays out as a matter of last resort (i.e., in cases of insolvency or where the liable company has ceased to exist). It only pays out to natural persons having incurred property damage as a result of mining activities.

***Dutch Gas Act (2000)***

*General*

The Gas Act, which became effective in 2000, as amended, implemented EU regulations on market liberalisation, security of supply, independent and non-discriminatory gas network operation, a fully regulated third-party access regime for access to domestic gas pipelines, domestic gas network ownership unbundling and, pursuant to EU sector regulation, the designation of ACM as an independent regulatory authority (see Section I.ii, *supra*).

*Small fields policy elements*

The Gas Act obliges GasTerra to take off the gas produced at the Groningen field. Under the Small Fields Policy, small fields are produced preferentially to relieve load on the Groningen field, which is conserved as a strategic reserve and used as swing producer.

The policy has been consolidated in the Gas Act, which lays down the statutory obligation for GasTerra to purchase the gas produced from small fields against a market conforming price, when gas is offered to it. The MEA may temporarily release GasTerra from this obligation for economic and financial reasons.

GTS must take in and transport downstream gas from all onshore and offshore fields, including small fields. The Gas Act secures that GTS will at all times be financially capable of investing in required transmission infrastructure, provided the MEA decides that the investment is necessary for systematic management of natural gas deposits. If the MEA decides that this is not the case, GTS need not accept the gas from the field in question. In that case GasTerra is equally relieved from its obligation to purchase such gas offered to it.

Subject to *ex post* supervision by ACM and the power of the MEA to adopt rules by ministerial decree *ex ante*,[19] GTS may unilaterally set the conditions for acceptance of natural gas into the transmission system.

Reinforcing the Groningen field's reserve and balancing function, the Gas Act instructs the MEA to set a production ceiling for the Groningen field at least once every five years. For 2006 to 2015 the ceiling has been set at 425 billion $Sm^3$ (or an annual average of 42.5 billion $Sm^3$).

*Gas specs*

A increasingly pressing problem is presented by the gradual change in the specifications of natural gas fed into and transported through the domestic grid as a result of the decline of small field gas production, an increased share in domestic consumption of natural gases imported from Norway and Russia, the import of LNG at the Rotterdam Gate Terminal[20] and increased volumes of injected renewable gas (derived from biogas). The MEA, GTS and Gate Terminal have agreed on transitional arrangements, to keep high calorific gas at current specs,[21] to be extended (for a third time) to October 2014 to allow

19 Decree of the Minister of Economic Affairs of 11 July 2014 regarding the establishment of rules regarding the quality of gas (Government Gazette 2014, No. 20452). This ministerial decree entered into force on 1 October 2014.

20 The calorific value of gasses from Norway and Russia and those imported at Gate Terminal is usually higher than the (high-calorific) gas produced from domestic small fields.

21 Notably a Wobbe index maximum of 54 $MJ/m^3$ to be maintained by GTS and a propane equivalent (or PE) rate of maximally 8.7 per cent for LNG imported by Gate.

large industrial consumers taking gas directly from GTS's high calorific transportation network to have their installations refitted to deal with changing gas quality.[22]

*Petroleum Products (Stockpiling) Act (2012)*
Implementing EU Directive 2009/119/EC on the obligation of EU Member States to maintain minimum stocks of crude oil or petroleum products, the 2012 Petroleum Products (Stockpiling) Act 2012 requires the Netherlands to maintain stocks (the 'statutory stock') of crude oil or crude oil products corresponding to at least 90 days of average daily net imports or 61 days of average daily inland consumption, whichever is the greater (normally the former). Such stocks are to be maintained in the Netherlands or a Member State of the European Union by the state-owned Netherlands National Petroleum Stockpiling Agency (COVA) (around 80 per cent) and by relevant market participants.

Subject to certain statutory conditions and consents, a market participant may transfer its obligation to maintain a stock of products as part of the statutory stock to COVA, which must accept the transfer at cost price, or a company established in the Netherlands or another EU Member State.

At least one-third of national stocks must consist of motor gasoline, gas/diesel oil and kerosene-type jet fuel. To the extent that COVA or market participants do not have sufficient stock to fulfil their obligations, they may book stocks available at third parties ('ticketing'). Ticketing of stocks held by third parties that are not established in an EU Member State is only permitted provided the country of establishment of the third party is a member of the International Energy Agency and the Netherlands has entered into a bilateral agreement with such country.

### ii Upstream oil and gas regulatory powers

***General***

The Mining Act gives principal regulatory powers in upstream oil and gas, apart from environment and planning in general,[23] to the MEA and the State Supervision of Mines (SSM). The SSM falls under the competence of the MEA.

Two statutorily established advisory bodies – the Mining Council and the Technical Committee on Soil Movement (TCB) – complete the main structure of decision-making, supervisory, enforcement and advisory bodies in upstream oil and gas.

***MEA***

The power to take binding decisions – notably the issuance, revocation and change of Mining Act licences, approval of mandatory production plans and other approvals, as well as administrative enforcement of Mining Act and subordinate legislation provisions

22 Letter from the MEA to the Second Chamber of Dutch Parliament, DGETM-EM / 13160139, dated 26 September 2013.

23 Licence holders are subject to various requirements in respect of, *inter alia*, waste water discharges. Compliance with such requirements is monitored by the SSM and enforced by the MEA.

and licence conditions – rests with the MEA. Small-fields provisions in the Gas Act are also administered by the MEA.

*The SSM*

The SSM supervises, and reports on, compliance with the Mining Act and subordinate legislation provisions and licence conditions. It also carries out operational inspections of prospecting, drilling, production and storage activities, with a view to well integrity and HSE aspects to the extent these are subject to Mining Act regulations. The SSM must report annually to the MEA on its activities and make recommendations on efficient and expeditious performance of these activities. The SSM's annual reports are made available to the public.

*Mining Council*

If solicited, the Mining Council, a non-departmental advisory body, advises the MEA on the exercise of statutory powers. The MEA must request the Mining Council's advice on the issuance or revocation of licences.

*TCB*

Concerns over recurring cases of soil movement as a result of oil and gas exploration and production, notably in the northern province of Groningen, have prompted the statutory establishment in the 2003 Mining Act of the TCB. It has advisory tasks with regard to both the MEA and citizens.

TCB provides the MEA, at his or her request, with advice on the exercise of Mining Act powers with a view to soil movement related consequences of contemplated decisions.[24] In addition, TCB has the statutory task to advise the MEA on the soil movement paragraph which, if the initiative involves onshore production, is a mandatory element of the production plan that a production licence holder must submit for approval to the MEA in advance of production.[25]

TCB provides private natural and legal persons, at their request, with information enabling them to establish whether a connection exists between soil movement and mining activities. Only those who have suffered or may expect to suffer damage to property that may reasonably be ascribed to mining activities have access to TCB for this purpose. In the case of damage suffered TCB's advice may, at the request of the affected party, include an opinion on the amount of loss.

Importantly, the Mining Act confers on TCB the power to commission expert investigation and to request information from the relevant mining enterprise.[26] As the

24 The MEA must ask TCB for advice on a decision, to be taken at the MEA's discretion, to impose on a licence holder the obligation to provide financial security covering liability for damage as a result of soil movement, or to change the amount of the imposed security.

25 Article 35(2) of the Mining Act.

26 Defined in Article 113(c) Mining Act as the natural or legal person who carries out mining activities.

Mining Act obliges a mining company[27] to provide such information within a reasonable term (as determined by TCB), failure to comply with an information request triggers the MEA's enforcement powers. The TCB's advisory powers do not prevent injured parties from bringing a civil suit against the relevant mining company, but may, rather, help them decide to file a lawsuit and provide material to support a claim.

***EU legislation***

Directive 94/22/EC[28] providing for common rules ensuring that authorisation procedures for the prospection, exploration and production of hydrocarbons will be open to all entities possessing the necessary capabilities, guaranteeing non-discriminatory access within the EU, has been transposed through, in particular, the Mining Act and subordinate regulations.

The EU's consecutive energy packages have been transposed into national legislation, through the Gas Act in particular.[29]

Regulation (EC) 1227/2011 on Energy Market Integrity and Transparency (REMIT), which aims at countering insider trading and market manipulation and increasing transparency in the wholesale markets for electricity and natural gas, required legislative action in the Netherlands. The relevant law, amending the Electricity Act 1998, the Gas Act, the Financial Supervision Act, the Economic Offences Act and the Code of Criminal Procedure[30] entered into force on 26 July 2013. ACER has provided guidance on the application of REMIT to national regulatory authorities, updated and extended on 22 April 2013 to cover the application of the market abuse definitions, the scope of REMIT in relation to EU financial market legislation, the application of definitions of 'wholesale energy market', 'wholesale energy products' and 'market participant', the application of the obligation to disclose inside information and the application and implementation of the prohibitions against market abuse.[31] During the summer of 2013 ACM conducted a consultation among market participants on a possible central platform for the disclosure of inside information and to prompt market participants to provide views on the need to establish a threshold for the publication of inside information relevant to the gas market.

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27 Defined for the purpose of the Mining Act paragraph on the TCB as a natural or legal person carrying out mining activities.

28 Directive 94/22/EC of the European Parliament and of the Council of 30 May 1994 on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbons, Official Journal of the European Union 30 June 1994, L 164.

29 The Third Energy Package was adopted in 2009 and comprises, to the extent relevant to the gas market, Regulation (EC) 715/2009 on conditions for access to the natural gas transmission networks, Directive 2009/73/EC concerning common rules for the internal market in natural gas, and Regulation (EC) 713/2009 establishing an Agency for the Cooperation of Energy Regulators.

30 Bulletin of Acts and Decrees 2013, 310.

31 Ref: A12-AWMS-04-03-guidance.

Directive 2013/30/EU[32] aims to establish effective control and liability mechanisms to prevent, remediate and respond to accidents in offshore oil and gas exploration and production. *Inter alia* it requires Member States to establish a centrally competent authority to monitor compliance with the directive's provisions, to ensure the licensing regime has regard to the financial and technical capability of licensees and that licensees are financially liable for environmental damage, and to allow for public participation. Member States must have transposed the Directive into national law by 19 July 2015. At the time of writing, a Bill to transpose the Directive had not yet been introduced to the Dutch parliament. However, public participation in decisions on applications for an exploration licence has been implemented through a policy guideline with effect from 18 July 2013.[33]

### iii Treaties

The Netherlands is a party to the Energy Charter Treaty (ECT) of 1994, which focuses on, *inter alia*, the promotion and protection of foreign energy investments on the basis of the more favourable of national or most favoured nation treatment, free trade in energy materials, products and energy-related equipment, freedom of energy transit, including through pipelines, and dispute resolution mechanisms for intra-state and investor–state disputes.

The Netherlands is party to over 100 bilateral investment treaties. Added to the equally extensive tax treaty network, this has significantly contributed to the attractiveness of the Netherlands as a country for multinationals to structure their foreign investments through.

## III LICENSING

### i General

The Mining Act distinguishes between exploration licences and production licences. Exploration of minerals is defined so as to include drilling. Mere prospection only requires prior notification and the submission of certain information to SSM, but may be subject to separate consent or licence from the MEA (in concert with the Minister of Infrastructure and the Environment or the Minister of Defence, as the case may be) in specific cases, related to shipping safety or military restrictions. *Ex ante* regulation of prospecting is achieved through the Mining Decree and the Mining Regulation.

Applications or exploration and production licences must be filed with the MEA. The Mining Regulation details the information to be submitted on application. The application must state the applicant's registration number with the Dutch Trade

32 Directive 2013/30/EU of the European Parliament and of the Council of 12 June 2013 on safety of offshore oil and gas operations and amending Directive 2004/35/EC, Official Journal of the European Union 28 June 2013, L 178/66.

33 Decree of the MEA of 9 July 2013, No. WJZ / 13120244, Government Gazette No. 20085 of 18 July 2013.

Register or a similar registration in another EU Member State,[34] implying that Mining Act licences can only be obtained by companies with a registered business in the EU.[35]

Once a complete application has been filed, the MEA must take a decision within six months. This term may be extended once for a further six months. The initial six-month term is extended by operation of law to allow for competing application procedures as described below.

### ii Competing applications regime

Upon application for a hydrocarbon exploration or production licence competing applications are allowed for 13 weeks following the publication of the former application in the Government Gazette and the EU Official Journal. The licence is then granted to the applicant whose application outperforms competing applications on technical or financial capabilities of the applicant, envisaged working methods, and efficiency and responsibility (including social responsibility).[36] If applications prove equivalent, then the interest of efficient and expedient exploration and production decides which applicant is granted the licence.

Two exceptions apply to the competitive application regime: (1) if the application for a production licence is made by the holder of an exploration licence for the field in question, then the production licence is awarded to that holder (provided other conditions, set out below, are met); and (2) if the holder of an exploration or production licence for a certain field applies for a production licence in respect of an adjacent field which is likely to pertain to the same reservoir (a common reservoir field), then only companies that possess an exploration or production licence for other fields that equally border on the common reservoir field are admitted, again during a period of 13 weeks, to file competing applications to produce the common reservoir field.[37]

#### *iii Grounds for licence refusal*

Only one hydrocarbon (exploration or production) licence can be in force in respect of a single area. No such licence can be granted if the relevant field has already been licensed for storage.

Grounds for rejecting a licence application are formulated exhaustively and include insufficient technical or financial capabilities or proposed working methods and a lack of efficiency and responsibility (including social responsibility) as evidenced during mining activities in the past. The financial capabilities test must relate to the applicant's ability to provide, if requested at any future moment in time, financial security to cover

34 Mining Regulation, Annex 1, A(2)(a).

35 As licensees under the Mining Act must be either natural persons or entities with legal personality (legal entities), non-incorporated subsidiaries and branch offices would as such not qualify to apply for a licence.

36 Each of these, if not satisfied, is liable to lead to a refusal of the licence outside the context of the competitive bidding, as will be seen below.

37 If such other adjacent fields turn out not to belong to the same reservoir, such competitors may be expected not to be able to secure a licence to produce the common reservoir field.

damage caused by soil movement or in connection with decommissioning or to ensure fulfilment of any of the Mining Act's financial obligations mentioned in Section II.i, *supra*. The provision of financial security in relation to any of these obligations is only rarely imposed in practice.

A production licence can only be issued if it is likely that the area to which the licence would apply contains economically recoverable reserves. In assessing whether this prerequisite is satisfied a number of parameters are taken into account, such as the extent and quality of the field, production cost (capital and operational expenditures), costs of decommissioning and sales price development.[38]

During the decision-making process the MEA is advised by the EBN (economical aspects), the SSM (applicant's technical capabilities), the Netherlands Organisation for Applied Scientific Research (geotechnical field aspects) and the Mining Council.

### iv Licence conditions and term

A licence must state the licensed activities and the minerals to which it applies[39] as well as the area to which it applies. The offshore sector is divided into quadrants of 1° latitude by 1° longitude, designated by letters. Each quadrant is subdivided into 18 blocks each of which measures approximately 410 km² on a 3 x 6 grid. An application for a hydrocarbon exploration or production licence must delineate the requested area by reference to one or more blocks.[40]

The application must include the requested term of validity of the licence applied for. Pursuant to the Mining Act the licence term is to be fixed in the licence and may not exceed the time needed to carry out the work committed in the application. An exploration licence must state the periods, within the overall term, during which exploration activities must be carried out and may state a period (or periods) for carrying out prospecting.[41] An exploration licence is automatically extended beyond the expiry date if, before that date, its holder has applied for a production licence and a decision has not yet been reached at the expiry date of the exploration licence. The term of production licences is equal to the life of field.[42] The MEA may extend the term of a licence,[43] provided the activities for which the licence had been granted have been carried out in

38 Second Chamber, 1998–1999, 26 219, No. 7, p. 81.

39 A production licence for certain minerals applies by force of law to minerals that are inevitably extracted with the production of the minerals whose production the licence was issued for.

40 Articles 1.3.2 and 1.3.3(2) Mining Regulation.

41 E.g., identification of drilling location(s) within two years, followed by drilling within one year.

42 Namely the period to deplete the field of its economically recoverable reserves.

43 In awarding a request for extension the MEA may at the same time reduce the licensed acreage.

accordance with the licence. The documents discussed hereafter will help the MEA to determine whether that is the case.[44]

Manifold and often very detailed provisions in the Mining Act, the Mining Decree and the Mining Regulation apply directly to mining activities. A failure to observe those may prompt revocation of a licence.

On 13 February 2014, the Mining Regulation was amended, providing for a change in the delineation of the 3 miles-zone, which is the demarcation of onshore and offshore mining and environmental legislation being applicable. As different taxes and environmental regimes apply on both sides of that demarcation, the change of the delineation may affect the applicable regime in the relevant block areas.

### v Work programme, multiannual programme and production plan

Pursuant to the Mining Regulation, an application for an exploration licence must include a work programme and an application for a production licence must include a multiannual programme of production activities.

In addition, the Mining Act requires a production licence holder to submit a production plan for approval by the MEA in advance of field production and to comply with the plan. The elaborate public preparatory procedure, as set forth in the General Administrative Law Act, enabling members of the general public and public interest groups to participate in decision-making, applies to the approval procedure for onshore initiatives. The production plan must provide a description of, *inter alia*, the expected quantity of recoverable reserves, the annually produced volume and production costs as well as, in the case of onshore production, soil movement and measures taken to prevent damage as a result of soil movement. The mandatory content of hydrocarbon production plans is detailed in the Mining Decree and in the Mining Regulation. The MEA may refuse to approve a production plan, or attach conditions or change conditions attached to, or revoke altogether, an approval decision only: (1) in the interest of the systematic management of mineral deposits; and (2) in connection with the risk of soil movement damage in the case of onshore production initiatives.

### vi Licence revocation

The MEA may revoke licences on exhaustively stated grounds only, in particular (the provision of incorrect information during application aside): (1) the licence is no longer required for the proper discharge of the activities for which it had been issued; (2) revocation is justified following a change in the technical or financial capabilities of the holder; (3) the holder has failed to act in accordance with the licence; or (4) the holder or, in the case of a licence held by more than one holder, the operator has failed to comply with applicable regulations.

44 Pursuant to the Mining Regulation the application for an exploration licence must include a work programme and the application for a production licence must include a multiannual programme of production activities. In addition the Mining Act requires the holder of a production licence to submit a production plan for approval by the MEA in advance of field production.

### vii Co-holding of licence, operatorship, transfer of licence or licence interest and change of control

Licences can be held by more than one entity. All entities holding the licence are each considered a holder, irrespective of their percentage interests, which are not revealed in the licence. If a licence is applied for by more than one entity, the application must appoint an operator. The replacement of an operator following the grant of the licence is subject to prior written consent from the MEA. The operator or the entity that acted as operator immediately prior to the expiration of the licence is responsible for compliance with Mining Act and subordinate law obligations.

A holder or co-holder can transfer a licence or its share in that licence to a third party, subject to the MEA's consent. The same grounds for refusal apply as at the initial application.

A change of control in a licence holder, notably following a share transaction, is not subject to the MEA's consent.[45]

## IV PRODUCTION RESTRICTIONS

### i Production entitlement, sales, export

Pursuant to Article 3(1) of the Mining Act, the Dutch state owns subsoil minerals within its jurisdiction.[46] Ownership transfers by operation of law[47] to the holder of a Mining Act production licence on extraction. As has been mentioned earlier, the applicant for a Mining Act licence must be registered in the Netherlands or another EU Member State, but it may be a subsidiary of a non-EU based parent or group of companies.

Barring specific trade bans, agreed on case-by-case basis under international law, the Netherlands is not familiar with restrictions on oil and gas production entitlements or exports of oil and gas.

As mentioned above, the Gas Act, consolidating the policy of controlled depletion of the backbone Groningen gas field, obliges the MEA to set a production ceiling for the Groningen field at least once every five years.

### ii Price setting

The Gas Act contains the statutory obligation for GasTerra to purchase gas produced from small fields at a market-conforming price, when gas is offered to it, except where the MEA has released GasTerra from this obligation for economic and financial reasons.

45 If, following a change of control, the licence holder becomes unable to remain compliant with financial or technical capability requirements, the licence can be revoked.

46 Including, based on relevant international law, the Dutch part of the continental shelf. It is recalled that pursuant to its Article 2(2) the Mining Act applies to minerals to the extent these occur at a depth of more than 100 metres beneath the earth's surface.

47 Article 2(2) Mining Act.

No rules exist determining the market conforming price, but GasTerra[48] has been applying a 'net-back' pricing system for many years. The net-back system basically means that small field producers are paid a price (the 'normative purchase price') linked to the average sale price realised by GasTerra's in the entirety of the market sectors where it trades. The purchase price is indexed to heavy fuel oil (reflecting pricing in the power and heavy industries market sectors) and gas oil prices (reflecting pricing in the household and SME market) with the indexes regularly updated. With the growing importance and liquidity of spot markets, spot prices, notably at the Dutch Title Transfer Facility (TTF) and the UK's National Balancing Point (NBP), have entered the pricing formula. Pricing will differ in the various contracts contingent upon, *inter alia*, carbon dioxide content (hence calorific value) and field load.[49]

## V ASSIGNMENT OF INTERESTS

### i General

The Dutch regulatory framework, as established under the Mining Act, offers a very light-handed approach to government involvement with licence or licence interest transfers. (See Section III, *supra*.) If regulation is relaxed, administrative burdens or constraints are not seen to be evoked by regulatory practice either.

### ii Timing

The decision on approval of transfer of a licence or licence interest must be rendered within a reasonable delay which, as per the General Administrative Law Act, may in principle not exceed eight weeks.[50] Pursuant to the relevant General Administrative Law Act provisions[51] absent a decision within the statutory delay, approval is obtained by operation of law.

## VI TAX

### i General

Profits made in upstream oil and gas are subject to both SPS, based on the Mining Act, and general corporation income taxation, based on the Corporation Income Tax Act 1969.

48 Gasunie before 2005.

49 A high load factor means low production flexibility. As this renders production relatively cheaper for the producer while decreasing flexibility in GasTerra's purchase portfolio, a high load factor will adversely affect the GasTerra purchase price.

50 This term may be extended by an additional reasonable term, provided that the applicant has been notified of the necessity of an extension prior to the expiry of the original delay.

51 Par. 4.1.3.3 of the General Administrative Law Act.

### ii Corporate income tax

The corporate income tax rate is currently at 25 per cent of taxable profits exceeding €200,000.[52] As a rule the corporate tax base of a Dutch resident taxpayer comprises all domestic and worldwide income. Relevant costs that can be taken into account to determine taxable profits include royalties, operating costs (including, under circumstances, interest), exploration costs, depreciation, anticipated future abandonment costs as accounted for in an abandonment provision, as well as the amount of SPS that remains after taking into account the 'creditable amount', mentioned below. Under the Corporate Income Tax Act 1969 losses as a rule can be carried back one year and carried forward nine years.

### iii SPS

SPS, at a rate of 50 per cent, is levied from the holder or co-holders of a production licence on profits that can be directly and indirectly attributed to the extraction of hydrocarbons (the ring fence). The allocation principles have been established in practice and case law. SPS is calculated similar to corporate income tax, but with (most) expenses 'uplifted' by an additional 10 per cent. To prevent corporate income tax and SPS from accumulating, a notionally calculated amount (generally referred to as the 'creditable amount') can be credited against SPS. Losses for the purposes of SPS calculation are available for three-year carry back and indefinite carry forward. The marginal fields tax incentive mentioned in Section II.i, *supra*, relates to SPS in that, provided certain conditions are met, in determining profits to which SPS applies, a 25 per cent deduction can be taken into account in respect of investments in new business assets that are used for marginal fields.

### iv Royalties

Royalty applies at a rate based on turnover. The turnover is the product of production volume (excluding processing and transportation volumes used during exploration or production) and unit sale price.[53] Turnover attributable to EBN's entitlement of 40 per cent of produced units is excluded from royalty taxed turnover. The rate builds up according to the volume brackets in the tables below. The percentages mentioned in the tables apply to volumes produced onshore.[54] For offshore production the percentage is zero in all volume brackets.

| *Produced volume of gas (in millions m³)* | *Percentage* |
|---|---|
| 0–200 | 0% |
| 200–600 | 2% |
| 600–1,200 | 3% |
| 1,200–2,000 | 4% |
| 2,000–4,000 | 5% |
| 4,000–8,000 | 6% |
| > 8,000 | 7% |

52 The rate below this threshold is 20 per cent.

53 A unit being 1,000 m³ in the case of oil and 1 million m³ in the gas of gas.

54 Including the land-side of the Dutch territorial seabed.

| *Natural Gas (in thousands m³)* | *Percentage* |
|---|---|
| 0–200 | 0% |
| 200–600 | 2% |
| 600–1,200 | 3% |
| 1,200–2,000 | 4% |
| 2,000–4,000 | 5% |
| 4,000–8,000 | 6% |
| > 8,000 | 7% |

The rate over any calendar year is increased by 25 per cent of the weighted average price of imported crude oil exceeds €25 a barrel. The rate is furthermore increased by 100 per cent in cases where the licence holder, pursuant to MEA exemption, has not entered into a cooperation agreement with EBN (see Section II.i, *supra*).

## VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

### i Environmental permitting

*General*

As a general rule the erection and operation of mining installations requires an environmental permit, based on the Environmental Permitting (General Provisions) Act (EPA), applying to Dutch territory, including the seabed extending 12 nautical miles from the coastline, or, if the EPA does not apply (notably on the Dutch part of the continental shelf), based on the Mining Act. The MEA is the competent authority to issue permits in either case. An environmental impact assessment can be part of environmental permitting in designated cases. In June 2014, a new bill was proposed to the Second Chamber, providing for one comprehensive set of laws related to environmental and planning which are currently laid down in different acts. The new bill will also affect environmental aspects of (offshore) mining activities and replace specific provisions in the Mining Act. Entry into force is not expected before January 2016.

*Mobile installations*

Mobile installations, except for those servicing a production location, do not require an environmental permit but may be used only following notification and submission of certain information to the MEA. The erection and operation of mobile installations that do and those that do not require an environmental permit are subject to general rules laid down in the General Mining Industry (Environmental Rules) Decree, promulgated under the Mining Act.

*Nature reserve protection*

Initiatives in protected nature reserves, designated under the Nature Conservation Act (NCA), and in ecologically important 'Natura 2000' areas, designated under the NCA pursuant to the European Birds and Habitat Directives,[55] additionally require an NCA

55 79/409/EEC and 92/43/EEC, respectively.

permit. A recently adopted Act[56] to extend the scope of the NCA to the Dutch part of the continental shelf entered into force on 1 January 2014.[57]

***Zoning***

Onshore initiatives that are not provided for in current zoning plans will require separate zoning consents.[58]

***Other permits***

Other permits that may be required in the context of oil and gas exploration and production activities include building permits, planning consents, water discharge and water injection permits.

### ii Decommissioning

***General***

The Mining Act prescribes that mining installations that are no longer used must be removed, including scrap and other materials at or immediately near such installations. The MEA may limit the obligation to a certain depth, to be determined at his or her discretion, beneath the soil of the surface water and may set a time frame within which the obligation must have been fulfilled. The MEA's power to determine a time limit can be used to allow assets that are no longer used for production to be re-established as part of an existing transport system, which would then obviate the need for removal.[59] The removal obligation rests on the licence holder or, if the licence is held by more than one company, the operator (see Section III, *supra*).[60]

The decommissioning regime with respect to cables and pipelines situated on the Dutch part of the continental shelf is slightly different in that the removal obligation does not exist by force of law, but applies if and to the extent that the MEA has ordered the removal. The obligation rests on the cable or pipeline operator or last known operator.

***Removal plan***

The Mining Decree requires a removal plan, the mandatory elements of which are detailed in the Mining Regulation, to be submitted for approval to the MEA prior to the removal of mining installations, having been used in production, that protrude from the surface water.

56 Act of 9 October 2013, Government Gazette 2013, 412.

57 As per Royal Decree of 28 October 2013, Government Gazette 2013, 419.

58 An example is provided by a ruling of the Council of State, the highest administrative law court in planning and environmental litigation, from 25 July 2012, case No. 201109314/1/R4, concerning a gas production initiative by Vermilion Oil & Gas Netherlands BV prompting objections from local residents. The residents' appeal was dismissed.

59 Explanatory Memorandum to Mining Act Bill, Second Chamber, 1998–1999, 26 219, No. 3, p. 27.

60 If the licence has expired, the obligation befalls the entity that last held the licence, or, if it was held by more than one licensee, the operator appointed most recently prior to the expiry.

The removal of mining installations (whether or not used in production) that are entirely situated below the surface water does not require a prior removal plan, but rules laid down in the Mining Regulation must be observed. The SSM must be notified at least 24 hours before and immediately following the removal of mining installations in both categories.

*Financial security*

The MEA may decide that financial security, in an amount at the MEA's discretion, must be provided to cover costs of administrative enforcement measures to be taken upon the failure of the licensee or operator to fulfil its removal obligations. Regulations are silent as to when the MEA can demand financial security. The application for an exploration or production licence may be denied, however, if the MEA is not satisfied that the applicant will be able to provide security if requested to at any point in the future.

## VIII FOREIGN INVESTMENT CONSIDERATIONS

### i Establishment

A corporation applying for a Mining Act licence must have a trade register registration in the Netherlands or similar registration in another EU Member State, but it may be a subsidiary of a non-EU based parent or group of companies. Dutch law recognises foreign legal personality and a foreign entity can obtain a Dutch trade register registration.

### ii Capital, labour and content restrictions

Under Dutch law no specific restrictions, controls or taxes apply on the movement of capital or foreign currency exchange.

As a rule a permit under the Foreign Nationals (Employment) Act is required for the employment (whether or not on an employment contract basis) of non-EU nationals on Dutch territory, including personnel working on construction projects and crew of ships deployed in offshore projects in Dutch territorial waters. A principal who has contracted works out is jointly and severally liable to pay fines for the employment by the contractor or subcontractors of personnel without the requisite permit.

### iii Anti-corruption

The Dutch Penal Code has a body of anti-bribery rules, targeting corrupt practice in the public and private sectors. None of these target the oil and gas sector in particular.

The Penal Code prohibits bribery of a public service employee (which is a broader concept than civil servant *strictu sensu*). Bribery includes the provision of a favour to speed up or otherwise facilitate a decision that the briber would have been entitled to normally. Both the briber and the public service employee are punishable.

Equally prohibited is the bribery of persons who are not public service employees. Both the briber and the employee are punishable. For the gift, service or promise to qualify as bribery, the employee must have refrained in bad faith from disclosing the gift to his or her employer.

A person or company accepting a gift, service or promise from an employee breaches anti-bribery rules if that person or company, when the gift was offered by the employee, had reasons to believe that the employee would refrain in bad faith from disclosing the gift, service or promise to his or her employer.

Criminal penalties range from two to four years' imprisonment or a maximum fine of €81,000 (as at 1 January 2014). In the Netherlands a legal entity can be criminally prosecuted and condemned for criminal acts of its corporate bodies or employees that are reasonably attributable to it. Criminal anti-bribery fines for legal entities can amount to €810,000 (as at 1 January 2014). In addition to the aforementioned penalties, the penal courts can issue orders for confiscation of the proceeds of a crime.

## IX CURRENT DEVELOPMENTS

### i Operations

*Shale gas*

Cuadrilla, based in the United Kingdom and specialising in European shale gas development, obtained two exploration licences to carry out exploratory drilling to determine the presence of economically recoverable shale gas in the province of Noord-Brabant and the Noordoostpolder region. Concerns among the general public, local governments and drinking water companies over public health, safety and environmental aspects of 'fracking' techniques used in shale gas production led the Dutch government to commission an expert investigation. The investigation came out largely in favour of shale gas production saying any risks were manageable within the framework of existing legislation and through adequate mining licence and environmental permit conditions.

Unsurprisingly, the expert report, completed in the summer of 2013, and the MEA's letter with which it was presented to the Second Chamber of Parliament[61] only heightened public debate. The matter threatened to cause a new rift within the struggling government coalition, and an opinion was sought from the Netherlands Commission of Environmental Assessment (NCEA) on the quality of the expert report. Among the NCEA's findings[62] is that the current regulatory framework fails to adequately (1) establish *ex ante* supervision; (2) lay down rules with regard to vibrations; and (3) ensure that an environmental impact assessment is carried out in advance of each shale gas exploration and production initiative. It concluded in addition that the State Supervisory Body of Mines, the principal non-executive supervisory body under the Mining Act, has insufficient staff to carry out the on-site inspections needed to ensure continual safety of shale gas exploration and extraction operations.

In the run-up to NCEA's report the MEA, as he revealed in a letter to the Second Chamber of Parliament of 18 September 2013,[63] following deliberations with NCEA, had meanwhile decided that all shale gas initiatives, including the exploratory drillings that had already been permitted to Cuadrilla, will be put on hold until a spatial structure

61 S. for the letter, dated 26 August 2013: Second Chamber, 2012–2013, 28 982, No. 132. The expert report is publicly available at https://zoek.officielebekendmakingen.nl/blg-246921.pdf.

62 It reported to the MEA in September 2013: report www.commissiemer.nl/advisering/lopendeadvisering/23.

63 Second Chamber, 2013–2014, 28 982, No. 133.

vision and related environmental impact assessment are available to identify suitable locations, if any, for shale gas exploration and production. The MEA expects the process to delay decision-making on shale gas initiatives by another 12 to 18 months.

***Earthquakes***

A spate of earth tremors and a general trend of subsidence, notably in the northern Dutch province of Groningen, commonly ascribed to (traditional) oil and gas exploration and production activities in the region, have caused some concern over the sustainability of onshore oil and gas exploration and production in the Netherlands.

As a reaction to growing concern and public discontent, the MEA sent a letter to Parliament on 17 January 2014, announcing measures to limit production from the Groningen field in order to avoid further earthquakes and soil movements. Production wells near the vulnerable village of Loppersum will be decreased from 15 to 3bcm per year in 2014, 2015 and 2016. The SSM advised NAM to cease production from additional wells, but this advice has been followed only in part. This measure will effectively lead to a Groningen field production ceiling of 42.5bcm in 2014 and 2015, and of 40bcm in 2016.

On 29 November 2013 NAM submitted its production plan for the Groningen field. This production plan requires formal approval from the Minister. The measures will be adopted once the Minister approves NAM's production plan for the next three years. The final decision was expected mid-2014 and will be subject to appeal. Further investigation into soil stability will have to be conducted and taken into account in the production plan that NAM will have to submit on 1 July 2016 for the following three years.

The measures announced by the Minister also include plans to reinforce buildings, houses and infrastructure. Furthermore, a compensatory payments package of €1.18 billion will be made available to the region. NAM will finance €1.125 billion; the province will finance the rest. As the Dutch state participates in the exploitation of the Groningen field through a limited partnership with NAM, through a complicated profits/costs allocation system, the state will ultimately bear 64 per cent of these costs (€114 million per year), while receiving 90 per cent of the profits. The state's reduced profits over the coming three years are estimated at €2.3 billion.

### ii Market

The Netherlands has a liquid and well-developed transaction market in upstream oil and gas. Transactions involving both licence interests and assets are frequent. The relatively newer phenomenon of transactions in upstream pipeline infrastructure would seem to appeal to long-term investors.

# Appendix 1

# ABOUT THE AUTHORS

**ROLAND DE VLAM**

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Roland de Vlam, attorney-at-law, specialises in energy law. He advises energy companies and other market parties on regulatory aspects of transactions and represents his clients in court proceedings as well as in litigation before the Energy Directorate of the Authority for Consumers and Markets. The scope of his work extends across the entire energy chain: gas (E&P, storage, LNG, transport and supply), power (generation, transport and supply), renewables, heat and CO2. He is also involved in other regulated markets and EU law. Roland is a member of the Dutch Energy Law Association. He regularly speaks and publishes on energy related topics.

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Rogier Sterk (1975), tax adviser, is a member of the Loyens & Loeff Energy Team. He advises clients who are engaged in the Netherlands with respect to the exploration for and production of oil and gas and companies which structure international exploration and production activities through the Netherlands. Rogier is further engaged with advising on transfer pricing related issues (advance pricing agreements, general audits, corresponding adjustments, mutual consultation procedures, etc.).

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