The dynamics of natural gas supply coordination in a New World
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Document Version
Publisher's PDF, also known as Version of record

Publication date:
2010

Link to publication in University of Groningen/UMCG research database

Citation for published version (APA):
Chapter 7
The ‘outer’ gas market integrators

7.1 Introduction
As opposed to the inner integrators, the outer integrators have access to the open seas and are thus able to develop LNG exports, which are subject to a greater degree of freedom than is the case for pipeline gas. While Chapter 6 was a review mostly of pipeline gas exporters with some LNG export ambitions on the whole, Chapter 7 concerns itself with LNG exporters which, in some cases, also export pipeline gas. The path-dependencies of these various countries (i.e., Qatar, Algeria, Norway, Libya, Nigeria, as well as other countries) differ considerably, with each NEF having achieved a different level of vertical integration, facing a different risk profile and diverging levels of export market diversification. The various outer integrators have differing production and export strategies and priorities. Just as is the case for the inner integrators, the outer integrators’ (projected future) domestic gas needs in some cases exert considerable pressure on volumes available for export.

Not only do these countries differ in terms of all the aspects named above, they have also evolved during different periods or phases of the interregional gas market’s overall evolution. For example, Qatar is a relative newcomer, having become the world’s largest LNG exporter in a short amount of time and doing so with a multi-market strategy. Qatari LNG is exported to a wide range of regional and sub-regional gas markets across the globe, making it a truly interregional player. Algeria and Norway have been active gas exporters since the 1950s and 1970s, respectively, and are mainly gas exporters to the European gas market. Nigeria, also a relative newcomer, exports mainly to markets in the Atlantic Basin.

What all these countries have in common is that they are becoming more interregional, with some of their gas exported to new markets farther away, owing to LNG. They must hence increasingly take each other into account, especially because of their global ambitions. For Russia, some of these countries present greater threats in terms of the potential loss of market share than others do, especially in the long run. The flexible nature of LNG and its potential impact on the structure of the European gas market is an issue of concern, particularly given the worldwide rise in liquefaction capacity. Interregional price developments, evolving hand-in-hand with developments in LNG trade, have encouraged countries to exchange information and monitor each other’s activities. It seems very timely, therefore, that with such an expansion
underway in interregional gas market developments, gas exporting countries have given more salience to venues for further dialogue.

The outer integrators will be covered in the same manner as Russia and Iran were in Chapter 6, i.e., reserves, production, institutionalisation, exports, etc. Qatar is covered in Section 7.2, followed by Algeria in Section 7.3, Norway in Section 7.4, Nigeria and Libya in Section 7.5 and other important gas-exporting countries in Section 7.6. Section 7.7 is a discussion about market power, an effort to assess or measure the extent to which various exporters are able to exert monopoly power both in the European gas market as well as within the Atlantic Basin. Section 7.8 is description of the current platforms for further cooperation and dialogue. Given the chapter’s length, the reader may wish to read the sections including country overviews independently.

## 7.2 Qatar

### 7.2.1 Gas reserves and current gas balance

As early as 1990, it was known that Qatar’s reserves offered a sufficiently long project life and opportunities to expand annual export volumes over a long period of time [Hashimoto et al. 2006]. Qatar has a reserve base of 25.5 tcm, 13.8 percent of the world’s total, with an R/P ratio of roughly a 100 years (based on the likely production as of 2013) [BP 2009].

Qatar’s gas production totalled 79 bcm in 2008, which amounts to 2.5 percent of the world’s total [IEA 2009a]. As far as oil production is concerned, Qatar has small reserves of 27.3 billion bbls (2.2 percent of the world’s total), having produced 1.3 mb/d (1.5 percent of the world’s total), with an R/P ratio 54 years and is a member of OPEC [BP 2009].

The North Field is to Qatar what South Pars is to Iran, in that the reserves of both countries are part of the same geological structure. For Qatar, however, the North Field represents 99 percent of reserves. Discovered by Shell in 1971, it is the largest single accumulation of non-associated gas reserves in the world, accounting for roughly 20 percent of the world’s proven conventional gas reserves (by the early 1980s, proven reserves for the field were already 8.5 tcm). The field forms the lynchpin for Qatar’s current and planned LNG activities and for the most advanced of Iran’s planned LNG developments as well as it domestic needs (see above). In 2005, fearing potential damage to the North Field’s gas reservoir (and potential overproduction); Qatar imposed a moratorium on further investment for the field.²⁹⁶ By this time,

²⁹⁵ Qatar’s gas reserves will last for over 500 hundred years based on the level of production in 2006, but is essentially already reduced to 100 years when taking into account planned LNG production (i.e., with full ramp-ups).
²⁹⁶ The moratorium Qatar announced in 2005 involves a 260 bcm/y ceiling on gas output from its North Field [Petroleum Economist 2007c]. There are concerns about the pressure and the effect that further development may be having on the
Qatar officially reached a liquefaction capacity of some 40.5 bcm/y and in the period leading up to 2020, it will bring online an additional 62.4 bcm/y worth of liquefaction capacity.\textsuperscript{297} For a graphical overview of Qatar’s gas balance, refer to Figure 7.1 below.

**Figure 7.1 Qatari gas balance in 2008**

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure7.1.png}
\caption{Qatari gas balance in 2008}
\end{figure}

\begin{itemize}
\item * UAE (15.4 bcm); Oman (1.7 bcm).
\item ** Spain (4.9 bcm); Belgium (2.3 bcm); France (0.4 bcm).
\item † South Korea (11.6 bcm); Japan (11.3 bcm); India (7.8 bcm); Taiwan (1.0 bcm).
\end{itemize}

Note: Totals may not add up due to rounding.

Source: own analysis, IEA [2009a].

### 7.2.2 The Qatari gas sector

1) Background to institutionalisation and strategy:

Despite efforts of the Qatari government to diversify the Qatari economy, Qatar is still heavily dependent on oil and gas income, accounting for 50 percent of GDP, roughly 85 percent of export earnings and 70 percent of government revenues in 2008 \[\text{EIU 2009b; CIA 2009}\]. From a historical perspective, Qatar has always been open to Western influence, as long as it suited and suits the interests of the royal family. Only throughout the 1980s and 1990s did it become clear to the Qataris that their long-run economic development could be laid by exporting gas and Qatar is therefore a latecomer to the interregional gas industry. It was the second phase of the North Field’s development which was to export gas via a pipeline to nearby Gulf Cooperation Council (GCC) countries, and the political problems surrounding the pipeline (particularly with Saudi Arabia), which motivated Qatar to export gas as LNG.

\[\text{field’s structure. Originally taken for three years, the moratorium was extended to 2010 later and there is no certainty about when it would be lifted [IEA 2009b].}\]

\[\text{\textsuperscript{297} Much of this capacity is currently under construction in and around Qatar’s liquefaction port, Ras Laffan [Cédigaz 2008a]. In 2006, it outpaced Indonesia as the world’s largest LNG exporter up to that time, Indonesia exporting 36.9 bcm in 2005 and Qatar 27.8 bcm, while in 2006 Qatar exported 35 bcm and Indonesia receded to 31.3 bcm as domestic consumption there increased from 35.1 to 38.2 bcm.}\]
The current Emir, having been in power since the mid-1990s, is more reform-minded than his predecessors, having given strong support to Qatar’s current LNG export drive [Flower 2008b].

Initially, Japan was the most important buyer of Qatari LNG, but Qatar gradually turned towards other regional markets as and when room in the Japanese gas market narrowed. During the early 2000s, some indications pointed to rising import needs in Atlantic basin markets, making them interesting growth markets. The energy price increases of the 1990s had stalled energy demand growth in Japan, just as both the North West Shelf (Australia) and the Qatar LNG Company (Qatargas) projects were mobilizing to secure long-term contracts with Japanese utilities. Qatargas was forced to wait until a new opening for gas deliveries again developed in Japan [Hashimoto et al. 2006]. With the jumpstart of Qatar’s first exports, on the back of Japanese state-backed loans and investments from major international energy players and their technical expertise, Qatar’s security of demand was ensured and the country made a successful overall LNG export début.

2) Decision-making:
According to the IEA, Qatar’s main advantages as an LNG producer and exporter include: its enormous gas reserves with high liquids content, a well-developed port (Ras Laffan) with space for expansion, quick government decision-making, a stable political climate (in an albeit unstable region) which provides for a favourable credit rating, well-coordinated commercial and public policy environment as well as a good geographical location vis-à-vis regional markets [IEA 2007a]. Qatari society is ordered largely long tribal lines and is not politically engaged, and against the background of that social fabric the royal family takes the key political and economic decisions [EIU 2009].

Qatar’s Dolphin project was originally envisaged a project linking the members of the GCC with a possible extension to Pakistan. However, opposition from Saudi Arabia to the pipeline's transit over its territory meant that Bahrain and Kuwait could not join, while the link to Pakistan was not pursued either. This left the project with extending only from Qatar to the UAE and Oman [Flower 2008b]. In addition, Saudi Arabia made major domestic gas finds of its own in 1990 [Hashimoto et al. 2006].

Japanese gas and electric companies garnered government support to bankroll a number of new LNG gas supply projects in the late 1970s and early 1980s, the Japanese government offered favourable financing via loans and export credits. Qatar General Petroleum Company (QGPC) also obtained loans backed by future oil sales [Hashimoto et al. 2006].

Qatar’s main advantages as an LNG producer and exporter include, besides its enormous gas reserves with high liquids content: (1) a well-developed port (Ras Laffan) with space for expansion, (2) quick government decision-making, (3) only two partners in RasGas 2 and 3 and Qatargas 2, 3 and 4 when investment decisions were taken, (4) a stable political climate (in an albeit unstable region) which provides for a favourable credit rating, (5) a well-coordinated commercial and public environment as well as (6) a good geographical location [IEA 2007a].
In most sheikhdoms, such as Qatar, which by definition have a traditional monarchical regime, the political leader or the crown prince chairs the Supreme Petroleum Council, reflecting a highly centralised decision-making structure, where formal procedures concerning the management of the company do not correspond to the true centres of power [Marcel 2005]. The main actors in Qatar’s gas sector are the royal family, the Ministry of Energy and Industry, and Qatar Petroleum (QP) as well as QP’s main subsidiaries (see Figure 7.2 below). In the case of Qatar, the Deputy Prime Minister, who also acts as Minister of Energy and Industry, chairs the broad of directors and is general manager. QP’s operations are therefore linked with state planning agencies, regulatory authorities and policy-making bodies [US Department of Energy 2007b]. Ultimately, all key decisions are approved by the Emir. See Figure 7.2 below for a schematic overview of these relationships.811

811 This overview is designed to provide a simplified, perhaps even oversimplified impression of decision-making in the Algerian gas sector. Informal and formal forces may also be at play to such an extent that it is beyond the scope of consideration for this study.
3) Foreign participation:
The key to Qatar’s institutionalisation has been attracting the technological know-how and capital necessary to develop its gas resources and balancing its success in doing so with preserving control over its resources through its own NEF, Qatar Petroleum (QP), which it fully owns.\(^{302}\) The result has thus far been embodied by Qatar’s massive liquefaction projects and their global each in various regional markets, predicated on a favourable ownership structure for both its foreign partners and QP (QP takes 70 percent in all its liquefaction projects, see below). Its major partners in its new liquefaction projects include some of the biggest and most conspicuous IEFs: ExxonMobil, Total, ConocoPhilips and Shell. The result of several years’ worth of development has led to the establishment of two subsidiaries: Qatar LNG Company (Qatargas) in 1984 and Ras Laffan LNG Company (RasGas) in 1993.\(^{303}\) Each company serves as an umbrella for a number of liquefaction projects, and each project has its own ownership structure serving as an umbrella or holding for the various numbers of trains per project (also see Figure 8.2 below).

Of the foreign partners involved in Qatargas and RasGas, ExxonMobil is by far the foreign partner with the largest stake in all the projects combined: it owns almost 20 percent of both companies combined, corresponding with some 20.6 bcm/y worth of liquefaction capacity, compared with some 2.5 percent share for Shell, or 4.3 bcm/y of liquefaction capacity (in Qatargas 4, which is yet to come on-stream). During the mid-1990s, Mobil’s involvement first in Qatargas and then in the newly established RasGas had paved the way for ExxonMobil’s close relationship with QP. Though Qatargas and RasGas fall under the same mother company, QP, they identify themselves as totally different companies and, while they compete efficiently, they also compete with one another [Petroleum Economist 2008a]. RasGas is driven more by ExxonMobil while Qatargas is driven more by Qatargas.

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\(^{302}\) In 1974, Qatar followed the trend toward nationalisation with other OPEC producers, establishing state-owned Qatar General Petroleum Corporation, with responsibility for exploration, production, refining, transportation and sales of oil and gas from Qatar [Hashimoto et al. 2006].

\(^{303}\) Qatar has been heavily dependent on foreign investors, both the major international energy firms and financial consortia, especially from Japan, to achieve its position as a major LNG exporter. Qatargas was the first Qatari LNG project to materialise as a partnership between QP (70 percent), BP and Total (7.5 percent each) and Marubeni and Mitsu (7.5 percent each). Qatar’s first major waves of LNG exports went to Asian gas markets, primarily Japan and South Korea. Japan’s Chubu Electric Power Company in Japan was a major factor in the purchase of the entire 5.3 bcm/y initial output from Qatargas’ first two trains. In 1992, BP’s withdrawal, motivated by a perceived lack of profitability of the Qatargas project for the energy major, was followed by Mobil’s possible entry in the project. For Mobil 7.5 percent ownership in the Qatargas project was insufficient to generate sufficient returns, inducing QP to set up a wholly new Greenfield venture, RasGas, while Mobil accepted a 10 percent ownership in Qatargas. By the time RasGas came onstream in 1999, Mobil had merged with Exxon to become ExxonMobil, where the latter’s share was 30 percent initially but was reduced to 25 percent, to include upstream shares of large Japanese and Korean buyers [Flower 2008b].
The development of Qatar’s gas resources was organised along three priorities: 1) develop gas production for domestic consumption (see below), 2) build an export pipeline gas to Dubai, Bahrain, Saudi Arabia and Kuwait and 3) build LNG export facilities [Hashimoto et al. 2006].

7.2.3 Domestic gas needs and strategy

Despite its vast export potential (see below) Qatar is likely to maintain a desire to balance exports (pipeline and LNG) and domestic market needs. Qatar’s energy mix consisted 81.2 percent of natural gas (some 20 bcm in 2008) and 18.1 percent worth of oil. Qatar’s domestic gas needs, 21.4 bcm are considerable when compared to its gas exports (57 bcm), accounting for 26 percent of its production (according to the IEA). Gas demand has increased substantially in the region with most of this rise in demand coming from the new industrial base, but there is also rising demand for power generation and desalination. Below is a brief account of the most important gas uses in Qatar, namely Gas-to-Liquids (GtL) production, petrochemicals and power generation:

1) GtL: Part of Qatar’s gas strategy is developing GtL, a highly profitable gas product, particularly with high oil prices. Currently Qatar has two GtL plants: the Oryx GtL plant, which came into operation in 2006 (in cooperation with a South African company), while Shell’s Pearl project is due to come on-stream in 2010-2011 [Flower 2008b]. Upon completion both Oryx and Pearl will require 18.25 bcm/y [US Department of Energy 2007b].

2) Petrochemicals: Just as in Iran’s case, Qatar has a petrochemicals programme, though on a much smaller scale. The second phase of the Al Khaleej project will produce 12.9 bcm/y of dry gas for local use in a range of petrochemical plants in and around Ras Laffan [Flower 2008b].

3) Power generation: Gas for power generation amounted in Qatar to some 5 bcm in 2006, likely to rise in line with the country’s continued industrial development. Qatar is restructuring its power sector and encouraging foreign investment to expand power generating capacity [US Department of Energy 2007b]. Part of the so-called Barzan project’s gas output (to come on-stream in 2012 at 14.2 bcm/y) is to be allocated to domestic gas use [Flower 2008b].

7.2.4 Gas export ambitions and strategy

Regional tensions played an important part in Qatar’s gas export strategy, as well as the sheikhdom’s desire to become more independent of Saudi Arabia (which had developed a dominant position in the world oil market) by becoming a major gas exporter and no longer being a merely marginal oil exporter [Hashimoto et al. 2006]. Qatar is obviously an ambitious

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Footnote:

304 At $50/bbl, annual revenue from the Pearl project would be $4.5 billion, yielding a payback period for Shell of just four years, with a CAPEX of $15 billion [Petroleum Economist 2008c].
exporter by volume, having grown to access different regional markets across the globe in a very short amount of time, by industry standards. The economic advisor to the Emir (and vice-chairman of RasGas), believed that only by accessing all major LNG markets could Qatar make the most of its resources [Petroleum Economist 2007a]. Qatargas also is fully aware that none of the major regional gas markets, Asia-Pacific, Europe or the US, could absorb the 100 bcm/y Qatar is capable of producing after all its trains come on-stream [WGI 2009g]. Hence their multi-market export strategy. Qatar exported 57 bcm in 2008,\(^{305}\) intending to have an export or liquefaction capacity of some 105 bcm/y by 2013 by bringing on-stream trains with, in most cases, 10.5 bcm/y worth of capacity each (see Figure 7.2). After these additions, Qatar is expected to halt expansion owing to the North Field moratorium, which is likely to stay in place until all the planned trains currently under construction have been brought fully on-stream (possibly by 2013) [IEA 2009c].

Flower [2008] estimates that the share of Qatar’s LNG exports going to Asian markets totalled 80.6 percent, to Europe 19.1 percent and merely 0.2 percent to the US in 2006, likely to shift roughly to 30.2 percent, 31 percent and 38.8 percent by 2012 as Qatar’s new export projects, mostly from RasGas 2 and 3 and Qatargas 2, 3 and 4 come on-stream. Below is an account of Qatar’s current and potential export flows by region:

1) **Regional exports to Gulf countries:** Just as Iran aims to expand its exports reach regionally, Qatar is tapping into regional markets in the Gulf. For Qatar, Kuwait may perhaps become a customer, possibly supplying LNG to an offshore floating re-gasification terminal [Gas Matters 2008a].\(^{306}\) Qatar currently also supplies the UAE and Oman through the roughly 20.7 bcm/y sub-sea Dolphin pipeline, running from Ras Laffan in Qatar to the UAE and onwards to Oman, while both of these countries are themselves actually considerable LNG exporters. Plans for the pipeline’s capacity to be expanded to 33 bcm/y are on hold due to the moratorium on the North Field. In April 2008, Qatargas and Shell agreed with the UAE to supply over 4 bcm/y worth of LNG output from Qatargas 4 as well [MEES 2008f].

2) **Exports and potential exports to Asia:** Qatari LNG exports to Asia began in the 1990s, with Korea and Japan as the main (and powerful) buyers of Qatari output, being the largest LNG importers. Exports to Asian (Asia Pacific) markets amounted to 32 bcm in 2008 (53 percent of Qatari output), with LNG provided by the Qatargas 1, RasGas 1 and part of RasGas 2 as well as the RasGas 3 projects. As for new exports to Asian markets, Qatargas 2 will provide some 2.66 bcm to CNOOC directly from 2009 onwards while 4 bcm worth

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\(^{305}\) Since year’s end 2008, Qatar’s gas exports have continued to rise still further, with the ongoing completion of the RasGas 3, Qatargas 2 and 3 projects, respectively.

\(^{306}\) Kuwait signed a $150 million deal with a US company, Excelerate, to build a floating re-gasification terminal.
of LNG supply to China’s PetroChina (CNPC) is sold through Shell from Qatargas 4 as well, starting in 2010 [MEES 2008f]. Korea Gas has signed up for 2.66 bcm from 2009 onwards [Cédigaz 2008b]. Much of the bulk of the remainder of Qatar’s Asia-oriented volumes has already been contracted for by Japan, Korea and India.

3) **Exports and potential exports to Europe:** A dramatic shift in the relative share of Qatari volumes exported to Europe will occur in 2009-2012 (as well as the US, see below). Qatar’s LNG exports to Europe have come on-stream piecemeal between 2005 and 2009, consisting mainly of output from Qatargas and RasGas earmarked mostly for Spain, Italy, France, the UK and Belgium. Qatargas as well as RasGas 2 will provide further volumes to the European market. Starting in 2009-2011, Total, Exxon and Shell are scheduled to begin supplying 2.46 bcm, 13.8 bcm and 6.3 bcm, respectively to the UK and other European markets from these companies [Cédigaz 2008b]. In April 2009, Qatargas signed a Sales and Purchase Agreement (SPA) with Poland’s Polish Petroleum and Gas Mining (PGNiG) for 1.25 bcm to start in 2014 [WGI 2009e].

4) **Exports and potential exports to the US:** Qatari exports to the US have only just begun to materialise: only 0.1 bcm worth of Qatari LNG arrived in US regasification terminals in 2008. This is due to the fact that Qatar has engaged in LNG sales on the US market under certain pricing conditions (see below), but no long-term flows have yet been brought on-stream. From 2008-2009 onwards, however, Qatargas 2, 3 and 4 are slated to respectively ship 16.3 bcm, 10.4 bcm and 6.3 bcm to the US market while Rasgas 3 is to ship 28.75 worth of bcm to the US market. The buyers of these volumes destined for the US are the IEF stakeholders themselves: Exxon, Conoco, Shell and Total, as well as a US energy firm further downstream.

7.2.5 **Qatar’s sales strategy**

Building on its early successes, Qatar has replicated the upstream business model in the form of other projects which aim at access to the world’s major regional gas markets. In so doing, Qatar has established a firm position throughout much of its entire value chain, owing in large part to the level of vertical integration and marketing expertise of its foreign partners. Qatar’s approach is clearly predicated on the belief that only by achieving vast economies of scale in production and shipping can Qatar compete effectively with pipeline gas and other sources of LNG [Petroleum Economist 2007a]. The large size of Qatar’s North Field, low production costs form the North Field (see section on market power), the large capacities of Qatar’s liquefaction terminals and Qatar’s Q-max tankers have all combined to provide Qatar with substantial economies of scale (see also section on market power) [Flower 2008b]. Correspondingly, Qatar’s gas sales strategy hinges on the level of value chain integration of both QP and its foreign partners. Several key aspects can be highlighted:
1) **Traditional long-term tape-or-pay contracts**: The bulk of Qatar’s LNG exports flow to regional markets under long-term contracts.

2) **Market-or-pay**: The Qatari strategy is to rely on the IEFs and their marketing experience to ensure enough volumes are sold while it engages in its own trades, enticing the IEFs with access to ample (low cost) reserves. Qatar’s interregional contracting strategy is aimed at maximising arbitrage gains in the short-term whilst securing demand through long-term contracts. Indeed, Qatar’s marketing strategy over the last few years has created a position where it has options to trade its LNG and enter into contracts with new purchasers on a short-, medium- or long-term basis [Flower 2008b]. Together with its foreign partners, QP owns capacity in a number of downstream re-gasification terminals in the US and Europe, and in the future, possibly other markets as well. The IEFs buy output from Qatar’s liquefaction plants (which they jointly own), mostly on a long-term basis (market-or-pay) [Boon von Ochssée 2009a], and then sell the output on a long-term and/or short-term basis (i.e., business models, also refer to Chapter 5). In the mean time QP itself does the same.

3) **Combining long- and short-term sales**: Arbitrage or diversion and short-term selling of LNG cargoes are combined with longer-term trade to optimise revenues. By owning re-gasification capacity in markets in Europe and the US, QP and its partners are able to sell uncommitted LNG or divert LNG originally sold under long-term contracts to other markets. Diversions are always part of Qatar’s sales strategy in order to assure that the flexibility exists to always get the best price for LNG cargoes [WGI 2009e]. Hence the LNG output from all of Qatar’s projects may be earmarked for various regional markets according to pre-agreed allocations under long-term contracts; however these allocations may not represent the ultimate destination of all cargoes. The outcome of the share of different regional markets in Qatar’s export portfolio after 2012 could be very different from the shares currently in place in medium- to long-term contracts [Flower 2008b]. Qatari officials do not expect the practice of short-term trading to become very widespread [WGI 2008c].

4) **Establishing a short-term selling platform**: In order to further benefit from a seller’s market for LNG, Qatar established an exchange, International Mercantile Exchange (IMEX), a pricing system designed to 1) develop real first-time ever LNG spot trading and 2) become the leading driver of market liquidity with the creation of an LNG financial derivative and facilities for trading a cargo-based contract. This IMEX system basically boils down to es-

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87 For example, Conoco Philips has also entered into an agreement in which it would acquire a position in Qatar’s North Field in return for a contract to buy from Qatargas for the US market [Jensen 2004].

88 As for re-gas capacity in Europe, QP owns 45 percent, ExxonMobil 45 percent and Edison 10 percent of the capacity of the Isola di Porto Levante terminal, Italy. QP owns 67.5 percent, Exxon 24.15 percent and Total 8.35 percent in the South Hook (Milford Haven) terminal and its expansion, in the UK. In the US, QP owns 70 percent, while Exxon and Conoco Phillips are yet to take a share as well in the Golden Pass re-gas terminal in Texas.
Establishing an LNG or energy bourse à la NYMEX to trade LNG spot cargoes [LNG Journal 2007]. This is in line with an overall process in which the LNG industry is witnessing increased hub-based, short-term trading, thus facilitating the short-term auctioning of interregional LNG cargoes. With Asian some buyers, Qatar has agreed to a fixed price in $/million British thermal units ($/mmbtu) terms and then lets the contract price revert gradually to indexation with the oil price, as is the case for LNG prices elsewhere in Asia [Flower 2008b]. In the US and the UK, Qatar sells on the basis of Henry Hub and/or NBP prices or a combination hereof elsewhere in Europe, where diverting cargoes to alternative markets can be easily arranged.

It should be noted that a sales strategy based on reserving gas in the form of LNG and pipeline gas for flexible trade, either regionally or on an interregional basis, carries with it significant downside price risks since these volumes are uncommitted in any market through take-or-pay contracts. The 2008-2009 economic and financial crisis highlights this risk.

### 7.2.6 Cooperation with other gas-exporting companies

Qatar obviously has strong business links with important IEFs, which have played an instrumental role in propelling Qatar to the position it is now as a major LNG exporter, having the technological know-how, organisational capabilities and access to capital. Qatar is already an important supplier to Asia. Now that it is also becoming an ever more important LNG exporter on a considerable scale to Europe and the US, discussion with other important gas-exporting countries becomes more relevant. Qatar is interested, as Saudi Arabia is in the oil market, with market stability as well as short-term profits [The Economist 2009a]. Cooperation on the following focal points has been or is being discussed, mainly concerning long-run cooperation:

1) **Large-scale pipeline gas-for-LNG swaps:** In July 2007, the *World Gas Intelligence* reported that Qatar has discussed with Russia the potential for multi-year swaps of LNG for European pipeline gas and associated spot trading arrangements. In a broader sense, Gazprom would create a ‘pool’ of flexible pipeline gas in storage in Europe while QP would create a similar ‘pool’ of LNG in the Gulf that would each be available for spot trading. The aim

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309 Most Asian LNG importers (mainly Japanese and Korean utilities) buy Qatar’s output on Free on Board (FOB) terms.

310 When gas prices in Europe are weak, Gazprom would make pipeline gas available to QP to satisfy its contractual commitments, allowing QP to transfer more LNG to higher-value markets outside Europe, sharing the benefits with Gazprom. Conversely, when European prices are high (and especially should Russian supply be tight, e.g., during the winter of 2005-2006), QP would ensure that adequate LNG is available to Gazprom in Europe to make up for possible shortages in supply needed to fulfil contractual obligations in Europe [WGI 2007a]. Though no apparent swaps of such kind have yet taken place and nothing more was heard about this possible form of Russian-Qatari cooperation, the rationale is clear and could serve as a means of optimising revenues in the long-term for both countries. It reflects how both Russia as an important, large pipeline gas ‘inner integrator’ and Qatar as a large LNG ‘outer integrator’ could act strategically vis-à-vis one another in
would be to ensure that both NEFs attain the benefits of arbitrage trading profits resulting from disparities in gas pricing in different regions and to minimise transport costs in the short-term. The 2008-2009 global economic and financial crisis has created a situation in which short-term gas prices on spot markets (in the US and Europe) have dipped below oil parity levels, and scarcity has given way to oversupply. This appears to have encouraged both Russia and Qatar to explore “adjusting their gas sales strategies to ease head-to-head competition that could undermine the oil-indexed pricing both still support for their base load long-term sales” [WGI 2010d], also refer to Case study 3 in Chapter 9 and to Chapter 10.

2) **The South Pars project:** At a concrete project level, Qatar is discussing the South Pars project already mentioned in the previous section, where its discussion with Russia and Qatar “studied ways to employ existing infrastructures for production, transport and export of natural gas and sharing infrastructures with reasonable tariffs. Investing in development of regional and international gas fields, producing and marketing for the natural gas was another major issue discussed by the Iranian, Russian and Qatari officials” [WGI 2008b].

3) **Bilateral Russian-Qatari cooperation:** In early 2010, Qatar and Russia have expressed mutual interest in investing in each other’s upstream sectors: Gazprom is said to be interested in bidding for development of Block D of Qatar’s North field, while QP may invest in the Yamal peninsula, including an LNG scheme [WGI 2010d].

### 7.3 Algeria

#### 7.3.1 Gas reserves and current gas balance

Algeria’s total proven conventional gas reserves amounted to 4.5 tcm in 2008, which is 2.4 percent of the world total, with an R/P ratio of 52.1 years [BP 2009]. Algeria produced 82 bcm/y in 2008, which was 1.7 percent of the world’s total gas production [IEA 2009a]. Algeria is also a significant oil exporter, possessing 12.2 billion bbls worth of oil reserves (1 percent of the world’s total), producing 1.9 mb/d (2.2 percent of the world’s total), with an R/P ratio 16.7 years and is an important member of OPEC [BP 2009]. Discovered in 1956, the Hassi R’Mel gas field (2.55 tcm) forms over half of Algeria’s reserves and provides a quarter of Algeria’s gas, while fields in eastern and southern Algeria, in the In Salah and In Amenas basins, account for much of the remainder of Algeria’s reserves [US Department of Energy 2009a].

These include a mixture of associated and non-associated gas fields. As recently as late 2008, various new gas discoveries were made in Algeria’s southeast (in the Illizi Basin) and in central Algeria (in the Gourara Basin) [MEES 2008k]. For a graphical overview of Algeria’s gas balance, refer to Figure 7.3 below.

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complementary ways. The GECF and the Gas Troika (see chapters 10 and 11) could act as forum where such cooperation is agreed upon behind closed doors.
### Figure 7.3 Algeria’s gas balance in 2008

- **Total domestic gas production**
- **Export by LNG**
- **Export by pipeline**
- **Domestic consumption**
- **Residual**

<table>
<thead>
<tr>
<th>Region</th>
<th>Total Supply</th>
<th>Domestic Consumption</th>
<th>Africa*</th>
<th>Europe**</th>
<th>Mexico</th>
<th>Asia-Pacific</th>
<th>Residual</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>82</td>
<td>0.1</td>
<td>0.2</td>
<td>36</td>
<td>18</td>
<td>1</td>
<td>25</td>
</tr>
</tbody>
</table>

* Tunisia (2.0 bcm); Morocco (0.6 bcm).
** Pipeline export: Italy (24.4 bcm); Spain (8.8 bcm); Portugal (2.5 bcm); Slovenia (0.3 bcm). LNG export: France (7.3 bcm); Spain (4.3 bcm); Turkey (4.1 bcm); Italy (1.6 bcm); Greece (0.6 bcm); UK (0.3 bcm).† Japan (0.7 bcm); India (0.5 bcm); South Korea (0.4 bcm); China (0.2 bcm); Taiwan (0.1 bcm).

Note: Totals may not add up due to rounding.

Source: own analysis, IEA [2009a].

### 7.3.2 The Algerian gas sector

1) **Background to institutionalisation and strategy**

For Algeria, oil and gas income accounted for 30 percent of GDP (45.1 percent according to the Economist Intelligence Unit), roughly 95 percent of export earnings and 60 percent of government revenues in 2008 [EIU 2009b; CIA 2009]. With its heritage as a former French colony and its proximity to the (southern) European market, Algeria’s gas export development has historically always been geared towards exports to that market, both by pipeline and LNG. Before 1979, the goal for Sonatrach was to build and hold markets in southern Europe [Hayes 2006]. Algeria is one of the ‘classic’ examples of Middle Eastern oil and gas producers breaking free from colonial rule during an era of decolonisation across the Middle East. The creation of the state-owned Algerian NEF, the *Société Nationale pour le Transport et la Commercialisation des Hydrocarbures* (Sonatrach) took place against the backdrop of French efforts to preserve France’s advantageous position in the Algerian energy sector [Marcel 2005].

Throughout the 1970s and 1980s, the fear of risking large sums of public funds led Sonatrach to export LNG, which brought more immediate revenues for the state [Marcel 2005]. Pipelines to bring Algerian gas to Spain and France were first proposed as early as 1963 by French companies, with French government backing [Pawera 1964]. Algeria later built the Transmed...
and Maghreb pipelines to Italy and Spain, and these two countries became Algeria’s first pipeline export markets, representing Algeria’s first major pipeline gas push into the southern European market during the 1980s and 1990s. Historically, Algeria has been prone to aggressive pricing behaviour in its long-term agreements, particularly vis-à-vis ENI with the building of the Transmed pipeline during the early 1980s, a dispute also known as the ‘gas battle’. Algeria is now a mature gas exporter and will continue to play an important role in the European gas market and beyond (also see below).

2) Decision-making
Key decisions in the Algerian energy sector are made by the state (which fully owns Sonatrach), with the Algerian Ministry of Energy and Mines being the principal government agency dealing with Sonatrach. During the early 1980s, Sonatrach was to be restructured to ensure that the fossil fuel sector would be controlled at the “suitable political level” [Benachenou 1980; Aïssaoui 2001]. The General Assembly is the main government decision-making body in the Algerian energy sector, which includes the governor of the Algerian central bank, a presidential representative and three leading ministers and is subsequently chaired by the Minister of Energy and Mines. In this manner, the General Assembly acts as a supreme petroleum council (as in the Gulf producing countries). The board of directors of Sonatrach acts as a buffer between the General Assembly and the company’s executive committee. Ultimately, all key decisions are taken by the General Assembly. See Figure 7.4 below for a schematic overview of these relationships.

Sonatrach dominates natural gas production and wholesale distribution in Algeria while state-owned Société Nationale de l’Electricité et du Gaz (Sonelgaz), a separate entity, controls domestic retail distribution [US Department of Energy 2009a]. Sonatrach’s subsidiaries handle transport, upstream, downstream and marketing and sales activities (including sales made abroad). Until recently, it even controlled regulatory aspects of Algeria’s energy sector. However, during the early 2000s, the government initiated a set of reforms which created two regulatory bodies, the Autorité de Régulation des Hydrocarbures and the Agence Nationale pour la Valorisation des Resources en Hydrocarbures (ALNAFT), which awards and regulate oil and gas

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512 The fact that ENI had fronted much of the capital invested in the Transmed project yielded Sonatrach immense bargaining power once the pipeline was completed [Aïssaoui 1999; Hayes 2006].
513 The National Energy Council, established in 1981, takes charge of both energy policy and strategy, at times restricting Sonatrach’s market flexibility, and it lost powers to the ministry after various reforms. When a law is drafted, the Ministry of Energy and Mines sends it to Sonatrach for review, usually approaching the relevant managers for comments and feedback [Marcel 2005].
514 This overview is designed to provide a simplified, perhaps even oversimplified impression of decision-making in the Algerian gas sector. Informal and formal forces may also be at play to such an extent that it is beyond the scope of consideration for this study.
This ended Sonatrach’s monopoly over pipelines and the downstream business, taking away regulatory responsibilities from it while it also takes away its control over the awards of exploration and production contracts. In this way the Algerian government hopes to make the bidding and award process more transparent and less centralised. In commercial negotiations with European customers, the energy minister has been prone to interfering with and sometimes taking the lead in pricing negotiations.

**Figure 7.4 Gas sector institutionalisation in Algeria**

* These include amongst others: Total, GdF, Suez, StatoilHydro (see below), Repsol, BHP-Billiton and ENI

Source: own analysis, based on: Marcel [2005]

3) **Foreign participation**

Under the new 2006 amendment, Sonatrach takes a minimum of 51 percent in any oil and gas exploration agreement made with foreign companies [MEES 2008c]. The Algerian government encourages IEFs, in participation with Sonatrach, to spend more on finding and developing new reserves [Marcel 2005]. Algeria ties much importance to foreign participations in an

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515 These two agencies include one agency to audit the industry’s health and the other to handle the promotion of exploration in Algeria. The *Commission de Régulation de l’Électricité et du Gaz* (CREG) was established in 2002 to further buttress regulation.

516 New price demands for gas through the Transmed pipeline, for example, were part of a broader shift in gas pricing policy sought by Minister of Energy Nabi. The new political leadership of Sonatrach would demonstrate unprecedented willingness to withhold supplies in order to achieve price demands. Algerian Energy Minister Nabi directed Sonatrach to demand from gas buyers an immediate increase to FOB parity with Algeria’s own high-grade crude oil in long-term contracts [Hayes 2006].
effort to optimise exploration and production activities, and through bidding rounds it attempts to entice IEFs to invest in exploration and production activities both through PSAs and as contractors. Having said that, Algeria has always been quite open to foreign investment and upstream activity is teeming with international energy firms, including, of course, French firms such as Total, Gaz de France Suez (GdF Suez), as well as from other countries, e.g., StatoilHydro from Norway (see below), Repsol from Spain, BHP-Billiton and ENI from Italy [US Department of Energy 2009a; IEA 2009b].

Algeria’s energy strategy priorities are: 1) gasification of Algeria’s domestic market, 2) exporting the remainder of its volumes by both pipeline and LNG in a way that optimises gas export revenues and 3) the domestic use of gas for oil lifting.

### 7.3.3 Domestic gas needs and strategy

As in the case of many gas exporting countries, Algeria consumes much of the gas it produces (at subsidised prices) and the government encourages gasification of the Algerian energy mix. The domestic pipeline network is centred on the Hassi R’Mel field, which is the hub of Algeria’s entire natural gas transport network. The field is linked to domestic transport pipelines going northwards, finally linking up with the Transmed pipeline to Italy and Algeria’s liquefaction terminals. The domestic pipeline network suffers from ageing infrastructure and is in need of modernisation, which Sonatrach is currently working on [IEA 2009b]. Algeria’s energy mix closely resembles that of Iran and Qatar: 37.2 percent originated from the use of oil, 60.6 percent form gas, 1.8 percent from coal and less than 1 percent from hydropower [BP 2009]. Algeria’s domestic consumption of natural gas was some 25 bcm in 2008, thus consuming a significant share of its production (some 33 percent). Thus domestic gas use is significant, with end-uses domestically consisting of: power generation (11 bcm in 2006, 40 percent of domestic demand), seawater desalination plants, petrochemicals and gas-based industry, with industrial customers taking off 7.3 bcm (27 percent of domestic consumption) [IEA 2008a]. Gas substitution is a key part of Algeria’s hydrocarbon strategy [Marcel 2005]. Past Algerian governments have changed their policies frequently on the basis of domestic pressures [Hayes 2006].

### 7.3.4 Gas export ambitions and strategy

Though Algeria is an important oil producer, the Algerian leadership sees Algeria’s energy potential in gas, and has corresponding ambitions [MEES 2008c]. In the long run, Algeria wants to develop itself as a transport centre for gas to Europe while maintaining and pursuing a strong LNG export position as it seeks stakes in re-gasification terminals in various markets. Algeria had a total export capacity of 77 bcm/y in 2008 (some 28 bcm/y of which consists of liquefaction capacity) [IEA 2008b]. Algeria exported some 57 bcm worth of gas in 2008, of
which 39 bcm was exported through Algeria’s 39 bcm/y pipeline network linking it to Spain and Italy, while some 21.1 bcm was exported as LNG. Algeria’s main export markets consist mostly of southern European countries around the Mediterranean: France, Turkey, Spain and Italy while it also supplies the US and Asian markets to much more limited extent. Algeria has remained mostly a regional European player, with some of its LNG exports going to the US and markets in Asia. Europe accounted for 94.7 percent of Algeria’s total exports in 2008 (see the gas balance in Figure 7.3 above).

Algeria’s export flows to various European countries together with its LNG export flows provide it with a significantly diversified export portfolio. Algeria’s choice for focusing on gas exports and the importance of a gas export strategy came in 1990 when a study prepared by the ministry and Sonelgaz in which they assessed expected gas export revenues, forecasts of national energy demand and the potential for new oil discoveries to offset declining reserves [Marcel 2005]. Algeria’s goal is to increase its production capacity for additional pipeline and LNG sales in Europe and other regional markets to 85 bcm/y by 2012 and 100 bcm by 2015 [IEA 2008a]. Below is an account of Algeria’s export flows in 2007, categorised first by pipeline and then by LNG flows.

1) Pipeline exports:
   a. Spain, Portugal and Morocco: Algeria’s pipeline exports to Spain amounted to 8.8 bcm, to Portugal 2 bcm and to Morocco 0.6 bcm in 2008. These exports were transported through the Maghreb pipeline, which has a 12 bcm/y capacity. Algeria aims to further expand export capacity to these markets in 2009 by completing the Medgaz pipeline with an initial capacity of 8 bcm/y, which interconnects directly with the Spanish network in such a way so as to be enable further flows to France and skirting Morocco in the process [IEA 2008a]. It is also designed to deliver gas to LNG and Liquid-to-Gas (LtG) plants in Arzew. Sonatrach renewed contracts or signed new ones with buyers in Spain and Portugal for pipeline gas deliveries (starting in 2008-2013 and lasting 10 years or more) [Cédigaz 2008c].
   b. Italy, Slovenia and Tunisia: To Italy, Slovenia, and Tunisia, Algeria exported 24.4 bcm, 0.3 bcm and 2 bcm respectively. Algeria exported these gas volumes through the 33.5

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[Marcel 2005]

[IEA 2008a]

[Cédigaz 2008c]
Sonatrach aims to expand its pipeline export capacity to Italy by constructing the Gasdotto Algeria Sardegna Italia (GALSI) pipeline, initiated in 2003, a pipeline which would further enable Algerian gas to flow directly to Italy through Sardinia and onwards further to Livorno in Italy, with a design capacity of 8 bcm/y and likely to be operational by 2010-2012 (and skirting Tunisia in the process). Sonatrach has signed or renewed contracts or signed new ones with buyers in Italy, Slovenia and Tunisia for pipeline gas deliveries (starting in 2008-2013 and lasting 10 years or more) [Cédigaz 2008c].

Uncertainties about domestic demand and Algerian desires to maximise revenues from LNG sales in other regional markets may reduce the availability of additional (pipeline) exports to Europe [CIEP 2008; OME 2007]. In developing its export ambitions, Algeria is not likely to exceed its export level as described above.

2) LNG exports:

a. European markets: Of Algeria's LNG exports to Europe, 7.3 bcm went to France, 4.3 bcm to Spain, 4.1 bcm to Turkey, 1.6 bcm to Italy, 0.6 bcm to Greece and 0.3 bcm to the UK. Sonatrach has various long-term contracts currently in place and accounting for volumes traded with buyers in France, Spain, Turkey, Italy and Greece for volumes of between 0.45 bcm and 4 bcm [Cédigaz 2008b].

b. Asian and US markets: Of LNG flows to non-European markets, LNG exports made their way to Japan (0.7 bcm), India (0.5 bcm), China (0.2 bcm), South Korea (0.4 bcm) and Taiwan (0.1 bcm). In 2008, Algeria exported LNG to various markets beyond the ones mentioned above. Sonatrach has various LNG contracts in place for LNG deliveries to buyers in the US and India of between 0.59 bcm and 1.25 bcm [Cédigaz 2008b].

Sonatrach operates 5 LNG terminals at Arzew and Skikda, on its Mediterranean coast. Arzew terminals GL4Z, GL1Z, GL2Z have capacities of 1.5 bcm/y, 10.4 bcm/y and 10.4 bcm/y, respectively. Skikda terminals GL1K-I and GL1K-II have 3.73 bcm/y and 4 bcm/y worth of

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518 During the 1980s, Algeria, Tunisia and Italy and their respective state companies built the Transmed, of which an extension delivers gas from Algeria to Slovenia. The pipeline's capacity was increased piecemeal to 33.5-34 bcm/y by the end of 2008 [CIEP 2008].

519 Sonatrach partners with four Italian companies in constructing the pipeline: 41.6 percent is to be owned by Sonatrach, 20.8 percent by Edison, 15.6 percent by Enel, 11.6 percent by Sfris and 10.4 percent by Hera Trading, [IEA 2008a]. The final investment decision has been delayed several times due to rising costs and difficulty in planning the route, while its completion also depends on competition from 86 bcm of planned/under construction liquefaction capacity [IEA 2009b]. Gazprom is reported to have been interested in taking a stake in the GALSI pipeline as part of an agreement between Sonatrach and Gazprom.

520 Based on [IEA 2008b] and [Cédigaz 2008a].

521 The GL4Z, GL1Z, GL2Z terminals were built in 1964, 1974 and 1981, respectively.
Sonatrach is constructing a replacement train at its Skikda location, with a due liquefaction capacity of 6 bcm/y, to be completed originally by 2011 but now delayed until 2013. Sonatrach is also constructing a new 6.5 bcm/y train at Arzew for gas from the Gassi Touil field, due for operation in 2012 [IEA 2009b]. Both projects would up Algeria’s liquefaction capacity from 28 bcm/y to 40.5 bcm/y by 2013. Sonatrach further aims to become an important LNG supplier to the US.

### Algerian sales strategy

Today, Algeria’s gas sales strategy is driven by a search for further sales depth in the southern European markets it currently supplies while (further) diversifying its exports by means of LNG. It is also driven by the European Gas Directive with the most obvious resulting bone of contention being the destination clause. Strategists at Sonatrach have felt that since the removal of the destination clause for European customers, “margins are made at Sonatrach’s expense”, with concerns also that its LNG could be reshipped from Europe to the US, for example [Marcel 2005]. Several key aspects Algeria’s sales strategy can be highlighted:

1. **Traditional long-term take-or-pay contracts:** The bulk of Algeria’s gas volumes (both pipeline and LNG) to its European customers are traded under long-term take-or-pay contracts, with roughly some 90 percent of volumes traded in this manner.
2. **Direct sales in Europe:** For several years, Sonatrach has had plans to establish marketing companies in Italy and France [IEA 2007a] Sonatrach is looking to secure its demand by acquiring downstream assets, a strategy of vertical integration similar to that of Gazprom. Algeria is also pressing importing countries to provide it with direct access to their domestic markets in return for a share in developing Algeria’s gas reserves [IEA 2008a]. In the UK, Sonatrach’s London subsidiary, Sonatrach Gas Marketing, sold 4.4 bcm/y (since between July 2006 and mid-2008) on the basis of a 20-year contract directly to British customers through the Isle of Grain re-gas terminal. In Spain it has likewise opened an office at the beginning of 2008 while in Italy Sonatrach Gas Italia is responsible for marketing Algerian gas directly to Italian end-users [MEES 2008l]. As part of its direct sales strategy, Algeria aims to pursue further diversification of its re-gas capacity holdings. Already having re-gas interests in the UK, France and Spain, Sonatrach aims to continue establishing minority stakes in re-gasification terminals in these markets, in Italy and in the US.
3. **Combining long- and short-term sales:** Sonatrach combines its long-term gas contracts with short-term or ‘spot’ trade as well, either through swaps (including pipeline gas-for-LNG swaps) or diversion of LNG cargoes originally sold under long-term contracts. The com-

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3. The GL1K-I and GL1K-II terminals were built in 1972 and 1981, respectively.
4. This train is being built to replace three trains destroyed at the Skikda plant in an explosion in January 2004.
5. Sonatrach owns 2.5 bcm/y worth of re-gasification capacity in the Isle of Grain, in the UK, and has already bought 3.4 bcm/y worth of capacity in this terminal’s expansion [IEA 2008a].
pany appears to see a share of 15 percent of its total gas volume as a suitable share designated for short-term trade. Indeed, Sonatrach has claimed that the share of its LNG traded in short-term, spot-type deals has risen to 12 percent in 2008, up from 8 percent in earlier years, corresponding with three spot LNG cargoes per month [MEES 2008]. Indeed, in early 2008, with the prevalence of a tight seller’s market for LNG in the Atlantic and Pacific, and between both basins, Sonatrach was reported to be much in favour of medium-term contracts and spot trade of individual cargoes.

According to Algerian energy minister Mr. Khelil, having amortised much of its LNG export capacity and infrastructure, Algeria is in a position to more easily engage in arbitrage and short-term sales, even with refurbishment costs to the old LNG plants Algeria’s liquefaction exports-to-capacity ratio is at 90 percent) [MEES 2008d]. Maintaining flexible exports is part also of a vision in which Khelil foresees rising domestic gas needs. Eventually, Sonatrach may also engage in more pipeline arbitrage (c.f. Norway, see section on Norway) between the various southern European markets, through this strongly depends on the development of hub trade in this region. According to expert interviews, even now, Algeria’s low exports-to-capacity ratio (68.6 percent utilisation in 2007) in its export pipeline system (i.e., the Transmed and Maghreb pipelines) points to use of possible arbitrage on the basis of medium-term contracts. With the slowdown in gas demand in its gas export markets, Algeria, has had re-consider its position on increasing its shorter term sales (given downside demand risks of uncommitted volumes), conceding the utility of long-term take-or-pay contracts [WGI 2009k].

It should be noted that a sales strategy based on reserving gas in the form of LNG and pipeline gas for flexible trade, either regionally or on an interregional basis, carries with it significant downside price risks since these volumes are uncommitted in any market through take-or-pay contracts.

7.3.6 Cooperation with other gas-exporting companies
Algeria not only cooperates with IEFs such as ENI (in its own upstream), but also with fellow NEFs. Cooperation on the following focal points has been or is being discussed, mainly concerning long-run cooperation:

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526 A Sonatrach manager was quoted as saying this strategy may "add value. We use the spot [market] when we can sell the volumes at a good price" [Marcel 2005, p. 202].
527 Minister of Energy and Mines, Chakib Khelil explained that, as far as long-term contracts with buyers in Europe are concerned, Algeria “does not have an option to terminate the contract, except to wait for another 15 years to do so, while in a short-term contract, it suffices to wait for just a year or two to renegotiate the price in an open and transparent manner” quoted in [MEES 2008].
528 Higher utilisation of pipelines has been recorded in 2008-2009 [Petroleum Economist 2009c].
1) **Up- and downstream cooperation with StatoilHydro**: Sonatrach cooperates with Norway’s StatoilHydro in Algeria’s upstream where StatoilHydro has made gas discoveries and jointly operates with Sonatrach in gas production [MEES 2008k]. On the downstream side, Sonatrach agreed in March 2008 with the Norwegian firm to supply 3 bcm/y worth of LNG to Cove Point LNG terminal in the US from 2009 (where StatoilHydro owns capacity) [IEA 2008a].

2) **Up- and midstream cooperation with the Nigerian National Petroleum Corporation (NNPC)**: Algeria also cooperates with Nigeria’s NNPC on the possible construction of the Trans Sahara Gas (TSGP) pipeline, which would feed Nigerian gas (at 20-30 bcm/y) to Europe through the Sahara from around 2015 (see also Section 7.4 on Nigeria).[^329] For Algeria, the TSGP could supply additional gas requirements and provide transit fees.

3) **Up-, mid- and downstream cooperation with Gazprom**: Algeria enjoys historically close ties with Russia, both countries have achieved a great deal of technical cooperation [Marcel 2005]. Both countries have cooperated on building pipelines and carrying out gas swaps. In August 2006, Gazprom and Sonatrach signed a memorandum of understanding on “joint businesses in the oil and gas sector” and “the possibility of implementing joint prospects in international energy markets” [MEES 2006]. In exchange for a cancellation of Soviet era debts, Russia has ostensibly been given interests in Algeria’s upstream after the signing of two memoranda of understanding in 2006 and 2007 [RIA Novosti 2006]. Gazprom’s interests are primarily driven by an appetite for Algeria’s strategic gas assets, particularly as far as LNG is concerned and participation in key pipeline projects linking Algeria to Europe (GALSI in particular) [RIA Novosti 2007a].[^330] Though in the end that agreement fizzled out and not much in the way of concrete results have been reached since then, Algeria and Russia look forward to developing a network of joint oil and gas projects in North Africa. By way of asset swaps, both companies may engage in portfolio optimisation through swapping pipeline gas for LNG deliveries and swapping amongst LNG cargoes (probably on a larger scale than seen thus far) [PIGR 2008a].

### 7.4 Norway

#### 7.4.1 Gas reserves and current gas balance

Norway’s proven reserves amounted to 2.91 tcm in 2008, 1.6 percent of the world total with an R/P ratio of 29.3 years [BP 2009]. Production amounted to 103 bcm in 2008 (rising from only 49.7 bcm in 2000), some 3.2 percent of the world total. Norway is also an important oil producer, having 7.5 billion bbls worth of reserves (0.6 percent of the world’s total), with oil

[^329]: The availability of gas in the Algerian gas system could increase if the Trans-Saharan Gas Pipeline from Brass in Nigeria via Niger to Algeria would be built [IEA 2008a].

[^330]: Russia may wish to have access to commercial information by being part of the pipeline consortia in question.
production amounting to 2.4 mb/d (2.9 percent of the world’s total), with an R/P ratio of 8.3 years and is an observer to OPEC [BP 2009]. Norway’s reserves are located mostly offshore in three main areas on the Norwegian Continental Shelf (NCS): in the North, the Norwegian and Barents seas. Other major gas fields include Troll (1.3 tcm) and Ormen Lange (0.420 tcm) in the Norwegian Sea and Snøvit (0.193 tcm) in the Barents Sea [US Department of Energy 2006]. Troll alone accounts for 30 bcm worth of output, roughly one third of Norway’s production, containing over half of the proved remaining gas reserves of the Norwegian Continental Shelf (NCS). The Norwegian Ministry of Petroleum and Energy foresees a Norwegian production level not exceeding 140 bcm/y by around 2015 [IEA 2009b]. The fact that the government has placed such an emphasis on oil recovery and not traded gas provides Norway’s producers with relatively short-term reservoir optimisation decisions [Gas Matters 2008c]. For a graphical overview of Norway’s gas balance, refer to Figure 7.5 below.

**Figure 7.5 Norway’s gas balance in 2008**

- Total domestic gas production
- Export by pipeline
- Domestic consumption
- Residual

![Graph showing Norway's gas balance in 2008](image)

* Germany (27.5 bcm); UK (25.5 bcm); France (14.1 bcm); Italy (6.3 bcm); Belgium (5.7 bcm); Czech Republic (2.1 bcm); Spain (1.6 bcm); Austria (1.3 bcm); others (12.1 bcm; defined by total export minus exports on country level)

Note: Totals may not add up due to rounding.
Source: own analysis, IEA [2009a].

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Still other fields include Statfjord and Eldfisk in the North Sea. Other important fields include Sleipner East, Asgard and Oseberg which, together with Troll, account for almost 70 percent of Norway’s gas production (e.g., in 2006 they produced some 59.5 bcm). New gas finds are reported every so often: in 2005, for example, Shell made an important 0.7 tcm discovery in the Onyx prospect in the North Sea. Norway has brought a number of other satellite fields into production which has greatly helped it maintain and even increase output. The Troll East structure is estimated to contain reserves of 0.979 tcm [Petroleum Economist 2007b].

The Troll East structure is estimated to contain reserves of 0.979 tcm [Petroleum Economist 2007b].

Upstream activity, mainly at Ormen Lange and Snøhvit, may boost Norwegian production to 115 bcm/y by 2012 [CIEP 2008].

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7.4.2 The Norwegian gas sector

1) Background to institutionalisation and strategy:
Oil and gas income in Norway accounted for 25 percent of GDP, roughly 50 percent of export earnings and 30 percent of government revenues in 2008 [EIU 2009b; CIA 2009]. Norway is an oil and gas exporter with a completely different background to Iran, Qatar or Algeria. It is politically more integrated with the EU, being a European Economic Area (EEA) member and a member of the OECD. In Norway, just as in other oil and gas producing and exporting countries, state participation is seen as a necessary prerequisite for a stable and proper functioning of the energy sector [Bartsch 1999]. Norway’s petroleum and gas activities have evolved with what Gordon and Stenvoll refer to as successful ‘political entrepreneurship’, cooperation between public and private sectors [Gordon and Stenvoll 2007]. Norway first began producing oil during the 1960s, while gas exports took off during the 1970s and 1980s, propelling Norway to its current position as an important gas exporter to the European gas market [Bartsch 1999].

Norway’s development as a gas exporter evolved through and was centred on exports to the UK and continental Europe with the building for the first pipelines to these markets from the Ekofisk, Frigg and Statfjord associated gas fields. Tremendous importance lies in the large Troll field, which has brought about a major shift in Norway’s marketing strategy during the late 1980s and 1990s. The field’s importance lies in the size of reserves and the possibility of using Troll as a swing producing field to bring smaller, more risky fields and associated gas from oil fields into production [Bartsch 1999]. The Norwegian authorities have therefore played a strong role in determining that Troll should not only provide security of supply to buyers, but also give Norway the flexibility to enable sale of gas from other fields whenever suitable. During the late 1990s, the build-up of gas production from the Troll and Oseberg fields had been reduced in order to safeguard liquids production from these fields [Bartsch 1999]. Recently, gas production from the Troll field has again been postponed, because its development for gas exports would “would reduce the possibility to recover large volumes of oil from the field” [Norwegian Ministry of Petroleum and Energy 2007].

In a report by the ministry to the Storting in 1986, it was concluded that the aim of Norway’s gas selling policy should be maximisation of the value of Norway’s gas resources (in combination with oil) with the greatest possible level of coordination [Oil and Energy Department 1986]. It was also discovered that Troll contained important oil liquids, meaning gas production at Troll became a function of oil production as well, thus limiting Troll’s swing factor. The flexibility to produce associated gas was achieved with the Troll/Sleipner Gas Agreements, which included right-of-way for associated gas from other fields. The Troll Further Development project is a Norwegian-led programme especially designed to further develop Troll’s resources [Bartsch 1999].
1986]. This in part led Norway to centralise its gas exports in a Norwegian Gas Sales Committee (Gasforhandlingsutvalg, or GFU), especially in view of the high concentration and coordination of buyers’ interests in the European market. Norway must comply with EU competition regulations while ‘in return’ the country has access to the EU internal gas market. Before the GFU’s disbandment pursuant to EU pressure, the ministry appointed GFU to negotiate volumes and prices, with field allocations done in cooperation with the upstream partners [Bartsch 1999]. It also decided on the allocation of contracts to fields, ensuring the most profitable fields are allocated first; ultimately these are integrated with oil production.

2) Decision-making:
Despite its abstention from integration with the EU, short of membership, its membership of the EEA does compel Norway to apply a number of EU guidelines regarding liberalisation in the gas sector and privatisation. In late 2007, Norway merged Norske Stats Oljeselskap AS (Statoil) and Norsk Hydro into one entity, one national champion, StatoilHydro. The Norwegian state, owning 67 percent of StatoilHydro, has allowed the company to become commercial and flexible because it removed some of the financial interests of the state from StatoilHydro (see below). This holding is now managed by Petoro, a separate state-owned entity. StatoilHydro has the responsibility to make the government aware of market and technical issues, enabling it to make informed decisions about the depletion rate and prices [Marcel 2005]. This effectively relieves Statoil of its duty as a revenue collector typical of most NEFs.

The committee was set up by the Norwegian government to negotiate contracts on behalf of the participating gas companies, consisting of representatives of the then three Norwegian companies Statoil, Norsk Hydro and Saga. It excluded foreign players on the NCS for two reasons: a strong desire of the Norwegian state for control over resource development and because of important up- and downstream interests of most of the foreign partners, meaning gas sellers could be buyers at the same time, e.g., Shell’s interest in Ruhrgas, which could lead to gas-to-gas competition could arise, leading to downward pressure on Norwegian gas prices [Bartsch 1999]. Ultimately, the EU demanded and compelled Norway to end the practice carried out by the GFU, because it was considered a violation of EU antitrust rules, i.e., as a price-fixing cartel, and the committee was abandoned in 2001 when Norway was faced with pressure and fines on the part of the EU Competition authorities. The disbandment of the GFU left producers on the NCS free to market their own gas, and because Oslo had adopted the EU Gas Directive, it had to design a system that allowed gas buyers (not only producers) access to its sub-sea pipeline network [WGI 2002].

Over time, Norway’s economy became more closely intertwined with the EU economy. Norway never joined the EU, preferring instead to maintain its status as a member of the EEA, which was established in 1994. Pursuant to EU guidelines in 2000 which prescribed privatisation, the Norwegian government had already reduced its stake in Statoil from full to 70.9 percent ownership and 43.82 percent of Norsk Hydro. Norsk Hydro is exactly between public and private, having an easy access to capital.

Coordination of action and policies takes place with regard to CIS countries, Russia and the Caspian region in a triangular relationship between StatoilHydro, the Ministry of Petroleum and Energy and the Ministry of Foreign Affairs, which has a special sub-division in the Ministry of Petroleum and Energy [Zhiznin 2007].

This is the result of the creation of the State Direct Financial Interest (SDFI) in 1984, which absorbed part of the production interests of Statoil into a separate holding. Today, StatoilHydro (formerly Statoil), formally retains a high percentage by administering the SDFI on the basis of a bilateral Statoil-government arrangement [Bartsch 1999]. StatoilHydro dominates the market through its own equity shares and because it also sells the state’s shares [Petroleum Economist 2009c].
With the state as the largest shareholder, the Norwegian Ministry of Petroleum and Energy manages the state’s ownership interests in StatoilHydro. Ultimately the ministry is accountable to the Storting, the Norwegian parliament, which maintains legislative sway over governance and ownership of the state in StatoilHydro. The National Petroleum Directorate (NPD) is a regulatory body, designed to provide guidance on the management of the Norwegian oil and gas sector, giving the ministry the role of defining targets and setting standards through making policy. Gassco is a state-owned entity which manages transport capacity. It operates Norway’s pipeline network and ships gas from the NCS to Norway’s processing facilities and export markets (comparable in its role to continental Independent Transport Service Operators) on behalf of the owners in Gassled (see Figure 7.6 below for a schematic overview of these relationships).

Figure 7.6 Gas sector institutionalisation and ownership structure of StatoilHydro

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340 The NPD looks to StatoilHydro for ‘objective’, loyal advice, and the NEF continues to carry national responsibility for the resource [Marcel 2005].

341 This overview is designed to provide a simplified, perhaps even oversimplified impression of decision-making in the Norwegian gas sector. Informal and formal forces may also be at play to such an extent that it is beyond the scope of consideration for this study.
3) Foreign participation:
Foreign participation has been crucial to the early development of Norway’s oil and gas resources in the 1960s. Norway has always been open to foreign participation; however, the high share of the state in revenue streams of the entire sector reflects the fact that Norway has a tough fiscal regime for foreign companies.\(^{342}\) Oil and gas are owned by the state, and private, international companies are merely allowed to help in the exploitation in return for a level of profit deemed adequate to maintain their interest. An array of foreign partners such as Shell, GdF Suez, Total and other firms participate in Norway’s offshore production projects. Norway’s energy strategy priorities are: 1) using gas for domestic gas usage for oil lifting and 2) exporting the remainder of its volumes in a way that optimises gas export revenues.

7.4.3 Domestic gas needs and strategy
In 2008 Norway’s energy mix consisted of hydroelectricity by almost 70 percent, 21.3 percent for oil, 8.6 percent for gas and 1 percent for coal [BP 2009]. Norway’s domestic pipeline system is a set of various interconnected pipelines transporting gas from fields in the North and Norwegian seas to processing facilities ashore.\(^{343}\) The cheap availability of hydropower, owing to Norway’s geographical blessings, enables Norway to export some 95 percent of the gas it produces with low domestic gas needs. Domestic gas uses include:

1) Gas re-injection: Gas re-injection for enhanced oil production is central to Norway’s energy strategy, as it is in many other oil and gas producing countries. The Troll Oseberg Gas Re-injection (TOGI) scheme, for example, is designed to help coordinate gas and oil production from the Troll and Oseberg fields. According to expert interviews, though these injection needs rise as high as 30-35 bcm/y, much of the injected gas is eventually produced.
2) Methanol production: Apart from gas re-injection, Norway’s domestic gas consumption consists of feed gas for a methanol plant (Tejldbergodden) [IEA 2009b].

7.4.4 Gas export ambitions and strategy
Like Algeria, Norway’s future energy clout lies in gas and not oil, and it is a regional gas player as well, and public opinion is increasingly focussed on boosting revenues from sales of gas with exports [Petroleum Economist 2009c]. In 2008 all of Norway’s 84 bcm worth of gas exports went to European markets. (except for LNG from Snøhvit, which officially began flowing in late 2007 but has experienced significant technical problems and delays). A major player in the European pipeline business, StatoilHydro is expanding its LNG assets by beginning with ex-

\(^{342}\) The licensing terms specified a sliding scale, which means that the state could increase its participation in a find (after it was found to be commercially viable) to 80 percent in some cases [Bartsch 1999].

\(^{343}\) For example, the Asgard Transport and Statpipe systems feed gas into a treatment plant terminal in Karsto on the Norwegian west coast, where natural gas liquids are separated and exported by ship [US Department of Energy 2006].
ports from Snøhvit, acquiring re-gas capacity in the US (Cove Point) and entering the Shтокman project (see below) [IEA 2008a]. While Algeria plays an important role in southern Europe, Norway plays an important role in northern and Northwestern Europe.

The Norwegian export system pipeline system was designed gradually, with cumulative investments made in such a way so as to maintain flexibility, using riser platforms as hubs, mostly from the North and Norwegian seas to Norway’s west coast, interconnecting gas fields with both processing facilities and markets [Bartsch 1999]. Its exports flow to continental Europe through an elaborate network of five sub-sea pipelines, with a combined capacity of 86.3 bcm/y, while two pipelines with a combined 36 bcm/y link it to the UK, total export capacity being 127 bcm/y in 2008 [CIEP 2008]. According to expert interviews, Norway aims to have an export capacity to European markets of between 175 bcm/y and 200 bcm/y by 2015. With the development of Snøhvit LNG, it is clear that Norway is aiming to develop export capacities to new markets beyond Europe in the medium- to long-run. For now, however, Norway’s sphere of gas exports mostly extends to NWE, with its gas exports broken down as follows:

1) Pipeline exports:

   a. **The UK:** Norwegian exports to the UK amounted to 25.5 bcm in 2008, roughly 30 percent of its total exports. Volumes to the UK were transported through the Frigg pipeline to St. Fergus (12 bcm/y), which was built in 1977. As recently as 2006-2007, the Langedal pipeline (25 bcm/y) began exporting gas from the Ormen Lange field to Easington while the Tempen Link/Flaggs pipeline (11 bcm/y) began flowing gas from the Troll area to St. Fergus at that as well. Contracts with buyers in the UK have been signed in the early 2000s, most of which come to an end in the early 2010s and include delivery at the NBP [Cédigaz 2008c].

   b. **Continental Europe:** Some 58.5 bcm of Norway’s export went to continental Europe (70 percent of Norway’s total exports). Exports to Germany amounted in 2007 to 27.5 bcm, to France 14.1 bcm, to Belgium 5.7 bcm, and to the Czech Republic 2.1 bcm. These volumes largely came through Norpipe, running from Draupner to Emden, one of the first pipelines built in 1977. It had a capacity in 2008 of 10 bcm/y. Pipeline gas also flowed through the Zeepipe to Zeebrugge (14 bcm/y), which started flowing gas in 1993. The Europipe 1 (18 bcm/y) and Europipe 2 (24 bcm/y) pipe-

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54 Norway also brought into operation its Snøhvit liquefaction terminal in October 2007, of which 2.39 bcm/y and 3.9 bcm/y worth if LNG has been contracted to buyers in the US and Europe until the late 2020s [Cédigaz 2008b]. These figures are not included in the IEA statistics for 2007. Much of the export capacity to Europe was boosted with the building of the Statpipe system in the North Sea.
lines to northern Germany started gas flows in 1993 and 1998, respectively. The Nor-
frä (or Franpipe) pipeline, running from the North Sea (Draupner) to Dunkerque (17
bcm/y), began flowing gas in 1998. Further exports included flows to Italy (6.3 bcm),
Austria (1.3 bcm) and Spain (1.6 bcm). Norway (and its producers, which include
foreign companies) has a range of contracts in place, some still dating from the late
1970s and the Troll Agreements of 1986 [Cédigaz 2008c].

2) **LNG exports:** Norway’s Snøhvit project is Norway’s first proper venture into the LNG
business and became operational only in late 2007. Norway is therefore relatively new to
the world of LNG. The terminal, possessing one train, has a 5.6 bcm/y liquefaction capac-
ity and may be expanded to 10 bcm/y by 2012, pending the addition of new gas reserves
for the project [Cédigaz 2008a]. The project is centred on the Snøhvit gas field in the Bar-
ents Sea, having experienced start-up problems since it began operations, with large cost
overruns involved in bringing the terminal to full operating capacity. Snøhvit LNG is
contracted long-term to buyers in the US (2.39 bcm/y) and some 3 bcm/y to Europe (in-
cluding Spain and France) [Cédigaz 2008b].

7.4.5 **Norway’s sales strategy**
Norway’s gas sales strategy hinges on the flexibility of its pipeline transport system and the
accompanying production systems, which can be used to produce both oil and gas and inter-
change easily between the two on the one hand and between different gas fields linked to the
system on the other. Contracts with early buyers enabled Norway to build new pipelines, and
the return on those investments subsequently fuelled further pipeline development. The Troll
gas field discovery reshaped Norway’s gas export strategy (as explained above). Several key as-
pects of Norway’s sales strategy can be highlighted:

1) **Traditional long-term tape-or-pay contracts:** Just as in the case of Algeria, the bulk of Nor-
way’s gas to continental Europe is sold through long-term contracts with oil-indexation
(some 85 percent of its exports). Norway’s pricing strategy is based on the long-run mar-
ginal costs of its Troll field, which is included in its pricing formulae and that of other gas
sellers in Europe (see also Chapter 5).

2) **Direct sales in Europe:** Unlike Sonatrach and Gazprom, StatoilHydro does not have any
direct subsidiaries to conduct direct sales in Europe. Norwegian gas to the UK is sold on
the NBP spot market through short- to mid-term contracts indexed to the NBP.

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345 The Snøhvit project is owned 33.53 percent by StatoilHydro, 30 percent by Petoro, 18.4 percent by Total, 12 percent by
Gaz de France and the remainder by other parties. The construction of Snøhvit is seen as the only option for exploiting the
gas resources of the northern Norwegian waters, especially in the Barents Sea [Bartsch 1999].

346 The latest cost overruns put the price tag of the facility 74 percent higher than the original budget approved by the Nor-
wegian government in 2002 [PIGR 2008e].
Hydro jointly owned a subsidiary with Wingas in the UK, HydroWingas, but sold its share in that company to Gazprom in 2007.

3) Combining long- and short-term sales: Just as Algeria conducts arbitrage, mostly with LNG cargoes, Norway conducts arbitrage between the various markets it exports to by means of its export pipelines. With its diversified export routes and flexible export infrastructure (including the accompanying upstream flexibility, see above), Norway is able to use arbitrage between the various markets. Norway can use its export-to-capacity ratio (69.2 per cent utilisation in 2007 according to expert interviews) in the pipeline system to conduct arbitrage between all the various markets in question by maintaining excess capacity in the pipeline system. Norway can thus conduct arbitrage between the UK’s NBP and short-term markets in continental Europe, including both other spot markets (such as TTF) and short- to medium-term contracts. The strategy of retaining aside volumes for arbitrage may carry downside risks, particularly in view of further potential LNG exports to the UK and continental Europe [Gas Matters 2008c].

7.4.6 Cooperation with other gas-exporting companies

Norway cooperates extensively with foreign partners in Norway’s upstream sector. StatoilHydro is also internationally active with similar partners in upstream projects across the world, namely in Algeria, Angola, Venezuela, Brazil, Canada. The company is also active in various mid-stream projects. The most notable and relevant projects in Norway’s sphere of cooperation with other NEFs (and IEFs, in some cases) are listed below, categorised by upstream and mid-stream projects:

1) Upstream projects:
a. Upstream development of Shtokman: As mentioned in the section on Russia, StatoilHydro has been selected to help Russia develop the giant 3.6 tcm Shtokman gas field in the Barents Sea. For Norway, participation in the Shtokman project is of long-run economic importance, and it was therefore decided at both corporate and political levels that Norway’s participation in the project was essential. Because of the fact that Norway shares the Barents Sea with Russia and both countries are Arctic neighbors, both countries have regular consultations at a ministerial level [Zhiznin 2007].

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347 It should be noted that a sales strategy based on reserving gas in the form of LNG and pipeline gas for flexible trade, either regionally or on an interregional basis, carries with it significant downside price risks since these volumes are uncommitted in any market through take-or-pay contracts.

348 Based on expert interviews. Gazprom, Total and StatoilHydro formed the Shtokman Development Company, where Gazprom is the main shareholder (51 percent) and Total (25 percent) and StatoilHydro (24 percent) have minority stakes.
b. **Upstream development of Shah Deniz**: As mentioned in the section on Caspian Sea countries, StatoilHydro participates in the development of the Shah Deniz field in Azerbaijan’s offshore, being part of the BP-led consortium.

c. **Upstream development of reserves in Algeria**: As is mentioned in the section on Algeria, StatoilHydro is one of several upstream partners operating in Algeria in cooperation with Sonatrach.

2) **Mid-stream projects**:

a. StatoilHydro owns a third of the 10.4 bcm/y re-gas capacity at the Cove Point re-gas terminal in the US. StatoilHydro cooperates with Sonatrach in delivering LNG there, with Sonatrach providing LNG to StatoilHydro at Cove Point.

b. StatoilHydro holds a 50 percent interest in the Trans-Adriatic Pipeline (TAP), with an initial capacity of 10 bcm/y (up to 20 bcm/y). StatoilHydro’s participation in Azeri Shah Deniz field, combined with its share in the TAP pipeline, may improve project’s bargaining power in acquiring Azeri supplies [IEA 2008d].

### 7.5 Libya and Nigeria

Two other countries of further strategic importance to both the European and US gas markets are Libya and Nigeria. The former is more important for the southern European gas market while the latter plays a more interregional role through its LNG exports. In 2008, Libya’s gas reserves amounted to 1.54 tcm (0.8 percent of the world’s total) [BP 2009], producing 17 bcm and consuming 7 bcm, 41 percent of its production [IEA 2008b].

Libya’s proximity to the European gas market, as in the case of Algeria, makes of Europe a natural export market for Libya, which exported 10 bcm in total in 2008, refer to Figure 7.7 below for an overview of Libya’s gas balance. The Libyan National Oil Company (NOC) supplies gas to Italy through the Greenstream pipeline (which came online in 2004 and traverses the Mediterranean Sea to Italy), which has a capacity of 8 bcm/y and is to be expanded to 11 bcm/y as part of a supply agreement between Libya and Italy [IEA 2008a]. Libyan LNG exports amounted roughly to 1 bcm, which flowed to Spain, amongst other countries.

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84 The final investment decision is planned in the second half of 2009 and the pipeline would connect Greece to Italy via Albania, estimated to be operated in 2012.

85 Very little exploration work has been done, it is estimated that Libya could possess more than twice as many gas reserves as currently and officially recognised [Petroleum Economist 2008b].

86 Libya is an important OPEC oil producer, having 43 billion bbls worth of oil reserves and producing 1.8 mb/d in 2008, 2.2 percent of the world’s total [IEA 2009b]. Freeing up oil for export by substituting in gas plays an important role in Libya’s gas strategy, with growing domestic demand to put pressure on available volumes for export [IEA 2009b].

87 Libya’s Marsa El-Brega LNG export terminal has an export capacity of 4.4 bcm/y [Cédigaz 2008a]. Libya’s LNG exports have remained low largely due to technical limitations, in part caused by US and international sanctions which have for many years deprived Libya of the technology needed to extract liquefied petroleum gas from its natural gas. In September 2003, the UN Security Council lifted its sanctions over Libya [US Department of Energy 2007a].
As in a number of autocratic gas-exporting countries, the NOC in Libya and its key decisions fall under the auspices of the political leader (in this case, Colonel Gaddafi), reflecting a highly centralised system of decision-making. A number of actors are active in Libya’s upstream: Royal Dutch Shell is upgrading Libya’s liquefaction plant, the expansion of which has been delayed to 2013 [Cédigaz 2008a]. Engaged in exploration and production activities in Libya are Repsol, Wintershall, BP, ENI, OMV and Total [US Department of Energy 2007a]. Italy as historically always played an important role in Libyan affairs [Financial Times 2008d] and ENI is one of the leading foreign mid-streamers present in the country: ENI may develop a 5 bcm/y LNG export terminal at Metillah as well as participate in the Greenstream [IEA 2008a]. Additional pipeline supplies from Libya are uncertain as a result of domestic demand and pipeline competition that may dedicate a priority to LNG supplies [CIEP 2008]. Russia has taken a significant interest in oil and gas cooperation with Libya in a manner similar to that seen in the Algerian case. Gazprom and Libya’s leader, have discussed Gazprom’s role in expanding Libya’s refining capacity and its gas export infrastructure, possibly taking a 50 percent in the Greenstream pipeline [AGC 2007c]. Further discussion included cooperation between NOC and Gazprom in the all areas of the gas value chain: production, processing and marketing (crude oil) and gas. In mid-2008 Gazprom also offered to buy all of Libya’s gas, oil and LNG at competitive prices [PIGR 2008b]. The Libyan Investment Authority and Gazprom expect to establish a joint venture for activities outside Libya.

### Figure 7.7 Libya’s gas balance in 2008

<table>
<thead>
<tr>
<th>Total domestic gas production</th>
<th>Export by LNG</th>
<th>Export by pipeline</th>
<th>Domestic consumption</th>
<th>Residual</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Domestic consumption</strong></td>
<td><strong>Europe</strong></td>
<td><strong>Residual</strong></td>
<td><strong>Total supply</strong></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>10</td>
<td>0.01</td>
<td>17</td>
<td></td>
</tr>
</tbody>
</table>

* Pipeline export: Italy (9.9 bcm); LNG export: Spain (0.5 bcm).

Note: Totals may not add up due to rounding.
Source: own analysis, IEA [2009a].

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533 ENI is to own 75 percent of the pipeline’s expansion [IEA 2009b].
534 Gazprom has been awarded several potential gas production blocks in Libya’s Ghadames Basin during Libya’s first licensing round in late 2007. This may be one important reason for seeking a stake in the Greenstream pipeline [Gas Matters 2008b].
535 In late 2007, Gazprom obtained 49 percent stakes in C96 and C97 oil concessions held by Germany’s Wintershall through an asset swap with parent company BASF. Gazprom is to enter a partnership with ENI in the latter’s gas exploration and production blocks, pending approval from the Libya authorities.
536 As in the Algerian case, Russia agreed to cancel the Soviet-era debt owed to it by Libya in return for interests for Russian energy companies, i.e., Gazprom, amongst others [PIGR 2008b].
Nigeria had gas reserves of 5.2 tcm in 2008, 2.8 percent of the world’s total (and the largest in Africa). It produced 35 bcm and consumed 14 bcm, some 40 percent of its production [IEA 2009a]. Much of Nigeria’s associated gas is flared; with the level of its flaring is the second highest in the world after Russia. Nigeria’s National Petroleum Corporation (NNPC) is the country’s NEF, which conducts its business under the auspices of the Nigerian president. It relatively remote location from major, regional gas export markets has encouraged Nigeria to develop an LNG export strategy. It is an important player in the Atlantic Basin. Together with and through its IEF partners, Nigeria exported LNG to European markets (14 bcm in total), to the US (0.3 bcm) and Mexico (0.8 bcm) and markets in the Asia-Pacific region (6 bcm in total). See Figure 7.8 below for an overview Nigeria’s gas balance.

**Figure 7.8 Nigeria’s gas balance in 2008**

<table>
<thead>
<tr>
<th>Total domestic gas production</th>
<th>Export by LNG</th>
<th>Domestic consumption</th>
<th>Residual</th>
<th>Total supply</th>
</tr>
</thead>
<tbody>
<tr>
<td>14</td>
<td>14</td>
<td>6</td>
<td>0.1</td>
<td>35</td>
</tr>
</tbody>
</table>

* Spain (7.9 bcm); Portugal (2.7 bcm); France (2.3 bcm); Turkey (1.0 bcm).
* Mexico (0.8 bcm); US (0.3 bcm).
† Japan (2.5 bcm); Taiwan (2.2 bcm); India (0.4 bcm); South Korea (0.4 bcm); China (0.2 bcm).
Note: Totals may not add up due to rounding.
Source: own analysis, IEA [2009a].

Nigeria’s Nigeria LNG project, which has a 27.6 bcm/y liquefaction capacity with 6 trains, is jointly owned by NNPC (49 percent) and its foreign partners, including Royal Dutch Shell (25.6 percent), Total (15 percent) and ENI (10.4 percent). Production from Nigeria’s Seven Plus expansion of Nigeria LNG will likely not come on-stream (with a super-mega train capacity of 10.9 bcm/y) until 2014 at the earliest [IEA 2009b]. Brass LNG, a new Nigerian LNG project with a slated capacity of 13.6 bcm/y from 2 trains, is also targeting 2014 for first out-

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56 Also an OPEC member, Nigeria possessed 36.2 billion bbls worth of oil reserves in 2008 and produced 2.1 mb/d, 2.7 percent of the world’s total [BP 2009].
57 Nigeria’s president claimed in 2008 that satisfying domestic gas should be prioritised over exports, with the government potentially requiring producers to set aside as much as 25 – 30 percent of gas for Nigerian use [IEA 2008a]. Because many of Nigeria’s oil fields lack the infrastructure to produce and market associated gas, much of the gas is often flared (some 17 bcm in 2007), costing the country $1.46 billion in revenues [US Department of Energy 2009d].
58 In 2008, Nigeria exported 7.9 bcm to Spain, 2.3 bcm to France, 2.7 bcm Portugal and 1 bcm to Turkey.
59 In 2008, Nigeria exported 2.5 bcm to Japan, 0.4 bcm to India, 0.4 to South Korea, 2.2 bcm to Taiwan, 0.2 bcm to China.
60 NNPC owns 49 percent of Nigeria LNG, Royal Dutch Shell 25.6 percent, Total 15 percent and ENI 10.4 percent.
Portfolio buyers of output from Brass LNG include BG, GdF Suez, BP, ConocoPhillips and ENI. These delays are caused by concerns over security on the part of the IEFs and uncertainty over the government’s policies. Planned and proposed also are OK LNG and Progress LNG.

Nigeria may potentially become a pipeline gas supplier to Europe from 2015 onwards through the planned TSGP (with a maximum capacity of 20-30 bcm/y). Gazprom, Total and Sonatrach have expressed an interest to participate in this ambitious pipeline project, possibly in order to gain access to Nigeria’s considerable gas reserves. Nigeria claims it has set aside 450 bcm worth of reserves for the project [MEES 2008b]. However, the realisation of this project and the availability of Nigerian reserves for pipeline supplies are very uncertain due to domestic Nigerian demand, possible transit risks and priorities to LNG developments [CIEP 2008]. Furthermore, the advancement of its LNG projects makes one question the commercial fundamentals of such a daunting pipeline project [Petroleum Economist 2009a]. Gazprom also offered Nigeria to cooperate on gas exploration, production and transportation in a late 2008 memorandum of understanding [Financial Times 2008a]. In mid-2009, NNPC and Gazprom formed the 50/50 Nigaz joint venture, which will aim to explore for gas, build infrastructure for domestic development and gas-fired power stations, including a section of pipeline that could form part of the TSGP pipeline [Financial Times 2009a].

7.6 Other important countries

For Russia, the Caspian Sea producers, Iran, Qatar, Algeria, Norway, Libya and Nigeria, a number of other gas exporting or potential gas exporting countries are or may become important interregional players; and are likely to play important regional roles as well. Qatar has truly global potential, but always on limited basis when seen in regional terms. Other countries are also noteworthy, especially as far as LNG is concerned. Traditional LNG suppliers such as Indonesia, Malaysia, Brunei, and Trinidad and Tobago may face competition in terms of LNG supply from Australia and Egypt in the Pacific and Atlantic basins, respectively. These are joined by the UAE, Oman and, as of 2009, Yemen. Egypt and Iraq may perhaps become important suppliers to Europe by pipeline. Other important regional gas exporters include, for example, Canada in the North American market and the Netherlands in the European market.

Brass LNG is owned by NNPC (49 percent), ConocoPhillips (17 percent), ENI (17 percent) and Total (17 percent).

OK LNG would be owned by NNPC (49.5 percent), Royal Dutch Shell (18.5 percent), Chevron (18.5 percent) and British Gas (BG) (13.5 percent). Progress LNG would see Flex LNG, Mitsubishi and Peak Petroleum as participants [Petroleum Economist 2009a].

From Gazprom’s perspective, it may have principally economic strategic value in order to attain control over some of Nigeria’s gas production [Financial Times 2009b], as is ostensibly the case for Gazprom in Algeria and Libya. Indeed Gazprom is clearly keen to get stakes in transportation which may feed into Europe in case it attains its own gas supplies in those countries [Gas Matters 2008b]. Gazprom and Sonatrach signed an MoU about the pipeline in 2009.
which still play a significant regional role without necessarily being net interregional LNG exporters. For an overview, refer to Map 5.1 in Chapter 5.

The Pacific players of Indonesia, Brunei and Malaysia have formed the backbone of LNG production and exports to the Pacific Basin for several decades now. Indonesia’s reserves clock in at 3 tcm (1.7 percent of the world’s total), Malaysia at 2.48 tcm, and Brunei at 0.34 tcm. Indonesia is a considerable LNG exporter, producing 76.8 bcm in 2008, consuming 43.2 bcm, exporting 34 bcm [IEA 2009a]. However, its exports have been in decline due to a rise in domestic needs. Malaysia produced 61.5 bcm in 2008, consumed 43.5 bcm, exports being 34.1 by LNG to the same markets as Indonesia caters. With consumption of only 2.5 bcm, Brunei is a much smaller player, producing 12 bcm in 2008, of which it exported 9.8 bcm. Trinidad and Tobago is a traditional LNG exporter to the Atlantic Basin. In 2008, it had reserves of only 0.48 tcm, producing 34.7 bcm and exporting 17 bcm, mostly to the US, but also to Spain, Mexico, Japan, Korea and the UK.

Egypt had a reserve base of 2.17 tcm in 2008, 1.2 percent of the world’s total [BP 2009], producing 58.4 bcm and consuming 40.7 bcm in 2008. With a liquefaction capacity of 16 bcm/y in 2008, Egypt exported 17.7 bcm worth of LNG to various Atlantic Basin LNG markets (the US and Spain) but also to the Pacific (Japan and South Korea) in 2008 [IEA 2009a]. If gas could be transported through the Arab Gas Pipeline (AGP), Egypt would become a pipeline supplier to Europe. This pipeline has a maximum capacity of 10 bcm/y and links Syria via Jordan to Egypt, and could then be extended to Turkey and Iraq by 2009. Egypt could potentially deliver up to 2 bcm/y at the Turkish border. However, Egyptian pipeline gas supplies to Europe are very uncertain given increasing domestic demand in Egypt and planned LNG liquefaction capacity [CIEP 2008]. The country may add another 11.8 bcm/y worth of liquefaction capacity in the medium-term [Cédigaz 2008a]. Upstream investors include BG, Petronas and GdF Suez. For a more complete overview of potential flows from these countries to the Southeastern European gas market (also see Case study 2 in Chapter 9).

Iraq is perhaps the one gas-rich country with the most untapped gas (and oil) reserves in the Persian Gulf region (and the Middle East more broadly), apart from its neighbour Iran. It possesses an estimated 3.7 tcm worth of gas reserves, 1.7 percent of the world’s total [BP 2009], though due to underdevelopment and under-exploration of its oil and gas reserves more gas may yet be discovered. The large IEFs have long hoped to enter Iraq to access its oil and gas reserves [Financial Times 2009d]. After the fall of Saddam Hussein, post-2003 hopes for such

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60 In 2008, Indonesia exported 27.5 bcm in 2007 to Japan (19.5 bcm), South Korea (4.1 bcm) and to Taiwan (3.9 bcm).
61 In 2008, Malaysia exported LNG to Japan (18.7 bcm), South Korea (8.4 bcm) and Taiwan (3.6 bcm).
62 In 2008, Brunei’s exports went to Japan (8.5 bcm), South Korea (0.7 bcm), India (0.2 bcm) and China (3.5 bcm).
a return of the IEFs may have been dampened by Iraq's tough upstream bid terms in June 2009 [Financial Times 2009c]. Iraq produced and consumed 1.4 bcm in 2009 [IEA 2009a], mostly gas from associated gas fields located in the country's Basra area, 60 percent of it is flared due to insufficiently available infrastructure on site to utilise the gas [US Department of Energy 2009c]. Iraqi gas available for exports is still subject to great uncertainty due to country and legal risks and increasing domestic demand. Iraq has signed a memorandum of understanding with Syria for possible gas supply and transit to the Arab Gas Pipeline [IEA 2008a]. In the long run, Iraq could become a pipeline supplier to Europe, but this remains purely speculative [CIEP 2008].

The Middle East as a whole, including the UAE, Oman and Yemen, will essentially remain an important LNG supply region well in to the long-run. For economic and strategic reasons, Middle Eastern suppliers may opt for exporting primarily by means of LNG. From an economic point of view, the only pipeline gas supplier to Europe in the medium-term is Iraq [CIEP 2008]. Other potentially noteworthy but by no means major LNG exporters in the region include the UAE, Oman and, in the future, Yemen. The UAE had sizeable gas reserves of 6.4 tcm in 2008 (3.5 percent of the world's total) [BP 2009], producing 51 bcm and consumed 59 bcm. The UAE's LNG exports flowed mostly to Japan in 2008 (the UAE's LNG exports totalled 6.9 bcm), itself importing gas from Qatar. Oman had gas reserves of just less than 1 tcm in 2008 [BP 2009], producing 25.7 bcm and consuming 19 bcm. Oman's LNG exports amounted to 10.8 bcm, flowing mostly to Japan, India and China. Yemen's LNG is to come on-stream in 2009 with capacity of some 9 bcm/y with flows going to South Korea and the US [Cédigaz 2008b].

A relatively new player in the Pacific Basin and of increasing importance in interregional LNG terms is Australia. In 2008, it possessed (mostly offshore) gas reserves of 2.5 tcm, which is 1.4

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86 Shell has entered into Heads of Agreement (HoA) in September 2008 for the development of LNG exports from Iraq using associated gas from the Basra area as a feed gas (replacing its current fate through flaring) [MEES 2008i]. There are also plans involving Shell possibly drawing Iraqi gas as a feed into the vaunted Nabucco pipeline project through Turkey, which is subject to great uncertainty [MEES 2008j]. Iraq also aims to build a gas pipeline to Syria, possibly connecting it to the Arab Gas Pipeline, and in late 2008, Turkish state-owned Botas and TPAO formed a gas exploration and marketing partnership with Shell in Iraq [Petroleum Economist 2009b].

87 Iraq produced 14 bcm in 2006 according to the Iraqi Ministry of Oil, with some 8 bcm being flared. The immediate aim is to end flaring and free up more gas for domestic use, mainly for power generation and industry, Iraq plans to increase production to 70 bcm/y with exports beginning after 2012, according to the Iraqi Oil Minister [Petroleum Economist 2009b].

88 In mid-2008, European mid-streamers OMV and MOL signed an agreement with the Kurdish regional government in Iraq to begin gas exploration and production, circumventing the Iraqi government in Baghdad, which immediately blocked any such agreement [Financial Times 2008c].

89 In the long run, other Middle Eastern gas exporting countries (e.g. Qatar, Oman and UAE, combined with Iran and Iraq) may become also a pipeline supplier to Europe.

90 The UAE's total liquefaction capacity amounted to 6.4 bcm/y in 2008 [Cédigaz 2008a].

91 Oman's total liquefaction capacity amounted to some 13 bcm/y in 2008 [Cédigaz 2008a].
percent of the world’s total [BP 2009]. Australia is a relative newcomer to the LNG industry when compared to some of the countries mentioned above (beginning with exports in 1990 while the traditional LNG exporters referred to above predate this year in terms of first exports). It produced 45.2 bcm in 2008 and consumed 34.2 bcm, exporting 19.4 bcm worth of LNG [IEA 2009a]. By 2020, Australia could overtake Qatar’s 2012 LNG output target of 102 bcm/y [WGI 2009k]. Notable in Australia’s upstream is the extensive participation of IEFs in the various existing and planned liquefaction projects. This reflects a completely different institutionalisation as far as decision-making is concerned.

7.7 Market power in the Atlantic Basin and the European gas market

Existing and potentially new gas flows from Russia, Iran, Qatar, the Caspian region, Algeria, Norway, Libya, Nigeria as well as other countries reach the major markets described in Chapter 5 (in the form of pipeline gas or LNG) at a certain cost. These gas flows are produced, transported and distributed through infrastructures which require a long lead time to build. From a theoretical point of view, the LRMC, see Chapter 8 for a more complete definition) therefore need to be taken into account, i.e., the full cost of bringing an additional cubic meter to market. The LRMC determine, regardless of pricing in oil-indexation versus spot terms, the floor price for gas: “Growing production and transportation costs will always determine the minimal level of wholesale gas prices” [MEES 2009a]. Chapter 4 contains a theoretical account of market power both in terms of market share and cost (based on the LRMC), and it is applied here to provide an overview of the market power given current and future export potential of the most important gas-exporting countries (refer to it when interpreting the figures below). Large fields, large-diameter pipelines, large shipping capacity in LNG help breed economies of scale in gas flows, as large volumes of gas lower per-unit costs for each cubic meter. While the LRMC to bring these cubic meters to market include economies of scale, LRMC also encompass other costs which are fixed in the short run, such as capital costs.

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Footnotes:

73 Australia exported a total of 21.5 bcm worth of LNG to Japan (17 bcm), China (3.5 bcm), India (0.16 bcm) and South Korea (0.669 bcm) [IEA 2009a].
74 Australia’s LNG projects, NorthWest Shelf with a capacity of 19.2 bcm/y and Darwin LNG with 4 bcm/y have already accounted for 20.8 bcm worth of Australia’s LNG exports in 2007 [IEA 2008b]. Foreign IEFs and upstream companies in Australia include Woodside, BHP, BP and Chevron amongst others for NorthWest Shelf while ConocoPhillips, ENI, Santos and Inpex are involved in Darwin LNG. Some 5.7 bcm/y, 6.6 bcm/y and 5.3 bcm/y may be added by Pluto LNG (involving Woodside, Tokyo Gas and Kansai), Ichthys LNG (involving Origin and ConocoPhillips) and the Gorgon Project (involving Chevron, ExxonMobil and Shell), by 2011 2014 and 2015, respectively [Cédigaz 2008a]. More LNG projects, albeit with no clear start-up date are also slated, totaling almost 20 bcm/y worth of liquefaction capacity. Even if Pluto LNG, Ichthys LNG and the Gorgon Project come onstream, Australia’s liquefaction capacity would be brought to 41 bcm/y by 2015, if the projects do not experience the likely slippage incurred by the financial and economic crisis.
75 As is explained in Chapter 2 in [Smeenk 2010], the realisation of these projects requires long-term gas contracts, which play a crucial role as far as the financing of the entire value chain is concerned.
Gas transportation, whether by pipeline or LNG, remains very expensive and usually represents an important share of the overall cost of gas delivered to consumers [IEA 2008c]. Despite
the potential for LNG to affect different regional markets on an interregional basis, pipeline gas, especially in Europe, can still greatly affect the competitiveness of LNG due to lower economies of scale. Attaining a clear grasp of the market power gas suppliers in question requires a LRMC overview (including costs incurred from gas production, transportation as well as from transit fees and royalties) of the different gas suppliers. These costs are based on the various potential routes from these various gas suppliers to the different (sub-)regional markets by both pipeline and LNG. The importance of these figures lies more in their relative than absolute differences. An overview is provided in Figure 7.9 above, which includes LRMC estimates for 2020, based on existing as well as future gas value chains to Europe, involving gas fields and provinces not yet currently in use.

**Figure 7.10** Market shares of the various gas suppliers in the Atlantic Basin and Europe in 2007, compared with 2015 (LNG and pipeline)

In Figure 7.10 above, the market shares of the various gas suppliers to both the Atlantic LNG Basin (the US and the LNG-importing countries in Europe) and Europe are shown. The bottom line in this figure is that the market structures of the Atlantic Basin and Europe and the market shares of the players on these markets differ substantially amongst one another. For example, Russia has a large share of the European market as a whole but plays no role at all in
the Atlantic Basin market directly. Conversely, Qatar plays a significant role in the Atlantic Basin market today but will enlarge its market share significantly by 2015 when its new liquefaction plants come on-stream. The available LRMC information for the various supply routes to Europe and the US from a range of existing pipeline and LNG suppliers is combined with the figure above to provide a rough estimate of market power in figures 7.11 and 7.12 below.

Figure 7.11 The Lerner index for the Atlantic Basin market for LNG

Market power can be measured in terms of price and marginal costs as well as in terms market shares (see Chapter 4). This is done on a regional basis level (i.e., European market) as well as an interregional level or Atlantic Basin level in Figure 7.10. An interesting observation is that in terms of market share, using the Lerner yardstick, LNG players such as Nigeria and Algeria are pushed aside in 2015 by Qatar in the Atlantic Basin, where it gains immensely in terms of market power as measure by market share in that basin. In other words, Qatar gains in terms of market power in a market where the European LNG importers and their LNG import shares are assumed to form one single market together with the share of LNG imports on the US side (Qatar attains a Lerner value of 0.21 in 2007, but this figure rises to 0.85 in 2015), while Algeria’s market power decreases from 0.62 to 0.35, as indicated in Figure 7.11 above. In terms of market power when using the price yardstick, the changes from an interregional

Source: own analysis, IEA [2008] for 2007; CIEP [2008] and privately disclosed company data for traditional pipeline (incl. LNG) suppliers to Europe in 2015, based on export ambitions (Russia LNG supplies in 2015 based on Argus Connector; Cedigaz [2008] for other LNG suppliers in 2015.
perspective are only slight when comparing 2007 with the projections for 2015, except for Qatar’s giant push between 2010 and 2015.

At the regional European level, refer to Figure 7.12 below, Qatar plays an almost insignificant role in terms of market share in 2007 (0.02), improving slightly to 0.13 in 2015. By contrast, Russia has a Lerner index of 0.48 in 2007 when measured by price-cost margin and 0.52 when Lerner is measured by market share, making it a significant player in the European market. When its future increased LRMC (because of costly investments in new, greenfield supply sources) are factored into the price-cost margin index, the Lerner value falls from 0.48 to 0.40. In terms of market share, though, Russia’s Lerner index rises from 0.52 to 0.59 because it brings on-stream more volumes to the European market.

Figure 7.12 The Lerner index for the European gas market

Thus in a sense, Russia and Qatar are fully complementary, because on the interregional side Qatar is set to become the most important player in terms of market power, already being a significant player today while Russia plays no role yet whatsoever at the interregional level. Conversely, Russia has a strong position in the European market and will continue to build on that while Qatar plays only a marginal role from this perspective. It is worth noting that in
both markets and towards 2015, Algeria remains a significant player by all accounts, while interestingly the Netherlands actually has almost as much market power in the European market as Norway and Algeria, when comparing the price-cost margin component of the index with the market share component of the index. Libya is an important regional gas exporter to Europe in terms of price-cost margin (0.4) despite its low level of production.

7.8 The GECF and the ‘Gas Troika’

Ultimately, also part of Russia’s integrated gas strategy is company and state-level cooperation with other gas-exporting countries, as evidenced by the increased substance of the GECF and the establishment of a so-called ‘Gas Troika’ (in Chapter 8, these will be referred to as horizontal energy diplomacy at the state level). Only in recent years has collusion in the interregional gas market become a topic of discussion. Empirical attention is paid to the GECF and the Troika in this chapter, while Part IV aims to further investigate the scope and shape of potential cooperation amongst gas-exporting countries. For an overview of the GECF and Troika membership, as well as commercial cooperation at the project level between Russia and key gas-exporting countries, see Map 7.1 below.

For a number of years the GECF was perceived as a ‘talking shop’ or forum, dismissed as an organisation with little to no coherence and one in which Russia appeared not to behold any interest. Until recently the lack of a real decision-making body led the GECF not to be taken seriously as an influential body in the gas market [Hallouche 2006]. From early 2006 onwards, however, when Russia and Algeria began discussing further cooperation in the form of asset swaps against the backdrop of the Ukraine gas row with Russia, the organisation began to gather attention in the broader media. Meetings of the GECF have since been labelled as ‘gas-OPEC’ meetings, and by extension referred to as a gas cartel in the making. In early 2007, Stern even referred to the excessive media hype surrounding the GECF as a “media furore” [Stern 2007]. Many observers in and outside the gas industry, including policy-makers and academics, argue that a gas cartel could never possibly succeed due to the nature of gas trade; others claim that the GECF already embodies such an organisation. Whatever the validity of their arguments, attention to and developments in joint ventures and cooperation between the various gas-exporting countries have gained momentum. From an economic as well as a political point of view, gas-exporting countries, including Russia, may indeed desire joint management of supply capacity and trade flows [CIEP 2008]. The various gas-producing and exporting countries which are members of the organisation have nevertheless expressed diverging visions of the functioning and purpose of the GECF.

377 For some articles on the matter see for example [Forbes 2009], [Gas Matters 2009].
Asset swaps: up-, mid-, and down-; mid-swaps involving ENI Buying up all of Libya's oil and gas production for one year Gazprom stake in the Greenstream pipeline to Italy Joint development of Shtokman Setting up joint company to do Downstream potential gas (Libya Egypt) Possible market division: Long-term supply contracts to Joint ventures in up-, mid-, and Possible stake in Trans-Sahara Possible cooperation through South Pars joint development Possible access for Gazprom to South Pars joint development Possible cooperation in the Possible fringe competitor* 

Legend

- [ ] GEOF/Gas Troika member
- [ ] GEOF member
- [ ] GEOF observer
- [ ] OPEC member
- [ ] OPEC observer
- [ ] Gas field

Oil and gas-exporting countries:
Main platforms for cooperation

- [ ] GECF member
- [ ] GECF observer
- [ ] OPEC member
- [ ] OPEC observer
- [ ] Gas field

Map 7.1: GECF, OPEC, selected shared investments and cooperation along the gas value chain

Note: Other foreign interests/Gazprom's MoU's not included in figure e.g., Alaska, Bolivia, Egypt, India, Venezuela and Vietnam.

Sources: Gazprom's website company websites. IEA [2009b].

* Figure does not include all competitors, e.g., Trinidad and Tobago and unconventional production in the US; gas production from international energy firms.

Sources: Gazprom's website company websites. IEA [2009b].
The GECF

The Gas Exporting Countries Forum (GECF) was founded in 2001. The member states of the GECF together hold around two thirds of the world’s gas reserves. The GECF member states include Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad and Tobago and Venezuela. Observer countries include Kazakhstan, Norway and the Netherlands, refer to Map 7.1 above. Observer countries include Kazakhstan, Norway and the Netherlands. Though long seen as an informal club with little to no cohesion, which Russia was reticent about taking part in [Hallouche 2006], the GECF has gained much traction since 2006 and, in December 2008, decided to transform into an international organisation [IEA 2009b]. The GECF helped catalyse the formation of a working group led by Russia and Algeria, which sought to resist EU attempts to ban destination clauses that prevent buyers from reselling gas [Barnes et al. 2006]. The organisation became more formal with the set-up of a secretariat in late 2008 and the election of a secretary general in mid-2009, taking office in March 2010.

According to its mission statement, “[t]he GECF was set up with the objective to increase the level of coordination and strengthen the collaboration between member countries. The forum also seeks to promote dialogue between gas producers and consumers” [GECF 2009]. Indeed, a theme within the GECF has been to examine pricing formulas that link gas prices to oil and how to ‘de-link’ the pricing of these two strategic commodities [Bahgat 2009]. The group had several significant meetings in 2006-2008, most notably one which involved the formation of a high level ‘pricing group’ (see below). The potential of the GECF as a pricing group was demonstrated by the implicit cooperation between sellers of Middle East LNG into Japan and South Korea over 2006-2008, when none broke the line on relatively strict oil price indexation [WGI 2009k]. Cooperation between gas-exporting countries is aimed further at recovering for gas the same or greater value per unit of energy as oil, i.e., what they perceive to be the intrinsic value of their gas resources.

The aspect of differences of opinion over the charter appears to reflect some disparity between the interests of the member states. Sergei Shmatko, Russia’s minister of energy

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378 In 2007, the member states accounted for 36 percent of total gas production, which is expected to rise to 42 percent in 2030, according to the reference scenario of the IEA [2008b]. Together, they are responsible for almost 50 percent of the total exports [IEA 2009].

379 Venezuela and Iran, for example, favour a charter resembling that of OPEC, while Russia and Qatar wish to avoid allowing the GECF to resemble OPEC and appear to take a more commercial position rather than a political anti-Western one. Russia, Iran and Algeria appear ready to attempt coordination of long-term gas development and marketing strategies through the GECF [WGI 2009k]. Certainly one of the more hawkish countries within the GECF, Algeria openly advocates an organisation that calibrates long-run gas supplies to avoid large oversupplies over the long-term. Algeria became the first gas-exporting country to advocate the formation of an ‘OGEC’ in order to duplicate OPEC’s past ostensible successes [Davis 1984]. Putin claimed that “we do not intend to set up a cartel, but I think it is right to coordinate our activities;” in February 2007, in an address to the Duma, he said “we do not reject the idea of creating a gas cartel,” also saying that the idea of creating “a ‘gas OPEC’ is an interesting idea. We will think about it” and the “era of cheap energy resources, of cheap gas, is of course coming to an end” [RIA Novosti 2007c]. In his speech, Putin continued with the idea that “at the first stage, we agree with Iranian experts, partners and some other countries which produce and supply hydrocarbons to world markets in large volumes. We are already trying to coordinate our actions on developing markets and we intend to do so in the future” [RIA Novosti 2007c]. Valery Yazev, head of the Duma
said in 2009 that “energy and gas markets are such that no one of the participants can go on its own way. It is necessary to seek ways to enhance cooperation and coordinate activities based on mutually accepted principles. These countries will be able to find a wise balance between competition and harmonisation of their energy policies” [WGI 2009b]. Algeria’s energy minister, Chalkib Khelil called in March 2010 on other gas-exporting countries for a coordinated effort to restrict gas production amidst historically low spot prices in Europe and the US [Financial Times 2010a]. At the GECF meeting in Oran, Algeria, on 19 April, 2010, a recent meeting as of this writing, the GECF countries agreed to “continue to support the linking of gas to oil parity” [WGI 2010e] in light of the oversupplied market from 2009 onward. Algeria’s proposal to attempt a reduction in gas production to limit spot volumes was rejected by Russia and Qatar on the grounds that it may lead to a loss in market share, amidst Russian calls for the support of long-term contracts [WGI 2010e].

Against the background of the 2008-2009 global economic and financial crisis, Russian and Qatari gas delegations met ahead of the April 2010 GECF meeting and expressed their commitment to greater coordination and agreed to come up with a strategy to minimise price competition out to 2025, according to Russian reports [WGI 2010d]. Russia and Qatar both agreed to explore the idea of increased coordination in the interregional gas market in early 2007 [The Moscow Times 2007]. According to some sources, both of these important players have at least agreed to avoid competing for market share [WGI 2009c], a commitment which was strengthened in early 2010 [WGI 2010d]. Both are important suppliers by pipeline on the one hand and LNG on the other, and are thus critical to interregional gas flows, appearing more explicit and motivated to cooperate openly because of the onslaught of the regional and interregional gas oversupplies. Both countries reiterated their intent on gas trading, competition and potential cross investment, explicitly including the development of gas reserves in Russia’s Yamal peninsula and Qatar’s North Field [WGI 2010e].

Russia appears more interested in avoiding intense LNG competition and cooperating with LNG producers to swap LNG for pipeline gas in optimising short-term trades. Unlike Algeria and Qatar, which have export flexibility and diversity, owing to LNG, Rus-
Russia is attached to both long-term contracts and oil indexation as necessary underpinnings for capital commitments to new projects and domestic infrastructure. During the April 2007 Doha meeting of the GECF, Russia also supported the formation of a high-level pricing group within the GECF to study a common approach to pricing (particularly in view of the great worldwide disparity in gas prices at the time) [The Moscow Times 2007]. This view is particularly influenced by the idea that the EU acts as a monopsony buyer of Russian gas. Qatar’s position is characterised by an interest limited to tracking other exporter’s efforts to enter the LNG market, keeping itself informed of intentions of future market entrants in terms of capacities, especially those eyeing LNG investments [WGI 2009b].

A core group within the GECF: the ‘Gas Troika’

In what has been called an effort to further reshape the GECF, Russia, Iran and Qatar established the Gas Troika (or simply, the Troika) in late 2008 (these are the largest gas reserve-holders, holding more than half of the world’s gas reserves [BP 2009]). The aim of the Troika is, at least officially, to hold up to four meetings annually to discuss gas policy, including cooperation between the three countries, covering exploration, gas processing, transportation and sale of gas in an effort to create “a fair market for producers and consumers” and discuss “the most important gas market developments that are of mutual interest” [PIGR 2008f]. According to Gazprom, the Troika is to act as a “locomotive” for the GECF, which suggests the spearheading of the three largest gas reserve-holders in shaping long-run gas market developments [Nefte Compass 2008].

While Russia and Qatar both prefer to avoid the term ‘cartel’ per reference to the Troika, Iran claims that the Troika is a successful attempt at reaching “consensus to set up a gas OPEC” [MEES 2008a]. At sub-regional and regional levels, the Troika may act as a core group, or ‘locomotive’, in Gazprom’s terms, where the most important decisions are taken that affect the largest pipeline gas and LNG flows in different regions while other members of the GECF and non-members act more as followers, either cooperatively or as a competitive fringe. Qatar and Russia have discussed bilateral swaps or trilateral investments also involving Iran (also see Section 7.2 and Chapter 6), all ostensibly aimed at curtailing long-run competition and maximising profits [WGI 2008f].

83 Inadvertently, the Soviet Union, the Netherlands and Algeria raised gas prices jointly when faced with the issue of pricing at or above or under crude parity during the 1980s and 1990s, which is at a more regional level [Hayes 2006].
84 Qatar is more reticent about the GECF and the Troika, never having fully embarked on the latter, and seeing the GECF as a “forum with different thoughts and challenges” [WGI 2009d].
85 According to Gazprom’s annual report the ‘Big Gas Troika’ is designed to “coordinate energy policies of the powers that jointly account for some 60 percent of the global natural gas reserves [which] will contribute to the reliability and stability of energy resources supplies in the whole world” [Gazprom 2009a]. Gazprom’s CEO, Miller, explains that the purpose of the Troika is to “discuss the most important and mutually interesting issues of gas market development... We hope that this meeting can help establish cooperation and be a locomotive for activities of the gas exporting countries in a formal organisation” [MEES 2008a].
Together with Algeria, Iran, Qatar and Russia form the political and economic core of the GECF [IEA 2009b]. For example, Iran and Russia may cooperate on a shared pipeline to any imaginable market, agreeing with Qatar on a certain long-term level of supply, while LNG from any other imaginable third party gas exporter acts as a competing source of gas in that market. While this possibility is not explicitly pursued in the cases, it is however implicit in the sense that shared investments may compete with individual projects from other countries. The Troika may be more a political phenomenon than strictly economic. In any case, the Troika is “likely to have a strong influence over the path that the Forum will follow only from a political point of view as Iran is not going to become a significant gas exporter for many years” [IEA 2009b, p. 43].

Not a “gas OPEC” in the making just yet
As long ago as 1984, it was foreseen that the constraints of supply distribution in the US and Europe will necessitate an increasing reliance on natural gas from Russia and Central Asia or from countries that are either members of or are ideologically aligned with OPEC [Davis 1984]. Algeria was the first to propose cartelisation of the gas market during the 1960s. Today, the energy ministers in the GECF know each other personally through OPEC, which strengthens their potential cooperation on gas issues [Hallouche 2006]. Algerian Energy Minister Khelil has said that “in the long-term we are moving toward a gas OPEC… It will take a long time” [The Moscow Times 2007]. Nevertheless, for now, a direct comparison between OPEC and any form of cooperation in the interregional gas market is erroneous.

With the current structure and functioning of the interregional gas market, exporters’ short-term abilities to limit production are constrained by the predominance in the gas industry of long-term take-or-pay contracts. Cooperation in the gas market is unlikely to involve the control of output or influencing prices in the same manner as OPEC does [Bahgat 2009]. The functioning of a group examining the common interests of gas exporting countries (e.g., GECF, the Troika) is not the same as a quota-based OPEC, which regulates prices in a global and liquid oil market [Jaffe and Soligo 2006; Zhiznin 2007]. The term “gas OPEC” is inappropriate in serious professional discussions about the topic of cooperation in the gas market [Feygin and Revenkov 2007]. There is no mechanism by which the GECF, or Troika for that matter, can restrain production in the short run. Even Khelil concedes that the GECF is “more forward looking. It cannot control the volumes and price for the next ten years because it’s locked into long-term contracts and also the price of gas is locked to oil” [IEA 2009b, p. 43].

The complexity of the interregional gas market and the gas value chain, both for pipeline gas and LNG projects and the requirement of long-term stability of flows are an important driver for tacit cooperation and an impediment for formal cooperation. These factors de-

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86 Important contributions to this debate were made amongst others in Hallouche [2006], Wagbara [2007], Finon [2007]. Stern [2007], Jaffe and Soligo [2006], IEA [2009b].
crease the possibilities of OPEC cartel-like behaviour from the perspective of an interregional gas market [IEA 2009b]. Indeed, an opportunity for gas-exporting countries to create some form of capacity distribution and/or allocation is imaginable [Van der Linde 2005b]. In the Atlantic Basin especially, LNG exporters have an incentive to cooperate [Wagbara 2007]. It should be noted that the GECF has been keen to see long-term contracts maintained in order to assist with the underwriting of large capital projects and to provide stable incomes to its members [Bahgat 2009].

Indeed, “a more likely focus of GECF deliberations is the changing structure and supply of gas markets over a ten- to fifteen-year horizon, i.e., towards 2020 and beyond […] While the imperative to keep gas competitive with other fuels would still provide a formidable obstacle to any short-term market manipulation, the GECF could look to coordinate medium-term investment plans among its member countries” [IEA 2009b, p. 43]. This is a fundamentally different functioning than typical OPEC, cartel-type behaviour, which involves formal collusion by quota administration, on a short-term rather than a long-term basis. Stern points out that the overall message about the functioning of the GECF, primarily from Russia, is that “rather than control of export prices and volumes, what is under discussion is the possibility of cooperation and coordination between gas exporters principally to prevent competition” [Stern 2007].

In other words, gas-exporting countries may have room for collusion as a form of cooperation rather than outright cartelisation, in light especially of the nature of gas trade. Gas-producing and exporting countries may decide to further alter the GECF principles and its institutional character in order to protect their (market) interests [Zhiznin 2007]. The effects of the demand destruction may compel or even force gas-exporting countries to cooperate in one way or another, especially in the face of low short-term gas prices and their pressure on long-term, oil-indexed contracts. The economic and geopolitical reasoning behind greater cooperation between gas-exporting countries is dealt with in chapters 10 and 11, respectively. This topic is covered further in Chapter 10.

7.9 Conclusion

The internationalisation of various key and potentially pivotal gas-exporting countries and their NEFs will shape the future geography of the interregional gas market, both by pipeline and LNG. It is mainly from within the outer integrators that a great bulk of future interregional gas flows will originate by means of LNG. Each country has its own gas export ambitions and strategy, with domestic needs and constraints invariably acting as an important constraint on these ambitions. Also, the various countries differ substantially in terms of vertical integration, extent of cooperation with IEFs and sales strategies. Indeed, in some cases domestic needs are projected to exceed export potential. In the aftermath of the financial and economic crisis of 2008-2009, some countries’ gas export and sales strategies may be profoundly affected by the fall in gas demand worldwide (and the development of unconventional gas in the US).
A trend that should not be overlooked is Gazprom’s appetite for cooperation with foreign NEFs, particularly in North Africa and Nigeria, amongst others. Possibilities for cooperation also exist with Iran and Qatar, though deeper cooperation with Iran is a longer run prospect. In most cases, the pattern of Gazprom’s investments along the value chain in Nigeria, Libya and other countries fits the broader trend of greater, long-term NEF-NEF cooperation. For the time being, there appears to be a clear difference between Gazprom’s approach to regional gas exporters to the European gas markets (e.g., Libya and Algeria) and truly interregional exporters such as Qatar as far as joint projects are concerned.

The asymmetric pipeline and LNG flows to various regional rather than a global gas market and to diverging extents bears witness to the rigid nature of the interregional gas market (especially when compared to the oil market). Drawing the inner integrators into this conclusion, the long-run balance between flows in the form of pipeline gas flows from the inner integrators on the one hand, and LNG flows from the outer integrators on the other, will to a large extent help determine regional gas market structures. This is the case at least in theory. In practice, a number of challenges ensure that a great deal of these flows have not yet and will likely not materialise for the foreseeable future. In the medium-term Russia will each expand exports either by pipeline while Qatar does so through greater LNG exports. In the long run, these two gas market integrators are—based on observations concerning existing and potential market power—capable of balancing a future interregional gas market by both pipeline and LNG, where economies of scale will play a key role. To one degree or another, and pending the resolution of a number of conundrums, Iran may well be able to join these small group of countries able to profoundly affect regional gas market structures. While these uncertainties remain, important gas exporting countries are pursuing a number of joint projects, both regionally and more globally.

Parallel to but not strictly related to more on-the-ground cooperation in the form of projects, these countries have also given further shape to the institutionalisation of cooperation in the interregional gas market. The main vehicles for this cooperation are the GECF and the Troika. These vehicles can hardly be compared to OPEC, but rather, mirror an effort to find common ground in the face of the myriad developments in a dynamic and uncertain interregional gas market. What type of cooperation is likely to arise in the long run and how the institutions mentioned above are likely to continue to evolve, depends to a large extent on the evolution of the interregional gas market, in particular as it shifts from one phase of development to the next (i.e., towards more interregional expansion). As the interregional gas market continues to expand over the medium to long term, incentives for increased coordination of some sort appears warranted.