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Jan B Jansen og Joachim M Bjerke

Articles in Petroleum Law

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Preface

This issue of MarIus contains several articles to be read by students of Petroleum Law at the Law Faculty of the University of Oslo. We believe that these articles have a general interest for readers of MarIus as well.

Readers of MarIus should note that the articles published in the Petroleum Law compendia are frequently revised. However, revised articles will not be published again in MarIus.

The main emphasis of this edition is on the Petroleum Act, hereafter called the PA. The intention of the PA is to regulate all the important aspects of the petroleum activities on the Norwegian continental shelf. The regulatory emphasis is on the relationship between the authorities and the licensees, and the relationship between the licensees.

The book consists of two parts. Part 1 contains articles on topics related to the Petroleum Act which are written by Ulf Hammer, Anne-Karin Nesdam , Dagfinn Nygaard and Knut Kaasen. This Part begins with an overview of PA, followed by successive contributions on issues related to PA, including important aspects of the relationship between the licensee and third parties in the form of four liability regimes specially adapted to the petroleum activities.

Part 2 consists of Anne Karin Nesdam´s article on gas sales and Jan B. Jansen and Jochim M. Bjerke´s article on Norwegian Petroleum Taxation.

We wish you an interesting reading.

Kind regards,

Ulf Hammer
october 2011

Overview of content

Part I

The Petroleum Act

Ulf Hammer, editor

Innhold

1 Introduction

By Ulf Hammer, Professor dr. juris, University of Oslo

1.1 Resource base, production and exports

The Norwegian petroleum resources are located on the Norwegian continental Shelf (NCS). With the Ekofisk discovery in 1969, the Norwegian oil adventure really began. Production from this field started 15 June 1971, and in the following years a number of major discoveries were made. Today, there are 65 fields in production on the NCS. In 2009, these fields produced 2,3 million barrels of oil (including NGL and condensate) per day, and 102,7 billion standard cubic metres (scm) of gas. Norway ranks the sixth largest oil exporter and the eleventh largest oil producer in the world. It also ranks as the second largest gas exporter and the fifth largest gas producer in the world.[1] The gas resources represent the largest future resource potential.[2]

In spite of more than 30 years of production, only approximately 40 % of the expected total resources on the NCS have been produced. However, substantial parts of the NCS are now regarded as mature petroleum provinces (the North Sea, the southern parts of the Norwegian Sea). These provinces are characterized by familiar geology, minor technical challenges and well-developed or planned infrastructure. In these areas major new major discoveries are less likely. The challenge is to develop a considerable number of smaller fields located near the existing infrastructure. The frontier areas (northern parts of the Norwegian Sea and the Barents Sea) are characterized by little knowledge of the geology, significant technical challenges and a lack of infrastructure. Major discoveries may still be made in these areas.[3]

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1 Facts 2010, 14.

2 Facts 2010, 15.

3 Facts 2010, 30.

Gas is transported in offshore pipelines to the European markets. Norwegian gas exports meet approximately 25 to 35% of the European gas consumption. The Norwegian gas transport system is extensive, covering more than 7 800 kilometres of pipelines.[4] The first LNG-project, where gas is liquefied and transported by ship to European and US markets, is now part of the development of the Snøhvit field in the Barents Sea.[5]

Oil is mainly transported by ship to the markets. However, there are seven oil or condensate pipelines in operation on the Norwegian continental shelf.[6]

Norway can best be characterized as a typical producer country. Internal consumption of oil and gas is very small compared to exports. As a result, the regulation and the organization of the Norwegian petroleum activities are basically designed to promote Norway's interests as a producer country. In other words, the Norwegian regulation and organization is producer (or upstream) oriented. This makes the system different from the systems in most EU countries which are consumer (or downstream) oriented.

1.2 Levels of government

Norway has three levels of government; the central, regional and local levels. On the central level, the highest legislative and financial powers rest with Parliament and the highest judicial power with the Supreme Court , cf. the Constitution of 17 May 1814. According to the Constitution, the highest executive power formally rests with the King. According to constitutional practice, however, the real executive power rests with the Cabinet. The Cabinet leads a State hierarchy, which on the central level mainly consists of the ministries and the directorates.[7] In principle, each entitiy within this hierarchy can be instructed by superior entities; they are not independent State organs. In practice, directorates are established to execute the more detailed State powers within defined

4 Facts 2010, 44.

5 Facts 2010, 130.

6 Facts 2010, 194-198.

7 Some State functions are also exercised on the regional and local levels of government, but we will not go into these.

sectors, and they are not likely to receive more than general instructions. As to the lower levels of government, limited legislative, executive and financial powers have been allocated to regional and local municipalities pursuant to acts passed by Parliament. Internally, the municipalites are organized along the same principles of hierarchy as the State. Externally, they cannot be formally instructed by State organs. However, regulations passed by the municipalities must normally be presented to State organs for approval. We can conclude that Norway is organized as a unitary State (as opposed to a federal State).

In the Norwegian *petroleum sector* the relevant legislative and executive powers rest predominantly with the State. The Norwegian petroleum activities refer to offshore petroleum deposits, and thus a major part of the activities take place beyond the jurisdiction of the municipalities.[8]

The central governing function pursuant to the PA rests with the Ministry of Petroleum and Energy (MPE) which was established in 1978. This means that the MPE has the overall responsibility for the resource management, unless otherwise decided. The MPE does the preparatory work prior to the King's granting of production licences. The other major licences, approvals, consents, and decisions pursuant to the licence system are issued by the MPE. The central governing function implies that the MPE in the course of its work co-ordinates the input from several other ministries, government agencies, regional and local authorities, and various interest groups concerned, eg environmental interest groups. Of special importance is the input from the Ministry of Labour (ML), which has overall responsibility for the working environment, emergency preparedness, and safety aspects of petroleum activities.

Day-to-day control, including the more detailed approvals and consents, has been delegated to the Norwegian Petroleum Directorate

8 However, when it comes to development and operation of petroleum infrastructure on land, the municipalities execute important powers pursuant to the legislation which safeguards area planning and environmental interests. The Planning and Building Act constitutes the most important legislation in these respects, cf. Act no 71 of 27 June 2008.

(NPD) as regards management of the petroleum resources, and the Petroleum Safety Authority (PSA) as regards working environment, emergency preparedness and safety.[9] These two Government agencies are located in Stavanger. Administratively, the NPD is subordinate to the MPE, while the PSA is subordinate to the ML.

1.3 Legal and regulatory framework

1.3.1 Historic development

According to the United Nations Convention on the Law of the Sea (UNCLOS) art. 77 (1) the coastal State has sovereign rights for the purpose of exploring the continental shelf and exploiting its resources. Norway proclaimed sovereignty over the Norwegian continental shelf regarding exploration for and exploitation of subsea natural resources by Royal Decree of 31 May 1963.

The internal legislation started with *the 1963-Act*.[10] The 1963-Act contained three basic princiciples. First, the right to submarine natural resources is vested in the State. Second, the King may give Norwegian or foreign persons, including legal persons, the right to explore for or exploit natural resources. Third, the King may issue regulations concerning such activities. In principle, the State could have performed the petroleum activities itself in its capacity as resource owner. The alternative was to let companies perform the activities through a licence system.[11] The latter alternative was chosen, and in subsequent decrees issued pursuant to the 1963-Act, a licence system was developed. However, a very characteristic feature of the legal framework is the

9 The PSA was established 1 January 2004. Previously, the NPD was responsible for working environment, emergency preparedness and safety.

10 Act no 12 of 2 1 June 1963 relating to exploration for and exploitation of submarine natural resources. The 1963-Act still exists. It now regulates scientific research of the sea bed, and exploration for and exploitation of *other* subsea natural resources than petroleum resources.

11 The State could also have chosen an entrepreneur system or a production sharing system, but such alternatives have so far not been practiced on the Norwegian continental shelf.

strong State participation in the activities.[12]

The starting point for the development of the licence system was the 1965-Decree, passed pursuant to the 1963-Act section 3 in connection with the first licence round.[13] Large discoveries of oil and gas were made in 1969 (Ekofisk), which gave the Norwegian government the incentive to stipulate tougher licence terms under the subsequent 1972-Decree.[14] Under this decree, production licences were awarded which led to the discovery of several giant fields during the seventies and the beginning of the eighties (Statfjord, Gullfaks, Oseberg and Troll). Eventually, a petroleum act was passed by the Norwegian Parliament in 1985.[15] *The 1985-Act* represented a continuation of the licence system and a codification of government practice under this system. However, the purpose of the 1985-Act was also to regulate other important aspects of the petroleum activities, and in this context it introduced some novelties, among them a separate chapter on the licensee´s liability for petroleum pollution damage. In 1989, a new chapter on compensation rules with regard to the losses Norwegian fishermen suffer as a result of the petroleum activities was included in the 1985-Act.[16]

The 1985-Act was replaced by a new petroleum act in 1996, *the PA*.[17] By this time Norway had become party to the European Economic Area Agreement (the EEA Agreement).[18] The EEA Agreement implies that the EC Treaty (now the TFEU) and the EC secondary legislation (passed pursuant to the Treaty) is extended to cover the EFTA States (Iceland, Lichtenstein and Norway). However, EC secondary legislation adopted *after* entry into force of the EEA Agreement can only be included in the

12 See 1.3.5

13 Royal Decree of 9 April 1965 relating to exploration for and exploitation of petroleum.

14 Royal Decree of 8 December 1972 relating to exploration for and exploitation of petroleum.

15 Act no 11 of 22 March 1985 pertaining to petroleum activities.

16 Amendment Act of 9 June 1989.

17 Act no 72 of 29 November 1996. The preceding government “white papers” are Ot prp nr 43 (1995-96) and Innst O nr 7 (1996-97).

18 The EEA Agreement was signed 2 May 1992 and entered into force 1 January 1994.

Agreement subject to a decision by the EEA Committee.[19] On this basis, directive 94/22/EC on the conditions for granting and using authorizations for the prospection, exploration and production of hydrocarbons (the licensing directive), and directive 2003/55/EC (which replaced directive 98/30/EC) concering common rules for the internal market in natural gas (the gas market directive) have been included in the EEA Agreement. Norway is under an obligation to implement the rules of the EEA Agreement. Consequently, the PA reflects the principles of the EEA Agreement and the respective directives.

The PA introduces more flexible rules concerning, inter alia, the duration and geographical scope of production licences. The flexible approach is a result of the expansion of the petroleum activities to new areas, especially in the Norwegian Sea. In these areas the industry will meet greater water depths and longer distances to existing infrastructure. The PA opens for more benevolent licence terms in such cases. The PA also introduces a more detailed regulation of the abandonment phase, which by the beginning of the nineties had become an important subject in view of the shut-down of the first Norwegian petroleum fields. Apart from this, the PA basically represents a prolongation of the 1985-Act.

> It should also be mentioned that several regulations were adopted pursuant to the 1985-Act, which regulated the petroleum activities in more detail. The most important ones were the petroleum regulations and the safety regulations. These two regulations were replaced by new regulations, adopted by Royal Decrees of 27 June 1997 pursuant to the PA. Recently, new safety regulations have been adopted by Royal Decree of 31 August 2001.

Although the PA intends to regulate all important aspects of the petroleum activities, it does not exclude the application of other Norwegian laws.[20] The most important ones are the Petroleum Taxation Act, the

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[19] The EEA Committee consists of representatives from the EC Member States and the EFTA States. All decisions require unanimity between the EC Member States (on the one hand) and the EFTA States (on the other hand).

[20] Cf. the PA section 1-5.

Working Environment Act and the Pollution Act.[21] We will on certain occasions revert to this legislation.

1.3.2 The scope of the PA

The scope of the PA is regulated in the PA section 1-4. This section has to be read in conjunction with relevant international law and national laws. In particular, it has to be read in conjuction with the PA section 1-6, which defines several important terms of the Act.

According to the PA section 1-4 first paragraph, the Act applies to "petroleum activities in connection with subsea petroleum deposits under Norwegian jurisdiction." First, the scope is limited to subsea petroleum deposits.[22] "[S]ubsea" excludes petroleum deposits on land. Such deposits are regulated under a separate act concerning petroleum in the subsoil of Norwegian territory and the part of the sea bed subject to private property rights.[23] So far, this act has not been of any practical significance.

Second, the subsea petroleum deposits must be under "Norwegian jurisdiction". This jurisdiction is founded in international law and comprises Norwegian internal waters, Norwegian sea territory, and the continental shelf. The term "continental shelf" is defined in the PA section 1-6 l). It includes the sea bed and subsoil beyond the Norwegian sea territory, but not beyond the median line in relation to other states.[24] However, subject to agreements with other states Norwegian jurisdiction may extend beyond the median line. Norway has entered into agreements with the UK regarding the exploitation of fields crossing the median line, i.e. the Frigg and Statfjord fields. Norway has also entered into agreements with the UK and states on the Continent regarding the transportation of petroleum in pipelines from the Norwegian

21 Act no 35 of 13 June 1975 relating to taxation of sub-sea petroleum deposits. Act no 62 of 17 June 2005 relating to worker protection and working environment etc. Act no 6 of 13 March 1981 relating to protection against pollution and waste.

22 The term "petroleum deposit" is defined in the PA section 1-6 b).

23 Act no 21 of 4 May 1973.

24 Agreements to divide the continental shelf according to the median line principle were concluded between Norway and the UK in March 1965, and between Norway and Denmark in December the same year.

Continental Shelf to receiving terminals in the UK and on the Continent. These agreements imply a limited extension of Norwegian jurisdiction as regards the exploitation of the relevant fields and pipelines.

Third, the scope of the PA refers to petroleum activities "in connection" with the petroleum deposits as aforesaid. This means that petroleum activites under the Act can take place on land, provided that they are functionally connected to petroleum deposits offshore. New technology makes it possible to conduct petroleum activities on land, even though the petroleum deposit itself is situated on the continental shelf. The term "petroleum activity" is defined in the PA section 1-6 c). It comprises all activities necessary to develop a petroleum deposit, including exploration, exploration drilling, production, utilization and transportation. The latter terms are all further defined in section 1-6.

Utilization activities on land are to some extent covered by the Act, cf. section 1-4 second paragraph.[25] The term "utilization" encompasses a wide range of activities, cf. section 1-6 i). Some of these are conducted separately from production and transportation of petroleum. Refining and petrochemical activities belong to this category. Other utilization activities, typically liquefaction of gas, are closely connected to production of petroleum as defined in section 1-6 g). Consequently, utilization activities on land are regulated by the Act to the extent that they form an "integrated part" of production and transportation of petroleum.

We will further elaborate the general scope of the Act in connection with the presentation of system operation.[26] The PA contains comprehensive regulation on various aspects of liability. Chapter 7 on pollution damage and chapter 8 on compensation to Norwegian fishermen have special provisions on the scope of the Act. These provisions will be dealt with in later items of the Compendium.[27]

1.3.3 Resource management

The PA establishes a framework for State management of the petroleum

25 If such activities are conducted offshore, they are covered by the Act.

26 See 4.1.

27 See 9.3 and 9.4.

resources. The resource management is characterized by central planning and control. Thus, the PA section 1-2 first paragraph declares that the resource management is exercised by the King pursuant to the provisions of the act and decisions of the Norwegian Parliament.[28] The policy objectives of the resource management are stated in section 1-2 second paragraph.

As already mentioned, the Norwegian State is the owner of the sub-sea petroleum deposits. Petroleum is a limited and non-renewable resource with a large revenue potential. Consequently, the main policy objective, as stated in the PA section 1-2 second paragraph, is a long term management of petroleum resources for the benefit of the Norwegian society as a whole. This policy perspective is wide both as to the time frame and as to the range of considerations. The main considerations include State revenues, public welfare and employment, Norwegian industry and industrial development, and the environment. They reflect the revenue potential and the various interests that are influenced by the petroleum activities. The basic concern of the resource management, however, is to produce as much of the petrolum in place as possible to as little cost as possible. This efficiency requirement is stated in the PA section 4-1. Another important consideration is the safety aspect of the activities, which is reflected in the PA section 9-1 and in section 10-1.

The wide range of policy considerations has led to a high degree of government intervention in the petroleum activities. This intervention rests upon two main pillars. First, all phases of the activities are subject to direct government control through a licence system. This means that no major activity can take place without a prior licence or approval. Licences and approvals are subject to terms which open for detailed - but also flexible - regulation of each licensee´s activities. Thus, the general framework of the PA and the regulations passed pursuant to the PA is supplemented by an individual framework in the form of licence terms.

Second, the State regulates indirectly by organizing the activities. This organization now consists of two major components; State organized licence groups and strong State participation within the licence groups.

28 In this context the term "King" means the Norwegian Cabinet.

1.3.4 The licence system

As a starting point, the licence system consists of the exploration licence, the production licence and the pipeline licence (also called the section 4-3 licence). These are the formal components of the system which was introduced in the 1965- and 1972-Decrees. Each licence covers separate phases of the activities. However, one includes the approval of the development plan, since this approval and its connected terms in all important respects forms the basis for the licensee´s development of a petroleum deposit. The development plan was formally introduced in the 1985-Act, but in this regard the act only represented a codification of government practice. In addition, the PA has recently introduced the abandonment plan and the subsequent decision by the MPE, which have a similar function (as the approval of the development plan) in the abandonment phase.

The *exploration licence* is regulated in the PA chapter 2. The licence is given for a limited area and for a limited period. It gives the licensee a right, but not an exclusive right, to conduct various kinds of surveys of the sea bed in order to identify the potential for petroleum deposits.[29] The licensee has no right to drill for petroleum, and he has no right to obtain future production licences.

The *production licence* is the main licence of the system, and is regulated in the PA chapter 3. It gives the licensee an exclusive right to exploration, exploration drilling, and production of petroleum within a limited area and for a limited period. The licensee also becomes the owner of the petroleum when it is produced, meaning that the ownership is automatically transferred from the State to the licensee as the petroleum passes the well head. Production licences are issued in licence rounds.[30] There has been a continuous development of licence terms from licence round to licence round, but within each round the terms are basically standard. Consequently, the regulation of the licensees´

[29] The licence authorizes geological, geophysical, geochemical and geotechnical surveys.

[30] By winter 2011 there has been 20 licence rounds. See chapter 2 for more information on frontier areas and mature areas.

activities varies depending upon when they received their respective licences. Some standard terms have, however, been practiced more or less from the beginning. These include the obligations to pay an area fee, to perform an obligatory work programme and to enter into a joint operating agreement with the other holders of the production licence.[31]

Although the licensee is granted certain rights within the scope of the production licence, his subsequent activities are subject to government regulation and control. Petroleum deposits can not be developed unless a *development plan* has been approved by the MPE pursuant to the PA section 4-2. The petroleum regulations contain extensive requirements as to the contents of the plan. This makes it possible for the government to control all important aspects of the development, including efficient recovery of the petroleum in place, the tie-in of the development to existing or future infrastructure, safety and environmental aspects and so forth. In fact, all the various considerations under the resource management have to be taken into account at this stage, because a substantial degree of regulatory flexibility will be lost once the licensee has made his investments. The subsequent government control refers to more detailed aspects within the general framework of the approved development, e.g. the rate of production, the fabrication, installation and operation of individual installations.

Neither the production licence, nor the development plan, give the production licensee a right to build and operate a pipeline for the transportation of his petroleum, unless the pipeline is field dedicated (constructed to transport only the production licensee´s petroleum). However, most pipelines form part of an infrastructure transporting petroleum from several fields. There are large investments connected to the development of such an infrastructure.[32] A separate licence pursuant to PA section 4-3 is required. According to practice, a pipeline licence has been awarded to all field owners transporting petroleum through

31 Production licences are normally granted to a group of licensees. See 1.3.5 .

32 Investments on the Norwegian continental shelf tend to be very high due to large water depths and tough weather conditions. As to gas developments there are additional high costs connected to the development of an infrastructure of pipelines. The transportation distances from the fields to the market are becoming larger as new petroleum provinces are developed in the Norwegian Sea.

the pipeline, which means that the ownership structure of the pipeline more or less corresponds to the ownership structure of the co-mingled stream of petroleum (in the pipeline). The purpose of this system is to give the owners of the pipeline (the transporters) an incentive to charge low transportation tariffs to the owners of the petroleum (the shippers).

The final element in the licence system is the decommissioning plan and the MPE's subsequent decision, both of which are regulated by PA chapter 5. Prior to the expiration of a production licence or a pipeline licence, or the end of use of a fixed installation operated under such licences, the licensee is required to submit a decommissioning plan to the MPE. On the basis of the decommissioning plan the MPE may choose between several decisions, with alternatives ranging from complete or partial removal to continued use for petroleum or other purposes. Consequently, the PA leaves a wide margin of discretion to the MPE. But the MPE´s authority has to be exercised in conformity with the OSPAR decision 98/3 on disposal of offshore installations. We will revert to the Norwegian regulation and practice regarding the abandonment phase.

1.3.5 Organization of petroleum activities

As already mentioned, this organization consists of two major components; State organized licence groups, and State participation in the groups. In these respects, the Norwegian legal framework has developed certain characteristic features which clearly distinguishes it from other upstream oriented frameworks. In the following, I will concentrate on these features. I will also present the evolution of the organization of gas sales, and the recent establishment of a new operator for the gas transportation system (the system operator).

State organized licence groups

With a few exceptions in the first and second licence rounds, petroleum production licences have always been granted to a group of companies. From the third licence round, starting in 1974, these groups have been organized by the MPE on the basis of individual applications from the companies. In this context, the MPE has also appointed an operator for each licence group, who is responsible for the practical management of licence activities on behalf of the group.

Formally, a production licence is granted to each individual company of the group. One of the standard licence terms requires the company to enter into a joint operating agreement with the other companies (of the group). From the third licence round, these agreements have been made by the MPE. The contents of the joint operating agreements has developed from licence round to licence round, but within each round the terms have been basically standard. New agreements have not been subject to negotiations between the MPE and the companies. In spring 2007, a new joint operating agreement was introduced with retroactive effect from 1 January 2007. The new agreement will replace all former agreements. It has been made by the MPE, but this time the companies´ input has been considerable. They have conducted extensive discussions within OLF, the oil industry´s association. On this basis, the OLF has presented the unified view of the companies to the MPE.

Pipeline licences are also granted to a group of companies. In these cases, however, the companies negotiate a joint operating agreement which is subject to the MPE´s approval. There has been a general understanding that these agreements should reflect the same principles as the joint operating agreements for the production licences. Thus, even though the MPE´s involvement is less heavy with regard to these agreements, their contents has become fairly standard. Recently, the joint operating agreements relating to the gas pipelines have been amended as a result of the reorganizaton of the Norwegian gas sector.[33]

State participation in the licence groups

From the outset the system of State organized licence groups has been closely connected with a comprehensive State participation in the groups. The Norwegian State oil company, Statoil, was established in

33 See 1.3.5.

1972.[34] The purpose was (1) increased State revenues, (2) increased State influence in the activities and (3) increased "know how" compared to what could otherwise have been achieved through the normal licencing and tax systems.[35] In short, Statoil was meant to be a vehicle of the Norwegian State. Consequently, Statoil was granted a 50% participating interest in all licence groups from the third licence round. The joint operating agreements contained several privileges for Statoil, including a carried interest during *the exploration phase* and an option to increase its participating interest if a petroleum deposit was found.[36] In addition, the agreements contained voting rules which gave Statoil a dominant position in the decision making process.

With effect from 1 January 1985, however, Statoil was reorganized *(the 1985-reform)*.[37] A financial arrangement was established between Statoil and the State whereby Statoil´s participating interest was split into a Statoil economic share and a State economic share, called the State Direct Financial Interest (SDFI). According to this arrangement, a share of the costs accrued and a corresponding share of the revenues generated in the licence groups were directly channelled to the State. The financial privileges concerning carried interest and optional increase of participating interest were only to be exercised in favour of the SDFI. Since this was only a financial arrangement between Statoil and the State, Statoil managed the SDFI in the licence groups on behalf of the State. The State itself had no formal position versus the other licensees in the groups. However, as a consequence of the reorganization, Statoil´s dominant position in the licence groups was considerably reduced through a change of the voting rules in the joint operating

34 That establishment was based on a decision of the Norwegian Parliament of 2 June 1972.

35 Cf. St prp nr 113 (1971-72) p. 8.

36 The carried interest during *the exploration phase* meant that Statoil did not pay its share of the exploration costs. These costs were carried by the other companies in the licence group.

37 This was based on St meld nr 73 (1983-84) and Innst S nr 321 (1983-84).

agreements. The latter change was given effect for all licences.[38]

> The financial priviliges of Statoil/SDFI were gradually reduced. By 1991, the carried interest provisions had been repealed, and with effect for all production licences. In the 14th licence round, the optional increase of Statoils participating interest was repealed, but only with effect for licences granted in this round and onwards.[39]

From the 15th licence round, Statoil was not granted an interest in all licences. This is a consequence of Norway´s implementation of the licencing directive. According to the directive Statoil must be treated as a normal commercial entity, which excludes any form of privilege in favour of Statoil. On the other hand, the directive does not exclude or limit a direct participation by the State. This participation can be managed by the State itself, or through a legal person, cf. the directive art. 6. In the 15th licence round, the latter alternative was chosen; Statoil managed the SDFI on behalf of the State.[40]

In 2001, a new major reorganization took place *(the 2001-reform)*.[41] Statoil was no longer regarded as a vehicle for the Norwegian State. Consequently, Statoil was partly privatized and introduced on the stock exchange. The State is still a majority owner.[42] In addition, the State sold 15% of SDFI to Statoil and 6,5% to other interested oil companies. The Norwegian constitution does not allow a partly privatized Statoil to manage the SDFI. Therefore, the management of the SDFI has been transferred to a new 100% State owned company, Petoro. Petoro´s management of the SDFI is regulated in the PA chapter 11. Petoro´s *internal* relationship with the State is structured in the same manner as Statoil´s previous relationship with the State. Petoro´s *external* relationship with

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38 This required amendment of existing joint operating agreements, but the licensees accepted this because the change of voting rules was for their benefit.

39 Cf. St meld nr 26 (1993-94) p. 20.

40 For more information on the SDFI pursuant to the 1985-reform, see Selvig, The State´s direct financial interests in petroleum licences, p. 13-29, in: Selvig, Statens styring av petroleumsvirksomheten, Oslo 2001.

41 This was based on St prp nr 36 (2000-2001) and Innst S nr 198 (2000-2001).

42 At 1 January 2011, the state owns 67 % of the shares.

the other licensees and third parties represents a novelty. Petoro´s position in this regard is that of a licensee, cf. the PA section 11-2 second paragraph. Petoro is represented in all the relevant licence groups and takes part in the groups´ decision-making. However, Petoro cannot be held financially liable. The State is responsible for all financial claims from other licensees and third parties. Formally, the claims must be adressed to Petoro, cf. the PA section 11-3.

The management of the SDFI will be the main purpose of Petoro. Petoro will not apply for licences or perform the function of an operator, and it will not sell the State´s share of produced petroleum. The latter task will be performed by Statoil on behalf of the State. Statoil performs its task according to a sales instruction adopted by Statoil´s general assembly.[43] According to the sales instruction item 4, Petoro shall supervise Statoil´s sale of State petroleum. Summing up, it has not been the intention of the 2001-reform to create a new Norwegian oil company.

Organization of gas sales

The organization of Norwegian gas sales has developed through five phases. In the *first* phase gas was sold from fields where the production licence had been granted in the first and second licence rounds. The joint operating agreements under these licences had been negotiated by the licensees themselves, and as a result, the gas sales negotiations were conducted by the group under the leadership of the operator, who happened to be a foreign oil company.

In the *second* phase, Statoil took a leading role in the gas sales negotiations as a result of its initial 50% share in all new production licences. In the fourth licence round (1979) Statoil´s leading role was formalized in the (State made) joint operating agreement. However, Statoil´s leadership did not exclude the other licensees from taking part in the negotiations.

The *third* phase started with the ninth licence round (1985), i.e. just after the reorganization of Statoil. The new joint operating agreements introdu-

[43] This instruction was adopted before the part privatization of Statoil. In other words, the sales instruction was adopted by the State as sole owner of Statoil.

ced a gas negotiating committee for each licence consisting of Statoil and - to the extent that they had been awarded licences - the other two Norwegian companies Norsk Hydro and Saga. The effect of this arrangement was the exclusion of the foreign oil companies from the gas sales negotiations. This arrangement continued up to the 15th licence round. However, by that time the coordination of gas sales within the framework of the individual licence group had lost most of its significance.[44]

The *fourth* phase started in 1987 with the establishment of a national gas negotiating committee (GFU) consisting of the three Norwegian companies, and under the leadership of Statoil. Contrary to the previous gas sales arrangements, this one was not related to individual gas fields. It related to all gas resources on the Norwegian continental shelf. The arrangement was based on political guidelines adopted by Parliament in 1987, and subsequent guidelines.[45] According to these guidelines, GFU negotiated supply contracts with foreign buyers.[46] At this stage, the contracts were not related to any specific field. All contracts were signed by the GFU companies as sellers. After signature the contracts were subject to the MPE´s approval. Then, the MPE allocated contract volumes between producing fields, so-called contract fields. In this context the MPE received advice from a special supply committee (FU) consisting of all the major gas producers, including the foreign oil companies.[47] After the allocation of contract volumes, the GFU companies transferred their contractual positions to the licensees of the contract fields. Thus, in their capacity as GFU companies, Statoil, Norsk Hydro and Saga operated as a sort of sales agent for the contract fields.[48]

If certain fields were clear candidates for allocation of contract

44 However, it should be borne in mind that the old arrangements still formally exist since they are regulated by joint operating agreements that cannot be unilaterally changed.

45 Cf. St meld nr 46 (1986-87) p. 58-65.

46 During negotiations, the continental buyers are organized in a similar fashion as the GFU.

47 The FU was established in 1993.

48 In addition they maintain their positions as individual licensees, and thus producers.

> volumes already at the negotiating stage of the process, the GFU companies in some instances invited the licensees of these fields to participate in the sales negotiations. Provided prior notification to the MPE, such participation was in accordance with the political guidelines.[49]

Formally, the relationship between the GFU companies was regulated by an agreement, which had been approved by the MPE. As to the licensees of the contract fields, they were from 1996 under a licence obligation to follow the political guidelines.[50]

As part of the 2001-reform, a *fifth* phase was introduced. The GFU system was dissolved with effect from 1 June 2001 as regards gas sales to buyers located in the EEA. It was completely dissolved 1. January 2002.[51] There is no longer any local or central coordination of gas sales; it is up to every licensee to sell its share of produced gas on an individual basis. Thus, one has opened up for competition among gas producers on the Norwegian continental shelf.

System operation

Gradually, an infrastructure of gas pipelines has been developed on the Norwegian continental shelf (the transportation system).[52] All the gas fields are connected to the transportation system. This development requires a coordinated operation and development of the system as a whole (system operation). First, there has to be a balance between gas volumes fed into the system and gas volumes taken out of the system. And the co-mingled stream of gas in the transportation system has to meet the quality specifications pursuant to the gas contracts.[53] The system operator coordinates production from the fields in order to meet these specifications. Second, the different parts of the system are physi-

49 Cf. St meld nr 2 (1992-93) p. 104.

50 This obligation was introduced as a licence term and as a term in the joint operating agreement in the 15th licence round. Between 1987 and 1996, the GFU system was not regulated in the individual licences and joint operating agreements.

51 Cf. Royal Decree of 1 June 2001.

52 See 1.1.

53 The production from each field varies as regards quality.

cally linked together. If one part of the system is shut down for maintenance, that may easily affect the operation of other parts. Consequently, the system operator coordinates maintenance activities. Third, the transportation system has to be developed to meet future demands for transportation. This may involve expansion as regards transmission distance and/or transportation capacity. Such development requires coordinated planning by a system operator. System operation also involves economic coordination regarding allocation of transportation capacity and stipulation of transportation tariffs.

Individual pipelines are built and operated by licence groups pursuant to PA section 4-3.[54] Statoil was operator for almost all of these licence groups.[55] On this basis, Statoil operated the transportation system as a whole. Furthermore, Statoil performed system operation as a vertically integrated company.[56] In a liberalized gas market, it is very important that system operation is conducted in a neutral manner. A system operator, who is organized as a vertically integrated company, has strong economic incentives to perform system operation in a way that favours the company´s own production to the detriment of its competitors in the gas market. For these reasons, Statoil´s system operation was transferred to a new 100% State owned company, called Gassco, with effect from 1 January 2002. This was part of the 2001-reform and the subsequent abolition of the GFU system. As a next step, the joint ventures owning gas pipelines pursuant to the PA section 4-3 merged to one joint venture, called Gassled, with effect from 1 January 2003. The gas pipeline licences now belong to Gassled. According to the MPE´s consent to the merger, the pipeline licences have been extended to 31 December 2028.[57] Thus, the Norwegian gas infrastructure is now managed by one operator, Gassco, and owned by one joint venture, Gassled. Gassco´s system operation will be dealt with in item 4 of the Compendium.

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54 See 1.3.4.

55 Innst S nr 198 (2000-2001) p. 16.

56 A vertically integrated company performs all the successive functions in the value chain, i.e production, transportation and sale of gas.

57 The MPE´s consent of 20 December 2002 pursuant to the PA section 10-12.

1.4 The Norwegian model

Summing up, the Norwegian legal framework with regard to the petroleum activities is based on the State´s ownership to the sub-sea petroleum resources, and the general policy objective that this national resource shall be developed for the benefit of society as a whole. Since Norway is a big exporter of petroleum, the national economic interest leads to an optimization of the revenue potential from a producer´s point of view.

Although the State has chosen not to perform the petroleum activities itself in its capacity as resource owner, the main characteristic features of the legal framework must be seen in connection with the basic State ownership. These characteristic features are the State organized licence groups, the comprehensive State participation within the groups, and the licence system whereby all phases and aspects of the activities are subject to State control. All these regulatory elements are characterized by a strong central coordination by the resource owner represented by the MPE.

Since Norway became a member of the European Economic Area (EEA), a new legal dimension has been added to the national regulation. This has led to the abolition of the GFU system. Otherwise, it has not led to significant changes in the Norwegian model of central coordination.

2 Access to Resources on the NCS

By Ulf Hammer

2.1 Jurisdiction

In this article, I will primarily deal with the production licence, which is the main instrument for providing access to petroleum resources on the Norwegian continental shelf (NCS). But before presenting this licence and the licence system it is part of, it is necessary to explain the jurisdiction on the NCS. First, it is necessary to explain the international law basis for Norwegian jurisdiction over its natural resources on the NCS. This is regulated by the Law of the Sea Convention. Second, Norway is part of the EEA Agreement, which is important also from a resource management perspective. Several provisions in the national legislation concerning access to resources represent an implementation of the EEA Agreement.

2.1.1 International Law – The Law of the Sea Convention

Pursuant to art. 77 no. 1 of the Law of the Sea Convention (UNCLOS) the coastal State exercises over the continental shelf sovereign rights for the purpose of exploring it and exploiting its natural resources.[58] This is the international law basis for Norwegian jurisdiction over its petroleum resources on the NCS. However, the jurisdiction is not general as on the land territory, it is limited. The limitation is functional, cf. "for the purpose of…" In other words, the jurisdiction is limited to certain activties in connection with petroleum resources.

The jurisdiction on the continental shelf relates to natural resources.

[58] Pursuant to art. 56 no 1 of the UNCLOS, Norway exercises similar rights in the Exclusive Economic Zone (EEZ). The EEZ consists primarily of the water column above the continental shelf. Most importantly, these sovereign rights relate to the living natural resources, such as fish. They also encompass wind energy production, which has a large potential on the NCS.

This is mainly mineral and non-living resources of the seabed and subsoil, cf. art. 77 no. 4. A question is whether reservoirs on the continental shelf can be regarded as a natural resource, when such reservoirs are used for the storage of carbon dioksyde (CO2) injected into the sea bed. The Norwegian government is in the process of proposing new legislation in this respect pursuant to the Act no 12 of 21 June 1963 relating to exploration for and exploitation of other subsea natural resources than petroleum (the Continental Shelf Act). This implies that subsea reservoirs on the continental shelf used for permanent storage of CO2 are considered to be a natural resource over which Norway exercises sovereign rights. Thus, CO2 stored in subsea reservoirs on the NCS does not pose jurisdictional problems. The same procedure has been adopted in other jurisdictions.

The sovereign rights are exclusive in the sense that if the coastal State does not conduct said activities on the continental shelf, no one may undertake these activities without the express consent of the coastal State, cf. art. 77 no. 2.

The term continental shelf is defined in UNCLOS art. 76 as the sea-bed beyond the territorial sea to the outer edge of the continental margin, and in any case 200 nautical miles. The continental margin is further defined in art. 76, implying that the continental shelf may be smaller due to adjacent states. The continental shelf between them must then be agreed through delimitation agreements. Norway has entered into delimitation agreements with Denmark and the UK, Iceland, Denmark/Greenland and Russia based on the median line principle. The delimitation agreement with Russia was signed on 15 September 2010 and has summer 2011 been ratified by the respective Parliaments.[59]

2.1.2 EEA Law – The EEA Agreement

Norway is part of the EEA Agreement. This makes Norway a part of the EU internal market, which aims to achieve a free flow of goods, services, persons and capital. The agreement is entered into between the EFTA

[59] The Storting and the Duma.

states (except Switzerland) and the EU states.[60] Together they constitute the European Area. The agreement is important also from a resource management perspective. In the preamble tenth paragraph the parties emphasize a prudent management of natural resources. Furthermore, they intend to base their future legislation on high levels of health, environment and safety, cf. eleventh paragraph.

The agreement is based on two levels. The primary legislation consists of the EEA agreement itself. The agreement has been transformed into Norwegian legislation by the EEA act.[61] The secondary legislation consists of directives and regulations included in the EEA agreement by decision of the EEA committee.[62] This legislation has been implemented in many Norwegian acts and regulations pursuant to art. 7 of the EEA agreement. As far as the petroleum sector is concerned, the so-called licensing directive and the gas market directive I and II have been included in the EEA agreement and implemented in the PA and the PR.[63] I will come back to relevant provisions in the following. Gas market directive III is in the process of inclusion into the EEA agreement.

According to art. 126 of the EEA agreement it applies on the terrritories of the parties. The wording excludes the NCS, which is not a part of the territory of Norway. All the same, the licensing directive and the gas market directives have been included in the EEA agreement and implemented in the PA and the PR. Although these directives – for Norway – will mainly affect the petroleum activities on the NCS, the EEA parties considered it useful to include the directives in the EEA agreement.

Another discussed provision is art. 125 which states that the agreement shall not affect the parties´rules regarding property rights. The prevailing view is that this article does not prohibit complete public

60 The EEA agreement was signed 2 May 1992 and entered into force 1 January 1994.

61 Act of 27 November 1992 no 109.

62 The EEA committee consists of the parties to the agreement. They make decisions on the basis of unanimity, cf. art. 93 (2) of the EEA agreement.

63 Directive 94/22/EC on the conditions for granting and using authorizations for the prospection, exploration and production of hydrocarbons, Directive 2003/55/EC concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC. These directives are in appendix 4 to the agreement.

ownership of resources, which Norway has recently introduced as regards water falls, but that this ownership has to be exercised in accordance with the principles of the EEA agreement. So far, the agreement has not raised similar disputes regarding the ownership of Norwegian petroleum deposits on the NCS, as such ownership stems from the exclusive right under international law for Norway to declare its property rights to its natural resources. Such declaration was made by Norway on 31 May 1963.

2.1.3 National law - The Petroleum Act

On this level, I will primarily deal with the Petroleum Act.[64] But it should be noted that several national acts are relevant in connection with the petroleum activities. In addition, several regulations containing more detailed provisions – supplementing the act – have been adopted pursuant to PA section 10-18 first paragraph.

Pursuant to the PA section 1-1 the property rights to the petroleum resources on the NCS is vested in the Norwegian State. This implies as a starting point, that the Norwegian State is free to conduct all petroleum activities itself, or through a state-owned company. This is the situation in several petroleum provinces around the world.[65] Instead, the Norwegian State has established a licence system where private and State owned companies participate as licensees together with the State. The reason for this was to attract technologically competent and financially strong companies to perform petroleum activities on the NCS. I will soon revert to the licence system.[66] But it follows from the above that commercial companies do not own the petroleum while it is still in the underground. As licensees, however, they become the owners of their proportionate share of petroleum produced.

Furthermore, the State has an exclusive right to resource management, cf. PA section 1-1. This basically represents a national codification of the principle in UNCLOS art. 77 no. 2. I will revert to the term

64 Act 29 November 1996 no. 72 relating to petroleum activities.

65 Jens Evensen, Oljepolitiske synspunkter, Oslo 1971.

66 See 2.2.

"resource management".

The scope of the act needs some early clarification. As a starting point, the act relates to petroleum activities in connection with sub sea petroleum deposits under Norwegian jurisdiction, cf. PA section 1-4 first paragraph. In this respect, a few issues need to be underlined. First, the deposits have to be located on the NCS. There is a separate act dealing with deposits under Norwegian land territory and the part of the sea bed subject to private property rights, but so far there are no indications of petroleum deposits there.[67] Second, the act relates to petroleum activities in connection with these deposits. The term petroleum activity is defined in PA section 1-6 c). The term is wide and covers activities in connection with a petrolem deposit, including exploration, exploration drilling, production, transport, exploitation and decommissioning (abandonment). These activities are further defined in other parts of PA section 1-6. They do not necessarily have to take place on the NCS. In fact, several of them take place on land, typically in landing and processing terminals. They illustrate the *functional scope* of the act. However, the PA does not cover transmission, distribution and supply of gas on Norwegian territory. The latter activities are regulated under the Act on Common Rules for the Internal Market in Natural Gas.[68] This act will not be dealt with here. Third, the petroleum activities have to be performed on facilities. This term is defined in PA section 1-6 d). It should be noted here that this term does not comprise supply and support vessels or ships that transport petroleum in bulk. Activities on supply and support vessels, however, may be covered by the PA to the extent that such activities are functionally connected to petroleum activities. Pure maritime activities, e.g. nautical activities, fall outside the PA. As to transport of petroleum in bulk, these activities are considered to be normal shipping activities.

[67] Act of 4 May 1973 no. 21.
[68] Act no 61 of 28 June 2002.

2.2 The licence system

2.2.1 Resource management

The PA section 1-2 first paragraph introduces the resource manager: the King, who is the highest executive body of the Norwegian state hierarchy. In practice, the King only has a formal role. The real executive powers rest with the Cabinet, which has to a large extent delegated its powers to the Ministries. And the Ministries have further delegated authorities to subordinate Directorates. This delegation of powers is reflected in the PA and in the regulations adopted pursuant to the PA. In practice, the resource manager acts as licencing and regulatory authority.

Petroleum is a limited non-renwable natural resource with a large revenue potential. These characterstics form the basis for the resource management, which is the objective of the PA. According to PA section 1-2 second paragraph, petroleum resources shall be managed in a long term perspective for the benefit of Norwegian society as a whole. The provision lists several broad concerns, which the resource manager has to take into account. These include the generation of income, welfare and employment. Furthermore, the resource manager shall take into account a variety of interests affected by the petroleum activities, including the environment, Norwegian industry, and regional and local policy considerations. However, these broad concerns are all effect oriented. They do not directly emphasize petroleum as a limited and non-renewable resource. Those concerns are reflected in PA section 4-1 which generally states that production of petroleum shall take place in such a manner that as much as possible of the petroeum in place is produced. Furthermore, the production shall take place in accordance with prudent technical and sound economic principles and in such a manner that waste of petroleum or reservoir energy is avoided. Formally, PA section 4-1 is directed towards the licencees, but it is generally understood that the resource manager has to take this provision into account as well when issuing licences, and making decisions and regulations.[69]

The broad aims of PA section 1-2, cf. PA section 4-1, can be achieved by different means. One is state ownership and state management of the petroleum resources. This is common practice in several petroleum provinces around the world, e.g. in Saudi Arabia and Mexico. Or the state can enter into contracts with the oil companies, either as entrepreneurs or as owners of part of the production (production sharing contracts).[70] Norway has chosen a licence system where companies execute petroleum activities pursuant to a licence whereby they become the owner of their proportionate share of petroleum produced. A similar system has been adopted in the UK. A characteristic of licence systems is that they do not inhibit the state´s financial and legislative powers. Consequently, the companies have to rely on stable and well-functioning states for their investment protection. But the Norwegian system also contains an important element of state ownership, which is exercised within the licence system. I will soon come back to that.[71]

2.2.2 Characteristic features of the Norwegian licence system

The Norwegian licence system consists of the following licences: the exploration licence, the production licence and the specific licence to install and to operate facilities for transport and utilization of petroleum.[72] In addition, the approval of the Ministry of Petroleum and Energy (MPE) to the development plan (plan for development and operation) and the MPE´s decision relating to disposal of installations on the basis

69 Another provision in the same category as section 4-1, is section 10-1 which contains require ments to prudent petroleum activities. According to this provision, the petroleum activities shall take due account of the safety of personnel, the environment and the financial values which the facilities represent. Furthermore, the petroleum activities must not to an unreasonable extent impede shipping, fishing, aviation or other activities.

70 An overview of the different systems and their implementation in various states is given by Jens Evensen l. c.

71 See 2.4.4.

72 This is normal practice, but the wording of PA section 4-3 may also include production facilities. I will come back to this.

of the decommissioning plan are regarded as parts of the licence system. Although these approvals and decisions are not licences and thus not formal parts of the licence system, they constitute important decisions relating to specific stages of the petroleum activities. In this regard they resemble the licences: Before the company can enter into a new stage of the activities, it needs a licence or a government approval/decision. In connection with these successive licences or approvals/decisions, the Ministry may stipulate conditions when they are naturally linked with the activities to which the individual administrative decision relates, cf. PA section 10-18 second paragraph.

Other characteristic features of the licence system are the State´s organization of the licence groups in joint ventures and the comprehensive direct State participation in the licence groups. These elements are further elaborated in chapter 2.4.

2.3 The exploration licence (PA chapter 2)

2.3.1 Scope and contents

Subsquent to the opening of new areas pursuant to PA section 3-1 the Ministry may grant exploration licences.[73] The authority has been delegated to the Norwegian Petroleum Directorate (NPD).The purpose of this licence is to explore the potential for future petroleum deposits. The term "exploration" is defined in PA section 1-6 e). We are basically talking about seismic surveys of the underground, not drilling (except shallow drilling) for petroleum or production of petroleum. Only companies need a licence, the State itself can conduct activities without a licence, cf. PA section 1-3. The latter provision is general; it applies to the whole chain of petroleum activities. But it is very practical in *the exploration phase*, since the NPD conducts seismic surveys without an exploration licence. When a licence is necessary, the contents of an application is dealt with in the Petroleum Regulations (PR) section 3.

Exploration licences are granted for a limited area and with a limited

73 PA section 3-1 is dealt with in chapter 2.4.2 below.

duration of 3 years, cf. PA section 2-1 third paragraph. The scope of the licence is decided by the licence authority, the NPD. The latter may also stipulate terms for the licence, including terms about sale or exchange of exploration results, cf. PR section 4. Normally, commercial companies performing exploration activities, are specialist companies dealing with exploration activities and selling the results to the oil companies on commercial terms.

2.3.2 Relationship to the production licence

An exploration licence gives no right to future licences, including production licences. Furthermore, this licence does not entail exclusive rights, meaning that several licencees and/or the NPD may conduct seismic surveys within the same area at the same time.

2.4 The production licence (PA chapter 3)

2.4.1 Introduction

This is the main licence determining access to the petroleum resources on the NCS. Initially, there were no international restraints on Government authority when granting production licences. As a result, national oil companies, especially the 100% state owned company, Statoil, were given a privileged position. This practice changed with the EEA agreement and the implementation of the licensing directive into Norwegian law. Today, all companies have to compete for production licences without any discrimination on the basis of nationality, cf. art. 4 of the EEA agreement.

In the following, I will first focus on the procedure for granting production licences, then on the group of companies holding a licence, i.e. the licence group, state participation within the group, and the rights and obligations pursuant to a production licence.

2.4.2 The award process

Initially, a distinction has to be made between mature areas and frontier areas. The mature areas have been opened before and petrolum activities have commenced. In these areas, the geology is well-known and the fields are located near existing infrastructure.[74] From a government perspective, it is important to develop these areas rapidly while the infrastructure is still in place. Consequently, licence rounds are announced every year. This is called Announcement in Predefined Areas (APA). Frontier areas – on the other hand – are areas where the geology is little known.[75] The first step in the procedure for granting new production licences in frontier areas is the opening of new areas, cf. PA section 3-1. An impact assessment is carried out by the MPE, where special focus is on the impacts of future petroleum activities on all relevant aspects, such as society, trade, industry and other users of the sea such as fisheries, and the environment. Subsequently, the impact assessment is sent on a broad public consultation to local, regional and central authorities, and organizations that are presumed to have a special interest in the matter.[76] Finally, the decision to open a new area is made by Parliament. In the Northern Norwegian Sea and the Barents Sea Parliament has passed plans for the management of these areas, including the opening for petroleum activities (Comprehensive Management Plan). The management plan for the Barents Sea was passed in 2006.[77] A similar plan for the Norwegian Sea was passed by Parliament in 2009. In these plans, special emphasis is put on environmental impacts and the relationship between petroleum activities and fisheries interests, shipping and other relevant issues. As a result, certain areas have not been opened for petroleum activities for the time being.[78]

When an area has been opened for petroleum activities, the next step is the announcement of the area with a view to submission of applications for production licences, cf. PA section 3-5. The annoucement

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74 Mature areas are basically in the North Sea and in the southern part of the Norwegian Sea. See Facts 2010 p 30-32.

75 Frontier areas are basically in the northern part of the Norwegian Sea and in the Barents Sea. See Facts 2010 p 32-33.

76 More detailed rules on impact assessments pursuant to PA section 3-1 are in PR chapter 2A.

77 Facts 2010 p. 33.

78 This applies to the Lofoten area in particular.

will contain information on – inter alia – the areas for which applications for new production licences may be submitted, which award criteria and licence terms shall apply, and which terms that are open for negotiation. The announcement shall be published.[79] I will revert to the award criteria and the licence terms.

The normal procedure on the NCS has been licence rounds with applications from individual companies.[80] On this basis the MPE has composed licence groups. The rationale was to give the licence authority flexibility in composing groups with the best mix of technical competence and financial capacity. The licensing directive does not prohibit such composition of individual applicants, cf. art. 5 no. 1 of the directive, provided that the determination is made on the basis of objective and non-discriminatory criteria. On this basis the Norwegian practice has continued, with a few exceptions.

The award criteria are stated in PR section 10, which reflects art. 5 no.1 of the licensing directive. These criteria are the technical competence and financial capacity of the applicants, and their plans for exploration and production in the areas for which production licences are sought. Other objective and non-discriminatory criteria may be taken into account, provided that two or more applications are considered equal.

Finally, the production licence is awarded by the King in Council, cf. PA section 3-3 first paragraph. This is a formal procedure. In practice, the Government will have prepared all aspects of the decision in advance. Normally, production licences are awarded to joint stock companies registered in Norway.[81] But licences can also be awarded to natural persons domiciled in an EEA state, or to entities registered within the EEA area, cf. PA section 3-1 second paragraph.

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79 In the Norwegian Gazette (Norsk Lysingsblad) and the Official Journal of the European Union.

80 The first licence round was in 1965. Up till 2010 there has been 20 licence rounds on the NCS. In addition licensing in predefined areas (APA) has been practiced every year since 2003.

81 If the company is foreign, they establish a Norwegian affiliate in order to meet these requirements.

What can a discontent applicant do? The company may have received a smaller licence interest than it applied for, or no licence interest at all. Since the decision is made by the King in Council, the highest body in the state hierarchy, an administrative compaint is not possible. Administrative alteration is a possibility, but not very practical unless the King´s decision is illegal, cf. the Public Administration Act section 35. Such illegality may be due to incorrect application of the legislation, incorrect facts, incorrect procedure, or abuse of discretionary power. The dissatisfied applicant, may however complain to the European Survellance Authority (ESA) if he thinks that the licence award is contrary to the EEA agreement. Such a complaint may end up in the EFTA Court. The applicant may also raise a law suit against the Norwegian Government in Norwegian courts. If the case has an EEA perspective, a preliminary ruling is possible from the EFTA Court.

2.4.3 The Licence Group

A licence group is composed for each individual licence. The relationsship between the licencees is governed by the Agreement for Petroleum Activites (the Agreement). Enclosed to the Agreement as appendix A is the Joint Operating Agreement (JOA). The Agreement and the JOA are made by the MPE. They are standard documents. The oldest one, the JOA, has been revised several times.[82] The agreements are entered into by the licencees, but the agreements are licence terms, cf. PA section 3-3 fourth paragraph. On this basis, it can be argued that the agreements are part of the licence, and that they have to be interpreted in the same manner. Contrary to normal agreements between private parties where the purpose of interpretation is to find the aim of the parties, the Agreement and the JOA must be interpreted ojectively like the licence.[83]

What characterizes the joint venture? It is not a legal person pursuant to Norwegian company law. In fact, the company act (CA) makes a clear exception for joint ventures operating pursuant to the PA.[84] But

82 The latest version is of spring 2007.

83 This mode of interpretation is similar to interpretation of acts and regulations.

84 CA section 1-1(4).

the principles of the CA may supplement the JOA in certain cases. In other words, the principles of the CA may apply correspondingly to the extent that they are suitable. The joint venture – not being a legal person – can be characterized as an expence fellowship. The expence fellowship is based on co-ownership according to licence interests. It must be noted here that the fellowship does not comprice produced petroleum. Each licensee owns its part of produced petroleum.[85]

The parties to the joint venture and their respective licence interests are stated in the Agreement item 2. The voting rules of the joint venture are contained in the Agreement item 3. The main rule is a combination of the number of entitities behind a decision and the licence interests they represent. The reasoning behind this voting rule was to give smaller entities a reasonable voting influence in the licence groups. But there are exceptions here. Certain decisions regarding surrender of a licence or revocation of part of the licence area require unanimity. And the company managing the State Direct Financial Interests (SDFI), Petoro, has a veto right regarding certain decisions in the licence group. I will soon revert to this.[86]

The structure of the joint venture is dealt with in the JOA. The Management Committee (ManCom) is the supreme organ of the joint venture, cf. art. 1. In the ManCom all licensees are represented and it is led by the licensee which is operator. The JOA contains detailed rules on the tasks of the ManCom, both as to substance and procedure. Furthermore, it has a general competence to decide upon any matter that is connected to the activities of the joint venture.

The operator is another important entity of the joint venture. The operator is appointed by the MPE, cf. PA section 3-7. Normally, the operator is one of the licensees. If this is not the case, the duties regarding the licensees apply correspondingly. The operator is also identified in the Agreement. The competences of the operator are regulated in the JOA art. 3. The operator conducts the day-to-day management of the joint venture. Internally, the operator prepares decisions by the

[85] See 2.4.7

[86] See 2.4.4.

ManCom. Externally, the operator represents the joint venture towards contract parties and third parties. The operator performs his duties on a "no gain – no loss" basis. This is standard practice for petroleum activities. The gains the operator recovers as a licensee, owning part of the production. More than that, the operator gains valuable technical expertise which may be beneficial when future licences are awarded.[87] Therefore, the task as operator is highly regarded by the oil companies. It is natural that the operator does not incur any losses when performing his duties on behalf of the joint venture. But the operator is responsible for losses incurred by the other parties (of the joint venture) that are the result of wilful misconduct or gross negligence of the operator.[88]

2.4.4 State participation

State participation is a very typical component of the Norwegian licence system. The State is owner of the resources in the underground, and could have conducted all the petroleum activities itself. Instead, the State has organized its participation in petroleum activities through a licence system. In this system, the State is owner of certain licence interests. But the ownership has changed over time.

As a starting point, State participation in the licence system was carried out through Statoil, Initially a 100% state-owned limited company which was formed in 1972. Statoil was granted a 50% licence interest in all licence groups from the third licence round. The JOAs contained several privileges for Statoil, including a carried interest in *the exploration phase* and an option to increase its participating interest if a petroleum deposit was found. In addition, the JOAs contained voting rules which gave Statoil a dominant position in the decision-making process.

With effect from 1 January 1985, the State´s ownership was reorga-

87 See 2.4.2 on award criteria.

88 Cf. JOA art. 3.5. According to this provision, the operator shall under no circumstance be liable for any loss suffered by the parties in connection with damages to third parties caused by a spill of petroleum outside the safety zone.

nized. An arrangement was established between Statoil and the State whereby Statoil´s licence interests were split into a Statoil economic share and a State economic share, called the State Direct Financial Interest (SDFI). But this was an internal arrangement between Statoil and the State. According to this arrangement a share of the costs accrued and a corresponding share of the revenues generated by Statoil in the licence groups were directly channelled to the State. Externally, towards the other members of the licence groups, contract parties and third parties, Statoil was still the formal licensee – with its previous licence interests. However, Statoil´s dominant position in the licence groups was considerably reduced through changes of the voting rules in the JOAs.

In 2001, a major new reorganization took place. A basic distinction was made between the role as owner and the role as resource manager. The latter role was best executed by the licence authority and regulator. Consequently, Statoil was no longer regarded as a vehicle of the Norwegian State, and was partly privatized and floated on the stock exchange.[89] However, the special rules of the Act on Limited Companies (ALC) regarding companies wholly owned by the State do not apply to a partly privatized Statoil. Therefore, the State does not have full control as an owner of the company. Against this background the management of the SDFI has been transferred to a new company, 100% owned by the State, called Petoro. The management of the SDFI is the main purpose of Petoro.

Petoro´s management of the SDFI is regulated in PA chapter 11. The relationship between Petoro and the State represents a prolongation of the previous relationship between Statoil and the State. Since Petoro is organized as a limited company 100% owned by the State, the latter can direct Petoro´s activities as an owner through the General Assembly pursuant to the special rules (pertaining to 100% state-owned companies) of the ALC. But contrary to Statoil, Petoro´s activities as a main rule are limited to activities under the PA, cf. PA section 11-1 first paragraph. This means that Petoro´s activities must be within the functional

[89] The State is still a majority owner. At present it owns 67% of the shares.

scope of the act, cf. PA section 1-4. Petoro must manage the SDFI according to commercial principles, cf. PA section 11-2 first paragraph. Wider resource management objectives are pursued by the licence authority and regulator according to the PA.

The State itself does not apply for licenses; it reserves a licence interest for itself (without any competition), cf. PA section 3-6. This is according to the licencing directive.[90] It is also specified in the PA that the State owns the licence interests, which it reserves for itself, cf. PA section 11-1 first paragraph. Petoro is only the manager of these licence interests. And Petoro does not compete for this service.

In relation to the other licensees the 2001-reform implied important developments in a formal sense. Petoro – as manager of the SDFI – represents the State in the licences and joint ventures. Formally, Petoro then is a licensee and a party to the JOA which regulates the relationship to the other licensees in the joint venture, cf. PA section 11-2 second paragraph. As a party to the JOA, Petoro takes part in the decision-making of the joint venture. But Petoro is never operator of the joint venture, the most attractive position for oil companies. The reason is that Petoro is not an ordinary oil company, but a manager of the SDFI. Therefore, Petoro is a relatively small company with approximately 60 employees.

Petoro can oppose decisions by the ManCom that would not respect the conditions and requirements specified in the production licence regarding depletion policies and the State´s financial interests, cf. PR section 12 third paragraph and the JOA art. 2.3.[91] This is called the veto right. By exercising the veto right, Petoro functions as an instrument for state control. In practice, the veto right has not been used.

Petoro does not own produced petroleum, the State does. Statoil still sells the State´s share of produced petroleum, but now under the supervision of Petoro. Supervision of this kind entails an administrative challenge for Petoro, but does not require the organization of an oil company.

[90] Article 6 no. 3.

[91] These provisions reflect art. 6 no. 3 sub-para 3 of the licensing directive.

Externally, the licensees will incur contractual obligations and liabilities towards third parties, for example liability for pollution damage pursuant to the PA chapter 7. This is also the case as regards Petoro, but the State is directly liable for any obligations incurred by Petoro by contract or otherwise, cf. PA section 11-3. Petoro will only receive the claims and forward the claims to the State. And bankruptcy proceedings cannot be instituted against Petoro.

Finally, it can be asked what kind of entity Petoro is. Formally, it is almost like a hybrid, conducting a mix of commercial functions (PA section 11-2) and public functions (the veto right) on behalf of the State. But in practice, Petoro functions as a commercial entity.

2.4.5 The scope of the licence

We can distinguish between the functional and geographical scope and the duration of the licence. The functional scope consists of the licence activities. According to PA section 3-3, a production licence entails a right to exploration, exploration drilling and production of petroleum. These terms are defined in PA section 1-6. What is important to note here is that the term production does not encompass transport or utilization of petroleum. In order to conduct such activities a separate licence pursuant to PA section 4-3 is required unless the activities are covered by the approval of the developmen plan. I will revert to the latter approval and licence in a separate article. [92] Both decisions are part of the licence system.

A production licence may cover one or several blocks or parts of blocks, cf. PA section 3-3 first paragraph.[93] This does not mean that all the production activities necessarily take place within this area. Certain activities can take place on land based on today´s modern technology. This is according to the functional scope of the act.[94] But the petroleum deposit itself has to be within the licence area. To this

[92] Development of Fields and Infrastructure.

[93] The continental shelf is divided into blocks of a certain longitude and latitude, cf. PA section 3-2.

[94] See 2.1.3.

extent, the geographical scope of a production licence is the licence area. The licence area is an important topic prior to the award of production licences. In the invitation to submit applications, the licence area is singled out as a negotiating item. In other words, this item can be negotiated between the applicant and the MPE. On the other hand, the licensee, i.e the licence group, can later – on specicific terms - relinquish parts of the area covered by the licence, cf. PA section 3-14. The licensee can also apply for a partitioning of the licence area and that a separate production licence is awarded for the new area, cf. PA section 3-10. The new licence can then be transferred to other companies, which opens for restructuring of licence groups and more easy unitization of licence activities. I will revert to unitization.[95]

The duration of the licence is regulated in PA section 3-9. We can distinguish between three licence periods. First, the initial period is up to 10 years. Second, the prolongation period (after the initial period) is normally 30 years, but can be up to 50 years depending on the expected size of the petroleum deposit. The prolongation period is stipulated in the licence, and is a typical negotiating item. It should be noted that the licensee can require a prolongation provided his fulfilment of the work commitment and the other terms of the licence.[96] Historically, the licensee could keep 50% of the licence area. This reflected a compromise. The licensee should have necessary incentives to explore the licence area in the initial period. On the other hand, the licensee should not keep unnecessary licence areas in later periods. Now, the licence authority, i.e. the King, decides on this matter when awarding licences. This opens for more flexible solutions. Third, the licensee can apply for a special prolongation of the licence. This is practicable when the petroleum deposit cannot be produced completely within normal licence periods.[97] The duration and the terms for such a prolongation are stipulated by the MPE. On the other hand, the licensee can on specific terms surrender the licence, cf. PA section 3-15.

95 See 2.4.7.

96 See 2.4.6.

97 The Ekofisk and Troll fields are typical examples here.

It can be discussed whether the singling out of specific licence terms as negotiating items has any impact on the status of the licence; is it a contract between the Norwegian government and the licensee? This issue has much influence on the competence of Norwegian authorities to change licence terms to the licensees´ detriment, and was a key issue for the licensees some years ago. Today most changes of the licence terms are beneficial for the licensees in order to maintain the competitiveness of the NCS. Consequently, the status of the licence does not raise big discussions any longer. The parties seem to agree that the licence is not a contract.

2.4.6 The obligations of the licensee

PR section 11 generally states the type of concerns which conditions for production licences can be based on.[98] The provision reflects art. 6 no. 1 and 2 of the licensing directive. Conditions must be based solely on the need to ensure that petroleum activities are carried out in a proper manner. Furthermore, a variety of non-economic concerns and – to a certain extent – economic concerns can be taken into account. The latter are limited to systematic resource management (e.g. production rate or the optimization of the production activities) and the need to ensure fiscal revenues.

The most important obligation of the licensee in the initial licence period is the obligatory work commitment. Here we have to distinguish between frontier areas and mature areas.[99] In frontier areas, the licensee has to drill a certain number of exploration wells.[100] This requires a majority decision in the licence group. If no majority descision is reached, and no licensees wish to drill the well in any case, the licence has to be surrendered. If some licencees will drill in any case, the rest have to withdraw from the joint venture. In mature areas, there is sub-

[98] It should be noted that several conditions are codified in the PA and the regulations passed pursuant to the PA. But in the following, the conditions in the production licence are discussed.

[99] See 2.4.2.

[100] The production licence 19th licensing round item 4.

stantial knowledge of the area, and it is important to develop fields quickly. This is reflected in the work commitment (in these areas). Therefore, the licensees shall decide whether to prepare a plan for development (in addition to drilling exploration wells). If no such decision is made, the licence has to be surrendered. If the licensees decide to continue operations, they have to prepare a plan for development for the MPE´s approval within a fixed time limit from the award of the licence. Otherwise, the licence has to be surrendered.[101]

Another important item is the miscellaneous conditions.[102] These conditions contain several prohibitions on drilling and production to protect the environment and the fisheries. Amongst others, a zero discharge obligation - as a main rule - is stated. Initially, this obligation was formulated in Government reports to Parliament.[103] But these reports are not binding for the licensees. They have to be mentioned in the licence documents as well. When references to these reports are taken into the production licence, the obligations in the reports are put into effect also for the licensees. In addition to the references to the Parliament reports, this item contains several references to acts and regulations. The latter references are not strictly necessary from a legal perspective, but may have informative effects for the benefit of licensees and authorities.

The area fee can be mentioned here, cf. item 2. It is regarded as a rent for the licence area, but it is only applicable in the prolongation period in order to give licensees sufficient incentives for exploration. More detailed provisions for the calculation of the area fee are found in PR section 39.

2.4.7 The rights of the licensee

The basic rights of the licensee are stated in PA section 3-3. However, there are important derogations to be derived from (rest of) the act. First, the licensee becomes owner of produced petroleum. But the

[101] Awards in predefined areas 2005 item 4.

[102] Item 5 in licences for both mature areas and frontier areas.

[103] See Report to the Storting No. 25 (2002-2003).

manager of the SDFI, Petoro (who participates in the licences on behalf of the State), does not own produced petroleum.[104] Second, the licensee has exclusive rights to exploration, exploration drilling and production within the licence area. But if the petroleum deposit extends beyond the licence area, the licensee has an obligation to conduct joint activities with other licensees of the adjacent area, cf. PA section 4-7. The international term for such joint activities is "unitizaton". But the PA goes further. This obligation also applies in case of several petroleum deposits located in separate licence areas, if joint activities would obviously be most efficient. And others have certain rights to exploration, to place facilities, and to explore for and produce other natural resources than petroleum within the licence area, provided that these activities are not to the unreasonable inconvenience for the petroleum activities, cf. PA sections 3-11, 3-12 and 3-13. The rights to place facilities according to PA section 3-12 have been important as an infrastructure of pipelines for the transport of petroleum has been established across licence areas. In the future, offshore wind parks have a large potential. Building and operation of wind turbines offshore are regulated by a separate act.[105] But the relationship to the petroleum activities is regulated by the PA .Third, the licensee acquires a production right according to PA section 3-3, but the contents of this right depends on future licences and approvals, especally the approval of the development plan pursuant to PA section 4-2. I will come back to this in a separate article, Development of Fields and Infrastructure.

[104] See 2.4.4.

[105] Act 4 June 2010 no. 21 relating to renewable energy production offshore (offshore energy production act).

3 Development of Fields and Infrastructure

By Ulf Hammer

3.1 Introduction

3.1.1 The scope, objective and means of the Act

The scope of the Act is functional. This means that several activities are comprised by the Act even if they are conducted on land. But the petroleum deposits themselves have to be on the Norwegian Continental Shelf (NCS), cf. PA section 1-4. Furthermore, the main objective of the Act is resource management, a wide concept introduced in PA section 1-2. The scope and objective of the Act is explained in more detail in a previous article.[106]

The primary means in the resource management pursuant to the Act is the licence system. It consists of several licences, approvals and decisions relating to successive stages of the petroleum activities: the exploration licence, the production licence, the MPE´s approval of the development plan, the specific licence to install and operate facilities, in practice for transport and utilization of petroleum, and the MPE´s decision relating to disposal of installations.[107] The licensee cannot enter these successive stages of the activities without a prior licence, approval or decision. In Access to Resources on the NCS, I presented the exploration licence and the production licence. Now, I will present and discuss the MPE´s approval of the development plan and the specific licence to build and operate insttallations. Together, these decisions apply to the development of fields and infrastructure. The removal of installations will be dealt with in a separate article.[108]

[106] Access to resources on the NCS.

[107] Ministry of Petroleum and Energy.

[108] The Abandonment Phase.

3.2 The development plan (PA section 4-2)

3.2.1 Relationship to the production licence and the specific licence to to install and to operate facilities

According to the production licence, the licensee has a right to produce petroleum, cf. PA section 3-3. But this is only a starting point. We have to distinguish between if and how to develop a petroleum deposit. The if-question is regulated by the production licence. The how-question is regulated by the development plan and the MPE´s approval of this plan.

Initially, there was a clear distinction between the development plan and the specific licence to install and operate facilities, cf. PA section 4-3. The latter only included facilities for the transportation and utilization of petroleum. This is still mostly the case in practice. But the licence pursuant to PA section 4-3 may now also include production facilities if they are not covered by the development plan, cf. PA section 4-3. I will revert to this issue.[109]

In the following, I will start with the preparation of the development plan. As a starting point, we can distinguish between the internal decision-making in the licence group (joint venture) and the external decision-making of the MPE.

3.2.2 The decision-making in the licence group

The operator prepares a development plan for the parties in the ManCom, but the voting rules in the ManCom are different than the general voting rules in this respect. The principle here is that no party can be voted into a field development. Therefore, each party has to accede to the development plan, cf. art. 16 of the JOA.[110] If all parties do not accede, the interested parties can develop the field sole risk, cf. art. 19 of the JOA. This means that they take all project costs and income. The non-acceding parties do not incur costs or income, and they cannot participate in the project at a later stage.

[109] See 3.3.1

[110] The JOA for the 20th licensing round.

When the internal decision-making in the licence group is completed the development plan is sent to the MPE for approval according to the PA section 4-2. Now, the external process begins.

3.2.3 The contents of the plan

The contents of the plan is generally regulated in the PA section 4-2, with more specific requirements in the PR sections 20 to 22c. The development plan consists of two parts; a plan for the development of the petroleum deposit and an impact assessment. I will first deal with the deposit.

What kind of information is required when a field development is planned? First, geological information on the reservoir is necessary. The PA section 4-2 second paragraph requires information on economic aspects, resource aspects, technical, safety related, commercial and environmental aspects. To be more specific: The reservoir rock must be described including its characteristics as to porosity and permeability. Shifts in the rock formation must also be described. These characteristics determine the flow of petroleum in the reservoir, and how many wells that are necessary. And the number of wells determine how many drilling facilities that are necessary. The drilling facilities must be described. Traditionally drilling was performed on platforms, but in recent years ships have also been used. On deep sea levels sub sea drilling takes place.[111]

The production profile can be mentioned here. According to PA section 4-4 the MPE shall approve the production profile prior to or simultaneously with its approval of the development plan. As a starting point, the natural pressure in the reservoir leads to a production profile where production rises quickly to a plateau level, and then decreases rapidly. In this manner only approximately 20% of the reservoir is produced. But the degree of recovery can be increased by injection of gas and/or water. Injection of carbondioksyde is also a possibility. On the NCS up to 50% of the reservoirs are now produced by means of different

[111] Ormen Lange and Snøhvit are typical examples here.

kinds of injection. These methods and the installations they require must be described in the development plan.

Although the development plan primarily deals with production facilities, it shall also contain information on installations for transport and utilization which are comprised by PA section 4-3, cf. PA section 4-2 second paragraph. The latter facilities are not comprised by the approval of the development plan; a separate licence is necessary. But the connection of the production facilities to the existing or planned infrastructure on the NCS has to be described. The removal of installations has also to be described. This is a requirement in the IMO guidelines on removal, which will be dealt with later on.[112]

In addition to the above the licensee must give information on operation and maintenance and economic aspects. He must also make an impact assessment of the activities. What impact will they have on other activities and the environment? The general provision on resource management must be recalled here, cf. PA section 1-2. More detailed provisions on the procedure and contents of an impact assessment are found in PR sections 22, 22a, 22b and 22c. [113] The MPE may also demand impact assessments for a larger area than comprised by the development plan, cf. PA section 4-2 third paragraph. The purpose is to assess the combined effects of several developments. But such an assessment may only be required when special circumstances apply.

The licensee must also give information on what other applications are needed on land, cf. PA section 4-2 second paragraph. Here must be recalled the functional scope of the act, cf. PA section 1-4. This means that the PA to a certain extent regulates activities performed on land as well. But this does not limit the application of existing land legislation. The PA will overlap the latter.[114]

112 See The Abondonment Phase.

113 The impact assessment is sent on a broad hearing to affected authorities and interest organizations, cf. PR section 22a fourth paragraph.

114 The Planning and Buildiing Act is a typical example here.

3.2.4 Time of field development

The starting point here is that substantial contracts for the building of installations must not be entered into prior to the MPE´s approval of the development plan, cf. PA section 4-2 fifth paragraph. The reason is quite obvious; this plan lays the framework for the whole development and the possibilities of the MPE to influence events require that substantial contracts do not inhibit its decision-making.

Furthermore, the MPE may require the postponement of field development, cf. PA section 4-5, or the commencement or increase of production, cf. PA section 4-6. The former authority was used back in the 1980ies to adapt the timing of new projects to capacities of Norwegian suppliers of goods and services. But due to art. 4 of the EEA agreement, which forbids discrimination on the basis of nationality, this practice has stopped. Besides, the prospectivity of the NCS today does not warrant a delay of new projects. The challenge these days is to find new petroleum resources. PA section 4-6 has never been used so far, but new investments to increase the rate of recovery or to adapt new field developments to existing infrastructure may require the use of this provision in the future.

3.2.5 Approval

We can distinguish between external and internal procedures here. According to internal guidelines between the Government and Parliament, projects above 10 billion NOK (or approximately 1 billion EURO) shall be submitted to Parliament. The Parliament´s comments will have a binding effect upon the MPE´s margin of discretion. But this step in the procedure is not mentioned in PA section 4-2.

According to PA section 4-2, the development plan is approved by the MPE. This approval determines the external relationship between the MPE and the licensees, and will have a binding effect upon the licensees.

3.2.6 The MPE´s margin of discretion

The restrictions on the MPE´s margin of discretion arise in two regards: First, what kind of considerations may be taken into account when a development plan is approved or repudiated.[115] The restrictions in this regard follow from general principles of Norwegian public law. The MPE may not base its decision on considerations outside the PA. This is not very restrictive in practice, since the aims of the PA are very wide, cf. PA section 1-2. Section 4-1 on prudent recovery is more restrictive, but may be deviated by resource management considerations or "other significant social considerations", cf. PA section 4-4 first paragraph.[116] The considerations must also be proportional; the MPE´s decision must be appropriate and necessary, and the means must not surpass the objectives. A similar principle can be found in EEA law. The proportionality test is most practical in connection with the stipulation of terms.

Second, there are restrictions on what terms the MPE can stipulate in connection with its approval of the development plan. The PA contains several terms that stipulate specific obligations on the licensee. But a general provision can be found in PA section 10-18 second paragraph: "In connection with individual administrative decisions, other conditions than those mentioned in this act may be stipulated, when they are naturally linked with the measures or the activities to which the individual administrative decision relates." The question then is how comprehensive "naturally linked" is. That depends on the administrative decision, in this case the approval of the development plan. The development plan establishes a general framework for the development of the field. A lot of considerations are relevant, see the contents of the plan.[117] Consequently, a lot of terms will be naturally linked with the development plan. PA section 10-18 second paragraph does not

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115 According to PR section 20 fourth paragraph the MPE shall explain its reasons in a separate document that is to be made public The requirement to explain reasons follows from the public administration act. But the requirement to state the reasons in a separate document that shall be public, follows from PR section 20.

116 I will soon come back to PA section 4-4.

117 See 3.2.3.

limit the MPE´s margin of discretion to any significant extent here. The PA is supplemented by general principles of Norwegian law and EEA law also in this regard. The proportionality principle is similar (in Norwegian law and EEA law) and requires that the means, i.e. the terms, do not surpass the objective. In addition the terms must be appropriate and necessary.

More specific restraints on the MPE´s authority can be derived from the licence system. The realtionship to the previous production licence warrants some comments. According to this licence, the licensee has a right to conduct petroleum production. But this is only a starting point. The contents of the production right, is decided by the MPE´s approval of the development plan. In environmentally fragile areas, the licensee risks costly and burdensome terms for the development plan. Such terms have not stopped projects so far. They are not considered as an amendment, or even a revocation, of the production licence.

What are the consequences for future licences, approvals or permits? When the licensee has done costly investments pursuant to the development plan, future government decisions may be perceived as an amendment of the development plan if they imply changes to investments made pursuant to that plan. Amendments of the plan can be made according to general principles of Norwegian administrative law. But such amendments must be motivated by strong public concerns or new circumstances. This is a confinement in government discretion according to the PA or regulations pursuant to the PA.

But what about decisions pursuant to other legislation, e.g. the pollution act? According to this act section 7 first paragraph, pollution is forbidden unless a discharge permit is granted pursuant to section 11.[118] Discharge permits are awarded by the Climate and Pollution Control Directorate (CPCD), and the permits can relate to all stages of the petroleum activities. They may also be costly or imply heavy investments for the licensee and holder of the discharge permit. Formally, the PA

118 We are here talking about constant leakages of petroleum or other harmful substances. The act does not apply to abrupt spills of petroleum on the continental shelf, cf. section 4 first paragraph of the pollution act.

does not imply restrictions on government authority pursuant to the pollution act. But in practice the development plan will limit the margin of discretion of the CPCD as far as regards discharge permits awarded after the development plan.[119] Here must also be recalled that environmental authorities take part in the hearing of the development plan.[120]

Based on the effects of the development plan, we can say that the MPE´s margin of discretion narrows over time. A good illustration of this point is the regulation of the production profile, cf. PA section 4-4. As a starting point, the production profile is approved prior to or simultaneously with the approval of the development plan, cf. section 4-4 first paragraph. This approval is based on PA section 4-1 – prudent recovery – but broader resource management considerations and socio-economic concerns may also be taken into account. On the basis of the approved production profile the licensee can apply for production quantities, cf. section 4-4 third paragraph.[121] The production profile cannot be deviated unless new reservoir information or other new information apply. According to section 4-4 fourth paragraph the production profile can be changed, provided that strong socio-economic reasons make it necessary. Furthermore, such a change shall be allocated to all petroleum deposits, taking account of long term gas contracts and deposits that cross the border line to other states´continental shelves. Finally, such decisions are made by the King in Council. Summing up, the requirements in all respects – as to material and personal authority – are stricter. In practice, this authority has been used when Norway has complied with decisions on production limitaions by OPEC.

A question here is whether changes in the production profile, e.g. production restrictions, are contrary to the EEA agreement. The question arises because all Norwegian gas is exported, mostly to national or regional markets in the EU. According to art. 12 of the EEA agreement quantitative export restrictions and measures with equivalent effect are

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119 Jon Vegard Lervåg, MarIus no. 363 p. 116-121.

120 See 3.2.3.

121 This is now done once every year.

forbidden between the parties (to the agreement).[122] This provision only applies to distinctly applicable export restrictions, cf. the Groenveld-decision by the European Court of Justice (ECJ) (now Court of Justice of the European Union (CJEU)). [123] The decisions pursuant to PA section 4-4 apply to production on the NCS. In other words, they are not distinctly export oriented. Consequently, the EEA agreement does not limit the Norwegian government´s discretion in this regard.

3.3 The special licence to build and operate installations (PA section 4-3)

3.3.1 Scope. Licence award

This licence, also called the section 4-3 licence, has traditionally applied to transport and utilization facilities. Characteristic of these facilities is that they are used by several licence groups to different fields and that they to some extent are situated on land.[124] According to a fairly recent amendment of the PA section 4-3, the latter provision may now also comprise production installations, provided that they are not covered by the development plan. The reason is that also such installations may be used by others, especially in the later stages of the field development when new fields are connected to existing installations to exploit spare capacity. This necessitates a separate licence for these new activities both with regard to duration and terms.[125] As a consequence, the formal distinction between the production licence and the specific licence to build and operate installations is not so clear anymore. We can say the licence pursuant to PA section 4-3 now generally applies to installations that function as an infrastructure.

The licence award is regulated differently than the production

122 The EEA agreement has been transposed into Norwegian law by the EEA act section 1 . See Access to Resources on the NCS 2.1.2.

123 ECR 1979 p. 3409.

124 The scope of the PA also comprises activities on land when they are integrated with the petroleum activities offshore, cf. section 1-4 second paragraph.

125 Ot. prp. nr. 46 (2002-2003) p. 14.

licence. First, the licence is awarded by the MPE. Second, the licence terms and the duration are decided by the MPE´s discretion; the PA does not contain any specific regulation in these respects. This means that the duration and the terms are adapted to each specific project. But this applies to the building of installations. When we come to the operation of these installations, another regulatory perspective arises. The terms are regulated in detail in several regulations, especially as regards tariffs. I will come back to that.[126]

The licensee shall submit a plan for the building and operation of the indtallations, cf. PA section 4-3 second paragraph, and the contents of this plan is regulated in detail by PR section 29. According to the latter provision, the plan shall deal with economic, resource related, technical, environmental and safety aspects of the project. This resembles the kind of information required in the development plan and several of the detailed provisions in that regard apply correspondingly, cf. PR section 29 fourth paragraph.

3.3.2 The licence group

The licensing directive does not apply with regard to section 4-3 licences. Consequently, the MPE composes licence groups according to its own discretion. But certain principles have evolved in practice. First, licence groups are composed on the basis of ownership to petroleum transported through the installation. Thus, the licence group can consist of companies from several fields transporting petroleum. This affects section 4-3 licences both as to duration and terms. Second, the size of the licence interests shall reflect a neutrality between owner and shipper (user) interests.[127] The shippers shall have an ownership interest in the installation according to the flow of petroleum transported through the installation. On this basis, the owners have a disincentive to charge high tariffs; companies are not inclined to pay high tariffs to themselves. This functions as a self-regulating mechanism. However, it

126 See 3.3.5.

127 This principle was first formulated in St. meld. nr. 46 (1986-87) p. 67-69.

has not stopped the development of strict regulations for gas tariffs.

The State takes part in these licence groups as well. The State reserves a licence interest for itself, cf. PA sections 3-6 and 11-1. The State ownership is managed by Petoro, cf. PA section 11-2.[128]

At this point, it is necessary to make a distinction between oil and gas pipelines. We can here talk of a two tier system. Oil pipelines are organized in the same way as production installations (under a production licence). There is one joint venture with one operator for each installation or group of installations tied to each other. In other words, there is one joint venture for each pipeline or transport system. Gas pipelines are organized differently. By the MPE´s approval of 23.12. 02 pursuant to PA section 10-12, the existing joint ventures for gas ransport to the UK and the Continent were merged to one joint venture, called Gassled.[129] Simultaneously, a new state owned company, Gassco, was appointed as operator with special responsibility for the whole gas transport system. I will revert to Gassco´s position.[130]

3.3.3 The licence terms

As to technical tems, PR section 28 lists several terms which the MPE may stipulate in connection with a section 4-3 licence. These terms are specifically related to pipelines. The MPE may decide on the landing point of the pipeline and its routing, dimension and capacity. Furthermore, the MPE may decide on its tie-in to other facilities and which petroleum shall be transported in the pipeline. However, such a decision cannot be to the detriment of shippers that have been allocated capacity in the pipeline on the basis of previous approvals by the MPE. This leads to the economic terms for the use of pipelines and/or processing facilities. In this regard, we are talking about capacity allocation and tariffs.

As to economic terms relating to third party access (TPA), I have to

[128] See Access to resources 2.4.4.

[129] Terms were stipulated according to the general provision of PA section 10-18 second paragraph.

[130] See System Operation

reiterate the previous distinction between oil and gas facilities. Although the starting point is the same, cf. PA section 4-8, the detailed regulation is quite different in those regards due to the gas market directive. TPA is dealt with in later articles. The following presentation is just an opening.

3.3.4 TPA: Oil pipelines and production facilities

According to PA section 4-8 first paragraph first sentence, the MPE can require TPA to installations comprised by PA sections 4-2 and 4-3. On this basis the MPE has passed regulations on the use of facilities by others, called the TPA-regulations. But the TPA-regulations do not apply to the gas facilities listed in the tariff regulations, cf. the TPA regulations section 1. This means that the TPA-regulations deal with oil pipelines and processing facilities on production platforms.

And we are talking about negotiated TPA as regards the latter facilities. More detailed rules on the negotiations are provided by the TPA-regulations.[131] The negotiations shall be conducted on transparent, objective and non-discriminatory terms, and as to final contracts profits shall primarily be based on petroleum production. In other words, tariffs shall be reasonable for the users. High tariffs shall not be an impediment to the development of new fields. This principle has been practice on the NCS for a long time. Previously, the MPE approved all agreements entered into to control this principle, but this practice does not apply any longer due to the TPA regulations.

3.3.5 TPA: Upstream gas pipeline network

According to PA section 4-8 first paragraph second sentence, natural gas undertakings and privileged customers, have a right of access to upstream pipeline networks.[132] The latter term is defined in PA section 1-6 m). Basically, we are talking about pipelines constructed and ope-

131 Regulation on the use of installations by others, stipulated by the MPE 20 December 2005.

132 All customers belong to this category since 1 July 2007, cf. PA section 1-6 o).

rated as part of a production project, or used to convey natural gas to a processing plant, a terminal or a final landing terminal. This definition comprises the Norwegian gas transport system to processing facilities in Norway and further to final landing terminals in the UK and on the Continent.

More detailed rules on TPA and capacity nanagement are found in PR chapter 9. Here we will also find technical rules on the dispatching of gas volumes. Very specific rules on tariff calculation are in the tariff regulations. We can call this scheme regulated TPA. The scheme is based on gas market directive II.[133] It will be dealt with in later articles.

3.3.6 TPA: Carbon Capture and Storage (CCS)

According to PA section 4-8 third paragraph, the MPE can decide that petroleum installations are used by others for the purpose of CCS. In this case, the provisions of PA section 4-8 regarding negotiated TPA apply. There are several aspects of this operation which may not have any connection to the petroleum activities. e. g. the capture of CO2 from land based facilities and the storage of CO2 from these facilities. Hence, these aspects are outside the scope of the PA. These aspects will be regulated pursuant to the contintinental shelf act, which now applies to exploitation of other resources than petroleum resources, and the pollution act.[134] Moreover, a new directive applies to storage of CO2.[135] But so far it has not been included in the EEA agreement.

3.4 Conclusions

The Norwegian licence system is upstream oriented. We see that clearly as regards the development of fields and infrastructure. The development plan and the special licence to build and operate installations concern the development of installations within the functional scope of the PA.

133 Directive 2003/55/EC. It will be replaced by gas market directive III, i. e. directive 2009/73/EC. The latter directive has not yet been included in the EEA agreement.

134 Ot. prp. nr. 48 (2008-2009) p. 11.

135 Directive 2009/31/EC.

A characteristic feature of the licence system is the degree of central coordination that it entails. The major licences are awarded by the MPE (and the King as regards the production licence).

Another characteristic feature is the strong State participation within the licence system. The State owns licence interests, which are managed on a dayly basis by Petoro.

The Government exercises control in successive stages of the activities through the licence system. The authority is wide at the outset. But the authority gradually narrows over time. The important factor here is the approval of the development plan. Pursuant to this plan major investments are made, and these investments can in many cases not be altered later on.

In addition, the international framework limits Government discretion. We see this most clearly as regards the EEA agreement. Important directives for the internal market, e.g. the licensing directive and the gas market directives, have been included in the EEA agreement and implemented in the PA and regulations pursuant to the PA. Thus, the European legislative development influences the Norwgian licence system. The international framework as regards the abandonment of installations must also be taken into account. I will come back to this in a separate article.[136]

[136] The Abandonment Phase.

4 System operation

By Ulf Hammer

4.1 The Norwegian upstream gas chain

Natural gas produced on the Norwegian Continental Shelf (NCS) is transported through pipelines to regional markets on the Continent and in the UK.[137] Oil is mainly transported by ship to global markets in Europe, in the US and elsewhere. In the following, we focus on gas transportation.

The Norwegian upstream gas chain consists of the following functions: Gas is produced from subsea petroleum deposits on the NCS. These petroleum deposits typically contain both oil and gas. In such cases, current technology requires an initial processing of produced petroleum on the platforms to separate oil and gas components. Normally, oil is loaded into tankers and transported to the global markets.[138] Rich gas is fed into pipelines and transported to treatment terminals on the Norwegian coast. Rich gas consists of wet and dry components, and needs further processing before marketing. In the treatment terminals the wet components are separated from the dry components. Natural gas liquids (NGLs) are loaded into tankers and transported to the market. Dry gas is fed into landing pipelines crossing the NCS. These pipelines lead to receiving terminals on the Continent and in the UK. At the outlet flanges of the receiving terminals the gas, now called sales gas, is fed into transmission pipelines.

The scope of the PA covers production on the NCS, initial processing on the platforms (located on the NCS), transportation to treatment terminals on Norwegian territory, and the further processing in the

[137] Gas can also be cooled down to liquefied gas (LNG) and transported by ship to the market. So far, only one project (Snøhvit) has adopted this transport solution. See Facts 2007, p. 170.

[138] In a few cases oil is transported by pipeline. See 1.1.

terminals, cf. section 1-4 first and second paragraph.[139] As to the further transportation to the receiving terminals, the application of the PA rests upon agreements between Norway and states on the Continent and the UK, cf. section 1-4 first paragraph. As a main rule, these agreements allow Norwegian jurisdiction over the pipelines and parts of the receiving terminals. Naturally, the PA does not cover transmission, distribution and supply of gas on the territories of foreign states (the European downstream gas chain). But the PA does not cover transmission, distribution and supply of gas on Norwegian territory either (the Norwegian down stream gas chain). The latter activities are regulated under the Act on Common Rules for the Internal Market in Natural Gas.[140] So far, only one small pipeline network and a couple of LNG facilities fall under this Act. The Act will not be further elaborated here. Summing up, the PA deals with the Norwegian upstream gas chain.

4.2 The system operator function

The building and operation of pipelines are subject to a pipeline licence pursuant to the PA section 4-3. The building and operation of treatment terminals are covered by the production licence, cf. the PA section 3-3. The respective licenses have been granted to a group of licensees, who have entered into a joint venture agreement. Each licence group has owned and operated its part of the network. The MPE has appointed one of the licensees as operator. The operator´s task is to conduct daily activities on behalf of the joint venture. The operator performs this task on a no profit no loss basis.

Gradually, a network of interconnected pipelines has been established under successive pipeline licences. The producing fields on the NCS are connected to this upstream pipeline network. However, efficient resource management requires a coordinated operation and development of the whole network. This coordinated operation and development is called system operation. It can be divided into two main categories:

139 See 1.3.2.

140 Act no 61 of 28 June 2002.

- Technical coordination. First, it entails the (1) dispatching of gas and coordination of gas flows from different fields.The dispatching process aims to achieve a balance between the gas volumes fed into and taken out of the system. The fields produce different gas qualities, but the quality of the co-mingled stream in the upstream pipeline network has to meet the quality specifications in the transportation contracts. Gas flows also need to be coordinated to optimize the production of liquids (oil and condensate) from fields containing both oil and gas. Second, it entails (2) coordinated maintenance of the network, including the fields that are connected to the network. All the installations in the network are physically linked. Consequently, the shutdown of individual installations for maintenance needs to be coordinated in order to avoid disturbing the other installations in the network. Third, it entails the (3) coordinated planning of new capacity and/or expansion of existing capacity with a view to meeting the future demand for gas from the network.

- Economic coordination. First, it entails the (1) allocation of transportation capacity to the different users of the network. Second, it entails the (2) stipulation of transportation tariffs; i.e the price for transportation capacity.

The above aspects of technical coordination promote short term and long term security of supply. The economic coordination is necessary to achieve efficient and non-discriminatory access for users to the network. These concerns reflect major aspects of resource managment, cf. the PA section 1-2 and section 4-1.[141] However, the abolition of the GFU system has paved the way for competition among gas producers on the NCS.[142] This event coincides with the inclusion of gas market directive II in the EEA Agreement and the implementation of the directive in the PA (and the regulations pursuant to the PA). The main purpose of the directive

141 See 1.3.3.

142 See 1.3.5 (c).

is to achieve a competitive, secure and environmentally sustainable market in natural gas, cf. art. 3 (1) of the directive.[143] In order to achieve this objective it is very important that the system operator is organized as a company with no commercial interests in the gas market, and that all aspects of system operation are conducted in a neutral manner. These new aspects of resource management will be further elaborated in the following.

4.3 The system operator: Organization

Until 2001, Statoil was the operator of almost all gas pipelines on the NCS. In fact, Statoil operated 94% of the capacity in the upstream pipeline network. In addition, Statoil operated the treatment facilities and most of the receiving terminals. Statoil´s dominant position enabled it to exercise a system operator function from its control centre at Bygnes.[144] Formally, Statoil exercised the sum of its operator functions pursuant to the joint venture agreements for the various licence groups. However, Statoil was - and still is - organized as a vertically integrated oil company covering all functions in the gas chain. Under the GFU system this was no problem; the gas producers on the NCS did not compete with each other. In the new liberalized system post GFU, Statoil could easily exercise its system operator function to the detriment of its competitors in the gas market.

On this background, the 2001-reform led to the establishment of a new State owned system operator, Gassco.[145] Organizational changes have also taken place on the ownership side. The joint ventures established pursuant to the pipeline licences decided to merge their activities. The outcome is one joint venture with effect from 1 January 2003, called Gassled.[146]

In connection with the merger of the existing gas pipeline joint

143 Gas market directive III is in the process of inclusion in the EEA Agreement. It will be implemented in the PA and PR, but will not be further dealt with in this article.

144 St prp nr 36 (2000-2001) p. 72.

145 See 1.3.5 (d).

146 See 1.3.5 (d).

ventures to Gassled, the MPE appointed Gassco as operator for Gassled.[147] As operator for Gassled, Gassco exercises the system operator function as described above. It does not build or operate individual pipelines, but shall have the overall responsibility in the latter regard as well. The scope of Gassco´s responsibilities encompasses the Norwegian upstream gas chain, i.e the upstream pipeline network and associated treatment and receiving terminals.[148] Contrary to Statoil, Gassco is organized as an independent system operator (ISO). This means that Gassco has no commercial interests in the gas market.

The 2001-reform also led to changes in the agreements regulating the internal relationships in the licence groups. First, it must be noted that Gassco has not been appointed as a licensee pursuant to the PA section 4-3. Consequently, Gassco is not a party to the joint venture agreements. Two new agreements have been established, supplementing the joint venture agreements: (1) an operating agreement between the joint venture and Gassco, and (2) a technical services agreement between Gassco and the previous operator, in most cases Statoil.[149] These agreements imply that Statoil´s function as operator pursuant to the joint venture agreements has been transferred to Gassco.

> However, Gassco has not taken over all of Statoil´s rights and obligations. First, Gassco is the new chairman of the management committee, but it has - contrary to Statoil´s previous position - no voting rights. Only the licensees have voting rights. Second, Statoil continues to manage daily technical operation and maintenance under the overall responsibility of Gassco. Formally, Statoil has been appointed as technical services provider.

[147] Cf. the MPE´s decision of 20 December 2002 pursuant to the PA section 10-12.

[148] St prp nr 36 (2000-2001) p. 75-77.

[149] For the sake of simplicity we refer to Statoil in this context. Similar agreements have been - or are being - entered into with Gassco and the other operators (Norsk Hydro, TotalFinaElf and ConocoPhillips).

4.4 The system operator: Performance of activities

4.4.1 Implementation of the gas market directive

The above amendments to the joint venture agreements imply that Gassco has been integrated in a modified joint venture structure among licensees on the NCS. This means that Gassco as operator is subject to the control and instructions of the management committee in the joint venture. The other members of the management committee - the ordinary licensees - are fully integrated oil companies. Clearly, this organizational structure can impede Gassco´s neutral exercise of the system operator function. This problem has been addressed in the recent amendments to the PA and the Petroleum Regulations (PR), passed pursuant to the PA. The amendments to the PR have been adopted as a new chapter 9 on access to upstream pipeline networks.[150] The amendments to the PA and the PR have been adopted to implement the gas market directive in Norwegian legislation pursuant to the EEA Agreement art. 7 b). The Norwegian implementation can be summarized as follows:

First, the recently amended PA section 4-8 first paragraph states that natural gas undertakings and eligible customers have a right of access to upstream pipelines. The PA does not specify how this access shall be organized. According to the gas market directive art. 18, Member States shall implement a system of regulated access. Art. 20 (1) provides a wider framework for the Norwegian upstream pipelines: Member States shall take the "necessary measures" to ensure that natural gas undertakings and eligible customers are able to obtain access to such pipelines. The access criteria are spelled out in the PR chapter 9. These criteria are more stringent than those of art. 20 of the directive; they reflect the system of regulated access pursuant to art. 18. They are dealt with in item 5 of this Compendium.

Second, chapter 9 contains rules on Gassco as system operator. They supplement the recently adopted PA section 4-9. The PA section 4-9 first

[150] The amendments entered into force 1 January 2003.

paragraph authorizes the MPE to appoint a system operator, but it has not been necessary to apply this provision as regards Gassco. The latter had already been appointed as operator for Gassled.[151]

Gassco´s duties pursuant to the PR chapter 9 mainly concern capacity allocation and coordination of gas flows. These duties will be dealt with here.[152] To a significant extent these duties involve the powers of a public authority.

4.4.2 Scope of the PR chapter 9

The PR chapter 9 applies to "upstream gas pipeline network". The term is defined in the PA section 1-6 (m), whose first sentence is a direct translation of the corresponding definition in art. 2 (2) of the gas market directive:

> "Upstream pipeline network" means any pipeline or network of pipelines operated and/or constructed as part of an oil or gas production project, or used to convey natural gas from one or more of such projects to a processing plant or terminal or final coastal landing terminal."

According to second sentence of section 1-6 (m), the definition does not comprise those parts of an upstream pipeline network that are used for local production activities.[153] And the definition does not cover activities in processing plants (treatment terminals) and landing terminals (receiving terminals). However, the MPE has decided that the PR chapter 9 also applies to the latter facilities, cf. the PR section 69 second paragraph. Consequently, chapter 9 covers the whole upstream gas chain operated by Gassco.[154]

151 See 4.3.

152 There may be some overlap between item 4 and item 5 as regards capacity allocation and other aspects of economic coordination. In item 4 these important topics are addressed from the perspective of the system operator. In item 5 they are addressed from the perspective of the users, i.e. natural gas undertakings and eligible customers.

153 This part of the definition is taken from art. 20 (1) of the directive, which specifies the scope of third party access to upstream pipeline networks.

154 See 4.1.

4.4.3 Capacity allocation

The primary market

As system operator, Gassco manages two markets for allocating spare transportation capacity, the primary market and the secondary market. As to the primary market, the transaction object is spare capacity. The term "spare capacity" is defined in the PR section 60 second paragraph:

> "For the purposes of this chapter "spare capacity" means the capacity that is physically available at any time, with the exception of capacity necessary to meet existing contracts for the right to use capacity in the upstream pipeline network, and to ensure the good transportation of natural gas and management of the upstream pipeline network."

This means that all capacity allocated under transportation contracts prior to the entry into force of the PR chapter 9 is excluded from the operator´s capacity allocation in the primary market.[155]

The operator allocates spare capacitiy pursuant to the access criteria of section 59.[156] The capacity allocation cannot be executed by others; the operator enjoys a monopoly in this respect. This implies that the operator is responsible for the external communication with the users, i.e. natural gas undertakings and eligible customers.[157] The operator makes information available on spare capacity, cf. section 66 fourth paragraph, enters into contracts with the users on behalf of the owners, cf. section 61 first paragraph, and refuses access if (access) conditions are not fulfilled, cf. section 59 fourth paragraph. The operator has developed more detailed procedures on capacity allocation in the form of a Booking Manual. The operator has consulted with the pipeline owners and users during the preparation of these procedures, cf. section 59 fourth paragraph.

[155] The PA chapter 9 entered into force 1 January 2003.

[156] See 5.

[157] Spare capacity is made available by pipeline owners through the operator, cf. section 61 first paragraph.

Internally, the operator to a large extent functions independently of the owners. The operator stipulates available spare capacity on the basis of "physically available capacity". This basis is subject to the owners´ approval, cf. section 61 second paragraph. The operator allocates spare capacity and formulates a standard contract (towards the users). The owners cannot instruct the operator in these regards, cf. section 66 fifth paragraph, and the operator shall not disclose business secrets revealed to him in the exercise of his duties, cf. section 66 fourth paragraph. These provisions establish "chinese walls" between the owners and the operator. They clearly deviate from the existing regulation under the joint venture and operating agreements.[158]

The PR chapter 9 establishes a comprehensive framework for State control of the operator´s exercise of his duties. To a significant extent, this State control replaces the owners´ control pursuant to the joint venture and operating agreements, as far as system operation is concerned. The operator´s allocation of spare capacity is regulated in detail, cf. sections 61 and 62. The relevant provisions are elaborated in item 5 of the Compendium. The strict regulation also applies to tariffs, cf. section 63. The MPE has issued detailed regulations on tariff calculation, supplementing section 63.[159] They will not be elaborated here. The MPE approves the operator´s standard contract (towards the users), cf. section 65 second paragraph. It may also approve individual contracts, cf. section 65 first paragraph.

The secondary market

As to the secondary market, the transaction object is capacity rights under existing contracts, entered into either before or after the entry into force of the PR chapter 9. Users who no longer need all their allocated capacity under existing contracts, cannot reserve the available capacity for themselves. Instead, natural gas undertakings and eligible customers who meet the access criteria of section 59, are entitled to use

[158] Cf. 4.4.1.

[159] According to the tariff regulations, the MPE stipulates the capital cost element of the tariff. The operator cost element is determined by the operator.

such available capacity, cf. section 64 second paragraph.[160] All transfer of capacitiy rights shall be reported to the operator, who controls the fulfilment of the access criteria, cf. section 64 first paragraph. The operator shall inform natural gas undertakings and eligible customers on available capacity rights, and keep business secrets confidential. In these regards, the same principles apply in the secondary market as in the primary market, cf. section 66 fourth paragraph.

The capacity rights may be transferred on a bilateral basis, or in an organized market.[161] As to the latter alternative, the operator has organized a market place for transferring capacity rights, cf. section 64 fourth paragraph. The same provision grants the operator a formal monopoly in this respect. As market organizer, the operator formulates rules for the market place. These rules are subject to the MPE´s approval. The MPE does not approve individual contracts in the secondary market unless it decides otherwise, cf. section 65 first paragraph.

As previously mentioned, the Norwegian implementation of the gas market directive reflects the regulated access alternative, cf. art. 18 of the directive. However, the detailed Norwegian regulation whereby an independent system operator allocates capacity in a primary and a secondary market goes further than art. 18. And, needless to say, this regulation goes considerably further than the general requirements of art. 20 regarding upstream pipeline networks.

The recent regulation on conditions for access to the natural gas transmission networks contains detailed provisions on capacity allocation similar to the Norwegian market based system.[162] But this regulation does not apply to upstream pipeline networks.

4.4.4 Coordination of gas flows

According to the proposed PA section 4-9, the MPE appoints a system operator who manages the upstream pipeline network as a whole. The

160 Cf. 5.

161 The MPE may decide that all transfers shall take place in the organized market, cf. section 64 fourth paragraph.

162 Regulation (EC) No 1775/2005.

PR section 66 second paragraph identifies the relevant tasks as regards technical coordination. These are coordination of gas flows and coordinated maintenance. As regards coordinated development of the network, PR section 66 A adresses the information process between the system operator and the natural gas undertakings/eligible customers. The purpose here is to provide the operator with a sufficient basis for evaluation of further development of the upstream gas pipeline network. Section 66 does not stipulate how the other tasks shall be performed. It generally states that the operator shall perform his tasks in a good and prudent manner. Furthermore, he shall act in an impartial and non-discriminatory manner, cf. section 66 first paragraph. And he shall conceal business secrets revealed to him during the technical coordination, cf. section 66 fourth paragraph.

The coordination of gas flows requires some explanations. According to the PA section 66 second paragraph the operator coordinates "[n] ominations of gas quality at inlets and outlets from the upstream pipeline network". In practice, the system operator conducts a dayly dispatching of the gas fields. The dispatching process consists of the following main elements: (1) Each producer issues his daily available field capacity to the gas shippers (transporting gas in the pipeline system). The gas shippers also receive daily gas nominations from the gas buyers. [163] (2) On this basis, each gas shipper issues his dayly capacity nomination (in the upstream pipeline system) to the operator.[164] (3) The operator balances available capacities and nominations for all the fields. Production units and pipelines may be unavailable and, consequently, imbalances must be corrected. (4) Finally, the operator issues his dayly field instructions to the shippers and/or producers.[165] These procedures are further regulated in the Shipper Manual, issued by Gassco.

The producers must follow the operator´s instructions. This is not

[163] A more detailed presentation of the dispatching process can be found in Dahl, Norwegian Natural Gas Transportation Systems, p. 89-91, Trondheim 2001.

[164] The latter nominations are regulated in detail in the gas sales contracts. See Brautaset, Kontraktsreguleringen ved salg av gass, p. 195-244, in: Brautaset et al, Norsk Gassavsetning, Oslo 1998.

[165] Most shippers are vertically integrated companies, which include production.

directly stated in the PR chapter 9, but is an essential premise for the operator´s dayly dispatching of the gas fields. Unforeseen events may necessitate changes to previous instructions. Such events may typically be unplanned shut-downs of production fields or pipelines. In these circumstances, the operator “may require that users adapt their supplies of natural gas at the inlet to the upstream pipeline network” to avoid operational disturbances or deteriorations in the gas quality, cf. section 66 third paragraph. In this context, “users” means producers in their capacity as gas shippers in the pipeline network. In special circumstances, the operator may also require similar adaptations from producers who are not gas shippers. On the other hand, the operator cannot require buyers to adapt their off-take from the upstream pipeline network. The operator has no legal relationship with the buyers. The operator shall develop procedures for the handling of unforeseen events, cf. section 66 third paragraph.

4.5 The system operator: Characteristics

As mentioned, Gassco was appointed as system operator in connection with the establishment of Gassled.[166] Gassco is organized as an independent system operator, whose sole purpose is to operate the upstream pipeline network and its associated facilities as a whole. Gassco represents a legal unbundling of the transmission function from other functions in the gas chain that goes beyond the requirements of the gas market directive. The gas market directive contains a legal unbundling requirement. The transmission function shall be incorporated in a separate company, cf. art. 9. However, this company may still be part of an integrated natural gas undertaking. In the latter case the transmission system operator must have decision-making rights independent from the integrated natural gas undertaking. Upstream pipeline networks are dealt with by art. 20, which contains no direct unbundling

166 See 4.3.

requirements.[167]

According to the PA section 4-9 second paragraph, the King may issue more detailed regulations on the system operator´s exercise of his duties. The Act signals that these duties may entail the powers of a public authority. The PR chapter 9 clearly reflects that the system operator exercises certain powers of a public authority. As regards capacity allocation, the operator functions as administrator of the primary and secondary market for pipeline capacities. The operator issues procedures for the handling of the respective markets, supervises the markets, and decides on access for natural gas undertakings and eligible customers. Disputes regarding the operator´s access decisions may be referred to the MPE for conflict resolution, cf. the PR section 68 which implements art. 20 (3) of the gas market directive.[168]

> The MPE may issue orders, either directly or through the operator, to enforce the access rights (for natural gas undertakings and eligible customers), cf. section 67 first paragraph. The MPE may also decide that individual contracts in the primary and secondary market shall be reported to the "Ministry or its authorised representative", cf. section 65 third paragraph. In its comments to the latter provision, the MPE indicates that the operator may be its representative.[169]

As regards coordination of gas flows, the operator also executes powers of a public authority. This is reflected in section 66 third paragraph regarding unforeseen events. However, the operator also executes such powers during the dayly dispatching of the gas fields. It is not up to the producers to decide whether they will follow the operator´s instructions; they have to follow these instructions in order to avoid operational disturbances or deterioration of the gas quality in the pipeline network.

[167] The directive defines "upstream pipeline network" and "transmission" in arts. 2 (2) and (3), respectively.

[168] The MPE may also appoint a special dispute settlement authority.

[169] The MPE may also issue orders on distribution and redistribution of capacity for reasons of resource management, cf. section 67 second paragraph. In such cases, orders are issued directly from the MPE.

We emphasize that Gassco´s functions as regards capacity allocation and coordination of gas flows are completely vested in the PA and the PR. Gassco has no ownership interests in the pipeline network. Consequently, Gassco cannot exercise similar functions as an owner. The ECJ (now CJEU) has held that an entity controlling and supervising the air space on behalf of states, and collecting charges for the exercise of such functions, exercises powers of a public authority.[170] In a similar ruling, the ECJ has held that an entity carrying out anti-pollution surveillance in a sea port on behalf of the port authority, and collecting charges for the exercise of such functions, exercises powers of a public authority.[171] There are clear similarities between Gassco´s system operation and coordinating/controlling functions relating to other infrastructures such as air fields and ports.

170 Case C-364/92, SAT vs EUROCONTROL (1994) ECR I, p. 55.

171 Case C-343/95, Diego Cali vs SEPG (1997) ECR I, p. 1581.

5 Third Party Access to Upstream Pipeline Networks on the Norwegian Continental Shelf

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5.1 Introduction

5.1.1 Theme

This article describes how the EU secondary gas market legislation has been implemented in relation to the offshore upstream pipeline networks on the Norwegian Continental Shelf ("NCS").

Third party use of infrastructure, i.e. both production and transport facilities, is a common feature in the Norwegian gas sector. Still, the focus on third party access ("TPA") to transport facilities has increased with the ongoing liberalisation of the European gas market and the passing of the secondary legislation regulating access to gas transport infrastructure upstream and downstream at the European Community ("EC") level. The passing of secondary legislation is clearly related to the increasing dependence on natural gas in energy supply within the EC and the global competition over the world`s energy resources. The main component of the EC secondary legislation is the so-called Gas Directive ("GD"), first passed in 1998[172] ("GD I") and later revised in 2003[173]

[172] Directive 98/30/EC of the European Parliament and of the Council of 22 June 1998 concerning common rules for the internal market in natural gas, cf. OJ L 204, 21.7.1998, p. 1–12.

[173] Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC, cf. OJ L 176, 15.7.2003, p. 57–78.

("GD II") and then again in 2009[174] ("GD III"), which establishes the obligation of each member state to ensure third parties a right to access to pipelines connecting producers and consumers, i.e. distribution, transmission and upstream pipelines. The Gas Directive has later been supplemented with the so-called Gas Transmission Regulation ("GTR"), first passed in 2005[175] ("GTR I") and later revised in 2009[176] ("GTR II"), which – as the name indicates – only contains detailed principles for the implementation of the right to access to transmission pipeline networks in the Gas Directive in order to achieve an integrated transport market within the EUs Member States.

In accordance with the procedure of Art 102 of the European Economic Agreement ("the EEA Agreement"), the EEA Committee has included both the original[177] and the revised[178] Gas Directive and the original[179] Gas Transmission Regulation, although not the new Gas Directive

174 Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (Text with EEA relevance), cf. OJ L 211, 14.8.2009, p. 94–136. While Directive 2009/73/EC entered into force 3 September 2009, its (main substantive) provisions are applicable from 3 March 2011 onwards, cf. GD III article 54.

175 Regulation (EC) No 1775/2005 of the European Parliament and of the Council of 28 September 2005 on conditions for access to the natural gas transmission networks (Text with EEA relevance), cf. OJ L 289, 3.11.2005, p. 1–13.

176 Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 (Text with EEA relevance), cf. OJ L 211, 14.8.2009, p. 36–54. While Regulation 715/2009 entered into force 3 September 2009, its (main substantive) provisions are applicable from 3 March 2011 onwards, cf. GTR II article 31, cf. article 32.

177 Directive 98/30/EC of the European Parliament and of the Council of 22 June 1998 concerning common rules for the internal market in natural gas, cf. OJ L 204, 21.7.1998, p. 1–12. Included in the EEA Agreement according to the Decision of the EEA Committee on 26th October 2001.

178 Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC, cf. OJ L 176, 15.7.2003, p. 57–78. Included in the EEA Agreement according to the Decision of the EEA Committee on 2nd December 2005.

179 Regulation (EC) No 1775/2005 of the European Parliament and of the Council of 28 September 2005 on conditions for access to the natural gas transmission networks (Text with EEA relevance), cf. OJ L 289, 3.11.2005, p. 1–13. Included in the EEA Agreement according to the Decision of the EEA Committee on 28 September 2008.

(GD III) and the revised Gas Transmission Regulation (GTR II) as of yet[180], within the scope of the EEA agreement. As a party to the EEA Agreement[181], Norway has had to implement the Gas Directive`s rules. Consequently, the EC secondary legislation strongly influences the resource management on the Norwegian gas sector.

Although the Directive regulates third party access to both upstream and downstream (i.e. transmission and distribution) pipeline networks, it is the Directive`s rules on third party access to upstream pipeline networks that first and foremost are of practical interest from a Norwegian legislative perspective. This is due to the fact that even though Norway is a major producer of natural gas, its downstream gas sector is marginal as the vast majority of the natural gas produced is exported to customers on the European Continent.[182] As Norway's gas reservoirs are all located offshore[183], the pipelines transporting gas from the production site offshore to shore, either in Norway or at landing sites in the UK or on the European Continent, all qualify as upstream pipelines in the meaning of the Directive.

The focus of this article is how the Gas Directive(s) rules on third party access to upstream pipeline networks are implemented in Norwegian legislation. [184] In other words, this article deals with the rules governing the right to third party access ("TPA") to upstream pipeline networks on the Norwegian Continental Shelf ("NCS") as found in the

180 The preparatory work for the inclusion of both Directive 2009/73/EC (GD III) and Regulation 715/2009 (GTR II) in the EEA Agreement, is well underway. At present, however, there is no date set for the EEA Committee`s review of these legislative acts for inclusion in the EEA Agreement.

181 Agreement between the European Community and some members of the European Free Trade Association (EFTA), cf. [1994] OJ 1/03. At present, Norway, Iceland and Liechtenstein are members of the European Economic Area ("EEA").

182 Norway is exporting approximately 90 percent of the total production on the NCS.

183 In the European countries with petroleum resources and where petroleum production takes place, i.e. the UK, the Netherlands, Denmark, Italy, Germany and Norway, virtually all of the natural gas reservoirs are located offshore. While in the UK, Denmark and Norway all of the natural gas reservoirs are located offshore, onshore production of natural gas is also known in the Netherlands (Groeningen gas field).

184 While the Directive is binding as to the result to be achieved, the choice of form and methods is left to the national authorities of the Member States, cf. Art 249(3) EC.

Act 29 November 1996 no 72 relating to petroleum activities ("the Petroleum Act"/"PA") section 4-8 (1)(2) and (1)(3)[185], cf. section 1-6 litra m), n) and o)[186], Regulation of 27 June 1997 to Act relating to petroleum activities ("the Petroleum Regulation"/"PR") chapter 9[187] as well as Regulation 20 December 2002 No 1724 relating to the stipulation of tariffs etc for certain infrastructure ("the Tariff Regulation"/"TR")[188]. As neither the scope nor the purpose of this article allows for it, the relevant provisions of the Gas Directive(s) will not be presented nor analysed as such.[189] In stead, in order to provide the necessary backdrop for the Norwegian rules on third party access to upstream pipeline networks, a short presentation of the key purpose of the Gas Directive(s) and the key measures introduced by the Gas Directive(s) to achieve this purpose will be given.

5.1.2 Legal Basis

Although the legal basis for third party access to upstream gas transport infrastructure is mentioned above, it is necessary to give a more detailed account of the relationship between the relevant legislative acts on third

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185 Adopted and included in the Petroleum Act by Act 28th June 2002 No. 61 on common rules on the internal market for natural gas ("the Natural Gas Act"/"NGA"), in force from 1 August 2002.

186 Adopted and included in the Petroleum Act by and amended by Amending Act 30 June 2006 No 60.

187 Adopted and included in the Petroleum Regulation by Amending Regulation 20 December 2002 No 1618 (entry into force 1 January 2003), as amended by Regulation 20 January 2006 No 49 and Regulation 19 December 2008 No 1476 (entry into force 1 January 2009).

188 As amended 27 May 2010 No 730 (entry into force 1 June 2010).

189 For an overview of GD II as such, see e.g. C.W. Jones (ed), EU Energy Law, Volume I – The Internal Energy Market (2nd edition) ("Jones I"). For an overview of GD I as such, see e.g. Sondre Dyrland and Ketil Bøe Moen, Market Opening and Third Party Access – An Overview of the EU Gas Directive ("Dyrland/Moen") (Oslo, February 2002). For a short presentation of the main elements of GD III and GTR II respectively, see Proposal for a Directive of the European Parliament and of the Council amending Directive 2003/55/EC concerning common rules for the internal market in natural gas, COM/2007/0529 final, and Proposal for a Regulation of the European Parliament and of the Council amending Regulation (EC) No 1775/2005 on conditions for access to the natural gas transmission networks, COM/2007/0532 final.

party use and third party access. Furthermore, the recent legislative developments at EC level and its expected influence on the Norwegian regime on third party access to upstream gas facilities must be commented on.

PA section 4-8 introduces a two-pronged approach to third party access to existing infrastructure on the NCS. A distinction is drawn between access to gas infrastructure on the one hand and access to oil related infrastructure on the other. While a regime of negotiated access subject to the Ministry's approval applies to production facilities and upstream oil pipeline networks, third parties have a right to regulated access to upstream gas pipeline networks and related technical facilities such as processing installations.

PA section 4-8 (1)(1) and (2), which are now supplemented by Regulation 20 December 2005 No 1625 on Third Party Use on Infrastructure ("TPUR")[190], provides a system of third party use to infrastructure in general, i.e. both production and transport facilities, upstream. Although third parties are <u>not</u> granted a right to access to infrastructure in general, it lies within the discretion of the MPE to decide that production and/or transport facilities, which are owned by a licensee, may be used by other producers.[191] In practice, third party use has been the result of negotiations between the licensees, and not orders issued by the Ministry. Still, any agreement on third party access shall be submitted to the Ministry for approval.[192]

PA section 4-8(1)(2) lays down the principle of right to third party access for natural gas undertakings and eligible customers domiciled in a state which is a party to the EEA Agreement. However, the access right established in PA Section 4-8(1)(2) is <u>expressly limited</u> to upstream gas pipeline networks, including technical facilities incidental for such access.

[190] In force from 1. January 2006

[191] For a detailed presentation of the provisions on third party access to production facilities, see Dagfinn Nygaard, Third Party Use of Production Facilities, Petroleum law – book 1, chapter 6.

[192] PA Section 4-8(2).

The question of how third party access to infrastructure is accomplished in practice does not follow from the provisions in the Petroleum Act as such. The further particulars of the design and details of both access regimes are to be found in (two separate) set of regulations. As a starting point terms and conditions for third party use of infrastructure in general are regulated in the Regulations on Third Party Use on Infrastructure ("TPUR"). However, the methods and the terms and conditions for, as well as possible derogations from, the right to third party access to upstream gas pipelines or upstream gas pipeline networks are determined separately. While the MPE is granted the authority to stipulate conditions and issue orders relating to such access in individual cases, cf. Section 4-8(1)(3) second alternative, it is of greater importance that a separate set of regulations for third party access to upstream pipelines is established in accordance to PA Section 4-8(1)(3). The terms and conditions for access to upstream gas pipelines and pipeline networks are found PR Chapter 9 and the Tariff Regulation.

> TPUR Section 1(1) states that its provisions apply to agreement for third party use of installations intended for production, transportation and exploitation of petroleum in general. As TPUR was passed and entered into force after the passing of PR Chapter 9 and TR, this could potentially lead to interpretation difficulties due to the principle of lex posterior. However, it is evident that the legislator has not intended the different set of regulations to overlap. According to TPUR Section 1(2) the provisions of the regulation do not apply to the extent that this result from the rules in TR. The wording of TPUR Section 1(2), i.e. the formulation "result from", indicates that the relationship between the sets of regulations have to be determined on an individual basis. Clearly this cannot be the intention of the legislator. From a legal technical point of view, and in accordance with the principle of lex specialis, a more likely understanding is that TPUR does not apply to transportation infrastructure already regulated in TR.

The secondary gas market legislation has undergone significant changes in a relatively short period of time. The latest development, the adoption and entry into force of GD III and GTR II, has yet to be included in the EEA Agreement and accordingly implemented in Norwegian legislation. As such, one might say that this article deals with Norwegian legislation on third party access to gas infrastructure in a transition phase.

> It should be noted that Norway has implemented the Gas Directive in full. While the PA implement the Directive´s provision on third party access to upstream pipeline networks, the Directive´s provisions on access to the transportation infrastructure downstream lead to the adoption of Act 28th June 2002 No. 61 on common rules on the internal market for natural gas ("the Natural Gas Act"/"NGA") and Regulation 14 November 2003 No. 1342 relating to Act on common rules on the internal market for natural gas ("the Natural Gas Regulation"/"NGR") implements the rules on TPA to downstream pipeline networks.[193]
>
> Although the Gas Directive mainly concerns itself with access to downstream pipeline networks, it is its provision on third party access to upstream pipeline networks that is of practical importance from a Norwegian point of view. As Norway exports approximately all the natural gas produces on the NCS, the domestic gas market in Norway is marginal and carries the characteristics of an emerging market. An emergent market means a Member State in which the first commercial supply of its first long-term supply contract was made not more than 10 years earlier.[194] Under both the former and the current Gas Directive, Member States with emerging markets may under certain conditions be exempted from the obligations to establish a third party regime to gas

[193] It should be noted that ESA has been of the view that NGR does not adequately implement the consumer protection rules adopted at EU level. The MPE has instigated the legislative process to make the necessary amendments to NGR to accommodate ESAs objections regarding end consumers rights prior to entering into and during existing contracts with a natural gas undertaking. On 13 December 2010, the MPE sent on public hearing a proposal to amend NGR by adding a provision imposing an particular information obligation on natural gas undertakings when they enter into and during the duration of a contract entered into with an end consumer, cf. http://www.regjeringen.no/nb/dep/oed/dok/hoeringer/hoeringsdok/2010/horing---endring-i-naturgassforskriften-/horingsbrev.html?id=628255 .

[194] GD II Art 2(31). (Similarly GD III Art 2(31).)

infrastructure.[195] However, for such an exemption to be granted it is a condition that a Member State apply. First in connection with the incorporation of GD II in the EEA Agreement, it was stated that Norway has status as an emergent market.[196]

The NGA only establish the right to third party access to gas pipeline networks downstream, i.e. transmission and distribution pipeline networks, leaving the Ministry of Petroleum and Energy ("MPE") with the competence to introduce regulations on more detailed terms and conditions for such access. With the passing of the NGR, the MPE utilized its competence.[197]

The passing and entering into force of both the NGA and the NGR may be seen as the first steps in the preparations of an emerging downstream sector. Even though the domestic gas market in Norway currently is marginal, the authorities see the possibility of an emerging downstream gas sector in the coming years.[198] Still, major investments have to be made before Norway has developed a downstream gas sector. While investors have expressed interest in making such investments, at present no commitments has been

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195 GD II Art 28(2). Identical to GD I Art 26(2). (Similarly GD III Art 49(2), except that Member States which qualifies as an emergent market may no longer derogate from the obligation to designate system operators etc).

196 For an overview, see http://www.regjeringen.no/nb/dep/oed/tema/EUEOS_og_energi/EU-direktiv-vedtatt-i-EOS-pa-olje--gass-.html?id=476013&epslanguage=NO.

197 The competences under the Gas Regulation are delegated to the Norwegian Water Resources and Energy Directorate ("NVE"), cf. Regulation of 23. September 2004 No 1292.

198 See e.g. St.meld nr 9 (2001-2002) Chapter 4.

made to carry out concrete projects.[199]

The Gas Directive(s) establishes a right to third party access to natural gas pipeline networks in general. The natural gas pipelines are divided into two categories. The first category is upstream pipeline networks, which are high-pressure pipelines designed for long-distance transport of gas from the production sites into the national gas markets at the wholesale level. The second category is the pipeline networks established downstream, i.e. transmission and distribution networks, with a view to deliver gas to customers within the market, referred to as "the system". The main focus of the Directive(s) is on access to the system downstream. One provision only which directly relates to third party access to upstream pipeline networks are found in the Directive(s), i.e. GD II Art. 20 (similarly GD III Art 34). It is important to note that, as opposed to the rules on access to the system, the rules on access to upstream pipeline networks has not undergone changes with the revision of the Gas Directive that took place in 2003 and 2009 respectively. Thus, the wording of GD II Art 20 (and GD III Art 34) is homologous to its counterpart in the first directive (i.e. GD I Art 23).

While the implementation of GD II and GTR in Norwegian legislation rendered amendments to the downstream regulatory regime (i.e. NGA and NGR) necessary, this was not the case as regards the (main

199 The fundament for the development of downstream infrastructure servicing both Eastern Norway, Western Sweden and Denmark was planned laid through investments in the Skanled pipeline, cf. Press release No. 20E/07: Pipeline project from Kårstø to Eastern Norway, Sweden and Denmark, dated 29.01.2007 and available at http://www.regjeringen.no/en/dep/oed/Press-Center/Press-releases/2007/Pipeline-project-from-Karsto-to-Eastern-.html?id=446800, and a separation unit in the Grenland area respectively, cf. Press release No. 101/07: Skanled fully financed – Ineos invests in gas separation in Norway, published 28.06.2007 and found at http://www.regjeringen.no/en/dep/oed/Press-Center/Press-releases/2007/Skanled-fully-financed--Ineos-invests-in.html?id=475423. However, the project was halted due to difficulties to get the necessary investments in place. First, the decision was made to continue the project without a separation unit, see http://www.gassco.no/wps/wcm/connect/gassco-no/gassco/home/presse/nyhetsarkiv/skanledprosjektet_videreføres. Eventually, the whole project was put on hold due to increased commercial risk combined with the global economic downturn that led to uncertainties as to the future gas demand, see http://en.wikipedia.org/wiki/Skanled.

substantive provisions on third party access in the) upstream regulatory regime. This is also likely to be the case as regards the implementation of GD III and GTR II. As the Norwegian access regime to upstream gas transport infrastructure is based on GD II, reference to the Gas Directive must be considered as reference to GD II. However, GD III will be referred to in brackets.

As the first and second Gas Directives has opted for a gradual market opening through the definition of eligible customers and the Norwegian authorities have sought to implement the minimum requirements of the Directive(s) only [200], PAs rules on access to upstream gas transport and transport-related infrastructure has been supplemented with further amendments as the legislative requirements gradually have become more stringent at the Community level.[201] Basically, changes in the community legislation regarding upstream gas transport infrastructure have mainly been met through revisions of the definitions of key concepts in the PA section 1-6 litra m), n) and o) respectively.

5.1.3 The Way Forward

In the following, the regime on third party access to upstream pipeline networks on the NCS will be accounted for. Introductorily, in order to provide the necessary backdrop for the Norwegian rules on third party access to upstream pipeline networks on the NCS, a short presentation of the legislative purpose of the Gas Directive(s) is given (in part 5.2). Secondly, as it influences on the design of the TPA regime to the upstream pipeline network on the NCS, the main elements in the structure of the Norwegian gas sector are accounted for (in part 5.3). In parts 5.4 to 5.9, the details of the TPA regime on NCS are presented. As presented (in part 5.4), the rules on third party access differ depending both on which pipelines and on in which market the transport capacity is sold and bought. The focus of this article is the rules on third party access to

200 Commentary to the Regulations of 20 December 2002 on amendments to the Regulations of 27 June 1997 ("the Petroleum Regulations") to the Petroleum Act ("the Comments"), Chapter 7 - General comments p. 9.

201 The Revision Act of 30. June 2006 no. 60.

Gassled in the primary market. The main question to address is who is granted access to what infrastructure and on which conditions. While the question of who has the right to access to what infrastructure are addressed in part 5.5, the common principles for access are introduced in part 5.6, the rules on capacity reservation will be presented in part 5.7 and the question of tariff regulation is addressed in part 5.8. Finally, in 5.9, the issue of enforcement of the rules will be shortly remarked upon.

5.2 The Legislative Purpose of the Secondary Gas Market Legislation: The Liberalisation of National Gas Markets and the Establishment of an Internal Gas Market

Traditionally the gas sector has been characterised by national markets with limited competition, and despite the fact that the gas sector is within the scope of the EC Treaty, hereunder the competition rules, little, if any, attention has been paid to community law aspects.[202] As energy supply was regarded as essential to individual welfare and the prosperity of society, there was a rather large consensus within the Member States that the market forces could not be relied upon and that strong public involvement through ownership and regulation was necessary in the gas sector. Due to this political climate, EC competition law was hardly ever enforced in the gas sector. As a part of the Commission's increased efforts to bring the national regulatory systems for the gas sector gradually into line with the basic principles of the internal market, extensive gas-related secondary legislation has been passed

[202] Within the scope of the EC Treaty itself, no special provision was made for the energy sector as such. As a result, comprehensive community law, hereunder the competition rules, apply to the energy sector. This view is reinforced by rulings of the European Court of Justice (ECJ), according to which the energy sector lies within the scope of the competition rules.

pursuant to Art 95 EC during the 1990s.[203] The Gas Directive(s) – and the Gas Transmission Regulation(s) - are the latest and by far the most important as they eventually will lead to a reorganisation of the European gas sector.[204] The main objective of the Gas Directive is to achieve an internal market in natural gas subject to free competition. In order to achieve this objective, the Directive introduces two key measures that shall ensure the introduction of competition in gas markets.

The first measure introduced in the Directive is the requirement that vertically integrated natural gas undertakings to separate network activities from the other activities in the value chain, i.e. so-called vertical unbundling. Originally, vertically integrated natural gas undertakings were only required to keep separate accounts for the network activi-

[203] It should be noted that, originally, the liberalisation process in the energy sectors was not instigated by the EC. During the last twenty years, the network-sectors, hereunder the energy sectors, have been liberalised in jurisdictions throughout the world, with US and UK as front runners. Gradually, the EU has caught up with the ongoing liberalisation process, particularly when it comes to the energy sectors. Today, it is safe to say that the EU has played an important role in the liberalisation of the energy sectors in Europe.

[204] The Gas Directive itself, and the process leading to its coming into existence, have been, and still are, controversial. The political challenges related to the liberalisation of the gas sector were particularly visible in connection with the Member States implementation of the Directive within the deadline of 10 August 2000. This impression was yet again reinforced in connection with the passing of the revised Directive. The Commission (DG Tren) has initiated formal proceedings pursuant to Art 226 EC against a majority of Member States before the European Court of Justice (ECJ) for lack of or faulty implementation of the requirements of the Directive, either in part or in full, see e.g. MEMO/06/152 of 4 April 2006 (Infringement procedures opened in the gas and electricity market sector, by Member State). Whilst the formal proceedings lead to the fulfilment of obligations and consequently the withdrawal of cases from the ECJ, a number of Member States have been convicted for failing to implement both Directive 98/30/EC, cf. e.g. cases C-259/01: Commission of the European Communities v French Republic, C-64/03: Commission of the European Communities v Federal Republic of Germany, and Directive 2003/55/EC, cf. e.g. cases C-354/05: Commission of the European Communities v Grand-Duchy of Luxembourg and C-357/05:Commission of the European Communities v Kingdom of Spain.

ties.[205] The unbundling of accounts is a way of preventing cross subsidising, a practice which eventually will distort competition.[206] In order to achieve real competition in the gas markets, the transport component has to be priced accurately. The gas price contains several costs components, i.e. production costs, transport costs, storage costs and revenue. Traditionally, the transport costs have not been reflected in the accounts of the vertically integrated undertakings. In order to protect itself against competition in the market, a natural gas undertaking engaged in transport activities has an incentive to charge excessive transport tariffs from gas suppliers basing their activity on third party access. Under GD II, stricter rules on separation apply to the system operators at any network level. The system operator are not only required to establish separate entities for their network activities, i.e. so-called legal separation[207,] but also to ensure that the management of the network entity is without ties to entities with activities at the other levels in the value

[205] GD I Art 12 and 13, which regulated transmission and distribution only. Still, producers, who also have interests in upstream pipeline networks, also seemed to be under a similar obligation to keep separate accounts for their transport activities. This obligation was based on the interpretation of GD I Art. 12.1, which refers to Art 23 regulating upstream pipeline networks, and the Preamble (22) stating that the national dispute authorities right according to GD I Art 23(3) to require relevant information when settling disputes should include accounting information about upstream pipelines. This interpretation is reinforced by the fact that information about the real costs related to the different activities is essential to achieve competition in the upstream gas sector as well, preventing cross subsidising and discrimination of third parties for the benefit of pipeline owners. GD I Articles 12 and 13 now have their parallel in GD II Articles 16 and 17 (and GD III Articles 30 and 31). Although the preamble of GD II (and GD III) does not contain a similar statement on the interpretation of GD II Art 20(3) (and GD III Art 34(3)), which is identical to GD I Art 23(3), this interpretation still apply as it is sufficiently incorporated and the reasoning behind this interpretation still apply.

[206] Separation of activities in the value chain, i.e. production, transmission, distribution, marketing and supply, in order to prevent cross-subsidising is of central importance to the liberalisation of the European gas sector. Such separation can be done either by unbundling of accounts or by legal unbundling, which means that the activities have to be carried out by separate undertakings. As mentioned, legal unbundling of the network activities, i.e. transmission and distribution, is required, cf. GD II Art 9 and Art 13.

[207] GD II Art 9(1) and Art 13(1)

chain, i.e. so-called management separation[208]. With GD III, more stringent rules on separation are introduced at the transmission level.[209] Basically, Member States are given the choice between ownership separation[210] or the model of Independent System Operation (ISO)[211].

Third party access to gas pipeline networks and related infrastructure is the second, and undoubtedly most significant, measure for competition introduced by the Directive. This measure is the establishment of a right for others than the pipeline owner to have their gas transported in the existing pipeline network. In other words: the pipeline undertaking has a duty to contract with and provide transport services to third parties. A liberalised gas market can only be achieved if suppliers and consumers are able to freely negotiate the purchase and sales of natural gas. Any gas sales and purchase agreements can only be finalised if parties have access to pipelines connecting producers and consumers, i.e. distribution, transmission and upstream pipelines. However, it is important to note that, as gas producers constitute an important category of potential gas suppliers, access to upstream pipelines is particularly crucial to the functioning of a liberalised gas market.

Both measures referred to above aim to regulate the market for gas transport. While third party access leads to the creation of a market for transport services, the unbundling of accounts ensures transparency and non-discrimination in the pricing of these services. Thus, the Directive seeks to introduce competition in the gas markets through the creation of a market for transport services. This regulation regime is based on the economic and structural characteristics of the European gas sector. The gas sector is a network-bound sector, characterised by the provision of goods (i.e. gas) through a fixed pipeline network inter-

208 GD II Art 9(1), cf. (2) and Art 13(1), cf. (2)

209 GD III Art 9, cf. Art 14.

210 Which is the Commissions preferred option, cf. COM (2007) 529 final p. 5

211 This option enables vertically integrated companies to retain the ownership of their network assets, but requires that the transmission network itself is managed by an independent system operator - an undertaking or entity entirely separate from the vertically integrated company – that performs all the functions of a network operator, cf. COM (2007) 529 final p. 6.

connecting producers and consumers. This means that the network as such functions as the market place, and access to the network is thus essential for access to the sales market.

A common feature for network-bound sectors is the enormous investments required in order to establish the fixed network. When the infrastructure is in place, the operation costs are relatively low. Due to the economics of scale of employing fixed networks, they cannot, or cannot easily, be duplicated. The characteristics of a fixed network as such are consistent with those used to identify what is referred to as a natural monopoly in economic theory. Until recently, economic theory considered the network-bound sectors as such to be natural monopolies due to the fact that the networks themselves undoubtedly are. In other words: the transport of goods and services was considered as an integrated part of marketing and supply. This has also been the case in the gas sector. As the gas sellers traditionally have owned the pipeline network, they have been able to use their monopoly in the pipeline network to monopolise the gas market within their geographical market area as well.

The directive introduces third party access in order to separate the gas sales market and the gas transport market. Even though the pipeline network by nature is a natural monopoly, third party access establishes the pipeline owners as service providers, with transport of third party gas as their main obligation. Thus, third party access to the pipeline network ensures the free movement of gas necessary to achieve competition in the gas sales market.

Although the main features of organisational structure described above are common for the downstream and the upstream markets respectively, it should be noted that there are some differences when it comes to the complexity of organisation. Traditionally, the European downstream gas markets have been national, with limited external and internal competition. A main feature of the European downstream gas market has been that a few national transmission undertakings have been the only buyers of gas from the producers upstream, and thereby the only suppliers of gas to the local distribution companies and the larger industrial customers. In other words: in each jurisdiction the national gas market has been organised as a formal supply monopoly, nationally, regionally and locally. At the same time, the market structure in most gas producing nations has been that of an oligopoly, i.e. a market with only few market participants involved in production and sale of gas.

In gas sales, the contractual flows have followed the pipeline network. As a consequence, the pipeline owners have enjoyed dominating market power. The introduction of third party access is expected to bring this traditional structure to an end. As ownership in a pipeline is not required for participation in the gas sales market, it will no longer be necessary to buy or sell gas through the traditional levels in the value chain. In principle, the solutions of the Directive make it possible to buy or sell gas at every level of the value chain according to the parties' own choice. Accordingly, the pipeline owner has a duty to contract and to provide transport services, the suppliers` geographical market is extended and the consumers are granted the freedom to choose their own supplier.

5.3 The Structure of the Norwegian Gas Sector

During 2001 and 2002 the Norwegian gas sector underwent a major restructuring. The restructuring of the organisation of and the access regime to the pipeline network on the Norwegian Continental Shelf ("NCS") were important elements in this respect. The restructuring of the Norwegian gas sector may be said to have resulted in a shift in the legislative purpose of the rules on access, characterised by a shift from a producer perspective to a consumer perspective.

Traditionally, the natural gas produced on the NCS has been sold under long-term gas sales agreements. Due to the enormous costs related to the development of infrastructure and the production of gas, the field owners need to be certain that the gas produced will be sold in the market. Hence, the field owners have entered into long-term gas sales agreements prior to the development of the gas reservoirs. Until recently, joint gas sales have been practised on the NCS. At first, the licensees of a single field entered into depletion contracts with their customers downstream. Later, the field licensees' freedom to enter into gas sales agreements on their own was eliminated as all gas sales agreements were negotiated and entered into by the national gas negotiations committee ("GFU"). The delivery obligations under the gas sales agreements were then transferred to a contract field subject to the recommendations of the negotiations committee ("FU") and the discretion of the Ministry of Oil and Energy ("MPE"). The contract field was not able to meet the delivery obligations under the gas sales agreement on its own. Hence, in order to be able to fulfil the delivery obligations, the contract field entered into supply contracts with a number of supply fields, again subject to the recommendations of the negotiations committee ("FU") and the discretion of the MPE.

Gas sold under the gas sales agreements was ensured transport rights in the upstream pipeline networks. The pipeline network on the NCS has developed successively with the location and development of the gas reservoirs. As gas sales agreements were entered into, a pipeline was established in order to connect the producers and the customers to the agreement in question if necessary. The building and operation of pipelines is subject to the granting of a licence by the MPE. Most often, the field licensees with delivery obligations under the gas sales agreements filed an application for the pipeline licence with the authorities. However, as the authorities are free to determine the composition of the holders of a licence for resource management purposes, the holders of the pipeline licence and the field owners with delivery obligations were not necessarily identical. Even if the pipeline licence was granted to the field licensees, their interest in the pipeline licence would not be identical with that in the field licence. However, as a rule the national oil company, Statoil, has been granted major interests in and appointed operator for virtually all of the pipelines built. Due to the enormous costs related to the development of the pipeline infrastructure, gas transport on and from the NCS was – and is – based on extensive third party use as the pipelines are dimensioned with the view of transport of gas from several fields. Legally, it was left to the discretion of the MPE to determine whether third party use should be allowed in each case. In practice, the users of the pipeline network have been both pipeline owners (in their capacity as shippers of their own gas) and other gas producers.

With the restructuring of the Norwegian gas sector, the system described above was altered altogether. The implementation of the Gas Directive and its rules on third party access was the last of four related measures taken with the view of restructuring the Norwegian gas sector.

First, the gas sales regime was altered as the gas sales negotiating committee (GFU) was abolished and company based gas sales (CBS) introduced instead. Now, each oil company is not only free to, but also requested to, sell their gas on an individual basis in the gas sales market. After the introduction of CBS, each gas producer has to actively reserve transport capacity in the pipeline network which links the producer with its customer.

Secondly, all of the transport pipelines essential for export of natural gas from the NCS were merged into a single pipeline network, Gassled.[212] It should be noted, however, that the transport rights in the individual pipelines are continued in the pipeline network as Gassled subrogates into the rights and obligations of the merged pipelines.

Thirdly, an independent and state owned operator of the pipeline network, Gassco, was established.[213] In order to ensure third parties access to the transport infrastructure on objective and non-discriminatory criteria and to prevent cross-subsidising, Gassco is without commercial interests in the sector and shall conduct its functions on a principle of no gain, no loss.

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212 In effect from 1 January 2003, see e.g. http://www.gassco.no/sw1365.asp.

213 The establishment of Gassco is not linked to the implementation of the Gas Directive. However, according to the current Gas Directive, the provisions on access downstream now require the establishment of both an independent transmission system operator (GD II Art 9) and an independent distribution system operator (GD II Art 13). According to the Gas Directive, however, only legal and management unbundling is required. As Gassco is owned by the State and without ownership interests in both the production and transport activities (i.e. ownership unbundling), the Norwegian model is still ahead of the EU law at this point.

Finally, the Gas Directive was implemented, establishing a right to third party access to the upstream gas pipeline network on the NCS.

As mentioned, the focus is here on the latter measure, i.e. the implementation of the Gas Directive and its implications for third party access to upstream pipeline networks on the NCS. However, it is important to note that (all) the (other) measures described above are of significance for the implementation of the Gas Directive and the organisation and designing of the access regime on the NCS.

The implementation of community secondary legislation has rendered a shift in the legislative purpose of the rules on access in the Norwegian legislation. While third party use of infrastructure in the Norwegian sector was motivated by the need for the efficient use of existing infrastructure due to the enormous costs involved in developing the necessary meshed and integrated infrastructure, the establishment of a right to access to gas pipeline networks is in the present regulatory climate first and foremost an important tool in preparing the ground for and establishing and maintaining a sales market for natural gas subject to free competition.

5.4 The Design of the Access Regime on the NCS: The Distinction between Categories of Pipelines and the Introduction of a Primary and Secondary Market for Transport Capacity

5.4.1 Distinction between categories of upstream gas pipeline networks: Gassled and others

While third party access as such is a familiar concept according to Norwegian petroleum law, the provisions on how third party access to upstream gas pipelines or pipeline networks is to be accomplished differ from the contractual practice applied on the NCS until recently. A distinction is drawn between upstream pipeline networks for which tariffs are determined by the Ministry in separate regulations and upstream pipeline networks where the parties themselves have the opportunity to negotiate commercial agreements for third party use. While the first category of upstream pipeline networks will actually be Gassled, the latter category consists of the pipelines that for various reasons were not included in the restructuring of the pipeline network.[214]

The distinction between these two categories of pipelines appear from the fact that not all of the provisions of Chapter 9 apply to all upstream pipeline networks located on or originating from the NCS. While Chapter 9 applies to Gassled in full, some – or, rather, the main – provisions of the Chapter are applicable to Gassled only.[215] In other words, third parties have the right to access to both categories of pipeline networks, but the form and methods for accomplishing such access to Gassled are regulated in greater detail. Accordingly, the pipelines that are a part of Gassled are those transporting the vast majority of the gas volumes produced from the NCS to shore, either in Norway, in the UK or at the various landing sites on the European Continent.[216] Thus, only the regulation of third party access to Gassled will be commented on in the following.

5.4.2 Two Markets for Transport Capacity

The Petroleum Regulations distinguish between two markets for transport capacity, i.e. a primary market and a secondary market, in which third party access to Gassled can be acquired. While the primary market is defined as a market where access rights are contracted between third parties and the owners of the upstream pipeline networks in their capacity as owners, the secondary market is a market where capacity rights already granted are transferred between the market partici-

214 Cf. PR Section 69, where reference is made to "upstream pipeline networks that are subject to the Regulations for determining tariffs" ("the Tariff Regulations"). The upstream pipelines and related technical facilities listed in section 1(3) of the Tariff Regulations, are those Gassled consists of.

215 PR Section 69(1).

216 Gassled encompasses all rich and dry gas facilities that are currently in use or are planned to be used to any significant degree, by parties other than the owners (third party use). New pipelines and transport-related facilities are intended to be included in Gassled from the time they are put to use by third parties, and are thus part of the central upstream gas transport system, cf. Facts 2010 Chapter 6.

pants.[217] In other words, access rights granted in the primary market may be transferred to other natural gas undertakings and eligible customers in the secondary market. Such transfers can take place either through bilateral contracts or over a market place, which is to be arranged and conducted by the operator.[218]

Irrespective of how a contract in the secondary market is entered into, the efficient operation of the upstream pipeline network requires that the operator is notified of any contract entered into in this market.[219]

While the underlying presumption of the Directive(s) is that of a single owner of the pipeline network, the upstream gas sector is organised in a way that results in several owners of a single pipeline. The pipeline owners are also shippers of gas in the pipeline. Furthermore, the system access rights need to provide the shippers (and their customers) with a sufficient degree of flexibility.[220] According to the basic principle of ownership, you can do with what you own what you want the way you want. When implementing the right to third party access on the NCS, the major challenge is to balance the principle of ownership and the need for flexibility on the one hand and the interests of third parties seeking access on the other. Two models have been discussed. As shown above, the capacity reserved is not necessarily the same as the capacity needed at the time of transportation. Thus, the first model creates a system where the pipeline owners and others with reserved capacity trade off the capacity they do not need to third parties. This model lies within the principle of ownership, but the establishment and maintenance of an effective trade regime are entailed with difficulties. The other possibility is to exempt from the principle of ownership entirely, introducing a "use it or lose it"-model. This latter model implies that the

217 PR Section 60(3) and (4).

218 PR Section 63(4). The MPE has reserved the right to decide, dependent on gained experience on the functioning of the market, that all transfers in the secondary market shall take place over the market place, cf. Petroleum Regulations Section 64(4)(4). However, the MPE has concluded that both trade options should be available to the market players (at least) to begin with, cf. The Comments, Chapter 6 – Hearing (p 7-8).

219 PR Section 63(3).

220 See 5.6.2 below.

operator is granted the authority to trade off reserved capacity, which the shipper fails to nominate prior to a fixed deadline, in a spot market operated on a daily basis. It may be argued that this latter model could be easier to enforce, and thus would be more efficient. When the Norwegian authorities have opted for the trade model, introducing a primary market and a secondary market for transport capacity, in the regulations, this is probably due to strong opposition from the major pipeline owners to a greater intervention in the principle of ownership than necessary.[221]

The model for access differs in the primary market and the secondary market. While the authorities have opted for the model of regulated access in the primary market, one might say that a (modified) model of negotiated access applies to the secondary market. Consequently, the terms and conditions for access in the primary market are regulated in detail in the regulations, while there is little or no need for such detailed provisions relating to the secondary market. Initially, the parties to a transfer agreement are free to determine the conditions, hereunder the payment, for the transfer of the access rights. However, the transfer of the access rights will only lead to a change of parties to – or, rather, a change of the shipper in - the transport agreement entered into in the primary market. The third party accedes to the original agreement with the carrier, i.e. undertaking the same rights and obligations of the first shipper. Consequently, the terms and conditions, hereunder the transportation tariffs, for access in the primary market indirectly apply in the secondary market as well. As the terms and conditions for access as such are predetermined, in practice the parties in the secondary market are only free to determine the capacity volumes due for transfer and the price for and the duration of the transfer of the capacity right in ques-

221 The elimination of the "use it or loose it"-model has been criticised. However, the MPE has dismissed the critic by pointing out that the new access regime is based on a (modified) use-it-or-loose-it principle as each shipper is obligated to trade off excess capacity. Furthermore, the MPE has argued that a "use it or loose it"-model will be both to inflexible and to difficult to combine with the existing gas sales agreements according to which the buyer has the right to make nominations shortly before delivery is to take place. Cf. the Comments, Chapter 6 – Hearing (p. 8).

tion. The transfer of access rights in the secondary market is subject to the principle of offer and demand and regulated under contract law. Accordingly, when accounting for the implementation of third party access on the NCS in the following, the focus is on the regulation of the primary market.[222] It should be noted, however, that for the purpose of ensuring third parties access upstream the secondary market will be most important. Third parties will probably have to obtain access rights through contract arrangements in the secondary market, as the pipeline owners in their capacity as shippers are likely to reserve all capacity in the primary market.[223]

5.5 Who is Granted the Right to Access to What Infrastructure?

5.5.1 Introduction

PA Section 4-8(1)(2) lays down the right to third party access to upstream gas pipeline networks, including technical facilities incidental for such access, for natural gas undertakings and eligible customers domiciled in a state which is a party to the EEA Agreement. In order to establish who has been granted a right to access and to what, the definition of upstream pipeline networks (in part 5.5.2) and natural gas undertakings and eligible customers (in part 5.5.3) must be presented.

5.5.2 Access to Upstream Pipeline Network

In the Directive(s) an "upstream pipeline network" is defined as "any pipeline or network of pipelines operated and/or constructed as part of an oil or gas production project, or used to convey natural gas from one or more such projects to a processing plant or terminal or final coastal

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[222] However, the common principles for access commented on in 5.6 below apply to both the primary and the secondary market. Additionally, some of the provisions regulating capacity reservation and capacity allocation in the primary market accounted for below are essential for the functioning of the secondary market.

[223] See 5.7 below.

landing terminal."[224] The definition of "upstream pipeline network" in PA Section 1-6 m) is to a large extent a reiteration of the definition in the Gas Directive(s). However, the wording of the definition in PA Section 1-6 m) deviates from that of GD II Art 2(2) (similarly GD III Art 2(2)), as it stipulates that parts of such pipeline networks and related facilities which are used for local production activities at the deposit where the natural gas is produced are not regarded as an upstream pipeline network. This is, however, in accordance with specifications made in GD II Art 20(1) (similarly GD III Art 34(1))[225], and included in the definition for regulation technical purposes. Thus, materially the Petroleum Act must be deemed to be in accordance with the Directive.

In accordance with GD II Art 20(1) (similarly GD III Art 34(1)), PA section 4-8(1)(2) stipulates that third parties have access to upstream pipeline networks, including facilities providing related technical services in connection with such access. Such facilities will include e.g. facilities where gas is made ready for further transport through an upstream pipeline. In other words, facilities providing related technical services necessary for access must be said to be considered part of an upstream pipeline network.[226] Consequently, the Directive and the Petroleum Act do not only regulate access to the pipelines as such but also to installations with processing facilities. This is due to the fact that processing of gas to some extent is a prerequisite for transport of natural gas. Here, processing means preparation of gas for further transport through the pipeline in question. As the gas qualities vary significantly dependent on the origin of the gas, the gas sales agreements specify the quality requirements of the gas sold (sales quality). The sales quality is not predetermined, but individually set in the gas sales agreements. As mentioned above, the pipeline network has matured as gas sales agreements have been entered into. According to the gas transport agree-

[224] Identical definitions are found in GD I Art 2(2), GD II Art 2(2) (and GD III Art 2(2)) respectively.

[225] Previously GD I Art 23(1).

[226] For example Draupner E and S, where gas flows are mixed to obtain the required quality.

ments, the owners of the pipeline built in order to connect the producer(s) and the customer(s) of the initial gas sales agreement are under a contractual obligation to deliver gas of sales quality at the landing point. Thus, the pipeline owners – or, rather, the operator of the pipeline - have to carefully choose the shippers of natural gas in the pipeline in order to meet this contractual obligation. Only shippers with natural gas compatible with the transport specifications are granted access.[227] In other words, the sales quality stipulated in the gas sales agreement is reflected in the technical requirements of the pipeline built to connect the producer(s) and the customer(s) of the initial agreement. The transport specifications thereby vary from pipeline to pipeline. The sales quality can be achieved in two ways, separately or combined. One method is to mix gas of different origins and thus with different molecular structures. The mixing of gas often take place in the pipeline network as such, provided that the molecular structure of the third party gas and the natural gas already shipped through the pipeline in question is relatively compatible. Another method is to process the gas in a processing plant. The method chosen depends on the quality of the third party gas and the technical requirements of the pipeline in question and the quality of the natural gas already shipped through the pipeline.

Access to related technical services is obtained only if such access is needed in connection with access to the upstream pipeline network as such. In other words, an independent right of access to technical facilities incidental to access does not exist.[228] However, the expression "transportation and/or processing" introduced by and used in the Petroleum Regulations is included to emphasise that some of the upstream pipeline networks that are subject to this regime offer transportation only, that others offer processing only, while still others offer both.[229] Depending on which upstream pipeline network that a shipper wishes to access, the shipper will be entitled to access provided that the shipper

[227] See 5.6.3 below.

[228] PA Section 4-8, cf. PR Section 59.

[229] PR Section 59(1).

has or will have a need for either transportation or processing or both.

5.5.3 Access is given to Natural Gas Undertakings and Eligible Customers

It follows from PA section 4-8(1)(2) that only natural gas undertakings and eligible customers domiciled in a state member to the EEA Agreement have the right to third party access to upstream pipeline networks on the NCS.[230] The terms "natural gas undertakings" and "eligible customers" are defined in PA Section 1-6 litra n) and o) respectively.

The definition of the term "natural gas undertakings" in Section 1-6 n) is a reiteration of the definition in the Directive(s).[231] According to the definition a natural gas undertaking means "a natural or legal person carrying out at least one of the following functions: production, transmission, distribution, supply, purchase or storage of natural gas, including LNG, which is responsible for the commercial, technical and/or maintenance tasks related to those functions, but shall not include final customers".

While the definition of eligible customers initially was used to allow for a gradual market opening, the concept is without practical importance after the internal market was fully liberalised, i.e. after 1st July 2007. It follows from PA Section 1-6 o) that all customers domiciled in a State member to the EEA Agreement are to be considered eligible after this date.

5.6 Common Principles for Access

5.6.1 Introduction

The right to access is conditional. First of all, there must be capacity available in the pipeline. Second, the third party requesting access must have an actual need for transport. Finally, the gas volumes the third party wishes to ship must meet, or rather: must be able to meet, the

230 PA Section 4-8(1)(2).

231 Identical definitions are found in GD I Art 2(1), GD II Art (2) and GD III Art 2(1).

technical requirements of the pipeline to which access is requested.

While capacity issues are dealt with later (in part 5.7), in the following both the requirement for the third party shipper to substantiate a need for access (in part 5.6.2) and the gas volumes technical and operational compatibility (in part 5.6.3) are dealt with.

5.6.2 Duly substantiated reasonable need for access

A "duly substantiated reasonable need of transportation and/or processing of natural gas" is a condition used in several situations.[232] First, in order to obtain a right to use capacity in an upstream pipeline network, the shippers of gas have to substantiate their need for transport or technical services incidental to such transport. Only natural gas undertakings and eligible customers with "a duly substantiated reasonable need" for transportation and/or processing of natural gas shall have the right to third party access upstream.[233] Secondly, the duly substantiated reasonable need of the pipeline owner is used to determine whether there is spare capacity available for third parties, i.e. others than the pipeline owners. This is the case both when it comes to allocation of spare capacity and allocation of new capacity due to the owner's investments in expanded or new infrastructure.[234] Accordingly, a pipeline owner has to have "a duly substantiated reasonable need" for transport or technical services incidental to such transport in order to be granted access. Thirdly, the right to hold on to any access rights obtained depends on the existence of such need at the time transportation or processing is to take place.[235] Natural gas undertakings and eligible customers shall be entitled to access whenever the party initially entitled to use the capacity no longer has a duly substantiated reasonable need of this capacity.[236]

232 When a third party requests access to Gassled, it will be for the operator, Gassco, to decide whether a duly substantiated reasonable need does exist, cf. the PR Section 59(4).

233 PR Section 59(1).

234 PR Section 61(7) and Section 62.

235 PR Section 64(2).

236 This provision is one of the measures meant to ensure the functioning of the secondary market.

The objective of the condition of duly substantiated reasonable need for access ("the DSRN criterion") is an efficient use of existing capacity. A shipper is not entitled to access to any capacity beyond their actual need for transportation of natural gas at any time. This prevents a shipper from distorting competition in the gas sales market by reserving unnecessary transport capacity, thus preventing other market participants from access. Additionally, this condition is also a measure to prevent speculation in capacity reservations for resale purposes only. However, it is left to the shipper with capacity reservations to assess whether there is a future need for capacity and, accordingly, whether there is any need to inform Gassco as to whether capacity will be reallocated to the market.[237] Thus, although the Ministry has the power to intervene if the shippers do not release capacity not needed in accordance with the principles mentioned above, one might still question whether the safeguarding of the objective is particularly efficient.

Access to natural gas that can be transported through the particular upstream pipeline network is a basic requirement for a need for capacity. Access to natural gas may be acquired either through production of one's own or by the purchase, borrowing or exchanging of natural gas. Shippers who have or will have production of their own or who have purchased, borrowed or exchanged natural gas, or intend to purchase, borrow or exchange natural gas, will be considered to have a need of capacity provided this gas may, and probably will be delivered through the upstream pipeline network concerned. In such cases the shippers may reserve capacity in proportion to their needs and which results in a reasonable flexibility in relation to the deliveries of natural gas concerned.

The term "reasonable need" is used to emphasise the need for flexibility in gas transportation. First, the sellers' delivery obligations under the gas sales agreements are flexible, both with respect to gas volumes and with respect to the delivery point. The delivery obligations may

[237] See also. Are Brautaset, Bringing the Ormen Lange Gas to the UK, published in Industribygging og rettsutvikling – Juridisk festskrift i anledning Hydros 100-årsjubileum pp 105-120, on p. 118.

vary with respect to gas volumes. The gas volumes shipped in the gas pipeline network are determined on a daily basis based on nominations from the customers. Under the gas sales agreements the gas buyers are entitled to take varying volumes within specified maximum and minimum limits. As the seller is obliged to deliver in accordance with the gas buyer's nominations, they must be able to deliver maximum volumes every day. As some agreements allow for the alteration of nominations within certain time limits, the sellers must be prepared to deliver maximum quantity plus 10 percent even though the buyers initially nominate less than the maximum delivery limits. The delivery obligation may vary geographically, i.e. with respect to the delivery point of the gas. Under some agreements, the gas buyers may change the delivery point at short notice. The seller's need to retain capacity to enable him to meet such maximum delivery obligations is regarded as reasonable need for the purposes of this provision. Secondly, a duly substantiated reasonable need for capacity may exist in order to have a possibility of operating in a short-term market. Thirdly, flexibility may be needed due to reservoir considerations. Uncertainty regarding the future development of the reservoir, the need for short- or long-term gas injection and other similar considerations may constitute grounds for allocation of spare capacity. Fourthly, flexibility may be needed due to production considerations, including varied take-off from gas production in associated gas fields. A duly substantiated reasonable need for capacity may also exist in situations where a field is not yet in production, but where a development plan is approved of or is being drawn up.

5.6.3 Technical and operational compatibility

For third parties to obtain access to the upstream pipeline network certain technical and operational requirements must be satisfied. The specifications of the natural gas to be transported and/or processed are required to be "reasonably compatible with the technical requirements and the efficient operation of the upstream pipeline network".[238] Conse-

[238] PR Section 59(3).

quently, the technical and operational compatibility of the gas determines whether a shipper is granted access or not. The principle of technical compatibility has many aspects. However, the authorities have particularly addressed two issues of significant importance for the operation of upstream pipeline networks.

First, the pressure in the pipeline network determines to which extent the gas stream can be transported over long distances. Additionally, the pressure in the pipeline is important for safety reasons. Thus, it is specified that the right to third party use depends on whether the gas is delivered with the "adequate pressure at the inlet so that the natural gas can reach outlet".[239]

Secondly, access may be available to a shipper but not another, dependent on the molecular structure of each shipper's natural gas. The molecular structure of the gas stream varies in the different upstream pipeline networks, either because the gas qualities vary in-between fields or because different upstream pipeline networks transport both gas that has been processed and not. The molecular structure of the gas stream in the pipeline networks has a side to the delivery requirements under the existing gas sales agreements. In order to reach sales quality, it is common to mix gas from several shippers in the pipeline network. This is particular relevant for dry gas pipelines. In the draft regulations, it was explicitly stipulated that compatibility "with the delivery requirements" was a condition for third party access. Reference to the delivery requirements was left out without comment in connection with the passing of the final text. However, the rewording of the provision has not led to any material change. According to the preparatory works of the regulations, access can still only be obtained if the third party gas can meet the specification requirements of the pipeline network in question, either through processing at processing facilities or through mixing with the natural gas of other shippers.[240] Principally, the delivery requirements of the gas sales agreements must be considered irrelevant to the gas transport agreements. Still, for historical reasons the trans-

239 PR Section 59(3).

240 The Comments, Chapter 8 – Commentary on the individual provisions p. 12.

port specifications of a pipeline will reflect the delivery requirements of the gas sales agreements entered into prior to the building of the pipeline. Thus, for the immediate future, the fulfilment of a pipeline's transport specifications will de facto lead to the fulfilment of the delivery requirements under a existing long-term gas sales agreements. Consequently, the provision's wording now more precisely reflect the separation of and the connection between the delivery requirements under a gas sales agreement on one hand and the transport specifications of a given pipeline on the other.

The specifications of the natural gas in question is required to be "reasonably compatible" with technical and operational requirements. Although the specifications of the third party gas initially are not compatible, access shall be granted provided this can be overcome in a relatively simple manner. This criterion does not impose strict requirements on the owner or the operator of the upstream pipeline network. Whether the incompatible technical and operational requirements can be overcome reasonably simply has to be determined in each individual case. In assessing what can be reasonably done, the potential consequences of the adjustment must be considered. As third parties seeking access are required to cover any additional costs, third party access cannot be denied due to increased costs. However, technical and practical problems, such as for example increased workload, changed time consumption and incorporation of new procedures etc, will be relevant when deciding whether the right to access is present. In the case of varying gas qualities, access can be denied if the third party gas cannot, neither through processing nor mixing with other gas deliveries, be adjusted to meet the quality requirements of the pipeline network in question.

5.7 Capacity reservation

5.7.1 Spare Capacity

Spare capacity in the upstream pipeline network is a condition for access, as the obligation of the pipeline owner is limited to make spare capacity available in the primary market.[241] Thus, third parties have access to spare capacity only.[242]

Spare capacity means "the capacity that is physically available at any time, with the exception of the capacity necessary to meet existing contracts on transport of natural gas and the right to use of capacity in the upstream pipeline network and to ensure the good management of the upstream pipeline network."[243]

When reference is made to the management of the pipeline network, it is to emphasise that the efficient operation of the pipeline network is not equivalent to the use of all physically available capacity in all pipelines at any given time. Due to several reasons it may not be expedient to fully utilise the physical capacity in one or more of the pipelines in the network. Practical examples of such reasons are i.e. the best possible utilisation of several pipelines collectively, maintenance reasons or the need to maintain a sufficient pressure level in one or more pipelines.[244]

In practice, limitations in the right to access is more likely to follow from the fact that the definition of spare capacity does not include the capacity necessary to meet the obligations of those who already have a right to use the upstream pipeline network. Such right of use may derive from contracts entered into before the entry into force of these Regulations, and from subsequent contracts. Basically, there is no spare capacity if a right to use the capacity in question already exists. In other words, the contractual obligations of the carrier are protected under the concept of third party access.

When the rules first were adopted, the Commission expressed the view that "it could be suggested that the unlimited preference of existing capacity reservations could under certain conditions amount to a

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241 PR Section 61(1).

242 This is in conformity with GD II Art 20, cf. Art 21 (similarly GD III Art 34, cf. Art 35), according to which access may be refused due to lack of capacity in the pipeline network.

243 PR Section 60(2).

244 The Comments, Chapter 8 – Commentary to the individual provisions (p 13 –14).

violation of EEA competition law".[245] It's the unlimited preference of existing rights, the so-called grandfather rights, that raised the Commission's concern. Referring to the fact that it suggests that the grandfather rights may violate competition law "under certain conditions" only, the Commission did not object to grandfather rights as such. Another stand would be inconsistent with the Gas Directive(s) which allows for refusal of access in the case of lack of capacity.[246] Rather, the Commission`s wording must be understood as a requirement that the design of the grandfather rights has to lie within the framework established by competition law. Accordingly, the Commission stressed that grandfather rights may be particularly problematic if they are "unlimited in time and scope".[247] In this respect, grandfather rights including possibilities for further extensions and prolongations at a later stage are explicitly mentioned.[248] However, the Commission (i.e. DG TREN) did neither express any definitive opinion nor give any definitive advice on the design of the grandfather rights granted under the Norwegian access regime. The distinct impression one is left with, however, is that the Commission was of the view that a similar scheme would not have been permitted downstream.

Such a view has now been confirmed by the European Court of Justice ("ECJ"), which recently addressed the question of preferential access to transport capacities, albeit in relation to the electricity grid. In its decision C-17/03 of 7 June 2005[249], the Court of justice of the European Communities decided on the compatibility with Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity, of preferential access given by the Dutch regulator to transport capacities, for imports resulting from long-term electricity supply contracts con-

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245 The Commissions letter of 7 November 2002.

246 GD II Art 20, cf. Art 21. (Similarly GD III Art 34, cf. 35.)

247 Ibid.

248 Ibid.

249 Case C-17/03, Vereniging voor Energie, Milieu en Water, Amsterdam Power Exchange Spotmarket BV, Eneco NV v Directeur van de Dienst uitvoering en toezicht energie ("VEMW e.a"), of 7th June 2005.

cluded prior to the Directive. Based on the ECJs conclusions in the VEMW case, the Commission has issued a note[250] stating that the grant to an undertaking of preferential transmission or distribution capacities must be considered as being discriminatory and is precluded by Directive 2003/54/EC (the Electricity Directive) and Regulation (EC) No 1228/2003 (the Electricity Cross-Border Regulation). Referring to the fact that the Gas Directive and the Gas Transmission Regulation provides for, in substance, identical principles and that the reasoning of the Court, i.e. that the grant of preferential treatment would risk jeopardising the transition from monopolistic and compartmentalised markets to open and competitive ones, contrary to the objective of the Directive, is also applicable to the gas sector[251], it is concluded that the Court ruling, in substance and spirit, is applicable to the grant of preferential transmission and distribution capacities of natural gas also.[252]

In its notification on preferential access, the Commission limited the applicability of the VEMW case to downstream transport infrastructure on the gas sector. This must be seen in correlation with the larger leeway granted in relation to upstream pipeline networks in general. GD II Art 20(2) (similarly GD III Art 34(2)) explicitly allows for preferential access to transport capacity. It cannot be excluded, however, that the preferential rights granted under the Norwegian access regime in the future may be challenged under community law.[253] Accordingly, the Commission's observations in relation to the access regime on NCS may primarily be viewed as a precautionary reservation on general terms.

As responsible for the day-to-day operation of the pipeline network,

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250 COMMISSION STAFF WORKING DOCUMENT on the decision C-17/03 of 7 June 2005 of the Court of Justice of the European Communities Preferential Access to Transport Networks under the Electricity and Gas Internal Market Directives ("Note on Preferential Access to Transport Networks"), SEC(2006) 547.

251 In this context, the Commission stresses that it has highlighted that the limited scope for moving gas around the European network prevents competition from new entrants and the success of market opening.

252 It should be noted, that reservations are made. For further details, reference is here made to the Note on Preferential Access to Transport Networks premises (11)-(14).

253 In particular, proportionality considerations may be expected to be of importance in this respect.

the operator has an overview of existing obligations and operational requirements at any time. Thus, what shall be considered physically available capacity is based on the recommendations of the operator.[254] The recommendation requires the approval of the joint venture, in accordance with its ordinary voting rules.[255] As the physically available capacity forms the starting point for determining spare capacity, the operator decides what is to be considered to be spare capacity based on the joint venture's decision on physical capacity.[256] The provision emphasises that, with duly regard to an efficient management, the available physical capacity in the upstream network shall be set as high as possible.[257] Not found in the draft regulations, this guideline was included without comment in connection with the regulations' passing. One might argue that the guideline only states the obvious. However, it emphasises that the decision of the joint venture must have a justifiable basis, or rather, must be justifiable on an objective and operational basis.

5.7.2 Reservation Principles and Procedures

Third parties desiring access to the upstream pipeline network have to take the initiative to gain such access themselves. Spare capacity in Gassled shall be offered collectively through the operator.[258] Thus, anyone seeking access to spare capacity in this pipeline network has to make reservations of capacity with the operator (Gassco).[259]

> There is a dual reason for the operator's key role in the reservation process. Firstly, the use of the operator as an intermediary simplifies the access process. There are several owners of the pipeline network. Thus, third parties do not need to contact each individual owner to find spare capacity. Secondly, the owners of the upstream

[254] PR Section 61(2)(1).

[255] PR Section 61(2)(2).

[256] PR Section 61(3)(2).

[257] PR Section 61(2)(3).

[258] PR Section 61(1).

[259] PR Section 61(3).

> pipeline network will not have the commercial freedom to negotiate terms and conditions for third party access. As mentioned, the primary market is regulated, meaning that standard tariffs (set by the Ministry) and standard contracts (composed by the operator and approved by the Ministry) apply. The lack of contractual freedom does not mean that the pipeline owners are without influence on the contractual conditions for upstream access.[260]

A booking system is established for the reservation of capacity. Capacity reservations in Gassled can be made at announced points in time. The operator shall set a deadline prior to which natural gas undertakings and eligible customers must make their capacity reservations. The capacity reservations must be made for specified periods of time, i.e. for the periods of time for which they have a duly substantiated need for capacity. The capacity reservations may take place both on a short-term or a long-term basis. However, long-term capacity reservations are prioritised in the allocation process.[261] Still, the operator may withhold a share of the spare capacity for allocation on a short-term basis.[262] In practice, however, allocation of capacity rights on short-term basis primarily takes place in the secondary market.

> The regulations only lay down the basic principles of the booking system. Within this framework, the operator is left to determine the further capacity reservation procedures. The Ministry presupposes that the users are consulted in advance, but emphasises that it is the operator who decides upon the further details of how these procedures are to be determined and how the provisions of the regulations are to be implemented.[263] Accordingly, Gassco has drawn up both a Booking Manual, which determines how capacity is reserved, and a Shipper

260 See e.g. PR Section 65(2) which stipulates that the operator, when drawing up the standard transport agreement, shall consult both owners and users of the relevant upstream pipeline network (i.e Gassled) and take their interests into reasonable consideration.

261 PR Section 61(5).

262 PR Section 61(5) i.f.

263 The Comments, Chapter 8 – Commentary to the individual provisions p 15.

Manual, which determines how to use the reserved capacity.[264]

5.7.3 Capacity Allocation

On the expiry of the deadline, different allocation principles apply depending on whether the total volume reserved by various shippers exceeds the spare capacity available or not.[265]

If the total volumes reserved do not exceed the spare capacity available, the allocation takes place in accordance with the shippers' reservations. Thereafter, eventual remaining spare capacity is allocated to third parties seeking access consecutively (first-reserved-first-served).

If the capacity reservations are in excess of the spare capacity available, rules on prioritising among the parties seeking access apply. In such cases, a distribution formula shall be determined by the operator.[266] Accordingly, the allocation is based on a principle of proportionate distribution of capacity. The distribution formula applies for a set period of time[267,] and is based on each party's need for transportation of natural gas.[268] To which extent transportation is needed must be determined on the basis of the production of the individual natural gas undertakings and eligible customers, and on their sales, loans or purchases of natural gas that give rise to a need for transport and/or processing in the

264 For an overview of the contractual regime developed in relation to the access regime to transport facilities, see Torkjel Kleppo Grøndalen, Gassco AS ("Grøndalen"), published in Martin Karset, Torkjel Kleppo Grøndalen, Amund Lunne, Den nye reguleringen av oppstrøms gassrørledningsnett (Sjørettsfondet 2005) ("Karset m.fl"), pp 119-218, on p 133 (Booking Manual and Shipper Manual in general) and p 152 and follwing (Booking Manual) and p 172 and following (Shipper Manual).

265 The allocation principles are laid down in PR Section 61(4)-(7).

266 PR Section 61(6).

267 As a general rule the distribution formula is expected to be determined on an annual basis, but it may be determined for other periods as well.

268 Either from own production or from purchases, sales or loans of natural gas or combinations of such resulting in a need for the transportation and/or processing of natural gas.

upstream pipeline network.[269] Only natural gas that satisfies the technical and operational specifications in the upstream pipeline network concerned is taken into consideration, when the shippers' need is to be determined. Furthermore, adjustments shall be made for the shippers' existing rights of use.

Irrespective of the total volume reserved, the owners of the pipeline network concerned are prioritised in the allocation process. First, the pipeline owners have priority to existing capacity.[270] Secondly, the preferential right of the pipeline owner applies to new capacity provided that the pipeline owner in question has invested in the expansion or building of the infrastructure in question.[271] Still, the preferential right of the pipeline owners is only of practical interest if the total capacity demand exceeds the spare capacity available. This preferential right to

269 The determination of an individual shipper's production may be based on the production permit, which determines the maximum annual quantity of petroleum that may be produces from each field. As the production permits are granted for time periods of different lengths, down to one year at the time, these permits will only be suitable to make forecasts on a short-term basis. Thus, the production forecast at some future point in time is better based on the course of production approved. It may also be possible to take into account the planned production from fields for which the course of production has still not been approved by the Ministry. In these cases, however, the operator will have to base its judgement on the shipper's estimates of future production.

270 PR Section 61(7). According to PR Section 69(3), the continuance of the pipeline owners' prior right as described in Section 61(7) shall be evaluated before 1 January 2008. Although this is not commented on in the Comments, PR Section 69(3) may be seen in relation with the Commission's letter of 7 November 2002 commenting on the (then) proposed access regime to upstream pipeline networks on the NCS. In this letter the Commission express doubts on whether the priority rights of the pipeline owners are in conformity with the principle of non-discrimination and requires further information in order to determine whether Section 61(7) and the understanding of the condition "duly substantiated reasonable needs of the owner or the operator" are fully compatible with the objectives and requirements of the Gas Directive. However, the rules on the pipeline owner`s prior right to capacity is still in place.

271 PR Section 62. It should be noted that the investors need for capacity now is taken into considerations in GD II (and GD III). As mentioned, investment in new infrastructure or capacity is proposed as a further ground for derogation from the right to access to the system for third parties, cf. GD II Art 22 (GD III Art 36), which according to the wording applies to upstream pipeline networks. Although the objectives of GD II Art 22 (and GD III Art 36) and PR Section 62 are different, both the motivation for and the effect of both provisions are the same.

spare capacity applies to any upstream pipeline networks on the NCS, not only pipeline networks where the Ministry determines the tariffs (i.e. Gassled).[272] Before spare capacity is allocated, account shall first be taken of the owner's reasonable need for capacity in preference to other users.[273]

If the pipeline owner has a duly substantiated reasonable need for capacity, third parties will not be entitled to access to this capacity. However, the owner's priority right to existing capacity is limited upwards to twice his equity interest in the upstream pipeline network concerned.[274] To meet a duly substantiated reasonable need in excess of twice its equity interests, a pipeline owner will have to compete with other natural gas undertakings and eligible customers for the right to spare capacity. Similarly, the pipeline owners' priority right to new capacity is limited upwards. In these cases, however, the preferential right of the pipeline owners is initially limited upwards to the proportional share of the investments made by the pipeline owner in question.[275] The Ministry may determine that this limitation shall not apply, setting a different ceiling for the priority rights. Such a decision may be made when there is an imbalance between the individual share of investment and the volume the individual shipper is expected to transport through the pipeline network in question.[276]

If the capacity reservations made by several pipeline owners exceed the spare capacity available, a proportionate distribution of spare capacity among the pipeline owners shall take place. According to the regulations, the operator shall determine a distribution formula, based on the same principles referred to above, for prioritising among the pipeline owners in these cases as well.[277]

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272 PR Section 61(7)(1), cf. Section 69(1).

273 PR Section 61(7)(1).

274 I.e. if an oil company owns 10% of an upstream pipeline network, it may be entitled to a first priority capacity reservation for its duly substantiated reasonable needs for up to 20% of the spare capacity.

275 PR Section 62.

276 The Comments, Chapter 8 – Commentary to the individual provisions p. 13.

277 PR Section 61(7)(2).

5.8 Tariff Regulation

5.8.1 Introduction

The transportation and/or processing of natural gas in the upstream pipeline network are services that the pipeline owners may – and will – claim payment for. As mentioned, the model of regulated access applies in the primary market.[278] Thus, it is stipulated that "tariffs for contracts in the primary market shall be in accordance with the provisions stipulated in and by virtue of this chapter", i.e. Chapter 9 in the Petroleum Regulations.[279] This means that a pipeline owner of an upstream pipeline network for which tariffs are determined by the MPE, may not claim payment for the right of use, except as provided for in rules given in or by virtue of Chapter 9.[280] In practice, this means that tariffs in the primary market for the use of capacity in Gassled will be regulated in separate regulations issued by the MPE.[281] Furthermore, the regulated tariffs apply to all shippers, meaning both the pipeline owners in their capacity as shippers and other shippers.

It follows from the above that in order to fully understand the tariff system on the NCS, the provisions of the Petroleum Regulations and the Tariff Regulations must be read in correlation. What the transport tariff is meant to cover is determined in principles set in the PR Section 63. First, the tariff is to be paid for the capacity reserved, not the capacity used (capacity fee). The character of the tariff and the considerations on which it is based will be explained in part 5.8.2. Second, the tariff consists of two elements, capital expenditure and operating expenditure.

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278 The tariffs, i.e. the payment for the right to use capacity in the upstream pipeline network, are of great importance. The tariff level in the gas transport market determines whether competition in the gas sales market will be established and maintained. If the tariff level is too high competition in the gas sales market may be distorted, as third parties do not find it economically sound to seek third party access in the pipeline network – and thus access to the gas sales market.

279 PR Section 63(1).

280 PR Section 69(1).

281 I.e. the Regulations for the stipulation of tariffs etc for certain facilities ("the Tariff Regulations") of 20 December 2002.

These elements and the principles for the determination of what these two elements may include are accounted for under part 5.8.3. How the tariffs are to be determined in the individual case, however, is stipulated in the Tariff Regulations, which divides the pipelines and related facilities on the NCS into four zones. The zone system and the principles on which this system is based will be dealt with in part 5.8.4.

5.8.2 Capacity Fee

If granted access to Gassled in the primary market, the third party has to pay a tariff for the right to use capacity in the upstream pipeline network. This tariff shall be paid irrespective of whether that capacity is actually used.[282] In other words, the shippers in the upstream pipeline network pay a capacity fee, i.e. a fee for the capacity put at their disposal.[283] The argument for the introduction of a capacity fee is that it "will help to ensure a more effective use of the capacity."[284] This argument is not further substantiated. However, a capacity fee will undoubtedly create an incentive to restrain reservation in the primary market. Although the shippers need for flexibility will continue to be reflected in the capacity reservations, the obligation to pay for the capacity reserved is likely to result in stronger and more sincere efforts to calculate their

282 PR Section 63(2).

283 This is contrary to the old regime, where the shippers in principle paid a commodity fee, i.e. a fee for the capacity used. However, this principle of paying for what you got was modified by the shippers obligation (for specified parts of the contract period) to pay for specified amount of the capacity granted even though not used. The obligation to pay nonetheless is known as the principle of ship-or-pay, and this principle reflects both the shippers need for flexibility and the pipeline owners need for reliable and continuous payments. The principle of ship-or-pay ensured the pipeline owner a minimum payment, irrespective of the actual transport of natural gas through the pipeline concerned. This ship-or-pay-system was combined with a throughput obligation on the shippers, i.e. an obligation to ship specified gas volumes. The throughput obligation was time limited as well and mainly introduced for security reasons, i.e. in order to obtain the pressure necessary for actual transport of natural gas through the pipeline. Thus, to some extent the capacity fee introduced in PR Section 63(2) can be said to be a codification of the ship-or-pay-system of the old gas sales agreements.

284 The Comments, Chapter 8 – Commentary to the individual provisions p. 18.

accurate need of transport and/or processing services.[285] But more importantly, the capacity fee constitutes an incentive to trade off capacity that turns out to be unneeded in the secondary market. Thus, the capacity fee is essential for the functioning of the secondary market. The main objective of the capacity fee, however, is to reduce the investment risk caused by the tariff regulation by ensuring the pipeline owners investment earnings. In other words, the capacity fee can be said to justify the price caps introduced by the MPE.

5.8.3 Tariff Elements

The costs of the pipeline owners are related to partly the constructing and building of the infrastructure (capital expenditure) and partly the operating of the infrastructure (operating expenditure). This fact is reflected in the tariffs, as they consist of two main elements, a capital element and an operating element.[286] While the capital element is supposed to cover the capital expenditure, the operating element is meant to cover the operating expenditure related to the pipeline network in question. Principles that determine what these two elements may include are established in the Petroleum Regulations.[287] These principles are to a large extent in conformity with the principles applied under the old regime with negotiated access subject to the Ministry's approval.

The capital element is determined by the Ministry.[288] When determining this element, the Ministry shall give consideration "to promoting the best possible management of resources."[289] The capital element shall be set in such a way that the infrastructure owner is ensured a

[285] However, this will in the end depend on a cost-benefit analysis on the part of those shippers with reserved capacity rights. One would expect that the cost of paying the transport tariff compared with the potential benefits related to keeping the capacity will be decisive for the decision of whether or not to offer unused capacity to the market. Thus, market monitoring and the possibility for sanctions are prerequisites for the efficiency of the system.

[286] PR Section 63(3).

[287] PR Section 63(4) and (5).

[288] PR Section 63(4)(1).

[289] PR Section 63(4)(2).

"reasonable return on the capital invested" in addition to having the capital expenditures covered.[290] With the term "reasonable" return reference is made to the authorities' decision that the market participants on the NCS shall make their profits mainly from the fields, and not the pipelines.[291] The return stipulated for pipelines and related facilities in the upstream pipeline network are partly based on this principle. However, "other special circumstances" may also be taken into account.[292] Prior to the implementation of the Gas Directive, tariffs in the newer pipelines have been determined so that the owners can expect a real pre-tax return of 7% on total capacity, with a possibility of additional income as an incentive for greater utilisation and cost-efficient operations.[293] This line is continued under the new regime.

In addition to the capital element, the pipeline owners may claim their operating expenditure covered by the shippers.[294] The key word here is "covered", as the operating element must be determined in such a manner that neither the owner nor the operator has any loss or profit on management of the upstream pipeline network (a principle of "no profit, no loss"). To ensure that the principle of no profit, no loss is complied with, the Ministry may specify which costs that shall or shall not be taken into account when calculating the operating expenditure.[295] TR Section 4 vi) now clearly specifies that operating costs not only covers the cost related to the day-to-day operation of the pipelines covered by the regulations but also costs that the operator incurs in accordance with PR Chapter 9, i.e. tasks related to capacity allocation and system operation, hereunder further development of the upstream gas network.[296] The Ministry may consent to deviations from the principle

290 PR Section 63(4)(3).

291 The Comments, Chapter 8 – Commentary to the individual provisions p. 18.

292 Existing contracts on capacity use may be such a special circumstance, cf. the Comments, Chapter 8 – Commentary to the individual provisions p. 18.

293 The Comments, Chapter 8 – Commentary to the individual provisions p. 18.

294 PR Section 63(5).

295 Such guidelines are established in TR Section 4.

296 For a presentation of the background for this specification, see http://www.regjeringen.no/upload/OED/pdf%20filer/Høringer/Gassinfrastruktur/horingsnotat.pdf.

of no profit, no loss "if consideration of efficient management so dictates".[297]

5.8.4 Tariff Determination

The Ministry has established Tariff Regulations, which set the principles for the determination of tariffs in Gassled. It is important to note that the total tariff (T) paid by a shipper is the product of a unit tariff (t) multiplied with the total capacity reserved in Gassled. The unit tariff is the key component in the calculation of the total tariff paid, as this tariff is established in such a manner as to reflect both the capital and operating expenditure in the pipeline network per Sm^3 of natural gas transported and/or processed. This is not clearly stated in the provisions of the existing legislation, but appears from the correlation and coherence of the provisions of the Petroleum Regulations Chapter 9 and the Tariff Regulations respectively.

The tariff determined on the basis of the principles of the Tariff Regulations, is the unit tariff.[298] For the purpose of determining this tariff, the pipelines and related facilities that constitute Gassled are divided into nine tariff areas, i.e. areas A – I. The most significant area is that of D, as this area covers the pipelines and technical facilities essential for the gas export to the downstream markets, the UK or the European Continent.[299] As technical facilities incidental for access to the export pipeline network (i.e. area D), area C (Kårstø) and area E (Kollsnes) are certainly of practical importance as well.

The unit tariff (t) within each area is established by the operator with the help of a tariff formula.[300] As mentioned above, the unit tariff is the product of a capital element and an operating element.[301] In short, the tariff formula determines which costs that are to be covered under the

[297] PR Section 63(5)(3). See also the Comments, Chapter 8 - Commentary to the individual provisions p. 18.

[298] TR section 4.

[299] For further details with regard to the pipelines and related facilities that constitute area A-E, reference is made to TR Section 1.

[300] The tariff formula and its details are accounted for in TR Section 4.

[301] Item 5.8.3 above.

capital and operating element respectively and how these costs are to be determined. The tariff formula applies to all zones, but its factors are determined individually for the different areas.[302] As a result, the tariff per unit for the right to use (t) differs in-between the defined areas, reflecting the cost differences due to the particulars of the pipelines and/ or related facilities within the given area. In order to reach the consumers downstream, capacity has to be reserved in several of the areas mentioned. The location of the field and the customers downstream respectively, determine the transport route of the natural gas and thereby the areas in which the shippers must reserve capacity.[303] Hence, the tariffs are determined on the basis of the areas the natural gas volumes are transported through on a case-to-case basis. The total tariff paid by a shipper is found by adding the product of the unit tariff and reserved capacity in each area the natural gas is shipped through.

The right of use comprises delivery of natural gas to inlets or taking natural gas out from outlets, or processing in area C and area E.[304] Accordingly, the pricing method of the Tariff Regulations may be described as a zone tariff system.

> The tariffs within an area are determined on the natural gas volumes delivered at the inlets or taken from the outlets or the gas volumes delivered for processing services. While the tariffs for transport are linked to the inlet to and/or outlet from the areas A, B, D and F to I, the tariffs for processing in both area C and area E

[302] TR Section 4.

[303] The upstream pipeline network on the NCS has been described as a "spaghetti"-system. This term is used to reflect that a shipper has to reserve capacity in the pipelines connecting the producer and the customer concerned. I.e. the contractual flow follows the physical flow of the natural gas. This fact constitutes a material difference between the gas sector and the electricity sector. In the electricity sector, the contractual flow and the physical flow are separated. Thus, the electricity grid is often compared with a water tank, which the producers fill and the consumers' drain off without giving a thought to the origin of the electricity they receive. During the restructuring of the upstream pipeline network, the adoption of the "water tank"-system to the gas sector as well was discussed. In the end, however, the parties could not reach an unanimous agreement and thus opted for the reservation system described.

[304] TR Section 3.

> are linked to the different services provided.[305]
>
> During the preparation of the Tariff Regulations, the zone – or point - tariff system was one of two possible pricing methods discussed. The alternative was a pricing method based on transport distance, which to a greater extent reflected the solutions of the gas transport agreements under the previous regime of negotiated access. However, a pricing method containing a distance-related component was rejected due to two main weaknesses. First, a distance-based method will not fully reflect the real costs incurred in the pipeline network. Secondly, such a method may have discriminatory effects as those gas producers located near their customers downstream may have been given an advantage.
>
> Still, on a general basis, the Commission has expressed reservations with regard to the "entry/exit system", as it is called, introduced by the Tariff Regulations at the time it was first adopted. According to the Commission, such entry/exit systems are generally considered compatible with the Gas Directive and competition law in the downstream markets with meshed systems. As the Norwegian system is characterised by clear flow directions and "not very meshed", the Commission raised the question whether "it might be incompatible with the principle of non-discrimination if for all transports to the UK or the European continent de facto identical transport fees are charged although the costs related to this transport might differ significantly."[306] The Commission does not conclude on this matter, but recommend that justifications for the entry/exit system are made "at least internally".[307]

If the necessary capacity is available, a shipper may change the inlet or the outlet for the natural gas shipped. The right to such changes is acknowledged by the authorities, but will be costly for the shipper. In such cases, it is stipulated that the shipper concerned has to pay the highest of the tariffs.[308]

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305 TR Section 2, which contains the definitions of the inlets, outlets and processing for each zone.

306 The Commission's letter of 7 November 2002.

307 Ibid.

308 TR Section 5.

Tariff settlement as such, i.e. determination of payment date and remedies in the event of default, is regulated in neither the Petroleum Regulations nor the Tariff Regulations, but left to be determined in the gas transport agreement. However, the pipeline owners do not have any negotiating freedom in this respect, as the gas transport agreements shall be in accordance with a standard agreement drawn up by the operator (Gassco) and approved of by the Ministry.[309] The terms and conditions of the standard agreement will not be discussed here.[310]

5.9 Enforcement

5.9.1 Introduction

The functioning of the gas transport market, i.e. both the primary and the secondary market, is left to the market participants under the supervision of the operator (Gassco).[311] The regulatory regime provides for provisions that give the market participants the necessary incentives to act according to the desired market behaviour.[312] Still, the Ministry has the competence to intervene in case of either market or regulatory

[309] PR Section 65(2).

[310] The standard agreement with appendices has not been made public, but is available to shippers on www.gasviagasled.com. However, in order to facilitate the evaluation of whether to become a shipper or not, upon requirement potential shippers are presented with the Standard Gassled Terms and Conditions and its Appendices, a Company Agreement regulating access to the secure online system, the Booking Manual which determines how to reserve capacity, the Shipper Manual which determines how to use reserved capacity and the Standard Parent Company Guarantee which is a part of the financial guarantees required for being registered as a shipper, see e.g. http://www.gassco.no/sw1858.asp. For a brief presentation of the contractual regime developed in relation to the access regime to transport facilities, see Grøndalen, published in Karset m.fl, pp 119-218, on pp 15-176, and a thorough presentation of the terms and conditions of the standard transport agreement, see Amund Lunne, Gassleds kontraktsvilkår for gasstransport (”Lunne”), published in Karset m.fl, pp 219-317.

[311] For further details, see Ulf Hammer, System operation, Petroleum Law, Book 1, Chapter 4.

[312] For example the correlation between the introduction of a capacity fee in the primary market, cf. PR Section 63(2), and the establishment of an obligation to transfer capacity assigned in the primary market but no longer needed in the secondary market, cf. PR Section 64(2).

failure. In the following, the different control mechanisms available for the enforcement of the gas transport market will be discussed briefly.

5.9.2 Enforcement of TPA

The authorities have the competence to intervene on their own incentive if the market participants do not apply to the rules on access.[313] If third parties are not given access to an upstream pipeline network in accordance with the provisions of Chapter 9, the Ministry, either directly or through the operator, may order the pipeline owner or the party entitled to access to give the third parties in question access to the requested capacity.[314]

Capacity may also be distributed or redistributed in cases where the rules on access have been applied correctly. The Ministry is granted considerable discretion when determining whether capacity shall be distributed or redistributed for resource management purposes. First, the Ministry may issue orders concerning the distribution or redistribution of the capacity if it finds that that capacity has not been distributed or is not being distributed in a manner ensuring the best possible management of resources, including regularity of supplies and regularity of production.[315] Secondly, the Ministry may issue orders concerning distribution and redistribution of capacity to avoid difficulties in the pipeline network which cannot be overcome reasonably easy, and which could prejudice the efficient, current and planned future production of petroleum, including that from fields of marginal economic viability.[316]

Irrespective of the foundation on which the Ministry has issued its orders, existing shippers whose capacity rights are reduced as a consequence of these orders shall be compensated.[317] The compensation shall reflect their costs of acquiring such capacity.

313 PR Section 67.

314 PR Section 67(1).

315 PR Section 67(2)(1).

316 PR Section 67(2)(2).

317 PR Section 67(3).

Actual or potential parties to a gas transport agreement may also seek the assistance of a dispute settlement authority in order to have their differences settled in conformity with the requirements of GD II Art 20(3) (similarly GD III Art 34(3)). Disputes regarding access rights to the upstream pipeline network on the NCS may be referred to the Ministry or its authorised representative for final decision.[318] As a dispute settlement authority the Ministry or its authorised representative may require the pipeline owners to render a separate account for transmission in the upstream pipeline network as well as any other information needed for resolving the dispute. Currently, the Ministry functions as the dispute settlement authority. According to GD II Art 20(3) (similarly GD III Art 34(3)), the dispute authority shall be "independent of the parties". Due to the Ministry's involvement in the state-ownership of Statoil and the state's direct financial involvement ("SDFI"), it might be argued that the Ministry is not sufficiently independent of the parties involved. The Commission has expressed that this question requires consideration.[319]

5.9.3 Enforcement of Tariff Principles

Individual contracts for use of capacity in the upstream gas pipeline network that are entered into with third parties shall not be forwarded to the Ministry for approval unless otherwise is decided by the Minis-

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318 PR Section 68.

319 The Commission's letter of 7 November 2002, Section 3. It should be noted, however, that reference must be made to GD II Art 25 which deals with access to *the system*, i.e. transmission and distribution pipeline networks. According to GD II Art 25(1), the Member States are obliged to designate one or more competent bodies with the function of regulatory authorities which "shall be wholly independent of the interests of the gas industry". According to GD II Art 25(4), this regulatory authority may act as a dispute settlement authority. A similar condition, i.e. with regard to the specification of the dispute settlement authority's degree of independence, is not included in GD II Art 20(3). Still, it may be argued that the wording of GD II Art 25 may influence the interpretation of GD II Art 20(3) on this point. In GD III the rules on the designation, the objectives and the duties and powers of the regulator at national level are significantly altered, see GD III Chapter VIII. Specifically, the rules on the regulators independence are more stringent, cf. GD III Art 39(4) and (5).

try.[320] This is contrary to the situation under the previous regime of negotiated access, which still applies to the other infrastructure than gas pipelines and technical facilities incidental to access to these pipelines.[321] Traditionally, such approval has been - and still is - an important measure to determine whether the terms and conditions for access, hereunder tariffs, are in accordance with the principles set by the authorities. However, contracts entered into in the primary market shall be in accordance with a standard contract that is designed by the operator and subject to the prior approval of the Ministry.[322] Contracts entered into in the secondary market may be required reported to the Ministry or its authorised representative.[323] Additionally, disputes on tariffs and other terms and conditions for access may be referred to the Ministry or its authorised representative for final decision.[324]

5.10 Summary

The implementation of the Gas Directive(s) in Norwegian legislation is of major importance in respect to establish a European gas market subject to competition. From a Norwegian perspective, the implementation of the Gas Directive(s) in Norwegian legislation has been carried out only with a view to fulfil Norway's obligations according to international law. Consequently, the implementation of the Gas Directive is not a part of a national gas liberalisation programme with the aim of balancing consumer and producer interests as such. As the Norwegian downstream gas sector is marginal, the implementation of the Directive in Norwegian legislation so far only affects producer interests. However, if and when the Norwegian downstream gas sector is emerging, this may change.

Prior to the implementation of the Gas Directive(s), Norwegian petroleum law and the pipeline treaties provided for a system of negotiated

320 PR Section 65(1).
321 PA Section 4-8(1).
322 PR Section 65(2).
323 PR Section 65(3).
324 PR Section 68

third party use of the upstream pipeline network established on the NCS. However, if compared with the prior negotiated system of third party use on the NCS, the rules on third party access of the Gas Directive distinguish themselves on some significant areas.

First, the Gas Directive imposes a legal obligation to grant third party access on the pipeline owners. After the implementation of the Directive, third party access is no longer a mere option subject to the authorities' discretion, but a legal right according to Norwegian petroleum law. While prior to the implementation of the Gas Directive only other producers were granted access upstream, in principle market participants on every level of the gas value chain now have the right to such access. However, the Directive's concept of third party access acknowledges and protects the prior contractual obligations of the pipeline owners. This is reflected in the conditions for access, both those set directly in the Directive as such and those which the Directive allows for and which are subject to the discretion of national regulatory authorities. Hence, elements of the prior negotiated access regime are reflected in the new access regime based in the Petroleum Act and related regulations.

Secondly, according to the Gas Directive both sellers and buyers of natural gas have the right to access. As a consequence, the implementation of the Directive has lead to an increase in the number of those entitled to access to the pipeline networks on the NCS. While the shippers in the upstream pipeline networks traditionally have been the gas producers located on the NCS only, market participants downstream now have the right to access. The experience so far, however, is that the vast majority of the capacity in the upstream pipeline networks developed in relation to the activities on the NCS continue to reserved and used by producers located there.

6 Third Party Use of Production Facilities

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6.1 Introduction

In the development of oil and gas fields on the Norwegian Continental Shelf ("NCS") infrastructure is sometimes shared between two or more fields. This is done primarily to reduce capital investment in order to improve profitability and make more fields commercial.[325]

In the case of production facilities, shared use is an alternative to an independent solution with dedicated facilities being developed for the fields in question. Normally this alternative becomes available when access to spare capacity in existing facilities allow cost savings for new fields being developed, but it may also be an integral part of the original development concept.[326] In either case there will usually be two (or more) licence groups[327] involved, who would enter into an agreement between the group owning the facilities and the group using the facilities, creating a bilateral contractual relationship.

This *chapter* addresses certain public and contract law aspects of such "third party use" or "third party access"[328] to production facilities. To distinguish between the groups in question, they are referred to as "owners" and "users"; the same terminology is used also for their respective fields and facilities.

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325 Technology and project management are also important means for cost reduction.

326 Examples of the former are the Snorre, Vigdis and Tordis developments which are in the vicinity of the Statfjord and Gullfaks fields, an example of the latter is the Ekofisk field complex where Ekofisk Center is used by all fields in the surrounding area.

327 Each of the groups will hold a production licence awarded in accordance with PA § 3-3 or be a unitized group between two or more production license groups. Whether the groups are unitized or not is irrelevant for the issues being dealt with in this chapter.

328 These conventional terms are imprecise as only a first and second party to a contract are involved. These terms are not employed in PA § 4-8.

In *section 6.2* the governmental[329] authority to control, administer and regulate third party use of production facilities is reviewed while the main contents of the commercial agreements are described in *section 6.3*.

The services that owners of production facilities may offer to users span a wide range. At one extreme the service is limited to transport of processed petroleum through the facilities into a pipeline, while on the other extreme all operations – drilling, production, processing and transport – of the user field are conducted at or from the owner field facilities.[330] In most cases, the services include processing of the production stream from the user field and export of the processed stream, commingled with the owner field stream, from the owner platform by pipeline (gas and liquids) or tankers (liquids). The rights and obligations of the parties are regulated by commercial agreements – often called "Tie-In and Processing Agreements".

As part of the introduction, it should be noted that a bilateral user-owner relationship (between two or more license groups) entails certain administrative and other transactional costs that can be avoided by forming a unitised, single license group comprising all licenses groups and fields involved.[331] Such multi-field unitisations may align the interests

329 As from 1st January 1997 the Ministry of Petroleum and Energy exercises the authority, hereinafter referred to as the "ministry". In the following, the terms "government" and "authorities" are frequently used, as other governmental bodies may be involved, such as the Storting (PDO approvals), the cabinet of ministers and the Norwegian Petroleum Directorate.

330 USR § 3 e) lists a range of different operations that may be conducted.

331 The major Åsgard (1996) and Snøhvit (2002) developments at Haltenbanken and in the Barents Sea are both multi field unitisations, Åsgard even involving both gas and liquid producing fields. In both cases, the unitisation was made as part of the field development decision. The Oseberg multi-field unitisation comprised producing fields using the Oseberg production facilities; the Oseberg field itself, the adjacent Oseberg South and other satellite fields. These already had bilateral agreements on use of the Oseberg facilities in place that were made prior to the development of the satellite fields when Oseberg was in production. These agreements were all abolished by the unitisation. This far all multi-field unitisations have been of fields in the same lifecycle when the levels of information about the fields are comparable, i.e. with or without a field production history. A multi-field unitisation was not required for the multi-field Ekofisk development as most of the fields were covered by the same license area (PL018).

of companies involved and allow for more efficient production planning for the fields, depending on the terms and conditions of the unitisation agreement.[332] This kind of unitisations fall outside of the scope of this *chapter*, but are mentioned here as a most viable alternative to bilateral agreements on use between the groups.

With respect to gas producing fields, costs of developing individual pipelines are excessive, thus most gas fields need access to pipelines shared by several fields for export.[333] Export of gas is therefore a separate venture falling outside of the business scope of production ventures. The business purpose of these two types of ventures are very different; a pipeline venture provides transportation services only, whereas a production venture primarily produces oil and gas, providing services is a secondary activity. Construction and operation of pipelines are also subject to a separate licence under the Petroleum Act ("PA") § 6-3.[334] Generally these and other features of gas export pipelines distinguish the use of them from use of production facilities in the international oil and gas industry, but may be even more so in Norway as all gas pipelines have been merged into one single system. Use of gas pipelines is not discussed in this chapter, due to these differences.

332 A key commercial issue in unitisations is the distribution of reserves between the groups involved as that determines the unit interest allocated to each company. As more information about the reserves are acquired, it may be found that the initial determination did not reflect the actual distribution of reserves, in which case an agreed mechanism for re-determination may apply. This possibility may maintain a de facto bilateral – and misaligned – relationship between the groups.

333 Pipeline transport is a physical requirement for gas as it needs to be contained until consumed or converted to liquid form, but as oil is a liquid, export of stabilized crude by tankers is often the most economical solution. However, oil normally contains amounts of associated gas that may be re-injected into the reservoir to enhance oil recovery or used for power generation at the facilities. Any volumes in excess of what is used for these purposes must be exported as flaring is not permitted. Virtually all fields on the NCS produce gas for export, either as primary product (i.a. Troll) or associated with oil production (i.a. Statfjord).

334 This applies both to gas and oil pipelines, but the Ekofisk Teeside line is the only major oil export pipeline on the NCS.

6.2 Public law aspects

6.2.1 Introduction

At a general level the Norwegian government and the oil companies have a common interest in third party use of facilities, as it may save development costs for users and increase income for owners. These potential savings and earnings for the companies would also result in a higher government take through taxes and state participation. It is necessary to recall that the objective of the Norwegian oil policy – the oil industry shall benefit the society as a whole[335] – translates into an objective of maximising state revenue which in turn can be used for purposes prioritised in the political process. However, in the actual cases there may be differences in opinion between government and companies on the advantages of third party use. This may be due to differences in the economic evaluations or other assessments of the benefits with such solutions.

The government applies macro-economic principles in its evaluation and focuses on investments in real assets and payment for production factors. This excludes items of great significance in a corporate financial valuation such as taxes, albeit that those differences are well recognised by the government.[336] Macro-economic or "socio-economic" valuations are attributed large weight in the governmental assessment of oil and gas projects on the NCS.

Another more subtle, but may be even more important, difference is the Norwegian policy of preventing production profits from being transferred from the fields to infrastructure owners by way of tariffs.[337] This policy is attributable to and consistent with the objective of the Norwegian oil policy; more profitable production will increase total

[335] PA § 1-2, which sets out that the administration of the resources shall be long term and to the benefit of the whole of the Norwegian society.

[336] Mitigating or avoiding tax distortions, "tax neutrality", is among the primary objectives of Norwegian tax legislation, especially petroleum tax, where the high rates make such distortions more pronounced.

[337] This objective has evolved over time; see St meld nr 66 (1986-87) and St meld nr 26 (1993-96). The objective is also expressed in USR § 6, 2nd para.

production and raise tax income. However, it also entails that government has a bias in favour of the users – as licensees in the producing fields – in the commercial relationship between users and owners of infrastructure.

6.2.2 Overview of legal framework

The PA and concomitant regulations constitute the legal means adopted to implement the objectives of Norwegian oil policy. The permits and approvals that are necessary for each significant step in the life of an oil or gas field from exploration through production to abandonment are described as "the licensing system".

Formal legal decisions within this licensing system are not the only vehicle for governmental control of the industry. Government may also seek to influence the activities by more informal means in a dialogue between the authorities and the licence groups. In addition, general guidelines made by political decisions are also used to control the activities.[338] However, the legal instruments are important as they set an agenda for the dialogue and create an incentive for the licensees to reach agreement with government on how to conduct the activities. Hence, the PA also serves as a basis for informal control. In the following this informal role of the licensing system will not be expanded on, but it remains important to be aware of it, even though the use of informal means of control may be diminishing in favour of a formalised normative approach.

The legal instruments available to government for control of third party use of production facilities are contained in the PA and the regulations on "Third party use of facilities"[339] ("USR") that became effective

[338] A good example is St meld nr 66 (1986-87) which established a Norwegian gas sales organization based on long term supply contracts sold on behalf of the different companies by a body with Statoil and Hydro as permanent members ("Gassforhandlingsutvalget – GFU, or the Gas Negotiation Committee). The right to supply the contracted volumes was allocated among Norwegian gas producing fields by the authorities. The organization was disbanded in 2001, after the EU commission had investigated the role of the GFU in alleged illegal joint sales for some time.

[339] Regulation 2005.12.20 nr 1625: Forskrift om andres bruk av innretninger.

in 2006.[340] Combined, the PA and USR allow governmental control, or at least influence, over a wide range of decisions concerning use of production facilities from the choice of field development concepts through to the pace of negotiations of the individual agreements on use of facilities. Under this legal structure, the PA itself primarily serves to regulate the initial decisions on field development and use of facilities by different fields, whether by multi-field unitisations or other forms of co-operation, whereas the USR primarily applies to the more "traditional" situation where a new development relies on existing production facilities and the user group negotiates the terms of access with the owner group.

The relevant sections of the PA are PA § 4-2 according to which approval of a Plan for Development and Operation ("PDO") is required for developing a field; PA § 4-7 which applies to joint operations between two or more licence groups and PA § 4-8 that directly regulates third party use of infrastructure including production facilities as further detailed in the USR. These provisions and regulations are all part of the licensing system, and vest authority with the government both to approve and instruct actions to be taken by the licence groups. They all relate to the production phase of a field, including engineering and construction of the field facilities. The rules that can be derived from these provisions and regulations set various limitations on how and when the authorities may exercise the power granted by them. In addition to these specific limitations, certain general limitations also apply.

According to Norwegian public law, government can only exercise power vested by legislative acts and may only pursue and protect concerns and interests that are relevant under the applicable legislation.[341] Due to the broad objectives for the administration of the petroleum industry, this principle only entails some wide limitations on the governmental authority. These may be discerned into internal and external factors. The internals relate to the project or activity itself, while the

340 The ministry submitted the USR on hearing by letter of 23rd August 2005 with some comments, which are referred to as "the explanatory comments to USR" herein.

341 These limitations are reflected in PA § 10-18, 2nd para.

externals comprise “public”[342] concerns and interests affected by the activity.

In making decisions related to a project, government may for socio-economic reasons alter the development solutions preferred by the licence groups and may in principle stipulate entirely different solutions, but a change, if made at all, would typically only modify the conceptual approach of the license groups.[343] Likewise, the authorities may make alterations due to safety and environmental considerations related to the proposed solutions. With respect to the socio-economic assessment of field developments, it must be emphasised that utilisation of existing facilities has been an expressed objective ever since the first major development projects were approved. On the external side, circumstances such as the economic impact of the activity may warrant alterations to the plans or schedules made by the licence groups, or form the basis for other governmental decisions. Among other external factors which government may take into account are broader concerns related to environment, interests of fisheries and other affected businesses.[344]

However, the interests of the licence groups must also be given due regard, the disadvantages they suffer must be balanced with the benefits of the other interests concerned. A governmental decision contrary to the interests of the licensees may only be taken if the benefits outweigh the disadvantages, to what extent would depend on the circumstances. In this context, the licence groups have good reason to expect to carry out their development plans after an exploration success, consistent with their rights under the production licence. Thus, the conflicting concerns and interests must clearly outweigh their interests in a com-

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[342] “Public” as used herein is a translation from Norwegian “samfunnsmessig”, which is a generic term for all matters related to the society as a whole.

[343] This could involve requirements to increase production capacity. During the 1970’s and 1980’s the authorities sought to influence choice of platform technology (concrete vs. steel etc) to increase the domestic content of goods and services procured for the development.

[344] The importance of such external factors is illustrated by the debate on imposing general limitations on petroleum activities in the Barents Sea, which resulted in a recent governmental proposal for a general management plan, see St meld nr 8 (2005-06).

mercial production to justify making any significant alterations to the development plans.

The specific limitations on the authority to control use of production facilities, which follow from the relevant provisions of the PA, apply within these general limitations on governmental authority. The government has authority to control both development concepts and terms of agreements between the parties, which are discussed in 6.2.2 *and* 6.2.3 respectively.

As Norway is an EEA Member State and shall adhere to applicable EU legislation[345] some remarks on EU legislation will complete this overview. With respect to gas pipelines, the EU Gas Directive sets certain limitations on the governmental control of access by giving "natural gas undertakings", including gas producers and gas distributors, a right to access gas pipelines – commonly referred to as "third party access" or "TPA".[346] However, it follows both from PA § 4-8 and the EU Gas Directive itself that it has very limited application on Norwegian production facilities. Firstly, the EU Gas Directive distinguishes between "upstream pipelines"[347] and pipelines for transmission or distribution of natural gas[348]. Norwegian gas pipelines are upstream pipelines that are subject to less detailed provisions of the Gas Directive than the corresponding provisions applicable to transmission and distribution. Secondly, the Gas Directive explicitly excludes any production facilities to which the pipelines might be connected.[349] The PA definition of "upstream pipelines"[350] may narrow this even further, thus, the Gas Directive would at most only apply to those parts of the facilities that are used solely for transport of natural gas and for these parts only to

345 See i.a: the preamble to directive 98/30/EC recital 1 and 3 and Act of 27 November 1992 no 109 § 3, ref EEA treaty articles 1 and 3.

346 Directive 98/30/EC concerning common rules for the internal market in natural gas, see Article 2 no 1 for the definition of "natural gas undertakings". This directive was implemented in Norwegian law by amendment of the Petroleum Act of 28 June 2002, effective from 1 August 2002.

347 See directive 98/30/EC Article 2 no 2, ref. Article 23 and Article 2 no. 3 and 5.

348 See directive 98/30/EC Article 2 no. 3 and 5.

349 See directive 98/30/EC Article 23 no 1.

350 PA § 1-6 m.

the extent it applies to upstream pipelines.

However, in a broader context the Gas Directive can be seen as an expression of a general principle of non-discriminatory access to all kinds of major oil and gas installations, including production facilities.[351] To the extent such principle applies, government could not use its authority to discriminate among different groups of users. Determining the extent and application of such principle would require a detailed investigation, which probably would not constrain but support long-standing governmental policies on access to gas pipelines and production facilities.[352] Regarding gas pipelines, the government implemented policies to control tariff levels in the late 1980s to prevent the owners, having a monopoly position, from earning excessive profits.[353] In 2001-02, these policies combined with the EU energy policies, of which the Gas Directive is part, and Statoil privatisation, brought about a fundamental change in the organisation of the Norwegian gas transportation system. The individual pipeline and terminal joint ventures were merged into the Gassled joint venture, which is operated by Gassco, an independent state owned company, and having regulated tariffs.[354] These changes have created a common Norwegian pipeline grid out of the previous structure of different independent systems, probably going well beyond any strict application of the EU Gas Directive. With respect to production facilities, the USR is only the last step in a regulatory development aimed at facilitating third party access, which dates back to conditions set for approval of the first field developments on the Norwegian Shelf. Thus, a more interesting investigation would be to what extent the EU policies and legislation, such as the EU Gas Directive, have strengthened and enhanced governmental objectives in respect of third party access to oil and gas pipelines and production facilities.

351 See directive 98/30/EC Articles 7 no 2, 10 no 2 and 23 no 2.

352 See USR § 6, 1st para, which sets down a non-discriminatory principle.

353 St meld nr 66 (1986-87) laid down certain calculation principles that would be applied for approval of pipeline tariffs; the “Zeepipe” principles.

354 See MPE Fact Sheet 2006, chapter 5 and FOR 2002-12-20 nr 1726 that stipulates the tariffs that apply to different sections of the pipeline grid, see § 1, 3rd para.

6.2.3 Control over development concepts to facilitate third party use

PA § 4-2 is a cornerstone in the licence system as a PDO approval marks the transition from *the exploration phase* to the production phase in the lifecycle of a field. A PDO covers all aspects related to the development concept for the field, except of any agreements or other commercial arrangements required for developing the field. The PDO will outline the main technical features of the concept as well as safety precautions and environmental effects. The PDO will also contain an analysis on the economic and public consequences of the project.[355] By the approval of the PDO, all these aspects are considered and the field development plan is modified, by terms and conditions for the approval, to the extent required to protect public interests.

For the licensees, PDO approval is necessary to commence development and production. For the authorities the approval offers the best opportunity to influence and adjust the development concept according to the relevant internal and external factors. At this stage, costs of alterations are relatively modest, allowing a reasonable amount of flexibility in the choice of concept. Formally, government grants the approval after submission of a PDO by the relevant licence group. However, due to the importance of the PDO approval a dialogue between the licence groups and the authorities will precede this, the extent of which will depend on the magnitude and impact of the development. In this process, the licence groups may alter the concept to the extent necessary to make it acceptable to the authorities.[356]

With respect to third party use of production facilities the importance of the PDO approval process is different between the owner and

[355] See the petroleum regulations §§ 22-23 on the required contents.

[356] When the Huldra field development decision was made, the Huldra group received offers for access to both the Heimdal and the Troll facilities. Although the Heimdal facilities were relatively new, they were about to be abandoned as the field was depleted, but the Huldra group accepted the Heimdal offer in consultation with the authorities precluding abandonment. The Heimdal facilites presently serve other fields in the area and the Heimdal field only produces when production from these other fields is curtailed.

the user fields. As the user field is about to be developed, a PDO approval will always be necessary. The PDO approval process for the user field may lead to third party use being chosen instead of an independent development.[357] With respect to the owner field, a PDO approval will only be necessary if the owner field is to be developed in conjunction with the user field.[358] However, during the initial approval process for a field it may be decided to amend the development concept to accommodate third party use of the facilities to increase the future probability of use.[359]

PA § 4-2 does not grant any authority to instruct the licence groups to take certain actions, except by the terms and conditions set for approval of a PDO. Hence, if the authorities would want to instruct third party access to production facilities, they must rely on other provisions of the PA. Such instructions may be given pursuant to both PA §§ 4-7 and 4-8. The circumstances under which these two provisions apply are different. The authorities have invoked neither of them to formally instruct third party use, which is probably more a demonstration of the effectiveness of PA § 4-2 PDO approval in achieving the desired results than a indication of a reluctance to promote third party use.

PA § 4-7 regulates joint operations between two or more licence groups and covers several situations. Primarily, the provision stipulates an obligation for different license groups to seek agreement on co-ope-

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357 Explicit examples of this is not easy to find as these alterations will be made prior to submission, but the propensity of such solutions in the vicinity of major facilities may be caused partly by the declared intent of government to utilize existing facilities.

358 Obviously there is no need for a PDO for the owner field when the user field will utilize spare capacity in existing facilities, but it could be necessary if major new construction were required to facilitate use.

359 The Heidrun and Frøy fields are both examples of fields adopted for possible future third party use. However, third parties have used neither of these facilities. The Heidrun field is still in production, so future field developments might still employ the installation, but the Frøy field is abandoned and the installation removed without ever being used by third parties.

ration when a single field extends into their respective licence areas.[360] However, this obligation also applies to activities on several fields "when that obviously is rational", which provides a basis for instructing third party use in such situations. As the obligation relates to co-ordination of activities between several fields, it will primarily be of relevance in the planning phase prior to development of the fields. Thus, PA § 4-7 supplements the possibilities for governmental influence on field development planning offered by the PDO approval process pursuant to PA § 4-2. PA § 4-7 also pertains to other activities than development and production, such as exploration, but this is not relevant in this context.

The authorities may instruct joint development and if necessary stipulate the terms of agreement pursuant to PA § 4-7, if the licensees in fields that could be developed jointly fail to achieve agreement "within reasonable time". Hence, the authority to instruct depends on whether the licensees have not performed their obligation to seek agreement to jointly develop the fields, which in turn depends on the interpretation of "when that obviously is rational" and "reasonable time". Of these, the former phrase sets the most important limitations on the authority. These limitations also apply to the authority to instruct third party use of existing facilities pursuant to PA § 4-7.

The term "obviously" requires the benefits to be clear and easily identifiable. In such cases, the licensees would normally reach agreement on joint development by themselves. Thus, instructions by the authorities would only be necessary if they should fail to agree on a joint development for some reason. In most cases this would be due to different evaluations of the benefits gained by joint development. When these are based on sound and prudent judgement, it can hardly be claimed that joint development "obviously is rational". Hence, this requirement limits the authority to instruct joint development to the rare

[360] When two or more licenses cover a field, the involved groups must be combined into one single group by a unitization agreement. These agreements are based on the JOAs stipulated by the government. Such "unit groups" have developed most of the fields on the NCS.

cases when the objecting licensees do so for other reasons than their prudent evaluation of the benefits of a joint development. In such cases, government will have authority to instruct joint development when "reasonable time" has elapsed. This phrase is probably of no real importance; the authorities would only interfere when it is clear that the parties are not able to progress negotiations despite of the clear benefits of a joint development.

In contrast with PA § 4-7, the exercise of the authority vested in government pursuant to PA § 4-8 does not depend on any actions – or lack of action – by the licensees, but permits government to instruct third party use of existing production facilities when certain criteria are satisfied.[361]

The criteria that must be satisfied for an instruction to be given fall in two groups. Firstly, the third party use must be "rational" or warranted by "public considerations". These two relate to the reasons for when an instruction may be made and are in effect a mere reference to all relevant internal and external factors. Thus, they do not limit the authority beyond what follows from the general limitations. Secondly, it must not "unreasonably" restrain the activities of the owners of the installation or third parties with an ensured right of use, who are both referred to as "existing users" in the following. This is a far more important restriction on the authority vested by PA § 4-8 than the former two. With respect to existing production it must be seen in context with PA § 6-6, 3rd para. According to this provision existing production may only be reduced when that is required to protect major public interests of economic or social nature. In view of this, there seems to be no realistic reason that would justify reduction of existing production to the benefit of a new third party user. The same would apply if owners have concrete plans to utilise any spare capacity for their own production. Hence, instructions pursuant to PA § 4-8 may in practice only be given when there is spare capacity in the facilities, which the owners have no

361 Historically, this is due to the provision originating from conditions allowing the authorities to instruct use that were set for the first field development approvals on the NCS.

immediate plans to utilise themselves. In such instances, government could use its authority to instruct as an instrument to prioritise among several potential third party users.

The USR cannot extend the authority of the ministry or any other governmental bodies to instruct or otherwise regulate use of production facilities beyond those limitations that apply to PA § 4-8 and other sections of the PA that may be applicable. This follows from the constitutional division of power between the legislative (the Storting) and the executive (the cabinet of ministers) branches of government; a regulation, which is made by the executive branch, must lie within the boundaries set by the legislative branch. This is also reflected in USR § 6, 1st para. Despite of these limitations, USR § 12 pretends to extend the application of USR to facilities that are leased by the owner group despite that PA § 4-8 only applies to "*facilities that are subject to PA §§4-2 and 4-3 and are owned by the licensee*" which is a cumulative provision making the application of PA § 4-8 dependent on the installation being both of a kind comprised by PA §§ 4-2 or 4-3 and owned by the licensee.[362] Thus, it appears that there will be sound basis for disputing the validity of USR § 12 and its application to a facility leased by an owner group from a third party to, if such third party would wish to do so. It is surprising that a corresponding amendment of PA § 4-8 was not proposed, or even contemplated, when the USR was prepared. This could have resulted in a broader political debate as to what extent a third party, for instance a rig owner, should have to accept a loss of control over its facilities when let out for petroleum production purposes.

According to PA §§ 4-4, 4-5 and 4-6 the authorities may reduce production, instruct or postpone development and prolong operations. Theoretically, these provisions may be used to schedule activities to

362 The explanatory comments to USR states that PA § 4-8 applies to all facilities comprised by §§ 4-2 and 4-3 irrespective of whether these are owned or leased by the owner group, apparently the ministry interprets the "and" as a reference to all other kinds of facilities owned by the licensee, which must be incorrect. This would extend the application of PA § 4-8 beyond the PA itself, for instance to onshore office buildings, bases or similar.

allow for third party use. However, all actions will be of significant detriment to the interests of the licensees, thus the benefits gained will probably never outweigh these disadvantages. Some of these provisions have been invoked, but then only to further major national economic considerations, for instance to reduce total Norwegian production in periods of very low oil prices.[363]

6.2.4 Control over the terms of agreement for third party use.

A PDO approval according to PA § 4-2 does not, as mentioned above, comprise the commercial agreements required to develop the field. However, agreements with other licence groups must also be approved pursuant to either PA §§ 4-7 or 4-8.[364] In most cases approval of a PDO will be denied until such agreements are submitted for approval. This requirement for approval of agreements prior to or concomitant with the PDO does not follow from the PA but from discretionary governmental practice.

When a development depends on third party use, the agreements between the owners and users may in principle be approved in accordance with PA § 4-7 as a joint activity[365] but, as PA § 4-8 specifically regulates such use, the approval will be given according to this provision. A PA § 4-8 approval will comprise all terms of the agreement, and the authorities may implement changes to any of these by setting conditions for approval, but this would be exceptional in respect of terms that the parties have agreed among themselves. However, as the ministry also has the authority to instruct content of terms not agreed within reasonable time, the parties have from time to time asked it to resolve issues where agreement has not been reached. As a consequence, the role of

[363] Production on the NCS was reduced in accordance with the identical § 20 fifth paragraph in the PA of 1985 in an attempt to strengthen oil prices following the dramatic fall in prices in the mid 1980s. The government also reduced production when in oil prices again fell in 1999.

[364] Until 1996 all contracts for goods and services should also be approved, but this requirement was abolished due to the EEA treaty.

[365] Unitization agreements are approved in accordance with PA § 4-7.

the ministry became more like a mediator or arbitrator than a regulator of agreements subject to PA §§ 4-7 and 4-8. The ministry has since 2000 taken steps to influence the negotiation process and the ensuing contents of agreements on third party use rather than just rely on approval of the completed agreements and resolution of any outstanding issues between the parties. The primary purpose of these steps is, however, to better facilitate third party use, not to alter the roles of ministry.

As a first step, the Oil Industry Association[366] developed a set of guidelines for negotiation of third party access to production facilities – the "TPA Guidelines" – on request from the ministry.[367] This request was made due to concerns that protracted negotiations and uncertainty about commercial terms were preventing development of marginal resources. The TPA Guidelines were aimed at facilitating non-discriminatory access and price transparency for use of facilities between license groups, but were not legally binding and were not adhered to in the extent expected by the ministry. Consequently, the ministry enacted the USR, which contains provisions of similar nature as the TPA Guidelines, but have the force of law as regulations. This development has resulted in a system whereby the ministry regulates contractual content at a general level by USR and only uses its power to instruct content under PA § 4-8 in case of disagreement between the parties. Thus, PA § 4-8 approval is only required in case an agreement were to be negotiated outside of the USR framework.

The USR sets out criteria for setting tariffs and procedures for negotiation of agreements on third party use. The tariff regulations pertain to the content of the agreements and are reviewed below, while the negotiation procedures are described in 6.3.2.

In view of the governmental objectives of optimising the overall

[366] "Oljeindustriens landsforening" www.olf.no comprises companies active in the Norwegian upstream oil and gas industry.

[367] The request was made in view of similar guidelines being implemented on the UKCS following an initiative by the UK Department of Energy, see St meld nr 39 (1999-2000). The UK guidelines and the merits of adopting similar approaches in Norway are discussed in the author's dissertation "Andres bruk av utvinningsinnretninger", Oslo 1997.

activity and maximizing state revenues, the tariffs are the most important subject of regulation, as they determine the distribution of the savings made by the third party use between owners and users. A high tariff level could discourage licence groups from choosing development concepts depending on third party access leading to increased total development costs and reduced socio-economic profitability of the fields in question. A low tariff level could discourage owner groups from making investments or otherwise facilitate use. When regulating tariffs, government must seek to balance these two concerns.[368] PA § 4-8 does not have any reference to retaining profits on the user field, but stipulates that the tariffs shall give the owners "a reasonable profit in view of risk and investment", which permits a reduction of excess profits to the benefit of the user group. USR § 6, 2nd para explicitly states that the agreements (i.e. the tariffs) shall be aligned with the "principle" that the profits from production shall be retained[369] at the field, but also states that the incentives for owners to maintain and invest in capacity at the facilities shall be preserved. There is no substantive difference between the two provisions as the concerns referred to in USR § 6 lie within the discretionary authority vested with government under PA § 4-8

The essence of these overriding concerns is that the tariff shall give the owners a reasonable rate of return on their investments including a premium to reflect the risk associated with the use, but not a share of the users' profits in excess of that. If the user field cannot sustain such tariff level, it can be presumed that a development based on use would not be economical. However, determining such tariff level is a complex matter due to the variety of risks and investments involved. Traditionally, the authorities have been reluctant to consider tariffs agreed by the parties as being unreasonable and to adjust them on the basis of PA § 4-8 and the expressed intention to retain the profit at the producing

368 See the explanatory comments to USR.

369 The reasons for retaining the profits on the user field are described in the explanatory comments to USR pointing out that the user group has taken a considerable exploration risk.

fields alone. USR § 9 gives clearer criteria for setting tariffs by detailing the elements that normally – as a "main rule" – shall be taken into account comprising costs, risks and profit components.

USR § 9 states two key principles that further clarify the overriding concerns reflected in PA § 4-8 and USR § 6. Firstly, as of a point of departure, that tariffs shall be calculated based on the services offered regardless of the profitability of the user field. This clarification is of particular interest as it effectively prohibits tariffs that are based on "user's ability to pay" or "the marginal cost of an independent development" and similar arguments employed by owners seeking a transfer of profit from the user to the owner field. Secondly, as a balancing element, that the owners shall have "a reasonable profit in view of the risk associated with the use". This is the only element in USR § 9 that preserves an incentive for the owners to offer services, as the other elements primarily concern costs or losses incurred due to the use. These include incremental operational costs and investments, which are commonly incurred by third party use of an installation. USR § 9 also comprises other costs and losses that owner groups generally would not incur such as deferring production or making investments to facilitate third party use without any commitments made by a user group.

Thus, the criteria in USR § 9 clarify that owners shall cover costs and earn a reasonable profit, but that profits in excess of that shall be retained on the user field. USR § 9 also expressly obliges the owners to explain the build up of the tariffs and other terms of an agreement. This may enable the authorities to ascertain whether a tariff violates the criteria of USR § 9 and could become a key instrument for regulating tariff levels, depending on how extensive such explanations will be in practice.

Recently, based on USR § 9, the ministry appears to have adopted a more rigid approach to tariffs, denying owner groups any significant profit element beyond 'incremental costs', but such approach in favour of user groups is not reflected in any public decision or policy documents. If pursued, this approach may be an example of the pendulum swinging to far in the opposite direction as tariffs covering incremental costs with only a small or no profit element will discourage owners from offering spare capacity to potential user groups. There is always some pain – administratively and operationally – associated with third party use and then there should be some gain – a profit – associated with it, too.

In the case of approved tariffs, it has been disputed whether the authorities could change them if they proved to create excessive profits or insufficient income for the owners. It was argued that when the ministry approved an agreed tariff it also endorsed it as being reasonable, which prevented it from making changes later on. However, the prevailing view was that the ministry could set new tariff levels pursuant to the criteria allowing amendment of decisions to the detriment of a private party benefiting from the decision as it was made. In support of this, it was pointed out that the regulations to the PA implied that subsequent changes to approved tariffs could be made. The criteria for amendment to the detriment of a party limit this to instances where major public interests suffer from the existing decision due to a change in circumstances. It was assumed that in the case of tariffs, these criteria would only be satisfied when there would be a risk of permanent loss of production if the users could not afford to continue operations.

Government adopted this view, when this situation actually did arise as a consequence of the steep decline in oil prices in 1999. The Ula field licensees considered ceasing production as they claimed it could not sustain the pipeline tariffs for oil transport. When the parties failed to agree to a tariff reduction, the ministry intervened and instructed a reduction based on the criteria allowing change of decisions and the provisions of the regulations and the Petroleum Act implying that changes could be made.[370]

Finally, it deserves mention that the government for a period of time sat the priorities – the sequence of access in case of capacity constraints – between the various fields using the first major facilities developed on

[370] The PA § 4-8 was amended in 2003, giving the ministry an explicit right to amend previously approved agreement terms, which comprise tariffs to ensure that socio-economical projects are commenced or implemented.

the NCS. This was done as a consequence of the regulation of the access to pipeline transport from these facilities.[371]

6.3 Agreements on use of facilities

6.3.1 The internal relationship in the licence groups

Licence groups, being composed of two or more licensees, i.e. oil companies, are conducting the oil activity on the NCS. The groups make decisions on how to conduct their activity in accordance with the voting rules, normally by majority vote.[372] The voting rules are part of the standard joint operation agreement that is entered into between the licensees in each license group (the "JOA").

Entering into an agreement on third party use is for the user group analogous to an acquisition of goods and services. Hence, the general majority voting rules apply. With respect to the owner group, some argue that unanimous approval is required as rental of spare capacity is outside of the purpose of a production licence, which is to explore for and exploit petroleum within the licence area. However, this does not seem to be a viable position. The production facilities and all other assets a licence group owns are acquired for the purpose of exploration and exploitation. Consequently they are joint assets, which may be used and disposed of in accordance with the general voting rules. Thus, agreements on third party use are subject to majority vote also in the owner group.[373] This also follows from PA § 4-8, which presumes that agreeing on third party use is an activity that can be conducted under a

371 The facilities are Ekofisk Centre and the Norpipe pipelines to Teesside in the UK (oil) and Emden in Germany (gas).

372 The voting rules are set out in the agreement between the licensees and the main exception from the majority vote is approval of PDO, which requires individual consent. Certain matters, such as relinquishment, require unanimous consent.

373 Conceivably, third party use might require extensive capacity expansion and construction of new owner facilities, which would require PDO approval. In such instances, the decision would not be subject to voting, but to the individual consent by each licensee.

production licence.[374]

USR § 11 states that all decisions related to requests, responses, negotiations and conclusions of agreements on use shall be made pursuant to the general voting rule that apply for each "venture" – i.e. the license group.[375] This statement amounts to an interpretation of the JOA which is made as an agreement between private parties, but there is no basis for legislating interpretations with binding effect on the parties to an agreement. It may be that the statement rests on a perception of the JOAs being license terms rather than contracts made between independent parties. The authorities stipulate the JOAs and entering into them is a condition for allocation of a production license, which suggests that they are license terms, not contracts. Their legal nature has therefore been subject to some debate and if deemed license terms, USR § 11 may be decisive in case of a dispute.

As all licence groups are composed of a fairly low total number of companies, in most cases some will participate in both the owner and user groups.[376] Due to this partial identity between the groups, the voting majority in both may consist of the same companies. When there is a conflict of interest between the groups, such majority could take undue advantage over the minority in the group where they have proportionally the lowest economic interest.[377] For third party use, the majority might set excessive tariffs when it has a bias on the owner side or conversely low tariffs when the bias is on the user side. As this is an inherent and recurring type of conflict of interest, a practice of electing

374 If third party use were outside the purpose of the owner group, such agreement would also require the establishment of a new legal entity to conduct this business and/or amendment of the JOA.

375 See also the explanatory comments to USR.

376 Statoil would normally participate in both, as the company was awarded an interest, typically 50%, in all licensing rounds between 1973 and 1993 (PL037-202). However, this is not the case anymore. Since 1993, Statoil has been awarded license interests based on application as other companies. In recent years, Statoil has also disposed of its interest in several licenses. In 2001, Petoro AS assumed the responsibility for managing the State Direct Financial Interest from Statoil and the number of licenses with a Statoil presence was further reduced.

377 Conflicts of interest due to partial identity on the company level are not limited to third party use.

side has developed by which each company negotiates on behalf of the side where it has its highest economic interest. This practice is now legislated in USR § 6, 3rd para. This may preclude or limit the opportunity to take advantage of the situation, but will not resolve a conflict if a majority actually takes advantage by making decisions that are to the undue detriment of a minority.

In such instances, the ensuing dispute would be resolved based on the general principle of loyalty between contracting parties in Norwegian private law. In Norwegian law on companies and associations, this aspect of the loyalty principle is referred to as the doctrine of abuse of power.[378] This is now contained in the current standard JOA entered into by all Norwegian license groups and is also reflected in USR § 6, 3rd para, which sets out that the negotiations shall be conducted in good faith ("redelighet og god tro") and pursuant to good business management ("god virksomhetsstyring"). The obligation to negotiate in good faith is an integral part of the loyalty principle, but the content and purpose of the term good business management is vaguer.[379] However, as a part of a regulation, it is unlikely to extend the application of the USR beyond the limitations that follows from the PA or the Norwegian private law principles of loyalty between parties.

If a decision constitutes an abuse of power, it may either be deemed null and void, or if that is not possible, the minority, the injured party, is entitled to restoration of its loss, if any. The decision must not necessarily be to the benefit of the majority itself, nor is it required that a gain has materialised. It is sufficient for declaring a decision invalid that it is suited to give someone an unreasonable gain at the expense of other members in the association. Furthermore, it is only required to demon-

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378 A license group must in this respect be seen as an association, even though it is exempted from the Company Act. This exemption is related to the procedural requirements of the act, and is not made to exclude the groups from relevant general principles of Norwegian law. The principle on abuse of power has been applied in several cases ranging from limited partnerships (komandittselskap) to housing associations (borettslag), and is also codified in Act no 59 of 6 June 1976 relating to Joint Stock Companies § 9-16.

379 The term is not expanded on in the explanatory comments.

strate that the majority should have understood that the decision was of such nature.

The doctrine does not deny the companies the right to pursue their business objectives even if that should be to some detriment of companies being in the minority. It only applies when a gain is “unreasonable”. What would constitute such gain has never been tried in any court or arbitration case concerning a Norwegian petroleum industry dispute. Hence, the actual limitations that the doctrine sets for the decision making in the license groups are uncertain.

6.3.2 The regulated negotiation procedure

The USR sets out a procedure for conduct of negotiations and conclusion of agreements beginning with the initial request made by a potential user to the owners. The key purpose of this procedure is to facilitate efficient negotiations and it is part of the governmental policy of creating incentives for increased use of production facilities to improve the socio-economic profitability of the industry.[380] The parties shall elect sides in the negotiations and act in accordance with the key principles and doctrines in Norwegian private law as described in chapter 6.3.1 above.

The USR distinguishes between requests for information on capacity and requests on use. These are regulated in USR §§ 5 and 6 respectively. The owners shall respond to a request on capacity[381] made be either a licensee or company pre-qualified[382] as licensee. This allows potential users to screen the capacities available around a discovery or a prospective field. A licensee would need such information when considering a field development or even in order to decide on drilling an exploration well. A pre-qualified company would have a legitimate interest in understanding the capacity available when assessing the value of a pro-

380 See St meld 39 (1999-2000) on use and the explanatory comments to USR.

381 The response shall be given within 15 days, which is intended to ensure a good flow of information and owners would need to have updated information available, see the explanatory comments to USR.

382 Pre-qualification by the authorities of companies as licensees and as operators was introduced to reduce license application costs as part of general effort to increase the activity level of thee industry, see St meld nr 39 (1999-2000).

duction licence it may wish to acquire.

A request on use pursuant to USR § 6 shall contain information about the services that the potential user is seeking, milestones and "relevant technical information" for instance on the reservoir and anticipated production rates.[383] The owners must respond to the matters addressed in the request within "reasonable time" and shall as a minimum advice the kind of services that may be provided, priorities of access, tariffs and "other relevant information".[384] Besides of this minimum information, "the owner may emphasize" that the use shall not "unreasonably" restrain the use of the facilities by themselves or by existing users. This reflects the limitations on the right to instruct use pursuant to PA § 4-8 and that existing use, regardless by whom, shall not be unduly curtailed. The owners may also "emphasize" that any petroleum flowing through the facilities shall be, "within reason", compatible with the technical specifications of the facilities and the need for efficient operations.[385] These circumstances could restrain existing use of an installation in same manner as lack of capacity to handle volumes. Different qualities of petroleum may also reduce the value of the petroleum already flowing through the facilities if the streams are blended.[386] The owners shall also facilitate expansion of capacity if none is available.

The parties shall agree on a schedule for the negotiations if they decide to commence negotiations following the exchange of requests and shall in such case advise the ministry of the commencement of and the schedule for the negotiations.[387] The owners shall disclose previously concluded agreements on use when the parties have agreed on the

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383 USR § 6 1st para.

384 USR § 6 2nd para.

385 USR § 6 3rd para.

386 Differences in qualities and value of petroleum can be mitigated by so called quality banks where the volumes allocated to the different parties are adjusted relative to the contribution or impairment their respective petroleum has made to the value of the final blend. Such quality banks are typically used for blended oil streams in pipelines, but may not fully adjust for value differences.

387 USR § 7, completion time should not exceed 6 months.

schedule for the negotiations.[388]

If the parties fail to reach agreement on one or more issues, USR § 13 stipulates that either of them may ask the ministry to resolve the dispute, in which case the ministry shall give each party an opportunity to present its position. The ministry may also request all information necessary to make a decision, which may either by made by a panel of experts or by the ministry itself.[389] Recently, the ministry has also decided that agreements that have been negotiated and are mutually agreed under the USR framework shall not be approved.[390] This decision in combination with the USR § 13 has placed the general regulation of contractual content within the USR and the ministry will only become involved in case of disputes. This system constitutes a formalisation of the role of the ministry as mediator or arbitrator that arises from its power to approve and stipulate terms of agreements under PA § 4-8. Previously, the ministry could refuse making a decision and refer the matter back to the parties; but the wording of USR § 13 imply that the ministry must make a decision if asked.

Finally, when an agreement is concluded and approved by the ministry pursuant to PA § 4-8, the parties shall report "elements of the negotiations" and key terms and conditions to the NPD for publication.[391] Efficient negotiations is also the main purpose of such publication, but it is also intended to "discipline"[392] the parties, probably with respect to the main principles expressed in the USR, for instance that profits shall be retained at the user field.

The ministry has also approved certain standardised terms and conditions for agreements, on third party use of production facilities, in accordance with USR § 10.[393] This "TPA Standard" is developed in co-

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388 USR § 8, the obligation to disclose pertains to agreement concluded after USR became effective.

389 USR § 13 and the explanatory comments to USR.

390 The decision was announced by letter of 6 September 2006 and is made pursuant to PA § 4-8, 2. para.

391 USR § 16.

392 See the explanatory comments to USR.

393 The terms and conditions are available from the NPD website http://www.npd.no

operation the industry and is meant for guidance only and the parties are free to negotiate on a different basis or to deviate from the standard terms, if they are used as basis for negotiations. The TPA Standard is generally consistent with the contractual pattern that has evolved for such agreements in Norwegian oil industry as described in *chapter 6.3.3*.

6.3.3 The main features of the agreements

Introduction

The agreements on third party use of production facilities, "Tie-In and Processing Agreements", regulate two main operational activities.[394] Firstly, the throughput of petroleum over the owner facilities and the services the owners shall render to the users. Secondly, the physical connection or "tie in" of the user field to the owner facilities. The former relates to the commercial objective of the agreements and the latter to the activities necessary to implement this objective. The following review comprises these two issues as well as the nature of the contractual obligations of the parties, with an emphasis on the throughput activity.

Initially it should be noted that all obligations of both owners and users typically terminate upon permanent cessation of their respective operations. For the users this will be when their field is depleted, depletion of the owner field will in most cases also cause the owners to terminate. However, the owner facilities may continue in operation based on income from third party use rather than production from the owner field.[395]

Throughput of petroleum and services rendered

[394] When nothing is noted, the description of the agreements below is based on the typical or normal regulations. There may always be individual agreements with deviating solutions.

[395] Heimdal is the first example of this kind of operation, see also PA § 5-1 where such usage is one of several alternatives listed for disposing of production facilities.

The regulation of the throughput is based on two strictly defined physical points of delivery and redelivery, situated at the in- and outlets of the petroleum stream at the owner facilities. At each of these points the parties have certain mutual obligations to deliver or redeliver and receive petroleum. The scope of services rendered by the owners is determined only by the difference between their obligations to receive and redeliver at these two points. Aside from that, there is no specific description on how the owners shall handle and process the petroleum. The TPA standard may entail a development in this respect as it provides for agreeing on redelivery specifications and a potential liability for the Owner, if the User refuses to take redelivery of petroleum that does not meet such specifications.[396]

This structure is followed regardless of the scope of services and of whether the agreements concern use of spare capacity in existing facilities or fields being developed in conjunction. The users are obliged to deliver all petroleum produced at a defined delivery point until "permanent cessation of production" of the user field. Thus, their delivery obligation comprises all commercially recoverable petroleum from the field.

The owner's receipt obligation does not correspond with this delivery obligation, but is restricted both with respect to quantity and quality of delivered petroleum. The quantities to be received are normally based on the assumed production profile of the user field with an allowance for production in excess of expectations. Restrictions on quality may be of a discretionary nature, like "petroleum suitable for processing", or stipulate specifications quantifying the allowable contents of certain components, temperature and pressure. The owners are only obliged to receive petroleum delivered within these restrictions and may deny receipt of excess volumes or petroleum of differing quality. Hence, the owners shall only receive petroleum from the users in the pace and state the users are able to produce it, if it is in accordance with their receipt obligations.

As the volumes that can be handled on the facilities are limited, the

[396] See section 16.5 of the TPA Standard

owners will limit receivable quantities to retain sufficient capacity for their own use. Quality restrictions ensure technical and commercial compatibility of the streams. Processing facilities are designed for certain qualities with which the user's petroleum must comply. Commercially, blending various streams may affect the value of the combined stream; hence there are extensive procedures for adjustment of the value of the blended stream between the parties; so-called quality banks. With respect to gas, the commingled stream must in any case satisfy the sales specifications.[397]

Operation of oil and gas fields will be interrupted by technical malfunctions, inclement weather, and other "unscheduled events" as well as "scheduled" maintenance. Hence, the receipt obligation is also restricted in case of temporary loss of or reduction in the handling capacity at the owner facilities. In the event of such "shut downs" the receipt obligations will be wholly or partly suspended depending on whether there is any capacity available to the users after the requirements of the owners have been satisfied. When there are two or more user groups, their access to any remaining capacity will depend on their internal priority. These priorities are normally sequential so that the first user has first priority and so forth, but pro rata distribution of available capacity between them does also occur.

When the owners have received the user petroleum, they will normally process it.[398] Their processing obligations are described by the quantity and quality specifications on redelivered petroleum. In most instances these do not constitute any specific obligations. With respect to quantity, the owners shall only redeliver what "remains" at the outlet of their facilities. Likewise the quality requirements refer in most cases only to the petroleum "as it results from" the processing on the owners facilities. However, sometimes these incorporate qualitative specifications applicable to the transport from the owner facilities. In general, the

[397] For instance, due to the widespread domestic use of gas, it must be without "objectionable odours" or not exceed certain minima for sulphur contents.

[398] In some cases processed petroleum is just transported through the owner facilities into a pipeline network.

owners shall only redeliver a proportionate part of the final stream; thus they will not have to compensate users with their own petroleum if quantity or quality should differ from what was expected.

The users typically pay a tariff per unit of throughput volume for the services rendered by the owners.[399] Such tariffs are referred to as unit tariffs, and there are in principle two main methods for calculating them. However, as these two may be varied and combined in many forms, there are a vast number of different tariff calculations in use. Capacity fees are seldom used. Such fees are rentals for the capacity required to satisfy the owners receipt obligation, and are common for pipeline transport. They are normally payable regardless of whether the capacity has been used and agreements with such tariffs are therefore often called "take or pay" agreements, even though "pay anyway" would seem to be a more accurate description.

One method to calculate a unit tariff is simply to agree a fixed amount per unit that covers all costs as well as profit. This amount is escalated on an annual basis according to an agreed index.[400] These are easy to maintain, as they require only a minimum of adjustments, in particular if they rely on historical data (e.g. measured throughput volume in a preceding period of time, such as the previous month) rather than forecasts for throughput and escalation. Such fixed unit tariffs are the most common today. By the other main method the unit tariff is calculated as a pro rata share of actual costs with a profit premium.[401] The calculation of these tariffs necessitates a vast amount of work, as they rely on various forecasts and require substantial audits to verify the actual amounts. This is probably why they are seldom used in recent agreements. However, pro rata sharing of certain operational cost items is sometimes used in conjunction with fixed unit tariffs.

Neither method is well suited for governmental control of the tariff

399 The units used are either barrels (bbl) or standard cubic meters (Sm3). 1 bbl. = 62 US gallons = 159 l.; 1 Sm3 = 1000 l. = 6,29 bbls.

400 The Consumer Price Index is commonly used, sometimes weighted with a petroleum price index.

401 All capital and operational costs (Capex and Opex) plus a profit element are divided by the total units of throughput to arrive at a cost pr. bbl or Sm3 as the case may be.

level. When a fixed amount is agreed, there will be no information on how it was calculated. Thus, unless background information is given, it is only possible to make a discretionary assessment of the reasonableness of the amount. Conversely, government will have to deploy significant resources to control the amount of information available when pro rata sharing is used. Even then, the final assessment of whether the tariff is reasonable will easily rest on a discretionary assessment of the profit premium. In both cases, a comparison with a "market level" may be made. However, in a market where there are significant opportunities for excessive pricing due to imperfect competition, this does not seem to be satisfactory. In general, the need for means of governmental control with the tariff level made little or no impact on the tariff structures stipulated in the agreements prior to USR. However, USR provides a better basis for governmental control of the tariff level, by both setting better defined criteria and obligation the owners to explain the build of the tariffs. The main issue may be how to balance the interests of the parities without di discouraging owners from offering capacity to potential users.

In general, the agreements distribute risk between the parties with a bias in favour of the owners. This may be a result of the relative negotiation strength of the owners, but is also a reflection of the secondary nature of third party use for the owners. Their principal business is production of the owner field; thus they will seek to limit any potential disturbances or liabilities by third party use as much as possible. The owners' ability to reduce their risk exposure is exacerbated by their knowledge and experience with both their field and its facilities. Conversely, the users must rely mostly on prognosis in assessing their needs when the agreements are made.[402]

This bias is most pronounced in the lack of correspondence between the delivery and receipt obligations, which expose the users to the risks of erroneous estimates of their needs, while it protects the owners

402 Normally the performance of facilities and field reservoirs improve over the field life. This tendency is the main reason for the large increases in oil production from most Norwegian fields compared to the initial forecasts.

against similar risks on their side. For instance, the limitations on quantity and quality reduce the risk of disturbances in the owners' production as they may delay or otherwise restrain the production of the user field. The users are also exposed to the risk of deficiencies in the handling of their petroleum on the owner facilities due to the "as it becomes" redelivery requirements. However, the owner bias is to some extent countered by the owners assuming the financial risk for ullage; under utilisation of their facilities. Due to the nature of the unit tariffs the users only pay for the actual utilisation of capacity.

Tie-In of User field to Owner's facilities

To make third party use physically possible, the user field must be connected to the owner facilities by pipelines and other means. In nearly all cases modifications must be undertaken on the owner facilities, which may also require new equipment to be installed. The contractual solutions regarding the responsibility of the parties for these "Tie in" operations have changed over the years, but are now fairly uniform.

Basically, the development of the user field comprises three elements: the user field facilities, various connections between the fields, and modifications of the owner facilities. The users are always responsible for all work related to the user facilities, normally also for the connection work.[403] In modern agreements the owners are responsible for all work done at their facilities.[404] As the modifications are incorporated into the owner facilities, they become the property of the owners.[405]

Even though the modifications are undertaken on behalf of the users, they have in most cases no mechanisms to influence the work, apart from a stated intent that it shall be done in close co-operation with them. This lack of control is further exacerbated by the scope of

403 This will depend on whether transport between the fields is one of the services rendered by the owners, but that is seldom the case.

404 In some older agreements the users are also responsible for the modification works, but this required extensive interfacing between the parties to allow the owners the necessary control with the work done.

405 The users will retain tax depreciation rights for the modification cost covered by them.

work normally being defined by vague functional criteria only. Consequently, the users are exposed both to schedule and cost overruns without much of a possibility to manage the work.

With respect to costs, the exposure will depend on the format of payment. In the typical case, users shall reimburse all costs. In these cases they are without any significant control neither of the performance of work nor of the costs. In view of the intense focus on costs within the industry, this is somewhat surprising. The reason may be that the owners, in particular their operator, refuse to assume any cost risks and to subject themselves to the scrutiny common in fabrication contracts between a construction company and a license group. In some instances it is set a lump sum for the modifications, which the parties may agree to alter if the scope of work is changed.[406] In these cases, owners have the risk of cost overruns, unless users consent to increase the lump sum. This risk increase for the owners may be the reason why lump sums have not become industry practice, in spite of strong support of them as a measure to reduce modifications costs.

A general impression is that the parties have not recognised that the owners do their work on behalf of the users, or rather that the owners have successfully refused to adopt such perspective. Thus, their commercial position is similar to that of a contractor, while their role in the "Tie in" portion of the agreements resembles that of an operator in a licence group. This creates an impression of there being a common interest between owners and users in controlling schedule and costs as there is between an operator and the other licensees in a group, which is not the case.

The Nature of the Contractual Obligations

There are two components in the agreements that are relevant for assessing the nature of the contractual obligations of the parties. These are the Prudent Operator concept and the Force Majeure clauses, which

406 Vague descriptions of the work may increase the difficulties in agreeing on an amount of change.

both originate from Anglo-American law. There are no clear distinctions as to when they apply, but this is of limited importance as they are of similar, if not identical, legal content under Norwegian law.

In the agreements the standard of care for contractual performance is either defined by the Prudent Operator concept or by descriptions of similar legal content. According to American law, proper performance requires that the conduct at least must satisfy the "customs in the field", but this may not always be sufficient due to new technological developments. Thus, within the limits of economic feasibility the best available practices and technology shall be used. Similar requirements would also follow from Norwegian background law. This standard sets tight requirements to contractual performance, but does not amount to a strict liability for performance. Inadequate performance will constitute breach of contract, but a failure to procure the prescribed result is not by itself a breach provided that the performance is in accordance with the standard of care.[407]

The Force Majeure clauses define both what constitutes a Force Majeure event and the contractual effects of such events. Any event that is "beyond the reasonable control" of the parties constitutes Force Majeure, provided that immediate notice is given and all reasonable actions to limit or prevent the consequences thereof have been taken. There is normally also a non-exhaustive list of events of such nature, including "breakage of machinery" and others that are within the sphere of control of the party in question. These will only constitute Force Majeure if their occurrence were beyond the "reasonable control" of the affected party. This must be interpreted narrowly. Events that are rare, but with which there is some experience and that may be controlled by cost effective means would not be beyond "reasonable control". It may be assumed that only novel or rare events, entailing excessive preventive costs, would constitute Force Majeure, if they lie within the relevant party's sphere of control. In general these considerations create a

[407] In Norwegian law this is referred to as a performance obligation ("omsorgsforpliktelse"), whereas a strict liability for procuring the agreed result is referred to as a result obligation ("resultatforpliktelse").

strict standard of care, similar to the one that follows from the Prudent Operator concept.

When there is a Force Majeure event, the party in question is relieved from any liability for failure of performance of his obligations. Thus, his performance is deemed to be contractually satisfactory, in the same manner as when the standard of care is satisfied.

The contractual implications of these Force Majeure clauses go beyond those associated with the concept of "Force Majeure" in Norwegian background law as the range of events that may constitute Force Majeure extend into the sphere of control of the affected party. Furthermore, according to Norwegian general principles, Force Majeure would only relieve a party from liability to pay damages not from breach of contract.

The TPA Standard maintains the approach of using both a Prudent Operator concept as the applicable standard of care and relief from liability to perform in case of Force Majeure, which includes events within the sphere of control of the affected party.[408]

6.4 Conclusions

Ever since the commencement of the oil activities on the NCS, the government has emphasised the need to utilise spare capacity in existing production facilities to reduce the total development and operation costs of the industry.

Legally, the key instrument for implementation of this policy is the PDO approval according to PA § 4-2. The PDO approval is a vital element in the licensing system and is used to control field development on the NCS, but there are only a few examples where this policy has been reflected in PDO approvals. This may be because the licence groups decide on such concepts following a dialogue with the authorities on the development alternatives. More importantly, the apparent lack of governmental control is probably due to a common interest in such use between the licensees and government. Both aims at maximi-

408 See sections 7 and 28 of the TPA Standard.

sing profit from the activities hence both will strive to reduce costs. Hence, in most cases the governmental objectives will coincide with those of the licensees.

Commercial terms, which distort the balance between owners and users, are the main reason for conflicts of interests between licensees and government. The ever stronger emphasis on the need to create incentives for use and to retain profit on the user field demonstrates an increased willingness to regulate third party use of existing production facilities by the Norwegian authorities. This may result in increased transparency permitting a more formalised governmental control than hitherto, despite of the technical and commercial complexity of third party use, which hopefully will strike a balance between user and owner group interests that promotes third party use that both are commercially sound and satisfy the governmental objectives of socio-economic profitability and efficient resource management.

7 Safety regulation

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7.1 General aspects

7.1.1 The role of law in safety

Improving the level of safety in the petroleum activities implies trying to avoid accidents that may cause damage to health, environment and investments. At first glance this is primarily a technological challenge. Structures, equipment and components have to be constructed in such a way that accidents do not happen when the installations are exposed to the physical stresses of operation and nature.

A closer look reveals, however, that technology alone will not suffice. "Soft issues" comes into play as well, due to the fact that the installations have to be constructed and operated by humans. This simple fact entails the need for adequate organisational structures, individual competence and adequate ad hoc discretionary decisions – all leading to safety as one of the end results. If these factors are disregarded, no technological achievement can guarantee that accidents are avoided.[409]

Of course, such guarantees can not be given under any circumstance.

[409] The Piper Alpha disaster on the United Kingdom sector of the continental shelf on the evening of 6th July 1988, killing 165 people, may serve as an illustration. The immediate cause of the disastrous fire was ignition of condensate flooding from a blind flange that could not withstand the pressure. The blind flange was replacing a valve that had been removed for repair. At that time there was no condensate in the pipe, and the flange was not intended to withstand the pressure of condensate. However, the operators in the control room on the night shift were not properly informed by the day shift that the valve had been taken out for repair. That night operational irregularities occurred. The operators took the natural action of leading the condensate into the alternative pipe, and the tragedy was a fact – resulting from inadequate communication rather than technological challenges. See the Lord Cullen report (The Public Inquiry into the Piper Alpha Disaster, Cm 1310, November 1990) at p. 1 and pp. 119-122.

Any activity will unavoidably involve "risk" that damage is caused to life/health, environment or installations. This "risk" may be defined as the product of 'probability of occurrence of an undesirable event' times 'the probable consequences if it occurs'. This implies that the risk can be reduced by reducing the probability that the event occurs at all, and/or by reducing the likely consequences if it nevertheless does.[410]

The endeavours to improve safety implies that all these elements have to be taken into consideration: The technological aspects, the "soft issues" and the choice between reducing likelihood of occurrence and/or consequences. Various types of expertise are needed for this purpose. Understanding of i.a. technological, psychological, economic, organisational and decision making aspects is vital. Nor can the rather cynic cost-benefit analyses be avoided – which in turn also calls for political considerations, such as whether it is considered acceptable that environment is put at risk if the cost of avoiding it exceeds a given amount or if the alternative simply is that the activity in question cannot take place.

So where does law come into this?

Law in this sector like elsewhere is a general tool for enforcing decisions that result from considerations based on such other types of expertise. But the legal tool is not a given element: It takes legal expertise to design the legal tool in such a way that it provides the best means for reaching the goals that have been defined in other arenas. The legal aspect also brings in some additional parameters of its own, e.g. certain limitations as to how and when "the rules of the game" may be changed.

In the following examination of how legal tools are applied to reduce risk of damages caused by petroleum activities offshore Norway, the details[411] of safety regulations are largely left aside. Rather, emphasis is

410 Thus, the general health hazard ("risk") offered by crossing the street of Karl Johan in Oslo may be in the same order as the risk offered by a nuclear power plant: The likelihood of an accident happening on the street is far greater than the likelihood of the power plant blowing up, but the consequences of an incident are far greater in the latter case.

411 The details of the safety regulation are numerous, and they have a tendency of changing ever so often.

put on the general systems, the relationship between the different players and the various legal techniques that are used to promote safety.

7.1.2 The emergence of Norwegian offshore safety regulation

(a) Ever since the very start of petroleum activities offshore Norway in the 1960's, there have been regulations aiming at preventing accidents from happening. The *first set of rules*[412] was designed in the tradition of industry safeguarding regulations, concentrating on rather practical "do's and don'ts" directed to the industry carrying out the activities. Some ten years later, the same path was followed in a more detailed manner, distinguishing between drilling, production and working environment issues.[413]

(b) At this stage, in the mid 1970's, a new concept was introduced in addition to the traditional approach: The *"internal control"* was made a part of the safety regulation.[414] The basic idea was that the industry should not limit itself to complying with straightforward regulatory obligations and prohibitions directly aiming at an acceptable level of safety. The industry was also – as a separate obligation – required to establish a system for identifying relevant requirements, checking that these were adhered to, implementing corrective measures if needed, and reporting all these activities to state authorities supervising offshore safety. This was to take place within the framework of general requirements imposed by the state in the form of "functional requirements", see (c) below.

412 The 1967 Royal Decree (25 August 1967) on safety in exploring and drilling for sub-sea petroleum deposits.

413 Royal Decrees 3 October 1975 replacing the 1967 Decree, 9 July 1976 on safety in offshore petroleum production, and 24 June 1977 on working environment in offshore petroleum exploration and production.

414 The Internal control system is by no means a Norwegian invention. It has been developed i.a. in US car and aviation industry over several decades. But Norwegian regulations have in the last 25-30 years taken the system a step further by more explicitly making it a distinct formal part of the state safety regulation regime, not just a matter for industry's internal organising of activities.

The internal control concept was far from fully developed back in the 1970's. In the following years the concept has been further refined and structured, a key element being that the industry is expected to supplement the often vague requirements of the regulations by defining more specific norms to be applied internally. The (so far) last stage was introduced by the regulations issued in 2010.[415] But since 2000 it is fair to say that the internal control system is a fundamental element in Norwegian safety regulation, and that the impact on petroleum activities imposed by the safety regulations cannot be fully understood without this fact being appreciated.

(c) Another line of development in the safety regulations is the move from detailed rules specifying methods to be applied, to rules that simply state which results are to be achieved. While the Decrees of the 1960's and –70's would give specific details on e.g. the construction of cranes or load-carrying structures, the 2010 regulations restrict themselves to stating that all facilities, including cranes and load-bearing structures should be constructed in such a way that they are able to function safely under the assumed operating conditions. The lack of engineering guidelines in such "*function requirements*" are often remedied by detailed 'cookbooks' contained in guidelines and recommendations issued pursuant to the regulations, or issued by (national or international) standardisation organisations and subsequently endorsed in such official guidelines or recommendations. But these details do not constitute legally binding requirements, just indications on possible (but not necessarily sufficient) ways to fulfil the legally binding requirements.

(d) Consequently, in parallel to the emergence of function requirements, there has been a *move from Decrees to guidelines* etc. as the primary basis for identifying in detail which obligations are actually placed on the industry and individuals employed in the petroleum activities. It is no longer possible – if ever it was – to derive specific direc-

415 See further 7.4 below.

tions on how to safely build and operate offshore installations from reading formal regulations. Accordingly, any such specific directions to be found will not be legally binding, as they will emerge from documents that do not possess such standing. This observation of course carries some legal implications that we will return to in 7.4.2(c) below.

(e) The regime governing offshore safety does not, however, operate solely on the general level that we have now described. The individual company (or, in principle, person) that is subject to the safety regulations will also have an individual link to relevant state authorities: The regulations may call for governmental approvals or exemptions at certain stages, or the authorities may want to intervene in the activities on a separate basis – e.g. because checks reveal that the company is not complying with what the authority think is a safe practice. In such instances the *general* provisions will be supplemented by *individual* administrative decisions. In other words: In addition to requirements that are applicable to all subjects operating in the sector, this specific subject is also obliged to comply with individual requirements that in principle apply to him only. Such administrative decisions will normally constitute *legally binding* requirements that are *more specified* and (often) precise than the general requirements. Thus, the regulator to a large degree abstains from expressing legally binding detailed requirements on a general level, but is not as reluctant on an individual level.[416]

(f) *In conclusion,* what we are left with, is a legally binding framework defining administrative and organisational systems to be established[417] and some general function requirements to be complied with in the ac-

[416] There may be several reasons for this, the obvious one being that relevant facts and considerations are easier to identify in individual cases than on a general level. On the other hand, the authorities generally emphasise that rather than making individual "approvals" to the industry a condition for certain activities to commence, the preferred term is "consent". This change of terminology aims at reducing the legal implications of the authorities' "fingers in the pie".

[417] I.e. the internal control, see 7.4.2 below.

tivities. But the details as to how safety in construction and operation is to be achieved, are to be found either in non legally binding documents (guidelines etc.) or in individual administrative (legally binding) decisions issued within the general framework. This shift away from regulatory details to rather abstract regulations is a characteristic feature in the development of Norwegian offshore safety regulation.

7.1.3 Different categories of safety regulations

(a) The safety regulation deals with two distinctly different issues.

First and basically, it establishes requirements that potentially have a *direct* effect on the risk level. In this category one find e.g. rules on how blow-out preventers for exploratory drilling should be constructed, and which qualifications welders should hold. These may be labelled requirements as to the *state of matters*. But the direct safety regulations also include requirements regarding *actions or occurrences*. Most important in this latter category are rules on procedures for operations, e.g. rules on how to weld certain critical elements of a structure or how to run risk analyses on the structure. The use of both methods, requiring the qualified welder to weld in the specified way, is likely to improve the level of safety. If direct safety requirements are not complied with, the risk for accidents is likely to increase.

Second, the safety regulation deals with matters that are likely to have an *indirect* effect on risk. For example, the operator may be obliged to apply for approval to run a drilling program, specifying the equipment he intends to use for the purpose. Or he may be ordered to report logs from his running of maintenance programs for the production facilities. The non-compliance with this kind of regulations will not in itself increase risk offered by the operations, as opposed to the situation if the operator employs unsafe drilling equipment or refrains from carrying out maintenance activities. But failure to report or apply for approvals may cause the direct safety rules (on maintenance or equipment) to become less effective, and may thus indirectly affect the risk.

(b) From a legal perspective, the *direct safety rules* are rather simple.

They constitute traditional examples of straightforward legal obligations, and non-compliance is likely to have the traditional consequences – admittedly with some "petroleum flavour" to them. To the lawyer or the engineer they may pose a challenge when determining their exact meaning,[418] but they do not constitute complex systems that are difficult to see or understand.

(c) *The indirect safety rules* are more complex. They form the legal basis for *safety control*. This includes both an passive element, i.e. monitoring that direct safety rules are observed in the operations, and an active element if such monitoring reveals a need for corrective measures. The latter may involve the prescription of individual and more specified and/or precise direct safety norms (by means of administrative decisions) to provide further guidance (7.4.4 below). The need for corrections may also necessitate the use of legal means of enforcement, such as coercive fines (7.5.2 below).

Therefore, a prerequisite for an effective safety control is that relevant state authorities are given the right of insight into the activities that are subject to control and to interfere with these activities should the monitoring reveal a need for that. The industry must be obliged to submit applications, plans, reports etc., and the authorities must be empowered to employ adequate corrective measures.

The indirect safety rules are, however, not restricted to establishing a necessary legal basis for the *state's* safety control. Safety control is also a matter for the industry itself. An important type of indirect safety rules are those dealing with the operator's internal control system: By requiring the operator to establish and maintain a defined system for managing his compliance with the safety regulation in general, his operations are not made totally safe, but the risk for errors causing accidents and damage is likely to decrease.

(d) Based on the above, two important observations may be made – both of them important to get the grips on safety regulation.

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418 We will return to that in section 7.4.2 below.

First, from a legal perspective the endeavours to improve offshore safety involves two major players: The state and the industry – or the operator in the individual case.

Second, the regulatory regime in this area require that each of them run a system for *"safety management"* comprising two elements: They should prescribe safety norms, i.e. define norms that should be met in order for risk for accidents to be reduced, and they should *establish a system* for safeguarding that these norms actually are met. The further details of this "safety management" of course varies between the state and the operator. But it is helpful to realise that both types basically amount to the same system.

The petroleum industry is of course engaged in safety aspects of its activities for several other reasons than compulsory state requirements: The level of compensation for damages caused by safety failures may call for increased efforts laid into technological innovation,[419] the general public image of the company involved may suffer or gain by its safety record, damage to equipment and installations may put them out of use and thus result in great losses, etc. However, in the following we concentrate on the compulsory elements – "the state's finger in the pie".

(e) In *summing up* this rather complex picture: Safety norms are twofold; the direct safety norms and the indirect safety norms. An important type of indirect safety norms are those that establish the legal basis for safety control. The prescription of safety norms and the performance of safety control together constitute safety management. The safety management is a matter for both state authorities and industry. From both a legal and a practical perspective these two players run separate systems for safety management. But of course they are also inter-linked.

In the following we shall have a closer look first at the state's safety management, then at the operator's, and finally at the interaction

[419] This aspect is also influenced by the state, ref. Petroleum Act Sect. 10-9 on liability for independent contractors and Petroleum Act Ch. 7 on liability for pollution damage.

between the two. But first we shall look briefly into the issue of jurisdiction: What is the jurisdictional competence of the coastal state outside of its own territory?

7.2 The problem of jurisdiction

The continental shelf is located outside the boundaries of national territory and territorial waters. Consequently, the coastal state need a specific basis in rules of international law in order to exercise jurisdictional powers[420] over the continental shelf and the activities taking place there. We will not embark into these issues in general, but illustrate their link to safety regulation by looking briefly into the issue of jurisdiction over floating devices employed in offshore petroleum activities.

While some of these devices are operating on a fixed location for their whole life, others are moving to and from. The latter are often registered in a national registry of ships. If this state of registry is not Norway, the fact that the vessel operates on the Norwegian continental shelf introduces a problem of international law: How is the power of jurisdiction over the vessel distributed between the "flag state" and the "coastal state"?

This question is relevant for several issues other than safety regulation, e.g. employment, insurance, tax, liability for tort, etc. In most of these other matters, the coastal state (here: Norway) can not exercise any jurisdiction over a foreign vessel operating in connection with petroleum exploration and exploitation offshore its coast – the vessel is more or less in the same jurisdictional position as any vessel on the high seas.[421] On safety issues, the situation is more complex. As long as the safety of the vessel, its operation and its personnel does not pose a threat to its surroundings, there is little need for the coastal state to intervene

[420] Generally, these powers include the power to regulate, adjudicate and enforce.

[421] Note that these jurisdictional issues are complex: The fact that the vessel is employed in petroleum activities distinguishes it from ordinary sea-going vessels because separate rules of international law are then brought into play. Also, the international law rules (and even the internal regulations) on safety zones establish a separate basis for a certain coastal sate jurisdiction over foreign vessels. However, we need not look into the general implications of this.

in any way; such matters can be left for the vessel's flag state to handle. But we can easily foresee situations where the interests of the coastal state are put in jeopardy by the presence and operation of the foreign vessel. This is specifically the case when the vessel is employed in such state's petroleum activities: The safety of the coastal state's installations can be put at risk by the vessel's faulty manoeuvring or construction activities, the environment may be harmed by spills, etc. For this reason, the coastal state would like to have the authority under international law to regulate (and enforce) certain aspects of the vessel and its operation. On the other hand, as seen from the state of registry, such interference would constitute competing jurisdiction, either removing said issues from flag state jurisdiction or complicating matters severely (i.a. because the vessel could – and in practice would – be subject to differing coastal state requirements depending on its geographical area of operation).

The balance is set by the UNCLOS art. 77:[422] "The coastal state exercises over the continental shelf sovereign rights for the purpose of exploring it and exploiting its natural resources."

This clause can hardly be said to clarify all issues related to continental shelf jurisdiction. But it emphasises that in our case the crucial point is to which extent the regulatory issue in question is likely to have a direct effect on safety aspects of exploration/exploitation, i.e. the core petroleum activities. On this basis, there is likely to be a jurisdictional difference between e.g. general working environment and crane operation procedures onboard a foreign construction barge engaged in heavy lift operations in an offshore development project. Also, the argument for coastal state jurisdiction grows stronger the closer the activities onboard the floating device – or the function of the device in general – resemble that of fixed installations. On this basis, there will be a general jurisdictional difference between ordinary ships (e.g. supply ships and shuttle tankers) and floating production platforms.

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[422] United Nations Convention of the Law of the Sea (Montego Bay, 1982). The same clause is contained in the Convention on the Continental Shelf (Geneva, 1958) art. 2 (1).

> In between these extremes there are numerous examples of floating devices that have more or less in common with ordinary shipping. One group comprises vessels specifically designed for standby, supply services, anchor handling, seismic or geological exploration, sub-sea work, etc. These vessels may both look like ordinary ships and operate more or less like them. The same goes for shuttle tankers, transporting crude from the offshore field to refineries onshore. All of these vessels at the outset would seem closer to the flag state that to the coastal state. In the other end of the scale we find vessels carrying out construction, pipe-laying or maintenance services. These vessels are often constructed exclusively for petroleum related operations, their activity and appearance typically deviate strongly from those of ordinary vessels, and their link to "core petroleum activities" is close. Safety aspects of activities onboard such vessels perhaps holds stronger resemblance to that on fixed platforms than to that onboard ships. Consequently, it may be argued that these vessels should be subject of coastal state jurisdiction.

In practice, the alternatives are not "no" or "total" coastal state jurisdiction. Rather, the issue is which aspects (activities, opertations, physical arrangements, qualifications etc.) onboard the mobile facility should be subject to what kind of jurisdiction. This follows form the key wording of the UNCLOS art. 77: "...sovereign rights for the purpose of exploring it and exploiting...".

Quite another matter is whether the coastal state sees it fit to exercise the jurisdictional power vested in it by international law. The competing considerations may be illustrated by the Norwegian position, which resembles that of most states hosting both its own international maritime activities and its own offshore petroleum activities. In general, Norway's flag state jurisdiction in the internal legal system takes the form of maritime legislation, while the coastal state jurisdiction is exercised by means of petroleum legislation (comprising several acts, see 7.3.1 below). A vessel registered in Norway would in principle be subject to both of these sets of regulations when it operates on the Norwegian continental shelf. As no problem of international law exists in this situation, it is for Norwegian authorities alone to decide which set of rules are to apply. The choice is based on considerations quite parallel to those relevant under the international law perspective, i.e. mainly the strength of the link between (i) the vessel and its operations and (ii) the specific features of petroleum activities as opposed to ordinary shipping. The result generally is that the vessel is not made subject to petroleum safety regulation only – as opposed to maritime safety regulation. On the contrary; it is for most purposes made subject to maritime regulation only, unless the vessel is very closely connected to core petroleum activities. This is not just a result of considerations parallel to those applied under international law. It is also a fear that giving the "petroleum perspective" the lead would in turn result in other coastal states doing the same, which would result in practical – and therefore commercial – restrictions being imposed on Norwegian vessels operating world-wide.[423]

In other words: Even if a state take the position of both flag state and coastal state in relation to the same vessel, the choice between "jurisdictional hats" may pose challenges.

7.3 State safety management: The structure of the safety regulations

The state's regulatory safety management comprises two main elements: The prescription of safety norms (directly and indirectly affecting the safety level) and the activities to see to it that the norms are complied with. There are strong interactions between the two. As a third element we find the means of enforcing compliance with the safety norms.

On the formal level, the offshore safety regulations comprise (i) statutes and (ii) decrees and regulations issued pursuant to each of the statutes (or pursuant to several of them in combination).

7.3.1 Statutes

The petroleum activities combine elements from various other activities.

[423] Similar arguments can be seen as basis for the efforts made for international standardisation of i.a. safety regulations within the shipping industry.

There are elements of industrial as well as maritime operations, and there are aspects of working environment as well as external environmental issues of pollution – to take some examples. Each of these aspects often carry with them a separate piece of legislation. For this reason, there is no single statute that exclusively regulate safety aspects of the petroleum activities. At least four distinctly different statutes are relevant for offshore safety:

Naturally, the most general statute applicable to offshore petroleum activities is the *Petroleum Act 1996*. This act contains several sections on various safety aspects of the activities, covering the whole range from safety for personnel to availability of installations (see further on this 7.4.2(a) below).

The *2005 Working Environment Act*[424] is also relevant. This act contains several sections with a bearing on safety aspects of the activity.

If the personnel on the other hand work onboard a *floating* device engaged in petroleum activities, the 2005 act will at the outset not come into play. After all, it is designed for onshore (i.a.) working environment issues, which may differ greatly from those involved in shipping. Instead, the *2007 Ship Safety and Security Act*[425] and the *1977 Seamen's Act*[426] will take care of i.a. safety aspects of the working environment onboard.

Specific risk factors relevant also in the petroleum industry are covered by separate pieces of legislation, such as the 1929 Electrical Supervision Act[427] and the 2002 Fire and Explosion Protection Act.[428] Also, because health issues may well have an impact on safety level, the specific health legislation is relevant to offshore safety. A total of six

[424] Act of 17 June 2005 No. 62 relating to working environment, working hours and job protection, etc. (the Working Environment Act).

[425] Act of 16 February 2007 No. 09 relating to Ship Safety and Security (The Ship Safety and Security Act).

[426] Seamen's Act of 30 May 1975 no. 18.

[427] Act of 24 May 1929 No. 4 relating to supervision of electrical installations and equipment (the Electrical Supervision Act) (amended several times, last time i 2009).

[428] Act of 14 June 2002 No. 20 relating to protection against fire, explosion and accidents involving dangerous substances and relating to the fire department's rescue tasks (the Fire and Explosion Protection Act).

health related acts thus form part of the basis for the detailed safety regulations (see further 7.4.1 below).[429]

Petroleum activities may pose a risk to the external environment. Therefore, the *1981 Act on Protection against Pollution* and on waste[430] is obviously relevant to this type of activity. So is the 1976 Act on Control of Products and Consumer Services.[431]

We may safely conclude that it is a challenge to keep track of all acts relevant to petroleum safety.

7.3.2 The role of Decrees and regulations

While the Petroleum Act by its very purpose is directly applicable to the petroleum activities, the other statutes are applied to these activities by specific provisions to that effect.[432] The details are complex and to some extent difficult to interpret. Also, the acts partly overlap, both in substance and in scope of application. The total picture thus becomes somewhat complex, to put it mildly.

However, in practice the regulatory regime is simpler than this. First, at the level of formal acts, there are few substantial provisions on safety to be found anyway. And second, most of the acts leave it to the King (i.e. the government by means of Royal Decree) to provide the details of how and under which circumstances the act shall be applied to offshore activities. Consequently, we can turn to the decrees (and the

[429] The six acts are the Act of 2 July 1999 No. 64 relating to health personnel, etc. (the Health Personnel Act), the Act of 2 July 1999 No. 63 relating to patients' rights (the Patients' Rights Act), the Act of 5 August 1994 No. 55 relating to protection against contagious illnesses, the Act of 23 June 2000 No. 56 relating to health-related and social preparedness, the Act of 19 November 1982 No. 66 relating to the municipal health service, and the Act of 19 December 2003 No. 124 relating to food production and food safety, etc. (The Food Safety Act)

[430] Act of 13 March 1981 No. 6 relating to protection against pollution and relating to waste (the Pollution Act).

[431] Act of 11 June 1976 No. 79 relating to the control of products and consumer services (the Product Control Act).

[432] At the outset, the geographical scope of the acts is restricted to Norwegian territory. (As to the basis in international law for extending the application to the continental shelf, see 7.2 above.) Specific provisions are needed to make the acts applicable to offshore activities. All the acts mentioned here contain such specific provisions.

regulations issued pursuant to them) in order to establish the total picture of the offshore safety regulation. At the outset these decrees (and regulations) can be understood and implemented without regard to the act or acts constituting their formal basis.

This also provides help in relation to the numerous governmental bodies involved:[433] By means of the central Decree (se further 7.4 below), the Petroleum Safety Authority Norway (PSA) is appointed the main state body in the field of offshore safety, co-ordinating the activities and responsibilities of the other state bodies that are administering the various pieces of legislation in the field.

7.3.3 Simplified approach

The conclusion so far is thus that although the legal and administrative basis for the state's offshore safety management is very complex at the outset, it boils down to a few components when we turn to the practical aspects of state engagement. To get a general understanding of the main issues we can concentrate upon one set of regulations and one governmental body: The 2010 Framework Regulations and the Petroleum Safety Authority.

7.4 State safety management: The 2010 Framework Regulations and the pursuant regulations

7.4.1 The structure of regulations

The basic legal framework for offshore safety is laid down in the Royal Decree 12 February 2010 relating to health, safety and environment in the

[433] The various acts, decrees and regulations that are relevant to offshore safety are administered by different ministries, directorates and other governmental bodies. Parallel to the heterogeneous set of acts etc. we therefore find a similar heterogeneous set of legal entities administering the sector. This complex picture is simplified by the Petroleum Safety Authority being made a coordinating body for all other governmental bodies involved in HSE aspects of offshore - and to some extent onshore - petroleum activities, ref. item 2 and 3 of the Royal Decree of 19 December 2003 No. 1592 establishing the Petroleum Safety Authority.

petroleum activities and at certain onshore facilities[434] (the *Framework Regulations*). Pursuant to this Decree,[435] four subordinate regulations have been issued by the competent directorates.[436] Each of these regulations cover a separate aspect of safety issues: Management, Facilities, Activities and Technical and Operational Matters, and each of them except the latter one is laid down jointly by all the four involved directorates. While the Management and Technical/Operational regulations contain provisions that are relevant in all phases and all aspects of the operations, the scope of the Activities and the Facilities regulations is defined according to the distinction between operations as opposed to state of matters.

The Framework Regulations provides exactly that: A framework for the offshore safety regulation. It defines the common scope of application for all the regulations, their common purpose and definitions, who is to be responsible for complying with all the regulations, and the common main principles for health, safety and environment, including what is labelled "health, safety and environment culture" (Sect. 15). Within this framework, the four regulations spell out in some detail what is required in each of the specific areas.

The common *scope of application* for all the regulations is generally

434 The inclusion of ”certain onshore facilities” in the scope of the Decree -- and consequently in that of the adjacent regulations -- is the main reason that the whole set of Decrees and regulations was amended in 2010 (from the previous version of 2001) following a lengthy process of deciding the extension of ”offshore” HSE to onshore processing plants closely linked to the offshore production facilities, and the related consequences for the powers of the enforcement agencies . The means of delimitation is simply that of explicitly referring to named existing onshore facilities (such as Kårstø, Sture, etc.), see the Framework Regulations section 6 litera f.

435 Formally speaking this is not quite correct, as the Framework Regulations do not constitute the legal basis for the four subordinate regulations. For undisclosed reasons, they are all legally rooted directly in (most of) the statutory provisions that also form the legal basis for the Framework Regulations – as well as in the provisions of the Framework Regulations that empower the relevant directorates to issue regulations (Section 68, first subsection, litera b). From a legal perspective the latter basis would suffice, and it would also underline the hierarchical structure that is intended between the Decree and the regulations.

436 They are The Petroleum Safety Authority Norway, the Climate and Pollution Agency, Norwegian Directorate of Health and the Norwegian Food Safety Authority. This reflects the fact that the regulations are based on the abovementioned acts, the enforcement of which is vested in the four different state agencies.

defined by reference to Sect. 1-4 of the Petroleum Act – with some adjustments following from the parallel provisions contained in the other acts upon which the Decree is based (ref. 7.3.1 above).[437] This implies that the basic criterion is whether the matter in question is "petroleum activity", defined in the Petroleum Act as "all activities associated with subsea petroleum deposits", and further defined by examples of such activities (Sect. 1-6 (c) and (e)-(i)). We need not go further into this; for our purpose it suffices to note that the Decree covers all aspects of activities that reasonably can be considered to have such a link to offshore petroleum activities that they may be relevant for safety in that activity,[438] including activities related to certain facilities onshore.

The *purpose* of the Decree and the four regulations is threefold (Sect. 1 of the Decree): To further "a high standard" for safety, achieve "a systematic implementation" of measures to fulfil safety requirements and objectives, and "further develop and improve" safety standards. While the first and last of these objectives aim directly at the fundamental objective of any safety legislation, the second objective points in

437 This method of defining the scope of application is rather complex. It may result in the various parts of the Decree (and hence: of the four regulations) having different scope of application depending on which act must be considered to form the formal basis for the provision in question. On the other hand this can hardly be avoided, assuming that (a) the Decree has to base itself on several acts, and that (b) these acts define their respective application on offshore matters differently.

438 Again, the various types of vessels engaged in petroleum activities create problems (ref. 7.2 above). The Framework Regulations Sect. 4 second para. state that "The following are exempt from the Working Environment Act and provisions in these regulations, which are laid down in pursuance of the Working Environment Act: a) supply, standby ....with vessels... and other comparable activities which are considered shipping, b) vessels carrying out construction....in the petroleum activities...." As explicitly stated, these exemptions only apply to the provisions of the Decree which are founded in the Working Environment Act, the reason being that the Act calls for such exemptions. However, the Petroleum Act does not, implying that those parts of the regulations that are laid down on the basis of that act may be applied to "activities which are considered shipping", to the extent that is allowed under Sect. 1-6 litera d defining "facility" under the Petroleum Act. This exemption thus illustrates the complexity added by the fact that the Framework Regulations are founded in several acts having slightly different scopes of application. The situation is somewhat confusing – as it has been in this area ever since the first safety regulations were issued in 1967.

a slightly different direction: In order to be able to "systematically implement" relevant measures to comply with safety requirements, the responsible party has to establish an administrative and organisational structure for this purpose. This objective thus constitutes the inception of the internal control system (7.1.2 (b) above).

Note should also be taken of the separate objective of developing and improving safety standards. This explicitly stated dynamic element of the regulations is natural in the sense that society's views on acceptable safety standards are indeed changing over time. Therefore, the regulations should reflect that the required safety level is not static. But the dynamic objective also introduces some legal challenges, at least if it is supplemented by operational requirements to the same effect – which it actually is:[439] At a given point in time it may be difficult to establish the relevant requirement, and consequently establish a basis for enforcement, ultimately in the form of criminal sanctions.

Finally, the *responsible parties* are defined. The Framework Regulations state that "the operator and others participating in the activities are responsible pursuant to these regulations" (Sect. 7, 1st para.). The term "others" covers both companies and individuals, implying that anyone engaged in "petroleum activities" has to observe the requirements of the Decree and the four regulations. But among this lot, the operator carries a special responsibility: He shall "ensure that anyone who carries out work on his behalf, either personally, through employees, contractors or subcontractors, complies with the requirements stipulated in the health, safety and environment legislation" (Sect. 7, 2nd para.). By this clause, the operator is defined as the central actor in the play, and his internal control system is defined as a key factor in making the safety legislation effective (see further 7.6.3 and 7.7 below).

7.4.2 Direct safety requirements

Requirements specifically prescribing "do's and don'ts" to achieve an

[439] See e.g. Sect. 10, 2nd para. of the Decree: "A high standard of health, safety and environment shall be established, maintained and further developed."

acceptable level of risk are not easily found in the legislation pertaining to the offshore sector. Rather than prescribing methods to be employed the legislation defines what is to be achieved – the results that the legislation and the administering authorities are aiming at. Such *function requirements* leave it for the responsible party to choose a method that is likely to achieve the required result.

> Therefore, the preference for function requirements is closely linked to the emergence of the internal control system: It becomes vital that the responsible party is in a position to be able to make the correct choices within the function framework defined by safety legislation. This internal prescription of norms is one element of internal control, the other being the act of checking that these norms are complied with and the introduction of possible corrective measures, see further 7.6.1 below.

(a) The safety legislation provides numerous examples of function requirements. On the very top level, the general provision on offshore safety is contained in the Petroleum Act: "The petroleum activities shall be conducted in such manner as to enable a high level of safety to be maintained and further developed in accordance with the technological development" (Sect. 9-1). The chapter containing general provisions states that "Petroleum activities according to this Act shall be conducted in a prudent manner and in accordance with applicable legislation for such petroleum activities. The petroleum activities shall take due account of the safety of personnel, the environment and of the financial values which the facilities and vessels represent, including also operational availability" (Sect. 10-1, 1st para.).

Three observations may be made regarding these provisions. *First*, the level of safety is not well defined. There is not very much help to be found in knowing that "a high level of safety [shall] be maintained" and that "due account of the safety of personnel" shall be taken. Admittedly, the subordinate regulations offer some specification as we shall see below, but the basic problem remains: The required level of safety is by no means precisely defined – and can hardly be. *Second*, whatever the required level may be, it shall be "further developed" to keep up with technological development. This dynamic aspect is essential, but it makes it even more challenging to identify the required level at any given point in time. And *finally*, the Act explicitly makes it a distinct end to secure "operational availability". In this way, the traditional concept of safety has been given a broadened meaning: Even if no harm is done to persons, environment or installations, it would contravene the industry's *safety* obligations under the Petroleum Act if an unplanned occurrence render the installation unable to fulfil its purpose, potentially entailing all consequences of contravening safety requirements.

(b) On a general level, the Framework Regulations offer some further guidance on the standards contained in the Act: The petroleum activities shall be carried out in a safe and prudent manner "based both on an individual and an overall assessment of all factors of relevance for planning and implementation of the activities as regards health, safety and the environment", and "Consideration shall also be given to the specific nature of the activities, local conditions and operational assumptions" (Sect. 10, 1st para.). Further, Sect. 11 provides i.a. that safety assessments "shall be carried out during all phases of the petroleum activities" and that if there is "insufficient knowledge concerning the effects that the use of technical, operational or organisational solutions can have on health, safety or the environment, solutions that will reduce this uncertainty, shall be chosen". But these provisions are obviously far too general to be of much help in the day-to-day business of planning, constructing and running offshore installations in a safe manner.

Some help can be found in the more specific provisions of the Framework Regulations and the subordinate regulations. However, most of them are function requirements, be it on a more detailed level. One illustration is a provision on loads and resistance: "Accidental loads and natural loads with an annual probability greater than or equal to $1x10^{-4}$ shall not cause the loss of a main safety function" defined as i.a. "maintaining the main load carrying capacity in load-bearing structures until the facility has been evacuated".[440] There are no legally binding directions as to how this end shall be reached (but there are guidelines directing the user to accepted standards, see further (c) below).

This is also the general picture: The regulations scarcely offer any detailed guidance in the form of *legally binding* and *generally applicable* rules on how the required safety standards shall be met. In the *individual* case, however, the regulations may be supplemented by administrative decisions which may contain further details and even specific methods to be applied in order to achieve the prescribed functions. This detailing in the form of individual norms is an aspect of the state's safety control, see further 7.4.4 below.

(c) In the legally *non-binding* form, extensive help is given to the responsible party in the form of guidelines and recommendations attached to the regulations.[441] The Facilities Regulations alone make reference to and recommend the use of a total of some 100 standards issued by some 12 different institutions in Norway and world-wide; the similar figures from the guidelines for the other regulations are somewhat lower. Each of the standards generally offer comprehensive and detailed guidelines and recommendations within their specific scope, usually describing methods to be used to achieve the results prescribed by the function standards rather than just detailing the results. In other words: There is no lack of detailed norms, not even in the form of detailed methods to be applied. But they are all *non-binding*.

This does not imply that the recommended standards are irrelevant from a purely legal perspective (from a practical perspective – e.g. to the engineer designing the facilities – they are of course highly relevant). The Framework Regulations state that "When the responsible party makes use of a standard recommended in the guidelines to a provision of the regulations, as a means of complying with the requirements of

440 Ref. the Facilities Regulations Sect. 11, 1st para. cf. Sect. 7, 2nd para. (b).

441 The above sited provision on accidental loads is accompanied by an official guideline recommending the use of i.a. several specified NORSOK standards for the purpose of designing the structure in such a way that the function requirement is met.

the regulations in the area of health, safety and the environment, the responsible party can normally assume that the regulatory requirements have been met." (Sect. 24, 1st para.). The wording may seem less stringent than what is normally found in Royal Decrees. But there is little doubt that the provision implies that by implementing the recommended standards the party responsible is in full compliance with the relevant regulation – unless specific circumstances strongly indicate otherwise. In this sense, the standard takes the role of a regulation. But not in the opposite meaning: The party responsible is in principle free to choose another way to achieve the prescribed results than the method given by the standard – such attitude will not necessarily amount to a breach of statutory obligations inherent in the function requirement of the regulation. But in this instance, the party responsible "shall be able to document that the chosen solution fulfils the regulatory requirements" (Sect. 24, 2nd para.). An important indication when determining whether the chosen solution actually fulfils the requirements, is of course the general impression left by the non-implemented standards.

(d) In summing up, most of the direct safety norms contained in the regulations are function requirements, leaving it to the party responsible to decide how the described results are to be achieved. But his freedom of choice is in practice limited because the official comments to the regulations recommend certain standards to be applied. The party responsible carries the burden of proof that his method is as good as the recommended one if he elects to deviate form it.

An important effect of this system is that there are no exhaustive regulatory requirements that relieve the industry form employing their best know-how in trying to achieve an acceptable safety level. This in turn means that safety requirements are not becoming static in the same way as if detailed do's and don'ts had been spelled out in the regulations. It also tends to place the responsibility for safety where it belongs – with the industry itself. But the system is totally dependant on the industry being able to undertake such a central and – to some extent – independent role in safety management. And the state would not do its part of the job properly if it did not see to it that the industry (and any party responsible) actually was in a position to play its role properly.

This leads us to the indirect safety norms.

7.4.3 Indirect safety requirements

While the direct safety requirements are directly aiming at improving the level of safety, by function requirements accompanied by recommended standards, the indirect safety requirements are dealing with matters that in turn may have this effect, but which are not aiming at having a direct impact on safety. If drilling operations require approval of a plan presented by the operator, the likely effect is that drilling becomes safer: In preparing the plan, alternative equipment and operational procedures have to be considered, decided and described, increasing the probability that the best choices are made and that they are subsequently properly implemented when drilling. Thus, the risk of damage is likely to decrease. But the direct approach specifying how the drilling actually should be performed, is likely to have a stronger impact on safety level than just requiring plans to be approved. Similarly, an obligation to report on maintenance work may have an indirect safety effect, while an obligation to perform certain maintenance work would potentially have a direct impact on safety.

The indirect safety norms may well be used in parallel with the direct norms. And there is little reason not to do that: Although the indirect norms may seem less potent than the direct norms as a means to achieve safety, they widen the range of tools available for the purpose. Rather that putting all bets on one horse – the detailed "do's and don'ts" that are likely to affect safety directly – the safety regulation also requires the industry to establish procedures and expertise for *handling and complying with* the direct safety requirements.

These indirect norms are also "do's and don'ts": The operator shall set up his organisation to certain standards, employ qualified personnel, check and report his activities, plan and apply for approvals, and so on. But although the legal tool basically is the same, the different object of regulation implies that the indirect norms operate on another level.

They impose two important obligations on the industry that do not follow from the direct norms. First, the industry shall establish a system that enables it to comply with the safety requirements in all its operations. It is not left entirely to the industry's discretion how this should be done – it has to carry out its own safety management in the required way. This requirement results in the internal control system, see further 7.6.3 below. Second, there shall be a formalised link between this internal control system and the state safety management: The industry shall by legally binding obligation establish a system for effectively relating to the state authorities that enforce safety regulations. This constitutes an important element in state safety control, in that various types of input from the industry itself in turn form a basis for the authorities' check that safety regulations are complied with. See further 7.7 below.

In this way, the indirect safety norms play a role in safety management in two important ways: They establish the legal basis for the internal control system and they constitute the legal link between this and state safety control. The safety regulations contain numerous examples of indirect safety requirements. Some illustrations: "The responsible party shall prepare and retain material and information necessary to ensure and document that the activities are planned and carried out in a prudent manner. The responsible party shall ensure that documentation demonstrating compliance with requirements stipulated in or pursuant to these regulations, can be provided."[442] There are several provisions obliging the party responsible to obtain consents and approvals at various stages of operations, and also a provision that generally authorises the Petroleum Safety Authority to decide by regulations or individual decisions that the operator "shall obtain consent from the Petroleum Safety Authority Norway before certain activities are initiated".[443] A less general, but not less important, example is the provision that "In connection with shift and crew changes, the responsible

442 The Framework Regulations Sect. 23, 1st para.

443 The Framework Regulations Sect. 29, 1st para. Detailed provisions are given in the Management Regulations Sect. 25, which lists ten different activities that need prior consent, e.g. manned underwater operations, major modifications and disposal of a facility.

party shall ensure necessary transfer of information on the status of safety systems and ongoing work".[444]

The most general indirect safety requirement is the provision that obliges the party responsible to "shall establish, follow up and further develop a management system designed to ensure compliance with requirements in the health, safety and environment legislation."[445] This is the very basis for the internal control system.

7.4.4 General regulations and individual administrative decisions

Both direct and indirect safety norms are general – they are prescribed in the form of statutes, royal decrees or regulations which are applicable to any party "participating in activities covered by these regulations".[446] We have also seen that the norms are general in the sense that they normally do not offer detailed guidelines directly applicable to a given situation.

There are two types of legal tools that can transform the general provisions into individual requirements tailored to a specific situation and party.

First, *exemptions*: The relevant ministries and their supervisory bodies "can grant exemptions from the provisions stipulated in or in pursuance of" the Framework Regulations, subject to taking into account the enforcing powers vested in other bodies, provided only that "special circumstances exist" and that a statement from the elected representative of the employees shall be enclosed with the application for

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444 The Activities Regulations Sect. 32. Failure to transfer such information was the direct cause of the Piper Alpha disaster in 1988, see footnote 412 above.

445 The Framework Regulations Sect. 17, 1st para. Section 12, 2nd para. reads: "The responsible party shall ensure that everyone who carries out work on its behalf in activities covered by these regulations, has the competence necessary to carry out such work in a prudent manner." Together, these sections imply that both the organisational structure and the individuals operating it shall be capable of identifying safety norms, complying with them, seeing to it that they are complied with and performing necessary corrective measures. See further 7.6.3 below.

446 Ref. the Framework Regulations Sect. 6 litera a defining "the responsible party" in relation to the regulations.

exemption if the exemption "could impact safety and the working environment".[447] Under Norwegian administrative law, this implies that the supervisory bodies are entrusted with wide discretionary power in deciding whether exemptions should be granted, and if so under which conditions.

Second, *individual decisions*: The supervisory bodies "can make the administrative decisions necessary to enforce the provisions stipulated in" the Framework Regulations.[448] Generally speaking, under general administrative law principles such decisions cannot amount to more burdensome requirements to the industry than those contained in the regulations; they can only specify and give details within the borderline of the general provisions of the regulations. Nor can they modify requirements contained in the regulations – such decisions have to take the form of "exemptions" and comply with any restrictions applied to such decisions. But in practice, these types of administrative decisions occur simultaneously, and then the scope may be wider. A typical example is approvals and consents that the operator has to apply for at certain stages of his operations. In deciding whether approval shall be granted, the supervisory body may consider the option of granting an exemption from a regulatory provision, in combination with a condition that tighten the requirements that already follow from another regulatory provision.[449]

Together, the provisions on exemptions and individual decisions result in the regulations becoming flexible: The requirements may be adjusted to individual circumstances, and experience gained may be reflected in the operational requirements without necessarily having to engage in the demanding process of amending regulations. This flexibility is also an important prerequisite in the correlation between the state's safety management and the industry's, see further 7.7 below.

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[447] Ref. the Framework Regulations Sect. 70.

[448] Ref. the Framework Regulations Sect. 69.

[449] If and to which extent the granting of exemptions may widen the authority to issue related individual decisions that exceed the requirements contained in regulations, is a complex and difficult question of general administrative law.

7.5 State safety management: Safety control

7.5.1 The objects of control, and the means of controlling them

The state does not restrict itself to influencing safety by laying down legal requirements in the form of direct and indirect safety norms. State safety management also comprises checking that the party responsible actually complies with the norm.

The safety control depends on which type of requirements are basis for the control.[450] Checking compliance with direct safety requirements differs fundamentally from monitoring compliance with the indirect norms, simply because the factual objects of the exercise are so dissimilar. We can draw a distinction between direct verification and indirect supervision.

(a) The *direct verification* deals with the industry's actual adherence to specific safety requirements: Are the valves tight, the level of corrosion acceptable, the load carrying structures sufficiently strong, the sub-sea operations safe, the crane operator qualified? This type of supervision is a form of "hands on" check of the activities and state of matters that are likely to have a direct impact on the risk for damages inherent in the industry. It follows the tradition of state involvement in industrial activities ever since the industrial revolution, and it also used to form the major part of state offshore safety control in the early days – prior to the emerge of the internal control system.

(b) The *indirect supervision* monitors and audits the industry's system for controlling its own activities, i.e. the internal control system. As we shall see below (in 7.6.3), the industry is required to document its

450 The term "control" is not precise. It may mean just the passive checking, or it may denominate the active steering – taking control. When describing state safety control, it is preferable to make a distinction between these two: The passive control implies to verify or audit the industry's operations, while the active steering requires that the passive control is followed by administrative decisions directed towards the industry. See further 7.4.4 above on administrative decisions linked to control.

internal control system. This documentation gives a strong indication of whether the required system is in place and working, which makes it a relevant object of safety control.[451]

But one thing is having a structured system for internal safety management in place, quite another is whether this system actually results in the activities being performed in compliance with relevant requirements. In order to verify this, the state control will have to look into the primary activities themselves: Does the internal control system work in that the valves actually are tight, etc.? In order for the indirect supervisory type of control to be an effective tool to ensure safety standards, it therefore has to be supplemented by the direct verification of the technical details that the internal control system is designed to handle – simply to safeguard that the system is actually working as intended.[452]

Consequently, there is a close link between the two types of state control – once the internal control system has been introduced and thus forms a natural object of state control itself. But the balance between the two has shifted: The development is towards increased weight being attached to the indirect supervision. This is explained by the emergence of function requirements. Along with a changed method for prescribing safety norms – from specific methods to general goals – the state's system for supervising safety has changed: The fundamental need is to secure that the industry is able to make adequate choices within the wide boundaries defined by the function requirements and that these choices are actually implemented in the activities, i.e. that the internal safety management works.

[451] See the Framework Regulations Sect. 67 2nd para.: The Petroleum Safety Authority "will carry out supervision of the management systems established pursuant to these regulations and will make the decisions necessary to implement provisions regarding the requirements for the administrative parts of the management systems [...]."

[452] An illustrative example of these alternatives is expressly stated in the Framework Regulations Sect. 67 i.f.: "Within their respective areas of authority, the supervisory authorities can order the operator to carry out verifications itself, or to have such verifications performed by others."

(c) Both direct verification and indirect supervision may in principle take two forms: The control could be restricted to *just monitoring* what is happening, or it could be a part of a *"go-stop-go" system*, implying that certain milestones in the operations cannot be passed unless the controlling authority, e.g. the Petroleum Safety Authority, has positively concluded that relevant requirements are met. Usually, this is combined with a requirement that the industry at such milestones shall apply for approval or consent to proceed, and that the application shall be supported by plans, information, documentation etc. allowing the Petroleum Safety Authority full insight into present situation as well as planned activities to the extent relevant to safety issues. Obviously, such approval system is more effective in the sense that the "burden of proof" is placed on the industry, while the monitoring system implies that the Petroleum Safety Authority itself has to pick up all relevant information and decide to act on that basis. On the other hand, the "go-stop-go" system unavoidably means that there will be "stops" awaiting approvals etc., which could be most disturbing to a rational progress of operations. In this respect the "looking over the shoulder" monitoring system has its benefits, as it allows industry to continue operations until positively stopped by the control authority.

(d) The actual physical control work *need not be performed by state employees*. State control may be based on input provided by others, e.g. classification societies like Lloyd's or Det norske Veritas, following *their* physical control. Although this system is much more developed in the area of maritime safety, it is also important in offshore safety.[453] Far more important, however, is the basis for state control that is provided by the industry itself – based on the work of its own employees or classification societies engaged by industry. The internal control system naturally includes that physical checks have to be performed and reported by the operator's own personnel (e.g. on the status of a high pressure

[453] On the UK continental shelf, the use of classification societies has been formalised in the concept of the "Safety Case" and the "Certifying Authority" certifying that relevant requirements have been met.

pipeline in the process module). State control may ensure that this is properly done by checking the same item itself. Or it may limit itself to checking that the internal control system is established (i.e. indirect supervision), and then use the output of the system – the reports form the operator's own checks – as a basis for state control of the physical items. The fact that this is in practice a frequent basis for state control makes it even more crucial that the internal system works properly – and consequently calls for an intensive indirect supervision.

(e) In *summing up*: Along with the emergence of function requirements, the state control has moved into supervising the quality of the industry's internal control system, including spot-checking that this system actually picks up and rectifies non-compliance. State control is not concentrating on directly verifying that safety requirements regarding physical aspects of the operations are complied with. In stead, this kind of control is based on the output of the internal control system – further emphasising the importance of this system being adequate and operational. The risk inherent in this approach is to some extent reduced by the implementation of "go-stop-go" approval systems, leaving it for the industry to convince the state control authorities at certain milestones that operations are and will remain safe.

7.5.2 Enforcing safety

Neither prescribing safety norms nor controlling that they are complied with will alone result in reduced risk for damages if the industry does not comply with the requirements. There is in addition a need for means for enforcing the requirements.

The Petroleum Act (and the other relevant acts) and the various regulations provide two types of such means of enforcement: The administrative and the criminal sanctions. The imposition of sanctions is based on the positive provisions of the safety legislation combined with the general principles contained in administrative and criminal law.

Under general administrative law a licence may be revoked if the licensee commits a major breach of conditions upon which the licence is based. The violated condition need not be express for a breach to have this effect, but it is of course a prerequisite that the rule violated can be fairly and objectively attributed to the licence. In relation to safety aspects, this implies that even if the compliance with safety requirements has not specifically been made a condition for an approval, licence, exemption or other type of individual decision, the non-compliance with safety requirements may result in the revocation of the beneficial administrative decision. In this way, general principles and rules of administrative law supplements shortcomings that may exist in the rules on revocation that are found in the safety legislation. Similarly, the Criminal Code is applied to the offshore petroleum activities by general reference,[454] which implies that the specific criminal sanctions contained in the safety legislation are supplemented by general rules.

Neither the Framework Regulations nor the detailed regulations issued pursuant to it contain any specific provision on sanctions. The Framework Regulations limits itself to making a general reference to the acts that form legal basis for the regulations: "Provisions with regard to penalties and other sanctions contained in the legislation relating to health, environment and safety are applicable to violation of provisions stipulated in and pursuant to these regulations" (Sect. 62). As the Petroleum Act contains the most general provisions in this respect, we in the following disregard the other acts.

Approvals, licences etc. may be revoked if provisions stipulated in or pursuant to the Petroleum Act are violated seriously (in which case a single violation is in principle sufficient) or repeatedly (in which case neither of the violations in principle need be serious).[455] The power vested in the supervising governmental bodies by this provision is restricted by the general administrative law "principle of proportionality" applied to an evaluation of the nature of the violation, what will be

[454] Criminal Code Sect. 12 (1) (a)-(c), making the act generally applicable to activities taking place on installations engaged in petroleum exploration or production and located on the Norwegian continental shelf, or activities within the safety zones established around such installations.

[455] Petroleum Act Sect. 10-13.

gained by a revocation and what will be the negative consequence of it to the licensee.

Revoking a licence – or even an approval – may under the circumstances be a rather drastic reaction. A more flexible alternative, introduced bye the Petroleum Act Sect. 10-16, is therefore using “coercive fines”: The issuance of an administrative order (e.g. that the operator should take or refrain from taking certain actions for safety reasons) may be linked to a threat that violation of the order will result in a daily fine, payable for as long as the violation lasts. This does not constitute a criminal sanction, just an administrative strong pressure upon the operator.

Finally, the Petroleum Act Sect. 10-16 also empowers the supervisory bodies to order a halt in operations that impose a safety hazard – i.e. that violates general or specific provisions of regulations or individual decisions. This, however, must be considered to be a direct means of ensuring an acceptable level of safety rather than a means of enforcing compliance with safety provisions that merely indirectly aim at reducing risk.[456]

The Petroleum Act authorises criminal sanctions in the form of penalties or imprisonment for wilful or negligent violations of provisions stipulated in or pursuant to the act. Imprisonment is naturally not relevant in relation to corporate bodies, but they may on the other hand be subject to very substantial fines even if no individual physical person acting on the company’s behalf can be fined, e.g. because he can not be proven to have acted negligently (or wilfully).[457]

7.6 Industry safety management

7.6.1 Overview

Like the state’s safety management, the industry’s safety management comprise two elements: The prescription of safety norms and the safety

[456] The same goes for the Safety Representative’s right to halt operations that he considers pose an immediate danger to life and health of employees, ref. the Working Environment Act Sect. 6-3.

[457] See the Criminal Code Sect. 48a.

control checking that the norms are complied with and instigating corrective measures if need be.

Obviously, the safety norms that the industry itself define and implement in its own activities have to observe the requirements that are laid down in the acts and regulations pertaining to the activities, as well as in the individual administrative decisions issued on that basis.

It may seem less obvious that also the control activities should be governed by statutory requirements. In relation to the state, it might be assumed that the industry's primary obligation is to comply with direct safety norms, potentially having a direct effect on the safety level in the activities, and that it would be for the industry to decide which means – in the form of safety control or other – that would seem feasible to secure such compliance. But as we have seen from the above discussion, an important element in the state's safety management is indeed the safety control carried out by the industry itself – the "internal control". Consequently, there is a need to direct the content of the internal control by stipulating legal requirements to that effect.

Thus, both elements of the industry's safety management have a legal compulsory basis. But they differ, both in terms of structure and detailed content.

7.6.2 Internal prescription of safety norms

The direct safety norms prescribed in acts, regulations and individual administrative decisions normally leave room for several alternative lines of action that will all be in compliance with the requirements. This is not just a necessary consequence of rapidly changing technology etc.; it is a deliberate means of forcing the industry to implement safety aspects into all daily activities without being tempted to simply lean on predefined regulatory solutions. The extensive use of function requirements is a consequence of this approach, so is the effect of placing the burden of activity on the industry by means of implying an approval systems rather than a monitoring system (7.5.1(c) above).

This system implies that the industry has to identify the limits of freedom, and then define its preferred alternatives within these limits.

This amounts to internal prescription of norms. Often, material elements consist of mere reference to various standards issued by (in most cases) private institutions and referred to in the guidelines that are attached to the regulations (ref. 7.4.2(c) above).

The internal norms may surface in internal procedures, technical project specifications, operating manuals, etc. These documents will in turn constitute relevant objects for state safety control: Sate supervisory bodies evaluate the solutions, and may react by requiring amendments to be made. More likely, the choices made by industry will be reviewed by the supervisory bodies in the context of the industry's applications for the various approvals, permits and licences that are needed to conduct the petroleum activities.

7.6.3 Internal safety control

While there are no specific provisions requiring the industry to perform "internal prescription of norms" (the need for this activity simply follows from the fact that the legally binding safety norms are not precise), there are several provisions requiring the industry to establish a system for internal control.

The general obligation follows from the Petroleum Act Sect. 10-6:[458] "The licensee and other persons engaged i petroleum activities comprised by this Act are obliged to comply with the Act, regulations and individual administrative decisions issued by virtue of the Act *through the implementation of systematic measures.*"[459]

The single purpose of the required activities is to ensure that relevant requirements contained in the act etc. are complied with. The establishing of this system is a requirement of its own: The obligations contained in Petroleum Act Sect. 10-6 are not fulfilled by complying with prescribed safety norms. And conversely, the obligation derived from this provision is not necessarily fulfilled by complying with all direct

[458] Similar provisions are not contained in the pollution act, the working environment act or in the products control act, but all of them provide legal basis for issuing regulations requiring internal control systems to be implemented.

[459] Emphasis added.

safety norms contained in acts and regulations.

More detailed requirements on the system for internal safety control are given in the Framework Regulations. The party responsible "shall establish, follow up and further develop a management system in order to ensure compliance with" the safety legislation.[460] On verifications, which are important elements of safety control, the Framework Regulations Sect. 19 provides that "The responsible party shall determine the need for and scope of verifications, as well as the verification method and its degree of independence, to document compliance with requirements in the health, safety and environment legislation." The actual verification "shall be carried out according to a comprehensive and unambiguous verification programme and verification basis."

The Framework Regulations Sect. 23 adds to this by requiring that the party responsible "shall ensure that documentation demonstrating compliance with requirements stipulated in or pursuant to these regulations, can be provided." Compliance on this point means that both internal prescription of norms, the checking that they are complied with, and any corrective measures following such check are well documented – which in turn implies that the internal control system must constitute a fully developed administrative structure within the organisation of the party responsible, though not necessarily (and in practice not) a separate part of the organisation. Sect. 18 points in the same direction, by obliging the industry to ensure that parties to contracts have the qualifications necessary to fulfil *their* obligations under the safety legislation (as such parties are themselves a "responsible party", ref. 7.4.1 above), and further that the contractual parties actually comply with these obligations during their performance of work under the contract. Again, these requirements mean that the internal control must constitute a systematic administrative approach to safety.

Albeit that these requirements do not constitute a detailed cookbook, they definitely provide guidance beyond the general requirement that there shall be internal control.

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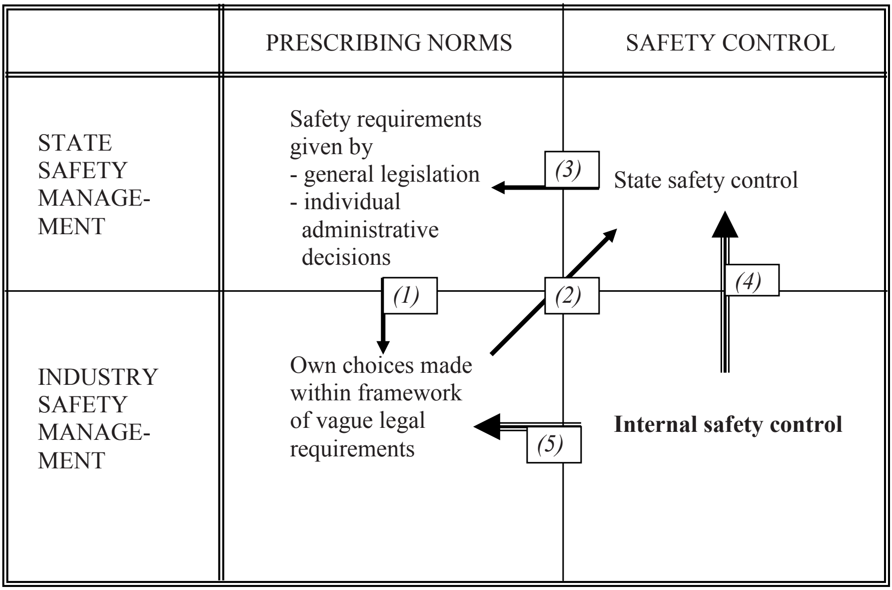
[460] Framework Regulations Sect. 17, 1st para.

7.7 The link between state and industry safety management

In the above description of safety regulation in Norwegian petroleum activities, it will have emerged that there are two players – state and industry, and that they both run a system for "safety management" that comprise two main elements: The prescription of safety norms and the control that these norms are complied with. It will also have shown that these two systems for safety management are not operating independently of each other. In this concluding chapter, we shall look closer at the interaction between these elements by placing them into a four square matrix.



The simple interrelation is that the state safety requirements *(1)* defines the limits within which the industry's choices have to be made, and that state safety control *(2)* checks that these choices are kept within these limits – and that they also are desirable from the supervisory body's point of view. This is rather banal. The interesting aspect is what happens if the control reveals that changes should be made to the industry's approach. As a matter of principle this happens in two fundamentally different situations. One is that the state control reveals that industry has not complied with the regulatory requirements. This may lead to sanctions being invoked in order to enforce the safety norms, see 7.5.2 above. The other situation is that the control reveals that the industry's choices are legally indisputable, but still not desirable. In this case, the control is likely to result in the norms being modified *(3)*. This could take different forms: The regulations could be amended, or – more likely – individual decisions could be made to the effect that the operator in question is left with a more narrow room for manoeuvring without changing the general regulatory provisions. Such detailing or specifying of the content of the regulations in turn means that the operator has to make new choices within the boundaries of legal requirements – the applicable safety norm has become more precise and the previous choice is no longer within its limits. So the operator chooses *(1)*, the state controls *(2)*, the norms may be further refined *(3)* by new administrative decisions based on the findings and evaluations of the control, and so on – until the supervisory body is satisfied with the operator's choices or time has run out because of the progress of activities. This circle of interrelated activities can be labelled "*prescription of norms through control*". It has the obvious potential effect of ensuring that an acceptable level of safety is achieved. The means is to restrict the area of flexibility left to industry by e.g. function requirements, based on insight gained by control.

So far, the circle does not involve the industry's internal control. This is by no means a sign that this box in the matrix is less important. On the contrary, the internal control is a crucial part of safety management in both regimes.

In relation to *state* safety management, the internal control provides an important input and basis for state safety control *(4)* in that reports etc. flowing from the industry's own control activities in practice quantitatively constitute the most central input – more central than supervision and verification carried out directly by state inspectors. This means that the quality of the internal control and its output has to be secured. Therefore, the internal control also constitutes a separate object of state control in order to ensure that it can serve the intended purpose. The internal control is made both a basis and an object for state safety control.

In relation to the *industry* safety management, the request for an internal control system means that the industry is forced to establish a structured system for managing safety issues. Inherent in this system are also the technical and organisational prerequisites for making the right choices within the flexible framework defined by i.a. function requirements – and indeed also the prerequisites for identifying such flexibility. Consequently, the internal control as it is required under the safety legislation is a crucial factor in the industry's internal prescription of norms *(5)*.

Rather than falling outside the scheme of safety management, we can conclude that the internal control system is a major contributor to the scheme, both on state and industry side.

8 The abandonment phase

By Ulf Hammer

8.1 Introduction

The development of a petroleum field can be divided into successive phases; i.e. exploration, production, and abandonment. This is also reflected in the PA. Each phase of the development is regulated by a separate chapter in the PA. Thus, chapter 5 deals with the abandonment phase.

The Norwegian legislation on abandonment has developed gradually.[461] The latest legislative effort is a result of two developments: One on the national level and one on the international level. On the national level, an increasing number of fields have stopped producing. The basic question is: what is to be done with the installations after production has ceased permanently? The answer relies on a complex balancing of interests.

The Norwegian continental shelf is characterized by deep water and severe weather conditions. Consequently, installations tend to be large. This makes removal operations technically difficult and cost-intensive. The conditions are similar to those on the UK continental shelf, but very different from those in the Mexican Gulf and most other offshore petroleum provinces.

The abandonment of installations also raises other concerns, especially relating to the safety of installations and personnel, the marine environment, and other uses of the sea. Summing up, the prospect of an increasing number of petroleum field shut-downs, combined with the complexity and variety of interests involved, call for a more comprehensive regulation of the abandonment phase.

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461 Abandonment was first regulated in the Royal Decree of 9 April 1965 s 50, then in the Royal. Decree of 8 December 1972 section 50, and then in the Petroleum Act of 22 March 1985 s 30.

On the international level the abandonment phase has received increasing attention in recent years. Norway has acceded to the IMO-guidelines and the OSPAR-decision, and is thus committed - as a contracting party - to take necessary measures to adapt its national legislation and practice to the new international framework.[462] The PA chapter 5 is a result of this adaptation. In the following, we will first present the international framework.

8.2 The international framework

8.2.1 The IMO-guidelines

The abandonment phase is addressed by the United Nations Convention on the Law of the Sea (UNCLOS). Contrary to previous international conventions, the UNCLOS art. 60 (3) does not contain an absolute requirement on complete removal of abandoned offshore installations:

> "Any installations or structures which are abandoned or disused shall be removed to ensure safety of navigation, taking into account any generally international standards established in this regard by the competent international organization. Such removal shall also have due regard to fishing, the protection of the marine environment and the rights and duties of other States. Appropriate publicity shall be given to the depth, position and dimensions of any installations or structures not entirely removed."

The International Maritime Organization (IMO) is regarded as "the competent international organization". On 19 October 1989, the IMO adopted a resolution containing guidelines and standards for the removal of offshore installations and structures on the continental shelf and in the exclusive economic zone (the IMO-guidelines). Formally, the IMO only recommends that Member Governments take into account the IMO-guidelines when making decisions regarding removal, cf. the

[462] In this regard, Norway practices a dualistic principle, i.e. the relevant international legislation has to be implemented in national legislation in order to have binding effect on the citizens.

preamble to the resolution sixth paragraph. Member Governments which have ratified the UNCLOS are obligated to take the IMO-guidelines into account, cf. UNCLOS art. 60 (3). As to Member Governments not having ratified the UNCLOS, one must assume that the guidelines will be reflected in State practice.

The IMO-guidelines supplement the UNCLOS art. 60 (3) and, consequently, reflect the flexible approach of the Convention. As a starting point, Coastal States are required to remove abandoned or disused installations, except where non-removal or partial removal is consistent with the guidelines, cf. the guidelines paragraph 1.1. This general provision is specified in the guidelines paragraph 3, which calls for complete removal of installations weighing less than 4 000 tonnes, excluding the deck and superstructure, and standing in less than 75 m of water. As to installations placed on the sea bed on or after 1 January 1998, the water depth criterion has been increased to 100 m.[463] In cases where an installation is not subject to a specific removal requirement, the issue of removal shall be based on a case-by-case evaluation by the Coastal State, taking into account, inter alia, the safety of navigation and effects on the marine environment, cf. the guidelines paragraph 2.1.

The guidelines paragraph 3 contains several practical provisions regarding installations which are left wholly or partly in place. The Coastal State shall ensure adequate maintenance, proper identification on nautical charts, and proper marking with navigational aids. If the installation does not project above the surface of the sea, the Coastal State shall provide an unobstructed water column not less than 55 m to ensure safety of navigation, cf. the guidelines paragraph 3.6. Furthermore, it shall ensure that the legal title to installations (left wholly or partly in place) remains unambiguous, and that responsibility for maintenance and the financial ability to assume liability for future damages are clearly established, cf. the guidelines paragraph 3.11.

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[463] Notwithstanding these requirements, an installation may be left whooly or partly in place, where complete removal is not technically feasible or would involve extreme cost, or an unacceptable risk to personel or the marine environment, cf. the guidelines item 3.5.

As to the future perspective, the guidelines paragraph 3.13 is of particular interest: On or after 1 January 1998, no installation shall be installed on the continental shelf, unless it can be completely removed upon abandonment or permanent disuse. In other words, the design or construction of installations shall not exclude future removal.

8.2.2 The OSPAR-decision

The Convention for the Protection of the Marine Environment in the North-East Atlantic (OSPAR) is a regional convention.[464] The Contracting Parties, including Norway, shall take all steps to prevent pollution in this area from land based and offshore sources, cf. OSPAR arts. 3 and 5. Dumping of installations is dealt with in more detail in Annex III to the Convention. Annex III art. 5 (1) reads as follows:

> "No disused offshore installation or disused offshore section 4-3shall be dumped and no disused offshore installation shall be left wholly or partly in place in the maritime area without a permit issued by the competent authority of the relevant Contracting Party on a case-by-case basis."

So far, the Convention reflects a flexible approach corresponding to the UNCLOS and the IMO-guidelines. However, according to Annex III art. 5 (1), the Contracting Party, when granting such permits, is under an obligation to implement "relevant applicable decisions, recommendations and all other agreements adopted under the Convention." Such decisions and recommendations are adopted by the Commission pursuant to art. 13 of the Convention. The Commission is made up of representatives of each of the Contracting Parties, cf. art. 10.

On 23 July 1998, the Contracting Parties adopted OSPAR-decision 98/3 on the disposal of disused offshore installations.[465] Norway has accepted the decision, and it entered into force 9 February 1999.[466] The

464 The convention is supplemented by four annexes.

465 The decision is supplemented by four annexes.

466 Parliament accepted OSPAR-decision 98/3 on the basis of St prp nr 8 (1998-99), cf. Innst S nr 80 (1998-99).

decision implies a substantial restriction of the discretionary powers of the Contracting Party. As a starting point, the decision prohibits the dumping, and the leaving wholly or partly in place, of disused offshore installations within the maritime area, cf. the decision paragraph 2. This implies that disused offshore installations have to be brought on land for further reuse, recycling or final disposal.[467] The prohibition does not cover offshore pipelines. In this regard, the Contracting Party retains its discretionary powers pursuant to the Convention Annex III art. 5 (1).

According to the decision paragraph 3, cf. Annex 1 to the decision, the Contracting Party may derogate from the prohibition. The following installations may be left wholly or partly in place:

- All or part of footings of steel installations weighing more than 10 000 tonnes, and placed in the maritime area before 9 February 1999.[468]
- All or part of a concrete installation, or a concrete anchor base.[469]

The Contracting Party may also invoke a general derogation, when it can demonstrate "exceptional and unforeseen circumstances resulting form structural damage or deterioration, or from other cause presenting equivalent difficulties". It should be noted that the decision presupposes more stringent requirements in the future. First, all steel platforms placed in the maritime area *after* 9 February 1999 will have to be removed. Secondly, the decision paragraph 7 foresees amendments in Annex 1 in order to reduce the scope of possible derogations under paragraph 3. The preparation of such amendments shall be considered at regular intervals.

Formally, the Contracting Party issues a permit to dump the installation (or part of it) in the maritime area. Only significant reasons may

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467 Cf. the preamble fifth paragraph to decision 98/3.

468 Topsides to steel installations are not covered by this exception.

469 Topsides to concrete installations are not covered by this exception.

justify a derogation. The assessment of the Contracting Party in this regard is regulated in detail in Annex 2 to the decision. The assessment shall consider the potential impacts on the environment and on other legitimate uses of the sea. It shall be based on descriptions of the installation, the proposed disposal site and the proposed disposal method. The assessment shall not only cover the proposed disposal, but also other options. Before the Contracting Party issues a permit, it shall consult other Contracting Parties according to detailed provisions in Annex 3 to the decision.[470]

The permit itself shall accord with the requirements of Annex 4 to the decision.[471] The permit shall specify the terms and conditions under which disposal at sea may take place. In particular, the permit shall specify the procedures to be adopted during the operation, and the management measures that are required to prevent or mitigate adverse consequences of the disposal at sea. The permit shall inter alia require arrangements for indicating the installation on nautical charts, arrangements for marking the installation with necessary aids to navigation and fisheries, and arrangements for necessary monitoring of the condition of the installation. The permit shall also specify the owner of the installation, and the person liable for meeting claims for future damage caused by the installation, and the arrangements under which such claims can be pursued against the person liable.

Finally, the decision imposes an obligation on the Contracting Party to report information on disposal permits and on their implementation to the Commission, cf. paragraphs 9 and 10.

8.2.3 A short comparison

Formally, the IMO-guidelines and the OSPAR-decision overlap each other in the maritime area covered by the OSPAR Convention, i.e. the North-East Atlantic. The respective frameworks overlap each other both as regards specific removal requirements, and as regards navigatio-

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[470] Cf. the decision paragraph 4.

[471] Cf. the decision paragraph 5.

nal, proprietary and liability issues concerning installations left wolly or partly in place. In reality, the IMO-guidelines have lost most of their practical significance in the North-East Atlantic as a result of the more stringent requirements of the OSPAR-decision. However, (unlike the OSPAR-decision) the IMO-guidelines require an unobstructed water column of 55 m, when installations (or parts thereof) are left beneath the sea surface. The guidelines also require adequate maintenance of remaining installations, which project above the surface of the sea.

8.3 The national framework

8.3.1 Introduction

The PA chapter 5 establishes a decision-making process based on the principle of a case-by-case evaluation. It starts with a decommissioning plan prepared by the licensee. On the basis of this plan, the MPE decides on the disposal of the installations.[472] This form of government control is a characteristic feature of the licence system pursuant to the PA.[473] However, in the abandonment phase the government control has to adhere to a comprehensive international framework.[474]

In the following presentation, I will first deal with the decommissioning plan and thereafter with the decision of the MPE. These issues refer to the relationship between the licensee/owner of the installation and the government. The PA chapter 5 also deals with the relationship between the licensee/owner and third parties. This is the liability issue, and it will be discussed in a separate context (together with other liability issues).[475]

8.3.2 The decommissioning plan

Formally, the decommissioning plan was introduced by the PA chapter 5.

[472] Ministry of Petroleum and Energy. See 1.2.

[473] As previously mentioned the decommissioning plan and the MPE´s subsequent decision form part of this licence system. See 1.3.4.

[474] See 8.2.

[475] See 9.

However, a decommissioning plan has been required by the MPE since the first cases arose in the beginning of the 1990s. In this respect, the new PA represents a codification of government practice.[476]

The obligation to prepare a decommissioning plan rests upon the licensees of production licences and section 4-3 licences, cf. the PA section 5-1. This means that both production installations and pipelines are subject to the plan and the subsequent decision by the MPE. As a result of the geographical scope of the PA, cf. section 1-4, also installations on land that are functionally connected to the offshore activities, are subject to the plan. In respect of such installations, however, the MPE has a limited range of decision alternatives.[477]

The obligation of the licensee depends upon two main events; the permanent disuse of the installations or the expiry of the licence, whichever event comes first.

> If the licence expiry comes first, and the installations may still be used, the licensee may apply for a prolongation of the licence instead of preparing a decommissioning plan. The obligation to prepare a decommissioning plan will then depend upon the outcome of the MPE´s handling of the prolongation application. The obligation to prepare a decommissioning plan also occurs if a licence is surrendered by the licensee or revoked by the MPE. I will not go further into these situations in the following presentation.

The licensee must present the plan to the MPE no earlier than 5 years, but no later than 2 years, prior to the above events. The purpose is to allow sufficient time for the MPE to handle and decide upon the plan before the events actually occur. However, the MPE may decide upon other time limits.

As to the contents of the plan, the PA section 5-1 is very general. In this regard the PA is supplemented by the petroleum regulations (PR)

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[476] The first case was the removal of the North East Frigg installations. The case was presented to Parliament by St prp nr 36 (1994-95). The next case was the removal of the Odin installations, cf. St prp nr 50 (1995-96).

[477] See 8.3.4.

chapter 6, which contain the more detailed provisions. The decommissioning plan shall consist of two parts; one part describing the decision alternatives and one part containing an impact analysis. As to the former part of the plan, the licensee is obligated to present all alternatives that are relevant to the specific case. These alternatives may range from complete or partial removal to continued use for petroleum production or transportation purposes or other purposes. They also include the mere abandonment of the installation in combination with future maintenance and inspections. In respect of each alternative, the licensee is required to evaluate the relevant concerns with regard to technical feasibility, costs and safety. As to the latter part of the plan, the licensee must evaluate the impact of each decision alternative with regard to the marine environment, other uses of the sea, and various interests on land that might be affected by the abandonment. Even though several alternatives must be presented and evaluated, the licensee shall recommend one of them, and it is recognized that this alternative will be described in more detail than the others.[478] The requirements of the petroleum regulations basically correspond to the requirements of OSPAR-decision Annex 2.

> The MPE may also exempt the licensee from the obligation to prepare the plan, or grant a partial exemption in the form of a less extensive plan. On the other hand, the MPE may require additional information or even a new or modified plan. In short, the PA enables the MPE to exercise wide discretionary powers as to the contents of the decommissioning plan. However, this flexibility has been substantially limited by the recent OSPAR-decision.[479]

8.3.3 The MPE´s decision regarding disposal

The decommissioning plan is not subject to the MPE's approval. Instead the MPE selects one of the alternatives of the licensee, but not necessarily the recommended one, and decides accordingly. In this respect the

[478] Cf. Ot prp nr 43 (1995-96) p. 49-50.

[479] See 8.2.2.

PA section 5-3 leaves a very wide margin of discretion to the MPE.

However, the practice of the MPE must comply with international guidelines and conventions. Paragraph 2 of the OSPAR-decision prohibits the dumping, and the leaving wholly or partly in place, of disused offshore installations. This prohibition does not cover offshore pipelines.

According to paragraph 3 of the OSPAR-decision, the Contracting Party may derogate from the prohibition. Formally, the Contracting Party derogates by issuing a permit to dump the installation (or part of it) in the maritime area. Only significant reasons may justify a derogation. The following installations may be left wholly or partly in place:[480]

- all or part of footings of steel installatons weighing more than 10 000 tonnes, and placed in the maritime area before 9 February 1999,
- all or part of a concrete installation, or a concrete anchor base.

So far, the MPE has handled more than 10 decommissioning plans.[481] In most cases, it has been decided that abandoned installations shall be removed and taken ashore. This applies to the steel installations on Odin, Nordøst Frigg, Øst Frigg, Lille-Frigg and Frøy. As regards the concrete installations on Ekofisk I and Frigg, permits have been given to leave the concrete substructure and protective wall on the Ekofisk tank, as well as the concrete substructure of the platform TCP2 on the Frigg field.[482] P rior to these permits, the MPE consulted the other Contracting Parties pursuant to the procedural rules of the OSPAR-decision.

As already mentioned, pipelines are not covered by the dumping prohibition of the OSPAR-decision. Here, the practice of the MPE

480 See 8.2.2.

481 Facts 2006, 47.

482 See St prp no 51 (2001-2002) as regards the Ekofisk tank, and St prp no 38 (2003-2004) as regards TCP2.

follows guidelines laid down by Parliament.[483] As a general rule, pipelines and cables may be left in place when they do not obstruct or present a safety risk for bottom fishing.

PA section 5-3 designates the licensee, the owner (who may be an entity other than the licensee) and the user (if the installation is to be used for other purposes than petroleum activities) as responsible entities. However, the MPE may decide to designate only one or two as responsible entities.[484]

When designating responsible entities, the MPE has to take into account IMO Guidelines Art 3.11 which imposes an obligation on the coastal State to ensure that legal title to installations and structures which have not been entirely removed from the sea bed is unambiguous, and that responsibility for maintenance and the financial ability to compensate for future damage are clearly established.

As to installations on land, the PA limits the discretion of the MPE as regards decision alternatives. The alternatives are confined to continued use in petroleum activities, including State take-over for such purposes.[485] Other alternatives are for other authorities (than the MPE) to decide according to the relevant land legislation.

8.3.4 State take-over of installations

A special decision alternative is State take-over of installations pursuant to the PA section 5-6. The State may take over an installation upon expiry of the licence or permanent disuse of the installation. This option does not apply to mobile installations.[486]

483 St meld no 47 (1999-2000).

484 In this context the term licensee also means the previous licensee if the licence has expired.

485 State take-over will not be discussed in this edition of Energy Law in Europe. Instead, reference is made to Energy Law in Europe, Oxford 2001 chapter 11 paras 11.233-11.235.

486 The distinction between these two categories of installations is based on a functional criterion. If the installation is designed to serve only one petroleum field, the installation is permanently placed. If it is designed to serve several petroleum fields, it is mobile. Cf. Ot prp nr 43 (1995-96) p. 53.

An important issue concerns compensation. If the installation is placed beyond the part of the sea-bed subject to private property rights, i.e. on the continental shelf, the State may take over the installation without compensation.[487] The King decides if and to what extent compensation shall be given for the take-over.[488] If, on the other hand, the installation is placed on land, or on the part of the seabed subject to private property rights, the licensee can claim full compensation pursuant to Norwegian law.

If the State takes over an installation - with or without compensation - it will also assume the responsibility for a future disposal pursuant to the PA. Normally, this will only be an attractive alternative, if the installation has a commercial value at the time of licence expiry.[489] The State can then continue to operate the installation until permanent disuse. The State can, however, take over the responsibility for a disused installation, i.e. an installation with little or no economic value, subject to a compensation from the licensee/owner of the installation to cover future costs. This decision alternative requires an agreement between the parties, cf. the PA section 5-4 fourth paragraph. The contents of such an agreement will in all respects be a negotiating matter between the parties.

487 That was the only alternative in the 1985-Act. See 1.3.1.

488 In this context the term "King" means the the Norwegian cabinet.

489 This may be due to the fact that the petroleum field is not depleted, or that the section 4-3can transport petroleum from other fields than the initial one(s).

9 Liability

By Ulf Hammer

9.1 Introduction

The PA contains four liability regimes dealing exclusively with the petroleum activities. The PA section 10-9 imposes an extensive vicarious liability on the licensee. The PA chapter 7 regulates liability for petroleum pollution damage. The PA chapter 8 has special compensation rules with regard to the losses Norwegian fishermen suffer as a result of the petroleum activities. Finally, the PA section 5-4 regulates liability in the abandonment phase. The liability regimes are supplemented by the general rules of Norwegian tort law.[490] In addition, the liability regulation in the Maritime Act (MA) and the Pollution Act may apply to certain aspects of the petroleum activities.

> The MA regulates tort issues related to ships and vessels, including those performing tasks in the petroleum activities.[491] The MA also regulates tort issues related to mobile drilling platforms, but not pollution damage resulting from a leakage or discharge of petroleum during a drilling operation.[492] Such pollution is regulated by the PA chapter 7. The Pollution Act regulates tort issues related to other forms of pollution damage than petroleum pollution damage.[493] It may apply when such pollution damage stems from the petroleum activities.

The following presentation will concentrate on the special liability regimes of the PA, with emphasis on their characteristic features. It

490 As a main non-statutory rule, liability occurs when negligence has been exercised. In addition, the courts have developed a strict liability for hazardous and dangerous activities.

491 Act no 39 of 24 June 1994.

492 MA section 507.

493 Act no 6 of 13 March 1981.

should be noted that these regimes apply when third parties suffer damage. If the injured party has a contractual relationship with the licensee, the liability issues will normally be subject to a contractual regulation that may deviate from Norwegian tort law.

The liability regimes are quite different in structure, but the main responsible party is the licensee.[494] This is due to the organizational structure of the Norwegian petroleum activities. Licences are normally issued to a group of licensees. One of the licensees is appointed as operator, and (in this capacity) performs the petroleum activities on behalf of the licence group. In practice, a major part of the work is sourced out to contractors and subcontractors. Thus, the practical work is carried out by a hierarchy of contractors with the licence group, represented by the operator, on top. Since much of the practical work is carried out by other entities than the licence group, this may in theory dilute the responsibilities of the group (and its licensees) towards the State and third parties. As a result, the PA prescribes that each licensee shall ensure that anyone performing work for him complies with the PA, including the regulations and decisions passed pursuant to the PA.[495] This kind of overall responsibility is also reflected in the liability regulations.

The designation of the licensee as the main responsible party also has strong economic and practical reasons. Apart from the Norwegian State, the licensees have the main economic interest in the petroleum activities. They are financially strong entities who are able to obtain adequate insurance coverage for their activities in the open market.[496] In these regards, they will normally be in a much better position than their contractors and subcontractors.

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[494] As far as the PA section 5-4 is concerned, the licensee is not the only main responsible party. This provision has several characteristic features that separate it from the other liability regimes of the Act. See 9.5.

[495] PA section 10-6.

[496] In recent years, several minor companies have been granted production licences on the Norwegian continental shelf. The major oil companies are less interested because they do not see the potential for large oil discoveries any longer.

9.2 The vicarious liability

The PA section 10-9 first paragraph regulates the liability of the licensee for damage caused by a person - legal or natural - who performs work for him, i.e. the vicarious liability of the licensee. It reads as follows:

> "If liability in respect of a third party is incurred by anyone undertaking tasks for a licensee, the licensee shall be liable for damages to the same extent as, and jointly and severally with, the perpetrator and, if applicable, his employer."

The scope of the liability is wide in several respects. First, the liability generally refers to damages caused to third parties as a result of the petroleum activities. The term "petroleum activity" is defined in the PA section 1-6 to cover all activities connected to the development of petroleum fields on the Norwegian continental shelf. Such development can be divided into successive phases, i.e. exploration, exploration drilling, production, and abandonment. In each phase the term not only covers the main activities which are conducted offshore, but also the related activites which are conducted on land, i.e. planning and building of installations. To some extent the PA also applies to main activities conducted on land if they are connected to a petroleum field offshore.[497] As to the damage, the PA section 10-9 is also generally formulated. However, in this respect the scope of the provision is limited by the application of the special liability regimes of the PA chapter 7 and 8. This means that section 10-9 does not apply to losses resulting from petroleum pollution damage and to the losses Norwegian fishermen suffer as a result of the petroleum activities.[498]

Second, the licensee is liable for anyone working or performing work

[497] The typical example is the transportation of petroleum through a pipeline from an offshore field to a terminal, which may be situated some kilometers onshore from the landing point.

[498] This is stated in the PA section 10-9 second paragraph with regard to petroleum pollution damage and in the PA section 8-1 fifth paragraph with regard to the losses suffered by Norwegian fishermen. However, the scope of section 10-9 is not restricted vis a vis chapter 8 when it comes to injuries to persons. See 9.4.

or services for him. This covers all kinds of contractors and subcontractors, including the employees of such entities.[499] It is not necessary that such entities have a direct contractual relationship with the licensee, as long as they are part of the hierarchy of entities which performs work related to the relevant licence.[500] In this respect, the vicarious liability pursuant to the PA is wider than other forms of vicarious liability under Norwegian tort law.

The PA section 10-9 equates the scope of the licensee´s liability with the scope of the contractor´s liability. The licensee becomes liable to the same extent as the contractor, and can thereby claim the same exemptions and limitations of liability.[501] If the requisite conditions for imposing liability against the contractor are satisfied, the contractor and the licensee are jointly and severally liable towards the injured party. In this respect, the PA section 10-9 has no provision which requires claims from the injured party to be directed towards the licensee. And if the licensee compensates the injured party, he can direct an indemnification claim towards the contractor according to Norwegian tort law. In other words, the PA section 10-9 has no provisions which shield the contractor with regard to claims from the injured party or the licensee (channelling provisions).

9.3 Liability for petroleum pollution damage

The PA chapter 7 regulates liability for petroleum pollution damage. According to the PA section 7-3 first paragraph, the licensee is liable for pollution damage regardless of fault, i.e. a strict liability.

This liability regime is in several respects different from the vicari-

[499] As to his own employees the licensee is liable pursuant to the general Act on torts chapter 2. According to section 2-1, the employer is strictly liable when the damage has been caused by negligence or wilful misconduct by an employee during his work for the employer.

[500] See 9.1.

[501] The ordinary vicarious liability provisions leave the scope of liability imposed on the vicarious party independent of the tortfeasor´s liability. Normally, it is a prerequisite for vicarious liability that the underlying tortfeasor has been negligent. The vicarious liability of the MA section 151 is one example.

ous liability of the PA section 10-9. First, the scope is regulated through a functional definition of the term "pollution damage", cf. the PA section 7-1. According to this definition, the provisions only apply when damage or loss is caused by pollution resulting from a leakage or discharge of petroleum from an installation or well, including costs of reasonable measures taken to prevent or remedy such damage or loss. Thus, discharge of petroleum from ships transporting petroleum is not covered by chapter 7. In this respect, the liability rules of the MA chapter 10 apply.[502] The definition does not specify the damage or losses which may result from a leakage or discharge of petroleum, or the injured parties, except that such damage or loss also includes lost fishing opportunities for fishermen. As to petroleum pollution damage, the fishermen always have to rely on chapter 7. They cannot invoke the liability regime in chapter 8.[503]

Second, the geographical scope is subject to a special regulation in section 7-2, which deviates from the general regulation in section 1-4.[504] Here, the PA focuses on where the damage occurs, and not where the damage stems from. In this respect, chapter 7 differs from all the other liability regimes. Chapter 7 applies when pollution damage as defined occurs on the Norwegian continental shelf, in Norwegian territorial waters, in Norwegian internal waters and on Norwegian territory. The installation which causes damage may be situated in those areas, but it may also be situated on the continental shelf etc. of another State. The PA chapter 7 also applies if the pollution damage occurs in sea areas outside the Norwegian continental shelf, but in such cases the liability regime mainly seeks to protect Norwegian interests.[505]

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502 These are in important respects similar to those in the PA chapter 7. According to the MA section 191, the owner of the ship is strictly liable for pollution resulting from discharge of oil, including bunkers oil, from the ship. The liability is channelled to the ship owner pursuant to section 193.

503 See 9.4.

504 See 1.3.2.

505 In such areas, chapter 7 applies if damage is sustained by Norwegian vessels, Norwegian fishing gear or Norwegian installations. However, this limitation does not apply if the damage occurs on the land or sea territory belonging to a State which has acceded to the Nordic convention on environmental protection of 19 February 1974.

Third, the strict liability of the licensee is combined with provisions whereby participants in the activities are wholly or partly shielded from liability. These provisions work at two levels. (1) If there are several participants in a licence, the injured party must direct his claim against the operator. Only if the operator fails to cover the claim, can it be directed towards the other licensees. (2) Other participants doing work or services for the licensee, i.e. contractors and subcontractors, are also shielded from liability claims from the injured party, cf. the PA section 7-4. In addition, they are shielded from indemnity actions by the licensee, cf. the PA section 7-5. They can only be made liable where they, or someone in their organization, have acted wilfully or with gross negligence, and even in these cases the damages may be reduced or set aside if this is considered reasonable.

The liability of the licensee is, in principle, unlimited. According to the PA section 7-3, however, the courts have discretionary power to reduce the liability partly or completely, if force majeure or similar events have contributed to the petroleum pollution damage. In theory, the liability may also be reduced if this is considered reasonable pursuant to the general provision of section 5-2 in the Act on torts.[506] The latter provision is probably more important with regard to the other liability regimes of the PA, which do not have a special force majeure provision like the one in chapter 7.[507]

9.4 Compensation to Norwegian fishermen

The PA chapter 8 regulates compensation to Norwegian fishermen for losses they suffer as a result of the petroleum activities. Foreign fishermen cannot claim compensation pursuant to this liability regime. Its purpose is basically to ameliorate the conflict between the petroleum and the fishing activities on the Norwegian continental shelf. This conflict could have been solved by economic grants from the State or

506 Act no 26 of 13 June 1969.

507 In comparison, the liability of the ship owner for oil pollution damage is limited to a specified amount pursuant to the MA section 194, cf. section 195.

the licensees. Instead, the legislator has chosen to solve the conflict by means of tort law principles adapted to the particular conflict.

It follows from the above that the PA chapter 8 only adresses economic losses suffered by the fishermen as a result of the conflict with the petroleum activities on the Norwegian continental shelf. Injuries to persons must be compensated according to Norwegian tort law or the other liability rules of the PA.[508]

There are three kinds of situations which open up for compensation. First, there is the situation where fishermen wholly or partly have to leave their traditional fishing fields because these are occupied by the petroleum activities. Such occupation is not due to an illegal act by the licensees. They have been granted the right to operate in the relevant areas pursuant to a licence issued by the State. For this reason, the PA section 8-2 designates the State as the responsible party. The liability of the State is, however, limited in time. After seven years from the initial occupation of the fishing field, the State is normally not obligated to pay compensation. By this time, the fishermen are expected to have adjusted their activities to the new situation. As to occupation, the licensees have no direct liability towards the fishermen pursuant to the PA. However, if the fishermen´s activities have been unnecessarily hindered by the activities of the licensee, the State may claim indemnification from the licensee.

The second kind of situation is where fishermen suffer losses due to pollution and waste from the petroleum activities. In this respect, the PA section 8-3 imposes a strict liability upon the licensee. It must be noted that this liability does not cover petroleum pollution damage. Such damage is regulated by the PA chapter 7.[509] Pollution in respect of chapter 8 may be chemicals and other toxic substances from the petroleum activities. Waste may be various kinds of debris left in the vicinity

[508] Cf. the PA section 10-9 in particular.

[509] The PA chapter 7 makes no distinction between fishermen and other injured parties or interests. See 9.3.

of the well site or along the sailing routes of supply vessels.[510] This means that pollution and waste may stem from the activities of contractors or subcontractors, e.g. the owners of supply vessels. In accordance with the general principles of the PA, the licensee is responsible for the activities of such entities.[511] And such entities are shielded from direct action by the fishermen. According to the PA section 8-1 fifth paragraph, the other provisions of the Act apply correspondingly to chapter 8. This means that the channelling of liability towards the licensee pursuant to the PA chapter 7 also applies with respect to chapter 8.[512]

The PA section 8-4 establishes a joint and several liability between different licensees, i.e. licensees belonging to different licence groups. This liablility deviates from general tort law principles. As to waste along the sailing routes, it may be relatively easy to connect the waste to the petroleum activities, but difficult to identify the responsible licensee, since a supply vessel may be doing service for several petroleum fields. In such cases, the PA section 8-4 establishes a two step procedure. First, the fishermen have to prove - according to general tort law principles - that the waste stems from the petroleum activities. Second, when it comes to identifying the responsible licensees, it is only necessary to prove that it is possible that the damage stems from their part of the petroleum activities. In practice, this means that if a supply vessel serves several petroleum fields that are located within a fairly limited area, all the licensees within that area are made jointly and severally liable for the damage.

The losses incurred as a result of pollution and waste will typically be loss of catch or time loss (due to interrupted fishing), or loss of or damage to fishing gear. The liability is in principle unlimited. The PA section 8-3 stipulates certain evidence requirements when compensa-

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[510] Such pollution and waste is covered by the general liability regime of the Pollution Act, but as a result of the PA chapter 8, the former act will only apply when such pollution or waste causes damage to other users of the sea. In such cases, the Pollution Act section 55 imposes a strict and unlimited liability upon the owner of the installation that has caused the damage.

[511] See 9.1.

[512] See 9.3.

tion is sought for time loss.[513]

The third kind of situation is where fishing gear is hooked up by installations on the sea bed, e.g. pipelines or drilling wells. In this respect the PA section 8-5 imposes a strict and unlimited liability on the licensee. This situation resembles the one where fishing gear is hooked up by waste on the sea bed. However, section 8-5 refers to situations where the installation is still in use and where it is easy to identify the responsible party.[514] If the installation on the sea bed represents such an obstacle that the fishermen have to leave the whole area, section 8-2 is applicable. We see that there are close relationships between the three liability regulations in chapter 8.

A notable feature of the liability regime in the PA chapter 8 is the handling of the fishermen´s claims for compensation. As a first step, the claims are handled by a special commission. Two commissions have been established, one dealing with compensation for occupation of fishing fields, and one dealing with compensation for pollution and waste and damage caused by installations.[515] The decision of the commissions may be presented to an appeal board. Its decision may then be brought before the ordinary courts, cf. section 8-6.

The same provisions as in the PA chapter 8 have now been introduced in the act on energy production at sea.[516] This act applies to wind farms at sea, which may occupy considerable areas. However, this act will not be dealt further with here.

9.5 Liability in the abandonment phase

The PA section 5-4 regulates liability in the abandonment phase. There are important overlaps between this liability regime and those presented above. Nonetheless, the PA section 5-4 is based on other principles.

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513 In order to claim compensation for lost fishing time in connection with locating, marking, retrieving or bringing ashore objects, the objects shall - as a main rule - be properly marked or brought ashore and presented to the police or port authority.

514 When the installation is abandoned, section 8-5 may also apply. See 9.5.

515 Cf. regulations of 12 December 2008 passed pursuant to the PA.

516 Cf. Act of 6 April 2010 chapter 9.

We will soon revert to this.

On the basis of the decommissioning plan presented by the licensee, the MPE decides on the disposal of the installation.[517] The PA section 5-3 designates the responsible party or parties for the implementation of the MPE´s decision. These are the licensee, the owner (if he is another entity than the licensee) and the user (if the installation shall be used for other purposes than petroleum activities). In this context the term licensee also means the former licensee (if the licence has expired). To the extent that they exist, all these entities will be responsible for the implementation of the MPE´s decision, unless the MPE decides otherwise.

> The State itself may take over the responsibility for abandoned installations, including future liability, cf. the PA section 5-4 fourth paragraph. This arrangement requires a special agreement between the State and the licensee/owner of the installation. It will also require a compensation from the licensee/owner to the State. The extent of the compensation will - together with all other issues - be subject to negotiations.

The PA section 5-4 is a very simple and general provision. It merely states that the responsible party pursuant to section 5-3 is liable for damages which occur during the implementation of the MPE´s decision, provided that such damages are the result of negligence or wilful misconduct by the party.[518] The economic scope of the liability is unlimited. Several entities may be reponsible for implementing the MPE´s decision pursuant to section 5-3, and thus several entities may be liable pursuant to section 5-4. In that case, they are jointly and severally responsible for the economic obligations arising as a result of the liability, unless the MPE decides otherwise. In this context, the MPE has to take into account the IMO guidelines art. 3.11 and the OSPAR-decision Annex 4, which impose an obligation on the Coastal State to establish legal title to the installations and liability for future damages.[519]

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517 See 8.3.3.

518 In fact, it is not necessary to enact a liability based on negligence, since this already follows from the main non-statutory rule in Norwegian tort law.

519 See 8.2.2.

> Notice should be taken of the PA section 10-7, which authorizes the MPE to require security from the licensees for their fulfilment of economic obligations resulting from the petroleum activities, including economic obligations towards third parties. This provision is especially important in the abandonment phase, when licensees are winding up their operations. In this connection the PA section 10-7 second paragraph specifies that security may also be demanded from the owner or the user of an installation, if he is a responsible party pursuant to section 5-3.

The following characteristic features of the regime can be identified so far. First, the main responsible party is not just the licensee, but under the circumstances also the owner and the user. Second, the number of responsible entities, and the matter of joint and several responsibility for economic obligations, may be subject to case by case decisions by the MPE. Third, there are no channelling provisions. The injured party may direct his claim against any of the parties responsible for economic obligations. The injured party may also direct his claim against contractors or sub-contractors of the responsible parties on the basis of Norwegian tort law. Finally, the principle of strict liability prevailing elsewhere in the PA has been deviated from in section 5-4.

However, the liability regime of the PA section 5-4, cf. section 5-3, does not exclude the application of the other liability regimes of the Act. These apply to all phases of the petroleum activities, including the abandonment phase.[520] In this phase, they are supplemented by section 5-4.[521] Decommissioning may entail disposal of the installation on the production site, in the sea elsewhere, or on land. During this operation, the vicarious liability of the PA section 10-9 applies. If fishermen suffer economic losses due to disposal in the sea, the PA chapter 8 applies. If petroleum leaks out from abandoned wells, the PA chapter 7 applies.

The position of the injured parties pursuant to the PA will depend on the circumstances. If the disposal takes place prior to licence expiry, the responsible party will be the licensee, and consequently, all the lia-

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520 Cf. the definition of "petroleum activity" in the PA section 1-6.

521 Cf. Ot prp nr 43 (1995-96) p. 52.

bility regimes of the PA apply. This is a practical situation. Due to the length of the production licences most fields will be depleted well before the expiry of the licence. If, on the other hand, disposal takes place after licence expiry, only the regime of the PA section 5-4, cf. section 5-3, applies. According to this regime, the responsible party may also be the owner and the user of the installation. In addition, only this regime is applicable when the installation is used for other purposes than petroleum activities.[522]

[522] However, in the latter circumstances (after licence expiry) the question arises whether liability rules outside the PA may apply in relation to the licensee, especially the non-statutory rule on strict liability for hazardous and dangerous activities. This question has not been addressed in the PA chapter 5, or commented upon during the preparation of the Act.

The Organisation of Norwegian Gas Sales and Competition Law

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Content

1 Introduction

Competition law has become increasingly relevant for activities on the Norwegian Continental Shelf (NCS) over the last decade. The real wake-up call for both the Norwegian authorities and the oil companies active on the NCS as to the impact of competition law was the so called GFU case[1], which was initiated by the European Commission ("the Commission") (i.e. DG Competition) and which mainly took place during 2000-2002.[2] The case centred on the allegation made by the Commission that the Gas Negotiating Committee (GFU), which jointly negotiated gas sales contracts on behalf of the producers of natural gas on the NCS for resource management purposes, was a sales cartel contrary to Art. 81 EC (now Art. 101 TFEU[3]). Although the Commission`s allegations were opposed on the basis of the doctrine of state compulsion[4], the case was settled out of court and resulted in the subsequent reorganisation of the Norwegian gas sales regime. Even after the dissolution of the sales cartel (the GFU) and the introduction of a system of company-based sales (CBS) on the NCS, competition law still has to be considered by the oil companies when organising their activities on the NCS. This article therefore deals with *the competition law aspects of the organisation of the sales of natural gas produced on the NCS.*[5]

The GFU case illustrates the particular importance of Community legislation for the organisation of the gas sales regime on the NCS. While the passing of secondary legislation in order to establish a trans-

1 IP/02/1084 of 17 July 2002

2 For a more detailed presentation of the GFU case, see part 3 below.

3 Consolidated version of the Treaty on the Functioning of the European Union, OJ C 83, 30.3.2010, pp. 47-199

4 For a short presentation of the doctrine of state compulsion, see, e.g., Jonathan Faull & Ali Nikpay (editors), The EC Law of Competition (Oxford, Second Edition, 2007) ("Faull & Nikpay (2007)"), Chapter 3: Article 81 pp. 217-218. See also Richard Whish, Competition Law (Sixth Edition) ("Whish") pp. 134-135.

5 For a general discussion of these questions (i.e., independent of the organisation of petroleum activities on the NCS), see, e.g., Christopher W. Jones (editor), EU Energy Law – Volume II, EU Competition Law & Energy Markets ("EU Energy Law II"), Part 3 – Articles 81 and 82 EC.

port market within the gas sector has previously been dealt with[6], the focus of this article is *the sales market for natural gas*. There is a close connection between the transport market and the sales market, as a well functioning transport market is a prerequisite for a competitive sales market. Experience from the ongoing process of liberalisation in respect of the energy sectors, i.e. both electricity and natural gas, has shown that simply facilitating competition through rules on third party access («TPA») is not sufficient to ensure the development of a competitive sales market. Real competition requires sufficiently liquid markets. However, as the bulk of gas reserves is sold under long-term sales agreements, the natural gas currently available cannot support sufficient trade, neither on a national nor on the Community level.[7] In other words, the companies that participate in the sales market have to be forced to compete. While the rules on TPA, by their imposition of a duty to contract on the owners of infrastructure, provide the structural changes necessary for a transport market and thus competition in the sales market to develop, the ordinary competition rules and their enforcement both prevent and correct market-distorting behaviour by those companies participating in the sales market as such.

Policy considerations both explain the Commission's (initiative for the) passing of special competition legislation (i.e., DG Tren) and its enforcement of ordinary competition law (i.e., DG Competition) in the gas sector. Natural gas is one of the most widely used fuels in the European Union (EU), accounting for approximately a quarter of the primary energy used. Around 42% of this gas is produced within the EU, in particular in the UK, the Netherlands and Denmark. This means

6 Anne-Karin Nesdam, Third Party Access to Upstream Pipeline Networks on the Norwegian Continental Shelf ("Nesdam, Third Party Access"), Petroleum Law – Book 1, Chapter 5.

7 See, e.g., Communication from the Commission Inquiry pursuant to Article 17 of Regulation (EC) No. 1/2003 into the European gas and electricity sectors. COM(2006)851 final, published at http://eur-lex.europa.eu/LexUriServ/site/en/com/2006/com2006_0851en01.pdf, and IP/07/26 of 10 January 2007 (Competition: Commission energy sector inquiry confirms serious competition problems), published at http://europa.eu/rapid/pressReleasesAction.do?reference=IP/07/26&format=HTML&aged=0&language=EN&guiLanguage=en.

that 58% is imported, and this proportion is increasing. Norway, Algeria and, especially, Russia are traditionally the most important sources of gas imported to the EU, although imports of liquefied natural gas by ship are growing fast, and are from a wider range of producing countries.[8]

Although this is expected to change somewhat with the future development of a national downstream sector, the vast majority of the gas volumes produced on the NCS is exported to customers on the European Continent. For all practical purposes, the gas produced on the NCS can be said to be sold to customers located within the boundaries of the EU.[9] Due to this fact, this article deals with the limitations on the gas undertakings` freedom of action that follows from *European competition law* when producers organise the sales of their share of the natural gas produced. In other words, the focus of this article is on the competition rules in the Treaty on the Functioning of the European Union (the TFEU) (previously the Treaty of Rome) – or more specifically Art. 101 TFEU and Art. 102 TFEU (previously Art. 81 EC and Art. 82 EC) and – to some extent – Art. 106(2) TFEU (previously Art. 86(2) EC). It should be noted, however, that Norway is a party to the EEA Agreement, which incorporates Art. 101 TFEU, Art. 102 TFEU and Art. 106 TFEU (previously Art. 81 EC, Art. 82 EC and Art. 86(2) EC) in Art. 53 EEA, Art. 54 EEA and Art. 59(2) EEA respectively.

The main focus of the article is the limitations that can be expected to follow from *Art. 101 TFEU (previously Art. 81 EC)*. As competition law has only been applied to the gas sector (or rather, the energy sectors as a whole) for a relatively short period of time, its application to these sectors is still developing. Accordingly, both case law and administrative practice are rather limited. In terms of the administrative practice

8 Factual information, published at http://ec.europa.eu/comm/competition/sectors/energy/gas/gas_en.html.

9 Producer companies active on the NCS have entered into gas sales contracts with customers in Germany, France, the UK, Belgium, the Netherlands, Italy, Spain, the Czech Republic, Austria and Denmark. The majority of the gas produced, however, is delivered to customers in Germany, the UK, Belgium and France, cf. Facts 2010 – the Norwegian Petroleum Sector («Facts 2010») chapter 6.

that does exist, the Commission has dealt mainly with alleged breaches of Art. 101 TFEU (previously Art. 81 EC).[10] In any case, even though it still applies, Art. 102 TFEU (previously Article 82 EC) has become of less practical importance following the passing of the Gas Directive[11] and the Gas Transmission Regulation[12] respectively.

It should be emphasised that this article mainly formulates and addresses *possible issues relating to Community competition law*, rather than providing definite answers on how these issues should be resolved. As previously mentioned the future application of competition law to the gas sector has yet to be decided. Not only is the existing case law scarce, most of what is available indicates the Commission's view on the application of the competition rules to the gas sector, as most cases so far have been settled out of court. The application of the law by the Commission (DG Competition) is not binding upon the European Court of Justice (the ECJ). Under Community law, it is the ECJ that establishes the law in cases of doubt. Because of the limited amount of practice, it is somewhat uncertain what approach the ECJ would take.

It should also be noted that the organisation of the value chain in its entirety, i.e., from production via transport to marketing and sales, may influence market conditions in the sales market. Since transport is subject to a particular regulatory regime that has been dealt with in a previous chapter[13], however, this article focuses solely on production,

10 For an incomplete overview, see e.g. MEMO/03/86, dated 16 April 2003, Application of competition rules to the gas sector, published at http://europa.eu/rapid/pressReleasesAction.do?reference=MEMO/03/86&format=HTML&aged=1&language=EN&guiLanguage=en, and MEMO/03/89, dated 24 April 2003, Application of competition rules to the gas sector, published at http://europa.eu/rapid/pressReleasesAction.do?reference=MEMO/03/89&format=HTML&aged=1&language=EN&guiLanguage=en.

11 Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC, OJ L 211, 14.8.2009, pp. 94–136

12 Regulation (EC) No. 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No. 1775/2005, OJ L 211, 14.8.2009, pp. 36–54

13 Anne-Karin Nesdam, Third Party Access to Upstream Pipeline Networks on the Norwegian Continental Shelf ("Nesdam, Third Party Access"), Petroleum Law – Book 1, Chapter 5.

marketing and sales only. In addition, the various issues related to and influencing freedom of choice concerning the organisation of the gas sales regime on the NCS, have been identified based on the practical needs associated with the activities on the NCS. Firstly, the various types of co-operation that take place on the NCS due to the particular requirements of the petroleum sector as such will need to be addressed (in part 5). The main question here is to what extent joint production is permissible under competition law. To answer this question, the various elements covered by the joint production need to be taken into consideration. Secondly, we examine the various types of co-operation that might need to take place on the NCS due to its particular conditions, especially as the NCS matures (part 6). In practice, this is a question of whether, and under what circumstances, joint selling might take place. Under a system of company-based sales, the issue of joint selling might arise in two different situations. Firstly, when gas is bought, either for injection purposes or to fulfil delivery obligations, it is necessary to consider whether this is in breach of the prohibition on joint selling. Regardless of the reasons for such concerted buying practices, the end result is that gas produced by several producers is offered to the market by a single producer and under the same terms and conditions (i.e., at a single price). Such practices thus have sufficient similarities with joint selling to necessitate further analysis. Secondly, with the maturing of the NCS, the gas resources located there are proving to be mainly marginal. Thus, joint selling from a single field could be a prerequisite for the development of these marginal fields and needs to be considered. Finally, other concerted practices that may be relevant due to the structure of the NCS need to mentioned (in part 7). This discussion can also be divided into two main issues; i.e., participation in several licences and the possibility of information exchange, and the use of standard agreements.

Before the material questions are discussed (in parts 5-7) within the framework of the theme and the delimitations presented above, and before conclusions are drawn on the basis of these discussions (in part 8), both Community policy considerations (in part 3) and jurisdictional issues (in part 4) have to be dealt with. First, however, we start with a short presentation of the current Norwegian sales regime (in part 2).

2 The Current Norwegian Sales Regime: Company-based Sales and Portfolio Considerations

The gas volumes available for sale at any given time are regulated by the production levels stipulated under each licence granted by the Ministry of Petroleum and Energy (“the Ministry”). According to the Petroleum Act (“the PA”) Section 4-4(1), the Ministry shall – prior to or concurrently with approval pursuant to Section 4-2 or the granting of a licence pursuant to Section 4-3 - approve a production schedule. Furthermore, the Ministry shall stipulate, for fixed periods of time and based on the production schedule on which the development plan is based, the quantity that may be produced, injected or cold vented at all times, cf. PA Section 4-4(3). Adjustments can be made in the light of new information on the deposit or other circumstances, cf. PA Section 4-4(3) in fine.

Within the confines of the production levels determined in the production schedule and the use of petroleum based on the production schedule, the gas companies have full possession of the gas reserves. The current gas sales regime as such is mainly reflected in the contract regime that applies solely on the NCS. According to the Petroleum Production Licence (“PPL”), the licensees are obligated to enter into a Joint Operating Agreement (“JOA”) within 30 days of the granting of the licence in question.[14] Under the current contract regime, the gas companies are both entitled and obligated to sell their gas individually.

[14] See e.g. 19th Licensing round – Petroleum Production Licence for Petroleum Activities, Art. 6

This follows directly from the JOA[15] Art. 23.1, which states that "[e]ach party has the right and obligation to take in kind and dispose of a share of *produced Natural Gas* which shall be equivalent to his Participating Interest [author`s italics]."

The ownership rights, as well as the liability and risk pertaining to the natural gas, are transferred to the licensee upon lifting.[16] Accordingly, prior to the commencement of production, the management committee is required to determine the delivery point for the transferral of ownership and risk.[17] Also prior to the commencement of production, the licensees are under an obligation to enter into a gas lifting and balancing agreement that determines the method employed for lifting.[18] A unanimous vote by the management committee is required for the adoption of the gas lifting and balancing agreement.[19] Although they are agreed upon by the licensees, both the delivery point (cf. JOA Art. 23.1(2) in fine) and the lifting agreement (cf. JOA Art. 23.2) need the approval of the Ministry.

There are two main types of lifting agreements in use on the NCS, i.e., so-called "flexible" agreements and "must take" agreements.[20] These categories of lifting agreements have been standardised and mainly differ as regards the licensee's freedom to determine their own gas lifting at any given time. The "flexible" agreements give each licensee the right, for certain periods of time, to lift lower gas volumes than their participating interest. However, this flexibility is rather constrained. According to these agreements, the field's longevity is divided into a "flexible" period, a "balancing" period and a "must take" period. Within the "flexible" period, the licensees are allowed to underlift, provided certain conditions are met. Firstly, the licensees are obligated to lift a

15 See e.g. 19th Licensing Round – Joint Operating Agreement concerning Petroleum Activities («JOA»), Part VI Disposal of Petroleum

16 JOA Art. 23.1(2)

17 Art. 23.1(2) in fine

18 JOA Art. 23.2

19 JOA Art. 23.2 in fine

20 Olav Boge, Gassproduksjon og konkurranserett. En vurdering av produksjonssamarbeidet på norsk sokkel i forhold til EØS artikkel 53, MarIus nr. 303, pp. 51-52

daily minimum. If the daily minimum is not lifted, the operator must try to sell the gas volumes in question. If the operator is successful, the net sales are to cover operation costs in the balancing area. In any case, the volumes are debited from the account of the licensee, which consequently loses the right to lift such volumes at a later point in time. Secondly, each licensee is not permitted to lift less than an annual underlift cap. If this underlift cap is not respected, the licensee incurs a reservoir loss. While lower volumes can only be lifted in the flexible period, the licensees` lifting rights are adjusted annually in the balancing period in order to compensate for underlifting that has taken place in the flexible period.

"Must take" agreements, on the other hand, do not allow for such flexibility. According to the "must take" agreements, each licensee both has the right to and is obligated to lift gas volumes equal to its share of the daily export volume from the balancing area.[21] Under the "must take" agreements, the operator is obligated to try to sell gas not lifted. If the operator is successful, the compensation paid for the natural gas shall cover the additional costs incurred by the operator and the operating costs of the balancing area. If the gas is not sold, the licensee that underlifts is obligated to compensate the other licensees for any loss caused by the underlifting.

A prerequisite for a well functioning company-based sales regime, is ensuring that the licensees have the necessary flexibility as regards sales of gas volumes in their portfolio. As the gas sales agreements allow the purchasers to adjust their nomination of gas volumes according to their actual needs within the contractual framework, the licensees should have the corresponding right to lift gas volumes that are either smaller than ("underlifting") or exceed ("overlifting") the participating interest in order to ensure the commercial flexibility of the licensees, as well as optimal utilisation of the production capacity of the field. Whether such lifting flexibility actually exists will vary depending on the reservoir characteristics and the particulars of the balancing area in each case. "Flexible" agreements are used where resource management con-

21 Boge p. 52

siderations make it possible to adjust the production rate within the balancing area.[22] "Must take" agreements are used where a given gas withdrawal is necessary to ensure optimal oil production (which is typically the case in relation to so-called associated fields) or to maintain operations on marginal fields.[23] While "flexible" agreements are customary, "must take" agreements are used in the limited number of cases where the need for optimal production dictates the lifting of gas.

The gas companies are now free to negotiate gas sales agreements based on each gas company's gas portfolio, i.e., their share of the gas produced in each and every licence they participate in, instead of being directly linked to the field's gas reserves. It should be noted that both portfolio considerations and market access considerations, i.e., the ability to use the transport infrastructure and thus be granted access, contribute to the individual gas company's decision on which volumes can be lifted and sold to which purchasers at any given time. In any case, the gas companies` freedom is not unlimited, as the sales agreements have to be negotiated and entered into within the scope of competition law.

3 Policy Considerations

Economists consider competition to lead to socio-efficient resource exploitation for the benefit of the consumer.[24] Competition between producers and suppliers of gas is expected to be expressed through reduced gas prices. The economists´ free competition model, however, is based

22 Boge p. 51
23 Boge p. 51
24 See, e.g., Whish p. 4

on a number of preconditions that are generally not fulfilled in reality.[25] Competition rules are supposed to secure the market process based on the principle of supply and demand.[26] In other words, competition rules seek to correct market failure due to lack of one or more of the presumptions that underlie the model of free competition. This is achieved by prohibiting market behaviour that is considered to have a negative influence on market conditions.[27]

There is no question that the Community competition rules apply to the energy sector, which includes the gas sector.[28] In general, the market structure of the gas sector does not facilitate competition. This is because of market characteristics that differs somewhat upstream and downstream. Upstream, there is a limited number of producers who more or less are all active wherever gas resources are located globally. Furthermore, there is a limited number of gas suppliers, due to an extensive degree of vertical integration in production, supply and infrastructure. Traditionally, the upstream sector has exhibited the characteristics of an oligopoly and the use of sales cartels has not been uncommon. Downstream, the gas sector has traditionally been organised as a formal monopoly. While transmission companies historically have been granted the exclusive right to sell gas nationally, distribution companies similarly have been granted the exclusive right to supply customers within the area in which each company is located.

Due to the network-bound character of the gas sector, and the fact that the transport infrastructure has the characteristics of a natural

25 See, e.g., Whish p. 7 et seq. Perfect competition requires that on any particular market there is 1) a very large number of buyers and sellers, 2) the products offered in the market is homogeneous, 3) consumers have perfect information about market conditions, 4) resources can flow freely from one area of economic activity to another, 5) there are no barriers to entry which might prevent the emergence of new competition and 6) there are no barriers to exit which might hinder firms wishing to leave the industry.

26 See, e.g., Olav Kolstad, Anders Ryssdal, Hans Petter Graver og Erling Hjelmeng, Norsk Konkurranserett – Bind I Atferdsregler og strukturkontroll («Norsk Konkurranserett I») p. 26

27 For further details, see part 4.2 below

28 For further details, see part 4.2 below

monopoly, competition rules have traditionally not been applied to the gas sector. The Commission, however, has actively sought to bring the energy sector generally into line with other sectors of industry by means of a three-staged approach.

Firstly, the Commission has initiated cases against a number of Member States for breach of the Treaty provisions prohibiting import and export restrictions.[29]

Secondly, the Commission has initiated the establishment of a regulatory framework.[30] In order to change the market structure and achieve the break-up of historical (cross-border) trade patterns, the Gas Directive(s) and the Gas Transmission Regulation(s) ensuring third party access to infrastructure, have been passed. This secondary regulatory framework both supplements and are supplemented by the application of Art. 102 TFEU (previously Art. 82 EC). There are examples of the Commission applying Art. 82 EC (now Art. 102 TFEU) to establish the principle of right to third party access in cases where refusal to grant access took place before the passing of the Gas Directive and the Gas Transmission Regulation.[31] There is also an example of the Commission challenging the conditions of an access regime concerning a particular pipeline.[32] Furthermore, the Commission has recently initiated proceedings against gas companies for market foreclosure in breach of Art. 82 EC (now Art. 102 TFEU) in the form of capacity hoarding

29 See, e.g., cases C-157/94 Commission V Netherlands, C-158/94 Commission v Italy, C-159/94 Commission v France and C-160/94 Commission v Spain, ECR [1997] I-5699

30 For further details, see Anne-Karin Nesdam, Third Party Access to Upstream Pipeline Networks on the Norwegian Continental Shelf, Petroleum Law – Book 1, chapter 5

31 COM/36.246 – Marathon/Ruhrgas/GdF et alia. The Marathon case concerns the alleged joint refusal to grant the Norwegian subsidiary of the US oil and gas company Marathon access to continental European gas pipelines in the nineties by a group of five European gas companies, i.e. the Dutch gas company Gasunie, the French gas company Gaz de France (GdF) and the German gas companies BEB, Thyssengas, Ruhrgas respectively, cf. IP/01/1641 of 23 November 2001 (Marathon/Thyssengas), IP/03/1129 dated 29/07/2003 (Marathon/BEB), IP/03/547 dated 16/04/2003 (Marathon/Gasunie) and IP/04/573 dated 30/04/2004 (Marathon/Ruhrgas and GdF).

32 COMP/38.075 – PO/UK Gas Interconnector (IP/02/401 of 13 March 2002 - Commission closes investigation into UK/Belgium gas interconnector)

and strategic underinvestment in the transmission system.[33]

Thirdly, the Commission has pursued the anti-competitive market behaviour of gas companies in individual cases.[34] With the explicit aim of establishing competition between both producers and suppliers respectively, both the organisation of the sales regime[35] and the design (i.e. both duration[36] and content[37]) of the gas sales agreements have been challenged.

With the liberalisation of the gas sector formal monopolies were abolished. However, despite the monopolies having been abolished legally, the monopoly structure still exists from in practice because of the lack of any real competition that might lead to the erosion of the dominant position of the incumbents (i.e., the former monopolists). The

33 COMP/39.315 – ENI (MEMO/07/187 of 11/05/2007)

34 For a non-exhaustive list of cases, see, e.g., MEMO/03/86 of 16/04/2003 and MEMO/03/159 of 29/07/2003. Further cases are underway, cf. MEMO/06/205 of 17/05/2006 and MEMO/07/187 of 11/05/2007

35 Focus has here been on joint selling, cf. Case No IV/E-3/35.354 - Britannia gas condensate field (Notice pursuant to Article 19(3) of Regulation 17) OJ [1996] C291/10 (joint sales from a single field), COMP/37.708 – PO/Corrib (IP/01/578 of 20 April 2001) (joint sales from a single field), COMP/36.072 – GFU - Norwegian Gas Negotiation Committee (IP/02/1084 of 17 July 2002) (joint sale from several fields) and COMP/38.187 - DONG/DUC (IP/03/91 of 24 April 2003) (joint marketing)

36 For an overview over the Commission's approach towards long-term and exclusive agreements, see, e.g., Jonathan Faull & Ali Nikpay (editors), The EC Law of Competition (Oxford, 1999 (first edition)) ("Faull & Nikpay (1999)") p. 709 et seq

37 Focus has here been mainly on anti-competitive provisions in the supply <contracts (use restrictions clauses, reduction clauses, territorial restriction clauses and priority rights), see e.g. COMP/37.542 - Endesa/Gas Natural (IP/00/297 of 27 March 2000) (use restriction clause), COMP/36.072 - GFU (IP/02/1084 of 17 July 2002) (commitments made by Statoil and Norsk Hydro, although it was emphasized that these commitments were not considered a part of the GFU case as such), COMP/36.559 - EdF Trading/WINGAS (IP/02/1293 of 12 September 2002) (reduction clause), Nigeria LNG (IP/02/1869 of 12 December 2002) (territorial restriction clause), COMP/38.187 - DONG/DUC (IP/03/91 of 24 April 2003) (use restrictions, reduction clause and priority rights for DONG), COMP/38.308 – ENI/Gazprom (IP/03/1345 of 06/10/2003) (territorial restriction clauses), COMP/38.085 - OMV/Gazprom (IP/05/195 of 17/02/2005) (territorial restriction clauses), COMP/38.307 – E.On Ruhrgas/Gazprom (IP/05/710 of 10/06/2005) (territorial restriction clauses), COMP/38.662 - GdF (IP/04/1310 of 26 October 2004),.and lastly, and still under consideration, COMP/39.401 – E.On/GdF collusion (MEMO/07/316 of 30/07/2007) (market sharing)

sector inquiry launched in June 2005[38], has identified particular problems, such as; high levels of market concentration, vertical integration of supply, generation and infrastructure leading to a lack of equal access to, and insufficient investment in infrastructure; and possible collusion between incumbent operators to share markets. [39]

The Commission is certain to continue its existing approach (i.e., a combination of regulatory measures and control of market behaviour). As the internal market in natural gas was completed by 1 July 2007, the (legal) structural remedies to ensure competition may now be said to be in place. Control of the gas companies´ market behaviour is thus increasingly important to facilitate competition in this sector. According to Regulation 1/2003[40], Community competition law is (mainly) to be enforced at the national level by national competition authorities ("NCAs")[41] and/or may be invoked before national courts[42]. It should be noted, however, that even though the enforcement of the Community competition law primarily takes place on the national level, the practice of the Commission is of vital importance and gives guidance to both national competition authorities and national courts. Although the Commission has the legal authority to pursue cases and its legal authority precedes that of the NCAs[43], it will concentrate the use of its resources on the most serious infringements and more fundamental issues.[44] However, the energy sector as such has been identified as a priority

38 IP/05/716 of 13 June 2005

39 IP/07/26 of 10 January 2007

40 Council Regulation (EC) No 1/2003 of 16 December 2002 on the implementation of the rules on competition laid down in Articles 81 and 82 of the Treaty (Regulation 1/2003), OJ L 1, 4.1.2003, pp. 1–25, as amended by Regulation 411/2004, OJ L 68, 6.3.2004, and Regulation 1419/2006, OJ L 269, 28.92006, respectively

41 Regulation 1/2003 Art. 5

42 Regulation 1/2003 Art. 6

43 Regulation 1/2003 Art. 11(6)

44 See, e.g., Regulation 1/2003 preamble (3)

area.[45] As noted above, the Commission has already intensified its enforcement of the competition rules in relation to the gas sector. In the wake of the sector inquiry, the Commission made it clear that it would pursue follow-up action in individual cases under the competition rules (in relation to anti-trust, merger control and state aids) and act to improve the regulatory framework for energy liberalisation to handle the problems identified under the sector inquiry.[46]

That having been said, the competition rules cannot be applied in a policy vacuum. There is a great need to accommodate a broader range of public interest factors in relation to the energy sectors in general and the gas sector in particular. Reference is here made to the energy sector`s vital importance for the functioning of and the (further) social development of a modern society. In other words, both security of supply considerations and the need to accommodate social equity and national social cohesion must be taken into account when applying the competition rules to the energy sector. Another factor to take into account, is that the energy sector contributes significantly to the government revenues of (the majority of) the Community's Member States.

These factors are now explicitly acknowledged in the Community's energy policy. Within the energy sector, the EU now operates with three essential policy objectives, i.e., sustainability, security of supply and competitiveness.[47] The need to strike a balance of sustainability, security of supply and competitiveness has been emphasised at the Community level. The challenges involved in relation to the balancing of these three policy objectives, has lead to a debate on the need for further liberalisa-

45 In its Communication of 2 February 2005 to the Spring European Council "Working together for growth and jobs, a new start for the Lisbon strategy", the Commission endorsed a more pro-active application of competition policy, in particular, by means of sectoral screenings for barriers to competition in inter alia the energy sector, see Communication to the Spring European Council - Working together for growth and jobs - A new start for the Lisbon Strategy - Communication from President Barroso in agreement with Vice-President Verheugen, COM/2005/0024 final, p. 16, published at http://ec.europa.eu/comm/competition/sectors/energy/inquiry/index.html.

46 IP/07/26 of 10 January 2007

47 The Commission's 2006 Green Paper on energy. See also MEM/07/15, dated 10 January 2007

tion measures in the energy sector.[48] Both the establishment and the upholding of competition in the gas sector are still considered essential tasks. Competitiveness is considered both a goal in itself and a measure to achieve the (other) objectives of sustainability and security of supply.[49] However, it could be expected that the emphasis on striking a balanceof sustainability, security of supply and competitiveness will influence the application of the competition rules.

In other words, from a producer perspective there is a need for a functional and pragmatic approach taking the characteristics of the gas markets into consideration when applying the competition rules on the gas sector. Although this is now expressed in the energy policy, there is still fear that lack of or limited knowledge of the functioning of the gas markets may lead to a formal legal approach to the competition rules. It is interesting to note that cases against Member States, i.e., export/import restriction cases and/or cases due to lack of implementation of the Gas Directive(s), have ended before the ECJ, while the majority, if not all, cases launched against gas undertakings for breach on the Community competition rules generally have been settled out of court. The settlement rate of the gas undertakings cannot be explained by the traditional arguments of court proceedings being time consuming and costly alone. The reasons for the lack of litigation could possibly be explained as mainly historical, as gas producers to a large extent are used to co-operate with national authorities. However, this will be to simplify matters. It is more likely that the gas undertakings choose to enter into negotiations with the Commission, due to the fact that they lack confidence in the ECJs insight and understanding of the particulars of the gas sector. In other words, the gas undertakings expect that both the possibility to influence on and the degree of predictability with the outcome of the case will be greater through negotiations with the Commission than in court proceedings before the Community courts.

The press releases published by the Commission whenever an out-

48 Memo/07/15, dated 10 January 2007

49 Commission Green Paper of 8 March 2006: "A European strategy for sustainable, competitive and secure energy", COM(2006)105 final, e.g., p. 8

of-court settlement is reached deal with the end results of the negotiations rather than (the finer details of) the legal argumentation of the parties. This makes it difficult to give an (inside) account of the legal approach of the Commission in these cases. It would also be natural to expect that the Commission, when applying competition rules to the gas sector, due to policy considerations and for negotiating purposes invoke more extensive claims than necessarily could be expected to follow from competition law. Still, in the wake of the sector inquiry and the steady increase in the case load, the Commission is starting to acquire a deeper understanding of the particulars of the gas sector. It seems safe to expect that this will clearly influence on the legal reasoning of the Commission and allow for a more pragmatic approach when applying the competition rules to the gas sector.

4 General Conditions for the Application of the Competition Rules

4.1 Introduction

Neither the scope nor the purpose of this article allow for an exhaustive presentation of competition law. As such, this article to some extent assumes that the reader is familiar with the basics of competition law. In the following, the finer details of material law are only commented upon where necessary in relation to discussions of the particular challenges faced (in part 5-8). Even so, it is necessary to comment on some key issues of practical importance for the choice of rules and their application. Firstly, the "effect on trade" criterion and its role in relation to the question of jurisdiction need to be commented upon (in part 4.2). Secondly, there is a presentation of the restrictive trade practices and the question of market definition (in part 4.3). These questions are closely interrelated, as market definition is of importance when establishing both whether an undertaking's behaviour is in breach of the prohibitions in Articles 101 and 102 TFEU (previously Articles 81 and 82 EC) and whether this behaviour has had or is likely to have a negative effect on trade. By way of introduction, there now follows a brief presentation of Art. 101 TFEU (previously Art. 81 EC) and Art. 53(1) EEA.

4.2 Article 101 TFEU

Both Art. 101 TFEU (previously Art. 81(1) EC) and Art. 53(1) EEA prohibits "all agreements between undertakings, decisions by associations of undertakings and concerted practices which may affect trade between Member States and which have as their object or effect the prevention, restriction or distortion of competition within the common market". The provision lists examples of agreements that have as their object or effect restrictive practices in breach of the prohibition, cf. Art. 101 TFEU (previously Art. 81(1) EC) litra a)-e) and Art. 53(1) EEA litra a)-e). While the list is not exhaustive, it mentions the most likely situations in practice.

The prohibition in Art. 101 TFEU (previously Art. 81(1) EC) – and Art. 53(1) EEA – is not absolute. Art. 101(3) TFEU (previously Art. 81(3) EC) – and Art. 53(3) EEA - provides that the prohibition contained in Art. 101 TFEU (previously Art. 81(1) EC) and Art. 53(1) EEA - may be declared inapplicable in the case of agreements that contribute to improving the production or distribution of goods or to promoting technical or economic progress, while allowing consumers a fair share of the resulting benefits, and which do not impose restrictions that are not indispensable to the attainment of these objectives and do not afford such undertakings the possibility of eliminating competition in respect of a substantial part of the products concerned. In other words, there are four cumulative conditions that have to be met before an exemption can be established.[50]

This means that the assessment under Art. 101 TFEU (previously

[50] The Commission has issued guidelines that examine the four conditions of Art 81(3) EC, cf. Communication from the Commission - Guidelines on the application of Article 81(3) of the Treaty (the Exemption Guidelines), OJ [2004] C 101.

Art. 81 EC) consists of two parts. The first step is to assess whether an agreement between undertakings, capable of affecting trade between Member States, has an anti-competitive object or actual or potential anti-competitive effects. The second step, relevant only where an agreement is found to be restrictive of competition, is to determine the pro-competitive benefits produced by that agreement and to assess whether these pro-competitive effects outweigh the anti-competitive effects. It is important to note that, while the anti-competitive effects are considered under Art. 101(1) TFEU (previously Art. 81(1) EC), the balancing of anti-competitive and pro-competitive effects is conducted exclusively within the framework laid down by Art. 101(3) TFEU (previously Art. 81(3) EC).

Agreements and/or practices in breach of the prohibition in Art. 101(1) TFEU (previously Art. 81(1) EC) and not exempted under Art. 101(3) TFEU (previously Art. 81(3) EC) are automatically void, cf. Art. 101(2) TFEU (previously Art. 81(2) EC). It is basically left to the market participants to evaluate whether their practices are in breach of Art. 101 TFEU (Art. 81 EC) and to carry the risk of their evaluations being incorrect. According to Art. 1(1) of Regulation (EC) No 1/2003, agreements that are caught by Art. 81(1) EC (now Art. 101(1) TFEU) and which do not satisfy the conditions of Art. 81(3) EC (now Art. 101(3) TFEU) are prohibited. Similarly, according to Art 1(2) of Regulation 1/2003, agreements that are caught by Art. 81(1) EC (now Art. 101(1) TFEU), but which satisfy the conditions of Art. 81(3) EC (now Art. 101(3) TFEU), are not prohibited. Whether prohibited or not, no prior decision to that effect is required.

4.3 Cross-border Trade: The Relationship between the Competition Rules at National and European Level and Jurisdictional Issues

4.3.1 Overview

Introductorily (in part 1) it was stated that this article only deals with the application of European competition law and in particular Art. 101 TFEU (previously Art. 81 EC) to the gas sales regime on the NCS. However, as Norway is not a member of the EU, it is necessary to explain just why European competition law is discussed in the context of this article. This explanation is divided into five parts. Firstly, the particular characteristics of the Norwegian gas trade are dealt with (in part 4.2.2). Secondly, there is a presentation of the different sets of general competition rules on both national and European level (in part 4.2.3). Thirdly, the relationship between the sets of competition rules at the European level is accounted for (in part 4.2.4). Fourthly, the "effect on trade" criterion is dealt with in further detail (in part 4.2.5). Lastly, the implications for the application of the competition rules in the context of this article are considered (in part 4.2.6).

4.3.2 The Particular Characteristics of the Norwegian Gas Trade

Although it is under development, Norway as yet has no significant domestic sales market for gas. Approximately 90 % of the gas produced on the NCS is exported. Norway is not only a major exporter of gas, but the gas is mainly exported to states within the EU.

Norwegian gas exports account for approximately 15 % of the European gas consumption.[51] The vast majority of the gas volumes exported is sold to Germany, United Kingdom, Belgium and France, where Norwegian gas accounts for 25 % to 35 % of the total consumption.[52] However, gas producers located on the NCS have entered into gas sales agreements with purchasers in Germany, France, the United Kingdom, Belgium, the Netherlands, Italy, Spain, the Czech Republic, Austria and Denmark.[53]

With the Netherlands as the main exception, the gas producing countries (i.e. Denmark, Germany, Italy and United Kingdom apart from

[51] Facts 2010 chapter 6

[52] Facts 2010 chapter 6

[53] Facts 2010 chapter 6. From Snøhvit supplies of LNG (Liquefied Natural Gas) are shipped to the US as well as Spain, cf. Facts 2010 chapter 6.

the Netherlands) within EU mainly produces for their own self consumption.[54] As mentioned above, the EU imports more than 50 % of the gas volumes needed to cover the total gas consumption within the Community, and its imports are increasing steadily.[55] Apart from the import of Norwegian gas, the EU covers the gap between its own gas production and its gas consumption needs through supplies from producers in Russia and Algeria.

To summarize, Norwegian gas is not only subject to cross-border trade, but also primarily sold to buyers located in the major EU-states. Within the internal Community market, Norwegian producers compete with other producers located both within and outside the internal market. This strongly influences on which set of competition rules will ultimately apply to the behaviour of the undertakings active on the NCS.

4.3.3 The Different Sets of Competition Rules Relevant on the NCS

As Norway is a party to the EEA Agreement[56], there are two general bodies of competition rules that apply directly; i.e., the Competition Act ("CA") of 5 March 2004 No. 12[57] and the EEA Agreement's rules on competition which, in contrast to the other provisions of the Agreement are not aimed at the Member States as such, but apply to undertakings directly.[58]

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[54] The Netherlands is in effect the only gas producing country which exports are significant.

[55] The five major gas supplying countries to Europe is Russia (26%), UK (16%), Norway (16%), the Netherlands (12%) and Algeria (11%) respectively.

[56] Agreement between the European Community and some members of the European Free Trade Association (EFTA), cf. [1994] OJ 1/03. At present the membership of the European Economic Area («EEA») is limited to Norway, Iceland and Liechtenstein.

[57] The Competition Act of 5 March 2004 No 12 entered into force on 1 May 2004, replacing the Competition Act of 11. June 1993 No. 65.

[58] This is also the case for Art. 101 TFEU and Art. 102 TFEU (previously Art. 81 EC and Art. 82 EC). In contrast to the other provisions of the Treaty on the Functioning of the European Union (previously the Treaty of Rome, as revised by the Treaty of Nice, Treaty of Maastricht and Treaty of Amsterdam), which are binding upon the Member States as such, the competition rules address the behaviour of undertakings directly.

The Norwegian competition legislation was revised for harmonisation purposes in 2004.[59] Thus, the antitrust provisions of the CA are based on the provisions of the EEA Agreement.[60] With the harmonisation of the CA[61], both the competition rules of the CA on the one hand and those of the EEA Agreement and the Treaty of Rome on the other are based on a *principle of prohibition*. In other words, specific types of anticompetitive behaviour on the part of *undertakings* active in the market in question are prohibited.

The *type of behaviour* prohibited is divided into two main categories in both bodies of competition rules. CA Section 10(1) prohibits restrictive practices between two or more undertakings. Dispensations can be made provided the terms and conditions in CA Section 10(3) are fulfilled.[62] Agreements entered into and decisions made in breach of CA Section 10(1) and without dispensation according to CA Section 10(3), are without legal effect, cf. CA Section 10(2). According to CA Section 11 any abuse by one or more undertakings of their dominant position is prohibited. The types of behaviour prohibited in CA Section 10 and Section 11 respectively are parallel to those prohibited in Art 53 EEA

[59] With the passing of Royal Decree of 24 November 2000, a committee was established for the purpose of undertaking an evaluation of the Norwegian competition law and proposing a new legislative framework on this area of law (the competition committee). The competition committee was particularly required to consider the question whether the Norwegian competition legislation should be designed based on the competition rules in the EEA Agreement for harmonisation purposes. In its preliminary report, published in NOU 2001:28, the Competition Committee recommended such harmonization.

[60] It is fairly common for Member States to the EU and/or EEA either to have introduced or to have adapted existing national competition legislation to those of the Treaty of Lisbon (previously Treaty of Rome) and/or the EEA Agreement respectively.

[61] The Competition Act of 11 June 1963 No. 65 contained four prohibitions of specific types of anticompetitive behaviour (cooperation on price, cooperation on tendering, market sharing and the setting of binding resale prices), but was first and foremost an enabling act allowing the Norwegian Competition Act to intervene against anticompetitive behaviour in general. Thus, it was said that the Norwegian competition legislation was based on both a principle of prohibition and a principle of intervention. With the passing of the Competition Act of 5 March 2004 No. 12, the harmonisation lead to the transition was made from a system based on the principle of both prohibition and intervention to a system based on the principle of prohibition only.

[62] Both block exemptions have been granted and individual dispensations can be made.

and Art 54 EEA, which in turn are identical to Art. 101 TFEU and Art. 102 TFEU (previously Art. 81 EC and Art. 82 EC) respectively. In other words, both national competition law and EEA and EC competition law prohibit anticompetitive co-operation and collaboration between several (two or more) undertakings as well as unilateral conduct by a single, dominant undertaking that has a similar anticompetitive objective or effect.

Although the type of behaviour prohibited by the respective sets of competition rules is identical, the CA and the EEA and/or the EC rules differ as to *under what circumstances* the prohibition applies, both geographically and objectively.

The rules apply regardless of whether an undertaking is privately or publicly owned. However, the rules only apply to undertakings that exercise an economic activity.[63]

Art. 1 EEA states that the aim of the EEA Agreement is to promote a continuous and balanced strengthening of trade and economic relations between the Contracting Parties with equal conditions of competition, and the respect of the same rules, with a view to creating a homogeneous European Economic Area (EEA). Accordingly, the Agreement is assumed to apply to all economic activity not explicitly exempted in Art 30 EEA.[64] Gas sales clearly constitute an economic activity, and are thus covered by the objective of the EEA Agreement.[65] It also follows from Art 24 EEA, with further references to Appendix IV, that the energy sector as such is covered under the agreement.[66] Similarly, the ECJ has made it clear that the Treaty of Rome in general, including its

63 See both CA Section 2 and Art. 56 EEA, cf. protocol 22 to the EEA Agreement.

64 Finn Arnesen, Statlig styring og EØS-rettslige skranker. Illustrert ved en studie i EØS-rettens betydning for styringen av norsk petroleumsvirksomhet («Arnesen»), p. 49 et seq.

65 Rune O. Pedersen, Den norske stats organisering av gassalget og konkurransebegrensningsreglene i EØS-avtalen, published in Are Brautaset, Eirik Høiby, Rune. O. Pedersen and Christian Fredrik Michelet, Norsk Gassavsetning. Rettslige hovedelementer («Brautset m.fl.»), pp. 465-579, on pp. 474-475, with further references.

66 Appendix IV to the EEA Agreement lists the Directives and Regulations EU has passed concerning the energy sector.

competition rules, applies to the energy sector as such.[67]

In order to determine the geographical scope and range of the CA, CA Section 10 and 11 have to be read in correlation with CA Section 5, according to which the scope and extent of the Act is limited to Norwegian territory. In contrast, the wording of Art. 53 EEA and Art. 54 EEA, as well as that of Art. 101 TFEU and Art. 102 TFEU (previously Art. 81 EC and Art. 82 EC), clearly implies that these provisions only apply provided the anticompetitive behaviour in question *may affect trade between Member States* (the "effect on trade"-criterion). While national competition law applies to market behaviour that has a negative influence on market conditions within the nation's jurisdiction, EU and EEA competition law applies to anticompetitive market behaviour that has a negative effect on the trade between the Member States of the respective treaties.

4.3.4 Norwegian Gas Sales and the Application of the Competition Rules in the EEA Agreement and the EC: the "Effect on Trade" Criterion

It follows directly from the scope and extent of the CA that the national competition rules are of limited practical importance in relation to the gas sales regime as Norway exports its gas to buyers on the European continent. However, the competition rules in both the EEA Agreement and the Treaty on the Functioning of the European Union (previously the EC Treaty) (hereinafter described generically as European competition law) may apply provided certain conditions are met.

Both Art. 53 EEA and Art. 101 TFEU (previously Art. 81 EC) apply wherever the agreement in question has an effect on trade between those states that are members of the Agreement or Treaty respectively. According to their wording, both Art. 53 EEA and Art. 101 TFEU (previously Art. 81 EC) only apply where trade between the Member States is affected. Art. 53 EEA specifies that it only applies to agreements

[67] See, e.g., case 6/64 Costa v Enel, ECR [1964] 1251, case C-393/92 Municipality of Almelo and others v NV Energiebedrijf Ijsselmij, ECR [1994] I-1477, case C-17/03 VEMW and case C-128/03 AEM.

between undertakings, decisions by associations of undertakings and concerted practices which may affect trade between Contracting Parties. Similarly, the main starting point under the Treaty on the Functioning of the European Union (as previously in the EC Treaty) is that the community competition rules apply to the internal market only, and that the rules shall be applied within the Member States of the EU. According to their wording, neither Art. 53 EEA nor Art. 101 TFEU (previously Art. 81 EC) contain requirements as to the source of either the undertakings or the agreements, but rather focus on the place where the agreement has as its "objective" or "effect" to distort competition. In-so-far as an agreement or concerted practice has an effect on trade as described in the provisions, it follows explicitly from the wording of the provisions that the prohibition on anti-competitive agreements may apply.

In contrast to the EEA Agreement, the EC Treaty (now the Treaty on the Functioning of the European Union) has been applied exterritorialy. It is not uncommon for the Community institutions to apply the competition rules to the activities outside the scope of the European Community provided they are having anti-competitive effects within the internal market. In other words, the effect on trade criterion contained in both Art. 101 TFEU and Art. 102 TFEU (previously Art. 81 EC and Art. 82 EC) has commonly been used to claim jurisdiction.[68] It should be noted, that the "effect on trade" criterion is not a jurisdiction provision in the traditional sense. In principle, the "effect on trade" criterion only regulates which behaviour that may be subject to limitations under the competition rules of both the Treaty and/or the EEA Agreement.[69] However, the *Woodpulp* case[70] is an example of how the ECJ has found that agreements *implemented* in the internal market are to be considered covered by the *Community competition rules*. The exact criteria under which jurisdiction can be claimed are somewhat unclear. Firstly, the ECJ has not explicitly stated when an agreement shall be considered

68 Faull & Nikpay (1999), Chapter 10, p. 698

69 Norsk Konkurranserett I p. 200

70 Joint Cases C-89/85 etc. *Woodpulp*, ECR [1988] 5193

implemented within the Community. Secondly, according to the reasoning of the ECJ in this case, the agreements´ effect on trade within the EU market was not in itself considered sufficient to claim jurisdiction. Nevertheless, gas sales agreements where the delivery obligations are fulfilled within an EU-state must clearly fall under the scope of the Community competition rules, even though the seller is located in a non-EU country (i.e., a so-called "third country").

As Norway is a member of the EEA, it could be expected that a case primarily would be based upon the competition provisions in the EEA Agreement. Art. 56 EEA contains rules on the allocation of authority between the EFTA Surveillance Agency ("the ESA") and the Commission when it comes to the application of the competition rules in the EEA Agreement. As a main rule, the ESA has authority in cases where the competition within the EFTA market[71] is affected. The Commission, on the other hand, is granted authority in cases where only the EU market is affected. In mixed cases, i.e., where both EFTA market and the EU market are affected, the allocation of authority is based on the turnover of the undertaking(s) in question. In cases where 33 % or more of the undertaking's turnover is related to its activities in the EFTA market, ESA is granted authority. However, the competition rules in the EEA Agreement have never been applied to the Norwegian gas sector. Instead, the Commission can be said to have chosen to apply the competition rules contained in the EC Treaty.

With the *GFU case*[72], the Commission made it clear that it would not hesitate to apply European competition rules (i.e., a generic term covering the competition rules in both the EC Treaty and the EEA Agree-

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71 Iceland, Liechtenstein, Norway and Switzerland are members of European Free Trade Association («EFTA»). EFTA is served by three institutions: the EFTA Secretariat, the EFTA Surveillance Authority and the EFTA Court. For further information on EFTA, see http://www.efta.int.

72 Case 36.072. See IP/01/830 of 13 June 2001 (Commission objects to GFU joint gas sales in Norway), http://europa.eu/rapid/pressReleasesAction.do?reference=IP/01/830&format=HTML&aged=0&language=EN&guiLanguage=en, and IP/02/1084 dated 17 July 2002 (Commission successfully settles GFU case with Norwegian gas producers), published at http://europa.eu/rapid/pressReleasesAction.do?reference=IP/02/1084&format=HTML&aged=1&language=EN&guiLanguage=en.

ment) to the activities on the NCS in particular in order to improve market conditions within the European Community. The Commission claimed authority towards Norwegian gas producers due to the fact that their activities ultimately affected the trade between Member States within the Community. To the extent that Norwegian gas competes with gas volumes of a different origin which are also sold in the Community market, the organisation of the sales regime as well as the design of the sales agreements may affect the trade between EU-states and thus fall under Community legislation.

As can be seen, the direct consequence of the "effect on trade" doctrine developed by ECJ is that the general competition rules in both the EEA Agreement and the TFEU (previously the EC) apply when the distorting market behaviour affect cross-border trade within the EU. The Commission claimed that the GFU regime constituted a sales cartel in breach with both Art. 81(1) EC (now Art. 101(1) TFEU) and Art. 53(1) EEA.[73] In view of the account given of both the legislative situation and the chosen approach in the GFU case, however, it can be argued that the Commission in principle chose between these bodies of general competition rules based on considerations of which set of rules that would give it the greatest leeway to achieve its objective in this specific case. The particulars of the *GFU case* illustrates that the application of European competition law in reality was detached from Norway's position as a member of the EEA Agreement. Not only were the Community competition law applied, but the Commission also attacked the GFU regime (almost) from its beginning (more precisely from 1989 onwards).[74] As Norway first became a member of the EEA Agreement in 1994, only agreements entered into from this date onwards would potentially be in breach of Art. 53 EEA and thus one would have expected that only the validity of gas sales agreements entered into from this point on was questioned.

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73 See IP/01/830 of 13 June 2001 (Commission objects to GFU joint gas sales in Norway).

74 IP/02/1084 dated 17 July 2002, published at http://europa.eu/rapid/pressReleasesAction.do?reference=IP/02/1084&format=HTML&aged=1&language=EN&guiLanguage=en.

4.3.5 The Effect on Trade Criterion

It has already been established that nearly all natural gas produced on the NCS are exported to the EU. Thus, the organisation of the marketing and sales of these gas volumes will necessarily affect the market conditions within the EU. In elucidation of the Community institutions practice thus far, the application of Art. 101 TFEU and Art. 102 TFEU (previously Art. 81 EC and Art. 82 EC) in relation to the activities on the NCS continues to be highly relevant. In the light of this, it is important to establish the subject matter of the "effect on trade" criterion.

According to existing case law, not much is required in order to fulfil the "effect on trade"-criterion.[75] It is sufficient that the anticompetitive behaviour in question directly or indirectly, actually or potentially, may influence the trade pattern between Member States. In other words, it is not necessary to establish a factual influence on trade. It is sufficient to establish that the behaviour may influence trade. Trade may be indirectly influenced, typically where a measure reduces the possibilities for entry in a country and thus import and export to and from this country. Effect on trade exists in those cases where the restrictive practices directly concern import or export. The typical example is where the agreement or the behaviour in question extends over the territory of several Member States. Measures that comprise the territory of a single Member State are normally considered to have an effect on trade, even though the measures do not directly concern import and export but still segmentation into national markets in itself counteracts the objective of an internal market. Even measures that involves only parts of the territory of a Member States may be considered to have an effect on trade in so far that the measures influences on import or entry of firms in the Member State in question. As the gas produced at the NCS is sold to purchasers within the EU, it is safe to say that the trade between Member States are affected.

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[75] However, the Commission has issued guidelines on their stand on how to determine the effect on trade, cf. Commission Notice Guidelines on the effect on trade concept contained in Articles 81 and 82 of the Treaty («Effect on Trade Notice»), OJ [2004] C 101/81.

According to the practice of ECJ, the restrictive practice and its effect on trade have to be appreciable in order to represent a breach of the prohibition. Whether there is an appreciable effect on trade depends upon an overall evaluation. The Commission has introduced quantitative thresholds in a notice to determine whether an agreement's restrictive effect on competition is appreciable or not.[76] This Notice does not deal with the question of whether or not an agreement appreciably affects trade between Member States.[77] However, it follows from this Notice that it is acknowledged that agreements between small and medium-sized undertakings are rarely capable of appreciably affecting trade between Member States.[78] The small and medium-sized undertakings are defined based on quantitative thresholds.[79] As the size of the gas companies conducting activities on the NCS clearly exceeds these thresholds, it is also safe to assume that these companies affect the trade between Member States appreciably.[80]

4.3.6 The Principle of Homogeneous Interpretation and Application of the EEA Agreement and the EC Treaty

In the following, any reference to and discussion of Art. 101 TFEU (previously Art. 81 EC) also applies to Art. 53 EEA. The competition rules in both the EEA Agreement and the TFEU (previously the EC Treaty) may apply to the activities on the NCS. At the same time, a homogeneous interpretation and application of the EEA Agreement and the TFEU (previously the EC Treaty) is required.[81] Ultimately, it is of

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76 Commission Notice on agreements of minor importance which do not appreciably restrict competition under Article 81(1) of the Treaty establishing the European Community (*de minimis*) («De Minimis Notice»), OJ [2001] C 368/13.

77 De Minimis Notice, preamble (3)

78 De Minimis Notice, preamble (3)

79 Small and medium-sized undertakings are currently defined as undertakings which have fewer than 250 employees and have either an annual turnover not exceeding EUR 40 million or an annual balance-sheet total not exceeding EUR 27 million, cf. De Minimis Notice, preamble (3).

80 Similarly, see Boge p. 56

81 Art. 105(1) EEA

limited importance which set of competition rules is applied in evaluating the Norwegian gas sales regime.[82]

Although there are no major material differences between the general sets of competition rules due to the harmonisation efforts described above, it is important to bear in mind that two conditions may lead to a differing interpretation and application of EU competition rules on the one hand and EEA competition rules on the other, and ultimately may result in different legislative assessments and solutions under the respective competition regimes.

Firstly, the legislative purpose of the rules differs slightly. A common denominator for the competition rules on both national and community level is that they seek to ensure sosio-economic efficiency through effective competition. This explicitly follows from CA Section 1, which states that the Act aims to promote competition in order to contribute to effective use of the society's resources. Although such an objects clause is found in neither the EEA Agreement nor the Treaty on the Functioning of the European Union (previously the Treaty of Rome), the competition rules at the community level are understood to have a similar purpose. Contrary to the CA, however, the competition rules at Community (European) level are also meant to contribute to the realisation and completion of the internal market.[83] It should be noted, however, that while the purpose of the EEA Agreement is still largely economic[84], the co-operation within the EU has been extended beyond an economic scope alone.[85]

Secondly, the relevant sources of law and legal authority are not entirely identical. Formally, only EU law passed before Norway entered

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82 See e.g. Fredrik Sejersted, Finn Arnesen, Ole-Andreas Rognstad, Sten Foyn and Olav Kolstad, EØS-rett (2. utgave) («Sejersted et al»), in particular chapter 4.1 and chapter 9.2, for a presentation of the principle of homogeneity and the instruments provided to ensure this principle. See also Sejersted et al chapter 4.6.

83 Art. 1 EEA. It should be noted, however, that while the objective of the EEA Agreement is still purely economic in nature, the co-operation within the framework of EU has been extended with the passing of the Treaty of the European Union.

84 Art. 1 EEA

85 See, e.g., Sejersted et al, p. 253 et seq, for a comparison of the scope of the EEA Agreement and the EC Treaty respectively.

into the EEA Agreement is legally binding. The EEA Agreement explicitly states that the provisions of the EEA Agreement identical to similar provisions in the Treaty establishing the European Community (now basically included in the Treaty of the Functioning of the European Union) and secondary legislation passed in relation to this Treaty, are to be interpreted in correspondence with case law decided by the ECJ before the EEA Agreement was signed.[86] While (secondary) EU legislation passed at a later date have to be implemented in the EEA Agreement by the express decision of the EEA Committee[87], case law decided by the Community courts after the EEA Agreement was signed is not automatically recognised as a source of law under the EEA Agreement. Still, the EEA Committee is under an obligation to monitor the development in case law and to ensure the homogeneous interpretation for the provisions of the Agreement.[88] Thus, due to the principle of homogeneous interpretation of the EEA Agreement and the Treaty establishing the European Community (now basically included in the Treaty of the Functioning of the European Union), cases decided by the ECJ are still relevant. Similarly, the Commission's administrative practice in relation to the provisions of the Treaty must be taken into consideration.

4.4 The Identification of the Relevant Gas Markets

4.4.1 Overview

The identification of the relevant gas markets is of major importance. The relevant market functions as a frame of reference against which an undertaking's market behaviour can be measured.

Whether an agreement (or a practice) actually prevents, restricts or distort competition, depends on whether the agreement affects the function of the market mechanism in such a way that competition in

[86] Art. 6 EEA

[87] Art. 102 EEA

[88] Art. 105 EEA. In order to achieve this objective, a system for exchange of case law between the ECJ and the EFTA is established, cf. Art. 106 EEA.

the market is curbed.[89] In order to determine which effect an agreement has on the function of the market mechanism, the market on which the agreement may affect (i.e., the *relevant* market) must be determined. Similarly, the identification of the market is necessary in order to determine whether the restrictive practices in question actually may affect trade between Member States.

Despite the importance of the market definition, there is limited practice giving guidance as to the definition of the relevant gas markets in particular. Due to the ongoing liberalisation process, one might say that both the principles for valuation of and the method for definition of relevant gas markets are still under development.[90] Neither the European Court of Justice (ECJ) nor the Court of First Instance (CFI) has submitted a legal precedent as to the legal definition of the relevant gas market.[91] Although it should be kept in mind that the practice of the Commission is without prejudice to both the Community courts, decisions made by the Commission may shed some light as to which factors that so far has been relied upon when defining the relevant gas markets.

Based on its experiences from a number of sectors, the Commission has issued a notice on the definition of the relevant market *in general*.[92] This notice is supplemented by the Commission's decisions in individual cases related to the gas industry. As there are few antitrust cases in which the Commission defines the relevant market in relation to the gas sector, the Commission's decisions in *merger cases* has proven to be the

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89 Norsk Konkurranserett I p. 256

90 Anne-Karin Nesdam, Relevant Energy Markets – Network-bound sectors and market definition, article published in SIMPLY 2003 («Nesdam, Relevant Energy Markets»), pp. 307-356, on p. 320

91 Nesdam, Relevant Energy Markets p. 319

92 Commission Notice on the definition of the relevant market for the purposes of Community competition law («the Commission's Notice on the Relevant Market»), Official Journal C 372, 9.12.1997, pp. 5–13. ESA has published a similar notice on market definition, cf. Decision of the EFTA Surveillance Authority No. 46/98/COL of 4 March 1998 on the issuing of two notices on the definition of the relevant market for the purpose of competition law within the European Economic Area (EEA), and on agreements of minor importance which do not fall under Article 53(1) of the EEA Agreement, published in both EEA Supplement No. 28/3 1998 and OJ [1998] L 200, p. 46.

main source to identify the factors relevant for the definition of gas markets as the liberalisation process progresses. Still, this case material needs to be applied with caution. Although clearly relevant as the market definition in antitrust cases and merger cases are based on parallel criteria, the Commission tends to use the market definition as a tool to achieve policy considerations. As the policy considerations under the antitrust rules and the merger rules is not necessarily identical, this has to be taken into consideration when evaluating whether and – if possible - to which extent the Commission's market definition in merger cases (without more ado) may be transferred to the application of the antitrust rules.[93]

The market definition has to be based on the specific factual and economic circumstances in each case. In general, the relevant market is divided into a relevant product market and a relevant geographic market. While the relevant product market is defined on the basis on which *types of products* that are considered substitutes by the consumers, one identifies the suppliers, the consumers and the geographic location of the different market participants in order to define the geographic market.[94] In other words, the market definition seeks to identify which products that are offered in the market, the geographic dimension of this market and whether there is time or seasonal market fluctuations.[95]

With regard to the gas sector, the Commission has applied a functional approach reflecting the supply structure in the gas market when defining the relevant market, both product wise and geographic wise.[96] Consequently, a further distinction has been drawn between upstream markets and downstream markets. While the term «upstream activiti-

93 This aspect will not be further commented upon in the following.

94 Norsk Konkurranserett I p. 268

95 Thomas Bruusgaard Høgseth, Vertikale begrensninger i langvarige gassalgskontrakter: en vurdering av forholdet til EF- og EØS-rettens forbud mot konkurransebegrensende samarbeid, (published in MarIus nr. 357 (2007)), electronically available at http://www.duo.uio.no/publ/jus/2007/61312/Vertikalexbegrensningerxixlangvarigexgassalgskontrakter.pdf, p. 31.

96 Faull & Nikpay (2007) p. 1393, with further references, and Nesdam, Relevant Energy Markets p. 327

es» is used to describe all activity until the gas is sold to wholesalers for forward sales within the EU, the term «downstream activities» refers to all activities below the wholesale level.[97] Traditionally, Norwegian gas has been sold in the markets upstream and the competition challenges relating to the organisation of the Norwegian gas sales (still) mainly arise in relation to these markets. As the producers which are active on the NCS after the liberalisation of the gas sector and the introduction of portfolio CBS increasingly sell their gas directly in the markets downstream as well as upstream, the market definition on both levels has to be commented upon for the purposes of this article.

Based on both the general guidelines issued and the specific merger cases, the relevant product market (in part 4.4.2) and the relevant geographic market (in part 4.4.3) on the gas sector will be dealt with successively in the following.[98] It should be noted, however, that rather than a thorough analysis of the market definition this presentation will be confined to a statement of the main principles upon which the market definition must be made and the market distinctions that the Commission has operated with thus far.

4.4.2 The Relevant Product Market

General

According to both the Commission's notice on market definition, the relevant product market covers all goods which are inter-exchangeable or substitutable due to their quality, price and area of use from a consumer perspective.[99]

Natural gas as a product has been distinguished from other energy

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97 Høgseth p. 33

98 This part is mainly based on Faull & Nikpay (2007) pp. 1392-1398, EU Energy Law II Part 2 The definition of the relevant market, Chapter 4 – The relevant product market – Gas, and Chapter 5 The relevant geographic market – Gas, Nesdam, Relevant Energy Markets, and Thomas Bruusgaard Høgseth, Vertikale begrensninger i langvarige gassalgskontrakter: en vurdering av forholdet til EF- og EØS-rettens forbud mot konkurransebegrensende samarbeid, MarIus nr. 357 (2007).

99 Similar follows from ESAs notice

sources. According to the practice of the Commission, a market with gas-to-gas competition has been identified. Furthermore, a separate market for forward sales of natural gas, i.e. the sale of natural gas before field development and production in order to ensure the development of the reservoir in question, has been identified.

Within the market for natural gas, the production and supply chain has been distinguished into separate markets. According to Commission practice, both the existing and the foreseeable degree of market opening have to be taken into account when defining these markets.[100] As the market conditions will change continuously as the liberalisation process progresses, the market must be defined based on the facts of the case at the given time. In other words, the gas undertakings must assess its market power on a continuous basis.

The Upstream Market

The Commission has applied a functional approach when defining the markets upstream. As the gas sector is network bound, the market participants are dependent on access to the different levels in the value chain.[101] Consequently, each level in the value chain has been identified as a separate market. Thus, it can be distinguished between four different product markets upstream. First, a market for exploration has been identified.[102] Second, a market for development, production and sale of natural gas to the wholesale level in general and to large industrial customers and gas-fired power generators has been established.[103] As this market is a forward market, i.e. market for the future delivery of natural gas from market participants active in gas production to market participants at the wholesale level, it is also known as the market for

100 See case M.3440 ENI/EDP/GDP, paragraph 16 and the Commission's Notice on the Relevant Market, paragraph 32

101 See, e.g., Faull & Nikpay (2007) p. 1393, with further references

102 Case M.1383 Exxon/Mobil, paragraph 15 et seq

103 See, e.g., cases M.1383 Exxon/Mobil, M.3052 ENI/Fortum Gas, M.3086 Gaz de France/Preussag Energie, and M.3293 Shell/BEB.

forward gas.[104] Third, the Commission operates with a market for transport of gas through upstream gas pipelines.[105] Fourth, based on case law, a separate market for the processing of gas can also said to exist.[106]

The Downstream Markets

While the product markets upstream is identified on the basis of activity, the product markets downstream is defined on the basis of which consumer group the natural gas is sold to. Based on inter alia volume demand, need for flexibility and other contractual terms and conditions, the Commission distinguishes between four main groups of customers, i.e. regional distributors, local distributors, industrial customers and business users and, lastly, small businesses and household customers, for the purpose of market definition.[107] While sale to the first three customers groups is characterised as sale at the wholesale level[108], the sale of natural gas to small businesses and household customers is considered to take place at the retail level.

The Commission has on a number of occasions divided sale of natural gas at the wholesale level into three (occasionally four) separate markets.[109] These markets correspond with the customer groups, i.e. sale to gas fired power generators, sale to large industrial customers and sale to local distributors.[110] Reference is generally made to the fact that these customers differ with respect to consumption levels, margins,

[104] Case IV/E-3/35.354 – The Britannia Gas Condensate Field – Notice pursuant to Art 19(3) in Regulation 17, OJ [1996] C 291/10, paragraph 5

[105] Case M.2745 Shell/Enterprise Oil, paragraph 10 et seq

[106] Ibid

[107] Faull & Nikpay (2007) p. 1395

[108] Peter D. Cameron, Competition in Energy Markets – Law and Regulation in European Union (2nd Edition) («Cameron») pp. 290-291

[109] Case M.3440 ENI/EDP/GDP, upheld by the CFI in its judgement of 21 September 2005 in Case T-87/05 EDP, ECR [2005] II-3745. See also Case M.3696 E.ON/MOL, premises 100-124 and 141, and Case 37.966 Distrigas, OJ 2007 C77/14 and IP/07/490. Here, the Commission allows for the segmentation of the Belgian market into several markets based on consumer groups, i.e. industrial customers, gas-fired power generators and wholesalers (probably in the meaning of national distributors).

[110] Case M.3440, ENI/EDP/GDP, paragraphs 217-270. See also EU Energy Law II p. 88.

tariffs for access to transport networks, prices, commercial and organisational aspects as well as special needs.[111] Other than to illustrate that the Commission based its market definitions on the specific market conditions in the Member States in question, these cases give little if any guidance on definition on downstream markets across-the-board.[112]

The market participants argue that supply to all large users constitutes a single wholesale market. It has been argued that the fact that natural gas is a good with the same specifications for all consumers, supplied though the same distribution chain, support the view of a homogeneous wholesale market.[113] If all consumers are free to choose their supplier, the suppliers are free to choose where to conduct their activity and there are no barriers to entry between the different market segments, a further delineation of the market may seem artificial. In a liberalised market, different consumer groups will have to compete for the natural gas on an equal footing, without different commercial needs and assumptions being taken into consideration. The tendency for gas producers to offer natural gas directly to the different groups of commercial buyers also supports the development of a homogeneous wholesale market. Although sale of natural gas to different consumer groups will give rise to price disparities on some occasions, these disparities will typically be linked to variations in the services offered in relation to and other individual adaptations made to the supply in question. As the gas markets mature, this tendency will probably strengthen. As the development towards more integrated markets are somewhat slow, however, the Commission continues to divide the downstream wholesale market into submarkets for now.[114]

As the production companies seek to optimise their gas portfolios

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111 Ibid

112 Similarly, Høgseth p. 35

113 Høgseth p. 35

114 See, e.g., Case 37.966 Distrigas, OJ [2007] C77/14. For a short presentation of the case, see IP/07/490. In this case, the Commission allows for the segmentation of the Belgian market into several markets based on consumer groups, i.e. industrial customers, gas-fired power generators and wholesaler (probably in the meaning of national distributors).

by selling directly to gas-fired power generators and large industry consumers, such sales are becoming increasingly common. Due to this development, it has been argued that the Commission in the future will need to operate with two types of product markets for natural gas downstream.[115] First, a market for wholesale supply to industrial customers, gas-fired power generators and local distributors directly attached to the national transmission network will have to be identified.[116] Depending on the degree of market opening, this market may be divided into three separate markets based on the consumer groups specified above. In order to be covered by the market definition, the undertakings in question have to be of a certain size enabling them to import natural gas directly and to exercise individual buying power. Second, a market for retail supply of natural gas, where the customers first and foremost buy their gas from distributors or forward gas sales companies within the Member State in question, is likely to develop. Dependent on the degree of market opening in the market in question, two submarkets may be identified; i.e., a market consisting of industrial buyers attached to the local and regional distribution network on the one side and a market for small businesses and household consumers on the other.[117]

4.4.3 The Relevant Geographical Market

General

The relevant geographic market is defined as an area where the market conditions are sufficiently homogeneous and thereby can be separated from adjacent markets where the markets conditions are noticeably (appreciably) different.[118]

The geographic dimension of neither the four different upstream markets nor the wholesale markets and retail markets downstream do coincide. The definition of the geographical market is of significance, as

[115] Høgseth p. 37
[116] Similarly EU Energy Law II p. 90 and Høgseth p. 37
[117] Høgseth p. 37
[118] The Commission Notice on the Relevant Market, paragraph 15

more is required in order to achieve an appreciable restrictive effect in a large geographical market compared to a smaller one. Still, a (detailed) presentation of the geographical scope of all the relevant product markets will clearly be too extensive. For the purpose of this article, however, the geographical scope of the market for field development, production and sale of natural gas upstream and the markets at the wholesale level downstream are of the main interest. Thus, in the following, the presentation will be limited to these two markets.

The Upstream Market

The geographical dimension of the market for field development and production of natural gas as well as the sale of the gas to wholesalers is highly dynamic in character.

The starting point, however, must be that this market is considered to cover the entire EEA area and probably Russia and Algeria as well.[119] In legal theory it has been assumed that the European internal market is the relevant geographical market for the production and sale of natural gas to wholesale dealers.[120]

That this is just a starting point follows from the merger case *Norsk Hydro/Saga Petroleum*[121]. Although the Commission stated that the EEA States, together with Russia and Algeria, formed the relevant geographical market for exploration, production and sale of natural gas as seen from a European demand perspective, the reason for this market definition was first and foremost the logistical problems connected with pipeline transport. Thus, the Commission allowed for the possibility that the geographical market could be confined due to differences in gas quality in different producer countries, constraints in existing transport infrastructure and the costs related to the gas transport.[122] However, the Commission did not find it necessary to finally conclude on these

119 See, e.g., case M.1573 Norsk Hydro/Saga Petroleum and case M.3052 ENI/Fortum Gas, paragraph 14

120 See amongst others Cameron pp. 292-293 and Høgseth p. 39

121 Case M.1573 Norsk Hydro/Saga Petroleum

122 Case M.1573 Norsk Hydro/Saga Petroleum, paragraph 15

matters for the purpose of the case, as they did not consider that the merger would result in either the establishment or the strengthening of a dominant position even on the narrowest market, i.e., the market for sale of Norwegian gas alone.

In this context, however, the possibility that constraints in existing transport infrastructure may influence on the market definition is of particular interest. It cannot be ruled out that the market definition may be narrower in situations where *temporary capacity constraints,* i.e., so-called bottlenecks, occur in the interconnectors linking the gas networks of the Member States. The nature of these temporary constraints may be both physical and contractual. While physical constraints in the interconnectors linking the national gas networks are not considered to be a major problem, contractual constraints commonly occur as the transport capacity is reserved through long term transport contracts, often to the advantage of former monopolists (the incumbents), and thus are not available to new market participants.[123] However, there are examples that the Commission has found that a state is isolated from its neighbouring countries and thus not a part of the internal market due to lack of interconnectors or insufficient transport capacity (i.e., physical constraints) in the interconnectors.[124] The *Britannia case*[125] is of particular interest in this respect. Referring to the lack of transport infrastructure connection Great Britain with the Continent and pointing to constraints in the existing pipeline between Ireland and England, the Commission found that Great Britain was a separate geographic market as such. As this case was decided upon before the British market was connected to the continental market through the interconnector between Bacton and Zeebrügge in Belgium, this market segmentation cannot be upheld in today's situation.

[123] See case M.3440 ENI/EDP/GDP, paragraph 273, regarding the lack of available capacity in the interconnector between Spain and Portugal.

[124] Case IV/E-3/35.354 Britannia gas condensate field, OJ [1996] C291/10. This was also considered to be the case in case M.931 Neste/Ivo, paragraphs 22-23, where the Commission based its decision on the fact that Finland was not connected to other pipeline networks than Russia.

[125] Case IV/E-3/35.354 Britannia gas condensate field, OJ [1996] C291/10

However, even though the British market and the Continental market now are connected from a technical point of view, one still might find that these markets are separate when the capacity in Bacton-Zeebrügge pipeline is fully booked (i.e., due to contractual constraints) or the pipeline is closed for maintenance purposes.

Assuming that varying capacity in the interconnectors will influence on the market definition, the geographical market may change within a very short time period under certain conditions.[126] As the market share of the gas producers and the gas suppliers will be larger than ordinarily when narrow, temporary markets are defined due to capacity constraints in the transport capacity, this leads to a greater need for vigilance on the part of these market participant in order to avoid breaching the competition rules.

The Downstream Markets

The geographical scope of the downstream markets at the wholesale level has normally not exceeded the borders of a single Member State, both before[127] and after the liberalisation of the European gas markets took place. After the market opening and the implementation of the gas marked directives, the starting point of the Commission is that the wholesale markets downstream have remained national in character. Most of the Commission's decisions are rudimentary and do only contain a rather superficial analysis of the definition of the relevant geographical market. Referring to the market structure, the Commission either states that the supply market is national because the wholesale supply of natural gas mainly is a national activity[128] or states that the incumbent still has a dominating position within its historical supply area in Member States where external market actors yet have to enter.[129] However, it has been argued that the narrow market definition

126 Nesdam, Relevant Energy Markets, p. 347

127 Case M.493 Tractebel/Diztrigaz, paragraphs 21-25

128 Among others, see cases M.3297 Norsk Hydro/Duke Energy, paragraph 14 and M.3294 ExxonMobil/BEB, paragraph 20

129 Cf. case M.3086 Gaz de France/Preussag Energie, paragraph 12-13

may have its background in and said to express the policy considerations of the Commission.[130] The narrower the marked is defined the more likely it is that the competition rules apply.[131]

It is too early to operate with a joint community market downstream. At present, the existing conditions for third party access to the transmission network are insufficient to support cross-border trade. Instead, the problem is contractual constraints as the transport capacity is reserved through long term transport contracts, often to the advantage of former monopolists (the incumbents), and thus not available to new actors.[132] When defining the relevant market, the Commission both needs to and will take the ongoing market integration in the EEA Area into consideration.[133] However, the Commission (or, for that matter, the ESA) cannot be in the front edge of the development. The market must be analysed and defined as it is, taking into account the different initiatives in order to accelerate the market integration. As numerous initiatives have been initiated in order to open the European gas market, it is only a question of time before a cross-border market definition may apply downstream as well. As when defining the geographical scope of the markets upstream, the need for sufficient physical transport capacity is essential when defining the geographic scope of the downstream markets.[134]

130 EU Energy Law II pp. 95-96

131 It should be noted, however, that the notifying parties in most cases have not considered the possibility of a market wider than the national and thus not forcing the Commission to take a stand. See, e.g., Case M.3410 Total/Gaz de France, paragraph 32.

132 See, e.g., case M.3440 ENI/EDP/GDP, paragraph 273, regarding the lack of available capacity in the interconnector between Spain and Portugal.

133 See, e.g., case M.2684 EnBW/EDP/Cajastur/ Hidrocantábrico, paragraph 18, case M.3440 ENI/EDP/GDP, paragraph 16, and the Commission`s Notice on the Relevant Market, paragraph 32

134 EU Energy Law II p. 96

5 Joint selling

5.1 Introduction

With the dissolution of the sales cartel GFU and the introduction of a CBS regime, one could claim that the question of joint selling is no longer relevant to activities on the NCS. However, the question of joint selling is still pertinent for a number of reasons.

Firstly, the NCS is a mature area. This means that the major finds have already been located. During the last couple of years, new resources located on the NCS have mainly been marginal. Furthermore, the fields located are often so-called associated fields (i.e., oil and gas fields). These types of fields require special operational conditions to ensure optimal production, which from a resource management perspective is important. In relation to associated fields, a certain withdrawal of gas may be necessary to ensure optimal oil production. In relation to marginal fields, the field's profitability may depend on joint selling. Besides the gas companies` commercial interest in production optimisation, optimal production is increasingly important in a situation where there is global competition over the gas resources available and the need for security of supply.

Secondly, under the existing sales regime, gas producers are known to buy gas produced by other producers. Such buying primarily takes place for two reasons. In part, gas may be bought for production purposes. Concerted buying of gas for injection purposes, i.e., the buying of injection gas to maintain the pressure in the reservoir and thus optimise the field's longevity, is common on the NCS. In part, gas may also be bought for commercial purposes. A gas producer may buy gas to fulfil delivery obligations under sales agreements entered into, i.e., the buying of gas for resale purposes. Both situations have similar effects to joint selling, as the gas volumes produced by two or more producers are ultimately sold by a single seller at a single price.

Joint selling is clearly prohibited under Art. 101 TFEU (previously

Art. 81(1) EC)/Art. 53(1) EEA. However, the prohibition in Art. 101(1) TFEU (previously Art. 81(1))/Art. 53(1) EEA applies only where joint selling cannot be objectively justified. The Commission has dealt with quite a number of cases concerning the question of joint selling over the years.[135] The general policy of the Commission is not to tolerate joint selling, unless compelling reasons are provided as a justification.[136] This case material constitutes the basis for the following analysis of whether, and under what circumstances, joint selling can be considered justified.

In the following, the questions of joint selling from several fields (part 5.2), joint selling from a single field (part 5.3) and concerted buying (part 5.4) will be dealt with. In this discussion, the presentation and analysis of the available case material will feature prominently.

5.2 Joint Selling from Several Fields – Illustrated by the GFU Case and the DONG/DUC Case

Not only did the GFU case[137] represent a turning point concerning the application of European competition rules to activities on the NCS, but it also illustrates *jurisdictional*, as well as *material*, aspects of the application of European competition law to the activities on the NCS. While the jurisdictional issues have been dealt with above (in part 4.2), the

[135] So far, the Commission has dealt with four cases concerning joint marketing and selling of natural gas, i.e. Case No IV/E-3/35.354 - Britannia gas condensate field (Notice pursuant to Article 19(3) of Regulation 17) OJ [1996] C291/10, COMP/37.708 – PO/Corrib (IP/01/578 of 20 April 2001) (joint sales from a single field), COMP/36.072 – GFU - Norwegian Gas Negotiation Committee (IP/02/1084 of 17 July 2002) (joint sale from several fields) and COMP/38.187 - DONG/DUC (IP/03/91 of 24 April 2003) (joint marketing).

[136] Cf. the statement made by then Commissioner Mario Monti in relation to the closure of the *Corrib case*, IP/01/578 of 20 April 2001 (Enterprise Oil, Statoil and Marathon to market Irish Corrib gas separately). See also EU Energy Law II p. 157.

[137] IP/01/830 of 13 June 2001 (Commission objects to GFU joint gas sales in Norway), published at http://europa.eu/rapid/pressReleasesAction.do?reference=IP/01/830&format=HTML&aged=0&language=EN&guiLanguage=en, and IP/02/1084 dated 17 July 2002 (Commission successfully settles GFU case with Norwegian gas producers), published at http://europa.eu/rapid/pressReleasesAction.do?reference=IP/02/1084&format=HTML&aged=1&language=EN&guiLanguage=en.

following focuses on the material aspects of the case. In short, the GFU case concerned the former practice of the *joint selling* of natural gas produced from *several fields*. Although the case dealt with anti-competitive practices that are now history on the NCS, it is desirable to present the case reasonably thoroughly.

Traditionally, the natural gas produced on the NCS has been sold under long-term gas sales agreements. Due to the enormous costs related to the development of infrastructure and the production of gas, the field owners need to be certain that the gas produced will be sold in the market. Hence, the field owners have entered into long-term gas sales agreements prior to the development of the gas reservoirs. Until recently, joint gas sales have been practised on the NCS. The methods employed, however, have differed over the years.

Initially, the licensees of a single field entered into depletion contracts with their customers downstream ("field depletion contracts"). Later on, the field licensees´ freedom to enter into gas sales agreements on their own was eliminated, as all gas sales agreements were negotiated and entered into by the gas negotiations committee ("GFU").[138] While only the Norwegian gas producers[139] operating on the NCS were members of the GFU on a permanent basis, other gas producers could be involved on a temporary basis in relation to specific negotiations if it was deemed necessary. Due to the advisory role of the GFU, the contracts negotiated by the GFU were only binding following the Ministry's approval. The fulfilment of the delivery obligations was not decided upon in the gas sales agreements as such. Instead, the delivery obligations under the gas sales agreements were transferred to a contract field

[138] GFU was established in 1987 as an advisory committee to the Ministry of Petroleum and Energy («MPE»). See, e.g., St.meld. nr. 39 (1999-2000) Olje- og gassvirksomheten, pkt 5 Gassvirksomheten, pkt 5.4 Det norske gassforvaltningssystemet, pkt 5.4.1 Organisering av gassvirksomheten

[139] At the time of its establishment were Statoil, Norsk Hydro and Saga Petroleum. With Norsk Hydros acquisition of Saga Petroleum in 1999, the members of the GFU were reduced from three to two. See e.g. St.meld. nr. 39 (1999-2000) Olje- og gassvirksomheten, pkt 5 Gassvirksomheten, pkt 5.4 Det norske gassforvaltningssystemet, pkt 5.4.1 Organisering av gassvirksomheten.

subject to the recommendations of the supply committee ("FU")[140], which consisted of the ten major resource owners and operators active on the NCS, and the discretion of the Ministry.[141] Due to the gas volumes involved, the contract field was normally unable to meet the delivery obligations under the gas sales agreement on its own. Hence, in order to be able to fulfil the delivery obligations, the contract field would enter into supply contracts with a number of supply fields, again subject to the recommendations of the FU and the discretion of the Ministry.[142]

The Norwegian authorities initiated the joint selling of gas through a single body for resource management purposes. The main purpose of the GFU - and the FU - was to ensure advantageous marketing possibilities for Norwegian gas in the long term.[143] This was an important part of the safeguarding of the overall resource management purposes, as it

140 The supply committee («FU») was established in 1993 at the initiative of the authorities and with the purpose of advising the Ministry on how alternative supply obligations could and would contribute to an efficient resource management. As to how different supply solutions would contribute to an efficient resource management, must be based on considerations of how the different alternatives affect the production of liquids, time critical reserves (tidskritiske reserver), resource management, utilization of existing and planned infrastructure as well as al risk assessment of the technical alternatives in relation to the gas activities upstream, cf. St. meld. nr. 39 (1999-2000) Olje- og gassvirksomheten, pkt 5 Gassvirksomheten/pkt 5.4 Det norske gassforvlatningssystemet/pkt 5.4.1 Organisering av gassvirksomheten.

141 The GFU/FU scheme was based upon a close co-operation between the licensees, the GFU, The FU and the authorities. Each licence group was obligated to report, on a continuous basis, to FU which volumes they could produce. Based on the data received, the FU made estimates on the volumes the NCS potentially could supply. These estimates again were the foundation upon which the GFU negotiated gas sales agreements with continental buyers. The agreements negotiated by the GFU and approved by the Ministry were then submitted to the FU for advice on how the delivery obligations should be fulfilled. The proposal of the FU was then sent the Ministry, which ultimately decided upon the field- and transport solution to be developed in order to fulfil the gas sales agreement in question. During this entire process, authorities and undertakings active on the NCS met on a regular basis for exchange of information and views.

142 St.meld. nr. 39 (1999-2000) Olje- og Gassvirksomheten, pkt 5 Gassvirksomheten/ pkt 5.4 Det norske gassforvaltningssystemet/ pkt 5.4.1 Organisering av gassvirksomheten

143 St.meld. nr. 39 (1999-2000) Olje- og gassvirksomheten, pkt 5 Gassvirksomheten, pkt 5.4 Det norske gassforvaltningssystemet, pkt 5.4.1 Organisering av gassvirksomheten. Similarly, St.meld. nr. 38 (2001-2002) pkt 7.1.1

enabled the authorities not only to develop the available *gas resources* gradually over time, and thus secure the Norwegian society a steady and reliable income over time (production and income purposes), but also to establish the infrastructure necessary to utilise these resources in a co-ordinated manner (infrastructure purposes). Due to the joint selling scheme, it was possible first to develop the gas fields considered most profitable from a socio-economic perspective and to ensure cost-effective development of both transport pipelines and processing terminals as the fields in question were developed.[144] In other words, the GFU/FU-scheme facilitated the co-ordinated development of gas fields on the NCS based on socio-economic considerations (development purposes).[145] At the same time, the gas produced on the NCS was sold to monopsonies on the Continent. The establishment of a sales monopoly thus also contributed to the attainment of a more equal bargaining position, thereby facilitating, from a producer perspective, favourable sales conditions in general and gas prices in particular.

Although the GFU/FU scheme was advantageous from a Norwegian point of view, the joint selling of gas through a single body was heavily criticised at Community level. In June and July 2001, after years of bickering, the Commission initiated formal proceedings against approximately 30 Norwegian gas companies, arguing that the GFU scheme was incompatible with European competition law.[146] The Commission challenged the validity of every gas sales agreement entered into under the GFU regime from 1989 onwards, arguing that the GFU constituted a sales cartel in breach of Art. 81 EC (now Art. 101 TFEU). It should be noted, however, that an undertakings´ anti-competitive behaviour constitutes a breach of Art. 81 EC (now Art. 101 TFEU) only if that undertakings´ behaviour is a result of its private autonomy and not imposed by the state (the "state compulsion"-doctrine). Both the gas

144 St.meld. nr. 38 (2001-2002) pkt 7.1.1

145 St.meld. nr. 38 (2001-2002) pkt 7.1.1

146 IP/01/830 of 13 June 2001 (Commission objects to GFU joint gas sales in Norway) and IP/02/1084 dated 17 July 2002 (Commission successfully settles GFU case with Norwegian gas producers).

companies and the Norwegian Government, which intervened in favour of the gas producers, claimed that Art. 81 EC (now Art. 101 TFEU) should not be applied in view of the Commission's practice of closing cases as soon as the anti-competitive activities in question had been aborted, since the GFU scheme had been discontinued for sales to the EEA as of June 2001, following the issuance of a Royal Decree of 1 June 2001.[147] It was also argued that Art. 81 EC (now Art. 101 TFEU) could not be applied, since the Norwegian gas producers had been compelled by the Norwegian Government to sell gas through the GFU system it has established.[148]

It should be noted that the Commission attacked the system established by Norwegian authorities by making their case against the gas companies directly. In light of the historical account of the development of an integrated selling regime based on close co-operation between the licensees, the GFU, the FU and the authorities described above, it should be clear that the Norwegian authorities not only requested the gas producers to develop the GFU/FU scheme for resource management purposes but also took active part in the system as such. A weakness in the state compulsion defence, however, was the lack of *formal imposition* of the scheme by the Norwegian authorities.[149] The initial development of the scheme took place without any formal (binding) imposition being made by the authorities.[150] This was sufficient to ensure the estab-

[147] According to this Royal Decree the joint selling of gas through the GFU within the EEA was immediately suspended and the GFU dissolved altogether from 1st January 2002, cf. St.prp. nr. 1 (2001-2002) Budsjetterminen 2002, Del 5, Pkt 8 Nytt gassforvaltningssystem

[148] For a more detailed presentation of the particulars of the GFU case, albeit from a producer perspective, see Jan Peter Jebsen, The GFU Case, published in Industribygging og rettsutvikling – Juridisk festskrift i anledning Hydros 100-årsjubileum, pp. 131-144. The GFU case is also commented upon in EU Energy Law II pp. 127-131.

[149] Under the case law of the ECJ, a formal imposition by the government in one way or the other seems to be requested, cf. Whish p. 134 with reference to Aluminium Producers, OJ [1985] L 92/1. It is not sufficient to fall into line with what they consider the government expects of them, which might be said to have been the case in relation to the GFU.

[150] St.meld. nr. 46 (1986-87)

lishment of the GFU/FU scheme in close co-operation between the undertakings and the Ministry, due to the Norwegian authorities` tradition of informal management based on the threat of refusal to award licences in the "next round" if the undertakings did not comply with the authorities` wishes concerning the undertakings` conduct under the licences already awarded. A formal imposition was first made 14 years after GFU was established, with the passing of the Royal Decree of 28. December 2000.[151]

After a comprehensive oral hearing in December 2001, negotiations for an out-of-court settlement were instigated. For the purposes of the settlement negotiations, the gas producers were distinguished into three categories based on their active involvement in the GFU regime. While the permanent members of the GFU constituted a category of their own, the six companies (actually) selling gas through contracts negotiated by the GFU (i.e., ExxonMobil, Shell, TotalFinaElf, Conoco, Fortum and Agip) were placed in a second category. The last group was made up of all the other Norwegian gas producers, in respect of whom formal proceedings had been opened. The content and extent of the commitments made under the settlement agreement entered into between the Commission and the gas producers, differed between the three categories of gas producers. While commitments had to be made by the first two groups of gas producers as part of the out-of-court settlement[152], the case was closed under the assumption that gas would be sold individually in the future by the last group of producers.

Both the content and the extent of the written commitments also differed between the categories of gas producers, as the main commitments were made by Statoil and Norsk Hydro in their capacity as per-

151 This Royal Decree was passed in connection with Norsk Hydros acquisition of Saga Petroleum in 1999, as the acquisition reduced the members of the GFU from three to two, and basically states that the GFU scheme should continue with Statoil and Norsk Nydro as the only members, cf. e.g. St. meld. nr. 39 (1999-2000) Olje og Gassvirksomheten, Pkt 5 Gassvirksomheten/pkt 5.4 Det norske gassforvaltnings-systemet/pkt 5.4.1 Organisering av gassvirksomheten

152 IP/02/1084 dated 17 July 2002, published at http://europa.eu/rapid/pressReleasesAction.do?reference=IP/02/1084&format=HTML&aged=1&language=EN&guiLanguage=en.

manent members of the GFU.[153] Accordingly, the commitments made may be divided into two parts. Firstly, and common to both Statoil and Hydro, as permanent members of the GFU, and the gas producers, selling gas under contracts negotiated by the GFU, written commitments to discontinue all joint marketing and sales activities had to be given. According to the settlement agreement, joint marketing and sales of gas were prohibited, but only as far as this was not compatible with European competition law. This means that existing supply contracts have to be individually renegotiated when they come up for review. Secondly, and only affecting Statoil and Norsk Hydro, written commitments had to be given to reserve certain gas volumes for sale to new customers, i.e., customers who in the past had not bought gas from Norwegian gas producers.[154]

Although it was specified that this was not a part of the GFU case, Statoil and Norsk Hydro also confirmed in writing that they would not introduce territorial sales restrictions and/or use restrictions in their gas supply contracts. As both types of clause are considered to prevent the creation of a single market, they are considered incompatible with European competition law. Still, such clauses are considered necessary by certain market operators. Thus, the Commission made a point of emphasising that Statoil`s and Norsk Hydro`s position "demonstrates that gas can indeed be marketed in the Community without these anti-competitive clauses."

The GFU case may be seen as an attack on long-term gas sales agreements as such. As mentioned by way of introduction, despite access to transport infrastructure, competition cannot develop unless there is gas

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153 IP/02/1084 dated 17 July 2002, published at http://europa.eu/rapid/pressReleasesAction.do?reference=IP/02/1084&format=HTML&aged=1&language=EN&guiLanguage=en.

154 The commitments were limited both in volume and in time, as Statoil and Norsk Hydro, under the monitoring of external auditors, within a commitment period from June 2001 to September 2005 undertook to offer for sale 13 and 2,2 billion cubic meters (BMC) of gas respectively to new customers on commercially competitive terms.

free to be sold in the market.[155] The commitments made by Statoil and Norsk Hydro, to offer gas for sale to *new customers* over a period of approximately four years, clearly address the need for liquid markets. Both the Commissions approach and the commitments made to ensure the settlement of the case suggest that the aim of the case was broader than breaking up the sales cartel. Not only did the Commission attack the gas sales agreements entered into by gas producers from 1989 onwards, but it continued the proceedings even after the dissolution of the GFU, in breach with its own practice. In particular the commitments accepted by the Commission as part of the (out-of-court) settlement, substantiate that the GFU case must be seen in the context of the liberalisation efforts reflected in the Gas Directive and the Gas Transmission Regulation. The arguments put forward by the Commission in favour of the commitments accepted, to a great extent confirm this interpretation of the GFU case.[156] When accepting the commitments on the volumes for new customers, the Commission noted that a significant number of European customers (most prominently large industrial users, electricity producers and new trading houses) were known to have actively looked for alternative sources of supply in the past and continued to do so today. It was thus argued that these commitments would facilitate the establishment of new supply relationships. It was further underlined that such new supply relationships should also have a positive impact on the European market structure, which is still characterised by dominant suppliers in almost all markets. It was noted that most of these dominant suppliers were already customers of the Norwegian gas companies and had bought significant gas volumes under existing contracts, which still had many years to run and which, in general, contained price review clauses.

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155 This is not the official interpretation though, see EU Energy Law II p 159, where it is stated that the GFU case and the DONG/DUC case illustrate that the Commission was ready to let the past remain untouched (by *not* unravelling existing long-term gas contracts) for the possibility to develop gas-to-gas competition through the sales of some amount of gas to customers other than the traditional clients.

156 IP/02/1084 dated 17 July 2002, published at http://europa.eu/rapid/pressReleasesAction.do?reference=IP/02/1084&format=HTML&aged=1&language=EN&guiLanguage=en.

This interpretation is supported by the fact that the Commission applied a similar approach in the DONG/DUC case[157]. The investigation by the Commission's Competition Directorate General (DG Competition) of the joint marketing of North Sea gas by the parties to the Danish Underground Consortium (DUC) started in July 2001. DUC, which accounts for 90% of Danish gas production, is composed of Shell (46%), A.P. Møller (39%) and ChevronTexaco (15%). The investigation also concerned certain aspects of the supply relationship between DUC and DONG, as established in Gas Sales Agreements in 1979, 1990 and 1993 between DONG and each of the DUC partners. By means of these contracts the DUC partners sold DONG enough gas to satisfy the entire Danish demand and to supply additional volumes to Sweden and Germany.

The antitrust investigation involving the incumbent Danish gas supplier DONG and the country's main gas producers, Shell, A.P. Møller and ChevronTexaco, was settled after the latter committed themselves to market their production individually and to offer gas for sale to new customers over a five-year period.[158] The outcome of the GFU case was used to support the Commission's legal position as well as to supply a model for the out-of-court settlement reached in the DONG/DUC case.

As the Gas Supply Agreements had been notified to the Danish Competition Authority, the Commission (initially) focused its attention on the joint marketing arrangements and DUC's understanding that the scheme was covered by EU Regulation 2658/2000, which exempts certain forms of joint distribution (so-called Specialisation Block Exemption). DG Competition disagreed with the parties` assessment and, following the example of the Norwegian gas companies in the GFU case (IP/02/1084 of 17.7.2002), the DUC partners - whilst maintaining their legal position - agreed to cease their joint marketing arrangements and

[157] IP/03/566 of 24 April 2003 (Commission and Danish competition authorities jointly open up Danish gas market).

[158] The DUC parties agreed to offer in total seven billion cubic meters of gas for sale to new customers over a period of five years starting 1st January 2005 or earlier if possible -, i.e. when new gas volumes are available. On an annual basis this corresponds to approximately 1.4 BCM, i.e. 17% of the total production of the DUC parties.

to market their gas individually in future.

In summary, the Commission has thus far not accepted arguments put forward to justify joint selling or joint marketing schemes. As we have seen, the Commission did not place any emphasis whatsoever on the fact that the GFU regime was motivated by resource management considerations. Similarly, in the DONG/DUC case the Commission dismissed a defence based on block exemptions.

5.3 Joint Selling from a Single Field – Illustrated by the Britannia Case and the Corrib Case

5.3.1 Overview

In the same way as joint marketing and selling from several fields, joint selling from a single field is in principle prohibited under Art. 101(1) TFEU (previously Art. 81(1) EC). The general policy of the Commission is not to tolerate joint selling, unless compelling reasons are provided to justify it.[159] This has been the conclusion in both the *Britannia case* and the *Corrib case*[160]. However, these cases illustrate that joint selling from a single field might be justified in special circumstances. Based on the case material available, a distinction may be drawn between fields that are deemed commercial (part 5.3.2) and fields that are marginal (part 5.3.3).

5.3.2 Commercial Fields

The existing case material, i.e., the *Britannia case*[161] and the *Corrib case*[162], relates to fields deemed commercial. In accordance with the

[159] Cf. the statement made by then Commissioner Mario Monti in relation to the closure of the *Corrib case*, IP/01/578 of 20 April 2001 (Enterprise Oil, Statoil and Marathon to market Irish Corrib gas separately)

[160] IP/01/578 of 20 April 2001 (Enterprise Oil, Statoil and Marathon to market Irish Corrib gas separately)

[161] Case No IV/E-3/35.354 - Britannia gas condensate field (Notice pursuant to Article 19(3) of Regulation 17) OJ [1996] C291/10

[162] IP/01/578 of 20 April 2001 (Enterprise Oil, Statoil and Marathon to market Irish Corrib gas separately)

Commission's general policy not to tolerate joint selling unless compelling reasons are provided as a justification, these cases illustrate how an overall evaluation based on the specifics of each case is conducted. At the same time, these cases prove that, at least in relation to commercial fields, economic and financial considerations are generally not considered relevant as an objective justification and thus as grounds for an exemption under Art. 101(3) TFEU (previously Art. 81(3) EC).[163]

The Britannia case

The Britannia field is located centrally on the Continental Shelf of the United Kingdom ("UKCS"). At the time of notification, the field was owned by Amerada Hess Ltd, Chevron UK, Conoco (UK) Ltd, Conoco Petroleum Ltd, Phillips Petroleum Company United Kingdom Ltd, Texaco North Sea UK Company, Santa Fe Exploration (UK) Ltd and Union Texas Britannia Ltd.

The gas reserves of the Britannia field itself were considerable.[164] Thus, the field owners could choose between selling the gas to purchasers located in either the UK market or on the European Continent. After having explored the prospects in each market, the decision was made to establish the necessary infrastructure to land the gas on the Scottish coast and to facilitate the selling of the gas in the UK market. The gas volumes were sold in the market for forward gas, i.e., the market for future deliveries of natural gas from producers to the wholesale level.

The field owners had entered into an agreement for joint marketing and selling.[165] According to this agreement, the field owners were to designate one of the owners to negotiate sales agreements with potential purchasers on behalf of the production joint venture as such. Each field owner still had the right to participate in the negotiations. The

163 This substantiates the findings in the GFU and DONG/DUC cases.

164 The reserves was estimated to 2,3 billion Sm3, which at peak production (in the period between 1998-2004) would mean a daily production of 740 million Sm3 or an annual production of 7,4 billion Sm3.

165 This agreement was in force between 1992 and 1994. Based on this agreement, joint sales agreements between the field owners and purchasers were entered into between July 1994 and December 1994.

negotiator`s authority was limited, as it could not act to bind the other field owners legally.[166] Based on the concerted negotiations, each field owner entered into separate gas sales agreements with the purchasers in accordance with its participating interest in the field. The field-owners` motivation for establishing the joint marketing scheme was not explicitly specified (in the notification published by the Commission). Based on the facts of the case, however, the main reasoning behind the scheme seems to have been to strengthen the bargaining power of the gas companies in general and to facilitate the investments necessary to develop the field through generating as high an income as possible.

The joint marketing and selling scheme was notified to the Commission. The field owners applied for an exemption under (then) Art. 85(3) EC (later Art. 81(3) EC, now Art. 101(3) TFEU) as well as a negative clearance in accordance to Art. 2 of Regulation 17/62. Although a negative clearance was granted, the Commission clearly had a negative attitude to the joint marketing and selling scheme as such. After having examined possible competition concerns, however, the Commission accepted the agreement. The Commission found that the agreement between the field owners was not in breach of (then) Art. 85(1) EC (later Art. 81(1) EC, now Art. 101(1) TFEU) as it was considered *not to have an appreciable effect* on the trade between Member States.

The effect of the agreement was evaluated on the basis of both its duration and the market conditions during the period when the agreement was in effect. Of vital importance in this respect was the Commission`s conclusion that the UK and the European Continental markets constituted separate markets due to the lack of transportation means between them.[167] The Commission noted that there was no Continental competitor present in the UK forward sales market. Similarly,

[166] Each field owner had the right to be informed and to give instructions during the negotiations. Each field owner could veto the gas sales agreements negotiated. Each field owner could also withdraw from the joint sales regime and offer its share of the gas individually on the market in competition with the other gas owners.

[167] The pipeline to Ireland was explicitly disregarded. It was pointed out that in addition to the limited capacity of this pipeline, it was only meant to ensure security of supply in cases of production disruptions in the Irish market.

it noted that gas from the Britannia field could not have been forwarded to the European market via the UK market due to the lack of infrastructure and uncertainty concerning future infrastructure. This line of reasoning might be considered questionable, as the UK Interconnector, linking the UK with the Continent, was being planned at the time. In any event, as this interconnector now is in place, and given today's liberalised market, one can hardly expect a similar reasoning, or similar result, today.[168] This is, to a great extent, confirmed by the Commission´s line of argument in the *Corrib case*.

The Corrib case

The Corrib gas field is located off the west coast of Ireland[169] and is owned by three oil and gas companies Enterprise Energy Ireland Limited, Norway's Statoil and US-based Marathon. The field was declared to be commercial. However, the field owners applied for an exemption under Art. 81(3) EC (now Art. 101(3) TFEU) to market gas produced from the Corrib field *jointly* for the *first five years* of production. It was argued that joint marketing would be *necessary to counterbalance* the purchasing power of the incumbent Irish energy companies.[170]

Whilst recognising the strong market position of the purchasers, the Commission raised competition concerns. In particular, it questioned *whether joint marketing* would bring about such *economic benefits* as were required under Community competition law. In this regard, the Commission took into account the fact that an increasing number of gas consumers would become "eligible", i.e., free to choose between suppliers, due to the ongoing liberalisation process. At the time, only power generators and energy-intensive industrial consumers were con-

168 Reference is here made to the account of relevant gas markets in part 4.3.

169 The Corrib gas field is of particular importance as it will be the only indigenous gas field of Ireland following the depletion of the existing gas field at Kinsale in the coming years.

170 These are Bord Gais Eirean (BGE), the state owned-gas company, and Electricity Supply Board (ESB), the state owned electricity company using large quantities of gas for electricity production.

sidered eligible in the Irish market. However, the Commission noted that the Irish customer-based power market was particularly likely to continue its rapid growth and thus offer *potential* sales outlets for gas suppliers. In other words, the ongoing liberalisation process was crucial to the result. One might say that the Commission, in its evaluation, placed emphasis on the need for a liquid market in order to support the ongoing liberalisation process. In doing so, the Commission based its decision on long-term considerations. Under the Gas Directive[171], Ireland was under the formal obligation to fully liberalise its gas market by 1 July 2007.

Because of the objections raised by the Commission, the field owners in the end withdrew their application for an exemption in respect of their joint marketing of the Corrib gas. As they had refrained from actually implementing the joint marketing arrangements, the Commission closed its investigation in the wake of their withdrawal.

5.3.3 Marginal Fields

Although the Commission has clearly stated that joint selling is prohibited under Art. 101(1) TFEU (previously Art. 81(1) EC), it has implicitly accepted the necessity of joint sales under certain conditions. It is expressly stated that compelling reasons for justification need to be provided. However, it is uncertain what circumstances (in the Commission's view) will qualify.

In this context, (so-called) marginal fields deserve particular attention. As the NCS is relatively mature, many of the new fields being located are so-called marginal fields. The development of all petroleum reserves depends upon the cost of development and production in relation to the price available for the produced petroleum in the sales market. However, the term "marginal fields" is used to describe fields

[171] At the time the *Corrib case* was decided, Directive 98/30/EC of the European Parliament and of the Council of 22 June 1998 concerning common rules for the internal market in natural gas, OJ L 204, 21.7.1998, pp. 1–12, applied. It has later been repealed by Directive 2003/55/EC, which then was repealed by Directive 3009/73/EC respectively.

where the cost/benefit ratio of development is marginal and the return on investments is thus particularly vulnerable to price fluctuations. In other words, the cost profile of these fields is such that oil companies will not make the necessary investments unless they have a guarantee that the gas produced will be sold and, furthermore, sold at a price that justifies the development. Furthermore, as the reserves on these fields are (often) relatively modest, a stable and continuous withdrawal of gas is necessary to maintain efficient operation. The lack of flexibility in production from marginal fields implies that each licensee`s individual portfolio considerations cannot be taken into consideration when selling the gas produced. Thus, the development of such fields may depend on the joint marketing and selling of the field's gas reserves.

Although it is clear that the Britannia gas field was deemed commercial, the particulars of the *Britannia case*[172] are of special interest for identifying compelling reasons to justify joint marketing and selling, in general and in relation to marginal fields in particular. Two lines of reasoning may be identified.

One possible approach is the "appreciable effect on trade" defence under Art. 101(1) TFEU (previously Art. 81(1) EC).[173] As mentioned above, negative clearance was granted by the Commission in the *Britannia case*, as no appreciable effect on trade could be established.[174] Whether a particular agreement will be considered to have an appreciable effect on trade depend on an overall evaluation based on the specifics of the case in question.[175] Under the de minimis doctrine, the Commission has established market share thresholds to determine what is not to be considered an appreciable restriction of competition under Art. 101 TFEU (previously Art. 81 EC).[176] However, this negative definition of

[172] Case No IV/E-3/35.354 - Britannia gas condensate field (Notice pursuant to Article 19(3) of Regulation 17), OJ [1996] C291/10

[173] For a presentation of the appreciable effect on trade criterion, see, e.g., Faull & Nikpay (2007) p. 227 et seq and p. 250 et seq

[174] Case No IV/E-3/35.354 – Britannia gas condensate field (Notice pursuant to Article 19(3) of Regulation 17), OJ [1996] C291/10, part [6]

[175] For further details, see, e.g., Faull & Nikpay (2007) p. 227 et seq and p. 250 et seq

[176] Faull & Nikpay (2007) pp. 250-251

appreciability does not imply that agreements between undertakings which exceed the thresholds will appreciably restrict competition.[177] In other words, the concept of appreciability and the concept of market power are not synonymous.[178] In the *Britannia case*, the lack of both an actual and (because of uncertainties concerning the construction of) potential (future) transport infrastructure prohibiting both the potential establishment of a Continental competitor in the British market and the sale of Britannia gas on the Continental market, was crucial when determining that the agreement had no appreciable effect on the trade between Member States.[179] As the gas markets gradually become more integrated, it could be argued that lack of transport infrastructure could be expected to be a less effective argument in today's market. In relation to marginal fields in particular, however, it could be asked whether the gas volumes in question (i.e., limited gas volumes) might be relevant in the evaluation of appreciability.

The second possible approach is the "necessary to develop" defence under Art. 101(3) TFEU (previously Art. 81(3) EC). While the particulars of, and the reasoning in, the *Corrib case* make it clear that joint selling in order to establish an equal bargaining position between sellers and buyers of gas is not considered a compelling reason for justification, the Commission's reasoning in the *Britannia case* still allowed for joint selling in order to ensure the development and utilisation of the located reserves. The *Britannia case* dealt with the market for the supply of natural gas from producers to buyers at the wholesale level (so-called forward gas). In this particular market the producers compete to sell their *potential production* to buyers, i.e., the development of production at a field and the sale of the produced gas for delivery at a time in the future.[180] Although it was not explicitly stated in the Commission`s communication in the *Britannia case*, it seems that (based on the context of

177 Faull & Nikpay (2007) p. 251

178 Faull & Nikpay (2007) p. 251

179 Case No IV/E-3/35.354 – Britannia gas condensate field (Notice pursuant to Article 19(3) of Regulation 17), OJ [1996] C291/10, part [6]

180 Case No IV/E-3/35.354 – Britannia gas condensate field (Notice pursuant to Article 19(3) of Regulation 17), OJ [1996] C291/10, part [5]

the case) that an underlying argument on the part of the field owners was that joint selling from the field was necessary for the development of the field. It is clear that the Commission in the *Britannia case* found that the objective (i.e., the development of the field as such) could be achieved in other ways than joint selling, although in what way was not explicitly stated. This follows from the fact that the Commission pointed out that each licensee could withdraw from the joint marketing and selling scheme at will and that the sales contracts, although jointly negotiated, were entered into by the field owners individually.[181] Although not accepting this line of defence in the *Britannia case* as such, the Commission did not rule out this line of argumentation as irrelevant.

Even though a "necessary to develop" defence seems relevant, the mere existence of a marginal field as such is not, in itself, sufficient. Apart from substantiating that joint selling is necessary based on the specifics of the case, the criteria in Art. 101(3) TFEU (previously Art. 81(3) EC) must be fulfilled. According to Art. 101(3) TFEU (previously Art. 81(3) EC) the agreement must contribute to improving the production or distribution of goods or contribute to promoting technical and economic progress. Furthermore, consumers must receive a fair share of the resulting benefits. The evaluation of these criteria, which are particularly important, is illustrated by the *Corrib case*. In relation to the *Corrib case*, the Commission focused particularly on whether joint marketing would bring about economic benefits as required under Community competition law. The conclusion was negative. When it can be determined that joint selling is decisive for the development of a marginal field, it could be argued that economic benefits will necessarily be a direct result of the agreement on joint selling. Still, as the consumers are required to benefit from the development as well, it has to be considered whether, and in what way, this could be said to be the case. If the joint selling based on the specifics of the case can still be said to result in economic benefits of which the consumers receive a fair share, there is an additional criteria that the restrictions must be indispensable

181 Case No IV/E-3/35.354 – Britannia gas condensate field (Notice pursuant to Article 19(3) of Regulation 17), OJ [1996] C291/10, part [4]

to the attainment of these objectives. In other words, proportionality considerations will be important under such a line of defence. And last, but not least, the agreement must not afford the parties the possibility of eliminating competition in respect of a substantial part of the products in question.[182]

5.4 Indirect Joint Selling: A Producer`s Buying of Forward Gas from Other Producers

5.4.1 Overview

As mentioned above, an undertaking's buying of gas from its competitors might raise competition concerns. This is because this situation resembles joint sales, as the gas volumes will ultimately be offered to the market through the same sales channel and at a single price. The buying of gas by one or more producers from other producers is not an uncommon feature of the activities taking place on the NCS. Although the effect of a producer's buying of another producer`s gas volumes is ultimately the same, the reasons for such buying may differ. In the following, various typical situations where producers buy gas from other producers on the NCS will be discussed separately. Firstly, concerted buying for production purposes will be considered (in part 5.4.2). Next, joint buying for resale purposes needs to be addressed (in part 5.4.3). As far as I have been able to determine, neither the ECJ, nor the CFI nor the Commission have dealt with this question in their case law. Thus, these situations must be assessed on the basis of the wording and the objectives of European competition law and considered in the light of the Commission's view on joint selling (as described in part 5.2 and part 5.3 above).

5.4.2 Concerted Buying for Production Purposes

It is not uncommon for an operator of a single field to buy natural gas, on behalf of the licensees, for injection purposes. While the term "con-

[182] Here, again, the gas volumes in question might come into play.

certed practices" applies, as several producers are buying the gas jointly, the term "production purposes" applies, as the injection gas is used to increase the pressure in, and thus optimise production from, the well.

The purpose of such buying is to ensure an optimal production profile. Even though the objective is not to restrict competition, the buying may have a restrictive effect. It is somewhat uncertain whether such a practice is likely to be deemed in breach of Art. 101(1) TFEU (previously Art. 81(1) EC).[183] One question is whether such sales can be said to have an appreciable effect as the volumes are relatively modest and are not likely to affect the market price. In any event, it is to be expected that these conditions may be of relevance to a possible exemption under Art. 101(3) TFEU (previously Art. 81(3) EC).

5.4.3 Single Buying for Resale Purposes

Overview

The buying of forward gas typically takes place in two different situations. As mentioned above, in relation to the definition of relevant gas markets, the term forward gas is used in relation to the future delivery of gas from producers to the wholesale level (cf. the *Britannia case*[184]). Firstly, gas volumes might be bought in order to fulfil obligations under existing gas sales agreements entered into by a producer. Secondly, such buying might take place in relation to later forward sales.

Buying in order to fulfil the producer's own delivery obligations

The fulfilment of the delivery obligations of the producers' active on the NCS is partly based on the buying up of forward gas in the upstream market. Under a system of portfolio sales, the gas undertakings enter into contractual obligations based on the estimated production from

[183] Similarly, see Boge p. 40, although this question is here discussed as a question of field based gas sales.

[184] Case IV/E-3/35.354 – The Britannia Gas Condensate Field - Notice pursuant to Art 19(3) in Regulation 17, OJ [1996] C291/10

each licence at a given time in the future. These estimates may not be achieved, either because of stops in production due to maintenance or other situations that could not have been foreseen. Thus, in order to avoid being in breach of the gas sales agreements entered into, the buying of external gas might prove necessary to fulfil delivery obligations under existing contracts.

It is clear that the *objective* of single buying in these cases is not to restrict competition as prohibited under Art. 101(1) TFEU (previously Art. 81(1) EC). The question remains, however, whether such purchases may still have a restrictive *effect* on competition and thus be in breach of Art. 101(1) TFEU (previously Art. 81(1) EC). In this respect, a crucial factor would seem to be whether the gas volumes are purchased at market price. If so, the cost profile of the producers` gas portfolios will continue to differ, thus allowing for competition on price between the gas producers. In other words, provided the price risk is located with the buyer of the gas volumes, *ad hoc solutions* could be expected to be accepted under European competition law. However, more fixed delivery solutions between certain producers will need to be evaluated further taking into account the specific market conditions.

Buying for later forward sales

These situations are characterised by the fact that the gas volumes are not bought to fulfil existing contractual obligations, but in order to be resold in the product markets upstream or downstream at a later point in time. In other words, such buying may more easily be said to have the objective or effect of restricting or distorting competition, cf. Art. 101(1) TFEU (previously Art. 81(1) EC). That having been said, buying for later forward sales may be considered justified under certain conditions. The main question is whether the sellers have sufficient market power to influence gas prices in the market.

Buying for later forward sales is of particular interest in relation to associated fields, i.e., fields with both oil and gas. As production of associated gas depends on the oil production, it is normally not possible to achieve a commercial production profile for associated gas volumes alone. This implies that production from associated fields depends on the existence of larger fields that "swings" their production in line with the production of the associated fields. The bargaining position of sellers of associated gas is normally quite weak. The sellers have to get rid of the gas volumes in question, but the burning of the gas volumes – as an alternative to the sale of the gas – requires a special permit. Consequently, it has been argued that the sale of associated gas through a joint sales channel is not likely to affect the market.[185]

Buying for later forward sales is not limited to the situation of associated fields. Purchasers may be interested in larger volumes than a producer can provide based on its production portfolio. It seems to be expected that such volume issues can, and will, be resolved by the aggregation of gas, either within the group of producing companies or through selling to a bigger producer.[186] The sales organisation of the first seller may be of importance when evaluating the competitive constraints of a producer's buying of gas volumes for later forward sales. To the extent that the producer (initially) selling the gas volumes lacks a sales organisation, it might be said that it was not likely to compete in the market anyway. This argument may apply to the situation on the NCS.

Traditionally, the gas undertakings granted licences on the NCS have typically been major companies, with experience from production of oil and gas globally and with great financial strength. While this is still the case, the number of smaller gas undertakings participating in a few licences and, thus, with rather restricted gas portfolios, has increased over the last couple of years. Depending on the degree of maturity of the different areas, there is some variation in the types of challenges faced in realising the commercial potential of (the undiscovered) resources of the NCS.[187] This is reflected in the awarding of licences by the Norwegian authorities. While only undertakings with broad-based experience, technical and geological expertise and strong finances are

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185 Boge p. 40

186 EU Energy Law II p. 158

187 Facts 2010 chapter 4

considered capable of exploring for, and developing, resources in frontier areas, smaller undertakings are increasingly granted licences in more mature areas with well-known geology and well-developed and/or planned infrastructure. Consequently, the organisation and the professionalism of these different categories of gas undertakings is bound to differ.

The limited gas portfolios of some of the smaller undertakings active on the NCS may be a factual barrier to trade for these companies. On the NCS, the location of the field and the infrastructure developed in the area where the field is located may be decisive for the undertaking`s market prospects. If the pressure in the field is insufficient, the gas undertaking may not be able to fulfil the technical requirements for the use of the network infrastructure (the "ability to use" requirements). Norwegian gas is either sold to the UK or to the Continent, and gas prices in the two markets differ. While the margins in one market may not commercially justify the production and/or lifting of gas for one producer, the composition of another gas producer`s gas portfolio, and thus possibilities for gas swapping, may allow that other producer to sell the gas volumes in question.

Still, as with the case of buying in order to fulfil existing delivery obligations, the location of the price risk may be of importance. The question to be assessed is whether the competition constraints will vary depending on whether the purchase price is dependent on, or independent of, the forward gas sales price.

5.5 Summary

Based on the above analysis, it can be concluded that, as a general rule, joint selling, as well as practices with similar effects to joint selling (i.e., joint buying), are prohibited under European competition law. However, as has been shown above, exemptions may be granted in situations of practical importance for activity on the NCS.

6 Joint Production

6.1 Introduction

As mentioned above (in part 2), the licensees are, according to the PPL, obliged to enter into JOAs. These JOAs cover all aspects of the production process until petroleum resources have been produced. While the licensees co-operate concerning the production process, they compete in the gas sales markets (upstream and downstream). As such, the JOA features the characteristics of a production joint venture between competitors.

Co-operation between two or more firms actually or potentially operating at the same level in the market, i.e., firms which can or do produce or distribute identical or substitutable goods or services, raises competition concerns due to the possibilities for horizontal restrictions.[188] However, a distinction is drawn between full-function joint ventures, where the parties agree to co-operate on every aspect of the business, and production joint ventures, where the parties agree to co-operate only with respect to production or services. While full-function joint ventures are considered under the EC Merger Regulation, production joint ventures are considered under Art. 101 TFEU (previously Art. 81 EC).

Although problematic under competition law, production joint ventures are generally looked upon favourably in the petroleum sector. This is reflected by the fact that the Hydrocarbon Licensing Directive[189] allows for the establishment of production joint ventures in the petroleum sector. Provided the principle of non-discrimination, and the procedures established to ensure respect for this principle, have been followed, the Hydrocarbon Licensing Directive allows each Member

188 EU Energy Law II p. 113

189 Directive 94/22/EC of the European Parliament and of the Council of 30 May 1994 on the conditions for granting and using authorizations for the prospection, exploration and production of hydrocarbons, OJ [1994] L 164/3

State freely to decide whether a (production) licence should be granted to a single entity or a group of entities.[190] This follows from Art. 1 no. 2 read in correlation with Art. 5 no. 1(3) of the Hydrocarbon Licensing Directive.

However, both the design and the implementation of the collaboration between several producers have to take place within the framework of Community competition law in each individual case. Production agreements seldom have the object of restricting competition[191], but they may still have the *effect* of restraining competition.[192] Although the case law of the Community Courts dealing specifically with the application of Art. 101 TFEU (previously Art. 81 EC) to horizontal co-operation agreements is limited[193], the Commission has issued Guidelines on Horizontal Cooperation Agreements, which are general in scope, stating its position in relation to such agreements and establishing an analytical framework for the most common types of such agreements.[194] According to these guidelines, Art. 81 EC (now Art. 101 TFEU) only applies to production agreements that are instrumental in restricting output in the market or which serve the purpose of fixing prices or partitioning markets.[195] Furthermore, the Specialisation block exemption Regulation[196] provides a safe harbour for production co-operations

190 Boge p. 15, with further reference to Finn Arnesen, Statlig styring og EØS-rettslige skranker. Illustrert ved en studie i EØS-rettens betydning for norsk petroleumsvirksomhet («Arnesen»), p. 156.

191 See part 6.2 below

192 EU Energy Law II p. 144. Similarly Boge p. 20, with further references to Richard Whish, Competition Law (Fourth Edition), p. 498.

193 Whish p. 573

194 Guidelines on Horizontal Cooperation Agreements, OJ [2001] C 3/2

195 Commission Notice - Guidelines on the applicability of Article 81 to horizontal co-operation agreements. Official Journal C 3 of 06.01.2001, p. 2. EU Energy Law II p. 144

196 Commission Regulation (EC) No 2658/2000 of 29 November 2000 on the application of Article 81(3) of the Treaty to categories of specialisation agreements, OJ [2000] L 304

between competitors.[197] These safe harbour clauses are also considered to apply to collaborations relating to natural resources such as petroleum and natural gas.[198] It is hard to believe that the safe harbour is of significance for the activities on the NCS, however, mainly due to the market share thresholds[199] but also the prohibition against hard core restrictions[200]. Production co-operation arrangements that do not benefit from the safe harbour clauses have to be examined to determine whether they are compatible with Community competition law.[201]

The following focuses on the licensing system as such and the ques-

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197 In order to benefit from the safe harbour of the Specialisation block exemption Regulation, two cumulative conditions have to be met. The first condition is that the combined share of the parties to the agreement does not exceed 20% in the market directly concerned by the co-operation. According to the Regulation, the market share is to be calculated on the basis of the value of the products sold the previous year. Furthermore, and of great importance, the sales of all companies belonging to the same group to each of the collaborating firms have to be included in the calculation. If, after a certain time, the market share exceeds the threshold of 20% but remains below 25%, the exemption continues to apply for two years. However, when the 25% threshold is exceeded, the exemption applies for only one year. The second condition is that the agreement must not contain any of the three hardcore restrictions, i.e. price fixing, output limitation or allocation of markets or customers (so-called black clauses). Provided that the conditions are met, an agreement providing for unilateral or reciprocal specialization in the area of production or joint production is presumed to be valid and fully compatible with Article 81(1) EC (now Article 101(1) TFEU).

198 EU Energy Law II p. 147

199 Without having certain numbers on the market shares of the different companies active on the NCS, there are indications that the (main) gas undertakings conducting their business on the NCS might have market shares above 20%. In the GFU case, for instance, the Commission based its reasoning on the fact that Norwegian gas in 1998 was 36% of the consumption in Belgium, 28% in France, 25% in Germany, 18% in Spain, 13% in the Netherlands as well as minor market shares in Austria and United Kingdom. As mentioned previously, the sales of all companies belonging to the same group of each collaborating firms have to be included in the calculation of the market share. As these numbers apply to the sale of Norwegian gas only, and the gas undertakings are active in production outside NCS as well, the market share thresholds may easily be exceeded (by some, if not all, of the gas undertakings in question).

200 The JOA and the lifting agreement together contain rules on sales, investment and production.

201 EU Energy Law II p. 147. For a presentation of relevant actors when assessing the question of whether participants are likely to gain, maintain or increase market power through co-operation in the energy sector, see, e.g., EU Energy Law II pp. 148-154.

tion of whether this may give rise to competition problems.[202] As already mentioned (in part 2), the undertakings conducting activities on the NCS are obliged to enter into production joint ventures under the licences granted by Norwegian authorities. Furthermore, the Norwegian authorities determine the output levels of each joint venture in order to maximise the longevity of the fields and ensure long-term revenues for Norwegian society. In other words, one might argue that the doctrine of state compulsion will apply in these cases.[203] However, there are uncertainties regarding the scope of the state compulsion doctrine.[204] In particular, there is a debate over whether, and to what extent, an undertaking is obliged to withstand an obligation imposed on it by the state that is in breach with the community competition rules.[205] Against this background, a further analysis of the situation seems to be justified.

It should be noted, however, that case law directly dealing with this question is limited.[206] Neither the ECJ nor the Commission has explicitly evaluated joint production in relation to Art. 81(1) EC (now Art. 101(1)

[202] For an in depth analysis, see, e.g., Christopher W. Jones (editor), EU Energy Law – Volume II EU Competition Law and Energy Markets. See also Olav Boge, Gassproduksjon og konkurranserett. En vurdering av produksjonssamarbeidet på norsk sokkel i forhold til EØS artikkel 53. MarIus 303. For a more general presentation on the rules on production co-operation in general, see Norsk Konkurranserett I Chapter 35.

[203] See e.g. Boge p. 60 et seq, who concludes that the fact that both the fact that gas undertakings enter into production joint ventures and the content of the JOA fall outside the scope of Art 53(1) EEA due to the state compulsion doctrine, but raises the question of whether the same can be said as regards to the lifting agreement entered into in accordance with the JOA.

[204] The case load concerning this doctrine is rather limited. The doctrine was established in the following cases, cases C-359 & 379/95 P Commission and France vs. Ladbrooke Racing and case T-387/94 Asia Motor France vs. Commission. According to these cases three conditions have to be met. First, the authorities have to make a particular practice comprehensive. Second, a legal basis has to be found for the practice the undertaking considers itself bound to exercise. Third, the undertaking(s) in question must have no choice as regards the implementation of the behaviour.

[205] See e.g. Boge p. 61

[206] COMP/37.732 - Synergen (IP/02/792 of 31 May 2002), dealt with the question of joint venture agreements on gas fired power plants. The Synergen venture between ESB, Ireland's dominant electricity company. and Statoil, the Norwegian gas company, was cleared only following strict commitments. However, this case is of no direct relevance in the context of this article.

TFEU).[207] However, in connection with the *Britannia case*, the Commission specifically addressed the scope of the co-operation agreement between the licensees of the field, without raising competition concerns.[208] The validity of the JOA entered into by the licensees of the Britannia gas condensate field under Community competition law was not, however, the question addressed in the *Britannia case*. The lack of a critique on the part of the Commission in this particular case does not necessarily imply, however, that the Commission does not consider that such agreements may not give rise to competition concerns in the petroleum sector.

The following presentation is divided into three parts. Firstly, there is a presentation of the reasons for joint production (in part 6.2). Secondly, there is an account of the competition concerns that arise in relation to joint production (in part 6.3), and thirdly, joint production on the NCS is evaluated (in part 6.4).

6.2 The Rationale behind Joint Production in the Gas Sector

The use of JOAs is not particular to the NCS. Production joint ventures can be said to be the norm in the petroleum sector[209] and their objective is not to restrict competition, but to spread risk.

One might argue that, in the petroleum sector, joint operations are necessary for management purposes. If this line of argument is followed, a distinction might have to be drawn between mature areas and frontier areas. As mentioned above, the demands with regard to the licensees´ technical experience, as well as their financial strength, are particularly high when licences are being allocated for exploration and

[207] However, the presentation of this issue in EU Energy Law II Part 3, Chapter 2, point 5, might be said to reflect the Commission's view on the matter.

[208] Case IV/E-3/35.354 – Britannia Gas Condensate Field (Notice pursuant to Art 19(3) in Regulation 17), OJ [1996] C291/10, part 3

[209] EU Energy Law II p. 142, where it is stated that «[c]ollaboration in the area of production can probably be said to be a wide-spread feature in the energy industry. Indeed, joint production of power, gas or petroleum products by competing suppliers are perhaps among the, if not the most, frequent category of co-operation to be found in the energy industry. »

development in respect of petroleum resources in frontier areas. The combined expertise of several undertakings may be needed to ensure efficient field development. As all areas have been considered frontier areas at some point, this argument may explain the existence of joint operations in existing fields on the NCS. Such considerations concerning efficiency could be said to have been accepted, to some extent, by the Community legislator.[210]

That the main reason for the joint production of petroleum is economic, is reflected in the fact that joint operation is the rule even when new licences are granted in areas now considered mature. Although the major gas companies have the financial strength to undertake the investments (in infrastructure for both production and transport) necessary to develop the petroleum resources in a single reservoir, they are reluctant to take on the risk of single-handedly making such an investment. The producers are not willing to "put all their eggs in one basket", so to speak, but choose to participate in several licences in order to spread their risk and to fulfil the (particularly) high revenue demands (which these undertakings operate with). If the gas undertakings were not allowed to co-operate, they could not necessarily be expected to be willing to undertake the necessary investments and operations on their own. Risk sharing seems to be acknowledged as a relevant factor when balancing negative and positive effects on competition.[211]

6.3 Joint Production and Competition Concerns

The use of JOAs is not particular to the NCS. Production joint ventures

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210 EU Energy Law II p. 143, where it is stated that production agreements «also generate efficiencies, e.g. in the form of economies of scale or scope or better production technologies.»

211 EU Energy Law II p. 143, where it is stated that «[r]isk sharing as practiced in production co-operations of the gas sector may also be an economic benefit to be taken into account.»

can be said to be the norm in the petroleum sector.[212] Still, the production joint ventures may have restrictive effects in the market.

Normally, producers of goods or service providers may compete both on quality and price. As already mentioned, the gas sales market differs somewhat, since the quality of the gas offered in the market is standardised in the gas sales agreements (gas sales quality) and is more-or-less the same for all customers. While both quality issues[213] and security of supply considerations may affect the choice between competing producers located in different producer regions (i.e., Norway, Russia and Algeria), the producers located on the NCS are basically left to compete between themselves on the basis of price alone.

At the same time, the scope for price competition between the parties to a production agreement may be constrained due to commonality of costs.[214] Production joint ventures are characterised by the fact that the producers working together necessarily share a common cost profile (a commonality of costs).[215] Under the JOAs, the field owners' influence on production and the production process is rather limited. The role of the field owners (i.e., licensees) is really that of distributors. This results in a standardisation of both costs and products.

In general, a substantial degree of commonality of costs is likely to be the result where two conditions are in place.[216] A first prerequisite is that production must account for a high proportion of the total costs of

[212] EU Energy Law II p. 142, where it is stated that «[c]ollaboration in the area of production can probably be said to be a wide-spread feature in the energy industry. Indeed, joint production of power, gas or petroleum products by competing suppliers are perhaps among the, if not the most, frequent category of co-operation to be found in the energy industry. »

[213] See, e.g., Norsk Hydro/Saga, referred to above, where different quality on gas from i.e. Norway, Russia and Algeria was mentioned as one of the factors that could limit the market definition.

[214] EU Energy Law II p. 145

[215] EU Energy Law II p. 145

[216] EU Energy Law II p. 145

the energy product.[217] The next is that the providers must combine their production activities to a significant extent.[218] These conditions clearly exist in relation to the joint production taking place on the NCS.

It should be noted that the system of CBS as a starting point allows for competition between producers participating in the same licence group. However, due to the problem of commonality of costs, the competition between products produced under the same licence is in reality rather marginal. Where competition between the producers active on the NCS still exists, this is because, under a portfolio-based sales regime, it is not the cost profile of one JOA, but of the portfolio of JOAs that the producers have licences to, that determines the cost profile of a particular producer and thus the margins on which the producer may compete in the gas sales market. Thus, the introduction of portfolio-based sales might be said to reduce the problem of commonality of costs, allowing the producers to compete on price. Still, the introduction of portfolio CBS cannot be said to solve all concerns relating to co-operation agreements between the gas undertakings.

The JOAs and/or associated agreements might be found to be designed in a way that reduces the parties´ freedom to act more extensively than is necessary to achieve the joint production. The JOA necessarily covers both technical and commercial aspects. This fact was highlighted in the *Britannia case*, where the Commission stated, when commenting upon the scope of the co-operation agreement between the licensees in the Britannia gas condensate field, that the licensees had jointly made both technical and commercial decisions.[219] The licensees' choices regarding the infrastructure to be used for the development of the field and their decisions on the size of the well, its location, pipe size etc., were referred to as technical choices. However, the management

217 According to the Commission production accounts for a high percentage of the total costs when production costs is i.e. 50% or 65-70% of the total costs for the final goods, se Guidelines on Horizontal Co-operation paragraphs 112,113, Appendix 3 and paragraphs 107, 108, Appendix 3.

218 EU Energy Law II p. 145

219 Case IV/E-3/35.354 – Britannia Gas Condensate Field (Notice pursuant to Art 19(3) in Regulation 17), OJ [1996] C291/10, part 3

committee's decision on issues such as the day of start-up (of production), the field's plateau period, and swing production, as well as decisions on periods for production stops and maintenance schemes, were all considered to be of a commercial nature. The JOA and its associated agreements (i.e., the lifting agreement) both contained provisions that restricted the licensees´ freedom in relation to sales, investments and/or production.

The price of goods or services can be manipulated, either indirectly (by restricting output) or directly (by raising prices). According to Art. 101(1)(b) TFEU (previously Art. 81(1)(b) EC), restrictions on production are particularly problematic. In relation to production co-operations in the energy sector in general, it has been argued that "[i]t is important for collaborators that their decisions regarding output levels necessary for the functioning of the production co-operation do not constitute a hardcore restriction of EC competition law."[220] In the gas sector, however, the production level is primarily predetermined by reservoir conditions. Furthermore, as mentioned above (in part 2), according to the PA Section 4-4, the Ministry ultimately stipulates the production level under each licence. Still, the question remains whether production joint ventures on the NCS restrict production – either indirectly or directly – in a way that is in breach of Art. 101 TFEU (previously Art. 81 EC).

A particular feature of the NCS is that, in order to spread risk, single undertakings are applying for licences in several fields and thus entering into JOAs if a licence is granted. In other words, the gas undertakings active on the NCS participate in numerous JOAs. The number of companies competing is rather limited from the start. This is even more the case because of a market structure where the producers are closely connected through cross-ownership. Even though each production joint venture as such might not be considered appreciably to prevent or restrict competition in the gas sales market, the structure of joint ventures across the NCS might have such an effect.

[220] EU Energy Law II p. 144

6.4 Evaluation of Joint Production on the NCS

6.4.1 Overview

Following the introduction of CBS, the main question is whether the JOA and its associated agreements may directly and/or indirectly result in a restriction on production levels. The JOA, which is a standard agreement, contains provisions on each licensee's freedom as to sales, investments and production under the licence in question. As regards the prohibition in Art. 101(1) TFEU (previously Art. 81(1) EC), agreements that limit or control production, markets, technical development or investment are listed in Art. 101(1)(b) TFEU (previously Art. 81(1)(b) EC) as particularly problematic. As mentioned previously, output may be limited in order to raise the prices of goods or services in question and all factors listed in Art. 101(1)(b) TFEU (previously Art. 81(1)(b) EC) influence the production level, directly or indirectly. Investments made by the parties to the production joint venture are decisive for the gas volumes that can be offered in the market in the future. Accordingly, the agreements have to be examined in order to determine whether their provisions on either investments or production within the joint venture may have anti-competitive effects. The following discussion addresses the possible anti-competitive effects of the JOAs` provisions on investments (in part 6.4.2), before examining the effects of the provisions on production in the lifting agreements (in part 6.4.3).[221]

6.4.2 Possible Restrictions on Investments

Article 101(1) TFEU (previously Article 81(1) EC) requires that the participants´ freedom to act is not limited in a way that harms competition. At the same time, the investment provisions of the JOA have to be designed taking into account the fact that the joint venture is a co-operation between several gas undertakings, where all participants are

[221] This part of the presentation is to a large extent based on Olav Boge, Gassproduksjon og konkurranserett. En vurdering av produksjonssamarbeidet på norsk sokkel i forhold til EØS artikkel 53, MarIus 303.

to have a say in key decisions and where such decisions shall ensure the common interest.

Under Art. 101(1) TFEU (previously Art. 81(1) EC), each party is required to have an independent right to invest in increased production capacity for the joint business. However, it is not required that this right to make individual investments should be unlimited. It must be possible for the party proposing such investment to make it independently, provided that the operation of the plant is not jeopardised and the other party refuses to participate in the proposed investment. This principle was laid down by the Commission in the Exxon/Shell case[222].

These criteria are met in the production joint ventures taking place on the NCS. Investment decisions in relation to the production joint venture are regulated in JOA Chapter IV Field Development and Chapter V Sole Risk Operations. However, these provisions differ depending on the stage that has been reached in the life of the field. When addressing the question of investment, a distinction has to be drawn between *the exploration phase* (prospection) and the development phase.

Activities in *the exploration phase* are regulated in the work program determined in accordance with JOA Art. 12. This program is adopted by the management committee in accordance with the ordinary voting rules established in JOA Art. 2.2. According to JOA Art. 19.2, each licensee also has the right to supplement the jointly conducted surveys, tests and drilling activities with similar operations that the party undertakes at its own risk.[223] However, this right to seek and obtain supplementary information is clearly a secondary one. Such sole risk operations cannot take place either before the obligatory work commitment in the PPL has been completed or if they interfere with plans or work programs, or if they endanger production from deposits that have been

[222] Case IV/33.640, Exxon/Shell, OJ [1994] L 144

[223] It should be noted, however, that such sole risk projects shall be carried out by the operator, cf. JOA Art 19.7. In other words, the licensees that participate in the sole risk project have only undertaken an obligation to pay the cost in relation to the project and not to carry it out.

already developed.[224] This is in line with the principle laid down in the Exxon/Shell case, i.e., limitations on the right to undertake individual investments are accepted as long as it is in the interests of the other licensees.[225]

When it comes to investments in *the development phase*, these are regulated in the JOA Chapter IV Field Development and Chapter V Sole Risk Operations. A field development may consist of several development steps. The gains may differ in each of the steps. Furthermore, the licensees may operate with different risk profiles as well as different rate-on-return requirements. Consequently, the licensees may not agree on whether and how a field should be developed. However, under the JOA, a single licensee can neither be forced to participate in the joint venture nor can it, alone or together with other participants, veto the development of a field.[226] According to the JOA Art. 16.3, the operator shall prepare a field development plan in close co-operation with the (other) licensees. This field development plan is submitted to the management committee, which decides whether the plan shall be adopted. The plan is then submitted to the Ministry and other relevant authorities (i.e., the environmental authorities) together with a field development application, cf. JOA Art. 17.2. Once the field development plan has been adopted by the management committee, each licensee shall, within a period of three months, notify the Ministry and the other licensees whether or not it accedes to the field development plan, cf. JOA Art. 17.3. A licensee's accession to the field development plan is binding in relation to the other licensees.[227] If all licensees have not acceded to the development plan within the time limit given in Art. 17.3, those parties that have acceded to the plan may propose that the development is carried out on a sole risk basis.[228] The licensees that wish to participate in a sole risk project, have to notify the Ministry and the other relevant parties in writing, cf. JOA Art. 20.2.

224 JOA Art. 19.3

225 Similarly, see Boge pp. 43-45

226 Similarly, see Boge pp. 45-46

227 JOA Art. 17.4

228 JOA Art. 20.1

This indicates that the provisions of the JOA do not limit investments and thus do not restrict production.

6.4.3 Possible Restrictions on Production

Once the necessary investments for the field`s development have been made, the question is whether, and to what extent, Art. 101(1) TFEU (previously Art. 81(1) EC) applies to the agreement`s provisions on production in the field's production phase. The question arises in two contexts. The first question is whether the regulation of the joint venture's total production may have anti-competitive effects. The second question is whether the regulation of each licensee's individual gas lifting may have restrictive effects.

Agreements that limit production are prohibited under Art. 101(1) TFEU (previously Art. 81(1) EC). The Guidelines on Horizontal Co-operations, however, exempt agreements concerning the production that is directly agreement on production cooperation.[229] Such agreements shall be evaluated in the light of the joint effects on competition of the joint venture. This must be seen in connection with the Norwegian authorities` regulation of the production level. The PPL regulates the supply of gas volumes to the market and a predetermined production profile takes the joint interests of the licensees into account. This production level is determined in order to optimise production. It is of little practical significance that the licensees are able to reduce production to lower levels than those allowed under the PPL in order to manipulate the gas price.

In this context, the regulation of the parties´ individual lifting of gas is of greater practical interest. The individual lifting is regulated in the Lifting Agreement. As mentioned above (in part 2), there are two types of lifting agreement. In this context, flexible lifting agreements are of interest, as they allow for underlifting of gas. Although the participants are obliged to follow the production program, according to these agreements, each licensee is allowed to underlift gas to some extent. At the

[229] Guidelines on Horizontal Cooperation Agreements, paragraph 90

same time, the right to underlift is not accompanied by a right for the other licensees to overlift. The result of a prohibition on overlifting is that total production from the field is limited once a single licensee chooses to underlift. If overlifting is permitted, however, the utilisation of the field`s entire production capacity is ensured. The question is whether a prohibition on overlifting is problematic under Art. 101 TFEU (previously Art. 81(1) EC). In the *Exxon/Shell case*, the Commission laid down the principle that each participant has the right to utilise production rights not utilised by other participants. A general prohibition on overlifting may thus appear problematic. However, natural gas is a non-renewable resource. As the possibility of overlifiting is restricted in order to ensure the balancing of ownership interests in the end-phase of the field, such a restriction appears to be legitimate.[230] Furthermore, it is highly unlikely that any possible anti-competitive effects of a prohibition on overlifting will have an appreciable effect.

6.5 Summary

In view of the line of argument above, it seems fair to conclude that the production joint ventures entered into on the NCS are unlikely to have anti-competitive effects. While production within the scope of the licence as such probably does not infringe Art. 101(1) TFEU (previously Art. 81(1) EC), the introduction of portfolio sales has resulted in the differentiation of products and different cost profiles among the gas undertakings, and thus facilitating competition between these undertakings. Agreements entered into outside the scope of the licence, i.e., production caps, lifting agreements, balancing agreements and/or joint buying of injection gas, may, depending on the circumstances, be exposed in relation to Art. 101(1) TFEU (previously Art. 81(1) EC). These agreements have to be evaluated on an individual basis.

On balance, most production agreements are considered economically beneficial.[231] More often than not, the efficiencies and risk sharing

[230] Boge p. 54

[231] EU Energy Law II p. 143

enabled through production agreements are considered to outweigh the possible negative competition effects of such co-operation.[232] This is particularly true in the case of co-operation agreements that significantly increase production capacity and output for a specific form of energy.[233] This explains why such production agreements, if they are deemed to be in breach of Art. 101(1) TFEU (previously Art. 81(1) EC), are exempted in accordance with Art. 101(3) TFEU (previously Art. 81(3) EC). In principle, the favourable view of production agreements does not depend on the structure that producers give to their collaborations, i.e., whether the producers consent to share a production facility, for instance through the creation of a joint venture (as is done on the NCS), or enter into specialisation or subcontracting agreements.[234]

7 Information exchange

In order for there to be competition, the market must not be too transparent. The market actors need to be uncertain as regards the market behaviour of their competitors. If not, tacit collusion between competitors, through adjustments to their behaviour, is likely. Information exchange increases transparency in the market, thus making such adjustment easier. This problem is especially relevant in oligopolistic markets. The particular characteristics of the market structure on the NCS, as mentioned above (in part 6.3), may give rise to transparency concerns. Information from one licence to another is exchanged within the organisation of a single licensee. The network of joint ventures, and extensive degree of cross-ownership, implies that the gas undertakings have access to information about plans for investment and production across the NCS. As such exchanges of information are reduced, if not eliminated, uncertainties as regards competitors` plans for future in-

232 EU Energy Law II p. 143
233 EU Energy Law II p. 143
234 EU Energy Law II p. 143

vestments, production and sales, the effect may be anti-competitive. Exchanges of information that may give rise to co-ordination of market behaviour may therefore infringe Art. 101(1) TFEU (previously Art. 81(1) EC).

As mentioned above (in part 6.3), the particular characteristics of the market structure on the NCS make information exchange a relevant problem. As each gas undertaking is involved in the production of gas on several fields, this gives the gas undertakings knowledge of the production profiles across the NCS and allows them to consider the totality of interests when making commercial decisions. It is thus important to distinguish between information that is market relevant and information that is production relevant. The *Britannia case* once again provides an illustration.

The problem of information exchange between competitors means that, the allocation of functions within the joint venture has to be examined.[235] As work programs and budgets are adopted by the management committee, the licensees are mainly given access to information on superior and strategic issues. The operator, on the other hand, is in a special position when it comes to access to information. As the operator carries out all activities related to production, it has access to technically and commercially relevant information on both a short-term and long-term basis.

In this respect, the authorities´ policy with regard to the award of operatorships on the NCS has exacerbated the problem. Although this has changed over the years, for a long while, only a limited number of companies were appointed operators. Consequently, Statoil still have a special position as both operators for gas fields and major sellers of gas in the gas market. In other words, the operators gain a valuable insight into activities on a number of fields. This gives the operator information advantages compared to other gas undertakings active on the NCS, i.e., the operator`s competitors in the gas sales market.[236]

Although the increase in the number of gas undertakings becoming

235 See EU Energy Law II p. 141 and Boge p. 91

236 Boge p. 93-94

operators may eliminate such information advantages, this also contributes to a more transparent market as regards investments and production decisions.[237] Access to, and exchange of, information thus needs to be controlled in order to avoid competition concerns. This is particularly true when it comes to information on each undertaking`s lifting of gas. This is reflected in the lifting- and balancing agreements.

In order to avoid information being exchanges on the future gas lifting of each gas undertaking, the lifting- and balancing agreements contains a nomination procedure. This nomination procedure is designed to avoid the licensees and the operator gaining insight as regards the gas volumes each gas undertaking has lifted and has the right to lift for the remaining part of the production year.

Under today's regime, the gas purchasers nominate their desired volumes under their respective gas sales contracts with a particular producer. This nomination is made through Gassco, which informs the field operator of the gas volumes that are to be lifted during a given production day. The field operator only receives information as to which licensee has lifted which gas volumes the day after the gas volumes have actually been lifted. Accordingly, the licensees do not receive information about which licensee withdraws which gas volumes and the field operator only receives such information following a delay.

The operator is obliged to keep a lifting and balancing account for each licensee. This account contains information on the volumes that have been lifted and the volumes that remain for lifting. These accounts are kept individually. While the licensees are kept informed of their own gas lifting record and the aggregated lifting in relation to the field, they are not given detailed information on the spread of gas volumes between the licensees.

In a transparent market with few market participants such as on the NCS, it is difficult to avoid information on the parties entering into contracts are becoming common knowledge. However, the commercial conditions in the gas sales agreements need to be kept confidential in order to maintain competition. In this respect, it is a problem that the

[237] Boge p. 94

gas sales agreements are relatively standardised. This relates to the fact that the gas undertakings share the main infrastructure. As this article (as mentioned in part 1) deals with the organisation of the gas sales regime and not the gas sales agreements themselves, this problem will not be discussed further here.

8 Conclusions

In general, the provisions of the EC Treaty apply to the Member States and restrict their freedom of action. The competition rules differ as they apply to, and regulate the conduct of, the undertakings active in any market. The above presentation of the organisation of the gas sales regime on the NCS highlights the fact that the competition rules are of great importance, both for the Norwegian authorities and the undertakings active in the gas industry.

While the analysis has shown that the gas sales regime is organised in a way that in general is not in breach of Art. 101 TFEU (previously Art. 81 EC), or is likely to give incentives for behaviour in breach of Art. 101 TFEU (previously Art. 81 EC), it also illustrates that it is important that both the authorities and the gas undertakings are aware of and address these questions when designing the regulatory framework and/or conduct business within that regulatory framework. Not only are the Norwegian authorities obligated to implement all measures necessary to fulfil their obligations under the EEA Agreement, but also refrain from implementing measures endangering the objectives of the EEA Agreement.[238] To the extent that the Norwegian authorities pass legislation or other measures in breach of the provisions of the EEA Agreement, including the competition rules, Norway may be brought before the EFTA Court.[239] More importantly, as illustrated by the presentation above, the gas undertakings may be held directly responsible. Although

[238] Art. 3 EEA

[239] Art. 31 ODA

the scope of the state compulsion doctrine is subject to debate, it is clear, based on the current case law of the Community institutions, that this doctrine will only assist the gas undertakings in a minority of situations. Thus, the undertakings must themselves ensure that their behaviour does not have an anti-competitive objective or effect in breach of the competition rules. Although the system in general seems to steer clear of the scope of Art. 101 TFEU (previously Art. 81 EC), this might change given the facts of a particular situation. Thus, each gas undertaking needs to stay vigilant in order to avoid breaching the competition rules. As the gas sales market becomes increasingly dynamic as the liberalisation process continues, this becomes even more important.

Norwegian Petroleum Taxation - An Introduction

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Content

1 Introduction

1.1 General features of the Norwegian system

The Norwegian State derives its revenue from petroleum resources partly through direct participation in the petroleum sector, and partly through taxation of the participants in the industry. The petroleum tax system is, to a large extent, based on taxation of net profits with a high marginal tax rate of 78%. This consists of 28% general income tax and an additional 50% Special Tax on income from petroleum production and pipeline transportation activities. In addition, certain environmental taxes, such as CO_2 and NOx taxes are charged, and an area fee is charged for acreage. However, these are of less importance to State finances.

Initially, the tax system also included taxation of gross revenue through royalty payments on crude oil production. This has been abolished over the years and it seems now that the Norwegian State is satisfied with a general system of taxation of net profits as a basis for capturing the State's share of the value of its petroleum resources.

The high marginal tax rate must be seen in connection with other features of the system, such as depreciation of investments in production facilities over 6 years from the year of investment, a deduction of uplift in the Special Tax basis, as well as certain incentives for newcomers to the industry etc.

The Ministry of Finance affirms that the current system is robust in withstanding price fluctuations in the crude oil and gas markets. The main features of the system have been upheld over many years, although we have seen important changes at regular intervals.

We do not expect that there will be any material changes to the tax system in the near future.

The industry appears to recognise that the system is well designed for the development and production of large fields and projects. It is more questionable whether the system gives the right incentives for enhanced recovery and extended production from a number of fields which are currently in sharp decline or in a tail-end production phase.

1.2 At a glance

The key features of the system are as follows:

+ Operating income
- Operating costs
- Depreciations (linear over 6 years from investment for production installations and pipelines)
- Exploration expenses, R&D[1], incurred P&A[2] and removal
- Environmental taxes
- Allocated financial costs
= General income tax base (28%)
- Uplift (7.5% of investment for 4 years)
= Special Tax base (50%)

1.3 Resource rent and justification of Government Take

A fundamental principal underlying the Norwegian petroleum activities is that the State is the owner of the resources. This principle is laid down in the Petroleum Act (1996) Section 1-1:

> "*The Norwegian State has the ownership to subsea petroleum resources and an exclusive right to resource management*" (our translation).

In general, the exploitation of limited and scarce resources should earn higher profits than normal business activities within a free market. Such super profit, often referred to as resource rent, should accrue to the

1 Research and Development

2 Plugging and Abandonment

State and the public through the ownership of the resources. Thus, the objective of a petroleum tax system is primarily to capture the resource rent, but at the same time ensure a sufficiently attractive return on the investments of the private investors. Technically, the tax system should be simple and provide for a cost efficient way to secure the income of the host state. At the same time, the host state needs to be conceived as a "reliable partner" for long term commitments of private investors. This is achieved through maintaining over time a sufficiently attractive tax system in combination with other parts of the overall framework for the industry. Investors require stability in the economic framework in order to earn the appropriate rewards on the investments made and the risks taken.

Host states have taken many different approaches to capturing the appropriate government take on the exploitation of natural resources.

A basic distinction can be drawn between contractual based systems on the one hand, and royalty/tax systems governed by legislation on the other hand. Traditionally, international oil companies have preferred contractual systems, where they can rely on principles of sanctity of contracts as a restriction on the host government to exercise its legislative and administrative powers to the detriment of a contracting party. Contracts have in some jurisdictions taken the forms of service agreements, and many jurisdictions have relied on production sharing agreements with a division of produced petroleum between the host state and the private oil company. International oil companies have also preferred that such contracts are governed by laws of other states than the host state, for instance English law, and arbitration in other venues than the host state.

The Norwegian State has implemented a concession system where participants are granted licences to produce the resources within a geographical area ("Production Licence" or "PL"). The competence of public bodies is established through legislation and regulations rather than contracts. This is also the basis for the petroleum taxation regime. In theory, such a system affords less protection to the private investors, since the restrictions on the exercise of legislative powers are limited.

Some examples under the Norwegian Constitution are that legislation may not be enacted with a retroactive effect (Section 97), and private property may not be expropriated without full compensation to the private party (Section 105).

In respect of the tax system, the State is, in principle, within its rights to change the system, increase or decrease rates or implement any other material changes. Under such a system the perception of a host state as a "reliable partner" becomes increasingly important.

In Rt.[3] 1985 page 1355 *Phillips*, the Supreme Court ruled in a matter where the terms of payment of royalty were changed in regulations from semi-annually to quarterly payments. The companies argued that the change was unmerited as a breach of a contract and that the change was also contrary to principles the Norwegian Constitution and administrative law. In its judgment, the Supreme Court judge stated

> "I do not specifically take a position as to whether at least certain of the provisions of PL 018 is a part of an agreement between the State and the licensees, or whether the licence as a whole must be seen as an administrative ruling, where the provisions on royalties are included as a set of terms for the rights under the licence" (our translation).

Even though the Supreme Court did not consider the contract argument, they concluded that the new 1972 regulations on payment of royalties could not be applied to the licences granted under the 1965 regulations.

The current fiscal system does not allow for arguments on contractual protection. Thus, the protection of the investors is to some extent afforded by the Norwegian Constitution and, more importantly, the perception of the Norwegian State as a reliable host state for the industry.

In some instances, the industry has argued that the State has implemented tax legislation in breach of the Constitution. Following a judg-

[3] Rt. = Norsk Retstidende (English translation = Supreme Court Law Report)

ment by the Supreme Court in 2004 (Rt. 2004 page 1921 *Shell*) where the court ruled in favour of A/S Norske *Shell* in respect of deduction of decommissioning costs on fields, the relevant sections of the GTA were changed in December 2005, but effective from 1 January 2005. The industry argued that this was giving new legislation with retroactive effect, but the issue was not pursued in the Civil Courts.

1.4 Brief history

During the late 1950s, very few believed there would be any petroleum resources located outside the Norwegian coast. Following the discovery in Holland of the Groningen field in 1959, it was recognised as a possibility that hydrocarbons could extend into the North Sea region. The first Norwegian licences were awarded in 1965. An act on Taxation of Subsea Petroleum Resources was adopted 11 June 1965. Under the Act Section 2, the general rules of taxation would apply to the activities. However, the Act also introduced tax reliefs in the form of reduced rates. The reasoning was that the prospects were uncertain and that the framework needed to be competitive as compared to adjacent states.[4]

Following a massive exploration program, the Ekofisk field was discovered within PL 018 in 1969. The first production commenced in June 1971 and at the same time several other large discoveries were made.

In 1972, the privileges under the 1965 Tax Act were abolished, and the industry paid taxes on the same basis as other Norwegian business enterprises. Up to 1975, the State revenues from the petroleum sector were collected from general income and net worth taxes, area fees, royalty, production bonus systems, net profit sharing licences, and the State's own direct participation with rights to participate on a sliding scale etc.

Major changes occurred in the market place during the first half of the 1970s. Prices increased significantly, coinciding with the Middle East war in October 1973 and several initiatives by the OPEC countries. In a White Paper to the Norwegian Storting in 1973, the Government

4 Ot.prp. no. 47 (1964-65) page 2

stated that it would consider the petroleum tax system, and an expert committee was established in January 1974. This led up to the White Paper Ot.prp. nr. 26 (1974-75) with a proposal for a new Petroleum Tax Act, which would increase tax rates significantly, and introduce other measures as part of an overall tax system for the petroleum industry. Two proposals in particular led to a strong debate: The introduction of (i) the Special Tax, and (ii) the Norm Price system for determining the tax value of crude oil produced, see section 6.2 below.

Several of the companies argued that the new fiscal regime was adopted in breach of the protection under the Constitution, since it was proposed also to apply to licences awarded prior to the 1975 PTA. Phillips Petroleum Company presented their views to the Storting, which were included as an attachment to the recommendation of the committee as follows:

> "As the oil companies were awarded production licences in 1965, the Norwegian authorities were aware that the exploration, development and exploitation costs in the Norwegian part of the harsh weather exposed North Sea would be higher than in other places. Acceptable tax legislation was adopted to balance the considerable costs and risks which the operations in the North Sea entailed. Now, when we are ready to commence production on a large scale, and even before we have made any profit, we are faced with the proposal of significant changes in the tax rules. We had not expected such changes because we used Act no. 3 of 11 June 1965 on Taxation of Subsea Petroleum Resources as a basis, which led us to believe that we, in respect of taxation, would be treated in the same manner as other activities in Norway" (our translation).

The companies reserved their right to try the new legislation in the courts, under the argument that it was adopted in breach of the Constitution.

The industry also obtained an opinion from a renowned professor at the Law Faculty in Oslo, supporting their position. The Government maintained that new legislation could be introduced and obtained further support from another professor at the Law Faculty, and from the Legislation Department within the Ministry of Justice.

The PTA was adopted, and the new petroleum tax regime was established. The Special Tax was introduced with 25%, giving a marginal tax rate in the range of 76%. Uplift was introduced as a relief against the Special Tax, with 10% of cost price of production and pipeline installations over 15 years. Finally, the PTA determined that crude oil sales should be valued at Norm Price, an administratively fixed price, to avoid transfer pricing issues on sales between related companies.

Prices increased again in the late 1970s. The petroleum tax system was changed in 1980 by increasing the special tax rate from 25% to 35%, and reducing Uplift.

In 1982 a change was introduced to the treatment of financial costs such as interest costs on financing. Financing costs have over years been a difficult issue for the Norwegian State. See section 8 below.

In the mid-1980s prices declined significantly in the market. The State recognised that changes to the tax system were required to maintain the attractiveness of investments in the Norwegian petroleum industry. The Special Tax was reduced again to 30%. Depreciations were accelerated by allowing depreciations to commence in the year of investment, rather than when the asset was taken into use. For new projects, a production allowance was introduced replacing Uplift. This was designed to support a major development of the Troll gas field, which at the time appeared to be a marginal project even though the gas resources were tremendous.

Up until 1987, the capital gains taxation and possibilities of tax arbitrage had effectively prevented transactions with Production Licences. In one case, the Ministry would not consent to a transaction which appeared to be heavily tax driven. Section 10 of the PTA was adopted in 1987, which opened up for tailor-made consents by the Ministry of Finance, with measures designed to maintain tax neutrality to the State. The new legislation resulted immediately in the conclusion of two major swap transactions between Statoil, TOTAL and Elf, involving Ekofisk and Troll.

In 1992, a major reform of the general tax system was enacted. This necessitated certain changes in the petroleum tax system, since the general income tax rate was reduced from in excess of 50% to 28%. Thus, the Special Tax was increased to 50%, giving a marginal tax rate of 78%. The recently introduced production allowance was abolished and Uplift was reintroduced.

In the period 2002 to 2005, new measures were introduced to attract newcomers to the Norwegian petroleum industry. The petroleum tax system was clearly advantageous to companies in a tax paying position, allowing them to deduct all of their exploration expenses in the taxable net income. In 2005, a particular system for annual refund from the State of the tax value of exploration costs was introduced. The new measures were clearly effective. We saw a major increase in the number of participants in the industry and in the number of exploration wells drilled.

Finally, in 2007 the ongoing problem of how to treat financial charges was resolved through a direct allocation system based on tax book values of assets in the off-shore tax regime.

1.5 Some facts and figures

The Norwegian petroleum industry is by far the largest contributor to the State's financing. In 2010, the sale of crude oil, natural gas and pipeline transportation services amounted to nearly 50% of Norwegian export values. The petroleum export amounted to close to NOK 500 billion in 2010, approximately 10 times the export value of fish.[5]

The State's direct taxes in 2010 from the petroleum sector were estimated at NOK 155.6 billion. In comparison, total revenues from VAT were estimated at NOK 189 billion.[6] Environmental taxes and Area Fee amounted to approximately NOK 3.6 billion.

The Norwegian Government Pension Fund - Global invests the accumulation of State revenues from the petroleum sector. The total market value of the fund amounted to approximately NOK 3,077 billion

5 Source: NPD fact sheet 2011

6 Source: Ministry of Finance website

at year end 2010.

In summary, the petroleum sector has accumulated tremendous value to the Norwegian State over the years and, in all likelihood, it will continue to do so for many years to come.

The direct taxes amount, of course, to significant figures also for the private participants. A company such as TOTAL E&P Norge AS, which participates in many of the Norwegian producing fields, reported taxes payable of NOK 21 billion for 2010. Many of the petroleum companies rank amongst the most important tax payers in Norway.

2 Assessment process

2.1 Introduction

When proposing the PTA to the Storting, the Ministry of Finance also found it necessary to establish a specialised body to ensure a satisfactory control and an efficient assessment of the industry. Thus, what is now named the Oil Taxation Office was established. The office handles the assessment of all licensees in the Norwegian petroleum exploration and production industry, as well as pipeline transportation licensees. The Oil Taxation Office currently has around 43 employees, and assesses in excess of 60 companies. The office has more employees per tax payer than any other assessment office in Norway. The office handles the assessment process through examining tax returns and additional correspondence with the tax payers. The annual assessment is rendered by the Oil Tax Board, which consists of individuals appointed by the State. The Board consists of five members with deputies.

The assessment may be appealed to the Appeals Board, which renders a final ruling in the administrative process. The rulings by the Appeals Board may be tried in the Civil Courts, see below.

2.2 Filing and disclosure requirements

The PTA Section 8 determines that general tax legislation shall apply, subject to any specific regulations set out elsewhere in the PTA. Thus, the disclosure and filing requirements follow from the Assessment Act (1980). Under the Act, each tax payer must file a tax return within the expiry of April each year following the income year. The filing requirements are extensive, detailing the basis for assessment of gross income and deductions, as well as other information which *is relevant for the completion of the assessment*, ref. the Assessment Act Section 4-3.

The general requirement for disclosure of information pursuant to the Assessment Act Section 4-1, is to act diligently and loyally. The tax payer is expected to contribute to his taxable income being assessed timely and correctly.

In addition to the tax return, the tax payer is under an obligation to submit any further information or documentation as requested by the Oil Taxation Office. One issue which comes up from time to time is whether a tax payer is under an obligation to disclose information which is not available to him, but which is available to affiliated companies within a group. For instance, resale prices on goods such as gas liquids may be of relevance in determining whether the transfer price between the Norwegian entity and an affiliated entity is on arm's length terms. In principle, it is clear that the company is not under an obligation to disclose information which it does not have access to. On the other hand, disclosure may be necessary to verify income and cost items and the appropriate tax basis. If reliable information is unavailable, the tax payer risks being assessed on a discretionary basis.

The Oil Taxation Office may also carry out audits in the offices of the tax payer pursuant to the Assessment Act Section 4-10 and Section 6-15.

It will have consequences for the tax payer if the information submitted is incorrect or insufficient. A penalty tax may be assessed under Section 10-2 of the Assessment Act. The penalty tax will normally amount to 30% of the tax which could have been avoided. When the tax payer has acted wilfully or with gross negligence, the rate may increase up to 60%. With a marginal tax rate of 78%, it is noteworthy that a penalty tax of 30% may increase the marginal tax rate on the income which has been insufficiently disclosed to more than 100%.

2.3 Transfer pricing documentation

Under the Assessment Act Section 4-12, a tax payer is also under an obligation to submit information on transactions with affiliated companies. Written documentation shall be submitted as a basis to consider the prices and the terms of the transactions, and whether the terms are in accordance with the arm's length principle. The documentation must be produced to the Oil Taxation Office within 45 days of a request.

The taxable income may be assessed on a discretionary basis if the tax payer has not complied with the transfer pricing documentation requirements, ref. the Assessment Act Section 8-2 third paragraph. Under the Act Section 9-2 no. 7, a tax payer loses his right to appeal the assessment if he has failed to submit the transfer pricing documentation.

The transfer pricing provisions were adopted with effect from January 2008. Subsequent practice has shown that the transfer pricing documentation tends to become extensive, and its usefulness in the assessment process is perhaps questionable, even though transfer pricing issues are of great importance in the assessment of the petroleum industry.

In summary, the filing and disclosure requirements are extensive and strict. Failure to comply with them can entail penalty taxes of substantial amounts, assessment on a discretionary basis, and losing the right to appeal the assessment.

2.4 Annual assessment

The Oil Taxation Office will conduct an extensive review and control of the tax return, and submit a number of letters with additional questions to the tax payers. The process is time consuming and the request for information may often seem excessive.

Proposals for an assessment are presented by the Oil Taxation Office to the Oil Tax Board, which renders the final assessments around 1 December in the year following the income year.

The assessments as such are not reasoned. From the correspondence with the Oil Taxation Office, and notices of potential deviations from the tax returns, the tax payer will normally be fairly familiar with the basis for assessments which are not in line with the submitted tax return.

The Oil Tax Board may also amend assessments from previous years. The overall time limit is ten years, but this is limited to two years after the expiry of the income year in the event that the tax payer has submitted correct and complete information in the tax return. Amended assessments by the Oil Tax Board are reasoned, and they will normally follow an extensive process of exchange of information and legal arguments between the Oil Taxation Office and the tax payer.

2.5 Appeals

The assessment decisions by the Oil Tax Board may be appealed to the Appeals Board for Oil Taxation. The time limit is three weeks and the appeal should state the items which are appealed, and the basis for the appeal. In practice, preliminary appeals are filed, and more substantive arguments are submitted at a later stage. The appeals process is also handled by the Oil Taxation Office, which summarises the appeal and the Oil Taxation Office's views in an Appeals Memo which is presented to the Appeals Board. The tax payers are not entitled to meet and give presentations to the Board. All filings will be in writing. The Board renders final administrative rulings on the assessment.

2.6 Civil courts

The appeals process is mandatory, to the effect that the Oil Tax Board's assessment may not be tried directly in the Civil Courts. Appeals Board rulings may be tried in the Civil Court, and a writ must be filed within six months of the ruling. If the Appeals Board has not given their ruling within one year after the expiry of the time limit for appealing, the assessment of the Oil Tax Board may also be tried directly in the Civil Courts.

The Civil Courts may try all points of fact and law which are argued by the two parties. The Courts will generally not try the discretionary parts of the assessment, which may be decided for instance in transfer pricing cases, where it is held that the contract prices are not on an arm's length basis.

A number of petroleum tax cases have been tried in the Civil Courts. Some have been successful with cases involving fairly substantial amounts. A few will be referred in more detail below.

The court system is a three tier system, where the District Court judgments may be appealed to the Appeal Court. Appeal Court judgments may be appealed to the Supreme Court, subject to approval to hear the case. Many cases will not be allowed in the Supreme Court. Thus, the Appeal Court judgments will often be the final judgment in cases.

3 Sources of law and interpretation

3.1 Legislation

The primary source of law is, of course, the legislation as adopted by the Norwegian Parliament, the Storting. The wording of the legislation is important in determining the scope and application of the rules which are expressed. However, since life has a tendency to develop differently from expectations, the wording of the legislation may not always give clear answers to the issues at hand. In addition, tax payers spend considerable efforts on tax planning, structuring of transactions etc., which often challenge the scope of the legislation. Tax planning is perfectly legal and acceptable, and to some extent also necessary to create an efficient tax system. A system must assume that tax payers act rationally to minimise the tax burdens levied by the State. On the other hand, there are clear limitations where legal structures and transactions may be disregarded based on tax avoidance principles.

The wording of the legislation will also be interpreted by the court to maintain a logical and rational structure to the tax system. An example is Rt. 2007 page 1729 *TOTAL,* where the Supreme Court held that a handling fee payable for services related to lifting of crude oil was not deductible as a separate cost, but included in the Norm Price applicable for the crude oil sale. See section 6.2 below.

3.2 Preparatory documents

Legislative bills to the Storting may be prepared through a lengthy process, often starting up with an expert committee appointed by the Ministry of Finance to evaluate the existing legislation and propose changes. The report of the commission is usually published and becomes part of a public consultation process. The Ministry will then issue a White Paper with proposals for new legislation to the Storting. The relevant committee in the Storting, the Finance Committee for tax issues, considers the proposal and renders its recommendation.

The process of proposing and adopting legislation is comprehensive and the preparatory documents may give guidance when interpreting the legislation itself. It is well recognised that legislation will be interpreted in accordance with guidelines in the preparatory documents themselves, or to achieve the objectives as expressed in the various documents.

In certain instances, the White Papers may express views on the interpretation of existing legislation. Such statements of interpretation will have limited weight. One example was Rt. 2004 page 1921 *Shell*, where the Ministry in a White Paper to the Storting expressed their position on the interpretation of the legislation which was at issue in the *Shell* case. The majority of the judges (3-2) stated that such points of view could have no weight when interpreting the legislation as this would lead to giving legislation retroactive effect through statements on interpretation (paragraph 86).

3.3 Court precedence

Court precedence is an important source of law when interpreting tax legislation. In particular, Supreme Court judgments will be followed by the lower courts, and mostly also by the Supreme Court. The Supreme Court renders thorough and reasoned judgments. The Supreme Court may also express more general points of view (obiter dicta). Such statements will not be binding to the same degree, but they will also usually be followed by the lower courts.

3.4 Administrative practice and opinions

The tax authorities will often render opinions on interpretation of tax legislation, which may be published. Such opinions will normally be followed by the administrative bodies themselves, but will to a lesser extent, be considered decisive by the Civil Courts.

3.5 Other sources

Tax legislation in general is extensively presented and discussed in legal textbooks. There is less literature on Norwegian petroleum taxation. A thorough thesis was published by Dr. Juris. Jan Syversen in 1991: "Skatt på petroleumsutvinning". The book is now somewhat out-dated, but still gives relevant guidance on many issues. The Oil Tax Director, Torstein Fløystad, has published the commentary to the PTA on Gyldendal rettsdata; www.rettsdata.no.[7] The comments are updated on a regular basis and serve as a source for practical and useful information.

The courts will consider views and opinions expressed by authors when rendering judgments in tax disputes. The weight of expressed opinions is probably more related to how well they are reasoned, rather than the status of the author.

7 Referred to below as Fløystad.

3.6 Government take

As set out in Section 1.3 above, the justification of a resource rent tax system is to ensure that the super profit accrues to the state and public as owners of the resources. This raises a question of whether the objective of collecting revenue to the State in itself is a relevant argument when interpreting the tax legislation. Such an argument would entail a fundamental breach of the principal of neutrality in the tax system, i.e. that income and expense items, as a general rule, should be subject to the same test when determining whether they are taxable or deductible respectively. The legislation would be interpreted widely to capture taxation of income, but narrowly to disallow expenses. It is unlikely that the courts will attach much weight to such arguments when rendering judgments.

On the other hand, it is a relevant argument when considering items of income or expenses as to whether they are generated through activities which are typically linked with the exploitation of the resources. Fløystad in Note 72 states:

> There are geographical and functional limitations to the special tax liability see note 73. When deciding whether (gross) income or costs fall within the special tax liability, the objective must be essential when applying the rules. This may probably be expressed so that the earning of income must be structured such a way that it facilitates an extraordinary profit. The assumption is that the potential profitability in one way or another is connected to the right [licence] to extract petroleum, i.e. that earning income is derived from this right. (Our translation)

The distinction between the two lines of arguments is not always entirely clear.

4 General tax liability and taxable entities

Under the GTA Section 5-1 all income derived from a business activity is taxable. As a general rule, it is not necessary to distinguish between separate businesses of a tax payer, since all income will be taxable.

Under the GTA Section 2-2, Joint Stock Companies are taxable entities. Most participants in the Norwegian petroleum sector are organised as Joint Stock Companies resident in Norway, and thereby taxable to Norway for their global income from their business activity.

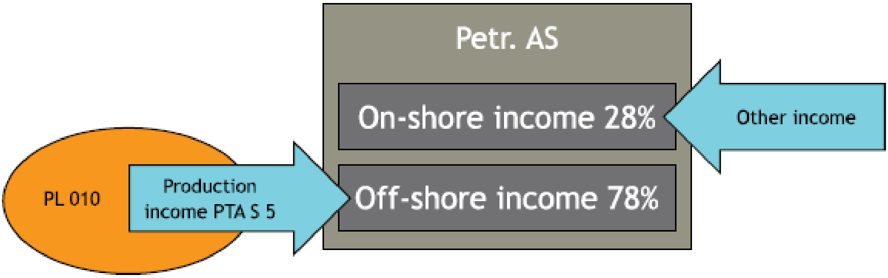
The petroleum activities in Norway are organised through the licence system, where the State awards a licence to explore and exploit petroleum resources in a geographical area. The group of participants in a licence carry out a business activity for their joint account and risk.

Under general company law, a business venture with joint and unlimited liability or pro rata unlimited liability is considered a separate legal entity, ref. the Company Act (1985) Section 1-1. Such companies are treated as transparent for tax purposes, GTA Section 2-2 second paragraph a, and the participants are taxed on their share of the net profits or losses stipulated as if the company was a tax payer, GTA Section 10-41.

Joint operating agreements for a licence within the petroleum sector are exempted from the company law regulations, Company Act Section 1-1 fourth paragraph, and they are also exempted from the net income assessment principle, GTA Section 10-40 second paragraph. Thus, participants in a Production Licence are assessed on their share of gross income, costs, depreciations etc. in the licence.

As we shall see below, the scope of the petroleum taxation also makes it necessary to distinguish between the activities of a company which fall within the scope of the Special Tax under the PTA Section 5, and other activities which are liable to the general income tax of 28%. The distinction is often referred to as off-shore income and on-shore income respectively.

The principle may be illustrated as follows for a company Petr. AS participating in PL 010:



5 Scope of the petroleum tax act

5.1 General

The PTA Section 1 sets out the scope of the Act, from a functional and geographical perspective. The objectives are twofold. One is to establish a general tax liability for the activities related to the exploitation of the petroleum resources on the Norwegian Continental Shelf.[8] This extends the tax liability of these specific activities beyond the geographical scope of the general Norwegian tax legislation.

Many of the activities will be liable to taxation only within the general income tax system with a tax rate of 28%. An example is drilling services for Norwegian licensees carried out by a contractor who is resident abroad.

The next objective is to establish the means of taxation of the resource rent. Section 5 of the Act sets out the liability to the additional Special Tax for tax payers carrying out production, treatment and pipeline transportation of petroleum resources, i.e. the typical exploitation of the resources based on licences awarded by the Norwegian State.

8 Norwegian Continental Shelf is referred to hereafter as NCS

We will go into more detail about the functional and geographical scope of the Act, in relation to liability to Special Tax under section 6 below.

5.2 Types of activities, functional

Section 1, first paragraph of the Act, establishes a tax liability *for exploration for and exploitation of subsea petroleum deposits and connected activities and work, including pipeline transportation of produced petroleum*. As a general note it is not required that all aspects of the activities are carried out within the geographical area. As long as the main functions of the activities take place on the NCS, it is not relevant if ancillary services (such as business accounting and legal), are located in other jurisdictions.

The Act distinguishes between exploration for and exploitation of the resources. Both activities will normally be carried out pursuant to licences granted by the Norwegian State under the Petroleum Act, and all such activities of the licensees will be taxable.

A licensee may carry out the activities on its own (or through the operator), through utilisation of its own equipment and employees, for instance drilling rigs and production installations with employed personnel. A large part of the activities is also carried out under service contracts with contractors. These may supply both the physical equipment and employees, both in the exploration phase and subsequently during production of the resources. Such service activities will be captured by the Act through the wording *connected activities and work*. Thus, all service activities related to exploration for and exploitation of the resources will be taxable under the Act. However, these services will not be subject to the Special Tax under Section 5 of the Act, ref. section 5.5 below.

Services carried out by companies or persons resident in Norway would be taxable to Norway under the global income principle in the general tax legislation. The effects of the Act are therefore primarily to establish a tax liability for such services rendered within the geographical scope by tax payers resident in other jurisdictions. In the Supreme

Court judgment HR-2011-1309-A *Allseas Marine Contactors*, a company resident in Switzerland had contracts with Phillips Petroleum Company Norway and Statoil during 1999 and 2000, related to pipe laying on the NCS. The company argued that the tax liability, pursuant to the PTA Section 1, was limited to the revenues attributed to the actual pipe laying carried out, and not to income which should be attributed to the head office activities in Switzerland, such as marketing, prequalification for services in Norway, and the negotiation and conclusion of contracts. The Supreme Court held that the gross revenues under the contracts were liable to taxation in Norway and no part could be attributed to the head office services for taxation purposes.[9]

As follows directly from the Act, *work*, i.e. personal employment, is liable to taxation when it is connected to the exploration and exploitations of the resources.

The Act specifically also establishes tax liability for pipeline transportation of produced petroleum. This entails that revenues from the transportation (tariff receipts) is taxable to Norway regardless of whether the owners of the infra-structure are domiciled in Norway or in other jurisdictions.

Typical services which will be encompassed within the Act are seismic services, drilling, catering and accommodation on installations, well services, maintenance contracts and so on. Activities of a more general nature will not be covered. Transportation of crude oil in vessels on the Norwegian Continental Shelf is not taxable under the Act, regardless of whether the crude oil is produced in Norway. The same applies to shipping of LNG from the Snøhvit-plant at Hammerfest.

Under Section1 second paragraph, the Act also applies to *treatment* of petroleum by installations used in exploitation or pipeline transportation, regardless of whether the petroleum is produced on the NCS. Extensive processing and other treatment services are carried out by and for different licence groups through tie-in and processing arrange-

9 It should be noted that the double tax treaty between Norway and Switzerland does not cover the NCS. Thus, the ruling is based on an interpretation of the internal Norwegian legislation.

ments. Services carried out for other licences on producing field installations would be taxable under the Act as income derived from producing assets. It would be more questionable as to whether services carried out by installations in fields which are shut down would be taxable, and in particular if the petroleum is produced in other jurisdictions. Such activities are taxable under the *treatment*-alternative, provided that the installations have been utilised in exploitation or pipeline transportation within the geographic scope of the PTA.

5.3 Geographical scope

The PTA Section 1first paragraph a) to d) sets out the geographical scope of the Act. Under a), the Act applies within the Norwegian waters and Norwegian Sea territory, and on the NCS. The NCS is defined in the Act as the seabed and the subsea areas reaching beyond the Norwegian Sea territories through the natural extension of the land territories until the outer boundaries of the continental margin. The limitation is 200 nautical miles of the base line, but not beyond the mid-line in relation to other states. A similar definition of the NCS is set out in the Petroleum Act (1996) Section 1-6 l).

Under Section 1 first paragraph b), the Act also applies in adjacent sea territories in relation to petroleum deposits which are extending beyond the mid-line to the territories of another state. Such trans-border fields will normally be produced jointly by the licensees of the two states, and pursuant to bilateral treaties. The treaties may also often deal with the taxation, where each state normally taxes its own licensees on its share of production from the field.

Under c), the Act also applies beyond the territories set out in the previous provisions in respect of landing of petroleum and connected activities and work, to the extent Norway is entitled to taxation under international law or treaties with another state. Typically, the provision establishes tax liability for landing of petroleum through the Norwegian dry gas or crude oil transportation systems. The current treaties with other states normally acknowledge Norway's sole right to taxation, at least in respect of petroleum produced on the NCS.

Finally, the Act applies under d), to transportation within the State of petroleum produced in Norway. The provision establishes the tax liability of pipeline transportation and receiving and export facilities. The PTR Section 8, sets out further details on the extension of a pipeline on-shore for tax purposes. The receiving facilities and export facilities are covered, whereas facilities for further treatment such as a refining or NGL fractionation facilities will be fall outside the scope of the PTA.

Under the PTA Section 1 third paragraph, the Ministry of Finance may also give specific regulations on the extension of the tax liability on transportation and treatment systems on-shore. This has been done for the Snøhvit LNG facilities at Melkøya in Hammerfest. Under general regulations, the LNG- facilities would most likely fall outside the scope of the PTA and be considered an on-shore activity. The Snøhvit-project was granted specific tax benefits in the form of accelerated depreciation and uplift. This required that the LNG-facilities were within the scope of the PTA.

5.4 Double tax treaties

Norway has concluded double tax treaties with all states bordering the NCS. The treaties partly regulate the right of each state to tax the relevant activity, but also protect the taxpayers through rules to prevent double taxation. The tax treaties may limit Norway's right of taxation on activities extending into the jurisdiction of other states. As an example, income from processing and transporting petroleum from the UK sector through a tie-in to a field in the Norwegian sector and transportation through a Norwegian pipeline system back to the UK, would be taxable by Norway. At the same time, revenue from production from the UK field will be taxable to the UK. The double tax treaty will normally prevent the same income from being taxed twice in the two States.

The double tax treaties will also have mechanisms for the states to mitigate double taxation of tax payers through mutual agreement procedures. There have been some instances of double taxation of income from transportation systems and landing facilities with the UK. Our understanding is that this was resolved through mutual agreements between the competent authorities.

A more practical issue is double taxation through transfer pricing adjustments, i.e. adjustments for tax purposes of income from transactions with related parties. This is further dealt with under section 14 below.

5.5 Petroleum production and pipeline transportation – liability to Special Tax

As follows above the Special Tax is designed to secure the resource rent due to the Norwegian State. Thus, it should by nature only apply to the typical exploitation of natural resources. These activities are carried out on the basis of licences granted by the State, which allow a super profit to be earned due to the scarceness of the resources.

It follows from the PTA Section 5, that tax payers carrying out *production, treatment and pipeline transportation* are liable to Special Tax on income from *such activities.* In principle, it could be argued that only production of petroleum pursuant to a licence should be subject to the Special Tax. The justification of the tax does not extend to more normal industrial activities such as refining and sale of products to end users, etc.

It could also be argued that pipeline transportation should not be taxed with Special Tax. Such transportation is an infrastructure service, where substantial investments in essential facilities and other entry barriers may open up for extraordinary profits through tariff charges. This is, however, more appropriately regulated through granting third parties access to facilities and fixed tariffs for utilisation as important measure of the State's management of the petroleum resources. It has also been the firm policy of the Norwegian State that profits from the petroleum sector should be earned on the production rather than on investments in infrastructure.

On the other hand, practical considerations favour including pipeline transportation in the Special Tax liability. Traditionally the infrastructure has been owned by the licensees in producing fields, roughly in proportion to their ownership in shipped gas. It would open up for major transfer pricing issues if income from pipeline transportation was taxed at lower rates than income from production of petroleum. During 2011, however, we have seen changes in ownership in the comprehensive Gassled system for transportation of dry gas, where new financial investors have acquired significant ownership interests and replaced the more traditional petroleum companies as owners. If this development continues, it could be discussed whether the Special Tax on pipeline transportation should be maintained, but we see it as unlikely that there will be changes on this point in the foreseeable future.

The main types of income which will be subject to the Special Tax are from: (a) the production of the petroleum pursuant to the production licences; (b) tariff receipts and other fees related to treatment of petroleum; and (c) tariff revenues from pipeline transportation of petroleum.

5.6 Integrated activities

Under general tax legislation, business activities carried out in Norway are taxable to Norway with the general income tax rate of 28%. Typically, a Norwegian petroleum company may be engaged within petroleum production, pipeline transportation, refining and retail sales of petroleum products. Those activities falling within the scope of the PTA Section 5 are also liable to Special Tax. Thus, where companies are engaged in several activities, it is necessary to separate those which will be taxable with the additional Special Tax. The liability is defined through an interpretation of Section 5 of the Act, i.e. what amounts to income from *production*, *treatment* and *pipeline transportation*. One could argue that all income earned by a taxpayer whose primary objective is to participate in these activities should be subject to tax. On the other hand, the Ministry of Finance assumed when preparing the PTR in 1975 that the Special Tax should only apply to the true production activities and pipelines transportation (a *narrow* interpretation of the PTA Section 5). Activities which normally also could be carried out by other business enterprises should be taxed under the general tax system. [10]

The Appeals Board has in a number of rulings held that Section 5 of the Petroleum Tax Act shall be interpreted more narrowly than the term *income derived by business activities* in the GTA Section 5-1. This was confirmed in a ruling from 1990 by the Appeals Board on taxation of profits from trading with gas, which is referred to in more detail in section 6.4 below.

Thus, for companies carrying out integrated activities only the more typical production and pipeline transportation activities will be subject to the Special Tax liability under the PTA Section 5.

When the companies engage in other activities, questions arise as to how to attribute income and costs between activities which may be more or less integrated. The PTR Section 12 sets out that

> *"[W]*hen a tax payer which carries out production of petroleum or pipeline transportation of produced petroleum within areas which are mentioned in the Petroleum Tax Act, Section 1, also carry out other activities or work, then income and costs shall be attributed so that income of production and pipeline transportation shall be stipulated as if this activity was carried out by an independent enterprise" *(our translation).*

The Supreme Court ruled on this issue in Rt. 2003 page 1376 *Statpipe*. The Statpipe transportation system was primarily designed to serve the gas evacuation from Statfjord and subsequently the Gullfaks and other fields. Later on, a number of fields were connected to the system which transported rich gas into Kårstø and dry gas further on to the European continent. At Kårstø, rich gas was fractionated in Zone 3 before NGL components were shipped out by vessels. It was accepted that the fractionation of NGL was an on-shore activity, i.e. outside the scope of the Special Tax liability under Section 5 of the PTA. A tariff system was established for Statpipe, where a tariff was charged to the gas shippers

[10] Utvalget 1976 page 459.

for transportation and treatment in different zones of the system. The principles for the tariff calculation were the same in all zones, i.e. both in zones taxable as pipeline transportation with Special Tax, and in Zone 3 which was only taxable onshore under the general tax system. In the assessment of the companies as owners in Statpipe from 1993, the net taxable income onshore was reduced significantly on a discretionary basis, thereby increasing the Special Tax Basis for the same companies as shippers of their own gas. One of the issues for the Supreme Court was the legal basis for a possible adjustment of the allocation of income and cost on-shore and off-shore. The Supreme Court decided that this issue should be considered under the arm's length principle set out in the 1911 General Tax Act, Section 54, corresponding to section 13-1 in the current GTA.

In summary, income and charges within the same taxable entity must be allocated between the activities liable to Special Tax and to other activities based on the arm's length principle; i.e. what would the allocation have been between independent parties.

There are, and have been, disputes related to the allocation of income on-shore on a number of tie-ins to onshore facilities for treatment of gas. In *Statpipe* and in similar cases, a major issue has been whether tariffs approved by the Ministry of Petroleum and Energy, or tariffs stipulated in Tariff Regulations by the Ministry, are binding also in the taxation. In *Statpipe*, the Supreme Court concluded that the approved tariffs were not binding where taxable income was to be attributed between the Special Tax basis and the on-shore tax basis.

Other forms of integrated activities which raise issues are: Sale and trading of crude oil produced on the NCS; and complex gas market activities ranging from sale of the taxpayers own produced gas to trading with gas purchased from third parties etc. Some of these issues will be dealt with further below.

5.7 Attribution of taxable income and deductible costs

An issue related to distinguishing between income subject to Special Tax and income taxable in the general income basis is attribution of income and cost items between the two tax regimes, or between separate taxable entities. With the significant difference in tax rates, it is, of course, tempting to attribute taxable income to activities or entities which are not liable to Special Tax in Norway. The opposite will apply to chargeable costs. Rules on attribution of income and cost items follow from principles of general taxation in Norway. The main rule is that the taxable entity which, pursuant to the underlying position (based on private law etc.) is entitled to a benefit, shall also be attributed the income for tax purposes. The same principle applies to costs.[11] Income and costs which are earned or accrued respectively for tax purposes may not be transferred to other taxable entities with effect for the taxation.

As an example, R&D activities carried out by a Norwegian petroleum company will normally be deductible in the Special Tax basis to the extent that it is related to the production business. If the activities result in patents or other protected intellectual property, affiliated companies of the entity may benefit from utilising the knowhow. Given that the Norwegian entity is the owner of the intellectual property, any benefits deriving from that ownership shall also be attributed to that entity for tax purposes, for instance through a licensing arrangement.

A slightly different issue of allocation is the appropriate pricing of transactions between taxable entities under common control or common interests otherwise. This is regulated by the GTA Section 13-1 which sets out that transfer prices should be based on the arm's length principal with a specific reference to the OECD transfer pricing guidelines. This is dealt with further under section 14 below.

11 Zimmer: Lærebok i skatterett 6th edition page 111.

6 Taxable income – special tax

6.1 General

As mentioned above, the Special Tax will secure the State's resource rent from the exploitation of the petroleum resources. Under this section, we shall discuss in more detail the types of income subject to the Special Tax.

Under the PTA Section 5, any income which is *derived from petroleum production, treatment and pipeline transportation* is liable to Special Tax. This will cover any income earned through production and sale of petroleum, such as crude oil, NGL and dry gas. Furthermore, income from processing of petroleum is captured, both the taxpayer's own produced petroleum, and services to third parties. Income from pipeline transportation is taxable. A company may also earn more ad hoc income, which is connected with the petroleum production. In these instances the tax treatment is more uncertain. Some examples are income from sub-leasing of rigs and profits on trading with crude oil and dry gas. Also. Other types of integrated activities may also raise complicated issues.

6.2 Sale of crude oil, Norm Price system

A particular feature of the Norwegian petroleum tax system is the Norm Price system for valuation of produced petroleum. The general principle at the time of adopting the PTA in 1975 was that taxable income would be the actual price on the products sold by the taxpayer. In Ot.prp. no. 26 (1974-75) p. 14, the Ministry of Finance pointed out the extensive integration and concentration of ownership in the petroleum industry, which would make it very difficult ("*often impossible*") for the assessment authorities to obtain access to the information required to determine the tax liability. In particular, transfer pricing issues would be a major problem since a large part of crude oil in international markets was traded between entities within the large groups. Thus, the Ministry proposed legislation which would allow for an administratively stipulated value of the petroleum produced on the NCS. The objective was that the price should reflect prices which could have been obtained on sales between independent parties in a free market. However, the Ministry emphasised that the interest of the companies would have to be appropriately taken into account. The Norm Price should not lead to *extra tax revenues through an artificially high price, but resolve the control – and administrative problems which otherwise would arise.*

At the time, several companies expressed concerns with the concept, including that an administrative body could easily set the prices too high. Thus, some proposals were that the Norm Price should only apply to inter-group sales, and that there should be an arbitration procedure to try the stipulated prices.

The Norm Price system was adopted more or less as proposed as Section 4 of the PTA. More detailed rules are given in the Norm Price Regulations (25 June 1976).

The PTA Section 4 first paragraph sets out that the Ministry may generally, or in a particular instance *with binding effect stipulate a norm price for petroleum which is produced*. Thus, the assessment will be based on the stipulated Norm Price, and not actual prices achieved by the companies.

The Norm Price is stipulated by a Petroleum Price Board which is appointed by the Ministry of Petroleum and Energy. The Ministry acts as a secretariat to the Board. The Petroleum Price Board stipulates the price retroactively, normally for each individual day. Previously, the main rule was that the price would be fixed quarterly, but recent fluctuations in the market required a more frequent fixing of the price. Norm Price may pursuant to the regulations be stipulated for a longer period when this is deemed practical and it is not unreasonable.

There is an administrative procedure where interested parties may submit views and the Board may consult with such parties and collect additional information. The stipulated prices may be appealed to the Ministry of Petroleum and Energy.

Experience has shown that the Norm Price system has been functioning satisfactorily, and the stipulated prices were appealed by the tax payers only on a few occasions.

Under the PTA Section 4, the Norm Price will stipulate the price petroleum *could have been sold for between independent parties in the free market*. The Act gives certain guidelines for the process. Account must be taken of obtained and quoted prices for petroleum of similar quality, with necessary adjustments for quality differences, transportation costs etc. to relevant markets. Thus, the Norm Price should reflect the specific value of the petroleum from each particular field. As an example, the Norm Price for Troll crude oil was set to USD 93.75 for 17 December 2010. The USD/NOK exchange rate was set to 5.59518. The price shall reflect what the Troll crude oil could have been sold for between independent parties.

The Norm Price is stipulated at a specific Norm Price Point. For petroleum landed through pipelines, the Norm Price is stipulated as the value at the landing point. For offshore loading, the Norm Price may be stipulated at the loading buoy offshore, or in a North Sea harbour. The Norm Price Point is important to establish transportation costs etc. in order to fix the fair market value of the petroleum at the designated geographical point.

The Norm Price also determines the timing of taxation. The produced petroleum is taxable at the time it passes the Norm Price Point. Section 2 of the Norm Price Regulations states that income is taxable at the Norm Price at the time the petroleum passes the point which is assumed as the delivery point of the stipulated Norm Price. Thus, it is immaterial whether the petroleum is subsequently shipped to the tax payer's own facilities, used in further downstream activities such as refining, or sold to affiliated companies or independent third parties.

As the Norm Price replaces the actual sales price, there may be differences between the recorded income in accounts from the sale of petroleum, and the value fixed by the Norm Price. These differences will not have any tax effect. A positive difference (sales revenue higher than Norm Price) will represent a tax-free income. A negative difference will be a non-deductible cost for tax purposes.

When the Norm Price is stipulated, it must be determined which costs are included in the value at the Norm Price Point. As mentioned above, the Norm Price should take account of transportation costs to the relevant market for the crude oil. As a general rule, costs which are assumed included in the Norm Price cannot be deducted separately. In Rt. 2007 page 1729 *TOTAL,* the company claimed deductions for a handling fee paid to Statoil on crude oil lifting from various fields where TOTAL had small participating interests. TOTAL had concluded agreements with Statoil where Statoil purchased the produced petroleum at the Norm Price Point for the fields. Furthermore, a service agreement was concluded where Statoil would handle the nomination procedure for the volumes up to lifting. TOTAL paid a fee to Statoil, referred to as a handling fee, for the petroleum. TOTAL argued that this fee represented a cost of getting the crude oil to the Norm Price Point where it was sold to Statoil. The Supreme Court found that the Norm Price assumes that the seller carries out all activities which are necessary for supplying the petroleum at the Norm Price Point. Costs accrued before the Norm Price Point are deductible. The court found, however, that the activities under the service agreement were mostly also covered by the sales agreement, and concluded that the service fees did not relate to any particular costs prior to the Norm Price Point. The fees represented a reduction in the value or a discount on the crude oil which was sold at Norm Price, and was consequently not deductible.

The legislation opens up for stipulating a Norm Price for all types of produced petroleum. The transfer pricing problem and the control requirements referred to in the preparatory works to the legislation were at the time primarily relevant to crude oil sales. In later years we have seen similar issues on dry gas and liquids sales between affiliated companies.

6.3 Dry gas and condensates

Sale of dry gas from the NCS was previously coordinated through a Gas Negotiations Committee where the Norwegian companies had a dominant role. The system ensured that gas contracts were negotiated between independent parties and the transfer pricing issues which were relevant to the crude oil production were of less importance for dry gas sales. The system of coordinated gas sales was upheld until 2003 when a major reform of the system for sale and transportation of gas was implemented. The EU competition authorities questioned the gas sales system in relation to competition regulations. Following the process with the EU, the joint marketing of Norwegian gas through the Gas Negotiations Committee was abolished, the important dry gas transportation systems were merged into Gassled and opened up to third party access, and a new tariff system was adopted within the new tariff regulations. As from 2003 the producing companies have marketed and sold their own gas under contracts with individual buyers.

Since Norm Prices are not stipulated for dry gas and condensate, achieved sales prices are the basis for taxation. Traditionally, large quantities of gas are sold to independent buyers under the long-term gas supply contracts where the price is often linked to crude oil price indexes. Over the years, the price structure in the different dry gas markets has been increasingly transparent with market reflective indexes on several trading hubs. Presently, gas is sold partly under long term contracts, and partly in well functioning markets in the UK (NBP) and other trading hubs on the European continent.

Sales to independent buyers do not raise any transfer pricing issues. However, we also see that many of the companies sell gas to their affiliated trading companies which handle the gas produced by the entire group in the various market places. Thus, transfer pricing issues have become increasingly relevant and complex also for dry gas sales. All gas sales between affiliated companies are subject to the arm's length principle under the GTA 13-1 which also refers to the OECD Transfer Pricing Guidelines and Methods. See section 14 below. The increasing liquidity in the European dry gas marketplaces, with indexes reflecting a large number of trades between independent parties, will represent a reliable basis for establishing arm's length prices on inter group dry gas sales.

In 2005, the Ministry of Finance considered various means to stipulate market prices for tax purposes for gas sales between affiliated companies. In Ot.prp. no. 1 (2005-2006) the Ministry concluded that it was difficult to introduce a Norm Price system due to the fact that the market value of gas may vary significantly with differing contract terms for the supply. The Ministry instead proposed a system where the companies could apply for an advance approval of the price on inter-group sales of natural gas. Rules were introduced in the PTA Section 6 fifth paragraph, under which the companies submit an application to the Oil Taxation Office. The Office may give an advance approval for a limited time period, usually not more than three years. The approval may not be appealed or tried in the civil courts. If the approval is accepted by the tax payer, it is also binding in the tax assessment of the company, both for the company and for the Oil Tax Board.

The system with advance approvals has not been very popular in the industry. To our knowledge, one approval was rendered in 2007, and another approval was recently rendered in 2011. The experience is that the process of obtaining an approval from the Oil Taxation Office requires substantial resources and is very time consuming.

By an Act of 25 June 2010, the PTA Section 6 was amended, and a system was introduced where all tax payers are under an obligation to report all terms of sales of natural gas which is taxable under the PTA Section 5. Terms and conditions must be reported to the Oil Taxation Office quarterly, within one month of the quarter. The intention is to create a database which can provide bench marks for the Oil Taxation Office for determining arm's length prices for dry gas. This raises some controversial issues, such as a tax payer's access to the relevant information in the database in the assessment process or in subsequent litigation.

The experience over the last few years has shown that it can be a challenging exercise to determine arm's length pricing of gas sales. The market is complex and it is difficult to understand the mechanics and the various value drivers in the market. Trading companies with large gas portfolios will trade actively to optimise the value of the portfolio.

When a producing company trades actively in the market, a question arises as to what types of income are included in the Special Tax basis. As mentioned earlier, it has been held that the Special Tax basis should be limited to the true production income, and should not extend to types of income which could also be earned by other tax payers than the producing companies.

In an Appeals Board ruling from 1990 (published www.Lovdata.no psk-19900219-A) the participants on the Ekofisk field had purchased gas from neighbouring fields. The gas could be used either for injection in Ekofisk, or it could be sold under the gas sales contracts with European buyers for gas produced at Ekofisk. The companies argued that the profit on the purchased gas was a trading profit which was not liable to Special Tax. The Appeals Board agreed that a regular trading activity would not in itself be an activity subject to Special Tax. In this instance, however, the Board concluded that there was such a degree of actual and commercial integration of the gas purchases and the oil and gas production from Ekofisk that the profit was income derived by the production activity and subject to Special Tax. Thus, if there is a high degree of *actual and commercial integration of the various activities*, the income will be liable to Special Tax.

6.4 Special Tax basis

It follows from the PTA Section 5 second paragraph that the Special Tax is assessed on the general income tax basis for activities liable to Special Tax. Losses from other activities may not be deducted in the Special Tax basis.[12] The Special Tax basis is established by applying the rules of the General Tax Act, supplemented by the particular rules set out in the PTA. The Special Tax is levied on the net income with an additional deduction of Uplift, which is an investment based deduction in the Special Tax basis, ref. section 7.4 below.

[12] But 50% of losses from other activities may be deducted in the offshore general income tax basis (i.e. 28% tax) of the petroleum production, treatment and pipeline transportation activites, ref. the PTA Section 3 c) last paragraph.

7 Deductions and depriciations

7.1 General

With a marginal tax rate of 78%, deductible costs are of course an important aspect of the tax system. As seen above, a number of measures have been introduced to ensure that taxable income is appropriately taxed to Norway through Norm Price regulations and arm's length pricing requirements. Similar concerns are also highly relevant on the cost side. Significant charges to the industry are based on inter-group transactions and services between related entities located within materially different tax regimes. Thus, the cost side is equally important when assessing the tax liability of each individual tax payer.

7.2 Deductible costs

As a general rule, all costs incurred to earn taxable income are deductible. In relation to the Special Tax, it is required that they are connected to the *production, treatment and transportation* activities which are liable to the Special Tax under the PTA Section 5. This means that all incurred operating costs, maintenance, all transportation tariffs, leases of facilities etc. are deductible in the tax basis.

There are certain particular provisions of relevance. Under the PTA Section 3 e), there is no deduction of sales provisions, discounts or costs on sale of petroleum between affiliated companies. The provision was adopted in 1980. It was assumed by the authorities that normally there would be minor sales costs on transactions within an affiliated group of companies. Based on the principle that only costs up to the point of taxation (Norm Price Point, see section 6.3 above) should be deductible, the express provision was added to disallow such discounts. It is our understanding that the provision has only been invoked by the Oil Taxation Office on transactions which are taxable in the Norm Price system, i.e. crude oil sales. Thus, an arm's length discount on, for instance, dry gas sales between related companies should not be disallowed. The reason is that it is difficult to distinguish between the price which is subject to the arm's length test and the discount. The net value of the transaction will therefore be tested under the arm's length principle.

Also general rules of taxation may restrict deductions for particular types of costs. One example is entertainment costs under the GTA Section 6-21.

It must also be distinguished between costs which are deductible and investments which are only deductible through depreciations. If a cost represents a benefit to a tax payer in the future, the main rule is that it represents an investment which will be capitalised, and then be considered for depreciations over time.

Exploration costs are deductible under the PTA Section 3 when they are incurred, regardless of whether or not the activities lead to commercial discoveries.[13]

R&D costs are deductible, unless they are connected to *specific projects which may or have become assets*, in which event they must be capitalised and depreciated, the GTA Section 6-25.

7.3 Investments in production facilities and depreciations

Investments may not be deducted immediately. It is required that they are capitalised and depreciated under the relevant rules for the type of investments or assets. In the general tax system, physical assets are depreciated under a declining balance system with different rates for groups of assets within different categories. The rates vary from 2% annually on office buildings to 30% on office machines and similar investments. Depreciations commence when the asset is acquired, or taken into use.

[13] In an Oslo City Court judgment (TOSLO-2010-44196) *Statoil*, the company argued that the same follows from general tax legislation. The City Court did not agree, and upheld the assessment where exploration costs incurred in Angola and Denmark were capitalised as investments in the various licences. The judgment was appealed.

The PTA Section 3 b) sets out particular rules on production installations and pipelines. These may be depreciated with 16⅔% annually from the year when the investment is made. Depreciations over 6 years from the year of investment will normally entail substantial tax credits. The production installations and pipelines will normally have a lifetime significantly longer than the 6 years. The expert committee which rendered its report in NOU 2000:18 argued that the depreciation rates were much too high compared to the economic lifetime of many of the assets in the petroleum sector (section 9.5.3). They suggested that new rules on depreciation should be introduced, but did not suggest a specific recommendation.

The rates have been upheld, and the elements of tax credit and the effects on the investment decision must be regarded as one of the parameters in the overall petroleum tax system.

The depreciation rates apply to fixed installations for production and treatment, and pipeline transportation, within the geographical scope of the PTA. Other physical assets will be depreciated under the rules of the GTA, even if they are connected to the business activities subject to Special Tax.

All costs incurred in the investment must be capitalised. This includes an allocation of indirect costs which can be attributed to development projects, for instance through allocation keys.

It further follows from Section 3 b) that investments in assets pursuant to a plan for development of cooling gas to liquid in large scale facilities located in the northernmost parts of Norway may be depreciated by 33⅓% per year. This was specifically designed as a tax incentive for development of the Snøhvit field with the LNG plant at Melkøya in Hammerfest. The investments in the project could therefore be depreciated over three years, whereas the LNG plant will produce for many years to come.

7.4 Special Tax basis, Uplift

Under the PTA Section 5 third paragraph, the Special Tax basis shall be reduced with an Uplift, which is set at 7.5% of the cost price of assets which are depreciated under the Act Section 3 b). The Uplift is allowed over four years, i.e. totalling 30% of the total investment. The Uplift is deductible in the Special Tax basis only, i.e. with the 50% tax rate.

7.5 Owning versus leasing of production installations

Only the owner of production facilities is entitled to the depreciations and Uplift, and the entailing tax credits as described above. This effectively prevented other types of enterprises from supplying such installations to the industry under operational leases. Lease charges are deductible as operating cost, but only when they are actually incurred by the tax payer.

In 1998 a new provision was adopted in the PTA Section 3 i) under which a party liable to Special Tax can claim deductions under particular rules stipulated in regulations issued by the Ministry of Finance. The main principle is that leasing of relevant assets shall, to the extent possible, be treated on the same basis as owning the asset. Thus, the regulations stipulate that the lease charges are disregarded and the lease deemed an acquisition at the commencement of the lease, and a realisation at the termination of the lease. A deemed cost price and sales price is stipulated and there are more detailed provisions on calculating depreciations and Uplift, and the interest component of the lease payments. At the termination, deemed capital gains and losses on a realisation of the asset are stipulated for tax purposes.

8 Financial charges

8.1 Challenges

Financial charges are deductible under the general tax system. It has been a continuous challenge for the Norwegian State how to treat financial charges within the petroleum tax system. One important concern has been to ensure that taxes in Norway are creditable under double tax treaties, in particular the treaty with the United States. It is important for a host state to ensure that double taxation is avoided for investors in the activities, to reduce the overall tax cost on the investment. This issue was tried in the US Tax Court in 1996, which concluded that the Norwegian Special Tax qualified as a creditable tax under internal US legislation.[14]

Maintaining deductibility in the Special Tax basis means that financial charges are deductible with the tax rate of 78%. This, of course, creates major incentives for debt financing rather than equity financing of investments. At the same time, a tax neutral system would require that interest income should be taxable at the same rates. There have been several cases in the Appeals Board and in the civil courts on transactions where the motivation for transactions has appeared to be to benefit from the interest deductibility in the Special Tax basis. Over the years, we have seen many initiatives from the Ministry of Finance in respect of changes to the treatment of financial charges. This has involved different allocation systems to attribute financial charges to the off-shore and on-shore activities respectively and another measure has been to limit the total amount of financial charges which are deductible in the Norwegian tax basis.

In 1975, financial charges were allocated on-shore and off-shore according to net taxable income in the two regimes. This system survived until 2001, even though it was widely recognised that it resulted in an over-allocation of interest charges to the Special Tax basis. In particular, the Norwegian companies, such as Statoil, Norsk Hydro and Saga Petroleum, benefited from over-allocating financial charges to the off-shore tax basis. By 2002, this allocation system was abolished and replaced by an allocation based on the written down tax values of assets in the two tax regimes.

Thin capitalisation was also a major issue in the assessment of the companies. The companies chose to debt finance the activities to the extent possible, and a large part of the debt financing was taken up

14 Referred to in NOU:18 page 123.

with related companies within the group. In the assessment bodies, a practice to establish arm's length requirement was developed, which in short required that exploration was deemed to be financed 100% with equity, whereas development could be financed with 20% equity and 80% debt. Excess debt financing would lead to a corresponding disallowance of financial costs. From 2002 a thin capitalisation rule was adopted in the PTA Section 3 h) requiring 20% equity of the total balance sheet. If the debt was higher, the interest charges would be reduced proportionately.

8.2 Current system

The system was again amended in 2007 by changes adopted to the PTA Section 3 d). The system now is a direct allocation system for interest charges on interest bearing debt allowable in the Special Tax regime. Deductible financial charges are calculated directly, and any excess interest costs are allocated on-shore. A formula was developed, which was generally considered to be tax neutral. It was, however, recognised that the new rules could have different effects for companies in different phases of the activities.

Net financial charges under the provision now include *interest charges and currency losses adjusted for currency gains on the debt*. The deductible charges are set to a share of the companies' financial charges equal to 50% of the tax book value as per 31 December of assets in the offshore tax regime divided by average interest bearing debt through the income year:

> Deductible charges = (0,5*tax book values off-shore year end)/(Average interest bearing debt)

Under the previous systems the allocation method opened up for adapting the financial accounts to maximise the allocation off-shore. Under the current rules, the allocation basis will not exceed 50% of written-down tax values at year end. Increasing debt will not materially increase the deduction of financial charges, and financial window dressing will have less effect on the total deductible charges.

8.3 Financial income

Under the current system financial income is kept outside of the Special Tax system, and taxed with the general income tax rate of 28%.

9 Annual refund from the state of the tax value of exploration costs

9.1 Background

Exploration costs are deductible in both the general income tax base and the Special Tax base. If a company has other taxable income, the State carries 78% of the costs through the deduction. If the company does not have other taxable income, the exploration costs will have to be carried forward against future income.

Over time it became evident that the Norwegian tax system favoured well established companies with producing fields and taxable income to shelter exploration costs. New entrants in the activity would have to finance exploration fully themselves, and carry losses forward against possible future taxable income. An attractive alternative was to acquire licence interests in producing fields to obtain taxable income as a shelter for exploration costs. The established companies were, however, not particularly willing to sell off their assets.

In St.meld. no. 2 (2003-2004), the Ministry of Finance outlined proposals to increase competition on the NCS by reducing the entry barriers and facilitating transactions in licence interests. This would improve the State's resource management, and increase exploration activities and efforts to enhance recovery from fields in decline.

9.2 Refund of tax value

In the White Paper Ot.prop. no. 1 (2004-2005) the Ministry of Finance proposed new legislation which would materially improve the situation for new entrants in the activities. In order to create more equal terms between companies in a taxpaying position and newcomers, the Ministry proposed that a company could claim an annual refund from the State of the tax value of its exploration costs incurred during the year. The new provisions were adopted in the PTA Section 3 c), effective for the income year 2005. Further changes in 2007 allowed the taxpayer to pledge the claim for the refund against the State. This enabled companies to finance exploration activity with security in the annual claim for refund.

The taxpayer can claim a refund of the tax value of *direct and indirect costs (excluding financial costs) for exploration for petroleum resources*. The first requirement is that the company carries out an activity liable to Special Tax under the PTA Section 5.

Exploration costs will typically be acquisition of geological data through seismic or geophysical collection, drilling of exploration wells, and costs of analysing data. The provision also opens up for a refund of *indirect costs*. In the preparatory works it was stated that a company which only carries out exploration could be entitled to a refund based on its entire costs. The Appeals Board has rendered several rulings which appear more restrictive. They have required that the costs in their nature must be exploration costs. Such costs could also attract a part of indirect costs which could be included in the refund basis.

The Appeals Board has not accepted costs of a more general nature, such as establishing a company, costs of prequalifying as a licensee, marketing costs etc., as exploration costs. Acquisition costs for licences will not qualify. They represent investments in the license as such. Subsequent exploration on the licence will, however, qualify for refunds. Transactions based on carrying of exploration costs can lead to a right to refund for the party carrying the costs. This follows from the regulations to the PTA Section 10, see section 12.2 below.

The refund can be claimed within the annual loss incurred by the company. Thus, if the company has other taxable income from production, the annual net loss will be the limitation of a claim for refund rather than the entire exploration costs.

The refund will be the tax value of the costs, i.e. 78% with the current tax rates.

The intention of the refund system was to encourage new entrants and more exploration. To this end, it has proven a success, and we have seen a steady increase in the number of exploration wells drilled annually after 2005. Approximately 40 companies qualified for a refund in 2009, and the total refund from the State was approximately NOK 9 billion.

An expert committee appointed by the Ministry of Petroleum and Energy in 2010 (the Åm committee) indicated that the attractive refund system for exploration costs could detract focus and resources such as rig capacity from enhanced recovery programs for existing field in decline, and they proposed that the refund system should be reconsidered. In the Petroleum Policy document (Oljemeldingen) St.meld. no. 8 (2010-2011) the Ministry of Petroleum and Energy stated that the refund system had been important as an incentive to increase exploration, and that they would maintain a policy where companies are treated equally regardless of their tax position (page 63-64).

9.3 Assessment

A claim for a refund is submitted annually together with the tax return. The claim is considered in the assessment by the Oil Taxation Office and the Oil Tax Board, and the approved exploration costs are decided in the assessment. The tax value is refunded during December in the year following the income year.

10 Refund of tax value of loss carry forward upon cessation

Under the PTA Section 3 c), a company may carry tax losses forward indefinitely. As from 2002, the annual loss is also adjusted with an interest to maintain its real value until it is set off against taxable income. This was introduced to make the system more attractive to newcomers.

In 2005 an additional incentive was introduced in the same White Paper as the tax refund on exploration costs. Through the exploration refund, the annual loss of the company resulting from exploration costs will be refunded. A company may, however, also have other costs leading to loss carried forward, such as depreciations of investments and costs which are not accepted as exploration costs under the refund system.

Under the PTA Section 3 c), a taxpayer may also claim a refund of the tax value of the loss carried forward when the business activity liable to Special Tax ceases. The tax value is the loss carried forward multiplied by the tax rate, i.e. currently 78%. The loss carry forward refund system again reduces the risk of participants in the Norwegian petroleum sector, by ensuring that the State, in the end, will carry 78% (provided the tax rates are upheld) of any losses resulting from the investment.

A loss carried forward may also be transferred to a buyer together with the entire business activity in which the loss originated. Thus, if a company sells off all of its Production Licences, it may also transfer the loss carried forward to the buyer, who in turn, can set off the loss against other taxable income.

11 Timing of taxation

11.1 Realisation principle

The petroleum tax system has been based on the general provisions on timing of taxation in the General Income Tax Act. Historically, the timing has been based on the accounts of the taxpayer, provided they were prepared in accordance with prudent accounting principles. From a tax reform in 1992, the importance of the financial accounts was significantly reduced, since there was a specific provision disallowing deduction of provisions based on *prudent accounting principles*. In addition, it followed from the PTA Section 3 g) that costs of removal of installations on fields on the NCS would not be deductible until the costs were actually incurred.

During the second half of the 1990s some companies claimed deduction for costs for decommissioning and plugging and abandonment, which were accrued in accounts under a unit of production principle. This issue was brought to the Civil Courts, and the Supreme Court rendered its decision in *Shell* in Rt. 2004 page 1921. The majority (3-2) concluded that decommissioning and plugging and abandonment costs were deductible. The State was not particularly happy with the ruling, and appealed similar cases to the Supreme Court to have the issue tried once more. The Supreme Court did not allow the appeal to be heard. In 2005 new legislation was proposed where a realisation principle was introduced as the new principle governing timing of taxation, clearly aimed at the *Shell* judgment. Under the GTA Section 14-2, a benefit shall be taken as income in the year when it accrues to the taxpayer. Costs may be deducted in the year when an unconditional obligation arises. The year of payment (a cash principle) is not relevant.

11.2 Decommissioning and removal

Following the new legislation in 2005, it is clear that decommissioning and plugging and abandonment, as well as costs of removal of installations are deductible when the costs are actually incurred, i.e. when the work is carried out. This means that there is a risk that a company does not have taxable income to shelter such costs, if the company does not have other producing assets. The costs will, however, be allowed to be carried forward, and the refund system upon cessation described above will ensure that when the activity ceases, the State will pick up the tax value of the losses (provided the refund system is not abolished in the meantime).

12 Transfer of licences, tax neutrality

12.1 PTA Section 10 – background and principles

Under general tax legislation, realisation of assets in a business entail a capital gain taxation or deduction of losses. In 1987 a new Section 10 of the PTA was adopted with the intension of ensuring a flexible system for handling licence transactions, and at the same time avoiding tax driven types of transactions. Section 10 states that all licence transactions which are subject to approval by the Ministry of Petroleum and Energy under the Petroleum Act (1996) Section 10-12 are also subject to approval by the Ministry of Finance of the tax consequences. The Ministry may stipulate specific conditions, which may deviate from the tax legislation.

In the preparatory works to the provision, it follows very clearly that the objective was to make licence transactions tax neutral to the State. For instance, the buyer should not receive a step-up of the depreciation basis of the transferred assets, unless there was a corresponding increase of tax payments (in NPV terms) on part of the Seller. Furthermore, if one party was in a loss carry forward situation, particular means would have to be introduced to neutralise the tax effects of a transaction to the State.

Initially, each transaction was handled individually with a specific approval rendered by the Ministry.

Over years, the Ministry has attempted to simplify the process through general regulations rather than specific approvals. By regulations 1 July 2009, transactions subject to the PTA Section 10 will be deemed approved if they comply with the requirements of the regulations. The regulations set out certain types of transactions and how they shall be treated for tax purposes to ensure the principle of tax neutrality to the State.

12.2 Section 10 Regulations

On transactions involving production licences, Section 3 of the Regulations set out that the consideration shall be a finally determined cash consideration which shall be treated as tax free to the seller and non-deductible for the buyer. Thus, the principle is that the transactions are carried out based on after tax values.

Furthermore, the seller shall transfer to the buyer any remaining tax depreciation basis and uplift related to the licence, whereas the seller shall retain losses carried forward and other deferred gain and loss tax liabilities.

Section 4 of the regulations sets out that in transactions with exploration licences where the buyer carries future exploration costs of the seller, the costs will be deductible (and thereby also eligible for a tax refund) for the party which finally carries the costs.

On transactions in shares in companies holding production licences, the main principle is that a transaction will have no effect on the taxes of the entity.

If the terms of a transaction do not comply with the requirements of the regulations, a specific approval will have to be obtained from the Ministry of Finance. A clear intention of the Ministry has been that the vast majority of transactions should be handled within the system of the regulations, and we anticipate that they will be reluctant to render specific approvals if the parties agree terms and conditions which differ from the regulations.

To obtain a deemed approval, information on the transaction with enclosed agreements and other relevant documentation must be submitted to the Ministry of Finance with a copy to the Oil Taxation Office.

13 Capital gains and losses on disposal of other assets

The PTA Section 10 system for taxation of transactions in licence interests will cover the majority of transactions involving assets on the NCS. In some instances, physical assets may be sold separately, or losses of assets through accidents may also constitute taxable events. Capital gains and losses on disposals of physical assets are taxable or deductible respectively, ref. the PTA Section 3 f). The taxation is deferred so that gains shall be taken as income with at least 16⅔% per year. Losses may be deducted with up to 16⅔% per year. Similarly, there is a carry back system for Uplift under the PTA Section 5 fifth paragraph.

The remaining tax book value of an asset which loses its value upon cessation of production from a field may be fully deducted in the year of cessation. This improves the after tax return on investment in fields which have a lifetime of less than 6 years from the date of investment.

14 Transfer pricing and discretionary assessment of income

14.1 Transfer pricing in general

Transfer pricing is the prices charged between related parties for goods, services or other assets. A large share of all international trade is between related parties. These transactions may not be subject to the same market negotiations as between unrelated parties. Any deviation from market conditions, whether intentional or not, will have direct influence on the profits of the involved parties and thereby the amount of direct taxes they will be liable for. Transfer pricing may also have an influence on the indirect taxes such as customs duties and VAT if the services, goods or assets are exported/imported.

Hence, there is a widespread concern of the tax authorities in most countries that transfer pricing is used by the multinational enterprises to shift profits, typically from high tax countries to low tax countries. Even between countries with the same tax rate, incorrect transfer prices will shift the tax revenue between the countries. Hence, even if the multinational group itself may not have any incentive to shift income, the tax authorities may be interested in reviewing the transfer prices to protect its own tax base. Transfer pricing may also be an important domestic challenge if the involved parties are subject to different tax rates or tax systems. A typical example is the Norwegian Petroleum Tax system with the additional 50% Special Tax.

The general principle regarding attribution of income is that an item of income shall be taxed in the hands of the person who has earned or is otherwise entitled to it according to the rules of civil law. Conversely, an expense is only deductible for the person who is effectively obliged to bear it. Once an item of income has been earned, the tax liability cannot as a general rule be avoided by transferring the income to another person. Likewise, where a taxpayer bears costs attributable to another person, the taxpayer will normally not obtain any tax deduction.

Even though the fundamental principles of income attribution (as well as the non-statutory general anti-avoidance norm) in many cases would be sufficient to adjust artificial transfer pricing between related parties, the General Tax Act has since 1911 contained an express provision establishing the arm's length principle in Norwegian tax law, now contained in the GTA Section 13-1.

The basic idea of the arm's length principle is that the transfer prices in related transactions should correspond with those which would be negotiated between independent firms. The arm's length principle is the agreed international standard to ensure a fair division of the tax base of multinational groups and most countries have implemented this in their domestic regulations. In addition, the arm's length principle is set out in the OECD Model Tax Convention, Article 9. Normally, the main part of this article setting out the arm's length principle is included in the various tax treaties entered into and, allegedly, in all tax treaties entered into by Norway.

OECD has carried out substantial work in order to detail the contents of the arm's length principle through the issue and continuous updates of the OECD Transfer Pricing Guidelines for Multinational Enterprises and Tax Administrations (OECD TP Guidelines), see section 14.3 below.

14.2 General Tax Act Section 13-1

The General Tax Act Section 13-1 (1) states that if a taxpayer's income or wealth is reduced due to community of interest with another party, the tax authorities may adjust the wealth or income. In the discretionary assessment, the wealth or income shall be assessed as if there had been no community of interest, 13-1 (3).

The provision has been used to ensure arm's length pricing between associated companies, and also to deny deduction of interest in thin capitalisation cases. A company is said to be thinly capitalised when its level of debt exceeds the level found in independent companies, and provided that the debt is from a related party.

When interpreting the contents of Section 13-1, it is relevant to consider the OECD TP Guidelines. This was confirmed by the Supreme Court in Rt. 2001 p 1265 *Agip* and is now explicitly set out in Section 13-1 (4). The tax authorities shall take the OECD TP Guidelines into consideration, both when determining if the income has been reduced and for the purpose of a discretionary assessment. The clause includes a reservation that this only applies to the extent that Norway has acceded to the Guidelines (which Norway has so far), and provided that the Ministry has not decided otherwise (which they so far have not), Section 13-1 (4) last sentence.

Pursuant to Section 13-1 (1), there are three conditions that must be fulfilled before the tax authorities may adjust the income;

- There must be a community of interest between the parties
- The income of the taxpayer must be "reduced"
- The reduction of income must be due to the community of interest

The condition "community of interest" is rarely disputed, as there is normally no doubt that the condition is fulfilled, typically because the involved parties belong to the same group of companies. However, a community of interest may be direct or indirect, formal or informal, and could in some instances be based on factors other than ownership. For instance, the controlling position of a creditor or the relationship between relatives could be sufficient to satisfy the requirement.

In order to ascertain that a reduction of income has occurred, one has to compare the reported income with an alternative "normal" situation assumed to prevail in an uncontrolled market. This is the key element of the arm's length principle – to determine what the price would have been between independent parties. The examination of whether the income is "reduced", Section 13-1 (1), is therefore not very different from the considerations of what the acceptable arm's length terms should be, Section 13-1(2). It is not relevant in which manner the income has been reduced, nor is it a requirement that the reduction of income has been intentional or substantial.

If it is established that there is community of interest and that the income has been reduced, the question is whether there is a causal connection between the two. If the associated enterprise is resident outside the EEA, or in an EEA state with which Norway has not concluded a tax information exchange agreement, the reduction of the income is presumed by law to be caused by the community of interest, Section 13-1 (2). In order to rebut the presumption, the taxpayer must prove either that community of interest does not exist or that there is no causal link between the special relationship and the reduction of income.

If the conditions for adjusting the income are met, the tax authorities will determine the amount of the taxable income seeking to establish what the income would have been if no community of interest had existed, 13-1 (3). The task is to consider on what terms and conditions the taxpayer would or could have contracted or conducted its business in dealings with unrelated parties. In these considerations, no particular transfer pricing method detailed in the OECD TP Guidelines is mandatory or excluded. Both internal and external comparisons may be appropriate. It is essential that a genuine discretionary estimation be made on the basis of all relevant facts and circumstances of the particular case. If the estimation is not genuine, but on the contrary arbitrary, the courts may annul the assessment. As noted above, the tax authorities shall normally take into consideration the OECD TP Guidelines when making their assessment.

In Norway, the number and amounts involved in transfer pricing adjustments have increased considerably over the years. Due to the high amounts involved and the high tax rates, companies subject to the petroleum tax regime have been faced with many challenges related to transfer pricing. However, considerable adjustments are also made by the other tax offices.

14.3 The OECD TP Guidelines

The OECD TP Guidelines provide more detailed guidance on the application of the arm's length principle set down in the Model Tax Convention Article 9 and in most countries' domestic law, in Norway Section 13-1.

The OECD TP Guidelines were first issued in 1979, with a comprehensive, thorough update and expansion in 1995. In particular, important new material was added on comparability (if a transaction between independent firms is sufficiently similar to a related party transfer) and with respect to the description of the transfer pricing methods, including the profit methods. Following the launch of the revised guidelines, further chapters and updates have been added, and with a more thorough revision taking place in 2010.

Following the 2010 update, the OECD TP Guidelines currently consist of nine chapters. These include a general description of the arm's length principle, the different methods that could be used to determine appropriate transfer prices and a description of the comparability analysis. In addition, the guidelines include specific chapters about documentation, intangible property, intra-group services, cost-contribution arrangements and business restructurings.

One of the basic principles under the arm's length principle and one of the key elements distinguishing transfer pricing from the non-statutory general anti-avoidance norm, is that the tax authorities must respect the transaction undertaken, OECD TP Guidelines clause 1.64. The transaction as such will only be tested in exceptional cases, being either that the economic substance of a transaction differs from its form or that the transaction undertaken, viewed as a whole, differs from that which independent parties could have entered into, provided that the actual structure impedes the tax authorities from determining an appropriate transfer price, clause 1.65.

When determining the transfer price, the OECD TP Guidelines describe five different transfer pricing methods that may be used. They consist of three traditional methods being: (i) the Comparable Uncontrolled Price Method (CUP), (ii) the Resale Price Method, and (iii) the Cost Plus Method; and two transactional profit methods, being (iv) the Profit Split Method and (v) the Transactional Net Margin Method.

The CUP Method determines the appropriate transfer price by comparing the price in the controlled transaction with the price charged in a similar transaction between independent parties. If sufficient comparable transactions exit, this method is the most direct and reliable way to apply the arm's length principle and thus preferable over all other methods. However, it is often difficult to find sufficiently comparable transactions.

The Resale Method begins with the price at which a product that has been purchased from a related party is resold to an independent party. This price is then reduced with an appropriate gross margin representing the amount an independent reseller would be seek to cover its costs and appropriate profit. The appropriate resale margin is determined by looking at the margin earned by the same reseller in comparable uncontrolled transactions (internal comparable) or by the margin earned by independent resellers (external comparable). The Resale Method is particularly appropriate if the reseller does not add much value to the product or service sold and where the resale takes place shortly after the related party transaction.

The Cost Plus Method starts with the costs incurred by the supplier of goods (or service) in a controlled transaction and adds an appropriate markup to this cost to find the arm's length price. The cost plus markup should be sufficient to cover the suppliers operating expenses as well as a profit margin. The markup is determined by looking at appropriate comparables, whether internal or external. The cost plus method is often used for provision of internal services (such as legal, accounting, HR, etc.) within a group as well as in captive insurance cases.

The Transactional Net Margin Method (TNMM) examines the net profit relative to an appropriate base (such as costs, sales, assets) realised by a related taxpayer in a controlled transaction with the profit realised in an unrelated transaction. Hence, the TNMM has clear similarities with the cost plus and resale price methods, except that it looks at the net profit and not a gross profit margin. Although the method has many weaknesses, data regarding net profits are often more available than gross profits. Hence, the method tends to be quite often used in practice.

The final method described in detail in the OECD TP Guidelines is the Profit Split Method. Unlike the others, this method starts by looking at the combined profit (or loss) incurred by the related parties in the transaction. Then this combined profit (or loss) is divided between the parties in an economically valid manner reflecting how independent parties would have divided the profit. The main benefit of this method is that it evaluates both parties in the transaction, not only the taxpayer. Hence, this method is recommended for highly integrated operations or where the parties contribute with unique intangibles.

The selection of a transfer pricing method always aims at finding the most appropriate method for the particular transaction. This does not mean that the taxpayer or the tax authorities are obliged to review and analyse all methods before a selection is made, and the taxpayer could also use methods not described in the OECD TP Guidelines – as long as they comply with the arm's length principle.

The Norwegian tax authorities are, pursuant to Section 13-1 (4), obliged to take the OECD TP Guidelines into consideration. In many instances, the OECD TP Guidelines provide valuable insight and basis for both the companies and tax authorities when working with transfer pricing. However, the OECD TP Guidelines are quite lengthy and not written as binding regulations. They are also a result of a lengthy process involving many countries, lengthy discussions and many compromises in order for all countries to agree to the text. Hence, the OECD TP Guidelines will often provide limited guidance for a specific case.

15 Current issues in petroleum taxation

Given the high tax rates, and the importance of the petroleum tax revenues to the State, it is not surprising that there are a number of large disputes handled in the administrative bodies and also in the Civil Courts. Some of the important cases have been the allocation of revenue between the off-shore and on-shore business sectors, which was the issue in *Statpipe*. There are still pending cases on how income should be attributed to activities taking place onshore.

The allocation system for financial charges has caused a number of disputes. Initially, thin capitalisation issues due to intergroup financing were controversial, until more firm guidelines were established in practice by the Appeals Board. Other issues related to financing have been more or less creative tax planning to benefit from the allocation of financial charges to the 78% tax regime. One such structure was reviewed by the Supreme Court in Rt. 2008 page 1537 *Conoco* where the State argued that an investment of the Norwegian Conoco entity in a receivable against a UK company acquired by the group should be set aside.

The Supreme Court awarded in favour of Conoco.

Another major issue was the timing of deduction for decommissioning and plugging and abandonment costs, which was finally resolved by the Supreme Court in *Shell*, and new legislation as a response from the State as from 2005.

Currently, the major issues appear to a large extent to relate to transfer pricing within the large multinational groups. The Oil Taxation Office has taken up the appropriate principles of allocation of indirect costs in the multinational groups, and the principles of distributing R&D-costs within these groups.

There are also a number of issues pending related to dry-gas sales such as: whether trading profits are taxable within the Special Tax basis; and the correct transfer price on sales to affiliated trading companies. Trading companies are often domiciled abroad, for instance in the UK, and the attribution of income to Norway or the UK will have significant tax consequences.

Even though the petroleum tax system has been maintained as a rather stable system over a number of years, the challenges for both the assessment bodies and on the companies continue.

Abbreviations

PTA – Petroleum Tax Act 13 June 1975

GTA – General Tax Act 26 March 1999

PTR – Petroleum Tax Regulations 30 April 1993

NCS – Norwegian Continental Shelf

PL – Production Licence

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