Long-term natural gas contracts and antitrust law in the European Union and the United States

Kim Talus*

Long-term natural gas contracts and their specific features are at the forefront of legal and policy discussions around the world. Issues like oil price indexation and price reviews, flexibility and take-or-pay clauses or a move to shorter term trading are being debated. This is particularly true for Europe where major changes are taking place, but also in places like Australia and Asia.

This study will focus on the antitrust treatment of long-term take-or-pay natural gas contracts and their specific provisions in the European Union and the United States. It will also examine the regulatory treatment of these contracts and the regulatory environment in which these contracts operate. Issues that are covered include questions on duration and volumes, take-or-pay provisions and oil indexation, destination or use restrictions, vertical integration and monopolization.

Recognitions and methodological remarks

This article was written as a part of a larger study on long-term natural gas contracts and EU competition law. The results of this study have been reported in this AIPN research article and in a book titled Vertical Natural Gas Transportation Capacity, Upstream Commodity Contracts and EU Competition Law (Kluwer Law International 2011). The focus in these two studies is different. The present article focuses on the legal aspects of the application of antitrust laws to natural gas contracts. It focuses on the application of law in the European Union (EU) and compares this to the situation in the United States (US). Drawing on the regulatory history in the US natural gas markets and the application of antitrust laws to long-term contracts, the study also provides for comparative remarks. The book on the other hand, focuses on competition ‘policy’ and the interplay between law and international geopolitics in the EU natural gas sector. It portrays a picture where the boundaries to the application of EU law in the natural gas sector are set by the geopolitics. It examines the role of politics in the application of law. The book also focuses on the question of how EU competition law should be applied to long-term natural gas commodity and capacity contracts, as opposed to the focus of this article which examines the application of the law.

* Lecturer in International Energy and Resources Law at the UCL School of Energy and Resources, Australia. Member of the CoE Foundations of European Law and Polity. Editor-in-Chief for Oil, Gas and Energy Law Intelligence (www.ogel.org).
This article has benefited from the discussions and comments from many academics and practitioners. I would, in particular, like to recognize the input of the late Professor Thomas Wälde, Professor Jonathan Stern, Mat Hughes, Professor Anthony Owen, Dr Mohan Kohle, Professor Andrei Konopolyanik, Professor Andrei Belyi, Professor Jacqueline Weaver, Peter Roberts, Darryl Anderson, Dr Henrik Bjornebye, Dr Bram Delvaux and Michael Hunt. I have also greatly benefited from the discussions on OGELFORUM and the material from the OGEL online journal.

One methodological remark is necessary. When conducting comparative research, the author always compares one legal order or a specific legal question to another. This means that one legal order is used as the base line for the comparison with the other. In this sense, the comparison is not symmetrical. In this study, the EU approach is compared to the US approach, not vice versa. As often is the case, this approach derives from the background of the author. An expert in EU law will compare this legal order to the other possible option. The EU legal order is the starting point against which other solutions are then measured and compared. In practice, this means that the application of EU law is examined in much detail. This examination is then complemented by an overview of the situation in the US. Here, the level of detail is lower and the intention is to provide a comparison to another legal order and another market highlighting and explaining the differences in approach, rather than an in-depth examination of the US natural gas markets and their regulation through sector-specific regulation and antitrust rules.

The approach of this article assumes that the reader will be familiar with the basic features of antitrust laws in the EU and the US. As such, it will not explain the basic applicable legal provisions or their correct interpretation. Instead, it examines the application of these rules in the energy markets, with focus on legal practice with respect to enforcement.

1. Introduction: gas is different

Gas is different from oil. The lower energy content per unit, dependency on local infrastructure, asset specificity, capital expenditure and the need to secure a market at the early stages of a project makes the exploration and production projects for natural gas different from those of oil. As such, a typical contract would treat natural gas somewhat differently from oil and, from the producer perspective, the contract between the producer and the gas purchaser becomes crucial for the project. These factors speak heavily in favour of a contractual structure of a long duration and with stable pricing. Various clauses typically associated with these contracts have a specific function and provide for mechanisms to, for example, hedge price and quantity risks or ensure competitiveness. In addition to the questions relating to issues like the ‘hold-up problem’ or obsolescent bargain (as the producer will have made a substantial sunk investment in developing the gas field), the argument is that long-term supply contracts are an essential part of the financing of large scale natural resource projects by providing security as to off-take and prices, from exploration and production to pipelines and/or natural gas liquefaction facilities. The
The concept for project financing is in essence that a given project is financed independently and the project sponsor(s) use the cash flow from the project output to provide collateral and the return on the investment. Natural gas purchasers may also desire long-term contracts in order to guarantee security of supply. Long-term take-or-pay contracts thus play a key role. The scope for international trade and downstream market structure are also relevant factors, since the need for long-term contracts will be increased when the number of prospective purchasers and suppliers into any market is smaller. However, these traditional drivers of long-term contracts are being impacted by an array of market and regulatory developments and these are considered further below.

This research article focuses on the antitrust treatment of long-term take-or-pay natural gas contracts and their specific provisions. It covers both the upstream contracts, signed between the upstream producer, Gazprom or Sonatrach, for example, and the EU buyer, E.ON Ruhrgas or GDF Suez for example, and the downstream contracts between the wholesaler and the end-customer. EU natural gas markets are undergoing a significant change from a monopolistic and nationally driven system to an EU wide and competitive market, including the development of international pipelines. The liberalization process initiated in the late 1980s has seen the progressive introduction of regulation aimed at creating competitive conditions in the markets. Along with this sector-specific regulatory regime, the European Commission has pushed the EU liberalization agenda through the application of EU competition laws. Given the momentum of this process and the changes caused by the global financial crisis, in addition to increased volumes of available LNG and the emergence of unconventional gas, including shale gas, tight gas and coalbed methane, the EU natural gas markets serve as an interesting experiment of regulatory choices and their effects. As such, focusing on the EU is a natural starting point.

In addition to EU natural gas markets, this article examines the progress of US natural gas markets and their regulation. The article examines and reflects on both the different market structures, existence of indigenous production compared to the reliance on external producers, and the very different developments of market regulation. However, even with these differences, there remain certain similarities in the approach to long-term natural gas contracts in both the EU and the US. Unlike the sections of the article concerning EU natural gas markets, the objective of the sections on US natural gas is not to provide a detailed picture of the markets and their regulation. The history of US natural gas markets is both old and colourful and as such, this article does not pretend to provide the whole picture with all of its nuances. Instead, the objective is to provide an overview of the regulatory setup, including the approach of the antitrust laws, applicable to the US natural gas markets. This will allow the reader to see certain differences and certain similarities to the situation in the EU.

The article initially explains some of the main characteristics of the EU natural gas markets and the main regulatory developments in the EU energy acquis. Once this has been done, the focus moves to the application of EU competition law in natural gas markets. In this context, the article first examines the competition law treatment of downstream contracts. The upstream contracts and certain provisions, including destination, take-or-pay clauses and oil price indexation clauses, in these contracts will
thereafter be examined. Where the approach of the European Commission is known and case law exists, the focus is on the application of the law. Where no case law or guidance exists, certain elements affecting competition law treatment is highlighted.

2. Long-term natural gas contracts and EU competition law

Introduction

Despite the recent changes in the natural gas markets both globally and in the EU, EU 27 is a net importer of natural gas, increasingly dependent on a very few producing countries. While some EU Member States, the UK and the Netherlands in particular, possess natural gas resources and others have potential to develop non-conventional natural gas resources, the bulk of natural gas for the EU comes from three sources: Russia (42 per cent), Norway (24 per cent) and Algeria (18 per cent). However, it must be noted that these percentages represent only the imports. Indigenous production in the EU represents 36 per cent of the total supplies and together with Norwegian supplies the figure is 55 per cent. Even with the potential emergence of unconventional gas, the picture is unlikely to change dramatically in medium term. Similarly, the demand for pipeline gas, which decreased significantly since the global economic crisis began, is already showing signs of recovering demand.

Due to this external dependency, the EU natural gas trade has two distinct components: a commercial, economic and legal component and a political component. This article focuses on the first mentioned component and will largely exclude the political aspects of natural gas markets in the EU.

Long-term natural gas commodity contracts have for decades been the backbone of the EU security of supply. From the 1970s, these contracts have been used to import more than 250 Bcm/year of natural gas to the EU area. Accepted as the modus operandi among both producers and the EU purchasers, the traditional view is that long-term take-or-pay contracts provide for a security of demand for the producer and security of steady supply for the purchaser. The producer has the certainty of demand and can plan for the necessary investments with a long-term rationale. The purchaser has the certainty of supplies and can therefore adopt a long-term strategy in downstream markets.

This traditional setting has now started to change in the EU. Due to the increasing flexibility that LNG, spot markets and potentially unconventional gas provide, the significance of long-term take-or-pay contracts from the purchaser point of view has started to change. These contracts and their built-in flexibility mechanisms are no longer the only sources of supply for the national incumbents. Instead, many EU purchasers have access to LNG and spot markets and the development of international pipelines has the potential to further increase their supply options. These alternative sources of supply, together with the storage of natural gas where this is possible, provide for flexibility in the incumbent’s purchasing portfolio that downplays the need to rely on long-term contracts for all the quantities necessary to supply the downstream customers.
The global financial crisis was followed by a recession that subsequently resulted in a significant decrease in the demand for natural gas. This, combined with the emergence of unconventional natural gas resources in the US, effectively closed the US markets for LNG imports and turned some of the LNG import facilities to export facilities. Consequently, the available volumes of natural gas both in terms of pipeline gas and LNG in the EU have increased considerably. The new volumes of LNG coming online from places such as Qatar, originally targeting the US markets but now being redirected to the EU markets and the boom in short-term trading and spot markets that followed in the EU have changed the environment in which traditional long-term natural gas contracts operate.

A further significant change has been the progressive liberalization of gas supply markets and the gradual integration of European gas supply markets due to new pipelines and regulatory measures (see further below), providing gas producers access to a greater range of gas purchasers.

In addition to these changes in the factual environment, there are also significant changes in the way in which natural gas markets are viewed in the EU. In approximately 20 years, the EU approach to natural gas markets has moved from very much a monopolistic and state controlled system to a more competitive and liberalized market. The regulatory framework that applies to natural gas transactions has changed considerably in the last 10 years. The introduction of third-party access (hereafter TPA) and congestion management as well as unbundling and the elimination of destination clauses and priority access regimes in the transmission system have all had a profound impact on the way in which natural gas markets function and on the role of long-term natural gas contracts.

The changing role of long-term contracts and the uncertainty that EU energy market liberalization has created are, understandably, causing concern for some producers, Gazprom in particular. For the producing countries, the revenue from hydrocarbons, be it oil or natural gas, is often the main or an important source of government income. Russia and Algeria are not exceptions to this. While Algeria is a major LNG exporter, thus capable of taking advantage of the flexibility of the international LNG trade, Russia and Gazprom are still largely relying on their EU customers and EU sales of natural gas via pipeline. While there are new projects that take advantage of the more flexible international LNG trade, such as the Sakhalin projects, and even if the diversification to China is slowly emerging, Russian gas exports are still mainly directed to the EU member states.

In keeping with the experience of producers, the new rules of the game and the potential loss of market shares due to the changes in the way the downstream markets operate have caused concerns for EU importers as well. These concerns have resulted in increasing discussion about the suitability of the current form of long-term natural gas contracting in the new market environment. These concerns are likely to lead to renegotiations of the traditional natural gas commodity contracts and to changes in certain provisions in these contracts.

The above changes in the EU natural gas markets have created a need to re-evaluate the traditional European energy governance paradigm based on long-term contracts.
traditional structure of long-term natural gas contracting with take-or-pay clauses, oil price linkages and netback pricing appears to have reached a cross-road. While long-term contracts were deemed a necessary component of energy security of EU natural gas markets for many years, the context in which these contracts operate has significantly changed. In tandem with this need to re-evaluate the role of the traditional contractual structures, a need to critically assess the antitrust treatment of these contracts has emerged.

The critical elements of the traditional natural gas trade in the EU are: 1) long-term take-or-pay contracts with a duration commonly ranging from 15 to 30 years between the producers and the EU purchasers with duration of the contract matching the duration of the investment; 2) on-border sales; 3) net-back pricing based on the replacement value of alternative fuels, minus the transportation cost from the delivery point to the market where the gas is consumed (because of this pricing mechanism, the prices differed even at the same delivery point); 4) destination clauses that prevent price arbitrage by the EU buyers; and (5) the distribution of risk based on a scheme in which the volume risk is assumed by the buyer and the price risk is assumed by the seller. As will be seen in the following sections, many of these elements have been or are currently being assessed from a competition law perspective.

This section will now provide an overview of the regulatory changes that have caused the above described need to re-evaluate or even adopt the traditional long-term natural gas contracts.

**Development of EU natural gas market regulation: unbundling and access**

**Unbundling**

Unbundling of network operations from supply activities is a fundamental measure to foster non-discriminatory treatment of a request to access the network. In the most basic terms, unbundling is necessary because there is an internal conflict of interest within a vertically integrated company: by allowing access to the network, the transmission/distribution branch of the company creates competition for the supply arm, which will have a negative impact on the overall return of the company. Logically a company will strive to maximize the group revenue and, in fact, the management also has this obligation to shareholders. This is in conflict with the idea of market liberalization: taken to the extreme, it will eliminate any and all competition and prevent market entry.

In practice, however, different degrees of unbundling can be achieved and have been recognized in the first, second and third Natural Gas Market Directives. The different kinds of unbundling models are as follows:

**Accounting unbundling**

This form of unbundling adopted in the first natural gas market Directive from 1998 calls for separation of accounts of network activities from those of generation and supply activities. In practice, the vertically integrated company can continue to exercise these different activities as long as accounts are clearly separated.
Management unbundling
This approach pushes the process of separation one step further. Following this model, the management of the network activity must be independent from that of the rest of the activities of the energy company. Together with the accounting unbundling, this was the limit of the first natural gas market Directive.

Legal Unbundling
Under this model, adopted in the 2003 natural gas market Directive, the network operations become even more independent from other activities since a separate legal entity is set-up and will be called to exercise all the activities of the network operator.

Ownership unbundling
This last and most pervasive form of unbundling requires the vertically integrated company to divest assets in favour of third parties which are not themselves involved in generation or supply. This is the most invasive form of unbundling as it requires a change in the property rights of the network operator. This was the original aim of the European Commission when it introduced the idea of a third natural gas market Directive. However, due to a political resistance from certain EU Member, France and Germany in particular, and, to a lesser extent, questions on the compatibility of ownership unbundling with general EU law and even European Convention of Human Rights, the new provisions on ownership unbundling were accompanied by other somewhat less intrusive options.

Under the new regime, EU Member States are given a three-way choice. In practice, they may decide to opt either for full ownership unbundling, an independent system operator model (ISO), or an independent transmission operator (ITO) model put forward by the Council. This last model, which did not appear in the original proposals of the Commission, allows the ownership of network to be maintained with the supply companies, but attempts to ensure the neutrality and independence of the transmission operator through a set of detailed conditions, including independent management, a supervisory board, a compliance officer and the possibility of substantial fines in case of mismanagement.

Despite these differences, both ownership unbundling and the ISO/ITO alternatives require that one company cannot be involved in both transmission and supply/generation. Compared with the traditional vertically integrated business model that was adopted in the EU natural gas industry in its early days, these developments have a profound impact on the way the natural gas business is run. Together with the new rules on TPA and congestion management, they also impact the traditional contractual model for natural gas trade in the EU.

TPA, capacity allocation and congestion management
As was already seen in the context of unbundling, the development of the sector-specific regulation from the Directive 30/1998 to the second and now third energy law packages
has been remarkable. The first natural gas Directive reflected the limits of the political possibilities of the time and, with options on regulated and negotiated TPA, it should be considered only as the first step towards a more market oriented regulatory model. The second energy market package with the Directive 55/2003 and the Regulation 1775/2005/EC took a significant step towards a regulatory system that can accommodate the emergence of a further degree of competition through eliminating the possibility to negotiate the TPA and, thus, making the regulated TPA the only alternative. However, contrary to initial expectations, that regulatory framework failed to create competitive natural gas markets in the EU. This failure was documented in the Sector Inquiry and has thereafter been widely debated. The new regulatory framework adopted by the third energy market Directive extends the application of the TPA rules to new areas and pushes the obligations of the TSO to a new level by, for example, highlighting TPA aspects in infrastructure investments and the need to ensure long-term viability of the system. Clearly, the visible trend throughout this development from first to second and third package is a move towards a more comprehensive regulation of TPA and a move towards shorter term and more flexible network capacity reservations. This will be illustrated in the below discussion.

In general terms, the TPA in the sector-specific regulation relating to EU natural gas markets is developed through three levels of regulation with very different levels of detail. The general framework is established in the third natural gas market Directive 73/2009/EC which, as will be examined below, establishes the basic rules and principles of TPA. The content of these rules and principles are then further specified in Regulation 715/2009 on conditions for access to the natural gas transmission networks. This Regulation focuses on access issues and complements the more general natural gas market Directive. However, the third and most detailed level of regulation are the network codes and guidelines that can be adopted on the bases of Regulation 715/2009.

As mentioned above, the general framework and minimum requirements to TPA in the natural gas sector are laid down in the Directive 73/2009/EC. At this general level, the access rules are not very different from those governing TPA to electricity networks. In the most simplified terms, the Directive requires that the regulated TPA regime is based on published and pre-approved tariffs that are applied in a transparent and non-discriminatory way. In addition, there are provisions addressing many related issues such as balancing, details on publishing and on fixing or approving the tariffs or the methodologies for their calculation (though most details, including return on risk or investment incentives, are left for the national regulatory authorities).

Article 41(6) of the Directive also requires that the national regulatory authorities draft the procedures for the allocation of cross-border capacity and congestion management. However, in practice, the details of this requirement are largely left for the more detailed Regulation 715/2009, which, in Article 13, includes a list of factors that the TSO and the national regulatory authority must consider. These include: cost-reflectivity or requirement of a market-based system such as auctions (reflecting the market value instead of costs), need to provide investment incentives, mandatory use of separate entry–exit point...
system for network charges and the need for convergence of the national systems in the longer term.

The basic requirement of the Regulation 715/2009/EC is that the capacity allocation must facilitate new investments and be compatible with market mechanisms such as spot markets and trading hubs. Also, capability to adapt to developments in markets and cross-border exchanges of natural gas in particular seem to be a central requirement. The tariffs for entry and exit capacity must be set separately and, as in the more general provisions of the Directive 73/2009/EC, must be cost-reflective or based on market value. As in all parts of the EU energy acquis dealing with access issues, the requirements of non-discrimination and transparency accompany the more detailed provisions.

According to Article 14, the TSO should offer (1) both firm and interruptible and (2) both short-term and long-term TPA. According to Article 2 of Regulation 715/2009, long-term capacity means a capacity right of one year or more and short-term capacity means less than one year. According to the Guidelines annexed to the Regulation, TPA should be offered down to a minimum of one day.

In the event of contractual congestion, the Regulation makes a clear distinction between situations of unused and fully used capacity. Where contractual congestion occurs, any unused capacity should, according to Article 16(3), be offered on a secondary market, at least on a day-ahead and interruptible basis. Where this capacity is released on an interruptible basis, the primary capacity holder can recall the capacity if it needs it. However, where possible, at least a part of the unused capacity should be offered as firm capacity. According to the Commission staff working document from 2007, this means that in the event that capacity is persistently left unused, a firm ‘use-it-or-lose-it’ principle would advocate in favour of total loss of capacity. Here, capacity would first be temporarily taken away from the primary capacity holder and, in the event of continuous unused capacity, the capacity would be permanently lost. This is to reduce the possibilities of capacity hoarding. From an enforcement cost point of view, it is also logical to treat this type of structural surplus of capacity differently from occasionally unused capacity.

One of the controversial aspects of the new developments, including the draft Pilot Framework Guidelines for Capacity Allocation on European Gas Transmission Networks, is the approach to pre-existing capacity contracts. Here, the sanctity of agreements and legal certainty must be balanced with the need to develop the market and the changing factual context of long-term contracts.

The current plan is that all capacity contracts and/or relevant clauses in various general terms and conditions be amended within six months from the entry into force of the future network code. Regardless of the specificities of a given contract and whether the contract allows for modifications, all contracts are to be modified to correspond to the new network code. Similarly, no tacit extensions can be allowed.

It is important to note certain factors when assessing the question of pre-existing capacity contracts. First, in many cases the capacity agreement has emerged through self-contracting: the vertically integrated operator has concluded a transit agreement with itself. This will have an impact when examining the weight of arguments based
on pacta sunt servanda and similar legal principles. Second, many of the pre-liberalization agreements were extended just months before the new access regime was introduced.\textsuperscript{43} The vital importance of TPA as the main rule and the need to adopt a strict interpretation of any derogation from TPA was underlined by the European Court of Justice in both the C-17/03, VEMW and others,\textsuperscript{44} and in the C-439/06, Citiworks.\textsuperscript{45} This emphasis on the TPA will have an effect on the interpretation of the exemptions provided in favour of long-term capacity contracts under the EU energy acquis. Finally, a distinction must be made between situations where specific conditions of capacity contracts are modified and where the entire contract is deemed unlawful.

The clear trend in the network access regimes and capacity allocations is towards shorter and shorter capacity services. In a very short period, we are moving from very long-term, 25 years and above, to very short-term capacity services, up to interruptible intra-day capacity services. While this move towards shorter term services is in many ways welcomed as it allows for new competition to emerge, the rationale and the nature of natural gas business should not be forgotten. Clearly, short-term capacity is necessary for competition and development of the markets. However, it is equally clear that long-term capacity is necessary for investments and security of supply. There is a need to consider and take into account the long-term nature of the natural gas business. With the move towards shorter and shorter TPA services, the risk of confusion between short-term trading and price arbitrage and long-term investment-based reservations is looming. Different transactions have a different economic rationale. Given that long-term commodity contracts continue to play a role in the EU natural gas supply, there is a need for long-term network capacity contracts matching the commodity contracts. If this is accepted, long-term should be comparable to the economics of the underlying commodity contract (i.e., the supply and delivery of gas for a number of years). One way of doing this is to allow the shippers to book consecutive multi-year capacity services.

These regulatory changes affecting the EU natural gas markets have a significant impact on traditional long-term contracting. The natural gas chain is no longer controlled by two companies, the external producer and its EU customer. Instead, there are new stakeholders with sometimes conflicting strategies and objectives. There is a risk of a contractual mismatch where the duration of the capacity contract differs from that of the commodity contract potentially resulting in the inability of the seller to deliver the contractual volumes to which it has committed.

In addition to these changes in the regulatory approach to markets affecting the long-term natural gas contracting, there are significant developments in the competition law enforcement in the natural gas markets having similar effects on traditional long-term natural gas contracts. These developments will be examined next.

**Downstream natural gas contracts**

**Duration and volumes**

The long-term supply contracts used in the upstream natural gas sector have traditionally been mirrored by a similar contractual structure in the downstream markets. Under this
scheme, the EU natural gas purchaser is locked to a specific producer through a long-term contract over a defined period of time. However, by concluding long-term contracts with its customers, industrial customers in particular, the importer locked in the necessary demand to match the supply. However, according to the Commission, this structure may invoke significant efficiency losses and may be detrimental for the consumers. Long-term downstream contracts would reduce, if not eliminate, the ability of the customer to choose its supplier, with this arguably compromising customers' general right to choose their supplier in accordance with the sector-specific regulation after the full market opening had occurred in July 2007. As such, these long-term downstream contracts reduced the potential for the competitive market structure to emerge.46

After a period of uncertainty in how these contracts would be treated under competition law scrutiny, the European Commission and some of the national competition authorities decided a number of cases which clarified the situation. These cases include Gas Natural,47 Distrigaz48 and E.ON Ruhrgas,49 as well as Repsol50 and Synergien.51 Among these cases, Distrigaz, having been decided by the Commission and relating specifically to downstream natural gas markets, is undoubtedly the most important. It may even be presumed that this case, together with the other cases mentioned above, was the ‘guidance in an appropriate form on the compliance of downstream bilateral long-term supply agreements with EU competition law promised by the Commission.52 In addition to these cases, the European Commission has discussed these contracts and its method of assessing them in its Sector Inquiry. The Commission has indicated that it would focus in particular on the following: (1) the volumes tied under the individual exclusivity contract; (2) duration; (3) cumulative effect of a web of contracts; and (4) efficiencies suggested by the contracting parties. In addition, the Commission will consider issues such as countervailing buyer power, the nature of the customer and other entry barriers.53 The Commission method of assessing the downstream supply contracts from an EU competition law perspective will now be examined.

In practice, the two first items on the Commission list, volumes and duration, should be examined together. In several cases relating to either de jure or de facto exclusivity contracts, the volumes have played a key role, together with the question of duration. Contractual exclusivity requires the buyer to commit to purchase all or a very high portion of its total demand from a single supplier. De facto exclusivity may come in the form of fidelity rebates or minimum purchase obligations based on historical demand. In the Gas Natural case, for example, the Commission held that the long-term supply contract with the Spanish electricity generator Endesa was in practice an exclusivity contract as it covered virtually the entire demand of Endesa.54 Through reducing the purchase volumes by around 25 per cent, Endesa would remain as a purchaser on the market and would attract new suppliers to the Spanish markets, through LNG in particular.56 Repsol, another Spanish case but concerning the distribution of petrol and diesel to service stations in Spain through long-term agreements, related to de jure exclusivity, as the agreements contained clauses providing for the exclusive purchase of fuel by service station operators in Spain.
For the volumes in question, there are several factors that must be considered: (1) volumes vis-à-vis the total customer demand, as in the Gas Natural; (2) volumes vis-à-vis the total volumes sold by the supplier, as in Distrigas; (3) volumes as compared to the total volume in the markets; and finally, (4) a distinction between the volumes delivered and volumes contracted, as in E.ON Ruhrgas. This difference must be noted, as there is customarily a degree of flexibility in the take-or-pay agreements.

In E.ON Ruhrgas, a case related to the use of long-term gas supply contracts in the downstream natural gas markets, gas transmission companies and distributors in particular, the central rationale of the decision by Bundeskartellamt, the German competition authority, was to set thresholds that combined volumes and duration. Accordingly, gas supply contracts with terms of more than two years and covering over 80 per cent of the customer’s total demand were not allowed. Similarly, supply contracts with terms of over four years and a requirement satisfaction of over 50 per cent were deemed anti-competitive. In other words, gas supply contracts could not exceed a term of four years in situations where they covered 50 to 80 per cent of the total customer requirements. For contracts covering more than 80 per cent of the requirements, a maximum term of up to two years was accepted. To avoid the obvious, the decision also regarded several supply contracts between a supplier and customer as one contract to prevent market foreclosure effects caused by splitting contracts into different periods. The significance of this decision as guidance can hardly be overestimated. The stated intention is that this decision should serve as a model for the whole natural gas sector in Germany.57 While this decision was not made by the Commission but by the German authorities, it was made in close collaboration with the Commission and the acceptance and endorsement of the substance of the decision by the Commission is clear.58

In Distrigaz, the Commission expressed some concerns over Distrigaz’s supply contracts with industrial customers. In connection with a Commission investigation pursuant to Article 102 TFEU into Distrigaz gas supply activities in Belgium, the preliminary assessment showed that the company had a dominant market position in the market for supply of gas to large customers in Belgium. As a customer usually has only one gas supplier at a time, competition for new customers only occurs when a new agreement is concluded. In this situation, the use of long-term contracts limits the scope for competition, resulting in foreclosure of the market. In particular, the combined effect of long-term contracts employed in the markets would have this effect.59 Just as with E.ON Ruhrgas, the Distrigas case concerned commitments that would remain in force for the period of four years, including that Distrigas would not conclude any gas supply agreements with resellers with a duration of over two years and no new contract with industrial users and electricity producers for longer than five years. In addition, Distrigas would ensure that for each calendar year a minimum of 65 per cent and on average for all calendar years a minimum of 70 per cent of the gas volumes supplied by itself and related undertakings to industrial users and electricity producers in Belgium would return to the market.60 This means that only 30 per cent of the total volumes sold by Distrigaz can be tied to long-term contracts with duration of more than one year. In addition to this,
long-term contracts with resellers cannot be more than two years in duration and for industrial users and electricity producers, the maximum term is five years (excluding new power plants).

The volumes would be calculated from total volumes supplied by Distrigas, and the company would have flexibility in managing its contract portfolio. The Commission has exemplified this by noting that Distrigas could, for example, conclude one-year contracts for 40 per cent of its sales and two-year contracts for 60 per cent of its sales or one-year contracts for 62.5 per cent of its sales and five-year contracts for 37.5 per cent of its sales. In both scenarios, Distrigas would meet its obligations under the commitment.61

There are significant similarities in these two cases. Among these is that the identity of the purchaser is regarded as a significant factor when assessing the acceptable duration. In both E.ON Ruhrgas and Distrigas, the contracts with gas resellers could not exceed two years.62 The absolute maximum duration on the other hand was set at five years. This figure was also adopted in another Commission decision, Repsol,63 and can certainly be considered as the maximum term for an exclusive downstream natural gas supply contract, except for specific cases such as investments in infrastructure. While the Commission did not require the abolition or termination of existing contracts, it did require that the customers be given unilateral termination rights for contracts of more than five years, as was the approach in both Distrigas and Repsol.

Tacit renewal of the contracts would not be accepted either. Again, this item was also of significance in the Repsol case. Similarly, the so-called ‘English clauses’, which give the incumbent supplier the right to match the offer of an alternative supplier before the customer can switch supplier, would be considered as anti-competitive. The ability of the customer to return to the market for new contracts is significant. This is particularly significant in the situation where a customer only has one gas supplier at a time, as the competition for new customers occurs only when a new agreement is concluded.64

In line with the approach of the Commission which considers the actual economics of a given situation, the cumulative effect of several contracts has been taken into account. In Distrigas, the detrimental effect of a web of long-term contracts employed in the downstream natural gas markets was considered significant.65 Similarly, the cumulative effect of the parallel networks of vertical restraints was important in Repsol.66

As to the efficiencies created through downstream contracts, new infrastructure investment in particular has been seen as a factor justifying either a longer duration or greater tied volumes.67 In addition, the long-term fuel supply68 seems to have been accepted as a justifying factor. This factor was considered relevant for the downstream markets in Electrabel.69 The case concerned exclusive rights granted to Electrabel to supply distribution companies in Belgium with electricity for resale to final consumers for a period of 20–30 years. In its final form, accepted by the Commission, this figure was reduced to 14 years and a gradual fade out for the volume of power supplied was included in the arrangement. While this case will not take us far in terms of assessing acceptable contract durations, due to change in circumstances brought by the liberalization, it does indicate the approach of the Commission vis-à-vis security of supply. The Commission explicitly noted that the significant principles in this case, which it sought to balance, were free
competition (‘to safeguard the opportunities provided by the Directive liberalising the single market in electricity by preventing the foreclosure for a long period of a significant part of the electricity market in Belgium’) and the principles of security and continuity of supply.\textsuperscript{70}

Much like the new investments in necessary infrastructure, facilitation of the entry of a new supplier to the market is considered as an efficiency gain. From a competition law perspective, the entry can appear in two ways: first, it is a well-recognized fact that vertical agreements can facilitate market entry; second, the entry of a new market player may not restrict competition in the sense of Article 101(1) TFEU. As such, the conditions for an exemption under Article 101(3) TFEU are usually fulfilled when a long-term contract is signed by a new entrant,\textsuperscript{71} if the contracts were to restrict competition appreciably and infringe Article 101(1) in the first place.

An example of a new entry, though by an upstream producer, is the Synergen case in which, after noting that the arrangement, including a 15-year exclusive gas supply contract, did fall within the scope of Article 101(1) TFEU, it was exempted under Article 101(3) TFEU. The Commission considered it significant that the long-term contract was the first large-scale gas supply contract for Statoil in Ireland and that this contract would ensure Statoil’s long-term presence in the Irish gas market.\textsuperscript{72} The reference to the ‘first large-scale contract from Statoil’ can be taken to indicate that the involvement of an external supplier was of significance in this case.

Similarly, potential entry was a significant factor in Gas Natural. The Commission noted that Endesa would have covered all its future requirements through the agreements and potential entrants were simultaneously foreclosed from any significant natural gas volumes. Electricity producers, such as Endesa, were also of great significance as they have the potential to enter the natural gas supply market through various tactics such as combined offers.\textsuperscript{73} More generally, the potential entry of a new supplier to the downstream market has clearly, and logically, been seen as a significant factor. In Gas Natural, the effect of the use restrictions on Endesa was a particular concern as the Commission seems to consider it to be a potential gas market entrant. According to the Commission, the modification in terms of duration, volume and resale restrictions would have significant positive effects in the Spanish energy markets for gas. Endesa would remain as a purchaser and would attract new suppliers to the Spanish markets through LNG in particular. On the other hand, it would have the capacity to increase competition both in natural gas markets through offering bundled gas and electricity sales to customers\textsuperscript{74} and in electricity markets where access to natural gas as a substitute for coal will contribute to competition.

Potential entry of new players was also of relevance in the GFU case.\textsuperscript{75} Here, the access of new customers to upstream producers was considered particularly significant. According to the Commission a significant number of potential European customers are actively looking for alternative sources of supply. These include large industrial users, electricity producers and new trading houses. The Commission used the opportunity provided in the case to squeeze the two main actors to agree to offer significant volumes (Statoil 13 Bcm and Norsk Hydro 2.2 Bcm, corresponding to around 5 per cent
of total sales in gas from Norway) of natural gas for sale to new customers over a period of around four years. This will provide an opportunity to bypass the dominant suppliers that have on-going long-term contracts for significant volumes with the Norwegian companies. At the same time, the case forced a significant change to the Norwegian gas trade with EU companies. Unlike before the GFU case where the Norwegian gas to the EU was marketed jointly by the Norwegian gas companies, each Norwegian producer would now conclude separate contracts with the EU buyers.

In addition to the duration and volumes, which have been the main focus of the EU competition law authorities due to the foreclosure these elements can directly create, the German competition law authority has had the opportunity to examine other provisions in the downstream natural gas contracts. The competition law treatment of the take-or-pay requirement, the resale restriction and the oil price linkage in the downstream contracts are examined next.

**Oil price indexation**

While the oil price linkage used often in both upstream and downstream contracts has not been examined by the EU institutions, the German Federal Court of Justice had the opportunity to examine the legality of price adjustment clauses in downstream contracts that are linked to the price developments of extra light fuel oil. While the German cases are not competition law cases, they are nevertheless of interest in an antitrust context. In essence, the Court concluded that it amounted to a disproportionate disadvantage for customers if the strict linkage of the gas price to the oil price allowed the provider not only to compensate price increases but to also generate additional profit out of it. As such, the relevant price calculation clauses unreasonably disadvantage the customers of utilities and are invalid pursuant to § 307(1) of the German Civil Code (Test of reasonableness of contents).

According to the Court, the utilities cannot base the use of such clauses on a protectable interest. This is also the case in relation to the use of ‘divergence clauses’, which are valid pursuant to the Price Information and Clause Act and aim to maintain a particular value ratio between performance and return. Such clauses may be based on a legitimate interest in long-term contractual relationships, if they are definite and suitable to ensure that the owed price matches the relevant market price of the service to be rendered. However, a market-based price for the supply of gas to the end consumer does not exist due to lack of effective competition. The fact that gas prices often develop in parallel to the price of light fuel oil is not based on market influences, but rather on the fact that linking the gas price to that of oil is in accordance with established practice.

Even the sole remaining credible interest of gas suppliers, to pass on the increases in costs to their customers, does not make the clauses valid. Although the Federal Court of Justice has in principle recognized a legitimate interest of gas suppliers to do so during the duration of a contract, it unreasonably disadvantages (discriminates) customers if the price adjustment provisions give the user the possibility of making an additional profit on top of shifting increased costs. These price adjustment clauses already offer the possibility
of an illegitimate increase in profits since extra light fuel oil is used as the sole variable for the adjustment of the unit price. This allows an increase of gas prices even if increased supply prices can be absorbed in other areas, like network and distributions costs—also when considering additional provisions on the change of base prices contained in sample contracts.

**Take-or-pay and resale restrictions**

Much like the upstream commodity contract, usage restrictions have been a central element of the downstream contracts. Such clauses are still used in various forms such as:

The natural gas supplied by the [company] is intended for the customer’s own operational purposes. Passing the gas on to third parties and use of the gas for non-operational purposes of the customer shall require the prior consent of the [company].

or

Natural gas is only supplied for the customer’s own purposes. It can only be passed on to third parties with the written consent of the [company]. Consent must be given if there are no outweighing energy supply reasons which contradict a transfer.

Similarly, take-or-pay clauses are widely used in downstream contracts and can take, for example, the following form:

If the customer does not comply with the minimum purchase obligation of Annex 1, he shall also pay for the volumes which he has not purchased at the mean valid energy price for the relevant contractual period weighted by the monthly volume (take or pay).

In a case from July 2010, the German competition law authorities had the opportunity to examine a case that raised both the question of acceptability of a take-or-pay clause and the acceptability of a resale restriction under competition law. While the competition authority explicitly noted that it will not deal with the question of take-or-pay element, it nevertheless accepted it as a legitimate risk division scheme. The resale restriction was, however, found to be anticompetitive, at least when it was applied in combination with a take-or-pay requirement. This case will now be examined in more detail.

The German competition authority approached the take-or-pay issue from a functional perspective examining the rationale behind the provision. As a general starting point, a gas supply agreement is in essence a purchase agreement under which a customer undertakes to pay the purchase price and, as an ancillary obligation, also to accept the object being sold. Should the purchaser default in acceptance of the power or gas, he still remains obliged to pay the purchase price. On the other hand he keeps his right to
delivery of the purchased object. Significantly for this case, a take-or-pay clause results in
the purchaser losing his right to delivery of the object in the case of a default in acceptance. Due to this, the delivery obligation of the supplier is linked with a time require-
ment. The take-or-pay element therefore results in division of risk where the volume risk is born by the purchaser and the price risk borne by the supplier (although the buyer will in fact bear the risk if contract gas prices were to be higher than gas market prices).

When a take-or-pay clause is combined with a prohibition of resale of the volumes covered by the minimum purchase obligation, the economic risks and opportunities of the contracting partners no longer match. The prohibition of resale and inability to
take the gas, results in the supplier neither having to bear the price risk nor the volume risk for the shortage, which may be as high as the amount of the minimum purchase obligation in the individual case. The supplier has the opportunity to sell the shortage a second time and to generate an additional profit independent of the amount of the prevailing market price. The purchaser in turn has to bear the full volume risk.

According to the German competition law authority, this problem following from the
difference in opportunities and risks may be avoided by excluding the minimum pur-
chase obligation from the prohibition of resale. This solution will still allow the main financial rationale of the gas supply agreement to be carried out as it still secures the sales in the amount of the minimum purchase obligation. As such, the restriction of compe-
tition in the form of a prohibition of resale linked with the contracts used by German companies would not be inevitable at least with regard to the minimum purchase obligation. The authorities also noted how a ‘soft’ prohibition of resale where the resale is subject to the supplier’s consent would essentially amount to the same situation.

Given the above, the authorities found a violation of EU competition law. They also
noted that while this type of agreement is a vertical agreement, a resale prohibition is a hardcore restriction which removes the benefit of the block exemption available for vertical agreements under EU competition law from the entire agreement.

The analysis in this case only concerned the volumes covered by the take-or-pay ob-
ligation. The German authorities clearly excluded the additional volumes that the pur-
chaser might require. As such, it allowed the continual existence of resale limitation beyond the take or pay volume. It did, however, make a note that the question of whether the prohibition of resale should be regarded as a restriction of competition also with regard to the flexible volume above the minimum purchase obligation, the possibility of an individual exemption under the EU competition law would have to be examined in detail. The authority also expressly reserved of reverting to this aspect later in separate administrative proceedings.

The above developments in the application of EU competition law in downstream
natural gas markets and the elimination of the downstream section of the vertical natural
gas chain from the producer to the end-customer have caused significant changes in the
position of the EU natural gas companies. The potential loss of customer base due to supply competition and the continuing take-or-pay obligation have increased the commercial risks of EU buyers. This risk has been amplified by the emergence of large volumes of low cost spot gas in the post-US shale gas and economic crisis era. A situation
where the customer has access to abundant volumes of LNG traded though the newly emerged spot market at a cost that is lower than the oil price indexed long-term contract price is putting pressure on the traditional EU purchasers. The take-or-pay obligation, oil price linkage and limited storage opportunities coupled with the inability to lock in the necessary demand, have caused a situation where a number of EU purchasers have initiated discussions over the need to renegotiate certain elements of the upstream natural gas contracts. The competition law treatment of these upstream contracts and their specific provisions will be examined next.

**Upstream natural gas contracts**

The current long-term upstream natural gas contracts were initially based on the Dutch Groningen model, which has been used to supply natural gas from Russia to Germany, Austria, Italy and France from the 1970s and later extended to other EU Member States as well. The same model has also been used for both LNG and pipeline exports from Algeria to Belgium, Greece, Portugal and Spain, as well as many of the Norwegian gas contracts with EU customers. It is also used for the exports from Nigeria to the EU and from Libya to Italy. In total, this type of contract is behind more than 250 Bcm/year of natural gas imports to the EU area. 82

Long-term upstream natural gas supply contracts have traditionally been considered as a cornerstone of security of supply in European countries. Through long-term contracts, the buyer, in many cases the national energy supply monopoly, could secure the national energy supply in the medium and long-term and make investment decisions based on predictable transportation needs. In practice, an importer, the national incumbent supplier, would manage a portfolio of several long-term contracts possibly with several producers and with different volumes and different prices, where circumstances permitted. The gas producer in turn could guarantee long-term revenue, which facilitates the large investment needed for exploration, production and long-distance transportation as well as other necessary energy infrastructure such as LNG liquefaction terminals. 83 For the gas exporter, the long-term contract therefore provides for a security of demand.

The liberalization of the energy markets has altered this traditional setting. In the new ideological context based on free and efficient competition, long-term upstream contracts have a much more controversial role: while it is admitted that they materially assist security of supply, 84 it is also recognized that they may result in or at least contribute to foreclosure of gas markets under certain circumstances. Because of the existing long-term contracts, new market entrants may be largely denied any chance of energy procurement from the producers, resulting in foreclosure of upstream markets, which also results in foreclosure of downstream markets. 85 Various anti-competitive effects are further highlighted when combined with other anti-competitive clauses regularly used in gas supply contracts: destination clauses, 86 use restrictions, 87 profit-sharing clauses 88 and other similar clauses intended to separate markets. In addition to these most anti-competitive clauses, the effect of the flexibility in the take-or-pay mechanism and the oil price indexation have sometimes also been seen as negative.
Long-term natural gas contracts and EU competition law: duration and volumes

While the Commission has not directly addressed the possible anti-competitive effect of long-term natural gas contracts between gas producers and the EU purchasers in its case law, it has nevertheless provided some guidance on this issue in some of the network-access-related cases, notably through GDF Suez and E.ON. These cases will now be briefly examined.

In GDF Suez, the Commission initiated proceedings further to finding that certain measures of GDF Suez might prevent or reduce competition in downstream supply markets for natural gas in France: ‘in particular, a combination of long-term reservation of transport capacity and a network of import agreements, as well as through under-investment in import infrastructure capacity’.

During the process GDF Suez and the Commission engaged in a dialogue and to address these concerns GDF Suez proposed to release immediately a large share (approximately 10 per cent, corresponding to around 7 Bcm per year) of its long-term reservations of gas import capacity into France, both for LNG re-gasification terminals and pipelines, in favour of third parties and to continue to reduce its share of these reservations to below 50 per cent in 2014 calculated from the total long-term capacity reservations for each year. There will also be a supervisory scheme in place to ensure that the long-term capacity has effectively been released and that this capacity has been offered to third parties.

The commitments given do not prevent GDF Suez from booking interruptible and short-term capacity. Similarly, in the event of insufficient demand for the capacity, the dominant or established companies, as the case may be, can only book capacity on a short-term basis. If the wording of the Regulation 715/2009 is followed, this means capacity reservations under one year are allowed for GDF Suez.

The E.ON case follows the same rationale: significant reduction of its firm long-term capacity reservations in the German pipeline system. The proposal of E.ON was offered in response to concerns that certain E.ON practices may have constituted a breach of EU rules on abuse of a dominant position under Article 102 of the TFEU. The concern in this case was that E.ON may have closed off competitors from the market by booking almost the entire capacity at key entry points into the gas network on a long-term basis.

According to the decision by the Commission on 4 May 2010, E.ON will reduce its firm bookings in the entry points of its German gas network to approximately 15 per cent by October 2010 and further to 50 per cent in the high-caloric gas market area and in E.ON’s grid for low-caloric gas to 64 per cent of the pipeline capacity. Like in GDF Suez, the decision does not prevent E.ON from booking short-term or interruptible capacity. Nor do these decisions prevent the companies from concluding long-term natural gas commodity contracts with external producers.

GDF Suez and E.ON are among the few recent competition law cases driven by the Commission to open up transportation capacity and alleviate capacity-related
foreclosure. Others include ENI, E.ON and RWE inquiries where the end result was divestiture of certain network assets. The difference to these cases, ENI and RWE for example, is that the GDF Suez and E.ON cases focus on these two companies as shippers, not as transmission system operators (TSOs). Where the commitments in the TSO-related cases aim at eliminating the incentive to discriminate and the correction of market distortion in the long-run, the GDF Suez and E.ON commitments result in an immediate and long-term release of network capacity, which given the duration of the commitments and the developments in the sector-specific regulation (examined below), will, if properly overseen, also result in a permanent structural change in the markets.

In addition to continuing the access-related case law, the present cases also follow the rationale of the earlier Distrigaz decision where the Commission imposed certain percentages as thresholds between activity that is considered anticompetitive and activity which is allowed. In Distrigaz, the thresholds were defined in percentages calculated from different supply volumes. In GDF Suez and E.ON, the threshold of 50 per cent of the total capacity represents, according to the Commission, a workable balance between the rights of companies and the need to create competitive conditions, ie ensuring rivals have access to sufficient network capacity to compete. The outcome in these two cases follows the same rationale that was adopted on the regulatory front in relation to the Nabucco pipeline. Here, the exemption decision under Article 22 of the Directive 55/2003/EC (now Article 36 of Directive 73/2009/EC) imposes a capacity cap on the share of annual capacity which the shareholders, all dominant undertakings in their home markets, can book at the total of all exit points. As such, the exemption from TPA only covers half of the pipeline capacity. The intention is undoubtedly that the decision complies with the requirement that a regulatory exemption under Article 22 of the Directive 55/2003/EC (now Article 36 of Directive 73/2009/EC) is only possible if the project enhances competition and is not detrimental to competition.

Even if the E.ON and GDF Suez cases primarily concern long-term capacity contracts, they are also closely linked to long-term commodity contracts. These cases have also provided indications on how EU competition law is likely to be applied to upstream commodity contracts that are used to import significant volumes of natural gas to the EU area. The Commission has for some time recognized that long-term contracts have an important role to play in European gas markets and should be left as an option for the suppliers as long as they comply with EU regulation and especially EU competition laws. However, little light was shed on what was meant by ‘as long as they comply with EU competition law’. Clearly, the GDF Suez and E. ON cases indicate that the key question is the volumes covered by these contracts. The long-term nature per se is not a problem but, instead, the focal point of the competition law enforcement is the large volumes these contracts cover. In essence, the rationale of the approach of the Commission seems to be that (1) long-term contracts may have a foreclosing effect; (2) this is true for both the long-term upstream commodity contracts and the long-term capacity reservation contracts; and (3) these different foreclosure risks can be addressed in different ways: to attack the supply foreclosure created by the upstream
commodity contracts (ie to ensure that rival suppliers can secure access to gas) or to attack the infrastructure foreclosure created by the infrastructure capacity contracts (ie to ensure access to infrastructure). The capacity-related case law now suggests that the Commission has decided to adopt the second approach. No doubt this choice is closely related to the complicated nature of long-term upstream commodity contracts.

It should also be noted that upstream gas supply contracts have significant legal, political and economic aspects. In addition to questions like legal certainty and protection of legitimate expectations and the complicated economic effects for both the EU markets and the external supplying markets, including the demand security to enable large-scale investments on continuing bases, the political aspects of these contracts speak heavily in favour of allowing long-term contracting with the external suppliers. As such, the solution to allow long-term contracting with the upstream suppliers and instead focus on the infrastructure foreclosure is welcomed. However, just as with the commodity contracts, it is necessary to take a pragmatic approach to long-term capacity contracts and recognize both the legal and the economic aspects of these contracts. The current approach of the European Commission to infrastructure access suggests a rather mechanical fifty–fifty split. The dominant company can retain half of the pipeline capacity while the other half have to be offered to the markets.

In this context, it must be noted that long-term commodity contracts play a central role as a significant supply relationships have been considered relevant in relation to the 50 per cent capacity cap. In the Nabucco exemption for the Bulgarian section of the pipeline, the relationship between the Bulgarian downstream supplier and Gazprom was considered significant as ‘the likelihood of Gazprom and its affiliates to effectively compete with Bulgargaz EAD is significantly reduced, given that Gazprom and its affiliates are Bulgargaz EAD’s almost exclusive suppliers and given that Russia, for which Gazprom holds an export monopoly, is currently Bulgaria’s near exclusive source of supply (whether for gas produced in Russia or merely transiting through Russia). In that situation, an outcome in which Bulgargaz EAD would hold 50 per cent of the Bulgarian exit capacity and Gazprom, or an affiliate of Gazprom, would hold the remaining 50 per cent, or indeed any additional share going cumulatively with Bulgargaz EAD’s share beyond 50 per cent, would not be pro-competitive’. Because of this, the capacity for these companies is capped jointly until Bulgaria sources less than 50 per cent of its gas supply from or through Russia or until such moment as Gazprom loses its export monopoly for Russian gas or gas transiting through Russia. A similar approach was taken in relation to the exemption for the OPAL pipeline. In that case the Commission considered that RWE and Gazprom should be considered jointly and may together account for no more than 50 per cent of capacity as long as substantial long-term gas supply agreements exist between them.

This suggests that the long-term upstream commodity contracts are not prohibited per se. However, this does not mean that specific clauses in these contracts may not have anti-competitive effects and thus violate EU competition law. Some of the provisions of these upstream contracts will now be examined.
Specific clauses of the upstream natural gas contracts

Destination clauses

Destination clauses and territorial sales restriction clauses prohibit the buyer from reselling the gas into other countries or other areas than those for which it is intended. These clauses enable a supplier to charge different clients different prices at the same delivery point. The roots of these territorial restriction clauses are the historical segmentation, both horizontal and vertical, of the EU energy markets. Large producers sold the gas to national incumbent suppliers but not directly to end-customers. The sales were limited to the area where the integrated incumbent supplier controlled the pipelines, typically their immediate home state. By limiting the freedom of the buyer to resell the gas outside a certain area, these clauses enable a supplier to maintain different price areas for the same product. In addition to price maintenance, destination clauses also reduce liquidity in the energy markets, making it easier to identify individual transactions and facilitating collusion between market players.¹⁰⁹ It is precisely because of these effects and general EU internal market objectives that the EU competition law prohibits destination clauses. Even in the event that a gas supply agreement would otherwise benefit from the vertical agreements block exemption, all such clauses would prevent the application of the block exemption.¹¹⁰

In addition to straightforward destination clauses, other more subtle ways of achieving the same result exist. An equivalent effect can be achieved through profit-splitting mechanisms and markets can also be divided through use restrictions.

Profit-splitting mechanisms allow the seller to control or affect the onward selling decisions of the buyer. This mechanism obliges the buyer to give the seller a share of revenues when the gas is sold outside the agreed area, typically a Member State. Such mechanisms can be divided in two broad categories: profit splitting and price splitting.¹¹¹ While the first mentioned one, profit splitting, will not eliminate all incentives to sell outside the original territory as only eventual profits will be divided, the second one, price splitting, will certainly do this and may also lead into losses.¹¹²

Use restrictions, in turn, limit the capacity of the purchaser to make decisions over the use of the product. It means that the gas sold to an electricity producer cannot be used for any other purpose than as a fuel for generating electricity. It cannot be resold. Much like a territorial restriction, a use restriction will create artificial barriers to markets and help compartmentalize a market.

The Commission has in the past moved against destination clauses used in various agreements, demanding their deletion as anti-competitive clauses which undermine the creation of a pan-European energy market. In addition to the destination clauses, the Commission has also successfully negotiated the deletion of other anti-competitive clauses, such as use restrictions¹¹³ or profit-sharing clauses,¹¹⁴ traditionally used in long-term gas supply contracts.

Most discussion has been provoked by the Gazprom cases, where the Commission negotiated the exclusion of prohibited clauses from the agreements between Gazprom and some of its EU trading partners, namely, ENI (Italy),¹¹⁵ OMV (Austria)¹¹⁶ and E.ON
Ruhrgas (Germany). In addition to these cases, the Commission has also negotiated the exclusion of similar clauses from, among others, a LNG-supply contract with one of the largest LNG importers to Europe, Nigerian NLNG, and an agreement with the Norwegian companies Statoil and Norsk Hydro. The Commission also concluded the negotiations with Sonatrach in 2007, after years of negotiation. Some of these cases will now be looked into in more detail.

Gazprom/ENI
In October 2003, the Commission issued a press release announcing the settlement of an investigation relating to certain gas supply contracts between Gazprom and ENI. This settlement closed the first investigation into a number of gas supply agreements between large external suppliers and EU purchasers. The settlement not only relates to the destination clauses, which were deleted, but also to other issues. The contractual commitments made by the parties were as follows:

1. The territorial restrictions were deleted from all existing agreements and ENI has the right to resell and transport the purchased gas where it wants.
2. Parties undertook not to introduce similar provisions to any future agreements between each other or any other parties.
3. The parties deleted the consent clauses according to which Gazprom was to obtain the consent from ENI in order to sell gas to any other customers in Italy from all existing agreements.

In addition to these contractual commitments, the following non-contractual commitments were made:

1. ENI committed to make significant volumes of gas available to non-Italian customers during a period of five years.
2. ENI committed to promote a capacity increase in the TAG pipeline from Baumgarten transporting Russian gas to Italy.
3. Finally, ENI undertook to enhance the TPA regime to the TAG pipeline. Commitment in this respect included the introduction of one-month transportation contracts, a congestion management system and the creation of a secondary capacity market.

The rationale of these commitments was to prevent compartmentalization of the market (contractual commitments) and enable new competition in Italy (commitment relating to the TAG pipeline) and in other Member States (commitment relating to the volumes that ENI should make available for third-party buyers). The relation between deletion of the territorial restrictions and increase in the transportation capacity of the TAG pipeline or the release of gas volumes may be queried.
GDF/ENI—GDF/ENEL

While most of the cases relating to territorial restrictions were closed after extended negotiations without a formal decision, the first to end with a formal decision were the GDF/ENEL and GDF/ENI\textsuperscript{127} cases.

The first case concerned a swap of LNG purchased by ENEL from Nigeria NLNG under an agreement from 1992. The agreement from 1997 stipulated that ENEL would exchange the LNG it purchased from NLNG (that was delivered to the Montoir de Bretagne LNG terminal) for LNG from Algeria (delivered to the Panigaglia LNG-terminal on the coast of Italy) and Russian pipeline gas delivered to Baumgarten (on the border between Slovakia and Austria). The duration of the arrangement was somewhere between 15 and 25 years. Further to a subsequent modification, a third delivery point for the gas provided by GDF was established to Oltingue (on the border between Switzerland and France).\textsuperscript{128} The agreement specified that the gas delivered to ENEL by GDF was intended for use in Italy (‘\textit{pour une utilisation du gas en Italie}’).\textsuperscript{129}

Interestingly, ENEL signed a second agreement with Nigerian NLNG for delivery of gas to Montoir de Bretagne in France in 1997. This agreement also contained an obligation for ENEL to use the gas delivered in Italy.\textsuperscript{130} Following the initiation of a Commission investigation, the parties deleted this clause from the agreement.

The second case concerned the transportation of LNG purchased by ENI in northern Europe. This agreement contained a clause specifying that the gas was destined for use in the downstream area from the delivery point (‘\textit{destinées à être commercialisées en aval du Point de Relivraison}’). As the delivery point (Oltingue) was located on the border between France and Switzerland, this meant that the gas could not be sold in France.\textsuperscript{131}

The companies advanced various explanations and argued strongly against the Commission interpretation of the objectives of these clauses. The Commission did not accept these arguments, and the Commission concluded both investigations by finding an infringement of Article 101 TFEU. That these are the first actual decisions in a string of many cases raises some concerns over discrimination. It seems that the previous Commission practice of closing all cases where large and important non-EU importers were involved without a formal decision declaring a violation of EU competition law and the willingness to engage in very long negotiations with Sonatrach and the approach adopted in the GDF/ENEL and GDF/ENI cases are not compatible. The factual situation in the latter cases did not strictly call for a formal decision: in both, the destination clauses had already been abandoned by the parties almost a year before the decision. Before discussing this issue a bit further, the Sonatrach case will be briefly examined.

Sonatrach

The negotiations with Sonatrach did not go as smoothly as they did in the other cases. Despite negotiations stretching over seven years, the Commission did not make a formal decision but went ahead with the negotiations, which finally ended in summer 2007.\textsuperscript{132}
In early July 2007, the representatives of both parties announced that the negotiations had been concluded. 

In the negotiations, both Sonatrach and the government of Algeria insisted on replacement of destination clauses by alternative mechanisms, such as profit-sharing clauses. This however was not accepted as such clauses in many cases have effects similar to a destination clause. Finally the parties agreed that:

1. Sonatrach would delete territorial restriction from all existing contracts and would not insert such clauses in any future contracts.
2. Profit-sharing clauses would only be applied in LNG contracts where the title to the gas remains with the seller until the ship is unloaded, which means sales under delivered ex-ship (DES) terms. Sonatrach will change the existing LNG agreements from other alternatives (FOB and CIF) to be shipped under DES terms.
3. Sonatrach will not use profit sharing clauses in future LNG contracts where the title of the gas is transferred to the purchaser at the port of loading.
4. Sonatrach will not employ profit-sharing clauses in any existing or future supply contracts for pipeline gas.

Based on the destination-clause-related case law, it is now possible to state that destination clauses in long-term upstream contracts are clearly considered as hard-core restrictions to competition, or black clauses, which are not generally capable of individual exemption and therefore prohibited under EU competition law. Profit-sharing clauses on the other hand are a more complicated issue and these clauses are assessed against their economic rationale and against the factual context of a given case. Where the clause reduces a company’s incentive to use the gas for other purposes than originally planned, thus reducing the potential benefits of sales outside a territory from the purchaser’s point of view, the clause may be considered anti-competitive. Here the passing of risk and title from the seller to the buyer seems to be of relevance. Under a DES shipment, this happens when the gas is unloaded from the ship in its destination. Prior to this moment, the seller is, in principle, free to divert the shipment to an alternative destination. However, it seems that in practice the solution in the Sonatrach compromise is quite formalistic, no doubt, resulting from the need to find a workable compromise between the Commission and Sonatrach and/or Algerian government. From an economic point of view, despite leaving some possibilities for trade outside of the agreed boundaries, profit splitting will also reduce incentives for trade because, depending on the agreed split, a significant part of profits will be transferred to the original seller or conversely to the original buyer. It may also lead to sharing of sensitive commercial information between the upstream seller and the EU buyer. This type of information might be necessary for the seller to calculate the shareable profit. It is therefore somewhat unclear whether the same formalistic approach would be adopted in the future cases relating to LNG shipments. On the contrary, for pipeline gas, both destination clauses and the profit-sharing clauses are prohibited under the EU competition law.
The Commission’s intention in destination clause cases was to increase supply competition. Destination clauses restrict this and to the extent profit-sharing clauses have a similar effect, they should be seen as violating EU competition law. The subjective intentions of the contract parties are irrelevant where the effect of the clause is the partitioning of EU natural gas markets.

**Oil price indexation**

Another interesting provision in the natural gas contracts in the EU is the natural gas price indexation to oil product prices. Unlike the USA, where gas-to-gas competition determines the natural gas prices, long-term EU natural gas contract prices have traditionally been based on the market value principle, which means the cost of alternative non-gas fuels. In practice, this translates into indexation to heavy fuel oil and light fuel oil or crude oil or a combination of these.

This linkage is based on the idea of switching capability of the customer where the price of natural gas would determine whether the customer burns oil or gas. However, today, this switching capability is more of a theoretical argument. Even in the longer term, meaning that the linkage could be defended through the argument that the customer will choose to construct an oil burning facility instead of gas or an installation with a switching capability, the argument is largely flawed. No new oil fired generation facilities are being constructed in the EU. The environmental concerns, modernization of natural-gas-based power production, limitations on emissions, etc have all resulted in a situation where the argument based on the switching capability is outdated. Based on these findings, the linkage between the two commodities could be questioned.

This has also been noted in the sector-specific regulation where the preamble to the new Third Natural Gas Directive makes a note that:

Natural gas is mainly, and increasingly, imported into the Community from third countries. Community law should take account of the characteristics of natural gas, such as certain structural rigidities arising from the concentration of suppliers, the long-term contracts or the lack of downstream liquidity. Therefore, more transparency is needed, including in regard to the formation of prices.

This could be interpreted to mean that while long-term commodity contracts are per se seen as a necessary component of the EU natural gas trade, the question of price formation must be addressed at some point. The 2007 Sector Inquiry also addressed the question of the oil price linkage. In essence, the traditional EU importers, the incumbents and the external producers argued in favour of the link. Many of the national regulators, the new entrants and traders considered the link as a symptom of the lack of competition due to contractual structures that continue to affect the markets rather than a technical pricing problem that should be addressed in isolation. In addition, some of these new entities and public bodies argued against the continuation of this linkage.
The situation has radically changed since 2007. A major milestone in the discussions on the correct pricing mechanism took place in August 2010 when the new Chairman of the Board of Management of E.ON Ruhrgas AG indicated that E.ON has moved against the continuing oil price linkage and that the current long-term contracts with this linkage need to be adjusted. This, to quote Professor Jonathan Stern, is nothing short of proposing a ‘revolution in the industry’. 143

There are several factors that have led to changing behaviour in the EU natural gas industry. These include the rapid and fundamental changes in world LNG markets that have resulted from a decrease in demand and the closure of US markets, linked to the emergence of unconventional gas, both of which have acted as catalysts for change through providing for increasing liquidity in the EU natural gas hubs. However, there is also an important regulatory dimension to this change. This paradigm shift in energy governance—from state to market, from plan to contract, and from monopoly to competition—has significantly changed the way in which EU natural gas markets are regulated and this has had a profound impact on the risk position of the contractual parties. Because of these changes, it is very likely that these changes will lead into a progressive introduction of spot indices in price indexation formulas. 144

The use of oil indexation in long-term contracts has been further complicated by the above-examined downstream-markets-related decisions from the German Federal Court of Justice in which the Court concluded that it amounted to a disproportionate disadvantage for customers if the strict linkage of the gas price to the oil price allowed the provider not only to compensate price increases but to also generate additional profit out of it. 145 This scenario would become relevant in a situation where, for example, the oil products that are used in the contracts as the basis for gas prices are different in the upstream contract used to import the gas and in the downstream contract that the EU supplier uses with its end-customers. If the price of gas to the final customer goes up more than it does for the EU supplier due to different price developments in different oil products, this would seem to fall under the undue advantage area that the German court was referring to.

Despite these changes and complications, it is unlikely that the European Commission will move against the oil price linkage in the near future. Instead, it seems that the market mechanism and the changes in the regulation and supply will be a catalyst for change. There is little need for an antitrust intervention where the market forces are working out the correct pricing mechanism. It would be both premature and dangerous for the European Commission to intervene and dictate the outcome of this on-going process.

**Take-or-pay provisions**

An issue that was raised in the 2007 Sector Inquiry was the effect of the take-or-pay provisions in the long-term upstream contracts. Different views emerged among different parties: it was argued by the incumbents that because of the volume risk the purchaser assumes under the traditional long-term contracts, the take-or-pay element of the contract is necessary since it allows for the necessary flexibility in their purchase and storage
In this context, it is necessary to understand that a normal take-or-pay provision does not stipulate a clear-cut obligation to take a specified volume of gas each day, month and year. Instead, it will have a range of flexibility for over- or under-deliveries. The buyer has the right to nominate less or more gas than would be the precise take-or-pay obligation and instead of the day or month, it is the annual take-or-pay quantity that it must respect. Even for the annual quantity, the buyer will frequently have a margin for manoeuvre, typically 80–110 per cent of the annual take-or-pay obligation. The volumes may also be adjusted over a period of some years.

The above view was contrasted by the new entrants, who argued that this element of the contracts internalizes the role of the wholesale markets, price and volume risk, with a negative effect on the development of a real EU wholesale market. In their view, liquid wholesale markets would render this element of the contract unnecessary. Companies could use the wholesale markets to manage price and volume risks. Clearly, this suggestion requires sufficient cross-border infrastructure to allow a wider market than the national market to emerge and that there are therefore many competing buyers. It also excludes periods of very significant demand decreases and changes in the supply markets, this situation being exemplified by the situation between 2008 and 2010.

While a take-or-pay obligation in the upstream contracts has not been questioned under the EU competition law, this issue has been discussed by the German competition authorities in its 2010 case law as we have seen in the sections on downstream contracts. Seemingly accepting a take-or-pay obligation as a legitimate risk-sharing mechanism, the Bundeskartellamt adopted a view that a take-or-pay provision in the downstream gas contract ‘is not per se objectionable under competition law’. However, in the German cases this minimum take obligation was complemented with a resale prohibition which made the overall arrangement anti-competitive and thus prohibited under both the German and the EU competition law.

Under the sector-specific gas regulation, the Third Gas Market Directive provides for a limited derogation to TPA for take-or-pay agreements. The first reference to these agreements is provided for in Article 35, which allows a gas company to refuse access to its system on the basis of (1) lack of capacity; (2) where the access would prevent it from carrying out its public service obligations; or (3) on the basis of serious economic and financial difficulties with take-or-pay contracts. The derogation for these take-or-pay agreements is then further specified in Article 48:

If a natural gas undertaking encounters, or considers it would encounter, serious economic and financial difficulties because of its take-or-pay commitments accepted in one or more gas-purchase contracts, it may send an application for a temporary derogation from Article 32 to the Member State concerned or the designated competent authority. Applications shall, in accordance with the choice of Member States, be presented on a case-by-case basis either before or after refusal of access to the system. Member States may also give the natural gas undertaking the choice of presenting an application either before or after refusal of access to the system. Where a natural gas undertaking has refused access, the application shall be presented without
delay. The applications shall be accompanied by all relevant information on the nature and extent of the problem and on the efforts undertaken by the natural gas undertaking to solve the problem.

This possibility for a derogation would suggest that the take-or-pay provisions are not prohibited per se under the EU law, and indeed they occur in various industrial contexts (for example, where a plant delivers certain chemicals or by-products to one or a small number of customers). The rationale of the derogation is, of course, to protect the established market players from unreasonable consequences arising from the change of paradigm ‘from state to market’. As noted by some, the use of this derogation depends largely on the development of the internal energy market. It seems that it has not been applied in practice.

Much like the downstream contracts in the German competition law case, the long-term upstream contracts are based on a scheme that divides the risk between the buyer and the seller. The take-or-pay clause, the destination clauses and the oil price linkage are all part of this mechanism. The elimination of destination clauses affected this scheme but allowed for its most central elements to be maintained. The elimination of the take-or-pay element would take away the main pillar on which these contracts stand. As such, it would require a new mechanism to import natural gas to the EU to be developed. As LNG and spot trading seems to increasingly provide for alternative procurement channels, it seems that any possible negative effects of the take-or-pay clauses are alleviated through market developments post-2008 and eventually, the take-or-pay element may become less relevant. However, long-term contracts (including take-or-pay obligations) may continue to be a commercially sensible part of leading gas suppliers procurement strategies together with short-term supplies, so as to ensure overall security of supply, whilst permitting greater flexibility to vary purchases in the light of changes in demand and competition.

**Conclusion on the application of EU competition law to natural gas contracts**

The developments in the global natural gas markets that have been noted throughout this article have various consequences on EU natural gas trade and for long-term contracts as an integral component of that trade. Increased volumes of low price LNG are available for EU purchasers. This provides for flexibility in the purchasing portfolio of EU companies. It has had a positive effect on short-term trading. Increased volumes of spot gas are available at various EU natural gas hubs. These developments have led to increased demands for de-linking the oil and gas prices. Despite this, long-term upstream contracts continue to be the backbone of the EU natural gas trade. There is no doubt that these contracts and their specific clauses will undergo a change in the mid-term. Destination clauses and other similar clauses restricting the rights of the buyer to dispose the purchased volumes have already been eliminated, except from certain LNG contracts. Oil/gas indexation of contract prices will disappear, the contractual volumes will be reduced and short-term spot trade will replace some of the long-term trading. In the mean time, the competition law treatment of these contracts and their particular provisions will evolve.
This article has provided an analysis of the past competition law enforcement relating to long-term natural gas contracts. However, it is necessary to note that the situation is not static and the application of EU competition law does not take place in a vacuum. On the contrary, the trend is towards increasing recognition of the economic context in which the competition law enforcement takes place. As such, it can be expected that new areas are going to be addressed and the enforcement will move from Western Europe towards the new Member States, which have so far been largely left alone.

3. The US approach to long-term contracting in the energy markets

Development of US natural gas market regulation: unbundling and access

The US has several areas with significant natural gas reserves. Geographically, the South Central US, including Arkansas, Kansas, Louisiana, Oklahoma and Texas, is the key natural gas-producing region, accounting for approximately half of the US natural gas production and proven natural gas reserves. While the same region consumes important volumes of natural gas, significant amounts are also transported to other consumption areas such as the North East and Midwest. The distances between the consuming and producing regions are covered by a highly sophisticated pipeline system. Unlike Europe, for example, the pipeline network in the US has mainly been constructed according to economic incentives rather than focusing on relatively small geographical areas (i.e., individual Member States). Large-scale pipelines transport natural gas from the production areas to the consumption areas. Prices are mainly set in trading hubs, such as the Henry Hub in Louisiana or various Transco zones along the east coast. There are currently hundreds of players involved in these markets as producers, pipelines and purchasers (as well as obviously a very large number of end-consumers).

Based on the current regulatory scheme and the division of regulatory competence between the state and federal levels, the US natural gas markets may be divided into intrastate and interstate levels. The interstate gas markets of the US are regulated by the Federal Energy Regulatory Commission (hereinafter ‘FERC’) pursuant to the Natural Gas Act. The FERC does not regulate the state markets, which are subject to state regulation. The FERC’s jurisdiction is limited to the transportation in the interstate pipelines and to certain sales as well as to persons engaging in these transactions. In addition to this, FERC has jurisdiction over specific issues such as the siting of LNG re-gasification terminals.

The historical development of the US natural gas markets is very different from that of the EU. Today’s US markets and regulatory set-up are the result of various developments involving re- and de-regulation, always followed by heavy litigation. In general, it seems as if the emphasis is moving from a state-centred regulatory system towards a federally regulated market.

In order to appreciate the current US regulatory scheme, it is necessary to understand the progress towards the status quo. These developments can be presented in various ways. For example, one can make a distinction between the unregulated era (1859–1938),
the regulated era (1938–1978) and the deregulated era (1978–present). An alternative way of looking at the past would be to distinguish between the era of state regulation (1889–1937), the first era of federal regulation (1938–1983) and the era of restructuring and deregulation (1985–present). This article adopts the latter approach.

**The era of State regulation (1889–1937)**

In the earliest days of the natural gas markets in the US, the gas pipeline business was organized through entities that were vertically integrated with either the natural gas producers or distributors (this actually continued into the second era, post-1938). Gas markets were largely local, created around the production areas. In these early days, natural gas was largely what is today called ‘associated gas’, ie gas found in association with oil deposits. In 1920, the progress in the steel industry made the construction of long-distance, high-pressure steel pipeline facilities possible. The first large-scale gas pipelines from Texas to Chicago in 1931 initiated the development of an interstate gas pipeline network. This started the progress towards a US-wide natural gas market.

During this period, the federal licensing and rate regulation did not exist. Pipelines were only regulated by state legislation and where a pipeline crossed a border, it also left the jurisdiction of one state and entered another. This resulted in various problems with conflicting orders from various jurisdictions on the one hand and complete lack of regulation on the other. To address these issues, the US Supreme Court issued opinions essentially stating that the regulation of interstate pipelines fell under federal jurisdiction.

After a series of discussions and reports, the US Congress enacted the Natural Gas Act of 1938, which ended the era of unregulated, or just state regulated, natural gas business.


The passing of the Natural Gas Act of 1938 started an era of federal regulation of the interstate gas trade. The Natural Gas Act is still in force today and, while it has been subject to modifications, it continues to regulate interstate pipeline business. Essentially, the authority over entry licensing and rate regulation was granted to the Federal Power Commission (the predecessor of FERC), and the Natural Gas Act organized the gas industry into a market in which gas pipelines had a natural monopoly position and these pipeline companies would purchase gas under long-term contracts from the producers at the well-head, transport it through its pipelines and then re-sell it at the ‘city gate’ to local distribution companies.

In order to control the monopoly power that the pipeline companies possessed, the Act did not adopt an open-access type of ‘common carrier’ model but rather opted for a cost-of-service rate-making model. These pipeline rates would have to be just, reasonable and non-discriminatory. The Natural Gas Act did not extend the price regulation to the price of natural gas (the well-head price), only to the transportation service. According to the commentators from that era, this model worked fairly well.
In 1954, the Supreme Court gave its opinion in *Phillips Petroleum Co v Wisconsin* finding that natural gas companies as defined by the Natural Gas Act and their sales in the interstate natural gas business ‘are subject to the jurisdiction of, and rate regulation by, the Federal Power Commission’. The Supreme Court also held that Congress did not intend to regulate only interstate pipeline companies. Rather the legislative history indicates a congressional intent to give the Commission jurisdiction over the rates of all wholesale of natural gas in interstate commerce, whether by a pipeline company or not and whether occurring before, during, or after transmission by an interstate pipeline company.

This meant that the well-head price, the price that a producer could ask for its gas from the pipeline company, for gas to be traded at the interstate level was to be regulated at the federal level. The federal jurisdiction and, consequently, the control of well-head price did not extend to the intrastate trade. This resulted in the creation of distinct interstate and intrastate markets. It is important to note that these two markets had very different price levels. As the price levels for the interstate trade were much lower than what they were for intrastate trade and it became relatively unattractive for producers to sell into interstate market. This situation created the false impression of a shortage of gas. Another problematic aspect was that the cost-based price levels were originally set individually for each independent producer. When this proved to be impossible because of the large number of producers, the Federal Power Commission opted for an area-rate system under which two prices were designated for each geographical area (one for old wells and one for new wells, with the intention of providing investment incentives).

Unsurprisingly, these policies lead to difficulties and gas shortages in certain areas. As a result, the Natural Gas Policy Act (1978) was passed by congress to address these issues. This new Act regulated the well-head prices (maximum price) for both intra and interstate gas trade. It also partially deregulated the gas business and started the era of deregulation. The jurisdiction to regulate these prices was also granted to the FERC (which came to replace the Federal Power Commission in 1977).

While long-term take-or-pay contracts had been used as a risk division mechanism from 1930, the Natural Gas Policy Act resulted in a boom of this type of contracting. As pipelines could not compete on price, they competed through non-price arrangements such as long-term take-or-pay agreements that offer the producer security against demand fluctuations. The amount of this type of contract went from about 35 per cent in the early 1970s up to about 90 per cent. Eventually, this resulted in excess pricing at a time of excess supply.

The gas prices unexpectedly started to rise, the result of various factors including the shift from the old industry structure and pre-existing long-term agreements and because of the policy of the FERC. Despite high prices, pipeline companies—believing gas to be in short supply—continued to purchase all available gas on long-term take-or-pay contracts allowing no renegotiation or flexibility. When deregulation revealed true availability of supply, prices fell sharply and the pipelines found themselves obliged to take volumes of gas at prices well above those created by new market conditions. This led to an era of court proceedings (*pacta sunt servanda v force majeure* and other legal
doctrines) and the enactment of laws that would circumvent pre-existing contract terms.173

By this time, the contractual structure of the gas industry was based on long-term agreements throughout the gas chain: producers and pipeline companies had long-term take-or-pay contracts in place, pipeline companies and local distribution companies had entered into long-term minimum bill contracts (similar to take-or-pay agreements), local distribution companies had captive customers and the price of gas was rising. Industrial players with switching capability had opted for other fuels and this obviously worsened the situation.174 State regulatory authorities, alarmed at the impact on consumers, began to invalidate minimum bill provisions, allowing distribution companies to extricate themselves from their obligations. This left pipeline companies contracted to take-or-pay for gas at prices far above market levels. In this situation, the FERC started working towards a comprehensive restructuring of the natural gas industry in the USA.

The era of restructuring and deregulation (1985–present)

After a number of attempts to rectify the problems discussed in the previous sections, the FERC and state regulatory commissions gave a series of ‘open access’ orders that enabled industrial users to bypass the pipelines, reducing their role to a transport service for gas to which they did not hold title. Buyer and seller could enter into a contractual relationship and enter into a transport contract with the pipeline.175 This was the beginning of a new era, that of the modern deregulated gas market.

At first, the FERC approved these transportation transactions on a case-by-case basis but the issuance of Order 436 gave the interstate pipelines a general right to provide transportation services to third parties. Essentially, Order 436 instituted the model of open-access, non-discriminatory transportation to permit local distribution companies, industrial users and other players in the downstream gas markets to purchase natural gas directly from gas merchants as an alternative to purchasing their requirements from the pipeline companies in a particular distribution area under the pipelines’ bundled sales services.

To achieve this, Order 436 adopted three key provisions:

1. the pipelines were required to permit their firm sales customers to convert their firm sales entitlements to a volumetrically equivalent amount of firm transportation service over a five-year period;
2. the pipelines were required to offer their open-access transportation services without discrimination or preference; and
3. the pipelines were required to design maximum rates to ration capacity during peak periods and to maximize throughput for firm service during off-peak periods and for interruptible service during all periods.

These open-access transportation services were not mandatory, but if the pipeline company decided to provide these services it had to respect the requirements of the Order.
This included separating the pipeline’s merchant and transportation functions. A large number of pipelines opted for this possibility and the number of applications and approvals for the status of an open-access carrier grew rapidly. In 3 years, virtually all major pipelines had been converted to open-access pipelines. As some commentators observed: ‘By 1989, a mature form of competition had come to natural gas. Enough pipelines had opened their systems to form a pipeline network. Markets had evolved far enough to coordinate gas and transmission trading. The gas market had gained the broad participation of buyers and sellers, giving it the depth and liquidity characteristic of a competitive market. The gas pipeline industry is no longer a natural monopoly’.177

Another important policy change that was implemented in conjunction with Order 436 was the ‘shipper-must-have-title’ policy. Under this policy, the shipper must have the title to the gas when it is delivered to the transporter and while the gas is in transit. The rationale behind this policy was obviously to prevent private and unauthorized brokering or withholding of capacity and to promote transparency in the markets.179

However, despite the success of Order 436 and the open access rules, important market imperfections remained. For example, pipelines offered superior service for bundled sales (as opposed to transportation services only).180

These remaining problems were addressed in Order 636, the most significant restructuring measure by the FERC. The objective was to:

finalise the structural changes in the [FERC’s] regulation of the natural gas industry...and...will therefore reflect and finally complete the evolution to competition in the natural gas industry...so that all natural gas suppliers, including the pipeline as merchant, will compete for gas purchasers on an equal footing...because...this promotion of competition among gas suppliers will benefit all gas consumers and the nation by ensuring an adequate and reliable supply of clean and abundant natural gas at the lowest reasonable price’.181

While Order 436 (and other previous orders) had tried to promote non-discriminatory access to transportation service without dealing with issues relating to vertical integration, Order 636 required functional unbundling of transportation and sales. Merchant pipelines were forced to separate their sales activities and transportation services into different units. Order 636 did not require any kind of divestiture in the form of ownership unbundling, but required that the companies engage in an internal restructuring of their activities.182 The idea behind this functional unbundling was to ensure non-discriminatory transportation services for third-party gas and the pipeline company’s own gas. Functional unbundling had the desired result, increasing competition between various gas sellers and mitigating the market power of pipeline companies.183

Key provisions and requirements of Order 636 are:

- Functional unbundling
- Non-discriminatory transportation services
Encouragement to develop marker centres where various pipeline systems interconnect
- Expanded access to interstate storage facilities
- Capacity release programme and related electronic bulletin boards
- Common rate design

Concurrently with the provisions of Order 636, the FERC regulation provides for the release of firm transportation capacity where this capacity exceeds 31 days at a price less than the maximum tariff rate. In such a case, the information about the release has to be posted for competitive bidding on the pipeline’s Electronic Bulletin Board. Even discounted releases or releases for less than 31 days have to be notified within 48 hours of the release, even if the transaction is exempted from the competitive bidding requirements. The rationale behind these posting requirements is obviously to promote transparency and hence provide the opportunity for interested parties to bid for available capacity. Similarly, the rationale behind the bidding requirement is to ensure that the capacity is allocated to the player that most values it. Together, these requirements promote transparency and efficiency and eliminate undue preference and discrimination in the natural gas transportation market. They form an integral part of the FERC pipeline open-access programme.

These changes, Order 636 in particular, altered the US natural gas markets profoundly, creating the conditions for a competitive market structure to emerge. Order 636 turned many of the pipeline companies into pure transporters of natural gas, instead of gas purchasers and re-sellers. Many services that these pipeline companies abandoned in changing their business approach were then picked up by newly created hubs (connection between various pipelines including physical transportation from one to another and balancing). As a consequence, the wholesale markets in the US have moved from the well-head to the hubs. Major hubs are today typically operated by one or more of the inter-state pipeline companies and are located at the interconnections between several pipelines. As one author put it: ‘In short, the utility world after Order No. 636 looks entirely different from the utility world of the early 1980s.’

**Developments in long-term contracting in the US natural gas industry**

Over the last 20 years, the trend in the US has been towards shorter natural gas contracts, a move driven by developments in both the markets and the regulation. A factor contributing to this has been the increasing trust on the purchasing side that sufficient volumes of natural gas and sufficient transportation capacity is available in the short term, reducing the need to contract for the certainty that a long-term agreement provides. Similarly, the maturity of the infrastructure has mitigated the need to employ long-term agreements (both in terms of financing aspects and the captivity of customers due to the existence of a web of natural gas pipelines). On the regulatory front, the uncertainty relating to changes in the regulatory set-up for the natural gas industry functions as a disincentive for long-term commitments and contributes to shorter contract duration. Similarly, the *ex post* regulation is an incentive to short-term contracting. Unlike the
past, marked by 10–20-year contracts, today, one-year gas supply contracts (the commodity contracts) are considered to be ‘long-term’. The ‘normal’ duration for a transportation contract (the capacity contract) is today somewhere in the 5–6 years range. The duration is longer in cases of new infrastructure or additions to existing infrastructure.

This shortening of gas supply and gas transportation contracts has made the planning of operations much more difficult. The pipeline company cannot plan the need for long-term transportation capacity requirements with as much certainty as it could in the past. The producer has to live with the uncertainty about the customers and demand for the coming months and years.

The US authorities have been very reluctant to interfere with the market-based mechanisms that have driven the contract duration down. Trust in contracts as the primary means of addressing various uncertainties present in modern energy markets and the market-oriented approach is also apparent in the idea that agreements concluded between two parties are normally just and reasonable and should therefore not be touched or altered by the public authorities. This approach is based on the Mobile-Sierra doctrine that starts from the assumption that freely negotiated whole-sale energy contracts normally meet the ‘just and reasonable’ requirement.

The following sections focus on the application of the federal antitrust laws in the energy sector. Concurrently with the overall purpose of this study, these sections focus on long-term agreements, that is primarily long-term gas supply agreements. In addition to this, long-term capacity reservations will be discussed in detail as well. These issues may be approached from various angles. In an antitrust approach, it is possible to look at a long-term contract arrangement as cooperation between two parties and thus examine the application of Section one of the Sherman Act, for example. In this approach, the more general view of the US antitrust law on vertical agreements is also of particular interest. The second alternative antitrust approach is to look at long-term agreements as a means to monopolize a market, in which instance Section 2 of the Sherman Act is of particular interest. These issues will now be examined in more detail, with a clear emphasis on the case law in this area.

**Vertical restraints in US antitrust law: exclusivity agreements**

*Introduction: towards a more positive approach to vertical agreements*

Just as in the EU, the approach to vertical restraints in the US has changed over the years from a rather negative view towards a more analytical and positive one. As will be seen below, this trend has however not been as clear-cut, from condemnation to acceptance, as in the EU. This section focuses on the non-price vertical restraints, instead of price-related restraints, primarily exclusivity agreements under which the purchaser agrees, directly and explicitly or by matter of fact, to buy all or most of its requirement from one seller.

The case law of the US Supreme Court has moved from an initial rule of reason approach to vertical non-price restrictions through a *per se* condemnation in *Schwinn* and back to a more mature rule of reason approach. The case in point was...
the Supreme Court judgment from 1977, *Continental TV, Inc v GTE Sylvania, Inc*\(^{202}\) in which the Supreme Court specifically noted that certain positive effects could arise from vertical restraints whose market impact is complex because of their potential for a simultaneous reduction of intrabrand competition and stimulation of interbrand competition. The Supreme Court suggested (with references to academic literature) that these included the possibility of new entry or entry into new markets through offering protection for retailers who are able to make initial investments required in the early stages of new market entry. Similarly, more established players can induce retailers to engage in promotional activities or to invest in repair facilities in order to provide additional services that might be necessary (in the case of cars or major household appliances). The Court also specifically noted that:

> because of market imperfections such as the so-called ‘free rider’ effect, these services might not be provided by retailers in a purely competitive situation, despite the fact that each retailer’s benefit would be greater if all provided the services than if none did’.

Having found this, the Supreme Court expressly overruled the Schwinn approach. Referring again to the substantial academic and judicial authority that supports the economic utility of vertical non-price restraints and noting that there was little authority to the contrary, the Supreme Court concluded that the *per se* approach in Schwinn must be overruled. The Court also added that ‘departure from the rule of reason standard must be based upon demonstrable economic effect, rather than – as in Schwinn – upon formalistic line drawing’.

In overruling Schwinn, the Supreme Court returned to the rule-of-reason approach that governed the vertical restrictions before its judgment in Schwinn. Later, in the post-Sylvania case law, the Supreme Court (followed by lower-level courts) has followed the rule-of-reason approach considering factors such as the severity of the restraint and likely harm to free competition, market shares and market power, market structure, entry conditions, the purpose and intent of the restraint, scope and duration and the existence of other similar agreements in the same markets.\(^{203}\) In other words, there is no *per se* illegality or even a presumption of illegality of vertical restraints under current application of US antitrust laws.\(^{204}\)

As the main focus of this study is natural gas supply agreements and as the effects of these agreements can often be assimilated with exclusivity agreements, this section will focus on the US approach to long-term exclusivity agreements.

### Main case law on (long-term) exclusivity agreements

The US Supreme Court has had the opportunity to assess long-term agreements in a string of cases dating back to the early 1920s. Just as the general approach to vertical agreements, the approach of the Supreme Court has changed from its early days. This
article will provide an overview of this case law and will examine the most significant cases in more detail.

In the first case, *Standard Fashion Co v Magrane-Houston Co*,\(^2\) the Supreme Court held that Section 3 of the Clayton Act prohibited agreements by which the effect of such sales or contracts would probably lessen competition under the circumstances of the case, or create an actual tendency to monopoly. The Supreme Court also added that not every ‘remote lessening’ of competition was captured by the Act, only those which were substantial.

In another case, decided just a week after Standard Fashion, *United Shoe Machinery Corp v United States*,\(^2\) the Supreme Court found that even though a contract does not contain specific agreements not to purchase or use the goods of a competitor, if the practical effect is to prevent this, the arrangement falls under the Clayton Act. The Supreme Court also repeated the rationale of Standard Fashion, stating that the finding of domination of the relevant market by the lessor or seller was sufficient to support the inference that competition had or would be substantially lessened by the contracts involved.

Some 25 years later, in *International Salt Co v United States*,\(^2\) the Supreme Court held that in cases of tying, the necessity of direct proof of the economic impact of such a contract was not necessary where it was established that the volume of business affected was not insignificant or insubstantial and that the effect was to foreclose competitors from any substantial market.

Then came the Standard Stations case. Because of its significance, the next section looks at this case more closely.

**Standard stations**

The first major look at the exclusivity agreements by the US Supreme Court was in Standard Stations.\(^2\) This case was an appeal from a District Court judgment finding that the use of exclusive supply contracts was contrary to Section 1 of the Sherman Act and Section 3 of the Clayton Act. The District Court had held that lessening of competition or tendency to establish a monopoly was proved as it had been shown that the agreements in question covered ‘a substantial number of outlets and a substantial amount of products, whether considered comparatively or not’. According to the District Court, this ‘quantitative substantiality’ led automatically to the substantial lessening of competition. The District Court refused to consider the commercial merits or demerits of the system (as opposed to the system which prevailed before its establishment and which would prevail after the judgment if the Court declared the present arrangement invalid).

In this case the defendant, Standard Oil, was the largest gasoline seller in the area (seven states in western USA) with a market share of approximately 23 per cent. Sales from service stations that Standard Oil owned were approximately 7 per cent of the total sales in that area and sales under the exclusive dealing agreements with external, independent, service stations were just below this figure (6.8 per cent). The remaining sales were to larger industrial users.
Service Station sales of the six most important competitors of Standard Oil represented 42.5 per cent of total sales. The remaining 34.5 per cent were divided among more than 70 smaller undertakings.

The then-existing market structure was marked by similar exclusive agreements, also used by Standard Oil’s major competitors (only a very small percentage (1.6) of the retailers sold gasoline from more than one supplier).

The contracts differed from case to case, but some common features could be identified including undertaking to purchase all requirements of one or more products from Standard Oil.

In its judgment, the Supreme Court noted first that it had previously, in *International Salt Co v United States*, held sufficient that it could be shown that ‘the volume of business affected’ is not ‘insignificant or insubstantial’ and that the effect of the contracts is to ‘foreclose competitors from a substantial market’ without it being additionally necessary to demonstrate any actual economic consequences. Importantly, however, the Supreme Court now made a distinction between tying arrangements and requirements contracts, noting that certain important economic differences existed. According to the Supreme Court, tying agreements hardly serve any other purpose than to suppress competition. This, however, was not the case concerning requirements contracts. This group of agreements may bring beneficial economic effects to both buyers and sellers and may therefore also be advantageous for the consumer. The Supreme Court stated:

In the case of the buyer, [requirement agreements] may assure supply, afford protection against rises in price, enable long-term planning on the basis of known costs, and obviate the expense and risk of storage in the quantity necessary for a commodity having a fluctuating demand. From the seller’s point of view, requirements contracts may make possible the substantial reduction of selling expenses, give protection against price fluctuations, and - of particular advantage to a newcomer to the field to whom it is important to know what capital expenditures are justified - offer the possibility of a predictable market. They may be useful, moreover, to a seller trying to establish a foothold against the counterattacks of entrenched competitors. Since these advantages of requirements contracts may often be sufficient to account for their use, the coverage by such contracts of a substantial amount of business affords a weaker basis for the inference that competition may be lessened than would similar coverage by tying clauses, especially where use of the latter is combined with market control of the tying device.

Thus, even though the qualifying clause of Section 3 is appended without distinction of terms equally to the prohibition of tying clauses and of requirements contracts, pertinent considerations support, certainly as a matter of economic reasoning, varying standards as to each for the proof necessary to fulfil the conditions of that clause. If this distinction were accepted, various tests of the economic usefulness or restrictive effect of requirements contracts would become relevant. Among them would be evidence that competition has flourished despite use of the contracts. Likewise
bearing on whether or not the contracts were being used to suppress competition, would be the conformity of the length of their term to the reasonable requirements of the field of commerce in which they were used. Still another test would be the status of the defendant as a struggling newcomer or an established competitor. Perhaps most important, however, would be the defendant’s degree of market control, for the greater the dominance of his position, the stronger the inference that an important factor in attaining and maintaining that position has been the use of requirements contracts to stifle competition rather than to serve legitimate economic needs’.

However, the Supreme Court also noted that the above-mentioned tests are very difficult to carry out in practice, particularly so for a Court:

to demand that bare inference be supported by evidence as to what would have happened but for the adoption of the practice that was in fact adopted or to require firm prediction of an increase of competition as a probable result of ordering the abandonment of the practice, would be a standard of proof if not virtually impossible to meet, at least most ill-suited for ascertainment by courts’.

After having found this, the Court concludes that the qualifying clause of Section 3 is satisfied by proof that competition has been foreclosed in a substantial portion of the sector affected. In this particular case, it was clear that requirement contracts foreclose the access of competing suppliers and that these agreements affected a substantial share of the petroleum products retail sales. While competition had perhaps not declined, these agreements created a ‘potential clog’ on competition that Section 3 of the Clayton Act, should it become actual and would impede a substantial amount of competition, attempts to eliminate.

While the Supreme Court made the important distinction between tie-in and requirements agreements, noting that the economic effect of these two types of agreement were inherently different, the Court seemed to fall short of an actual rule-of-reason approach, rejecting the demand that actual or probable economic consequences should be shown to exist. Because the Court in this case adopted this ‘quantitative standard’, it has been suggested that it did in fact approve the *per se* approach in this case.²¹⁰

Another significant case in this context decided just over 10 years after Standard Stations, was Tampa Electric. This case will also be examined in more detail.

*Tampa Electric*²¹¹

In the 1950s, all electrical generating plants in peninsular Florida burned oil. Despite this, one company, Tampa Electric, decided to try coal as boiler fuel in the first two units of new generating plant constructed at the Gannon Station. Tampa Electric entered into coal supply agreements with certain companies to provide for the foreseeable coal demand for its coal-based production. According to the agreement, Tampa Electric was to be supplied with ‘total requirements of fuel... for the operation of its first two units to be installed at
The Gannon Station... not less than 225,000 tons of coal per unit per year’ for a period of 20 years.

The Supreme Court started its assessment by discussing the general application of Section 3 of the Clayton Act, with references to its previous case law.

Where an agreement is found to be an exclusive dealing arrangement, it does not necessarily violate Section 3 of the Clayton Act. A violation is only possible where it is probable that performance of the contract will foreclose competition in a substantial proportion of the affected markets. In assessing whether this will occur, certain factors must be considered. These include: (1) determining the line of commerce (the type of goods, wares, or merchandise, etc, involved); (2) the geographical markets affected must be separated from other markets because the threatened foreclosure of competition must be in relation to the market affected; and (3) foreclosure following from the agreement must be found to constitute a substantial proportion of the relevant markets. To determine this substantiability in a given case, the probable effect of the agreement in the relevant markets must be weighted against the probable immediate and future effects which pre-emption of that share of the market might have on effective competition therein. Factors to consider include the relative strength of the parties and the proportionate volume of commerce involved in relation to the total volume of commerce in the relevant market area. The monetary value of an agreement does not in itself have much effect.

The Supreme Court also noted, significantly for this study, that while protracted requirements contracts can be suspect in the context of antitrust legislation, they have not been declared illegal per se. ‘Even though a single contract between single traders may fall within the initial broad proscription of the section, it must also suffer the qualifying disability, tendency to work a substantial – not remote – lessening of competition in the relevant competitive market’.

After this initial general discussion, the Supreme Court focused on the circumstances of this particular case. First, the Court noted that it was not likely that the pre-emption of competition to the extent of the tonnage involved would substantially foreclose competition in the relevant coal market. The factors that the Court considered in its assessment were:

- The amount of trade on the markets (an annual trade in excess of 250,000,000 tons of coal and over a billion dollars)
- The market structure (no seller with a dominant position in the market, no myriad outlets with substantial sales volume)
- Contractual structures (no industry practice of using exclusive contracts, no restrictive tying arrangements)

Based on these considerations, the Supreme Court suggested that the contracts concerned may have an economic advantage to both buyers and sellers. With references to Standard Stations, the Court noted that the agreement could assure supply from the buyer’s perspective and from a seller’s perspective and enable the substantial reduction of
selling expenses, give protection against price fluctuations, and offer the possibility of a predictable market. Very significantly for this study, the Court also noted that:

the 20-year period of the contract is singled out as the principal vice, but at least in the case of public utilities the assurance of a steady and ample supply of fuel is necessary in the public interest. Otherwise consumers are left unprotected against service failures owing to shutdowns; and increasingly unjustified costs might result in more burdensome rate structures eventually to be reflected in the consumer’s bill. The compelling validity of such considerations has been recognized fully in the natural gas public utility field’.

The Court emphasized that the above considerations did not mean that utilities would be immunized from the application of Clayton Act but instead that, in judging the term of a requirements contract in relation to the substantiality of the foreclosure of competition, case-by-case considerations of the parties’ operations are relevant.

Based on these and other factors, the Supreme Court concluded that the contract in this case did not amount to the foreclosure of a substantial volume of competition.\(^\text{212}\) The Court also seems to hold it significant that Tampa was a public utility company and in order to meet its obligation to continuously supply power to the public, it had to secure a reliable and sure energy source at a predictable price.\(^\text{213}\)

**Case law from the lower Courts**

Another relevant case is Omega \(v\) Gilbarco from the US 9th Circuit Court of Appeals. Gilbarco was the market leader in product innovation and improvement with high-quality products and had 55 per cent of the domestic markets for certain dispensers in 1995. The business of Gilbarco was centred on approximately 120 standard form ‘Domestic Distributor Agreements’ with an initial duration of one year and thereafter terminable on a 60-day notice by either party.

The plaintiff, Omega Environmental, did not manufacture products, purchasing its requirements from other players (purchases by the entire network were consolidated). It functioned as a national service and distribution network and provided ‘one-stop shopping’ to consumers of petroleum dispensers and related equipment. In order to grow, the company had acquired some of the existing market players, including two authorized Gilbarco distributors.

As a response to the new competition from Omega, Gilbarco decided to continue to do business only with service station equipment distributors who would sell only the Gilbarco line of retail dispensers. Further to this decision, it notified the distributors that had been acquired by Omega that it would not continue the relationship with them.

Omega brought a suit on various grounds including resale price maintenance for petroleum dispensing equipment and allocation of territories and customers in violation of Section 1 of the Sherman Act. They also claimed violations of Section 3 of the Clayton Act. After a verdict finding that Gilbarco had engaged in exclusive dealing, unfair
competition, breach of contract, negligent misrepresentation and tortious interference, the case was appealed to the 9th Circuit.

The Court commenced by discussing exclusive dealing agreements more generally. According to the Court (with references to academic opinion and previous case law from circuit Courts and the Supreme Court), the main antitrust-related problem with exclusive dealing arrangements is their tendency to foreclose the market from existing and new competitors. The foreclosure affects the portion of the market covered by the agreement during the term of the agreement. The Court also noted that in a way all agreements have a foreclosure effect, at the minimum for the actual product bought through the agreement, as no other entity can purchase precisely that product. The Court furthermore stated that there are well-recognized benefits from exclusivity arrangements: for example, they often enhance inter-brand competition. For these reasons, the exclusive dealing arrangements are not \textit{per se} violations of antitrust laws but must be assessed under the antitrust rule of reason. Only arrangements that probably foreclose competition for a substantial share of the line of commerce affected violate Section 3 of the Clayton Act.

The Court then moved to a case-specific analysis, finding that the relevant markets in this particular case were the sale of retail gasoline dispensers from manufacturers in the US. The market share of Gilbarco was 38 per cent. The Court found that, despite this quite significant market share, anti-competitive effects were not likely. The reasoning of the Court was essentially that:

(i) There is a difference between those exclusive dealing arrangements imposed on distributors and those imposed on end-users, the former being generally less cause for anti-competitive concern. This is simply because where competitors can reach the final consumer by using alternative distribution channels (actually existing or even potential), it is very unclear whether such restrictions have a foreclosure effect on any part of the relevant market.

In this particular case, it seems that there was clear evidence that the manufacturer could use direct sales to end-customers as an alternative distribution channel. Similarly, there seem to have been potential alternative sources of distribution. In addition, some of the existing players such as service contractors sometimes become authorized dispenser distributors. Such alternatives play a central role in the antitrust assessment and indicate that there is not complete foreclosure, competitors being able to access final customers through various alternatives.

(ii) Short duration and easy terminability of the agreements affect and substantially reduce the potential foreclosure effect. As the distributor agreement could be terminated with 60-days notice, a distributor is not locked into the relationship but can actually make change where a better offer or better product becomes available.

(iii) There had been entry in this particular case. The Court illustrates this by referring to the increased market share of Schlumberger. The market share of this company
increased since its entry by at least one-third at the same time as the industry output in the retail dispenser market expanded substantially. Because of examples like this, it cannot be maintained that the exclusive dealing arrangement is an effective entry barrier of any significance.

Because of these factors the Court concluded that Omega could not reasonably infer probable injury to competition even in this highly concentrated market where the undisputed evidence shows increasing output, decreasing prices, and significantly fluctuating market shares among the major manufacturers.

The evolution of the case law

In essence, the developments and progress examined above have been described as including three periods: the first period marked by an emphasis on the market share and duration, the second period after Standard Oil marked by an emphasis on the ‘quantitative substantiality’, and the third period, starting from Tampa, marked by a ‘qualitative substantiality’.214 The next section very briefly looks at the evolution of the approach to certain specific aspects of exclusivity arrangements: duration, market share and foreclosure.

Duration

In the past, the duration of the agreement was very significant in evaluating the competitive impact of the exclusivity arrangement. The defence could argue that the foreclosure effect would only be present during the term of the agreement and the restraint would therefore be reasonable. The duration would be limited to recoupment of the necessary investment or to the time necessary to penetrate a new market.215 However, it was soon noted that concentrating on the duration overlooks an important aspect of the exclusive arrangement: the present impact of the arrangement. Today, the duration of the agreement is not the determining factor in the impact assessment. The nature of the market determines the impact and thus the acceptability of an exclusive dealing agreement.216

However, despite this, duration continues to be one significant factor. Here, the case law makes a difference between situations with new investments and the absence of such investments. Similarly, the duration is closely linked with the ability to terminate the contractual relationship.

In Great Laker’s Carbon Corp,217 some 7-20-year contracts covering the full output with the dominant seller in the industrial petroleum coke sector were seen as anti-competitive. A duration limited to three and five years was possible where a new plant was involved (necessary recovery period).218 It was also of particular significance in Omega v Gilbarco that the agreements could be terminated at short notice (and without adverse effects to the terminating party). Similarly, the short duration and the ability to terminate the contract were also significant in Western Parcel Express v United Parcel Service.219 These factors however are not always enough. In Minnesota Mining & Mfg Co v
the Court rejected the ‘ability to terminate’ defence with reference to another very significant factor: the high switching costs. In another case, United States v Dentsply, the Court refused to consider the ‘ability to terminate’ as a valid antitrust defence. It has been suggested that the Court did so because the large market share of Dentsply made it unlikely that a dealer would change from Dentsply to a small supplier. In other words, it seems that a contractual ability for a distributor or end-customer to terminate an exclusive supply arrangement may not be an offsetting factor where it would be costly to do (due to switching costs) or infeasible, for example, because the alternative supplier is too small to meet their requirements.

Market shares
Today, in assessing an exclusivity agreement, a court will first define the relevant markets (both product and geographical). It will then examine the degree of foreclosure. Exclusive dealing arrangements are usually considered reasonable as long as the foreclosure resulting from the arrangements is less than 40 per cent of the relevant market. If the market share of the company employing exclusivity clauses is large and it is therefore likely to have market power enabling it to raise prices or exclude competitors, the restraint is likely to be considered unlawful. Where the market share of a company is very large, the situation may also fall under the monopolization heading and be examined under Section 2 of the Sherman Act. This issue is discussed below.

Foreclosure
In addition to foreclosure in terms of market share, the actual competitive impact is now being assessed by courts, looking at factors such as entry barriers and market structure, including the number and the market shares of competitors.

After an initial period during which the foreclosure effect of an exclusive dealing arrangement was the focal point of the inquiry, the Courts have now recognized that consumers are not necessarily harmed by even high levels of foreclosure. In some cases, such as the Microsoft case, attention has shifted from foreclosure to market power and the ability to maintain that power.

To conclude, the evolution has moved from a negative to a much more positive view of long-term supply agreements. In Standard Stations and more generally in the early case law, the Court treated exclusive dealing agreements with great suspicion. In the more recent case law, starting from Tampa Electric, much more evidence on the harm or injury to the competition has been required. As has been seen, the analysis in Tampa is much like the rule-of-reason approach today. It has also been suggested that if the case came before the Supreme Court now, the approach would be called rule of reason.

The next section focuses on another antitrust approach to long-term supply agreements. These agreements may also be effectively used to wilfully monopolize or, in particular, maintain a monopoly position in the market. Such exclusion of potential competition through long-term exclusivity arrangements can be dealt with under Section 2 of the Sherman Act. This provision and some of the relevant case law will now be briefly examined.
Monopolization under Section 2 of the Sherman Act

Section 2 of the Sherman Act does not prohibit the acquisition of significant market power or a monopoly position as long as this results from superior skills, products, services or similar reasons. It does, however, prohibit the acquisition or maintenance of that position where this is not related to these factors but to other types of conduct. If a claim based on Section 2 is to succeed, it is necessary to show that (1) the company possesses monopoly power in a specific geographical and product market and (2) that this position has been acquired or maintained wilfully through unlawful means (‘economically irrational behaviour’ or conduct with ‘no rational business purpose’) instead of superior performance. Much like vertical agreements, these factors are assessed under a rule-of-reason scrutiny.

The monopolization scrutiny under Section 2 will commence by assessing whether the company possesses monopoly power. The starting point in this scrutiny is the market share of the target company. There are no precise market share thresholds above which a company is deemed to have monopoly power. However, the case law from the lower courts in the US suggests that where the market share is above 70–80 per cent, the company has usually been held to possess monopoly power. A market share of less than 50 per cent has usually been insufficient to establish monopoly power. The market share is only a proxy in determining monopoly power. Other factors that affect this assessment include stability of market shares, market structure and entry barriers.

Another significant step is to show the intent to monopolize, which considers the legitimacy of conduct through its intended effect on the competitive process. As put by Robert Bork: ‘The law can usefully attack [exclusionary conduct] only when there is evidence of specific intent to drive others from the market by means other than superior efficiency’. This ‘wilful acquisition or maintenance of monopoly power’ is assessed case-by-case and there is no comprehensive list of what constitutes prohibited conduct and what is regarded as normal business activity. However, there is a body of case law that deals with this question. For the energy markets, impermissible acts could take a number of forms. The focus here will mainly be on the use of long-term agreements to block new entry and refusals to transport natural gas through a pipeline.

As this section examines some of the energy-related case law relating to refusals to deal under Section 2 of the Sherman Act and the ‘essential facilities’ doctrine, it is first necessary to briefly discuss the US Supreme Court decision in Trinko and its possible implications for this case law.

In Trinko, the US Supreme Court specified that the leading case on refusal to deal, Aspen Skiing, is ‘at or near the outer boundary of §2 liability’ and constitutes a limited exception to the main rule that dominant companies are free to choose their trading partner and have no duty to aid competitors. The Court then emphasized that this conclusion would not change even if it considered to be established law the ‘essential facilities’ doctrine crafted by some lower courts. The indispensable requirement for invoking that doctrine is the unavailability of access to the ‘essential facilities’; where
access exists, as it does here by virtue of the [sector-specific regulation], the doctrine serves no purpose. [...] When there exists a regulatory structure designed to deter and remedy anti-competitive harm, the additional benefit to competition provided by antitrust enforcement will tend to be small, and it will be less plausible that the antitrust laws contemplate such additional scrutiny'.

Even if the implications of Trinko are still somewhat open (for example, it has been suggested that it remains unclear how far the effects of the case are intended to go in partially regulated industries), it seems relatively clear that the judgment will have significant consequences for the application of Section 2 in refusal-to-deal cases in the regulated industries. This means that, for example, where the Natural Gas Act and its interconnection and access provisions are applicable, the opportunity to employ Section 2 of the Sherman act is limited. Similarly, while the US Supreme Court did not take a definite stand vis-à-vis the essential facilities doctrine, it did significantly reduce, if not exclude, its scope of application in the regulated industries.

Despite this, the next section now examines the energy-related case law on refusals to deal under Section 2 of the Sherman Act. This analysis is necessary for the overall objective of this study, as it shows the US approach to refusals to deal and the role of long-term agreements. Accordingly, this case law can be examined from various angles: an essential facility angle, as a more general refusal to deal type of case law, and to assess the role of long-term gas supply agreements as a justification for an access refusal.

**Refusal to deal and the US essential facilities doctrine**

The perhaps self-evident point of departure is that even a monopolist is free to choose its trading partners and can refuse a business relationship with a particular company. In the notorious Trinko case, the Supreme Court again emphasized this point, noting that the courts must be very careful in determining that a decision to refuse to deal with a specific company is based on anti-competitive motives instead of normal and acceptable business strategies. One of the relevant issues raised by the Court in this case was the existence of prior dealings between the companies versus a new potential relationship. The existence of a regulatory set-up monitoring and enforcing fair dealings in the sector was also of particular significance.

The access issues are particularly sensitive in cases involving essential facilities (some natural gas pipelines and electricity interconnectors, etc). Under the US doctrine, the four elements for establishing an essential facility are: (1) a monopolist is in control of the essential facility; (2) the practical inability to duplicate the essential facility; (3) denial of use to a competitor; and (4) the feasibility of providing access. It is not required for an essential facility violation to occur that full access be denied. It may also occur where the access is offered at impractical hours, insufficient amounts are offered, or that the quality of service is inferior to what the monopolist offers to its own subsidiaries or preferential customers. However, where there is an objective and legitimate business justification for
refusing access request to a third party, there is no obligation for a monopolist to grant access to an essential facility, or where the ability of the monopolist to serve its own customers would also be restricted because of TPA.244

In the City of Chanute, Kansas v Williams Natural Gas Co,245 certain cities claimed that the pipeline company had refused to transport gas which they had purchased from third-party producers. Here the Court recognized the monopoly power that the pipeline company had in the area of the plaintiff cities but decided that there was a legitimate business explanation for the refusal of access. The pipeline company had the right to temporarily refuse TPA and related transportation services because of take-or-pay agreements that it had previously concluded. These agreements, under which the pipeline company had committed to purchase certain volumes of gas from producers, amounted to a significant value. (The case related, at least partially, to the restructuring of the natural gas industry and legislative and regulatory changes examined earlier in this study.)246

In a similar case, the State of Illinois ex rel Burris v Panhandle Eastern Pipe Line Co,247 the state claimed that the Panhandle Company had violated antitrust laws through refusing to transport natural gas purchased from other companies by its customers through its pipelines.

Just like many other companies at that time (in the late 1970s and 1980s), Panhandle had contracted to purchase expensive gas through long-term take-or-pay agreements, without force majeure clauses or any adjustment possibilities. When gas prices eventually dropped, the gas sold by Panhandle remained costly and its customers started to look for alternative sources. However, Panhandle had a ‘sole supplier’ provision in the contracts with its customers, which, of course, presented an obstacle to them. This provision was part of Panhandle’s FERC-approved ‘G tariff’ rate schedule, obliging Panhandle to use its best efforts to meet (often fluctuating) customer demand for gas and permitting customers to vary the quantity of gas purchased each month. In return, customers agreed to purchase their full requirements of gas from Panhandle. Significantly, to satisfy that obligation, Panhandle entered into a number of long-term contracts to secure sufficient gas volumes for the future.

When the customers of Panhandle requested the company to transport the gas it had purchased directly from third-party producers, Panhandle refused on the ground that enabling its customers to obtain gas from other sources would dramatically reduce demand for the expensive gas it was contractually obligated to purchase, exposing it to enormous take-or-pay liability. After certain regulatory changes, Panhandle modified its approach and agreed to transport third-party gas on the condition that it had a right of first refusal.

The District Court, affirmed by the Court of Appeal, looked at the issue from an essential facility angle (the state had based its claim on an essential facility violation) and found that it would have been economically feasible for competitors to duplicate much of Panhandle’s system within central Illinois by means of interconnections between competing pipelines and the construction of new pipelines. The Court also noted that to be liable for monopolizing an essential facility it must be feasible for the owner of the
facility to provide access to its facility. In this case the refusal was genuinely and reasonably motivated by the need to limit its potential take-or-pay liability, not by a desire to maintain its monopoly position by excluding competition in the sale of natural gas. This concern, when coupled with the regulatory flux that the natural gas industry was undergoing at the time, was sufficient to exclude the possibility that Panhandle was motivated by anti-competitive intent.

The less-known case of *American Central Eastern Texas Gas Co v Union Pacific Resources Group Inc* is also relevant to present discussion. This case was heard as an appeal from a decision by an arbitral tribunal. The arbitration award involved finding monopolization under Section 2 of the Sherman Act. The arbitrator found violation of the said provision as the defendant company had refused to grant certain agreements with the purpose of preventing new competition. The Court of Appeals affirmed the earlier decision of a District Court that had already confirmed the arbitration award.

The defendant company had engaged in anti-competitive activities which included the company’s requiring its customers to enter into long-term agreements in order to fill its pipelines and thus excluding others attempting to enter the same market. The strategy seemed to have been to employ a web of long-term agreements with a large number of existing customers in the relevant market to prevent entry (which was impossible because of inability to obtain transportation capacity and gas-processing capacity, both precluded through the use of long-term agreements). In addition to preventing access through filling the pipelines, it also prevented the construction of new pipelines feeding to the relevant geographical market. Where some capacity existed and where potential new entrants sought access to the pipelines, the company made the access conditional on certain uneconomic charges, and refused to give guarantees over the capacity, thus making access unworkable in practice. Similarly, the company failed to provide information it provided for its own group companies on the availability of capacity in excess of 30 days, the necessary hub allocation information (in a timely manner and with accurate information).

It would not be feasible to discuss the essential facility doctrine in the energy sector without mentioning the notorious *Otter Tail Power Co v United States*. In this case, Otter Tail refused to wholesale power to the municipal systems or transfer (‘wheel’) it over Otter Tail’s facilities from other sources to prevent the towns from establishing their own power systems when Otter Tail’s retail franchises expired. Unsurprisingly, the Court held that the company had abused its monopoly position over the transmission lines to foreclose competition.

However, if the access to a facility is not truly essential, if, for example, alternative ways to access a specific market exists, a claim based on essential facilities cannot succeed, as was the case in *Midwest Gas Services, Inc v Indiana Gas Co, Inc*. In this case, a company wanted to interconnect its gas storage field with a gas distribution pipeline in a situation where alternative (already existing) pipeline connections and routes existed, but were
clearly less attractive in an economic sense. Here, the Court noted that the most economical route is not an ‘essential facility’ when other routes are available.

Similarly, the requirement that access must be essential was not fulfilled in *Paladin Associates, Inc v Montana Power Co.*, the Court noting that a facility is ‘essential’ only if control of the facility carries with it the power to eliminate competition in a downstream market. In this case, the gas customers in the relevant downstream market received gas from sources other than the pipeline that, according to the claimant, should have been regarded as an essential facility. Because of these alternative sources and routes, the fact that the company had the control over a specific pipeline did not make it an essential facility as it did not have the power to eliminate competition in the downstream market.

**The US approach to forced access and the role of long-term agreements**

Looking at the above case law, the clear assumption in the US has been that the monopolist has the right to choose its trading partners and only very exceptionally have the Courts forced a company to give access to its competitors. In such cases, the burden of proof of the intent to monopolize has been heavy. In most cases, an objective reason for the access denial has been found to exist. In the cases concerning access to the natural gas pipelines, existing long-term take-or-pay agreements have been accepted as a legitimate business rationale for the denial of access. However, the courts have also paid attention to the practical effect of those long-term agreements. First, where the value and the potential liability stemming from the agreements have been high, the monopolist has had the right to protect itself from negative consequences. The fact that the long-term agreements have been concluded in order to secure delivery for the end customer seems to have been significant as well. Here, the Courts seem to have recognized the importance of the volumes involved in a particular case and agreements (contract volumes v total demand by the customer). The mere fact that economic circumstances would suggest that access should be granted, instead of, for example, forcing the potential competitor to construct new and competing facilities or where less advantageous access options existed, has not been held to satisfy the ‘essentiality’ of access by competitors.

Where the burden of proof regarding the intent to monopolize has been fulfilled, the Courts have not hesitated to find a violation of Section 2. However, as noted, these cases have in practice been rare. The case concerning American Central Eastern Texas Gas Company is of particular interest, the issues raised including factors like a web of agreements intended to block access and function as barriers to entry and preventing the construction of competing infrastructure.

As was already mentioned, long-term take-or-pay agreements have been accepted as a legitimate business reason to refuse access (potential liability and difficulty in supplying customers being the underlying rationale in most cases). Similarly, the long-term supply agreements have been accepted under Section 1 of the Sherman Act, and their positive stabilizing effects in the energy industry in particular have been recognized by the Courts.
4. Comparative remarks

These comparative remarks will offer some initial thoughts on the differences in the developments in the US and EU in terms of regulation of natural gas markets and the approach to long-term natural gas contracts.

The first notable difference on the regulatory front is the development of natural gas regulation. Unlike the EU where the liberalization efforts date back to the late 1980s, the trend towards the status quo in the US is a result of a long and progressive evolution marked by periodical resistance to certain choices, litigation and court decisions and attempts, errors and adjustments. Where the approach in the EU has been to tackle liberalization and move from monopoly power and state-controlled markets to EU wide and competitive markets through a series of legislative developments, in particular over the last 10 years, coupled by increasingly intensifying antitrust enforcement, liberalization in the US has been a slow process, from a legal, not market development, point of view. One apparent reason for this is the absence of models for US liberalization contrasted with several possible models for the EU. Where the US had to rely on attempt-corrective measures kind of approach, the EU could look at the US, UK and New Zealand for possible models, though the models provided by countries with internal production, and limited or no import dependency do not translate well into lesson for the EU gas markets. Even with this advantage, the EU experience is also marked by continuous adjustments in the regulatory models. Another possible reason is the greater trust in the markets in the US and the attempt to limit public intervention in the market mechanism as far as possible. In the US, the progress has been more market driven than public sector driven. The regulation has been enacted in response to markets and their developments. For example, federal regulation emerged as a response to commencement of interstate trade in natural gas. The situation in the EU has been very different. Regulation has been put in place to create a market, instead of as a response to markets. In the EU, the regulators have also shown their readiness to limit the market-based mechanism where considered necessary and replace the market-based progress with administratively led progress. In this sense, where the liberalization method in the EU has been very much marked by a top–down approach, the approach in the US has been bottom–up.

On the antitrust front, the approach to long-term natural gas contracts is similar in both markets. The relevant considerations in both areas relate to duration and volumes, market shares and foreclosure, contractual structures and the existence of overriding benefits. However, an important driver of the differences in US and EC case law, or the lack of it, seem to stem from the differences in the market structures.

As the US markets have a greater number of players and hundreds of thousands of producing wells and the existence of significant natural gas resources, the volumes covered by individual contracts are as a rule much smaller than those in the EU upstream markets. Similarly, the market power of a single market participant is smaller than in the EU where markets are largely dominated by the national incumbents that, due to historical reasons, still control most of the markets. Where the US natural gas markets rely mainly on internal production, the EU natural gas markets rely on a small number of
external producers. This rigidity of the upstream markets has an effect on the EU markets. Unlike the situation in the US, the bilateral contracts between the external producers and the EU purchasers can cover a significant amount of the overall demand of the importer. This may be illustrated by the situation in Hungary, where the contracts between Gazprom and the national incumbent, MOL, cover virtually the entire domestic demand. In addition to Gazprom (80 per cent of the requirements), Hungary relies on France (3 per cent), Germany (6 per cent) and other CIS sources of natural gas (11 per cent) for its imports. While Hungary is a somewhat extreme example as the market position of one company, Gazprom, is stronger than in many other Member States, and while the significance of a single producer might not be as important in some other Member States, the market share of the national incumbent gas supplier is as a rule very high. For example, France relied on suppliers from Russia (16 per cent), Nigeria (9 per cent), the Netherlands (19 per cent), Norway (27 per cent), Algeria (16 per cent) and other countries with smaller volumes (13 per cent). Even with lower markets, shares of the producers in France, the market share of GDF Suez, the national incumbent, is in the 80–90 per cent range. This difference in markets and supply means that where the concern in the EU relates to the foreclosure effect of large volumes contracts and few players, the US markets are much less influenced by competition concerns relating to large volumes and long durations.

As was noted, the EU downstream markets have similarly been marked by vertical contractual structures and the competition concerns here have related to durations, volumes and the web of similar contracts aggravating competition concerns. Here the strategic application of competition laws have had a positive impact and it seems that at least some, though certainly not all, downstream markets in the EU are now moving towards a US-type market structure with more players, different kind of products and so on. More generally, while a fully functioning spot market for gas is yet to emerge in the EU, the rapid and fundamental changes to world LNG markets have caused a significant change in this respect and created favourable conditions for short-term trading. In addition to the significant increase of available volumes and decreases in LNG prices, there is also an important regulatory dimension to this development. The introduction of third-party access along with ownership unbundling, driven by both regulatory changes and antitrust enforcement, has combined with elimination of destination clauses (and other historical elements of the market structure) to completely transform the regulatory context in which natural gas companies operate. These fundamental changes have had a significant impact on the markets, and spot trading in the EU natural gas markets has now taken off. This in turn has had a profound impact on long-term upstream natural gas contracts that are now rapidly moving away from the oil price linkage towards a new pricing scheme based on gas-to-gas competition.

Looking at the case law in the EU and the US, it is clear that duration is not the only key issue for the antitrust analysis of long-term contracts on either side of the Atlantic. In addition to the duration of contracts, the contractual volumes are a part of the analysis, the central question being the effects on the market. The effect of a contract covering very small volumes compared to the total volumes traded on the market will be small, despite
the long duration. On the contrary, even a relatively short-term contract covering very significant volumes can in certain circumstances foreclose a market temporarily and have major effects in the longer term, through, for example, blocking entry of a potential competitor. The upfront character of natural gas or infrastructure investments aggravates this potential problem.

The duration and the volumes in both the EU and the US case law are closely linked with the rationale of the contract. Where the contract is used as collateral or is otherwise necessary to back up large investments, a longer duration and larger volumes are acceptable. In the US, the construction of a new plant and the need for a recovery period (three to five years) legitimized contracts with a dominant company covering the full output of the new plant.264 In the EU, competition decisions which have limited contract terms to a five-year maximum term for downstream natural gas contracts did not apply to new power plant projects.265

The effects-based approach is also visible in the case law in both the EU and the US. In addition to the existence of a de minimis type266 of approach or requirement of substantial lessening of competition267 in both areas, the approach to market shares and the focus on foreclosure is apparent in both the EU and the US antitrust practice. In the US, exclusive dealing arrangements are usually considered as reasonable as long as the foreclosure resulting from the arrangements is less than 40 per cent.268 In the EU, the restrictions on the contract durations and volumes in the Distirgas case were applicable only as long as the market share of Distirgas was above 40 per cent, reflecting the 40 per cent threshold for dominance under the EU competition law.269 However, in both cases the existence of similar contractual structures,270 the total trade v the trade covered by the long-term contracts and the general market structure affect the antitrust analysis.

Also the rationale for the contract is a key issue. In the US, the use of long-term contracts to block entry was relevant in the American Central Eastern Texas Gas Co v Union Pacific Resources Group Inc.271 In that case, the defendant company had employed a strategy of excluding competitors by requiring its customers to enter into long-term agreements in order to fill its pipelines and excluding others attempting to enter the same market.272 The same strategy based on the use of a web of long-term agreements with a large number of existing customers in the relevant market to prevent entry was the central question in GDF Suez273 in the EU.

Similarly, both the EU and the US courts have recognized the beneficial effects of long-term agreements. Among these positive elements, they have recognized that they: (1) enable new investments in the supply chain;274 (2) provide the assurance of a steady and ample supply of fuel and that this is also in the public interest;275 (3) provide for protection against rises and fluctuations in the price;276 (4) enable long-term planning;277 and (5) secure sufficient gas volumes for the future.278 As is apparent, these factors have a common denominator, all being different elements of security of supply.279 Clearly, this body of case law suggests that long-term agreements are necessary for security of supply and that it has been accepted as an antitrust defence in both US case law and EU administrative case law. However, it has not been accepted as an overriding element but as a part of the antitrust scrutiny in a specific case.280
Many of these legitimating factors were recently confirmed in both the EU and the US. In the US, the US Supreme Court in *Morgan Stanley Capital Group Inc v Public Utility District No 1 of Snohomish County*, specifically noted that the US Courts have continuously recognized the stabilizing effect of long-term agreements and that these ultimately benefit consumers. As an example, the Court referred to the California energy crisis, noting how the decreased use of long-term electricity purchase agreements and the increasing reliance on short-term trading were at least partially behind the California energy crisis in early 2000. In the EU, the new sector-specific regulation has consistently confirmed the valuable security benefit of long-term contracting.

As to the antitrust scrutiny of refusal to deal cases, it seems as if the threshold for finding a legitimate business justification for refusal is lower in the US than in the EU. It seems as if the US approach is to protect the freedom to contract and to trust the markets to deliver the right balance between TPA and dynamic efficiency. Similarly, the situations in which a section of infrastructure has been held to be an essential facility and mandatory access was forced are much more narrow in the US than in the EU. Here again, in addition to a more ideological difference, US antitrust approach to vertical restraints being more liberal and the emphasis being on the freedom to contract, the more mature market structure in the US could also explain this difference. The practice in the US seems to be to interpret the essential facility doctrine in a very restrictive manner, as in *Midwest Gas Services, Inc v Indiana Gas Co Inc*, where alternative pipeline connections and routes existed, but were clearly less attractive in an economic sense. Here, the Court noted that the most economical route is not an ‘essential facility’ when other routes are available. Similarly, in *Paladin Associates Inc v Montana Power Co*, the Court noted that a facility is ‘essential’ only if control of the facility carries with it the power to eliminate competition in a downstream market. The existence of alternative natural gas sources and routes eliminated the essential facility character of an individual pipeline section and the power to eliminate competition in the downstream market. In the EU, the progress and the use of this doctrine has been very different. While the traditional application of the essential facility doctrine has been limited to requiring access, the Commission practice in the energy sector includes requiring investment to critical sections of the supply chain. Also the mere fact that a dominant company contracts for transportation capacity in its own network, regardless of the question of usage of the capacity, has now been deemed falling within the scope of the doctrine, as was the case in *GDF Suez* and *E.ON*. Compared to the US, the EU is more ready to use public intervention to correct market failures, the obvious difference, of course, being a more competitive market structure in the US and the absence of dominant companies controlling the network and making attempts to secure their market position.

5. Conclusion

The purpose of this research article was to examine and explain the application of antitrust rules to natural gas contracts. After an examination of the past and present approach in the EU and the US, it has been shown that despite the differences in legal practice, the
underlying objectives and the underlying economic rationales are similar. The differences in outcomes related primarily to different market structures and differences in the historical differences. As the market structure is different in these two areas, it follows logically that the application of the theory is also different.

One of the central differences seems to be in the approach to market design and the process of liberalization. The EU approach has been a top–down approach marked by administratively led liberalization. The EU institutions, the European Commission in particular, have driven the process and made attempts to create an optimal regulatory set-up for the energy markets. So far, progress has varied substantially between Member States, and must be viewed as ‘work in progress’—but the Commission has responded with further legislation, new European institutions and increasing guidance on matters such as congestion management and so on. In the US, the regulators have mainly reacted to market trends and the regulation has been designed to apply to problems in the markets and the political complexities have arguably been substantially less.

It is of paramount significance to note that this application of antitrust rules is time-specific and as such, it is subject to constant changes. A legitimate action today can be anticompetitive tomorrow. In the EU, long-term capacity reservation contracts moved from being supported, to being tolerated and further to being prohibited in a matter of years. A company in a dominant position might not be that tomorrow. The increase in cross-border infrastructure can widen the geographical scope of the relevant markets and thus dilute the dominant position of a company. As such, the application of antitrust rules is constantly moving target. Much care must be taken in applying past precedents to new market realities. The changes are rarely as significant and profound as they have been over the past 20 years in the EU, culminating in 2008–2010 period, but smaller changes occur constantly.

What then is the future of the traditional long-term take-or-pay contracts in the EU? It seems probable that while the long-term upstream contracts will continue to exist in the EU natural gas markets, they will evolve away from the traditional model. Oil price indexation in upstream long-term contracts will gradually disappear. Unlike many of the other fundamental changes in the EU energy market structures, this change is not forced by the regulators but is instead driven by the markets. Similarly, the development of a secondary market, increasingly available LNG and the flexibility that storage provides have reduced the need to rely on take-or-pay contracts for all of the required gas volumes. With the availability of these market-based flexibility tools, it is well possible, or even probable, that while the take-or-pay provisions would continue to exist, along with short-term trading, the volumes covered by the take-or-pay obligation would be reduced. The take-or-pay provisions of the long-term contracts are the key risk division mechanism in the EU natural gas trade. The buyer takes the volume risk while the seller assumes the price risk. Following the logic of the German downstream case examined (see ‘Oil price indexation’) above, it would seem that as long as the buyer is free to resell the volumes it has purchased on the secondary market, the negative impact of the take-or-pay provision is minimized. An antitrust analysis of this type of provision would have to
include the positive effect of these clauses, the security of demand for the seller and the security of supply for the buyer which seems to balance any negative effects.

On both sides of the Atlantic, the energy sector is one of the key areas of antitrust scrutiny. Because of the political sensitivity of the energy sector (oil, gas and electricity), there is a particular need for rigorous and independent antitrust enforcement. The geopolitical aspects of the EU natural gas markets and the close linkage between energy and the consumer in both the EU and the US highlight the political interests that are inherent in this sector. Because of these factors, the role and the rationale of long-term contracts is sometimes forgotten. Because of various beneficial attributes that have been discussed in this research article, long-term contracts should be allowed to co-exist with shorter-term trading. Among other things, they bring the necessary stability to the markets. They also reduce uncertainty and provide for investment stimulus. As such, it should be the markets that ultimately make the decisions on long-term contracting. Administratively led decisions in the most central elements in the trade in any sector carry a substantial risk of ‘getting it wrong’. In a sector like energy, we cannot take this risk.

Endnotes

1 As rightly noted by John Lowe, these two elements are the key characteristics of upstream natural gas contracts. E Smith et al, International Petroleum Transactions (Rocky Mountain Mineral Law Foundation 2010) 1047.
3 For a more detailed overview of the EU natural gas markets, including the current problems, see K Talus, Vertical Natural Gas Transportation Capacity, Upstream Commodity Contracts and EU Competition Law (Kluwer Law International 2011).
8 The political aspect and the interplay between law and (geo)politics is examined in detail in Talus (n 3).
11 However, it should be noted that there is currently a move back towards a publicly controlled market model where the role of public authorities is again increasing. This move from ‘State to Market and Back’ is described in K. Talus, ‘From State to Market and Back: The Role of the Public Sector in the Energy Markets—the European Experience’ OGEL (forthcoming).
12 The emergence of shale gas in the US, the large new projects from Qatar and other countries and other developments also complicate the economics of LNG trade.
volume and price risks are not the only type of risk a long-term relationship will face. Other risks include an economic risk (due to future demand and availability risk) and a political risk (which transforms into potential changes in the investment climate). More generally, where long-term contracts relate to project financing, this type of structure also requires a careful allocation of risks and return. (J Finnerty, Project Financing: Assets-Based Financial Engineering (Wiley 1996) 3.


18 Inquiry pursuant to art 17 of Regulation (EC) no 1/2003 into the European gas and electricity sectors (Final Report) (COM/2006/851 final) 10 January 2007, 14. (This report is hereinafter referred to as the ‘Sector Inquiry’). See also a speech by N Kroes, ‘A New European energy policy; reaping the benefits of open and competitive markets’ (Speech/07/63, Essen, 5 February 2007).


23 In addition, there is a specific provision, art 9(9), accepting the Scottish unbundling model which does not meet the requirements of the Directive but is nevertheless deemed as delivering the required competitive conditions.

24 Art 9 (et seq) of Directive 2009/73/EC.

25 Art 14 (et seq) of Directive 2009/73/EC.

26 Art 17 (et seq) of Directive 2009/73/EC.


28 Ownership unbundling has also been the result in a number of competition law cases where companies have offered structural remedies in form of network divestiture. See, for example, COMP/39 388—German Electricity Wholesale Market and COMP/39 389—German Electricity Balancing Market or COMP/39 402—RWE Gas Foreclosure.


32 The access to upstream pipelines was separately regulated. According to art 20, natural gas undertakings and eligible customers must be able to obtain access to upstream pipeline networks, including facilities supplying technical services incidental to such access. The parts of the upstream networks and facilities which are used for local production operations at the site of a field where the gas is produced constitute an exception from the TPA obligations of art 20. This access must be provided in accordance with the objectives of fair and open access, achieving a competitive market in natural gas and avoiding any abuse of a dominant position, taking into account security and regularity of supplies, capacity which can reasonably be made available, and environmental protection. Access can only be refused under the conditions listed in the Directive, although it must be noted that these conditions are sufficiently broad to enable the refusal. One condition, for example, concerns the reasonable needs of the owner, operator or other users. To strengthen this upstream access regime, a dispute settlement mechanism must be put in place.

33 For example, see the 2008–2010 editions of B Delvaux, M Hunt and K Talus (eds), EU Energy Law and Policy Issues (Euroconfidentiel).


35 Unlike the US and Australia, for example, the regulatory framework for electricity and natural gas in the EU is remarkably similar both in terms of content and history. For a comparison of the access regimes in EU electricity and gas regulation, see A De Hauteclocque and K Talus, ‘Capacity to Compete: Recent Trends in Access Regimes in Electricity and Gas Networks’ in B Delvaux, M Hunt and K Talus (eds), EU Energy Law and Policy Issues (Euroconfidentiel 2011).

36 The TSOs should promote the development of energy exchanges, the coordinated allocation of cross-border capacity through non-discriminatory and market-based solutions, with special attention to implicit auctions for short-term allocation (art 12(2)).

37 Art 13 and 16(2) of Regulation 715/2009/EC. The now explicit prohibition of point-to-point pricing plays in favour of new entrants as it eliminates the advantages to the incumbents caused by the ‘portfolio effect’. For this, see C Jones (ed), EU Energy Law: Volume I: The Internal Energy Market: The Third Liberalisation Package (Claeys & Casteels 2010) 326.

38 Art 13 of Regulation 715/2009/EC.
K. Talus

As regards industrial consumers or electricity generators, which are not covered by the E.ON Ruhrgas decision, Distrigas has

See n 59.

See n 48.


COMP/B-1/37966—Distrigas.

COMP/B-1/38348—REPSOL CCP.

COMP/37.542—Gas Natural

COMP/B-1/37966—Distrigaz.

Case C-17/03, VEMW and others, [2005] ECR I-4983.

C-439/06, Citiworks AG Flughafen Leipzig v Halle GmbH, Bundesnetzagentur, [2008] ECR I-3913. The latest and most

far-reaching case underlining TPA as a leading principle of EU energy law from the Court is the Opinion of Advocate General Jaasikinen in Case C-264/09, Commission v Slovakia, delivered on 15 March 2011. This case raises several interesting and complicated legal issues. Regarding the question of TPA and discriminatory nature of certain transportation capacity reservations, the Opinion recognizes certain problematic aspects of an expansive interpretation of the ECJ judgment in C-17/03 (raised in K Talus and T Wälde, ‘Electricity Interconnectors in EU Law: Energy Security, Long Term Infrastructure Contracts and Competition Law’ (2007) 32 European Law Review 133 and K Talus, ‘Role of the European Court of Justice in the Opening of Energy Markets’ (2007) 8 ERA Forum 435 but suggests that the capacity reservations in this case are discriminatory under the sector-specific regulatory framework. This approach follows closely the above line of cases where the ECJ has adopted a ‘third party access friendly’ interpretation of EU energy law. While this might be the correct approach from a competition point of view, there is a risk that this undermines investment incentives. Given the future investment needs in the EU energy markets, this could be a significant problem. However, in this case, the AG solved the problem by concluding that the rights arising from the BIT between Slovakia and Switzerland are protected under the EU law.

However, these contracts also produced efficiency gains. In particular, they have a risk-reducing effect through their ability to

hedge the customer against volatile price movements (depending on the pricing formula) and the seller against the quantity risk. For an in-depth analysis of the economics of the long-term downstream contracts in the EU context, see A De Hautecloque and J-M Glachant, ‘Long-term Energy Supply Contracts in European Competition Policy: Fuzzy not Crazy’ (November 2008) No 08-016 MIT—CEER Working Papers, 3.

Para 4 of the Guidelines annexed to the Regulation.


See the 2005/2006 activity report of the Bundeskartellamt

This figure was indicated in M Fernández Salas, ‘Long-term Supply Agreements in the Context of Gas Market Liberalisation: Commission closes Investigation of Gas Natural’ (2000) 2 Competition Policy Newsletter 55–58.


As regards industrial consumers or electricity generators, which are not covered by the E.ON Ruhrgas decision, Distrigas has more flexibility over the duration of the contracts, provided that the overall conditions to limit closing off the market are met.

Although it must be noted that the commitments offered by Repsol concerned the distribution of petrol and diesel to service stations through long-term agreements. Nevertheless, since the commitments are in parts very similar to those in E.ON Ruhrgas and Distrigas, it seems that this case is relevant in the evaluation of long-term natural gas contracts in the downstream markets.

Interestingly for the purposes of this study, Aghion and Bolton note that the duration of the contract should not be the (only) centre of attention. Instead, the focus should be on the ability of the contract to lock the contracting parties to each other. This proposition is based on the idea that in order to enter a monopolistic or oligopolistic market, the new entrant must either wait until the existing contract between the incumbent and the buyer expires, and then try to offer a more advantageous price to the buyer, or it has to offer an extremely low price. In the second scenario, it is the damages that the buyer must pay for breach of contract that determine the cost of entry, the price level that the new entrant must offer (new price plus the damages as compared to the price of the incumbent). See P Aghion and P Bolton, ‘Contracts as a Barrier to Entry’ (1987) 77 American Economic Review 388–401.

Interestingly for the purposes of this study, A Konoplyanik has been arguing the same effect following from the elimination of the destination clauses in the Art 307(1) of the German Civil Code (Test of reasonableness of contents) provides that: (1) provisions in standard business terms on the basis of which arrangements derogating from the contract to such an extent that attainment of the purpose of the contract is jeopardized; (2) subsections (1) and (2) above, and an unreasonable disadvantage is, in case of doubt, to be assumed to exist if a provision is not compatible with essential contractual provisions of the statutory provision from which it deviates, or limits essential rights or duties inherent in the nature of the contract to such an extent that attainment of the purpose of the contract is jeopardized; (3) subsections (1) and (2) above, and sections 308 and 309, apply only to provisions in standard business terms on the basis of which arrangements derogating from legal provisions, or arrangements supplementing those legal provisions, are agreed. Other provisions may be ineffective under subsection (1) sentence 2 above, in conjunction with subsection (1) sentence 1 above.

Interestingly for the purposes of this study, A Konoplyanik has been arguing the same effect following from the elimination of the destination clauses in the upstream contracts. Here the pre-existing balance of risk was affected by elimination of certain elements of the contractual balance that had existed for decades. For this, see A Konoplyanik, ‘Russian gas to Europe: from long-term contracts, on-border


For a detailed overview of the Groningen model and its use in the EU natural gas trade, see Energy Charter Secretariat, Putting a Price on Energy - International Pricing Mechanisms for Oil and Gas (Energy Charter Secretariat 2007), 143. The basic idea with the Groningen model was to attract the maximum rent for the State from the use of its natural resources.

A prerequisite for project financing in the energy sector, as with natural gas, is that there be sufficient demand for the output that the purchaser will commit to a long-term purchase contract and that the contracts include provisions strong enough to attract a financier to commit upfront funding to the project. (For these issues, see J Finnerty, Project Financing: Assets-Based Financial Engineering (John Wiley & Sons, Inc 1996) 4.)


Used, for example, in the agreement between DUC/DONG, see Commission Press Release, ‘Commission and Danish Competition Authorities jointly open up Danish Gas Market’ (IP/03/566), 23 April 2003 and in the agreements used by the two Norwegian companies, Statoil and Norsk Hydro, Commission Press Release, (IP/02/1084) (n 76).


Case COMP/B/139.316—Gaz de France (gas market foreclosure).


With certain restrictions on, for example, the potential buyers profile in terms of demand, payment guarantees to be provided and availability or likely availability of specified natural gas volumes.


Antitrust: Commission welcomes ENI’s Structural Remedies Proposal to Increase Competition in the Italian Gas Market (MEMO/10/29) 4 February 2010.


Commission exemption decision in Nabucco (CAB D/2008/142), 8 February 2008.

Article 22 (a) and (c) of Directive 55/2003/EC (now replaced by Article 36 of Directive 73/2009/EC).

This has been noted, for example, in the Second Gas Market Directive, preamble 25, Security of Supply Directive, preambles 8 and 11, Communication from the Commission, Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report) COM(2006) 851 final, 10, the Communication from the Commission to the Council and the European Parliament also recognizes that despite many positive effects, long-term agreements also serve to foreclose markets; Communication from the Commission to the Council and the European Parliament—Prospect for the internal gas and electricity market, (COM(2007) yyy final), p. 16.

See, for example, K Talus, ‘Long-Term Upstream Natural Gas Contracts and EC Competition Law—Efficiencies Under Article 81(3) and Objective Justifications Under Article 82’ in B Delvaux, M Hunt and K Talus (eds), EU Energy Law and Policy Issues (Brussels: Euroconfidentiel 2010) and Talus (n 3).
In addition to being the approach in the GDF Suez and E.ON cases, the same approach was adopted in the regulatory treatment of Nabucco pipeline. See Commission exemption decision in Nabucco (CAB D/2008/142), 8 February 2008.

COMP/38.085—PO/Territorial restrictions—Austria. See also Commission Press Release, ‘Competition: Commission secures improvements to gas supply contracts between OMV and Gazprom’, (IP/05/195), 17 February 2005.


Neuhoff and Von Hirschhausen, n. 10. For tacit collusion, see N Petit, Oligopolies, Collusion Tacite Et Droit Communautaire De La Concurrence (Bruylant 2007).

Commission Regulation (EU) No 330/2010 of 20 April 2010 on the application of Article 101(3) of the Treaty on the Functioning of the European Union to categories of vertical agreements and concerted practices (OJ 2010 L 102, 1), replacing Commission Regulation (EC) No 2790/1999 of 22 December 1999 on the application of Art 81(3) of the Treaty to categories of vertical agreements and concerted practices (OJ 1999, L 336, 21). This block exemption is not often available in the energy sector because of the important market shares the companies concluding these agreements regularly have.

Nyssen and Osborne, (n 88) 28. See also Commission Competition report 2002, 208.


For a detailed assessment of this issue, see Nyssen and Osborne, (n 88) 25–30.

COMP/37.811—Territorial Restrictions (1) Algerian gas export contracts; (2) Expansion of TAG pipeline. See also Commission Press Release, (IP/03/1345) (n 86).

For an overview of all the cases, see P. CAMERON, Competition in Energy Markets: Law and Regulation in the European Union (OUP 2007), p. 313-321. As the Sonatrach case was decided later, Cameron does not discuss this case.


COMP/38.662—GDF/ENI.

The clause specified that the gas was delivered solely for use within Italy.

Preliminary report of Sector Inquiry (n 85).

Commission Press Release (IP/07/1074), (n 120).


Commission Press Release (IP/07/1074), (n 120).

Technically, the Commission seems to have examined various proposals from the commercial parties and finally accepted the present solution as acceptable under EU competition law.

For a detailed explanation of the profit-splitting mechanism, see Nyssen and Osborne (n 88).


J Stern, Is there a Rationale for the Continuing Link to Oil Product Prices in Continental European Long Term Contracts? (NG 19, OIES 2007).

This is widely discussed in J Stern and H Rogers, The Transition to Hub-Based Gas Pricing in Continental Europe (NG 49, OIES 2011), J Stern, Future Gas Production in Russia: Is the concern about Lack of Investment Justified? (NG 34, OIES 2009) and Stern, ibid.


 Sector Inquiry, 219.

J Stern, Future Gas Production in Russia (n 140).

This has been suggested by Jonathan Stern in 2007 and repeated in 2009 and 2011. Stern and Rogers, The Transition (n 140), Stern, Future Gas Production in Russia (n 140) and Stern (n 139).

Bundesgerichtshof, VIII ZR 178/08 and VIII ZR 304/08. As was noted, this is not a competition but civil code case.

Sector Inquiry, 209.
Outside the antitrust context, take-or-pay provisions have been examined by various national courts such as in the UK where the Court considered a take-or-pay provision to be a penalty clause. See, e.g., M&E Polymers Ltd v Imerys Minerals Ltd, [2008] EWCH 344 (Comm), All ER (D) 445, para 46. For discussion, see M Polkinhorne and C Kirkman, ‘Choice of Law in Oil and Gas Agreements: What Difference does it make?’ (2008) 4 •The Paris Energy_ Series_No_4.pdf> accessed 11 July 2011. Similarly, n 149.


Although states retain the power to regulate state markets, there are certain developments that shift the competence for specific areas, such as LNG terminals, to the federal level. For this, see K Talus, ‘Access to Gas Markets: A Comparative Study on the Access to LNG Terminals in EU and US’ (2009) 31 Houston Journal of International Law.

In the case of remote oil fields, associated natural gas was flared. In the 1950s, about 20% of the natural gas produced was wasted. See M Raymond and W Leffler, Oil and Gas Production in Nontechnical Language (PennWell 2006) 13.

R Pierce, ‘The Triumph of Natural Gas’ (1995) 10 Natural Resources and Environment 53. Daniel Yergin describes the establishment of the US natural gas industry and the construction of the first pipelines to bypass the market power of Standard Oil. See D Yergin, The Prize: The Epic Quest for Oil, Money, and Power (Free Press 2008) 64 and 72–73, for example.

More generally on this period, see Pierce, n 157 540–2.


Similarly, n 149.

Although states retain the power to regulate state markets, there are certain developments that shift the competence for specific areas, such as LNG terminals, to the federal level. For this, see K Talus, ‘Access to Gas Markets: A Comparative Study on the Access to LNG Terminals in EU and US’ (2009) 31 Houston Journal of International Law.

In the case of remote oil fields, associated natural gas was flared. In the 1950s, about 20% of the natural gas produced was wasted. See M Raymond and W Leffler, Oil and Gas Production in Nontechnical Language (PennWell 2006) 13.

R Pierce, ‘The Triumph of Natural Gas’ (1995) 10 Natural Resources and Environment 53. Daniel Yergin describes the establishment of the US natural gas industry and the construction of the first pipelines to bypass the market power of Standard Oil. See D Yergin, The Prize: The Epic Quest for Oil, Money, and Power (Free Press 2008) 64 and 72–73, for example.

More generally on this period, see Pierce, n 157 540–2.


Although states retain the power to regulate state markets, there are certain developments that shift the competence for specific areas, such as LNG terminals, to the federal level. For this, see K Talus, ‘Access to Gas Markets: A Comparative Study on the Access to LNG Terminals in EU and US’ (2009) 31 Houston Journal of International Law.

In the case of remote oil fields, associated natural gas was flared. In the 1950s, about 20% of the natural gas produced was wasted. See M Raymond and W Leffler, Oil and Gas Production in Nontechnical Language (PennWell 2006) 13.

R Pierce, ‘The Triumph of Natural Gas’ (1995) 10 Natural Resources and Environment 53. Daniel Yergin describes the establishment of the US natural gas industry and the construction of the first pipelines to bypass the market power of Standard Oil. See D Yergin, The Prize: The Epic Quest for Oil, Money, and Power (Free Press 2008) 64 and 72–73, for example.

More generally on this period, see Pierce, n 157 540–2.


Although states retain the power to regulate state markets, there are certain developments that shift the competence for specific areas, such as LNG terminals, to the federal level. For this, see K Talus, ‘Access to Gas Markets: A Comparative Study on the Access to LNG Terminals in EU and US’ (2009) 31 Houston Journal of International Law.

In the case of remote oil fields, associated natural gas was flared. In the 1950s, about 20% of the natural gas produced was wasted. See M Raymond and W Leffler, Oil and Gas Production in Nontechnical Language (PennWell 2006) 13.

R Pierce, ‘The Triumph of Natural Gas’ (1995) 10 Natural Resources and Environment 53. Daniel Yergin describes the establishment of the US natural gas industry and the construction of the first pipelines to bypass the market power of Standard Oil. See D Yergin, The Prize: The Epic Quest for Oil, Money, and Power (Free Press 2008) 64 and 72–73, for example.

More generally on this period, see Pierce, n 157 540–2.
for discounted long-term capacity release) violates the FERC capacity release rules. Similarly, the FERC noted that buy/sell transactions were prohibited. (A prohibited buy-sell transaction is a commercial arrangement by which a shipper holding interstate pipeline capacity buys gas at the direction of, on behalf of, or directly from another entity (eg an end-user), ships that gas through its interstate pipeline capacity, and then resells an equivalent quantity of gas to the downstream entity at the delivery point.)


ibid 545.

ibid 546. See also Order 637, Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services, 90 FERC 61,109, 9 February 2000, 31–2.

Petrash (n 191) 557.

ibid 558.

ibid 557.

ibid 578–9. An exception to this is Order no. 637 that provided support for term-differentiated rates.

See United Gas Pipe Line Co v Mobile Gas Service Corp, 350 US 332 (1955); FPC v Sierra Pacific Power Co, 350 US 348 (1956). However, where the agreement was initially entered into under circumstances that make it clear that the other party had engaged in unlawful market manipulation that affected the level playing field idea behind the Mobile-Sierra doctrine, the presumption of fair and reasonable terms does not apply. Under such circumstances, the agreements are not even lawful and balanced arms-length negotiations. Morgan Stanley Capital Group Inc v Public Utility District No 1 of Snohomish County, 554 US, 128 S Ct 2733 (2008).

In addition to the many positive elements of the long-term agreements, these also have significant anti-competitive potential. For example, it is possible that the established company, in anticipating new competition, will use long-term agreements to lock in customers and foreclose the market from the potential competition or use long-term agreements to 'fill-up the pipeline'. These situations can be seen as unlawful exclusive dealing or the abuse of monopoly powers. See ABA Section of Antitrust Law (n 165) 137.

This section will not examine or discuss territorial or customer restrictions or other types of non-price restraint.

United States v Arnold, Schwinn & Co, 388 US 365 (1967). A per se condemnation approach had already been used in Miles Medical Co v John D Park & Sons, 220 US 373, (1911).


United Shoe Machinery Corp v United States, 258 US 451 (1922).


Bauer and Page, (n 203) 226. However, the authors note that subsequent cases seem to undermine this conclusion.


This approach ('substantial foreclosure') has been confirmed in the subsequent case law. For a recent example, see Be-H Medical, LLC v ABP Admin Inc 526 F.3d 257, 2008-1 Trade Cas. (CCH) § 76153, 70 Fed. R. Serv. 3d 748 (6 c 2008), subsequent determination, 334 F.3d 801 (6 c 2008).


Great Lakers Carbon Corp 199 F Supp 2d 362 (MDNC 2002).


Western Parcel Express v United Parcel Service, 190 F 3D 974 (9 c 1999).

Imnnesota Mining & Mfg Co v Appleton Papers, Inc, 35 F Supp 2 d 1138 (D Minn 1999).

United States v Dentsply Inc 2001-1 Trade Cas (CCH), 73,247 (D Del 2001).

ibid 232.
This is especially so when taking into consideration that the US and Canadian natural gas markets can be assessed as one market. Long-term agreements and volumes were also the object of another interesting, although not energy-related, case, Paladin Associates Inc v Montana Power Co (n 165) 171.

When a community serviced by Otter Tail decides not renew Otter Tail's retail franchise when it expires, it may generate, ‘When a community serviced by Otter Tail decides not renew Otter Tail’s retail franchise when it expires, it may generate,' (On the contrary, they are major regional and national retailers who are not likely to enter into agreements unless the terms are in their interest). (3) there was no clear evidence that one- and two-year contracts are standard in the industry (according to the interpretation of the Court, it had been suggested that all distributors engage in exclusionary behaviour involving customer lock-ins in the wake of new competition).


ABA Section of Antitrust Law (n 165) 175. See also ABA Section of Antitrust Law (n 165) 176. City of Chanute, Kansas v Williams Natural Gas Co 955 F 2d 10 (1992).

See Systemcare Inc v Wang Laboratories Corp, 117 F 3d 1377 (10 c 1997). This judgment partially overruled City of Chanute, Kansas v Williams Natural Gas Co.

Interestingly, the Court also noted that this prerequisite for essential facility liability suggests that essential facilities cases are no different conceptually from cases involving other monopolization theories, because it reintroduces ‘intent’ (ie ‘business justification’) back into the monopolization equation and excuses refusals to provide access justified by the owner’s legitimate business concerns.

American Central Eastern Texas Gas Co v Union Pacific Resources Group Inc, No 02-41010 (5th c 2004.) See also Indeck Energy Services v Consumers Energy Co, 250 F 2d 972 (6th c), cert Denied, 533 US 964, (2001), in which the company was sued for alleged anti-competitive behaviour involving customer lock-ins in the wake of new competition.

Appellate brief in American Central (n 249).

Otter Tail Power (n 243).

‘When a community serviced by Otter Tail decides not renew Otter Tail’s retail franchise when it expires, it may generate, transmit and distribute its own electric power.' Interconnection with other utilities is frequently the only solution. ibid 402 US 519 n 3. That is what Elbow Lake did in the present case. There were no engineering factors that prevented Otter Tail from selling power wholesale to those towns that wanted municipal plants or wheeling the power. The District Court found—and its findings are supported—that Otter Tail’s refusals to sell at wholesale or to wheel were solely to prevent municipal power systems from eroding its monopolistic position.’

Midwest Gas Services Inc v Indiana Gas Co Inc 317 F 3d 703 (7th c 2003).

Paladin Associates Inc v Montana Power Co, 328 F 3d 1145 (9th c 2003).

With references to Alaska Airlines Inc v United Airlines Inc, 948 F 2d 536, 544 (9th c 1991).

Long-term agreements and volumes were also the object of another interesting, although not energy-related, case, Advo Inc v Law Offices of Curtis V Trinko, LLP, 540 US 398 (2004). See also ABA Section of Antitrust Law (n 165) 171.


See, for example, Holmes (n 204) 9, 59–60.

Aspen Skiing (n 236).

Verizon (n 238).

MCI Communications Corp v AT&T Co, 708 F 2d 1081 (7 c 1983) and Otter Tail Power Co v United States, 410 US 366 (1973).

See also ABA Section of Antitrust Law (n 165) 175.

ABA Section of Antitrust Law (n 165) 176.


See Systemcare Inc v Wang Laboratories Corp, 117 F 3d 1377 (10 c 1997). This judgment partially overruled City of Chanute, Kansas v Williams Natural Gas Co.


Note that contracts to purchase are never per se violations of the antitrust laws, even in their most restrictive forms. See Gainesville Utilities v Florida Power Corp, 402 US 515, 517–520 (1971). Interconnection with other utilities is frequently the only solution. ibid 402 US 519 n 3. That is what Elbow Lake did in the present case. There were no engineering factors that prevented Otter Tail from selling power wholesale to those towns that wanted municipal plants or wheeling the power. The District Court found—and its findings are supported—that Otter Tail’s refusals to sell at wholesale or to wheel were solely to prevent municipal power systems from eroding its monopolistic position.'
Natural gas represents an important percentage of the total energy consumed in Hungary. Gas satisfies about half of Hungary’s primary energy demand and about 80 per cent of the population consumes natural gas. In recent years, approximately 80 per cent of this demand has been satisfied by imports, primarily from Russia (Case no. COMP/M.3696—E.ON/MOL).


See n 48.


Standard Fashion (n 205) and Tampa Electric (n 211).


Tampa Electric (n 211), See (n 48) and See (n 89).

American Central (n 249).

As noted, a similar strategy was at stake in Indeck Energy Services v Consumers Energy Co 250 F 2d 972 (6th c) cert denied 533 US 964, (2001), where the company was sued for alleged anti-competitive behaviour involving customer lock-ins in the wake of new competition.

See (n 89).

Great Lakes Carbon Corp 199 F Supp 2d 362 (MDNC 2002) and see n 48. Also, Comp/E-3/37.921—Viking Cable.


Morgan Stanley (n 198) and Standard Oil (n 208).

Standard Oil (n 208).

State of Illinois (n 247) and Electrabel/Mixed intercommunal electricity distribution companies in Belgium (Commission Competition Report 1997), 127, 128.

The acceptance of a security of supply argument as a part of an antitrust analysis in the EU was explicitly noted in Communication from the Commission—Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report) (COM/2006/0851 final). For a detailed examination of security of supply issues in the context of long-term gas agreements and antitrust, see Talus (n 3).

In Tampa, for example, it was certainly of significance that the share of the market covered by the agreements was very small.

Morgan Stanley (n 198).

Ibid.

Third Gas Market Directive, preambles 37 and 42.

It must be noted that the US Supreme Court, in Verizon (n 238), questioned the validity of an ‘essential facility’ doctrine noting how it was ‘crafted by some lower courts.’

Midwest Gas (n 254).

Paladin Associates (n 255).

See Alaska Airlines (n 256).

This was the case in the Gazprom/ENI case (see Commission Press Release (IP/03/1345) n 86.

See (n 89).