petroleum development consultants limited

Shaul Zemach
Director-General
Ministry of Energy and Water
216A Jaffa Road
PO Box 36148
Jerusalem
Israel

23 July 2012

Dear Shaul

International Gas Export Countries Review

The International Gas Export Countries Review report was prepared by Petroleum Development Consultants (PDC) as part of a project carried out by H.G. Yarden for the Ministry of Energy and Water to support the deliberations of the Government inter-departmental committee reviewing the future of the gas industry in Israel and the potential for gas exports.

The work was completed in December 2011 and covered as many relevant countries as possible. Since gas markets are dynamic, some aspects of any such report can get outdated as time passes. Of the counties covered by the report, most notable changes were in Tanzania, Egypt and Libya. In Tanzania the prospects are starting to materialise, as findings in East Africa (Tanzania as well as neighbouring countries such as Mozambique) attract more and more international oil and gas companies. Libya and Egypt are still undergoing significant internal changes, effecting both production and exports.

Yours sincerely

David Aron

David Aron
Managing Director

International Gas Export Countries Review

Report

Ministry of Energy and Water

12 March 2012

Contents

Figures

Tables

Abbreviations

bcfd	billion cubic feet per day
bcm	billion cubic metres

1. Summary

This report was prepared by Petroleum Development Consultants (PDC) as part of a project carried out by H.G. Yarden for the Ministry of Energy and Water (previously the Ministry of National Infrastructure). The work was prepared in order to support the deliberations of the Government inter-departmental committee reviewing the future of the gas industry in Israel and the potential for gas exports.

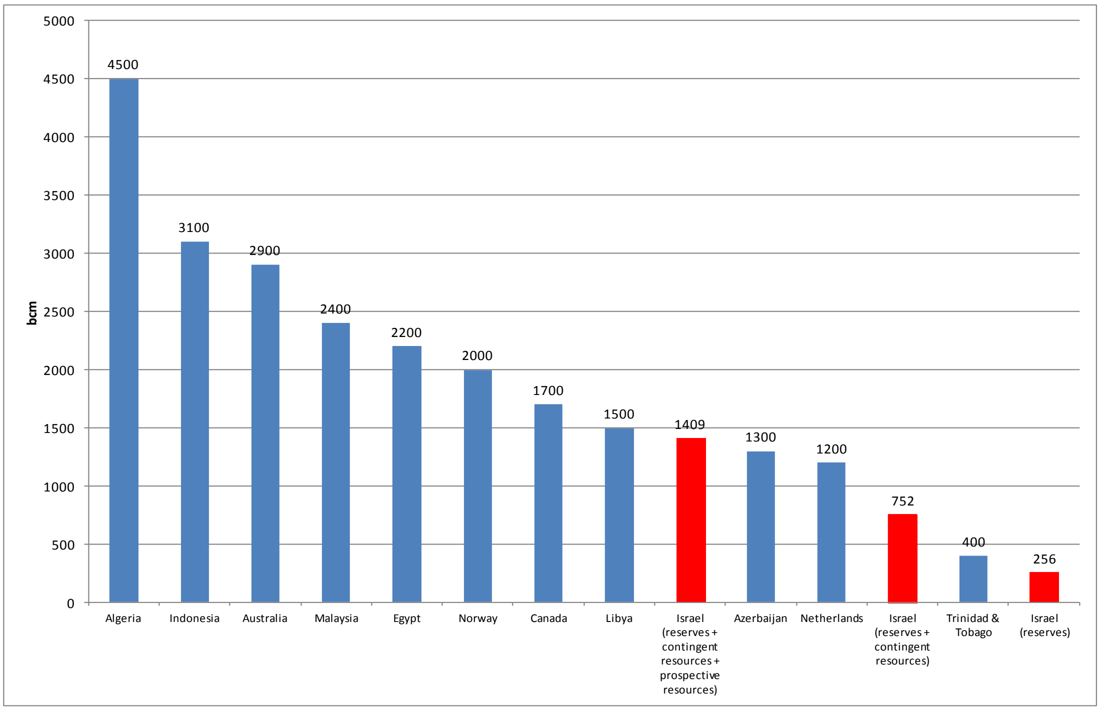
The report involved a comparison of twelve gas producing countries of which eleven were gas exporters and one (Tanzania) will be an exporter in the next 3-4 years.

The criteria for selection of the countries were as follows:

- Regional exporters
- Predominance of offshore production
- Similar reserve basis as Israel

A summary of the proven reserves for the eleven exporting countries compared to the reserves and potential resources in Israel is shown below in Figure 1.

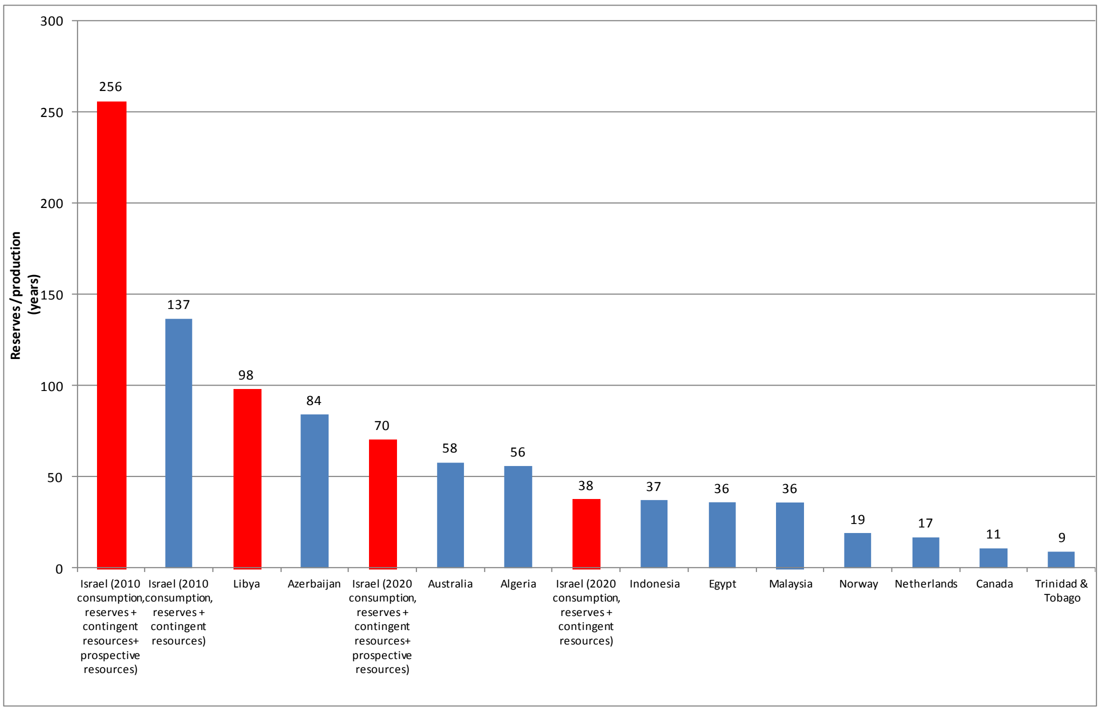
Figure 1 Reserve Comparison



Source: BP Statistical Review of World Energy, June 2011, PDC analysis

A summary of the proven reserve/production ratios for the eleven exporting countries compared to the proven reserve/production ratios and potential reserve/production ratios for Israel both for existing and future production levels is shown below in Figure 2.

Figure 2 Reserve/Production Ratios



Source: BP Statistical Review of World Energy, June 2011, PDC analysis

A summary of the main lessons learnt from this study are given below covering:

- Reservation policy
- Domestic supply incentives
- Low domestic prices
- Transit arrangements
- Sovereign funds
- Ammonia and methanol plants

Reservation Policy

Six of the countries reviewed have a domestic reservation policy.

There is no federal **Australian** policy on gas reservation although both Western Australia and Queensland have such policies. Western Australia which is the most gas dependent government has had such a policy since 2006 and this requires that 15% of every project should be reserved for domestic consumption. Queensland has a Prospective Gas Production Land

Reservation Policy which means a future call for tenders for petroleum exploration acreage may stipulate that the licence is subject to an "Australian market supply condition". This is a condition that gas produced from a resulting production licence must be supplied exclusively to the domestic market.

In **Canada** the province of Alberta maintained a policy of protecting its own gas consumption by requiring a reserve of 30 years to be kept. This policy was in force from 1953-88 and was only ended when Canada and the USA formed a free trade area. Public pressure in the early days of the industry forced producers only to export gas when domestic markets were ensured.

The **Egyptian** Government in 1999 decided to allow exports of gas but restricted it to 25% of production and only allowed foreign investors permission provided that they invested in local gas distribution companies. The strategy was revised in 2000 so gas exports were limited to 33% of the gas reserve base with the remaining gas reserve being split between domestic consumption (33%) and strategic reserve (33%). Egypt has also restricted the development of additional export facilities the most important being the expansion of the LNG export plant at Damietta.

The **Indonesian** Government in 2001 introduced a Domestic Market Obligation whereby 25% of any gas produced has to be set aside for the domestic market although the Constitutional Court ruled in 2004 that this should be 25% or more. However producers are reluctant to supply at low domestic prices and this is inhibiting gas development as a whole. The Donggi-Senoro LNG terminal plans received government approval only after 30% of the output was designated for domestic consumption. Similarly, a third of the output from Inpex's planned Masela floating LNG liquefaction terminal will be designated for the domestic market. In addition, recently the Government announced that it will allocate all output from the massive Natuna D-Alpha field for domestic use only.

In 1963 the **Netherlands** Government decided to export a significant part of the reserves of the huge Groningen field, without worrying about the depletion of gas reserves. However in 1974, the small fields policy (SFP) was adopted in order to increase the life of the gas fields for as long as possible. This requires the state gas company to buy gas from small fields at market prices. As there is a production ceiling this means that production from the large Groningen field is restricted and acts as a strategic reserve.

Trinidad and Tobago does not have a domestic obligation and it has been unable to encourage exploration in the last few years with the result that its reserves/production ratio has fallen to 8.6 years. Government policy was to keep this ratio at 25 years but it failed to attract further exploration in a number of licensing rounds.

Domestic Supply Incentives

A number of the study countries have attempted to improve exploration incentives to provide for domestic supply security with varying degrees of success.

The **Australian** State of Queensland has just introduced a provision that would allow tenders of production sharing licences to require an Australian market condition that would require in certain cases dedication of production to the domestic market.

In 2008 **Egypt** stopped the development of export facilities and this is one of the principal causes of a significant slow-down in exploration activity.

Although **Indonesia** has a domestic market obligation the low prices in the domestic market has caused a slow down in investment in further gas development. In addition there is now spare capacity in the export facilities.

The **Netherlands** developed the small fields policy to expand its reserves; exploration and development was encouraged by allowing the new fields to export their production while reserving the large Groningen field for domestic use.

In order to increase its reserves the **Trinidad and Tobago** government has reduced the petroleum profits tax from 50% to 35%, allowed 40% uplift on investments and has eliminated signature bonuses as well as state participation. However this has had only a minor affect on exploration activity with the low domestic price being a problem.

Low Domestic Prices

Low domestic prices in a number of the study countries make it difficult to encourage development of domestic supply.

In **Egypt** the purchase price for domestic gas is significantly lower than export prices and coupled with a ban on further exports this will result in lower exploration activity.

In **Indonesia** the domestic market obligation with a low price is having a negative effect on investment for further gas development.

In **Malaysia** domestic prices are lower than export prices and gas production in Malaysia has reached a plateau which will limit expansion of the domestic market. Malaysia, despite being the world's third largest LNG exporter, is now developing several LNG import projects to meet domestic demand.

Transit Arrangements

A number of the study countries were required to negotiate transit arrangements for their gas which involved state involvement.

Algeria had to negotiate transit arrangements through both Morocco and Tunisia and these arrangements were made through bilateral state agreements.

Azerbaijan has required access through Georgia and Turkey for its gas exports. The arrangements for gas transit through Turkey have been made through bilateral state agreement (Inter-Government Agreements).

In **Norway** in the initial phase of gas development no gas was landed in Norway both because of the lack of a domestic market and physical problems in laying pipe over the Norwegian Trench. Bilateral arrangements were made between Norway and the UK, France and Germany.

Sovereign Funds

The State Oil Fund of **Azerbaijan** was set up in 1999 to accumulate and manage Azerbaijan oil and gas revenues. As at 31 December 2010 the Fund was $22.8 billion.

The Petroleum Fund of **Norway** was set up in 1990 and changed its name in January 2006 to The Government Pension Fund Global. The fund is currently valued at about $560 billion.

Ammonia and Methanol Plants

Trinidad and Tobago is the largest exporter of ammonia and methanol in the world. However the industry is subsidised with the gas supply price being around $1.6/MMBTU in 2005.

2. Introduction

This report was prepared by Petroleum Development Consultants (PDC) as part of a project carried out by H.G.Yarden for the Ministry of Energy and Water (previously the Ministry of National Infrastructure). The work was prepared in order to support the deliberations of the Government inter-departmental committee reviewing the future of the gas industry in Israel and the potential for gas exports.

The report involved a comparison of twelve gas producing countries of which eleven were gas exporters and one (Tanzania) will be an exporter in the next 3-4 years. Generally the data used is publically available although PDC does have some additional information for certain countries based on its experience.

The criteria for selection of the countries were as follows:

- Regional exporters
- Predominance of offshore production
- Similar reserve basis as Israel

The application of these criteria can be seen below in Table 1.

Table 1 Selection Criteria

Country	Regional	Offshore	Reserve Basis	Gas Exporter
Algeria	✓			✓
Australia		✓	✓	✓
Azerbaijan		✓	✓	✓
Canada			✓	✓
Egypt	✓	✓	✓	✓
Indonesia		✓		✓
Libya	✓		✓	✓
Malaysia		✓	✓	✓
Netherlands		✓	✓	✓
Norway		✓	✓	✓
Tanzania		✓		
Trinidad & Tobago		✓		✓

The following information is provided for each country:

- Short summary of key issues with respect to the Israel situation and recent and current policies and decisions regarding exports
- Reserves 2010
- Exports per year 2010

- Production 2001-2010
- Consumption 2001-2010
- Reserves/production
- Reserves/consumption
- Description of gas production facilities (onshore/offshore, etc)
- Description of gas export (and import) facilities for gas and LNG
- Description of organisation of gas industry (national company, main players)
- Description of gas regulatory structure (upstream and downstream)
- Description of similarities of gas industry to Israeli gas industry
- Description of differences of gas industry to Israeli gas industry
- Lessons learnt for Israeli gas industry

3. Algeria

3.1. Key Issues

Algeria has very significant gas reserves and is one of the largest exporters in the world. A major part of the reserves is produced as associated gas from oil. Algeria has an extensive export infrastructure of pipelines and LNG liquefaction plants. Algeria was a pioneer in exporting LNG. Algeria is currently adding additional pipeline and LNG export facilities. There are no land availability issues and Algeria has a long coastline. Algeria has successfully negotiated transit rights with Morocco and Tunisia.

The state has played a major role in the development of the gas industry with the state company Sonatrach becoming one of the world's most important state oil and gas company. The role of the state is likely to have been particularly important in negotiating transit routes through Morocco and Tunisia.

3.2. Basic Data

3.2.1. Proven Reserves

As at 31 December 2010 Algeria had 4,500 bcm of proven gas reserves which compares with 3,300 bcm as at 31 December 1990.

3.2.2. Exports

Total exports in 2010 were 55.79 bcm of which 36.48 bcm were via pipeline and 19.31 bcm were via LNG.

The two largest export markets were Italy (27.56 bcm via pipelines and LNG) and Spain (12.05 bcm via pipelines and LNG).

3.2.3. Production

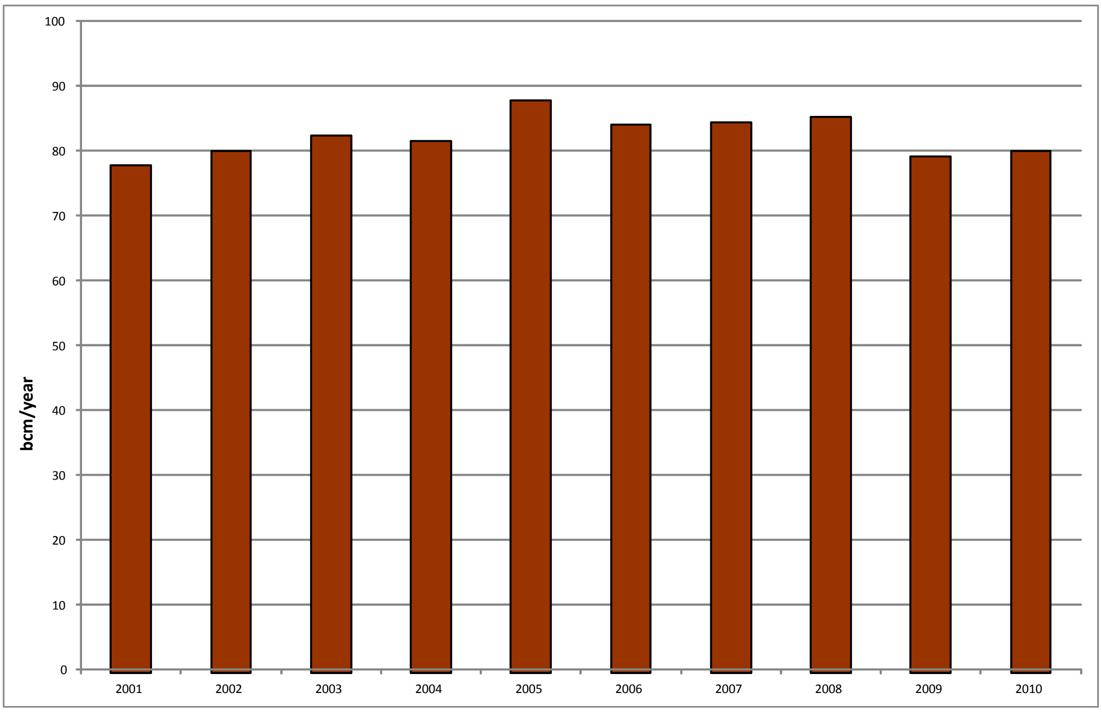
Gas production in 2010 was 80.4 bcm although it appears to have been in decline since 2005. Details of the production are shown in Table 2 and Figure 3. Around 60% of the gas is produced in association with oil.

Table 2 Algeria Gas Production (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
78.2	80.4	82.8	82.0	88.2	84.5	84.8	85.8	79.6	80.4

Source: BP Statistical Review of World Energy, June 2011

Figure 3 Algeria Gas Production



Source: BP Statistical Review of World Energy, June 2011

3.2.4. Consumption

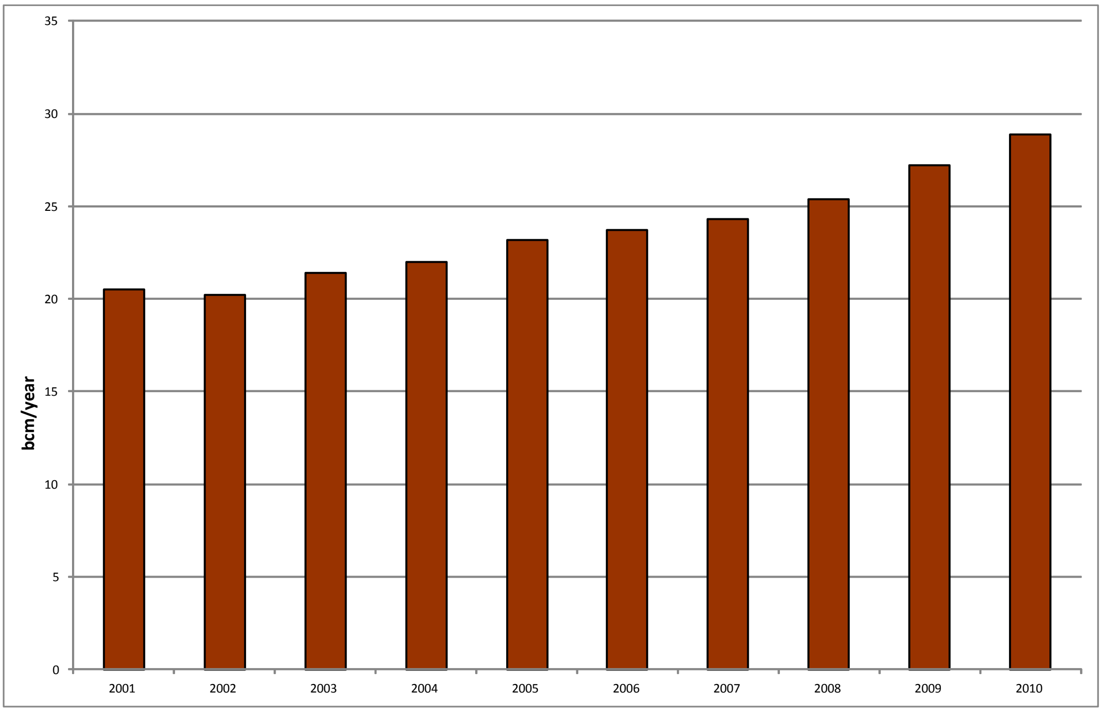
Gas consumption in 2010 was 28.9 bcm and consumption has been growing as shown in Table 3 and Figure 4.

Table 3 Algeria Gas Consumption (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
20.5	20.2	21.4	22.0	23.2	23.7	24.3	25.4	27.2	28.9

Source: BP Statistical Review of World Energy, June 2011

Figure 4 Algeria Gas Consumption



Source: BP Statistical Review of World Energy, June 2011

3.2.5. Reserves/Production

The reserves/production ratio is 4500/80.4 = 56 years.

3.2.6. Reserves/Consumption

The reserves/consumption ratio is 4500/28.9 = 156 years

3.2.7. Natural Gas Rents[1] (% of GDP)

The contribution of rents from natural gas to the GDP of Algeria is shown in Table 4 and Figure 5.

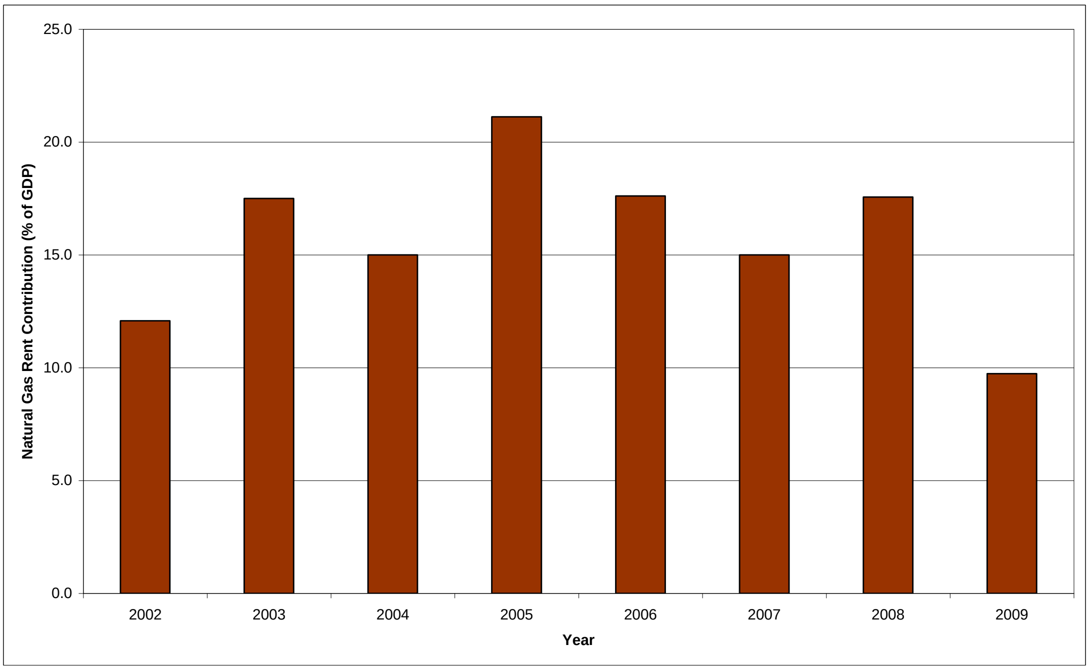
Table 4 Algeria Natural Gas Rents (% of GDP)

2002	2003	2004	2005	2006	2007	2008	2009
12.1	17.5	15.0	21.1	17.6	15.0	17.6	9.7

Source: World Bank

[1] Natural gas rents are the difference between the value of natural gas production at world prices and total costs of production.

Figure 5 Algeria Natural Gas Rents (% of GDP)

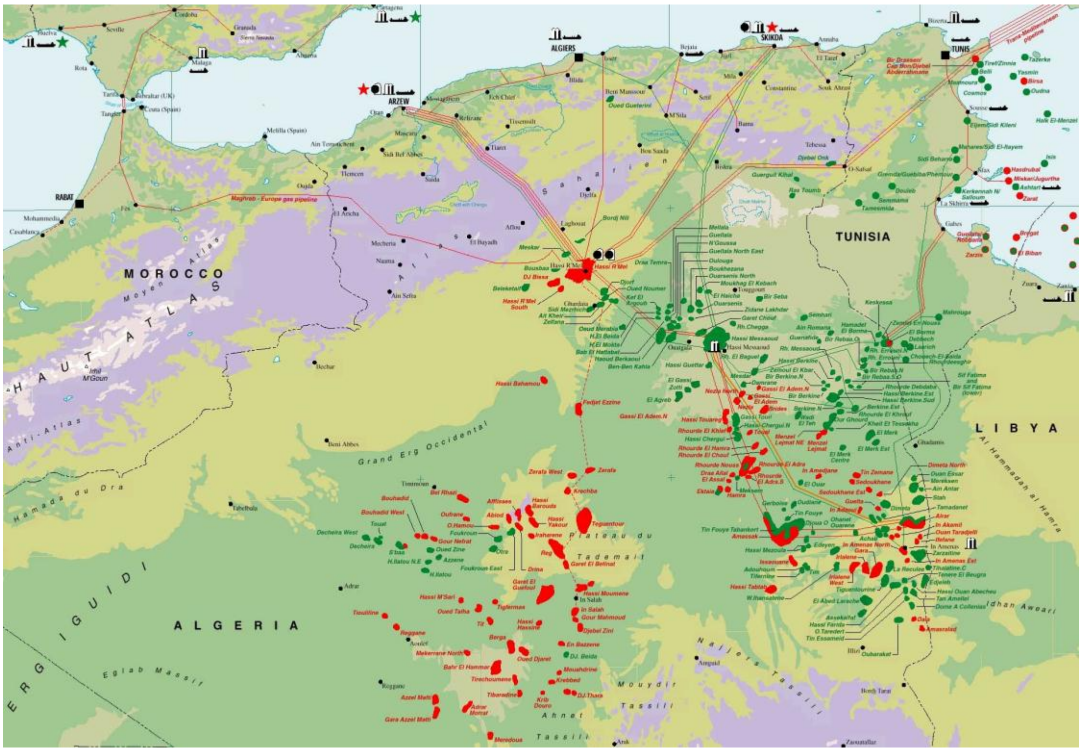


Source: World Bank

3.3. *Gas Production Facilities*

The Algerian gas industry has been built around the giant Hassi R'Mel gas condensate field discovered in 1956. This single field produces around 25% of all gas produced in Algeria with the remainder being produced as associated gas (with oil production) and new smaller fields in the south and south-east of the country. The location of the gas fields and domestic pipelines can be seen (in red) in Figure 6.

Figure 6 Algeria Oil and Gas Production Facilities



Source: Ministry Energy and Mines, Algeria

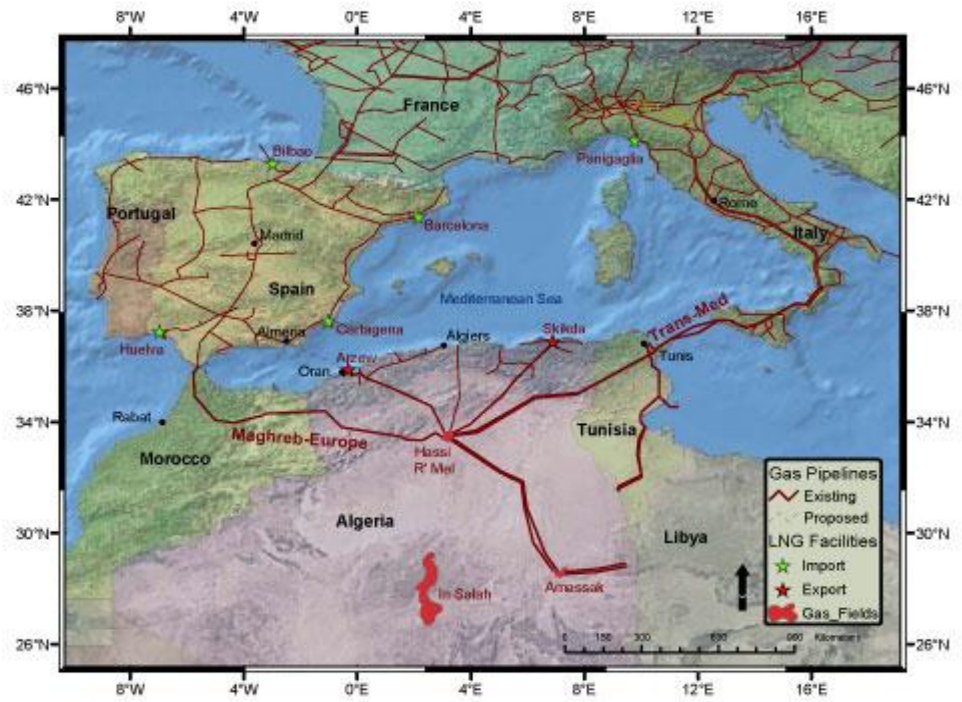
3.4. Gas Export and Import Facilities

Around 2/3rd of gas exports from Algeria move by pipeline through the Maghreb to Europe line from Hassi R'Mel to Spain and the Trans-Med line from Tunisia to Italy. These lines are shown in Figure 7. The lines have a total capacity of 34 bcm/year.

A further pipeline called Medgaz has recently been constructed from the Algerian coast to Almeria (See Figure 8). It has a capacity of 8 bcm/year.

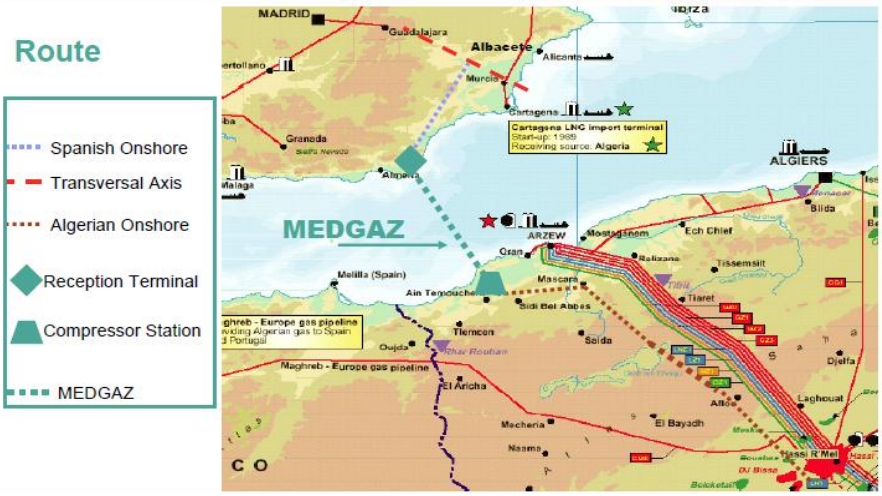
A further pipeline from Algeria via Sardinia to northern Italy is also being planned to come into operation in 2014 (See Figure 9).

Figure 7 Algeria Gas Export Lines



Source: Africa News

Figure 8 Algeria Medgaz Pipeline



Source: Medgaz

Figure 9 Algeria GALSI pipeline

Source: GALSI

The first LNG exports took place from Algeria to the United Kingdom in 1964. Algeria is one of the world's largest LNG exporters and its main customers are France, Spain and Turkey. The LNG export plants are shown in Figure 10.

Sonatrach recently announced that they were intending to construct two additional LNG liquefaction plants with a further 6.2 bcm per annum plant at Skikda and a 6.5 bcm plant at Arzew.

Figure 10 Algeria LNG Export Plants

Source: LNGpedia

3.5. Industry Organisation

Sonatrach the state oil and gas company dominates the gas industry. State owned Sonelgaz currently controls the retail gas industry. Algeria has increasingly allowed foreign participation in the upstream gas sector although Sonatrach has a controlling 51% interest in all joint ventures.

Algeria has been finding it difficult to attract foreign capital to its upstream sector and three consecutive bid rounds for oil and gas acreage failed to attract much interest. The Energy Minister has recently announced that in the future taxation will be tied to profits rather than turnover but the 51% rule on Sonatrach involvement is to remain. However in future Sonatrach will bear a higher share of the risk if projects fail.

3.6. Gas Regulatory Structure

Until the Hydrocarbons Act of 2005, Sonatrach was responsible for all activities including regulation and the issuing of exploration and production licences. These activities have now been transferred to other agencies with the Hydrocarbon Regulatory Authority assuming regulatory control of gas transportation and distribution. The National Agency for the Development of Hydrocarbon Resources (ALNAFT) now handles the control and issuing of production sharing agreements.

There are no direct restrictions on the export of gas. However a national energy policy can lead to production limitations. In addition under the Act ALNAFT may ask each gas producer to contribute in proportion to its own production to national domestic requirements. Finally it is required that marketing of gas abroad can only be conducted in a joint venture with Sonatrach.

3.7. Similarities to Israel

There are few similarities to Israel with the gas reserves in Algeria being significantly higher than the potential reserves in Israel.

3.8. Differences to Israel

The main differences between Algeria and Israel are:

- Algeria has significantly higher gas reserves than the potential reserves in Israel although Algerian gas reserves are dominated by associated gas which is less flexible than the dry gas fields found in Israel
- Algeria is very favourably located with respect to the gas markets in Europe and is connected directly by three separate pipeline systems to Europe
- The Algerian state has played an active role in exploring and producing gas unlike the situation in Israel where the state role has been confined to the development of a gas transportation system
- The development of an independent regulatory regime in Algeria is a recent phenomena whereas in Israel there is an effective semi-independent regulatory structure

3.9. Lessons Leant

The following are the main lessons:

- It is worth noting that Algeria has had a successful gas pipeline export business to Europe even though its main pipelines required transit rights through Morocco and Tunisia
- Algeria was a pioneer in the development of LNG export terminals and continues to invest in additional LNG terminals
- Algeria is also continuing to invest in additional gas pipeline export systems
- Gas production has been in decline and there appear to be inadequate incentives to encourage the international oil companies to increase their exploration activities in Algeria

4. Australia

4.1. *Key Issues*

Gas is becoming increasingly important in Australia both as a source of domestic energy supply and export income. It is the third largest source of Australia's energy supply after coal and uranium[2]. The ratio of gas exports to domestic consumption in Australia is about 50:50. Electricity accounts for 38% of domestic gas consumption, the industrial sector for 28% and households for 34%[3]. Australia is the fourth largest global LNG supplier according to 2010 estimates[4].

Various LNG projects are underway in Australia both from conventional natural gas and unconventional coal seam gas. Thus Australia is poised to become the second largest LNG supplier in the world by 2015 and likely to overtake Qatar to become the number one global LNG supplier by 2020[5].

4.2. *Basic Data*

4.2.1. Proven Reserves

As at 31 December 2010 Australia had 2,900 bcm of proven gas reserves which compares with 900 bcm as at 31 December 1990.

4.2.2. Exports

Total exports in 2010 were 25.36 bcm all of which were via LNG. The two largest export markets were Japan (17.66 bcm) and China (5.21 bcm).

4.2.3. Production

Gas production in 2010 was 50.4 bcm and it has increased steadily over the last ten years. Details of the production are shown in Table 5 and Figure 11.

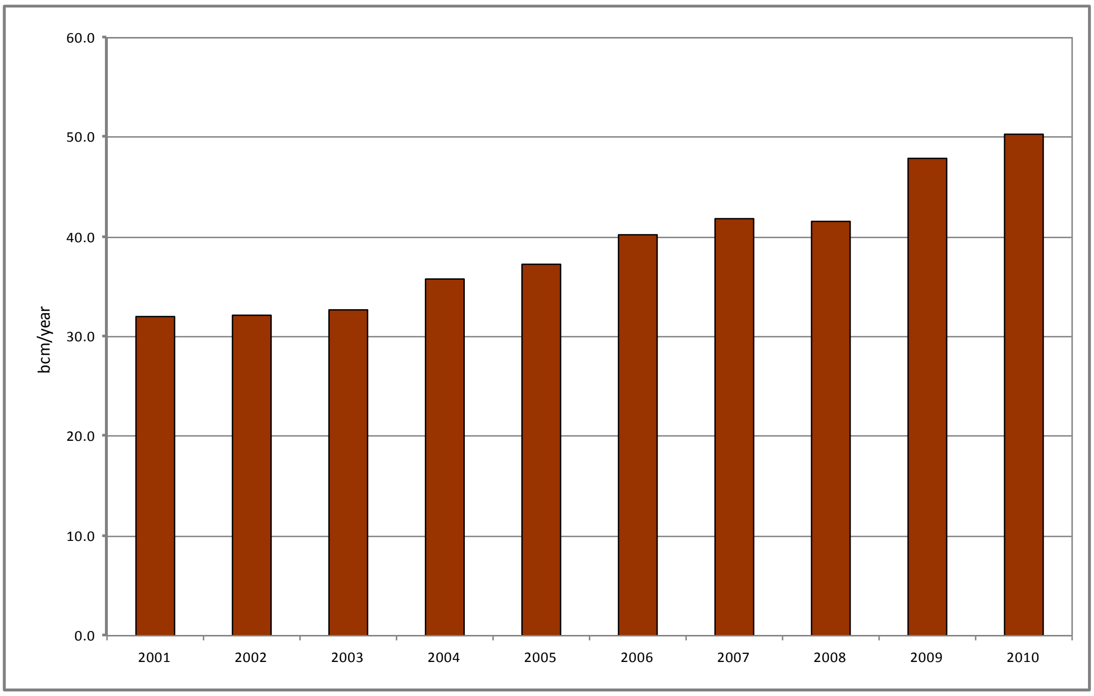
Table 5 Australia Gas Production (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
32.1	32.2	32.7	35.8	37.2	40.2	41.9	41.6	47.9	50.4

Source: BP Statistical Review of World Energy, June 2011

[2] Australian Energy Regulator, State of the Energy Market 2010
[3]http://www.eiu.com/index.asp?layout=ib3Article&article_id=1848389969&pubtypeid=1142462499&country_id=1550000155&category_id=775133077
[4] BP Statistical Review, 2011
[5] http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/8435318

Figure 11 Australia Gas Production



Source: BP Statistical Review of World Energy, June 2011

4.2.4. Consumption

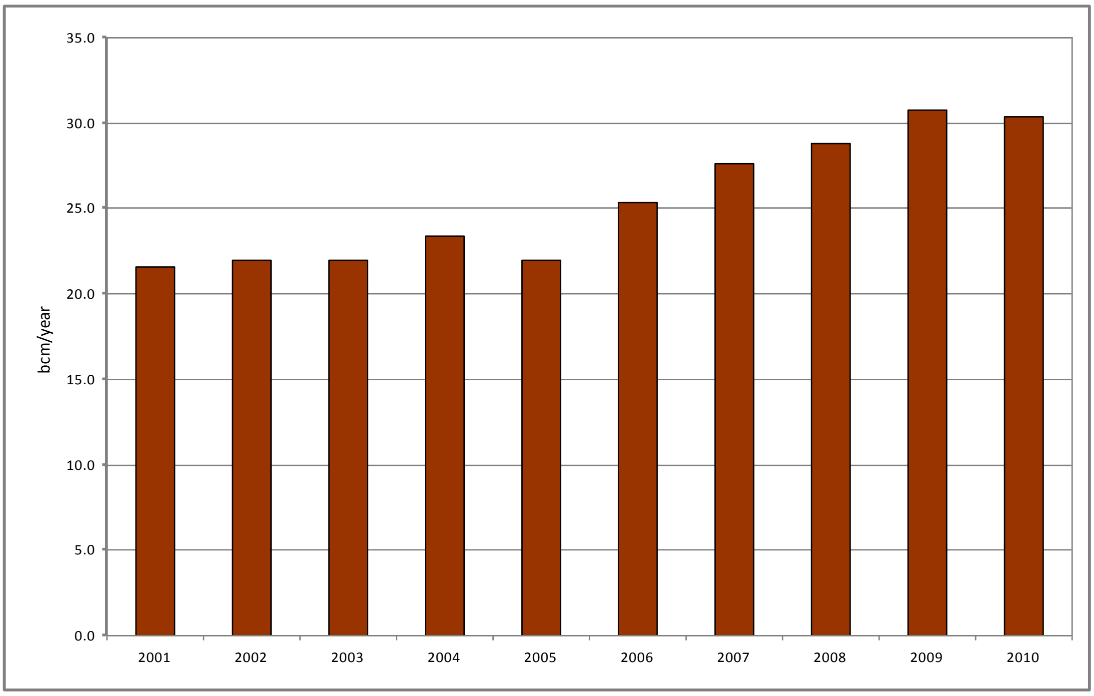
Gas consumption in 2010 was 30.4 bcm and consumption has been growing steadily as shown in Table 6 and Figure 12.

Table 6 Australia Gas Consumption (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
21.6	22.0	22.0	23.4	22.0	25.3	27.6	28.8	30.7	30.4

Source: BP Statistical Review of World Energy, June 2011

Figure 12 Australia Gas Consumption



Source: BP Statistical Review of World Energy, June 2011

4.2.5. Reserves/Production

The reserves/production ratio is 2920.1/50.4 = 58 years.

4.2.6. Reserves/Consumption

The reserves/consumption ratio is 2920.1/30.4 = 96.1 years.

4.2.7. Natural Gas Rents (% of GDP)

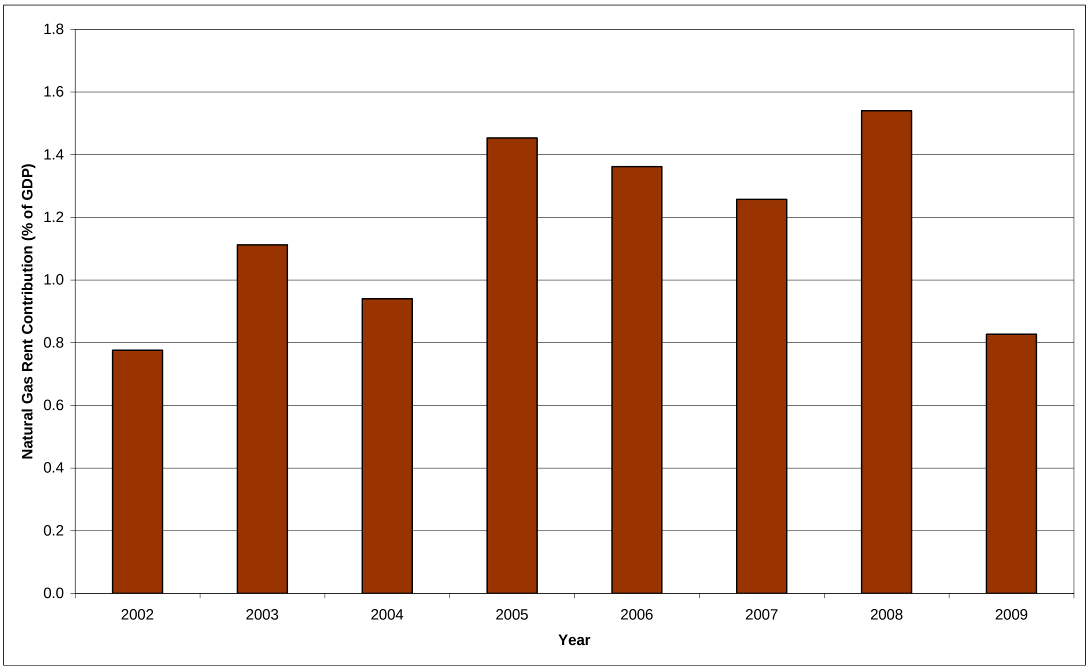
The contribution of natural gas rents to Australia's GDP is shown in Table 7 and Figure 13.

Table 7 Australia Natural Gas Rents (% of GDP)

2002	2003	2004	2005	2006	2007	2008	2009
0.8	1.1	0.9	1.5	1.4	1.3	1.5	0.8

Source: World Bank

Figure 13 Australia Natural Gas Rents (% of GDP)



Source: World Bank

4.3. Gas Production Facilities

Australia's conventional gas resources are produced mainly from three basins which jointly account for 96% of conventional natural gas production:

- Carnarvon (North West/Western Australia)
- Cooper/Eromanga (central Australia)
- Gippsland (Victoria)

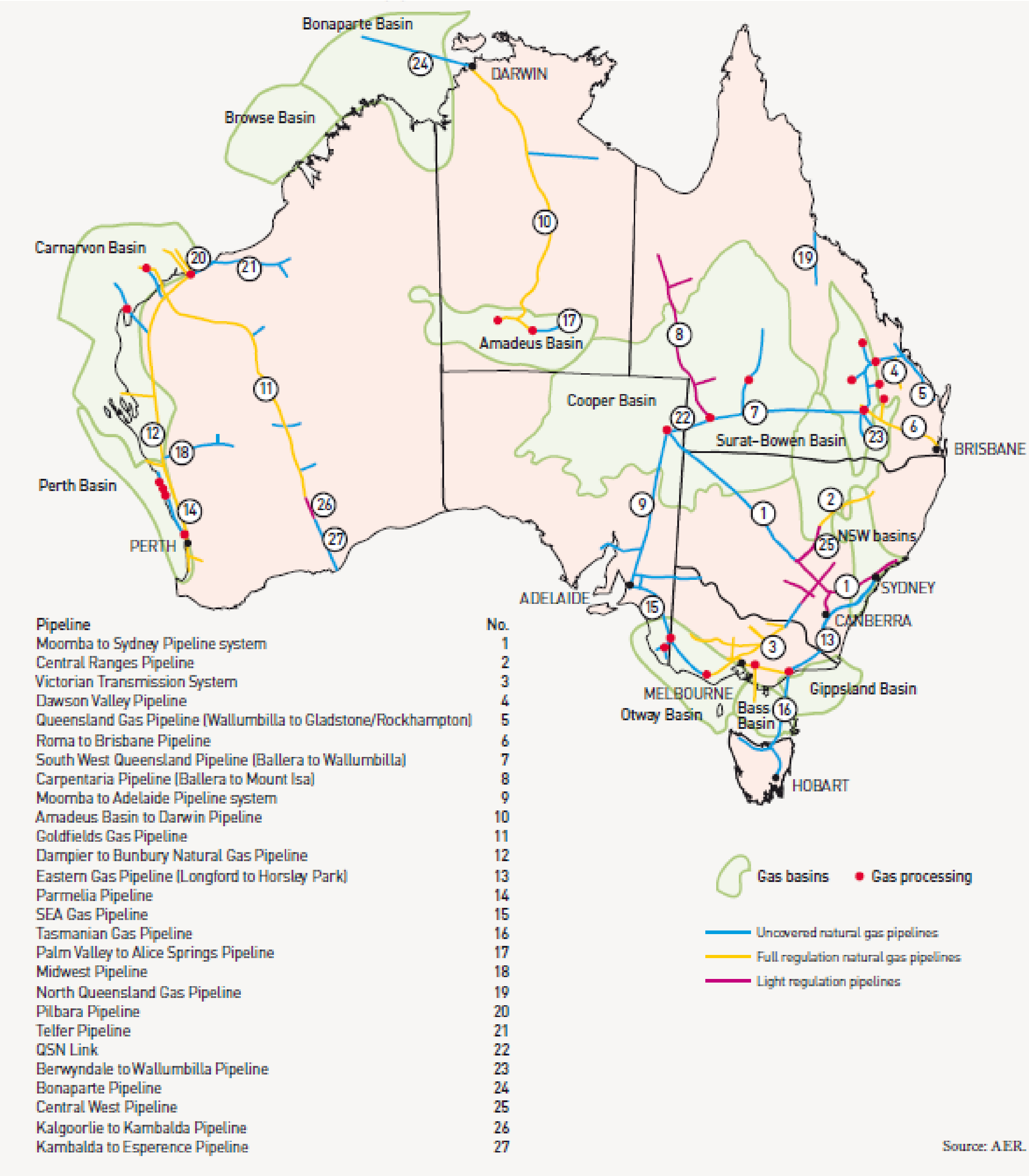
Other basins with conventional gas production are Perth, Browse and Bonaparte basins (Western Australia), Otway and Bass basins (Victoria) and Amadeus basin (Northern Territory)[6]. Coal bed methane accounted for 13% of gas production in 2010 and is produced in Queensland and New South Wales[7].

Approximately 79% of domestic consumption is supplied by six major producers including BHP Billiton (19%), Santos (18%), ExxonMobil (14%), Woodside (12%), Apache (10%) and Origin Energy (6%)[8].

Details of the main basins and gas transmission lines are shown in Figure 14.

[6] Energy in Australia, 2011
[7] http://www.eia.gov/countries/cab.cfm?fips=AS
[8] Australian Energy Regulator, State of the Energy Market 2010

Figure 14 Australia Gas Basins and Transmission Pipelines



Source: Australian Energy Regulator, State of the Energy Market 2010

The North West Shelf facilities (operated by Woodside) process hydrocarbons from gas and condensate fields in the Carnarvon Basin. Other participating companies in the North West Shelf Project are BHP, BP, Chevron, Shell and Japan Australia LNG[9].

[9] http://www.nwsg.com.au/default.aspx

The North Rankin A platform is the central hub of the North West Shelf Project's offshore gas production system and it combines drilling, production, utilities and accommodation facilities. The 0.074 bcm production facility is supported on a conventional steel jacket. The platform has a daily production capacity of up to 0.071 bcm of gas. A redevelopment project was approved in 2008 to access additional recoverable gas reserves from the North Rankin and Perseus gas fields. The project involves the installation of a second platform, North Rankin B.[10]

The Goodwyn A platform is connected to the Goodwyn gas field and combines drilling, production, re-injection, utilities and accommodation facilities. Goodwyn A has a daily production capacity of up to 0.05 bcm of gas. Dry gas and condensate produced from the Goodwyn area reservoirs and Echo/Yodel and Perseus satellite field reservoirs are exported to the nearby North Rankin A platform by an inter-field pipeline[11].

The remotely operated Angel gas platform is tied in to the North Rankin A platform via a 50 km subsea pipeline and is designed to allow for the tie-back of other discoveries in the area. Angel is supplied by three subsea production wells and is remotely controlled from North Rankin A via a subsea cable. The capacity is up 0.023 bcm per day of raw gas[12].

Natural gas is piped from offshore reserves at the North Rankin A, Goodwyn A and Angel platforms and the Cossack Pioneer FPSO through the Karratha trunkline to the Karratha Gas Plant for processing. The Karratha gas plant is an integrated gas production system where LNG, domestic gas, condensate and LPG is produced[13].

The Cooper Basin contains approximately 190 gas fields which feed into production facilities at Moomba in South Australia and Ballera in Queensland through approximately 5,600 km of pipelines via fifteen major satellite facilities incorporating field boost compression. The central gas processing facility in Moomba includes a natural gas liquids recovery plant and an ethane treatment plant. The Moomba facility also incorporates substantial underground storage for processed sales gas and ethane, while Ballera has a smaller underground storage system for processed sales gas[14].

The Gippsland Basin has been producing hydrocarbons since 1969, a total of 198.2 bcm of gas to date. By comparison with other Australian basins it is a mature basin but still relatively under-explored. Currently the Gippsland Basin

[10] http://www.woodside.com.au/Our-Business/North-West-Shelf/Offshore/Pages/North-Rankin-A.aspx
[11] http://www.woodside.com.au/Our-Business/North-West-Shelf/Offshore/Pages/Goodwyn-A.aspx
[12] http://www.woodside.com.au/Our-Business/North-West-Shelf/Offshore/Pages/Angel.aspx
[13] http://www.nwsssc.com.au/project.aspx
[14] http://www.santos.com/Content.aspx?p=217

has 17 developed offshore oil and gas fields, 24 offshore production facilities (platforms, monotowers and subsea completions), over 600 km pipeline network and 5 fields under development by 4 consortia. About 56.6 to 141.6 bcm of gas is estimated to remain undiscovered in the Gippsland Basin[15].

ExxonMobil operates 21 offshore platforms and subsea installations in the Bass Strait within the Gippsland basin. Gas produced in the Bass Straits is fed through a network of 600km underwater pipelines and transported onshore to the Longford gas plant.

4.4. Gas Export and Import Facilities

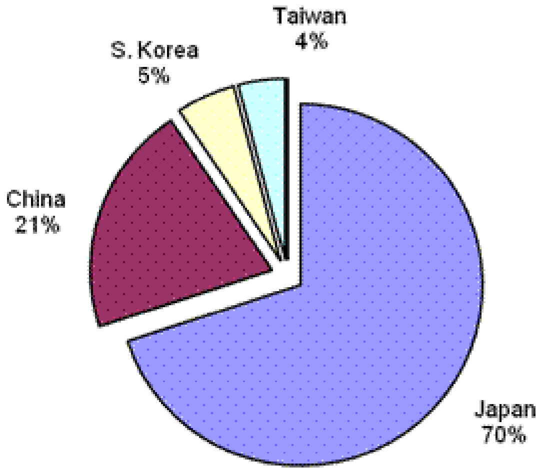
There are currently no imports of natural gas into Australia and half of natural gas production is converted into LNG for export and the other half is consumed domestically[16]. The geographical distance between Australia and its key gas export markets prevents pipeline trade, so all exports are in form of LNG (see Figure 15).

Australia currently has two LNG export facilities. The largest is the North West Shelf Venture (NWSV), operated by a consortium of six energy companies (Woodside, Shell, BP, Chevron, Japan Australia LNG, and BHP Billiton). It operates five offshore LNG trains with a total capacity of 21.5 bcm per year. It is supplied natural gas from nearby fields in the Northwest Shelf. The majority of LNG produced by the NWSV is exported to Japan through long-term contracts.

The second facility is the Darwin LNG operated by a consortium of ConocoPhillips, Santos, Eni, SPA, and INPEX. It has one production train with capacity of 3.96 bcm per year and exports LNG under contracts to Tokyo Gas Corp. and Tokyo Electric. Darwin is located on Australia's northern coast and is supplied with natural gas from the Bayu-Undan fields in the Timor Sea.

[15] http://www.dpi.vic.gov.au/earth-resources/oil-gas/prospectivity
[16] Energy in Australia, 2011

Figure 15 Australia LNG Exports, 2010



Source: Cedigaz

New LNG facilities coming online will substantially expand Australia's LNG export capacity. Some of the new conventional LNG projects include[17] the Pluto project near Karratha offshore Western Australia, with estimated LNG capacity of 5.7 bcm per year which is expected to have its first phase online in March 2012. Woodside Energy owns 90% of the venture supported by 15-year sales contracts with Kansai Electric and Tokyo Gas, which have 5% equity each. The project includes an offshore platform connecting five subsea wells and a 112-mile pipeline to an onshore LNG facility on the Burrup Peninsula. Plans for a second train are on hold as additional gas supplies are sought.

The Gorgon project off the northwest coast and led by Chevron (50%), with Shell and ExxonMobil (25% each), is under construction and expected to be completed in 2014. The Gorgon gas field is believed to contain 1,132 bcm of natural gas and is currently Australia's largest known natural gas resource. The project includes development of the Gorgon gas fields, with connection by subsea pipelines to Barrow Island, where gas processing facilities will have production capacity of 19.8 bcm per year with LNG export facilities. In the beginning of 2011, Chevron signed long-term sales agreements with Nippon and Kyushu corporations for sales of Gorgon LNG. The project is expected to annually produce 11.04 bcm of LNG.

The Icthys project, located offshore the northwest coast in the Browse Basin, is expected to begin construction in early 2012. The project is led by Japan's INPEX (74%) and Total (26%). A 528-mile undersea pipeline will connect the fields to a new export LNG terminal to be built near Darwin. When the project is completed in 2016, production is expected to be 10.8 bcm per year of LNG.

[17] http://www.eia.gov/countries/cab.cfm?fips=AS

The Wheatstone project in north-western Australia reportedly will begin construction in November 2011. It is led by Chevron (73.6 %), Apache (23 %), Kuwait Petroleum (KUFPEC) (7%) and Shell (6.4 %). KUFPEC and Apache joined the project as gas suppliers from their nearby Julimar and Brunello fields, which will extend the life of the project. Wheatstone is supported by long-term LNG sales contracts with Tepco and Kogas. When complete in 2016, the first two trains of its LNG export plant are expected to export 12.3 bcm per year.

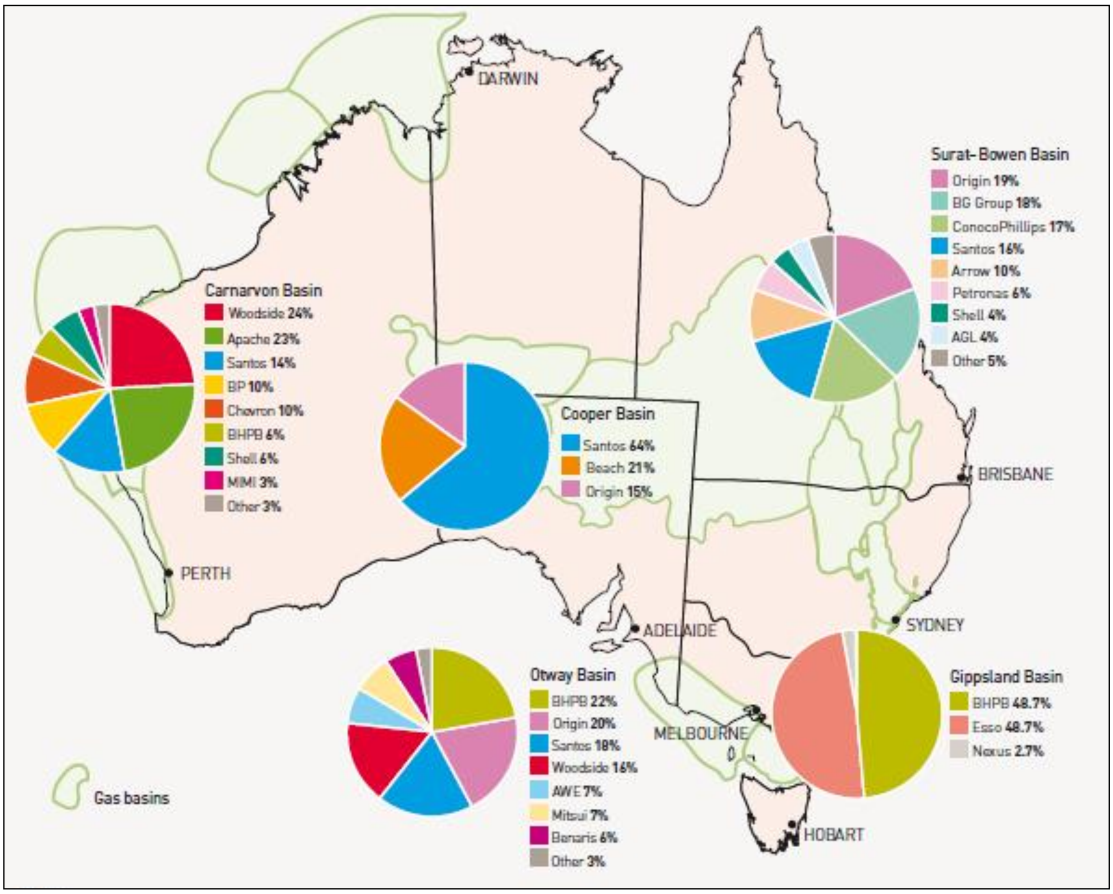
4.5. Industry Organisation

The Australian government has no ownership stake in the domestic oil and natural gas industry except in New South Wales where the state government owns interests in gas retail companies[18]. Government regulates the industry through the Department of Resources, Energy and Tourism (RET) and the Ministerial Council of Energy (MCE). In place of a national oil and gas company, the Australian government supports privately held indigenous companies, the largest of which are Woodside Petroleum and Santos[19]. Major private players include BHP Billiton, Chevron, ConocoPhillips, ExxonMobil, Origin Energy, BG Group, Apache, INPEX, Total, and Shell.

There is a preponderance of vertical integration in the Australian gas industry. Due to the increasing use of natural gas as a fuel for electricity generation, energy retailers are able to create synergies as well as manage price and supply risk through equity in gas production and gas fired electricity generation. Both Origin Energy and AGL Energy have substantial interests in gas production and electricity generation[20]. Upstream gas production and downstream gas processing activities are also integrated among many of the companies. Production and share of reserves are relatively concentrated as shown in Figure 16 and Figure 17 below.

[18] IEA Oil & Gas Security: Australia 2011
[19] http://www.eia.gov/countries/cab.cfm?fips=AS
[20] Australian Energy Regulator, State of the Energy Market 2010

Figure 16 Australia Domestic Gas Production Market Share, 2009-2010



Source: Australian Energy Regulator, State of the Energy Market 2010

Figure 17 Australia Market Share by Basin, 2010 (%)

COMPANY	CARNARVON (WA)	BONAPARTE (WA/NT)	PERTH (WA)	AMADEUS (NT)	COOPER (SA/QLD)	SURAT–BOWEN (QLD)	GUNNEDAH (NSW)	CLARENCE MORTON (QLD/NSW)	GLOUCESTER (NSW)	SYDNEY (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS
Chevron	32.6													21.0
Shell	18.2					10.1								14.2
Esso	15.0										44.5			11.8
Woodside	11.5													7.4
Origin			51.7		13.5	19.4						36.5	42.5	5.4
Santos	1.1	2.3		60.7	65.8	11.8	35.0				4.4	17.7		5.3
BHP Billiton	4.1										44.5	11.5		4.9
ConocoPhillips		11.6				19.4								4.9
QGC/BG						17.1								4.2
BP	5.1													3.3
MIMI	3.9													2.5
PetroChina						10.1								2.5
Apache	3.7													2.4
Petronas						6.1								1.5
AGL						2.9			100.0	100.0				1.5
Eastern Star Gas							65.0							0.9
ENI		81.9												0.9
CNOOC	1.3													0.9
Kufpec	1.2													0.8
Tokyo Gas	1.0													0.6
Osaka Gas	0.7													0.5
Metgasco								100.0						0.4
Nexus											6.7			0.3
Mitsui						0.7						8.3		0.3
AWE			48.3									8.1	57.5	0.3
Other	0.6	4.2		39.3	20.7	2.6						17.9		1.6
TOTAL (PETAJOULES)	68 353	1 198	33	156	1 157	26 202	1 520	397	669	154	5 233	1 163	275	106 511

Notes:

Based on proved and probable reserves at August 2010.

Some corporate names are shortened or abbreviated. Not all minority owners are listed.

Source: EnergyQuest 2010 (unpublished data).

Source: Australian Energy Regulator, State of the Energy Market 2010

4.6. Gas Regulatory Structure

The energy industry in Australia is regulated by the Department of Resources, Energy and Tourism (RET) and the Ministerial Council of Energy (MCE). The management of gas exploration and production is divided between the state and the Federal (Commonwealth) governments. The states manage applications for onshore projects, while the Commonwealth shares jurisdiction over offshore projects with the adjacent state or territory. MCE was created in 2001 to foster policy coordination between the Commonwealth and the state governments. It functions as the national policy and governance body for the

Australian energy market and is comprised of Ministers with responsibility for energy from the Australian government and all states and territories[21].

The Australian Energy Regulator (AER) is responsible for the economic regulation of gas transmission and distribution networks and enforcing the national gas law and national gas rules in all jurisdictions except Western Australia[22]. The Economic Regulation Authority undertakes this role in Western Australia[23].

Australia always consumed all its natural gas production domestically until 1989-90 when LNG exports started with the development of the North West shelf (in the Carnarvon basin)[24]. Australia favours a policy of ensuring that competitive gas supplies to both domestic and export markets are being maintained[25]. Due to emerging and expected changes in market dynamics, particularly increases in domestic prices and projected increase in domestic gas demand (especially for electricity supply – expected to increase from the current 15% to 44% by 2050), there have been calls for a national gas reservation policy to assure adequate domestic supply but the Australian Government believes this is unwarranted[26]. The government will however monitor market dynamics to assess policy outcomes given growing domestic gas usage. This will influence decisions that will be mindful of domestic gas considerations when granting production licenses. The government also wishes to pursue a policy of timely and competitive upstream gas development to prepare for increased gas demand. In order to achieve this, the government is considering changes to the lease retention arrangements so as not to indefinitely warehouse petroleum resources. Australia wishes to maintain and improve its standing as a reliable energy supplier in the global exports market[27].

Western Australia (WA) government maintains a policy of seeking a 15% domestic gas reservation from all gas projects, but applies it flexibly and considers the project's commercial viability[28]. WA is the most gas-dependent economy in Australia. Natural gas supplies half of the State’s primary energy requirements and fuels 60% of the state’s electricity generation. The policy was started in 2006 after a stakeholder consultation[29]. The rationale behind the policy was that although WA had approximately 80% of Australia’s total gas reserves, it still faced obstacles in meeting its domestic gas demands.

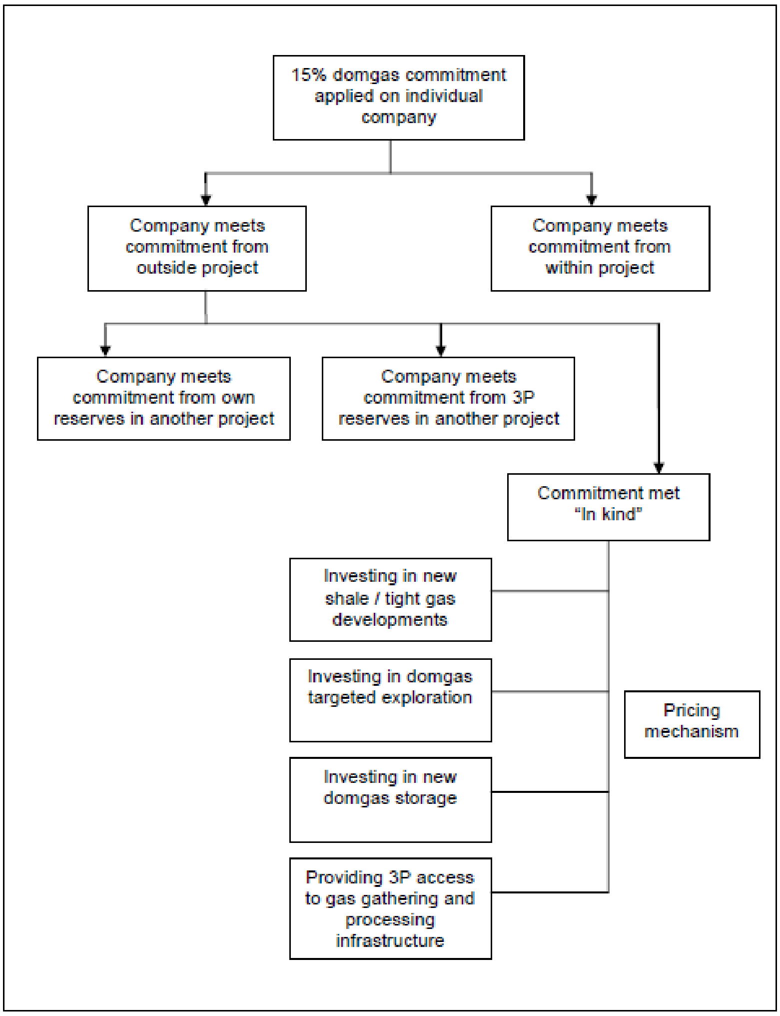
[21] http://www.eia.gov/countries/cab.cfm?fips=AS
[22] http://www.aer.gov.au/content/index.phtml/itemId/659161
[23] State of the Energy Market 2010
[24] Energy in Australia, 2011
[25] Draft Energy White Paper, 2011
[26] http://www.upstreamonline.com/live/article294121.ece
[27] Draft Energy White Paper, 2011
[28] http://www.claytonutz.com/publications/newsletters/energy_and_resources_insights/20110822/the_future_of_domestic_gas_reservation_in_wa.page
[29] http://www.claytonutz.com/publications/newsletters/energy_and_resources_insights/20061221/responses_to_wa_domestic_gas_reservation_policy.page

The three major obstacles identified were:

- the majority of the reserves are offshore in Commonwealth waters where the State has no control over, and receives no royalty payments for, these reserves
- the reserves are expensive to develop, and the highest economic return to project developers is likely to be obtained through developing large scale projects for export at world prices; and
- new domestic processing plants are costly and the WA economy requires only relatively small load increments which would not justify the appropriate investment.

In order to meet the 15% WA domestic gas obligation it has been proposed that producers are given some flexibility as seen in Figure 18.

Figure 18 Australia: Domestic Gas Obligation



Source: Meeting Domestic Gas Obligations - Discussion Paper (Domgas Alliance), 1 June 2011

In May 2011, the Queensland Petroleum Gas (Production and Safety) Act 2004 was amended to introduce a Prospective Gas Production Land Reservation Policy to secure Queensland's future domestic gas requirements. As a result of the amendments, a future call for tenders for petroleum exploration acreage may stipulate that the licence is subject to an "Australian market supply condition". This is a condition that gas produced from a resulting production licence must be supplied exclusively to the domestic market. There are certain exemptions to the domestic supply requirement, including if market analysis indicates that sufficient gas may be produced from existing and proposed Queensland gas developments to supply both the domestic market and export demand.

The changes have been welcomed by Queensland's energy and resources sector, which was concerned that the government would opt for an alternative gas reservation policy that would require a proportion of all Queensland gas production to be supplied to the domestic market – similar to the position adopted in Western Australia.

Ownership of gas reserves is vested in the state which issues exploration and production licenses. Exploration and development is usually carried out under joint venture arrangements. Joint ventures partners seek to market their gas on common terms and conditions, including price, and usually sign long-term sales contracts with gas utilities and other large customers[30]. Natural gas production facilities as well as transmission and distribution networks are all privately owned and operated.

Australia's gas markets have developed in response to governments' (both states and the commonwealth) reforms over the past two decades. A major outcome of the reforms has seen a move from state owned vertically integrated monopoly transmission/distribution/retail firms to the formation of competitive national market structures with private sector investment and participation[31]. The firms operating the transmission and distribution networks who have the potential to be natural monopolies are regulated through access arrangements which ensure that third parties are allowed access to these infrastructures with reasonable terms and conditions[32].

The domestic gas market is made up of three regions: Eastern market ((Queensland, New South Wales, Australian Capital Territory, South Australia and Tasmania); Western market (Western Australia); and Northern market (Northern Territory). The three markets are isolated geographically and this makes interconnection costly and uneconomic. Wholesale gas is sold mostly under confidential long-term contracts between producers, pipeline operators, major users and retailers.

[30] http://www.accc.gov.au/content/index.phtml/itemId/6018
[31] Draft Energy White Paper, 2011
[32] http://www.aph.gov.au/library/pubs/rp/2007-08/08rp25.htm

In order to increase the flexibility of market participants in buying and selling gas, the Victorian Wholesale Gas Market was established in 1999. About 10 to 20% of wholesale volumes in Victoria consist of gas traded at the spot price while the balance is made up of bilateral contracts or vertical ownership arrangements between producers and retailers. A short term trading market (STTM) was launched in September 2010 in the metropolitan hubs of Sydney and Adelaide as a day-ahead wholesale spot market for gas that aims to increase price transparency and improve efficiency and competition within the gas sector[33].

The National Gas Market Bulletin Board (BB) was established in 2008 to provide transparent, real-time information to gas customers, small market participants, potential new entrants and market observers on the state of the gas market, system constraints and market opportunities. It is a website that covers major gas production plants, storage facilities, demand centres and transmission pipelines in southern and eastern Australia. There is provision for facilities in Western Australia, the Northern Territory and north Queensland to participate in the future[34]. The Victorian wholesale market, the STTM and the BB are operated by the Australian Energy Market Operator (AEMO) with regulatory oversight by the AER to ensure compliance with the national gas rules.

4.7. Similarities to Israel

There are some similarities between Australia and Israel:

- Israel and Australia have national policies on developing natural gas as a primary energy source
- Both countries have large gas-based electricity generation sectors
- Natural gas supply is dominated by private enterprises in both countries
- Both Australia and Israel promote private-sector driven investment and development along the natural gas value chain

4.8. Differences to Israel

There are some differences between Australia and Israel:

- There are no restrictions on space for construction of facilities in Australia unlike Israel which has limited area available for terminal construction
- Australia does not import natural gas while Israel imports gas from Egypt.
- About 50% of Australia's gas production is exported and electricity accounts for 38% of domestic gas consumption. All of Israel's gas

[33] Energy in Australia, 2011
[34] State of the Energy Market 2010

production is consumed locally and electricity generation accounts for 90% of demand.
- Australia has no state (Federal) participation at any point along the natural gas value chain and the transmission/distribution networks are privately owned and operated competitively. Israel Natural Gas Lines (INGL) is a state-owned company that owns and operates national gas transmission networks and they monopolize gas transmission in Israel
- Israel's gas import is via pipelines while Australia only exports LNG.

4.9. Lessons Leant

The following are the main lessons:

- The Federal Government considered calls for a national gas reservation policy to assure adequate domestic supply but the Australian Government believes this is unwarranted
- Western Australia is the most gas dependent economy in Australia and the State has imposed a policy of seeking a 15% domestic gas reservation from all gas projects, but applies it flexibly and considers the project's commercial viability
- Australia pursues a policy of timely and competitive upstream gas development to prepare for increased gas demand. In order to achieve this, the government is considering changes to the lease retention arrangements so as not to indefinitely warehouse petroleum resources
- The Australian Energy Regulator is monitoring market dynamics and the issuing of production licences to assess policy outcomes given growing domestic gas usage

5. Azerbaijan

5.1. Key Issues

Although Azerbaijan only became a net gas exporter in 2007, the State Oil Company of Azerbaijan (SOCAR) built strong ties with new markets and aimed at a geographical spread of consumers to counterbalance the monopolistic position of Russia as a gas buyer and transporter. Azerbaijan's longer term aim is to monetise its gas assets by selling directly into the more lucrative competitive European gas markets.

Azerbaijan's proven gas reserves are estimated at 1,300 bcm, however a much greater volume of reserves is expected to be found. According to SOCAR the total volume of gas production in the country will reach 35-40 bcm by 2015. Shah Deniz II will add some 16 bcm of gas per year after 2017. By 2018 the annual total volume of gas production will reach up to 50 bcm. Azerbaijan generally prioritises gas for the development of its domestic economy and to substitute for crude oil which is more valuable as an export product, hence SOCAR announced that out of this amount, 30% will be kept for domestic consumption, which is expected to increase slightly until 2030, while 70% (30-35 bcm) will be available for export[35]. This proposed split of annual production between domestic consumption and exports is only expected to apply after 2017 once the second stage of Shah Deniz is operational.

Azerbaijan set up a sovereign wealth fund (SWF) in 1999, initially for its oil revenues but later for the gas as well. All government proceeds from the production sharing agreements are transferred to the SWF.

A key issue that Azerbaijan has confronted was the long lasting conflict with Turkey to secure transit of its gas to Europe (instead of selling gas to Turkey who would then on-sell it to Europe). The negotiations ended on 25 October 2011 with Turkey agreeing to buy some Azeri gas from the Shah Deniz II field and while allowing SOCAR to directly transport further quantities through its territory to Europe[36]. The Trans Andalou line is planned to start in 2017 and will initially carry 10 bcm per year which can be increased to 24 bcm per year at a later stage.

5.2. Basic Data

5.2.1. Proven Reserves

As at 31 December 2010 Azerbaijan had 1,300 bcm of proven gas reserves. No information is available on the status of reserves as at 31 December 1990.

The Shah Deniz Field, which was recently discovered and exploited, is estimated to have reserves of 1,000 bcm of gas[37]. Since its exploitation the rate of gas production has increased rapidly converting Azerbaijan from a net importer to a net exporter of gas.

However, the majority of offshore Azerbaijani reserves in the Caspian Sea have not been well explored yet. The planned exploration will only cover 30 out of more than 130 prospective gas fields.

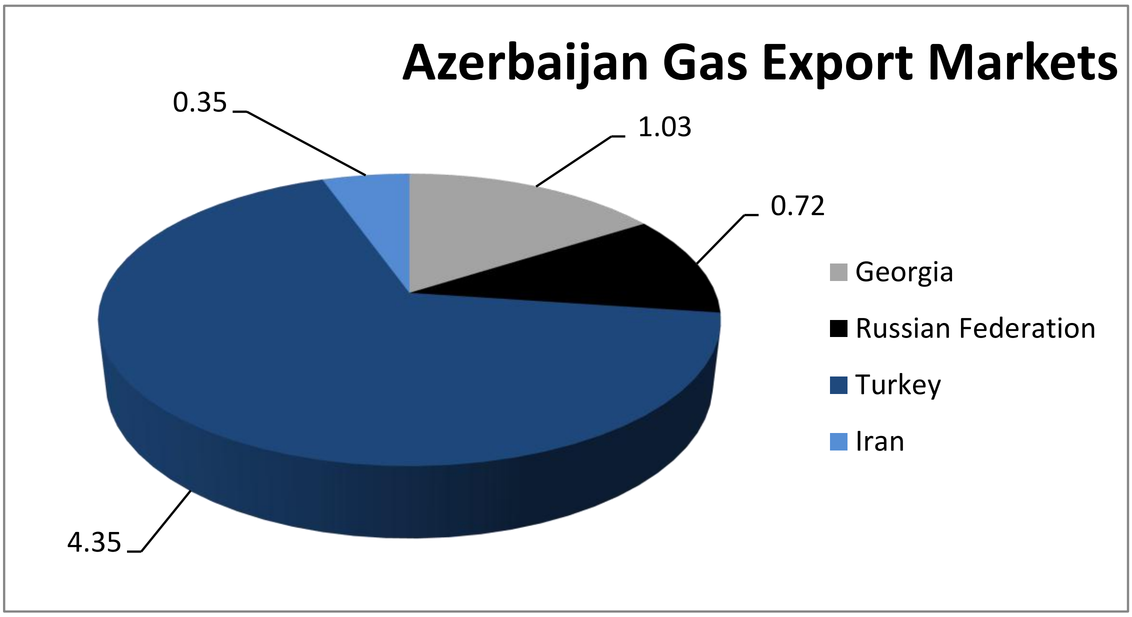
5.2.2. Exports

Total exports in 2010 were 6.45 bcm, all of which were via pipeline. By far the largest export market is Turkey which accounts for 67% of total exports, as shown in Figure 19. This is followed by Georgia, Russia and Iran. Turkey has very limited natural gas reserves and, thus, it mainly depends on imports to cover its domestic consumption needs. Turkey has a 9% share in the exploitation of the Shah Deniz II field and is expected to increase its imports of Azeri gas once Shah Deniz II comes into production.

---

[35] Stanislav Pritchin (2011) Azerbaijan’s new gas strategy, Turkish Policy Quarterly, available at: http://www.turkishpolicy.com/dosyalar/files/123-127.pdf
[36] Eurasianet (2011) Turkey: Gas Transit Deal with Azerbaijan Shakes up regional Energy Politics, available at: http://www.eurasianet.org/node/64536
[37] Dr. Vilayat Valiyev (2008) Azerbaijan Gas Sector Update, available at: http://www.narucpartnerships.org/Documents/Azeri%20gas%20sector_Valiyev.pdf

Figure 19 Azerbaijan Gas Export Markets (bcm)



Source: BP Statistical Review of World Energy, June 2011

5.2.3. Production

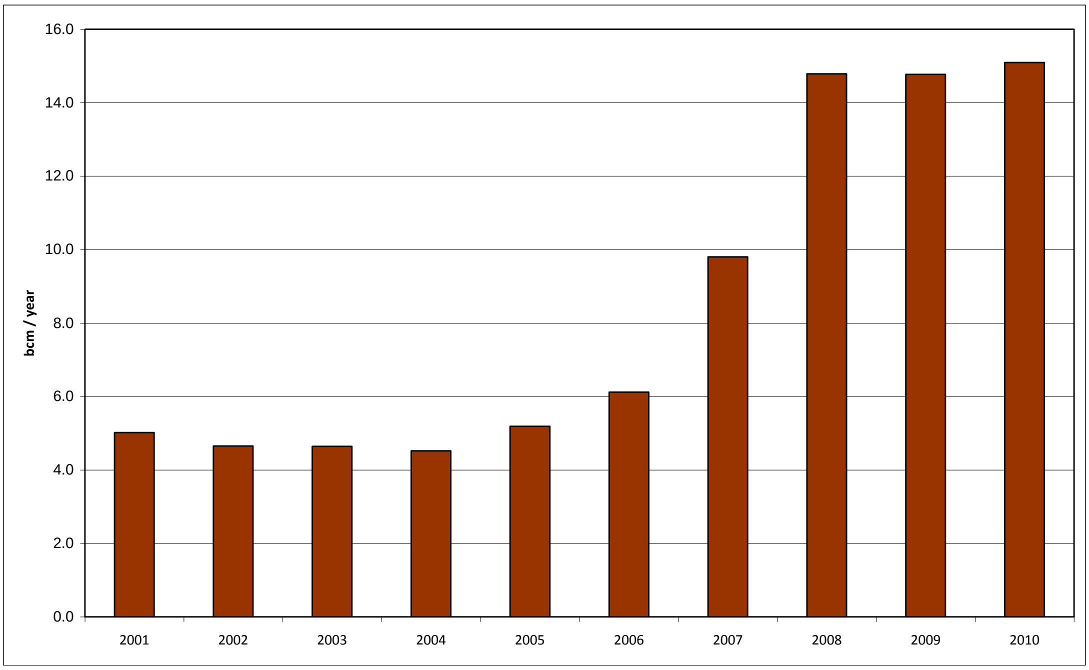
Gas production in 2010 was 15.1 bcm and it has increased significantly since 2006. Details of the production are shown in Table 8 and Figure 20.

Table 8 Azerbaijan Gas Production (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
5.0	4.7	4.6	4.5	5.2	6.1	9.8	14.8	14.8	15.1

Source: BP Statistical Review of World Energy, June 2011

Figure 20 Azerbaijan Gas Production



Source: BP Statistical Review of World Energy, June 2011

5.2.4. Consumption

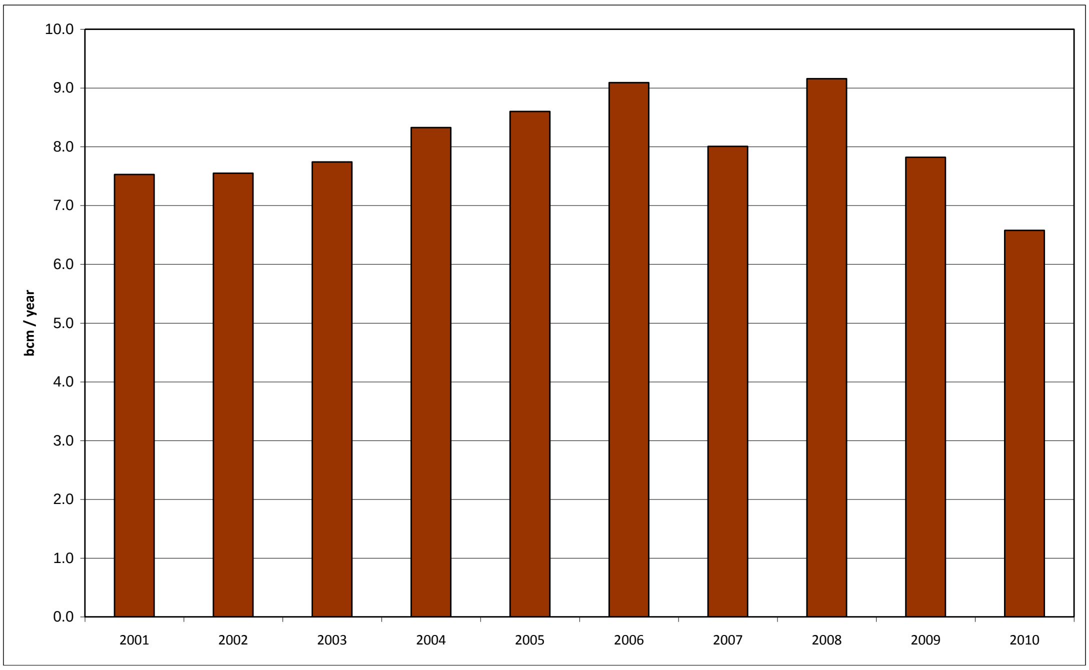
Gas consumption in 2010 was 6.6 bcm and it has been growing steadily until 2008 when it started declining as shown in Table 9 and Figure 21.

Table 9 Azerbaijan Gas Consumption (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
7.5	7.5	7.7	8.3	8.6	9.1	8.0	9.2	7.8	6.6

Source: BP Statistical Review of World Energy, June 2011

Figure 21 Azerbaijan Gas Consumption



Source: BP Statistical Review of World Energy, June 2011

5.2.5. Reserves/Production

The reserves/production ratio is 1300/15.1 = 86 years.

5.2.6. Reserves/Consumption

The reserves/consumption ratio is 1300/ 6.6 = 197 years

5.2.7. Natural Gas Rents (% of GDP)

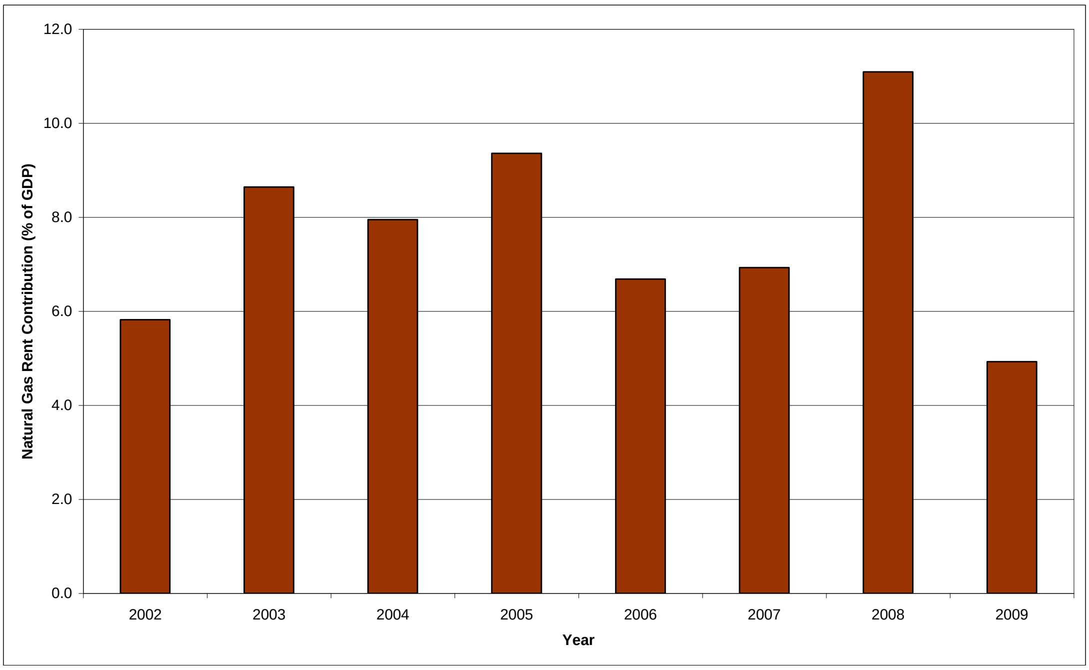
The contribution of natural gas rents to Azerbaijan's GDP is shown in Table 10 and Figure 22.

Table 10 Azerbaijan Natural Gas Rents (% of GDP)

2002	2003	2004	2005	2006	2007	2008	2009
5.8	8.6	8.0	9.4	6.7	6.9	11.1	4.9

Source: World Bank

Figure 22 Azerbaijan Natural Gas Rents (% of GDP)



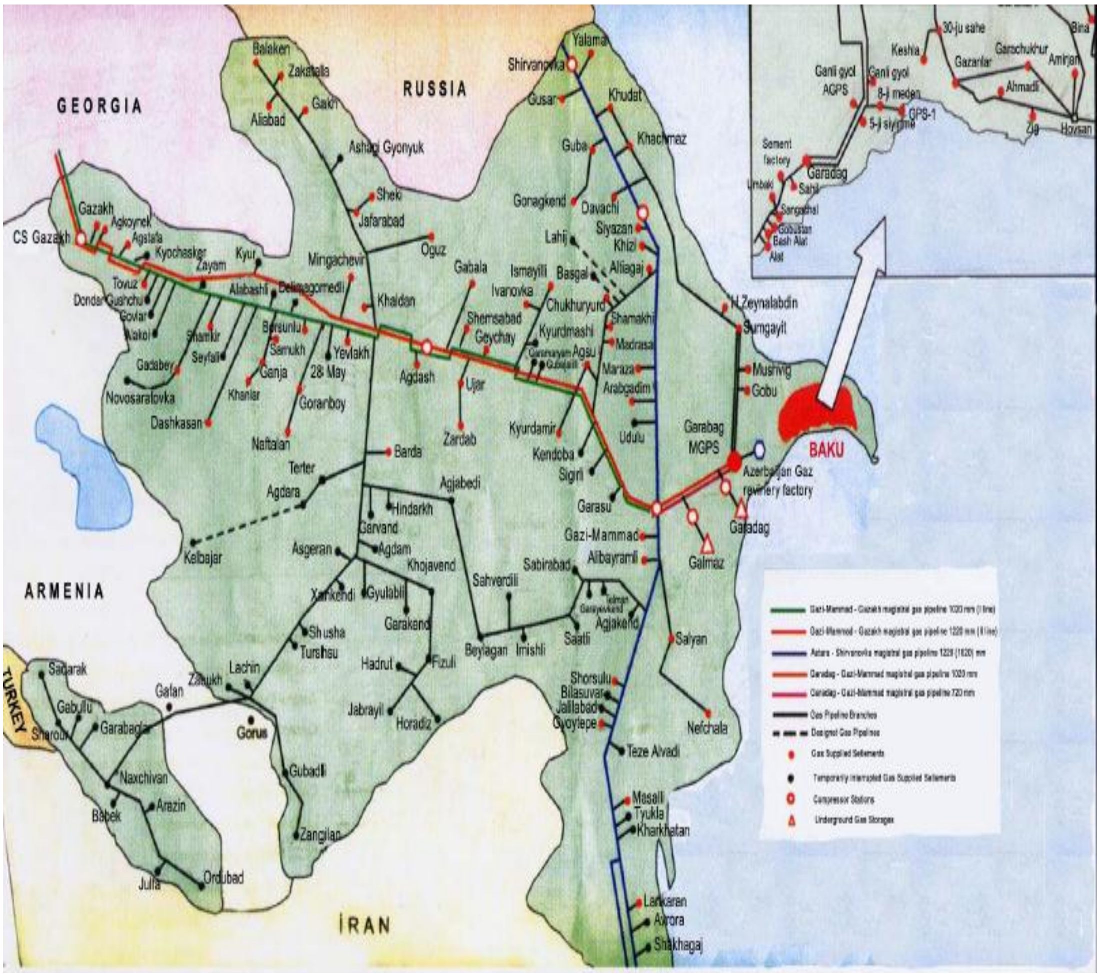
Source: World Bank

5.3. Gas Production Facilities

Gas production is almost exclusively from offshore fields. The largest gas fields are the ACG and Shah Deniz, which only began operation in 2007. The Guneshli field, part of the ACG oil and gas fields system, provides gas to the Azerigaz system for domestic use via an undersea gas pipeline to the Sangachal Terminal at Baku[38].

[38] Inogate (2011) Azerbaijan: Energy Sector Review, available at: http://www.inogate.org/index.php?option=com_inogate&view=countrysector&id=10&Itemid=63&lang=en

Figure 23 Azerbaijan Gas Facilities



Source: Dr. Vilayat Valiyev, Azerbaijan Gas Sector Update, NARUC, 2008

5.4. Gas Export and Import Facilities

Azerbaijan's production of natural gas before 2007 was not enough to cover its domestic needs and the shortfall was covered exclusively by Russian gas imports. The level of imports for 2005 and 2006 was almost 4.5 bcm[39]. However the discovery of the Shah Deniz gas field and its development led to Azerbaijan becoming a net exporter of gas.

Gas is exported to Georgia and Turkey using the South Caucasus Pipeline (SCP). In 2008, 5.5 bcm of gas were exported via the SCP.[40] The SCP pipeline is 690 km long and runs parallel to the BTC oil pipeline for most of its route, as shown in Figure 24, before connecting to the Turkish pipeline

[39] Inogate (2011) Azerbaijan: Energy Sector Review, available at: http://www.inogate.org/index.php?option=com_inogate&view=countrysector&id=10&Itemid=63&lang=en

[40] EBRD (2011) Azerbaijan Energy Country Profile, available at: www.ebrd.com/downloads/legal/irc/countries/azerbaijan.pdf

network at Horasan. The current capacity of the SCP pipeline is 6.6 bcm per year which is projected to increase to 19.8 bcm with the addition of compression stations. Gas was also exported to Russia in 2010, via the Gazimamed- Mozdok gas pipeline.

Figure 24 Azerbaijan South Caucasus Pipeline

Source: BP

Shah Deniz II is a giant project that will bring gas from Azerbaijan to Europe and Turkey. This will increase gas supply and energy security to European markets through the opening of the new southern gas corridor. The project is expected to add a further 16 bcm per year of gas production to the approximately 9 bcm from Shah Deniz I. It is one of the largest gas development projects anywhere in the world.

Proposals for the transportation of gas from the Caspian Sea to Europe are now being evaluated by the Shah Deniz consortium. Bids were submitted from Nabucco, Trans-Adriatic Pipeline and IGI-Poseidon. However a fourth pipeline is being progressed which is called the Trans Anadolu pipeline[41]. The line is planned to start in 2017 and will initially carry 10 bcm per year which can be increased to 24 bcm per year at a later stage. The consortium has a Turkish involvement of 20% and an Azeri involvement of 80%. Azerbaijan is

[41] Today's Zaman, 26 December 2011

represented by SOCAR; the Turkish side by the sate owned BOTAS and the Turkish Petroleum Corporation. International oil companies will be allowed to join the consortium in the construction stage.

5.5. Industry Organisation

All the institutions, related to the production and distribution of gas, are currently state owned. The majority of the country's gas production takes place at Shah Deniz fields by SOCAR. SOCAR is the publicly owned oil and natural gas corporation of Azerbaijan and is among the largest oil companies in the world. It is responsible for the running of gas pipelines and oil refineries in Azerbaijan. It was established in 1992 after the merger of Azerbaijan's two state oil companies, Azerneft and Azneftkimiya.

SOCAR is responsible for the exploration, preparation, exploitation of onshore and offshore gas fields in the Republic of Azerbaijan, as well as transportation, processing, refining and sale of gas.[42] SOCAR is also a big source of employment as it currently employs around 60,000 people[43]. SOCAR also has a considerable share in the two major export pipelines, namely the Baku-Tbilisi-Ceyhan (25%) and the South Caucasus Pipeline (10%). It also has shares in the Baku- Supsa pipeline and the Baku-Novorossiysk pipeline.

5.6. Gas Regulatory Structure

The medium and long term fuel and energy balance in the domestic market is monitored by Azerigaz, the Ministry of Industry and Energy (MIE) and the Ministry of Economic Development. The regulatory authority has an active role in forecasting expected demand.

Azerigaz is the responsible authority for investments in the pipeline network and in the gas transportation system. Azerigaz is also responsible for developing operating and planning standards for cross-border exchanges[44].

The Subsoil Law of 13 February 1988 regulates the process of production, processing, transportation, storage, distribution and sale of oil and gas. According to this law, only Azerigaz is allowed to have access to the grid, while individual suppliers are now allowed to sell gas directly to consumers.

In the absence of a production sharing agreement law and a law on petroleum every oil and gas concession in the form of a production sharing agreement is approved into the law of Azerbaijan prevailing over any other conflicting Azerbaijani law.

---

[42] Azerbaijan portal (2011) SOCAR, available at: http://www.azerbaijan.az/portal/StatePower/Committee/committeeConcern_01_e.html
[43] SOCAR website (2011) About us, available at: http://www.socar.az/about-en.html
[44] EBRD (2009) Azerbaijan country profile, available at: http://www.ebrd.com/downloads/legal/irc/countries/azerbaijan.pdf

The Energy Resources Law of 30 May 1996 provides the social, economic and legal basis of state policy in energy resource use.

The State Oil Fund of Azerbaijan was set up in 1999 to accumulate and manage Azerbaijan oil and gas revenues. This Fund may be categorized as a savings fund for future generations, which diversify portfolio assets from a non-renewable resource and manage the effects of Dutch disease. The Fund primarily invests foreign currency and assets generated from oil and gas exploration and development in investment-grade securities such as government agency bonds, corporate bonds, and mortgage-backed securities.

According to its Investment Policy, up to 60% of the Fund's investment portfolio can be managed by external managers. The assets given to an external manager cannot exceed 15% of total amount of the investment portfolio. The Fund was $22.8 billion as at 31 December 2010.

The fund is directed towards the following objectives:

- Preservation of macroeconomic stability, ensuring fiscal tax discipline, decreasing dependence on oil and gas revenues and stimulating development of the non-oil sector
- Considering that oil and gas are depletable resources ensuring inter-generational equality with regard to the country's oil wealth and accumulate and preserve oil and gas revenues for future generations
- Financing major national scale projects to support socio-economic progress

5.7. Similarities to Israel

There are some similarities between Azerbaijan and Israel:

- Both Israel and Azerbaijan are small countries with populations of 8.3 million and 8.7 million respectively.
- Both countries have successfully encouraged international companies to invest in, and develop, their hydrocarbon resources[45]
- The two countries are also similar in terms of their strategic geographic position with Israel having direct access to the Mediterranean Sea and Azerbaijan having direct access to the Caspian Sea. However, both face difficulties in developing export routes to the major markets
- Both countries have large resources relative to domestic needs, but immediate neighbours with whom gas trade at internationally competitive prices is (highly) problematic.

[45] The 'Contract of the Century' was signed between the Azeri Government and a consortium of oil companies in 1994 to develop the huge Azeri-Chirag-Guneshli field

- Both countries have difficult regional political situations and security risks with Israel having well documented regional problems and Azerbaijan having particular problems with Russian activity near its transit lines in Georgia

5.8. Differences to Israel

There are some differences between Azerbaijan and Israel:

- Azerbaijan has reserved a significant role for the state in its oil and gas industry
- Azerbaijan has set up a sovereign wealth fund for hydrocarbon revenues
- The latest export system has been developed initially through a Turkish-Azerbaijan state arrangement although the international oil companies will be allowed to join at a later date
- Azerbaijan has developed gas export pipeline routes involving transit countries such as Georgia and Turkey

5.9. Lessons Leant

The following are the main lessons:

- Azerbaijan has used state involvement to develop its transit routes particularly when inter-governmental agreements are required
- Upstream development is strongly linked to export markets; the large Shah Deniz II development will only be sanctioned once export contracts are agreed as the domestic market is already served by existing fields
- Consideration should be given to the establishment of a sovereign fund for funds from oil and gas production

6. Canada

6.1. Key Issues

Canada is the second largest natural gas producer in the world after the United States. Proven natural gas reserves as of 31 December 2010 were 1700 bcm.

In Canada, natural gas is used primarily in the residential and commercial sectors for heating. In the industrial sector natural gas is used for process heat in the production of chemicals, and for generation of electricity. The country's natural gas is found in sedimentary basins either onshore or offshore[46].

[46] Crude Oil and Natural Gas Resources, Natural Resources Canada: Atlas of Canada

One of the key issues with Canada could be the management of natural gas reserved within the country over the next decade, with regards to consumption and export of the resource.

6.2. Basic Data

6.2.1. Proven Reserves

As at 31 December 2010 Canada had 1700 bcm of proven gas reserves which compares with 2700 bcm as at 31 December 1990.

6.2.2. Exports

Total exports in 2010 were 92.40 bcm of which all 92.40 bcm were via pipeline. The only export market was the United States of America.

6.2.3. Production

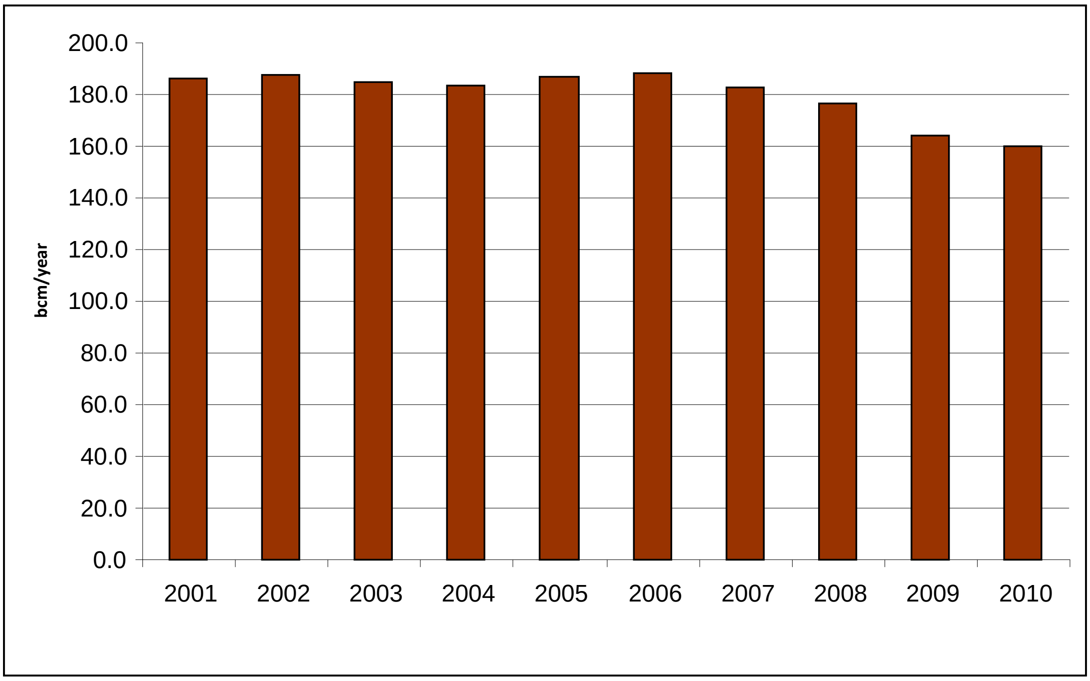
Gas production in 2010 was 159.8 and it has been reasonably stable over the last ten years. Details of the production are shown in Table 11 and Figure 25.

Table 11 Canada Gas Production (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
186.5	187.9	184.7	183.7	187.1	188.4	182.5	176.4	163.9	159.8

Source: BP Statistical Review of World Energy, June 2011

Figure 25 Canada Gas Production



Source: BP Statistical Review of World Energy, June 2011

6.2.4. Consumption

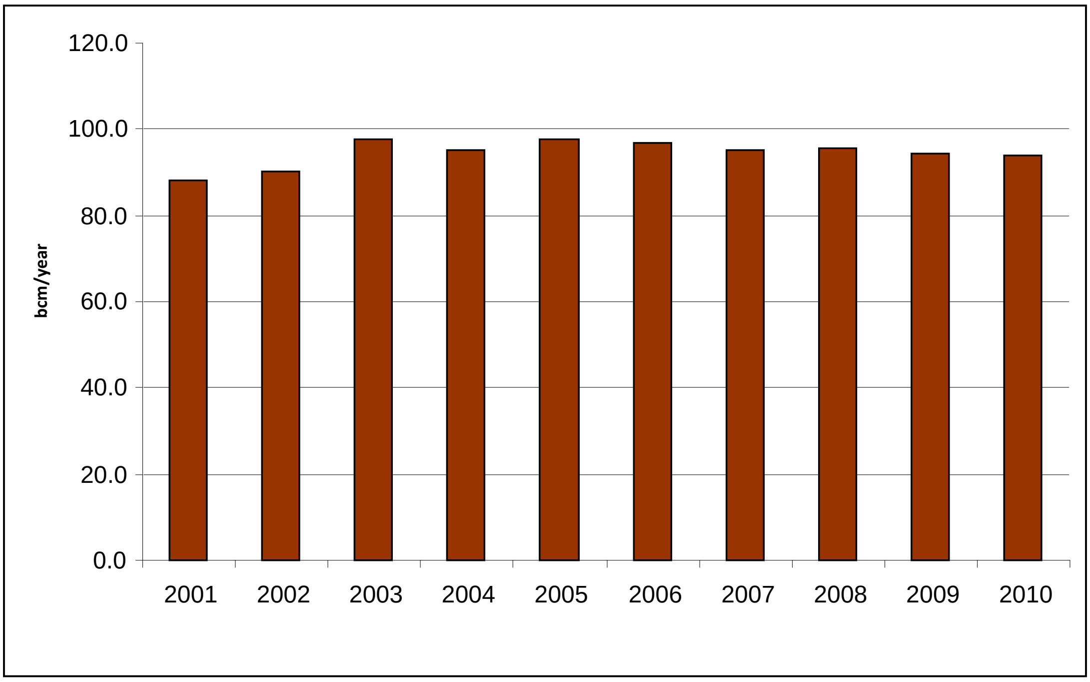
Gas consumption in 2010 was 93.8 bcm and consumption has been reasonably stable since 2001 as shown in Table 12 and Figure 26.

Table 12 Canada Gas Consumption (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
88.2	90.2	97.7	95.1	97.8	96.9	95.2	95.5	94.4	93.8

Source: BP Statistical Review of World Energy, June 2011

Figure 26 Canada Gas Consumption



Source: BP Statistical Review of World Energy, June 2011

6.2.5. Reserves/Production

The reserves/production ratio is 1700/159.8 = 11 years.

6.2.6. Reserves/Consumption

The reserves/consumption ratio is 1700/93.8 = 18 years

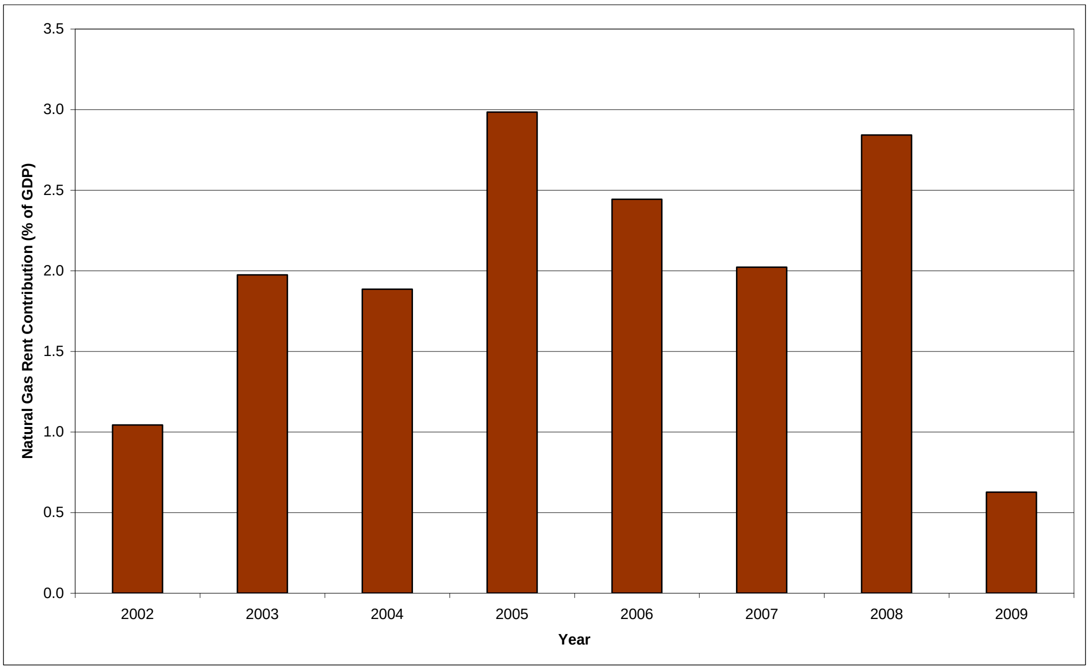
6.2.7. Natural Gas Rents (% of GDP)

Natural gas contributes to Canada's GDP as shown in Table 13 and Figure 27.

Table 13 Canada Natural Gas Rents (% of GDP)							
2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
1.0	2.0	1.9	3.0	2.4	2.0	2.8	0.6

Source: World Bank

Figure 27 Canada Natural Gas Rents (% of GDP)



Source: World Bank

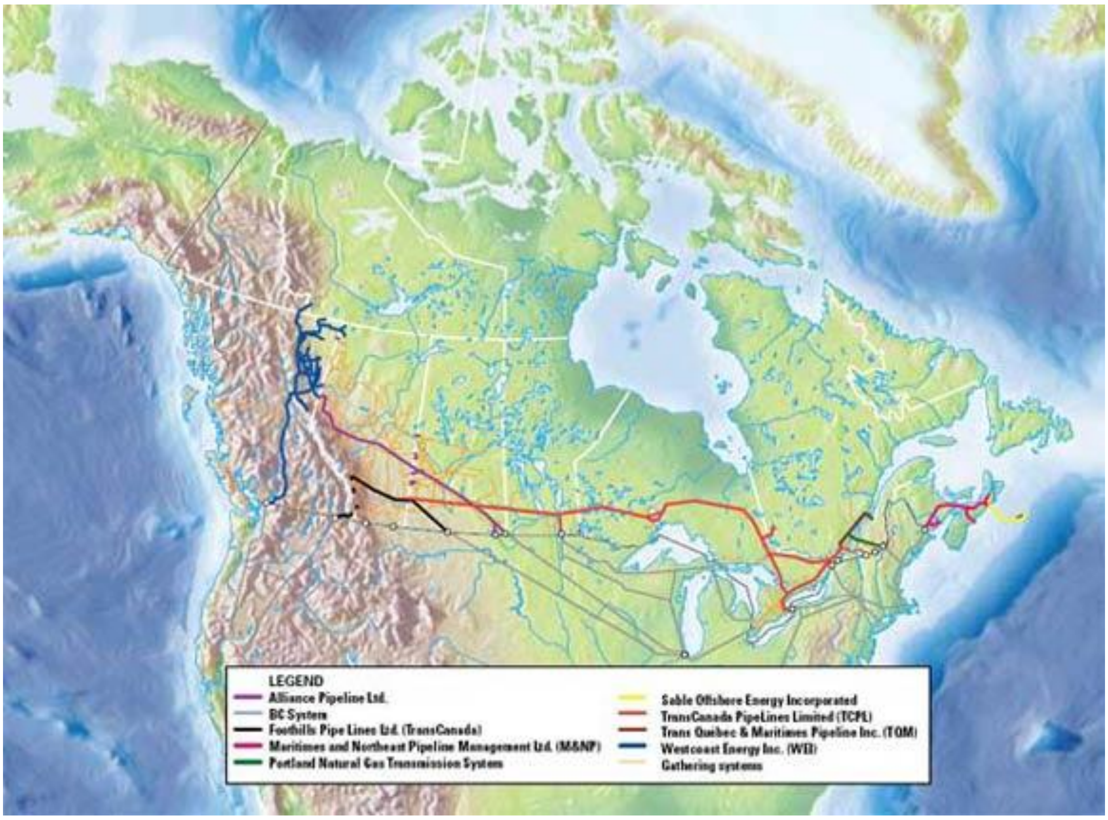
6.3. Gas Production Facilities

In Canada, the main gas-producing area is the Western Canadian Sedimentary Basin, with Alberta, British Columbia and Saskatchewan accounting for 83%, 13% and 4% of its production respectively. In Ontario, the southern Yukon and Northwest Territories, minor onshore established reserves also exist.

Offshore production at Sable Island, Nova Scotia) commenced in 1999. The Hibernia Project (offshore Newfoundland and Labrador) also produces natural gas, which is used for on-site operations and reservoir injection.

There is a large gas pipeline network in Canada shown in Figure 28 which is regulated by the National Energy Board (NEB).

Figure 28 Canada Natural Gas Pipelines



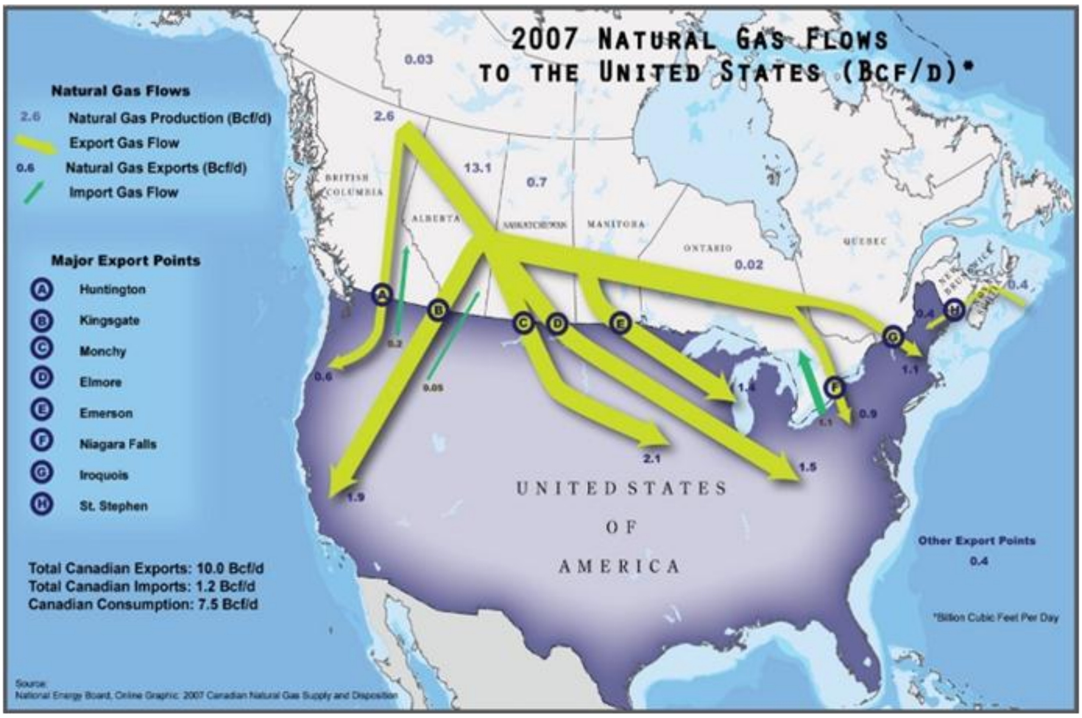
Source: National Energy Board

6.4. *Gas Export and Import Facilities*

Figure 29 shows the exports of gas from Canada to the USA. The main destinations for the exports are the Central, Midwest and Pacific Northwest regions. Canada also imports natural gas from the United States (for example, in Ontario) where and when it is cheaper to obtain than from Western Canada and to take advantage of existing pipeline infrastructure and storage facilities[47].

[47] Crude Oil and Natural Gas Resources, Natural Resources Canada: Atlas of Canada

Figure 29 Canada Natural Gas Exports (bcfd)



Source: National Energy Board.

Although gas production in Canada is much lower than that of the USA, Canada consumes significantly less than it produces allowing it to export the surplus to the USA.

Canada currently has one operating LNG import facility, the Canaport terminal in Saint John, New Brunswick. There is a proposed LNG export facility in the Port of Kitimat, British Columbia[48].

Canada first exported natural gas in 1891 from the Bertie-Humberstone field in Welland County to Buffalo, New York. Gas was later exported to Detroit from the Essex field through a 20cm diameter pipeline under the Detroit River. In 1897, the pipeline stretched the Essex gas supply to its limit with the extension of exports to Toledo, Ohio. This prompted the Ontario government to revoke the licence for the pipeline and in 1907 the province passed a law prohibiting the export of natural gas and electricity.

By early 1930, there was talk of a pipeline from Turner Valley to Toronto. A parliamentary committee looked into ways to inject gas down old wells, set up carbon black plants or export the gas to the United States. Another proposal called for the production of LNG.

[48] Liquefied Natural Gas, Natural Resources Canada, www.nrcan.gc.ca

Further discoveries in Alberta led to the demand from the producers to export gas to the USA. Before giving approval, the provincial government appointed the Dinning Natural Gas Commission to inquire into Alberta's likely reserves and future demand. In its March 1949 report, the Dinning Commission supported the principle that Alberta should have first call on provincial natural gas supplies, and that Canadians should have priority over foreign users if an exportable surplus developed. Alberta accepted the recommendations of the Dinning Commission, and later declared it would only authorise exports of gas in excess of a 30-year supply.

Shortly thereafter, Alberta's Legislature passed the Gas Resources Conservation Act, which gave Alberta greater control over natural gas at the wellhead, and empowered the Conservation Board to issue export permits. This led to the creation of the Alberta Gas Trunk Line (AGTL), which gathered gas from wells in the province and to deliver it to exit points.

There were many reasons for the creation of AGTL. One was that the provincial government considered it sensible to have a single gathering system in Alberta to feed export pipelines, rather than a number of separate networks. Another was that pipelines crossing provincial boundaries and those leaving the country fall under federal jurisdiction. By creating a separate entity to carry gas within Alberta, the provincial government stopped Ottawa's authority at the border.

The federal government, like Alberta, treated natural gas as a resource that was so important for national security that domestic supply needed to be guaranteed into the foreseeable future before exports would be allowed.

Westcoast Transmission Co. Ltd. was the first applicant to receive permission to export gas from Alberta in 1951 although its initial application was rejected. Westcoast received permission in 1952 to take 1.4 bcm/year of gas out of the Peace River area of Alberta for five years. The company subsequently made gas discoveries across the border in British Columbia which further supported the scheme. However, the United States Federal Power Commission (later the Federal Energy Regulatory Commission) rejected the Westcoast proposal for imports to the USA. Westcoast returned with a revised proposal, found a new participant in the venture, and received FPC approval. Construction began on Canada's first major gas export pipeline.

The regulatory process for Transcanada Pipeline Ltd (TCPL) proved long and arduous. After rejecting proposals twice, Alberta finally granted its permission to export gas from the province in 1953.

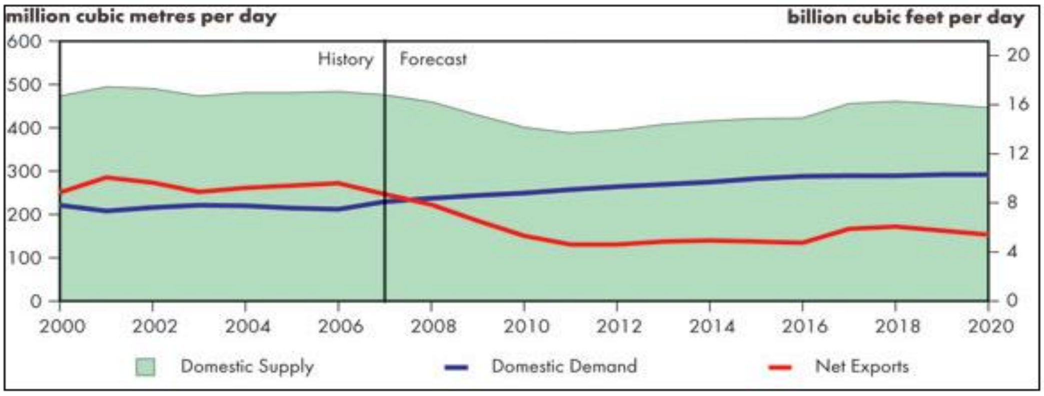
At first, the province waited for explorers to prove gas reserves sufficient for its thirty-year needs, intending to only allow exports in excess of those needs.

After clearing this hurdle, the federal government virtually compelled TCPL into a merger with Western pipelines. When this reorganized TCPL went before the Federal Power Commission for permission to sell gas into the United States, the Americans welcomed it [49] [50] [51].

Not until the implementation of the Canada-United States Free Trade Agreement (signed in 1988) did natural gas become a freely traded commodity between the US and Canada.

NEB prepared a forecast of the future use of Canada's gas[52] which is shown in Figure 30. This indicated that supply would be reduced in the future although demand continues to rise slowly giving an overall reduction in net exports.

Figure 30 Canada NEB Gas Forecast



Source: NEB

6.5. *Industry Organisation*

There are hundreds of oil & gas companies operating inside Canada varying from large international players such as Encana to small junior players based in Alberta.

The process of rights issuance is based on a bidding system. It is an industry-driven process and the bidding system is based on a single criterion; generally the amount of money a company will commit to explore a particular parcel and drill an exploration well in the first five years. The company bidding the greatest amount of money for a parcel is awarded the license.

---

[49] Earle Gray. Ontario's Petroleum Legacy: The birth, evolution, and challenges of a global industry (Edmonton: Heritage Community Foundation) 2008
[50] Quoted in Peter McKenzie-Brown, Gordon Jaremko, David Finch, The Great Oil Age, Detselig Enterprises Ltd., Calgary; 1993
[51] History of the Petroleum Industry in Canada. http://en.wikipedia.org/wiki/History_of_the_petroleum_industry_in_Canada
[52] Canada's Energy Future: Infrastructure Changes and Challenges to 2020 - Energy Market Assessment

When an operator decides that it is appropriate to develop a hydrocarbon discovery, it must convert the rights into a Production Licence and get approval to develop from the regulator by submitting a Development Plan.

6.6. Gas Regulatory Structure

In Canada's federal system of government, jurisdiction over energy is divided between the federal and provincial and territorial governments. NEB is an independent federal regulatory agency that regulates the Canadian energy industry. Its primary responsibilities include:

- Inter-provincial and international oil and gas pipelines and power lines
- Export and import of natural gas under long-term licenses and short-term orders

Provincial regulation of oil and natural gas activities, pipelines, and distribution systems is administered by provincial utility boards. The producing provinces impose royalties and taxes on oil and natural gas production; provide drilling incentives; and grant permits and licenses to construct and operate facilities. The consuming provinces regulate distribution systems and oversee the retail price of natural gas to consumers.

6.7. Similarities to Israel

There are limited similarities between Canada and Israel:

- In the early days of the development of the industry there were calls for domestic consumption to be protected and exports limited
- Canada has a neighbour with large requirements for gas (USA) which is similar to the situation in Israel (Europe)

6.8. Differences to Israel

There are some differences between Canada and Israel:

- Producers are subject to both federal and provincial regulation in Canada whereas in Israel there is a single level of regulatory authority
- Canada has extremely cold winters and gas is very important in heating
- Canada has limited requirements for its gas and is able therefore to export significant quantities
- There are no controls on export from Canada to the USA now as there is a single free trade area whereas Israel has no such obligation
- Canada is reaching the point at which exports would be reduced into order to maintain domestic requirements

6.9. Lessons Leant

The following are the main lessons:

- Alberta maintained a policy of protecting its own gas consumption by requiring a reserve of 30 years to be kept. This policy was in force from 1953-88 and was only ended when Canada and the USA formed a free trade area.
- Public pressure in the early days of the industry forced producers only to export gas when domestic markets were ensured.

7. Egypt

7.1. Key Issues

With an annual domestic consumption of 45.1 bcm and LNG exports of 15.1 bcm in 2010, the Egyptian gas market is large. Domestic gas demand has seen rapid growth over the last decade and has more than doubled since 2000. The power generation sector, accounting for 55 % of total demand in 2010 and industrial sectors (through fuel switching and dual fuel usage) accounting for close to 25 % have been the key drivers of gas demand in Egypt over the past two decades.

Recent discoveries of large domestic natural gas reserves and falling oil production since the mid 1990's have been the main reasons for the government to promote the expansion of domestic natural gas markets. Traditionally an oil exporting country, Egypt was a net crude oil importer for the first time in 2010.

Egypt's natural gas production today far exceeds its domestic consumption and it has been a natural gas exporter since 2005, exporting between 25% and 30% of domestic production over the last few years. In 2010, 15.2 bcm were exported.

The initial decision to export gas was made as early as 1999 through the Government of Egypt's (GoE) Integrated Gas Strategy until 2017. Falling oil exports, the associated reduced inflow of foreign currency and growing global natural gas demand were the main drivers for the decision to be taken. Increased gas exports would enable the petroleum sector to meet its liabilities to foreign partners and the additional revenues allowed Egypt to import the rest of the domestic market needs of LPG and gasoil. The policy of actively exporting gas would also significantly increase Foreign Direct Investment in Egypt.

However, the priority of the government is to ensure that domestic gas market needs are met and to pursue an increased gasification strategy. The initial Gas Strategy therefore limited gas exports at 25% of domestic gas production capacity and only allowed exports for foreign investors under the premise that they also invest in local distribution companies. The Strategy was revised in 2000 and now sets the limits of gas exports to 33% of the gas reserve base. The remaining gas reserves have to be equally split between domestic consumption (33%) and strategic reserve (33%). These limits are set out in the constitution and are valid until 2020.

More recently the GoE has reaffirmed its strategy to ensure that supplies to domestic market should be prioritised over exports. In 2008, amid increasing domestic demand levels and growing public pressure against gas exports (particularly to Israel), GoE announced that no new gas exports would be made until the end of 2010. This has lead to delayed plans for export infrastructure expansion, most notably the delay to the expansion of the LNG plant at Damietta. To date, the freeze on new export agreements is still in place and Egypt is seeking to renegotiate tariffs on existing export contracts with Israel and Jordan. Drilling activities in Egypt have been falling since 2008[53], it is likely that much of this can be attributed to export restrictions, although the period has also seen continuing low domestic gas prices, a global economic downturn and unprecedented political instability in Egypt.

A key issue for GoE is that domestic gas market prices are heavily subsidised. With increasing domestic demand levels, GoE will have to purchase a greater share of gas from its joint venture upstream partners. Even though the purchase price is reported to be capped at favourable (to GoE) prices (between $/MMBTU 3.5 and 3.65) [54], the low domestic gas tariffs[55] mean increasing budgetary pressures on GoE.

With proven reserves of 2,200 bcm and considering that 33% of strategic reserves have to be kept, sufficient gas reserves are in place until 2035[56]. If however, the allowed export limits are reached every year, the reserves would only last until 2025.

Besides the Levant region, the main potential export markets for Egyptian gas at the time the export decision was taken were South European gas markets. This resulted in the construction and expansion of LNG liquefaction plants at Damietta and Idku which have been in operation since 2004 and have a combined capacity of 18 bcm. Export pipelines to Israel and Jordan have a capacity of 9 and 10 bcm per year respectively. The pipeline export facilities are currently very underutilised, while the LNG facilities are operating at below average utilisation of around 80%.

[53] http://www.egyptoil-gas.com/read_article_issues.php?AID=404
[54] However, the recent discoveries and developments are in deep offshore waters where drilling and development is very expensive, in contrast to the very low cost onshore gas fields initially developed in Egypt
[55] Gas prices range between $/3MMBTU (energy intensive customers) and $0.9 /MMBTU (residential users)
[56] This assumes a compound annual growth rate of 1.7 % until 2030 based on Potential of Energy Integration in Mashreq and surrounding countries (ESMAP, June 2010).

7.2. *Basic Data*

7.2.1. Proven Reserves

The proven reserves in Egypt were 2,200 bcm as at 31 December 2010 and 400 bcm as at 31 December 1990..

Most fields are located in the Mediterranean off the Nile Delta region and in the Western Desert regions. The ultimate gas reserves may be higher than 2,200 bcm. The US Geological Survey estimates the GIIP resources in yet to be discovered offshore gas fields alone to be around 6,000 bcm[57]

7.2.2. Exports

In 2010, 15.2 bcm of natural gas or close to 25% of domestic production were exported. LNG accounted for 9.7 bcm of total exports with major offtake markets being Spain (2.6 bcm), the United States (2.1 bcm) and South Korea (1.0 bcm). In 2010, Egypt ranked tenth (out of sixteen) in the world in terms of LNG export volumes.

The remaining 5.5 bcm of 2010 exports were delivered through (i) the Arab gas pipeline to Jordan (2.5 bcm), Lebanon (0.2 bcm) and Syria (0.7 bcm) and (ii) the Arish-Ashkelon gas pipeline to Israel (2.1 bcm).

7.2.3. Production

Gas production levels in Egypt in 2010 were 61.3 bcm down from 62.7 bcm in 2009. Despite this drop in production, Egypt's gas production has shown a sharply increasing trend over the past decade approximately tripling from over the period 2000 to 2010. Details of the production are shown in Table 14 and Figure 31.

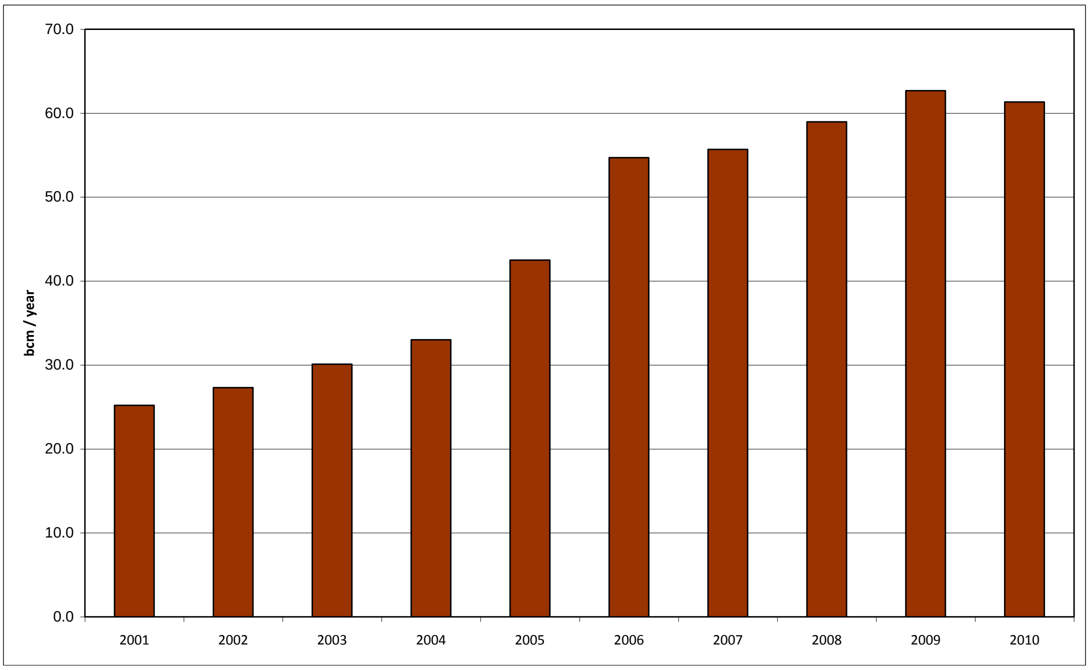
Table 14 Egypt Gas Production (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
25.2	27.3	30.1	33.0	42.5	54.7	55.7	59.0	62.7	61.3

Source: BP Statistical Review of World Energy, June 2011

[57] Egypt's waters hold Significant Untapped Gas Reserves, Rigzone 16 July 2010

Figure 31 Egypt Gas Production



Source: BP Statistical Review of World Energy, June 2011

7.2.4. Consumption

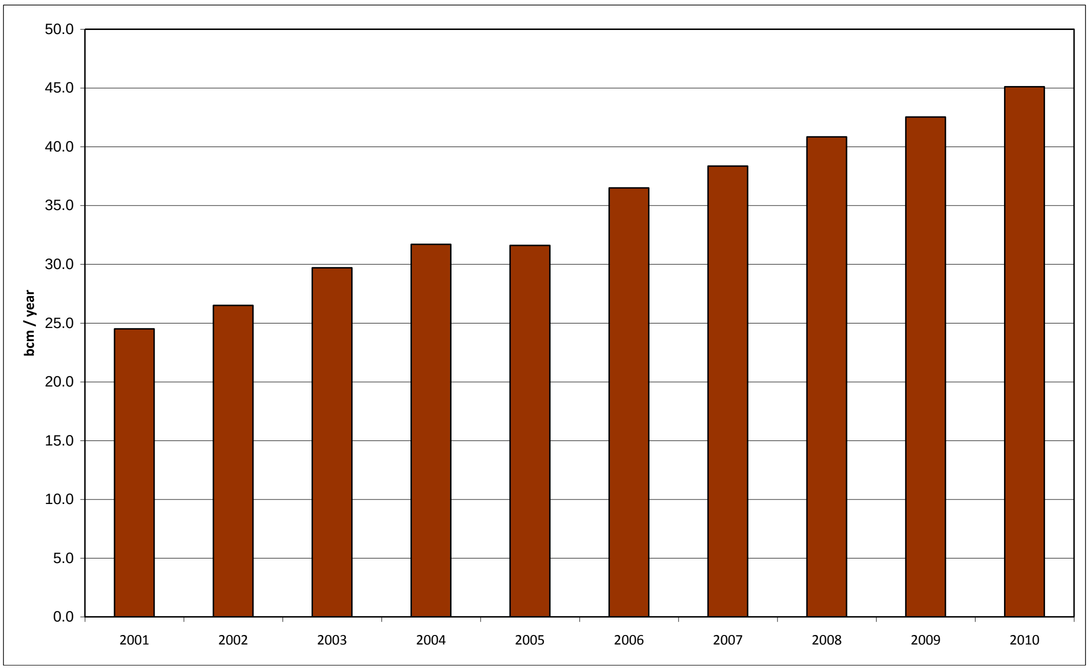
Gas consumption has shown a strongly increasing trend since 1995, more than doubling over the past decade reaching 45.1 bcm in 2010. Details of the consumption are shown in Table 15 and Figure 32.

Table 15 Egypt Gas Consumption (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
24.5	26.5	29.7	31.7	31.6	36.5	38.4	40.8	42.5	45.1

Source: BP Statistical Review of World Energy, June 2011

Figure 32 Egypt Gas Consumption



Source: BP Statistical Review of World Energy, June 2011

7.2.5. Reserves/Production

The reserves/production ratio is 2200/61.3 = 35.9 years.

However taking into account current regulations and future production levels proven gas reserves are more likely to last for just less than 20.2 years. Currently, and valid until 2020, only 66% of total reserves can be extracted with the rest having to be kept for strategic purposes

7.2.6. Reserves/Consumption

The reserves/consumption ratio is 2200/45.1 = 48.8 years

With increasing consumption levels in future and taking into account of the strategic reserve limitations, a more realistic ratio is 25.1 years.

7.2.7. Natural Gas Rents (% of GDP)

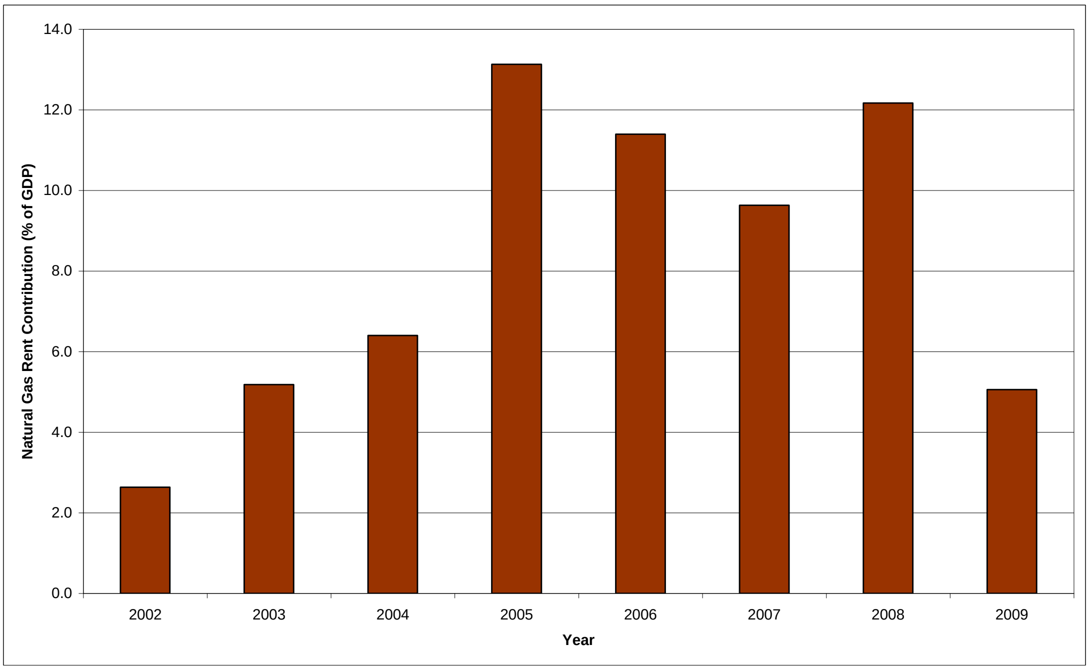
Natural gas rents' contributions to Egypt's GDP are as shown in Table 16 and Figure 33.

Table 16 Egypt Natural Gas Rents (% of GDP)

2002	2003	2004	2005	2006	2007	2008	2009
2.6	5.2	6.4	13.1	11.4	9.6	12.2	5.1

Source: World Bank

Figure 33 Egypt Natural Gas Rents (% of GDP)

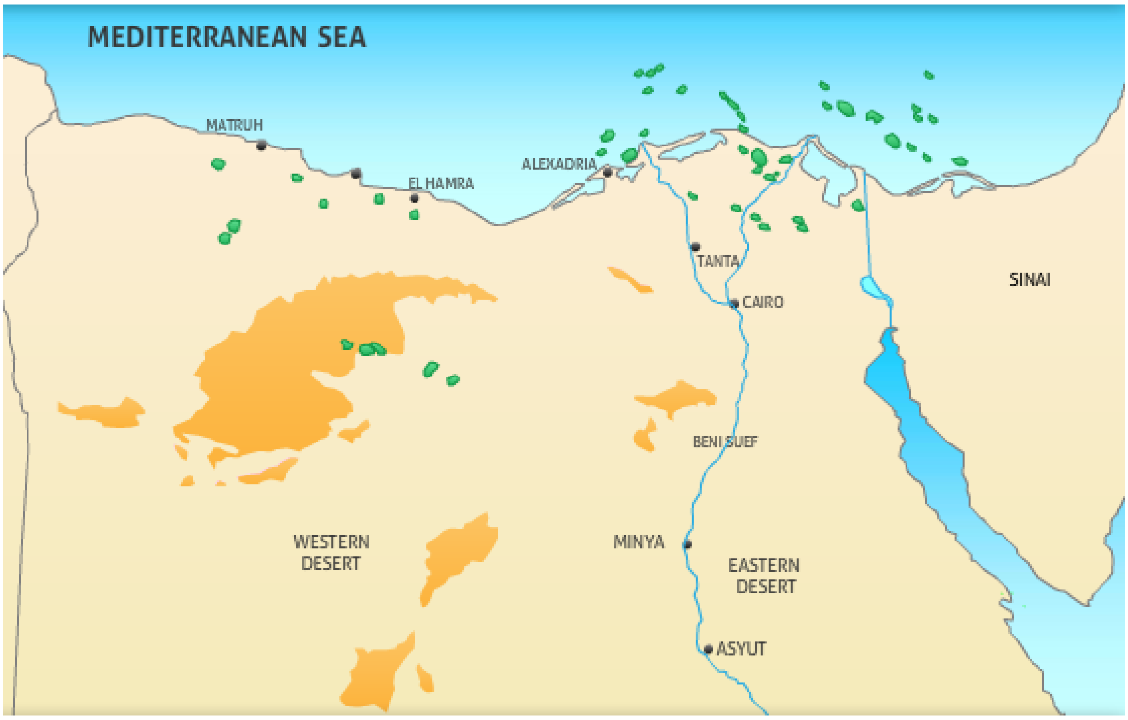


Source: World Bank

7.3. Gas Production Facilities

Egypt has a large number of gas fields that are currently producing with highest concentration of fields is located in the Mediterranean off the Nile Delta as can be seen in Figure 34.

Figure 34 Egypt Gas Fields

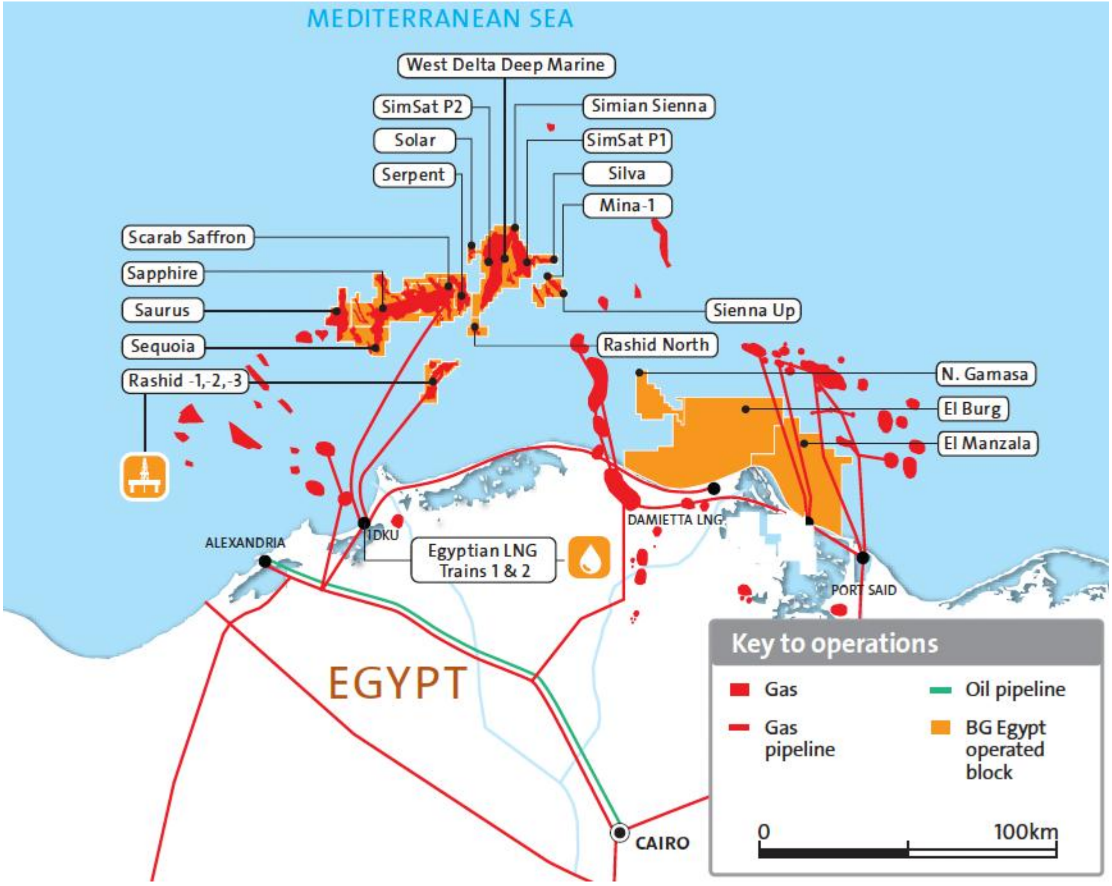


Source: Ministry of Petroleum website

Close to 70% of national production is from the offshore Mediterranean fields. The largest of them lie in the West Delta Deep Marine concession, where five fields - Scarab, Saffron, Simian, Sienna and Sapphire - were brought into production between 2003 and 2005 (see Figure 35). Other major producing areas include the Western Desert (17%), the (onshore) Nile Delta (8%) and others (5%): Gulf of Suez oil fields, Sinai and Eastern Desert.

In the Western Desert, the Khalda Area and Obaiyed fields are the most important natural gas areas. They have lower development and operating costs than fields in the Mediterranean region due to the network of pipelines and processing plants. Most of the production is piped to Alexandria via the 280 km pipeline.

Figure 35 Egypt Offshore Fields



Source: BG website

7.4. Gas Export and Import Facilities

Egyptian Gas is exported by both LNG and pipelines

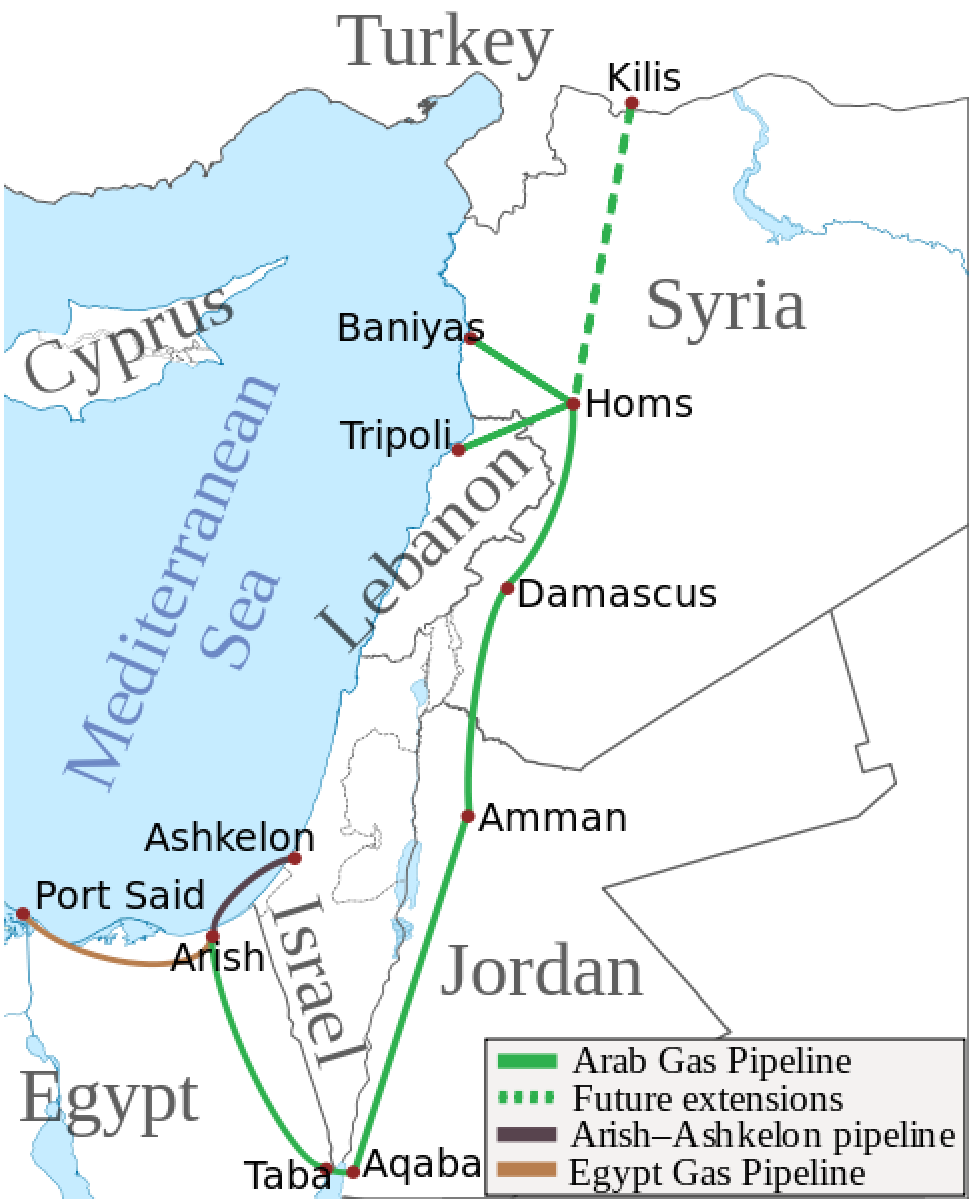
There are two LNG facilities exporting mainly to Spain, the US and South Korea. In 2010 these accounted for two thirds of total exports (9.2 bcm); The Egyptian LNG plant at Idku (capacity of close 10 bcm/year) and the SEGAS LNG plant at Damietta (capacity of 7.5 bcm/year) have been in operation since 2004 and 2005 respectively (see Figure 35).

The export pipelines are shown in Figure 36. The Arab gas pipeline exports gas to Jordan, Lebanon and Syria. Operational since 2003, the pipeline is 620 km and has a capacity of 10 bcm/year. In 2010 however only 3.4 bcm were exported from Egypt to Jordan, Syria and Lebanon, suggesting a considerable underutilisation of the pipeline. The pipeline is majority owned and managed by the state owned company EGAS through its subsidiary GASCO.

A 100 km submarine pipeline to Israel connecting Arish and Ashkelon connects the Arab gas pipeline in Egypt to Israel. The pipeline became operational in February 2008, and is owned and operated by the East Mediterranean Gas Company, a joint company of Mediterranean Gas Pipeline

Ltd (28%), the Israeli company Mehrav (25%), PTT (25%), EMI-EGI LP (12%), and the state owned EGPC (10%).The total physical capacity of the pipeline is 9 bcm/year and agreements between Israel and Egypt provide a framework for the purchase of up to 7.5 bcm/year of Egyptian gas by Israeli entities.

Figure 36 Egypt Gas Export Pipelines

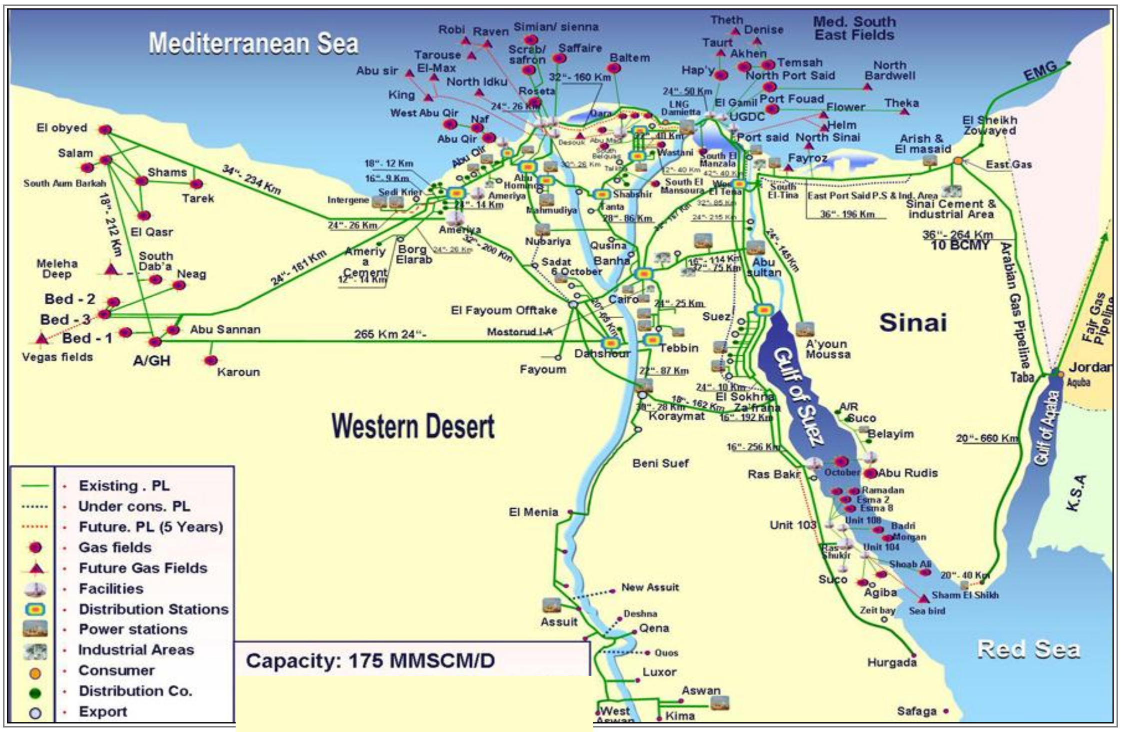


Source: Wikipedia

7.5. Industry Organisation

The upstream natural gas sector is open to participation by the private sector through conventional production sharing agreements with the state owned Egyptian Natural Gas Holding Company (EGAS). A fully owned subsidiary of EGAS, The Egyptian Natural Gas Company (GASCO), is responsible for planning and operation of the transportation system. GASCO supplies gas to power plants, industrial consumers and Petroleum industry customers if connected to the high pressure grid. Figure 37 shows the gas transportation network in Egypt.

Figure 37 Egypt Gas Transportation System



Source: EGAS webs

The two LNG facilities are owned and operated by companies, which are majority owned by private companies. Egyptian LNG, the operator of the Idku terminal is owned by BG (35.5%), Petronas (35.5%), EGAS (12%); Egyptian Gas and Petroleum Company (EGPC) (12%) and GDF Suez (5%). SEGAS LNG, the operator of the Damietta terminal is owned by ENI (40%), Union Ferosa (40%), EGAS (10%) and EGPC 10%.

7.6. Gas Regulatory Structure

EGAS regulates the development of natural gas resources under the supervision of the Ministry of Petroleum. EGAS is responsible for planning the natural gas industry and related projects; participating in the exploration, development and production of natural gas; operating and maintaining gas networks and pipelines; managing natural gas transmission; distribution and marketing; and operating LNG projects in conjunction with private owners.

In upstream gas operations, EGAS always participates with a private investor in the exploration or development of gas and is closely involved in the management of exploration and development projects. The Egyptian Government is entitled to a royalty in cash or in kind of 10% of the total quantity of gas produced. Additionally, EGAS is entitled to a share of the production of gas after deduction of gas covering the exploration costs incurred by the investor. This share will be determined in the production sharing agreements.

In case of a national emergency, the Government has the right to acquire part or all of the gas production, with full indemnification to the contractor and EGAS, in accordance with acquisition rights in the PSA.

EGAS sells the gas to end users and distribution companies at regulated tariffs set by the Ministry of Petroleum upon recommendation by EGAS. Table 17 shows the current regulated gas prices by consumer category. These costs appear to be far below the true economic cost of exploring, transporting and distributing gas estimated to be $3.52/MMBTU.

Table 17 Egypt Regulated Gas Prices

Customers	Price ($/MMBTU)
Energy intensive industry	3.00
Other Industry	1.25
Residential	0.92
Power sector	1.40

To operate and maintain their networks, distribution companies earn a fee per connection which is based on a unit charge for gas but has a regulated cap of EGP100 ($16.7) per customer per year. Furthermore, the distribution companies are supported by the Government to cover the cost of distribution network expansion. The average estimated cost of connecting households to the network is divided into two parts:

- EGP 1,000 ($166) is paid by the distribution company which is reported to cover the material costs and
- EGP 1,500 ($250), for civil works, is paid through the connection charge to the consumer.

To date, the distribution companies do not assume full capital risk and in the case of the two public distribution companies they do not mobilise the capital required to extend the network. Private companies mobilise a part of the financing required up-front and are repaid by the Government, through EGPC.

Hence, 40% of the estimated capital cost of connecting consumers to the distribution grids is subsidised by the public sector and the rest is funded by the consumer.

7.7. Similarities to Israel

There are similarities between Egypt and Israel:

- Both Israeli (Noble estimate 5.7% per year) and Egyptian (1.7%) gas markets are growing at a fast pace. In both countries the power generation sector is the key driver of demand.
- Both countries pursue a policy of increased gasification driving domestic demand growth in the sector further forward.
- Although Egypt is a sizable exporter today, it only started exporting in 2004 when the necessary export infrastructure was in place although the decision to export gas was taken in 1999 when proven reserves were considered enough to warrant a gas exporting strategy. Egypt was therefore in a similar position in the late 1990's as Israel is now
- Both countries are located within the same geographic region and would have the same pipeline gas trading partners. Both Israel and Egypt have access to the Mediterranean, enabling easy LNG exports to Europe and the rest of the world.

7.8. Differences to Israel

There are some differences between Egypt and Israel:

- Egypt's gas market is about nine times larger than that of Israel. The main reasons for this difference are a considerably larger population and therefore greater energy demand, the existence and development of domestic natural gas sources and a policy of increased gasification in Egypt
- Another major difference between Israel's and Egypt's gas market situation is that Egypt has become a gas exporter over the last 5 years, while Israel has become a gas importer.
- The current political uncertainty in Egypt also stands in contrast with Israel's political stability. This results in uncertainty for investors, a slow decision making process on key gas policy questions and a halt to necessary reform programmes

7.9. Lessons Leant

The following are the main lessons:

- Upon the discovery of sufficient gas resources to cover domestic demand and exports in 1999, the Government decided to pursue an export oriented gas strategy. Although it limited exports to one third of existing reserves, two LNG facilities and two gas pipeline export facilities were developed. With prospective access to global markets, international companies increased their exploration and drilling activities and provided a substantial part of the inflow of foreign investment into Egypt.

- Subsequent explosive domestic gas demand growth has led the government to prioritise gas production to cover domestic demand. In 2008 all new gas export projects were halted and to date this decision still stands. This was also in response to very high global gas prices in 2008, providing an incentive for operators to increasingly sell gas into global markets.
- The reversal of gas strategy from export oriented to domestic market focused was a key factor in triggering a number of adverse effects: a current underutilisation of gas export facilities, increased budgetary pressures through higher subsidy payments and reduced gas exploration activities.
- The low price cap the Government set to purchase gas from upstream operators is likely to have been too low to act as an incentive for operators to sell to the domestic markets. Particularly in light of high international gas prices in 2008 and high commercial returns to be achieved in LNG markets.
- This suggests that gas export limits should have been set as percentage of annual gas production instead of gas reserves. This would ensure that if producers want to export large volumes, they will also have to produce large volumes for domestic markets. The halt in gas exports discourages upstream activity, reserves do not increase, leading to a perpetuation of the current situation.

8. Indonesia

8.1. Key Issues

Indonesia is the fourteenth largest holder of proven natural gas reserves in the world, and the third-largest in the Asia-Pacific Region. In 2010, proven reserve was estimated to be around 3,100 bcm, with another 1,000 bcm of potential reserve. Indonesia's gas exploration and production started in the late 1950s and was geared towards export. Domestic consumption in the early days of Indonesia's gas sector was almost negligible at around 0.5 bcm per annum.

However, domestic consumption has risen over the years, as more and more industries switched from using crude oil to gas for their energy source. Domestic gas prices have been kept low compared to international prices, giving more incentives for industries and later for commercial and household customers to use gas instead of oil. In the early 1990s, domestic consumption reached 20 bcm.

In 2001, with the enactment of the Oil and Gas Law No.22, the Government of Indonesia introduced a Domestic Market Obligation (DMO), which requires

25% of gas produced by any producers to be set aside from each production sharing agreement for the domestic market. However, there is a degree of uncertainty as to the implementation and enforcement of the DMO, as the Oil and Gas Law requires DMO to be up to 25% of production, while the Constitutional Court in 2004 stated that the DMO was to be 25% or more. Another uncertainty created by the DMO requirements is the price that the Government of Indonesia will pay for the DMO. Domestic gas prices are at least a third less than international prices[58], making gas producers reluctant to meet their DMOs.

This has become a politically charged topic in Indonesia, as gas producers are reluctant to supply domestic customers given that domestic prices are significantly lower than export prices. This prioritisation of domestic market was said to have impeded investment in gas developments in Indonesia, as investors are deterred by the low domestic prices[59].

Combining the DMOs and the declining gas production[60], Indonesia has had difficulties in meeting its LNG export contract obligations. Some of the renewed LNG contracts have reduced the amount of LNG for export, diverting the volumes for domestic use instead.

The Donggi-Senoro LNG terminal plans received government approval only after 30% of the output was designated for domestic consumption. Similarly, a third of the output from Inpex's planned Masela floating LNG liquefaction terminal will be designated for the domestic market, according to the regulator BPMigas. Indonesia also plans to reorient the output from the Bontang LNG plant into the domestic market over the next decade. Though the plant will remain operational, it will send LNG within Indonesia and no longer serve export markets by 2020[61].

In addition, recently the Government announced that it will allocate all output from the massive Natuna D-Alpha field for domestic use only. Natuna D-Alpha is estimated to hold 1,300 bcm of recoverable gas reserves and 2,200 bcm of potential reserves[62]. The proven reserve from Natuna D-Alpha will be able to supply domestic demand for 32 years given the current 2010 consumption levels. However, the Government has not decided when this field will be developed.

The government has also pursued other policies to secure domestic supplies, and has recently considered importing LNG for domestic usage. This results

[58] International Energy Agency (IEA), Energy Policy Review of Indonesia, 2008
[59] http://www.thejakartapost.com/news/2011/02/22/domestic-gas-supply-scarce-despite-huge-reserves.html
[60] The old fields are declining while new fields are not being brought onstream
[61] http://www.eia.gov/countries/cab.cfm?fips=ID
[62] http://www.thejakartaglobe.com/home/indonesia-plans-to-reserve-natuna-gas-for-domestic-market/363171

from the fact that Indonesia is a large archipelago with many Islands and remote locations with no pipeline connection to the producing fields. Additionally, as much of existing production has been committed to exports, there is insufficient for domestic needs and low domestic gas prices provide poor incentives for new developments.

In order to accommodate LNG imports, plans for several LNG receiving terminals are underway in Indonesia. The first re-gasification terminal, a 4 bcm joint-venture between Pertamina and PGN, will supply the Jakarta market starting in the first quarter of 2012. Pertamina also plans to invite bids for an additional receiving terminal of similar size to serve East Java. In addition, Pertamina and PLN (Indonesia's state electricity firm) have announced plans to develop eight LNG receiving "mini terminals" by 2015, with a total capacity of around 2 bcm. These terminals will be scattered throughout the eastern region of the island nation, and are intended to guarantee supply of natural gas for electricity plants[63].

8.2. Basic Data

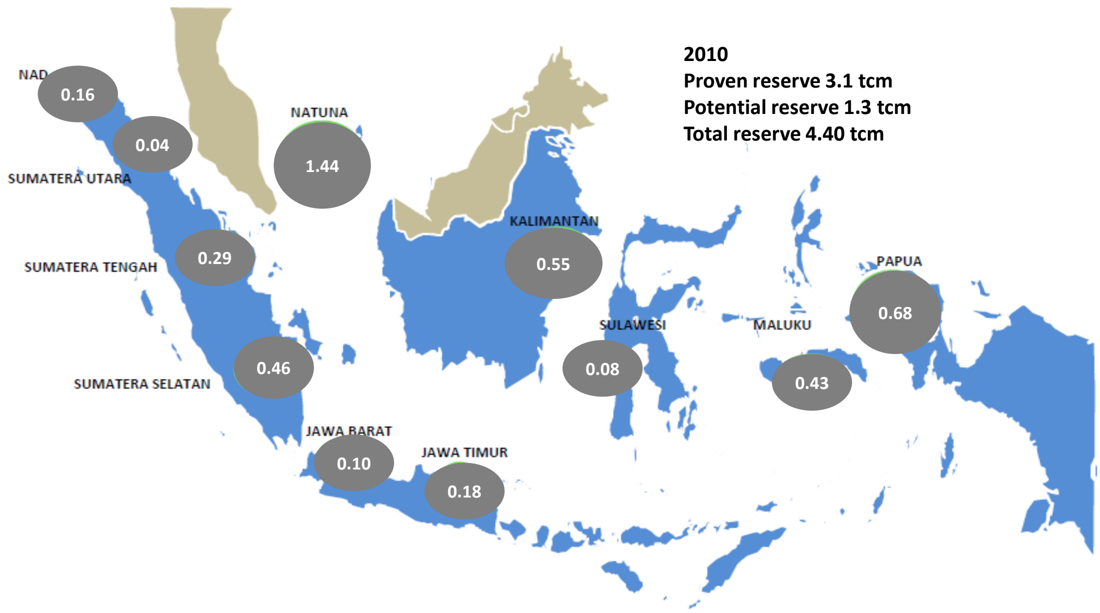
8.2.1. Proven Reserves

Indonesia has 3,100 bcm of gas proven reserve as at 31 December 2010 compared to 2,900 bcm as at 31 December 1990.

The largest reserve in Indonesia is the offshore Natuna gas field, with total reserve of 1,440 bcm as of 2010. Second largest is the East Kalimantan field, with total reserve of 550 bcm. Figure 38 shows the location of proven and potential reserves in Indonesia.

[63] http://www.eia.gov/countries/cab.cfm?fips=ID

Figure 38 Indonesia Gas Reserves



Source: Ministry of Energy and Mineral Resources, Directorate General of Oil and Gas, Indonesia Gas Statistics, 2010

8.2.2. Exports

Indonesia's gas production was geared toward exports since the beginning of oil and gas exploration. Currently, Indonesia exports around 50% of its natural gas production and is the largest LNG exporter in the Asia-Pacific region. By 2009, the country became the sixth largest exporter of natural gas, exporting around 35 bcm in 2009, increasing to almost 42 bcm in 2010.

The majority of Indonesia's gas exports are transported as LNG, and only about a quarter of its gas exports are transported via pipeline to Singapore and Malaysia[64], with which it has two pipeline connections: one from its offshore fields in the West Natuna Sea, and the other from the Grissik gas processing plant in Sumatra. These pipelines have a combined capacity of approximately 11.2 bcm per year and deliver gas to Singapore and Malaysia under long-term contracts, which are set to expire around 2020.

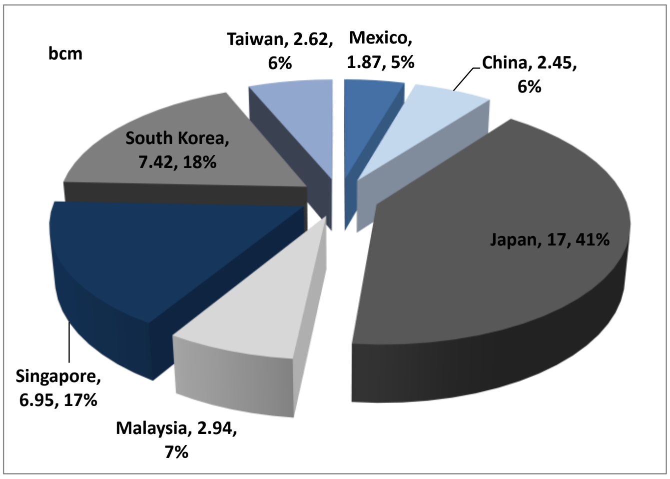
Japan is the major destination for Indonesia's LNG exports, accounting for about 40% percent of total exports, followed by South Korea at 17% of total exports. Figure 39 illustrates Indonesia's natural gas export destinations.

The LNG supply contract for around 16 bcm with Japan expired in 2010. The new contract significantly reduced the committed volume[65]. A new ten-year

[64] Malaysia faces similar problems to Indonesia: it is a major LNG exporter but the combination of export-committed production, field locations remote from population centres and low domestic prices have led to a shortage of gas production for domestic markets
[65] As Japan, in a break with its traditional approach, has decided to buy some of its gas on the spot markets at (currently) much lower prices

supply agreement was signed in 2007, and Indonesia guaranteed 4.08 bcm (or 3 million tonnes LNG) to be delivered to Japan in 2011, and 2.72 bcm (2 million tonnes LNG) for the rest of the agreement period[66].

Figure 39 Indonesia Gas Exports, 2010



Source: BP Statistical Review of World Energy, June 2011

South Korea has a couple of supply contracts for around 2.72 bcm/year (2 million tonnes LNG per year), expiring in 2014 and 2017. South Korea and Taiwan also have signed contracts for LNG from the new LNG plant in Tangguh. However, the new contracts are short term, from 2010 to 2012, and for less than 1.65 bcm/year (1 million tonnes LNG per year) only[67].

China has a 25 years contract to receive around 3.5 bcm/year (2.6 million tonnes LNG per year) from Tangguh, which begun in 2009[68]. This has been a controversial contract, since the price agreed was based on crude oil prices, and was capped at a very low figure of $ 2.40/MMBTU. This price was revised, and in 2006 a price of $3.35/MMBTU was agreed after long negotiations.

Since 2002 Indonesia has been struggling to meet contracted supply commitments to Japan, South Korea and Taiwan due to gas output shortfalls and rising domestic demand.

8.2.3. Production

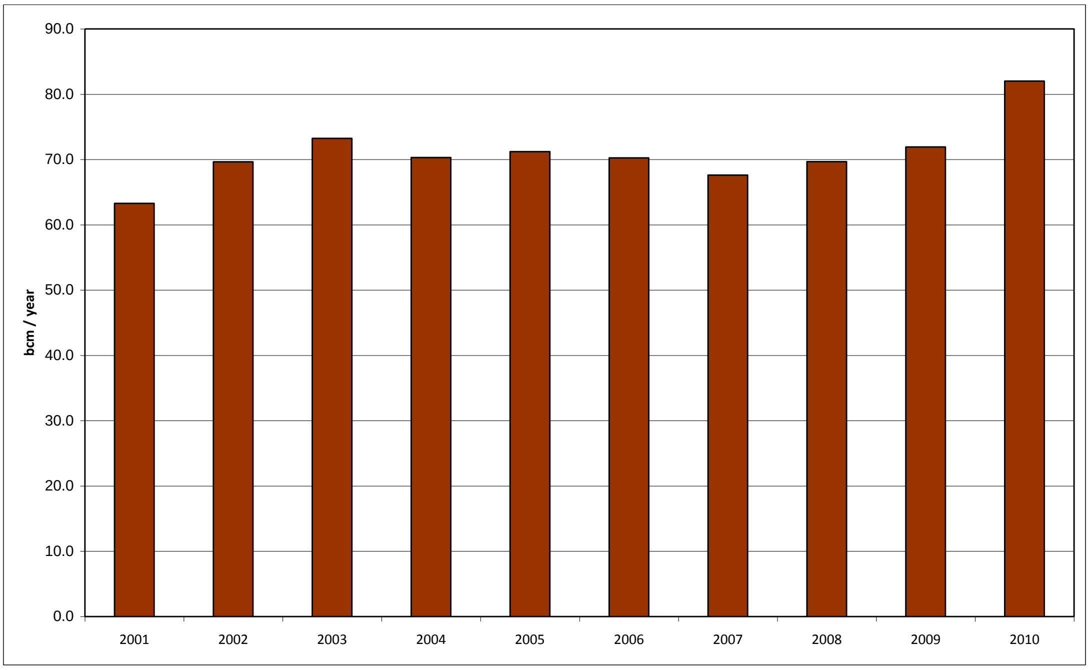
Indonesia’s gas production has steadily increased over the years, as shown in Table 18 and Figure 40 and in 2010 82 bcm of gas was produced.

[66] http://www.japanfocus.org/-David_Adam-Stott/3029
[67] As above
[68] As above

Table 18 Indonesia Gas Production (bcm)									
2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
63.3	69.7	73.2	70.3	71.2	70.3	67.6	69.7	71.9	82.0

Source: BP Statistical Review of World Energy, June 2011

Figure 40 Indonesia Gas Production



Source: BP Statistical Review of World Energy, June 2011

As the diagram shows, gas production has slowed down due to depleting fields. However, Indonesia still has un-tapped proven reserves, and there are plans for new gas production locations.

8.2.4. Consumption

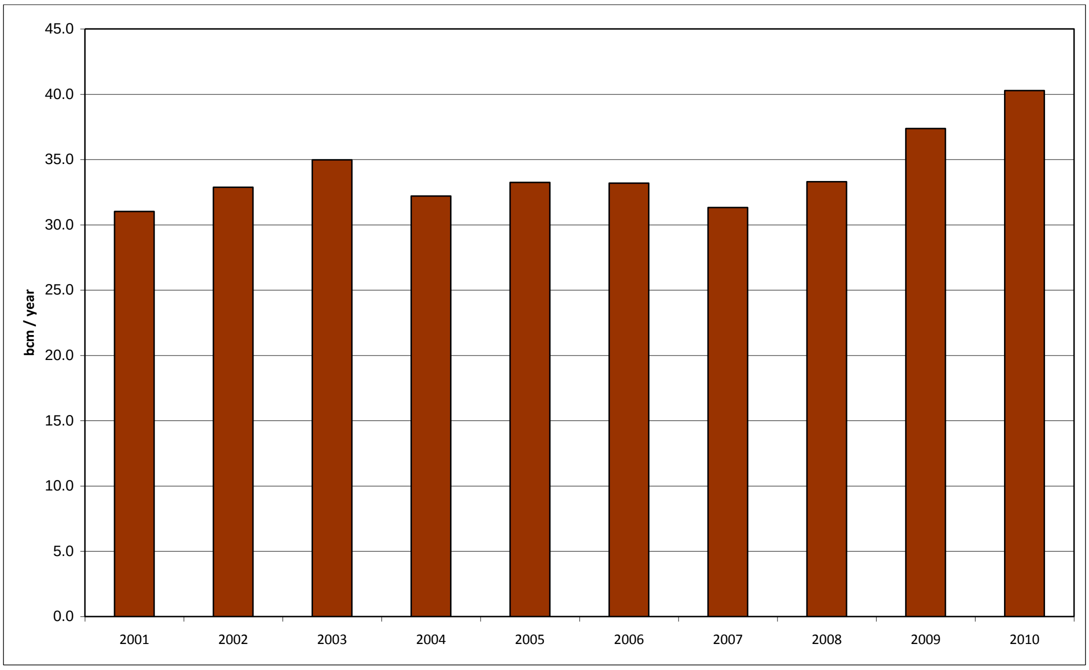
Indonesian gas production initially was geared towards exports, but the country's declining oil production and increasing oil prices have driven an effort to shift increasing volumes toward domestic consumption. In 2010, Indonesia consumed 40.3 bcm of natural gas, or about half of its total gas production (see Table 19 and Figure 41).

The power sector is the largest gas consumer (around 22% of total consumption), followed by fertilizer and ceramic industries (around 20% and 15% respectively. Household consumptions only accounts for 1% of total consumption. Other consumers include small industries and commercial establishments. The power sector is expected to be the most significant driver of future consumption growth.

Table 19 Indonesia Gas Consumption (bcm)									
2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
31.0	32.9	35.0	32.2	33.2	33.2	31.3	33.3	37.4	40.3

Source: BP Statistical Review of World Energy, June 2011

Figure 41 Indonesia Gas Consumption



Source: BP Statistical Review of World Energy, June 2011

8.2.5. Reserves/Production

The proven reserve/production ratio in 2010 is 3100/82 = 37 years.

8.2.6. Reserve/Consumption

The proven reserve/consumption ratio in 2010 is 3100/40.3 = 77 years

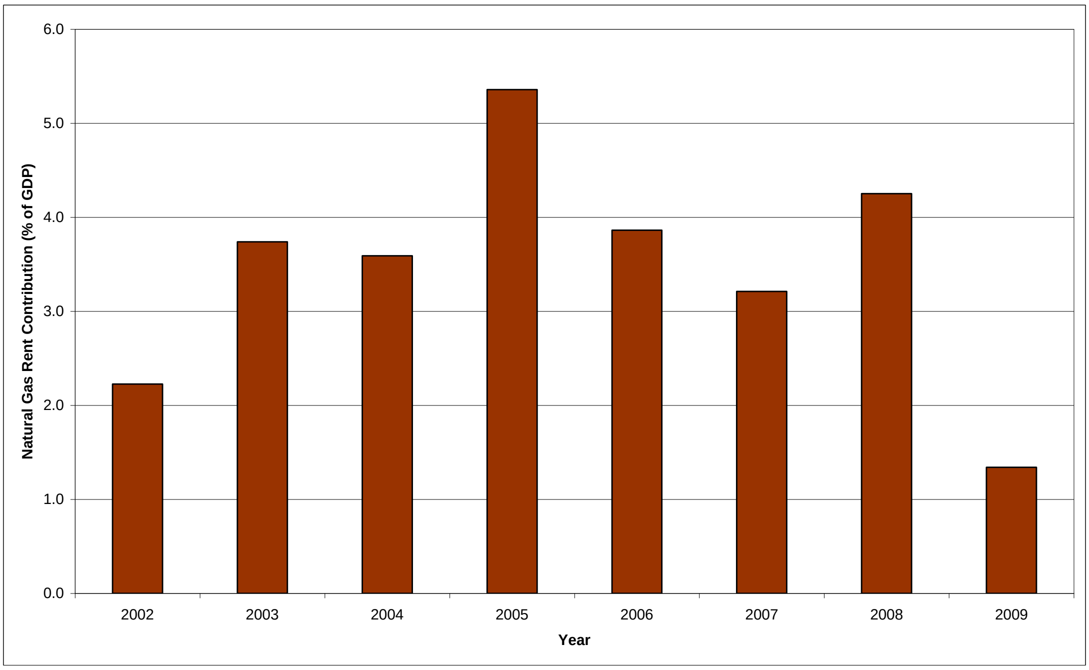
8.2.7. Natural Gas Rents (% of GDP)

Natural gas rents' contributions to Indonesia's GDP are shown in Table 20 and Figure 42.

Table 20 Indonesia Natural Gas Rents (% of GDP)							
2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
2.2	3.7	3.6	5.4	3.9	3.2	4.3	1.3

Source: World Bank

Figure 42 Indonesia Natural Gas Rents (% of GDP)

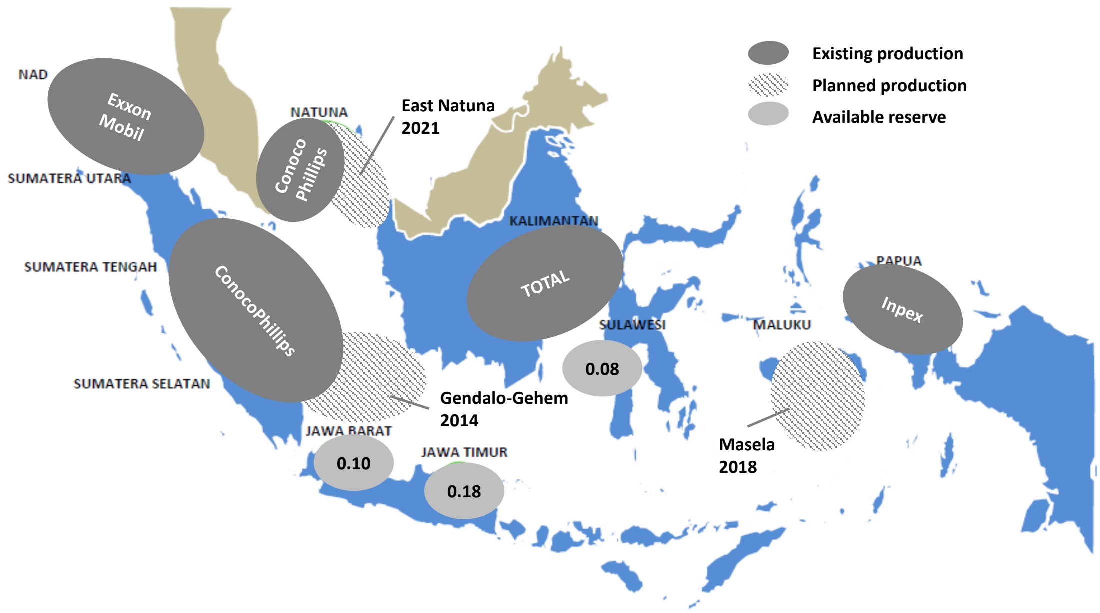


Source: World Bank

8.3. Gas Production Facilities

Indonesia's geography presents a challenge to resource development, because the archipelago nation's most prolific blocks of conventional gas reserves are located far from its major demand markets. Figure 43 shows Indonesia's existing and planned gas production facilities.

Figure 43 Indonesia Gas Production Facilities



Source: Adapted from Ministry of Energy and Mineral Resources, Directorate General of Oil and Gas, Indonesia Gas Statistics, 2010 and planned production data from http://www.eia.gov/countries/cab.cfm?fips=ID

The most significant areas for current natural gas production are:

- East Kalimantan's offshore fields, particularly the Mahakam production sharing contracts operated by Total
- South Sumatra, particularly the onshore corridor production sharing contract operated by ConocoPhillips
- Aceh and North Sumatra, including ExxonMobil's declining offshore Arun field
- South Natuna Sea, offshore Block B operated by ConocoPhillips
- West Papua, onshore production for LNG export operated by Inpex

There are several major new gas projects in development for the next decade, with a combined potential volume of 1,700 bcm, adding 20 years of production potential. These include:

- Natuna D-Alpha field – estimated to hold 1,300 bcm to be developed by Total, Petronas and Pertamina in 2021
- Gendalo-Gehem deepwater gas project – estimated to produce 11.2 bcm per year starting from 2014, developed by Chevron, together with ENI and Sinopec
- Masela offshore block – estimated to hold 400 bcm to be developed by Inpex , expected to begin production in 2018[69]

[69] http://www.eia.gov/countries/cab.cfm?fips=ID

In addition to its considerable conventional gas resources, Indonesia also holds an estimated 12,700 bcm of coalbed methane (CBM). CBM reserves are located relatively close to Indonesia's population centres, primarily in South Sumatra and Kalimantan. First production is expected to begin in late 2011 and 2012. Though local consortiums hold many of the existing CBM production sharing contracts, BP, Eni and Dart Energy also hold shares in Indonesia's CBM blocks[70].

8.4. Gas Export and Import Facilities

There are three operational liquefaction terminals in Indonesia, with a combined production capacity of about 44 bcm per year, as shown in Table 21. In 2010, Indonesia exported about 31 bcm of LNG.

Table 21 Indonesia LNG Facilities

Name	Location	Capacity (bcm/year)	Commercial Operations
Operational		**44.04**	
Arun	Aceh	2.86	1978
Bontang	East Kalimantan	30.83	1977
Tangguh	Papua	10.36	2009
Planned		**6.27**	
Donggi Senopro	Sulawesi	2.86	2014
Masela	Arafura Sea	3.42	2016+

Source: EIA, May 2011

The Bontang LNG terminal in East Kalimantan is the largest in Indonesia at about 31 bcm/year, and one of the largest in the world. Bontang delivered its first cargo in 1977, and was followed shortly thereafter (1978) by the Arun liquefaction terminal in Northern Sumatra. Due to a lack of sufficient additional gas reserves in the Arun field, LNG exports from the Arun plant have been declining in recent years, and are expected to stop altogether by 2014[71].

Both of these LNG terminals were constructed under supply contracts to Japan, who is the largest importer of LNG from Indonesia; in each case the development required an export contract. Additionally, Japan also has a supply contract to receive LNG from Tangguh in Papua and later on from Masela in the Maluku province.

The newest addition, BP-operated Tangguh in Western Papua, came online in 2009 and exported almost 10 bcm in 2010[72]. LNG from Tangguh sold under supply contracts with Japan, China, and South Korea[73]. BP had originally

[70] http://www.eia.gov/countries/cab.cfm?fips=ID
[71] As above
[72] As above
[73] http://www.japanfocus.org/-David_Adam-Stott/3029

intended to add a third train to Tangguh's first two trains, but has not yet proceeded with plans for this project.

The next anticipated addition to Indonesia's liquefaction capacity is the Donggi-Senoro LNG plant in Central Sulawesi. The project developers (Mitsubishi, Kogas, Pertamina, and Medco) signed a final investment decision in early 2011, and the 3 bcm/year plant is expected to be commercial in 2014. Inpex received government approval at the end of 2010 for the Masela liquefaction terminal in the Arafura Sea, but has delayed the expected start-up date of the floating LNG liquefaction terminal until 2018.

8.5. Industry Organisation

Most of the large international oil and gas companies are present in Indonesia's upstream gas sector, with Total, ConocoPhillips and the state-owned enterprise Pertamina producing than 50% of total gas production. Participation in the upstream gas sector requires the companies to sign a production sharing contract with BP MIGAS (the regulator). The contracts allocate the revenue shares between the production companies and the Government of Indonesia. Typically, the production companies will receive 30-40% of revenue after deductions to cover operating costs.

The New Oil and Gas Law No.22/2001 introduced a Domestic Market Obligation (DMO) for oil and gas, and require producers to set aside up to 25% of production for domestic use. However, there are some uncertainties over the requirements, as the Constitutional Court in 2004 stated that the DMO should be equal to or more than 25%.

Indonesia's gas distribution utility Perusahaan Gas Negara (PGN) currently operates more than 3,500 miles of natural gas transmission and distribution pipelines. PGN operates around 82% of transmission network, while transmission network for exports to Singapore and Malaysia is operated by Pertagas, a subsidiary of the state-owned enterprise Pertamina. PGN also operates around 87% of all distribution networks, with the rest owned and operated by small private retailers, mostly for industrial use.

8.6. Gas Regulatory Structure

The Government institution responsible for overall policy and sector planning of the gas sector is the Directorate General of Oil and Gas (DGO&G) under the Ministry of Energy and Mineral Resources (MEMR). The DGO&G is also responsible for allocating acreage through bidding rounds.

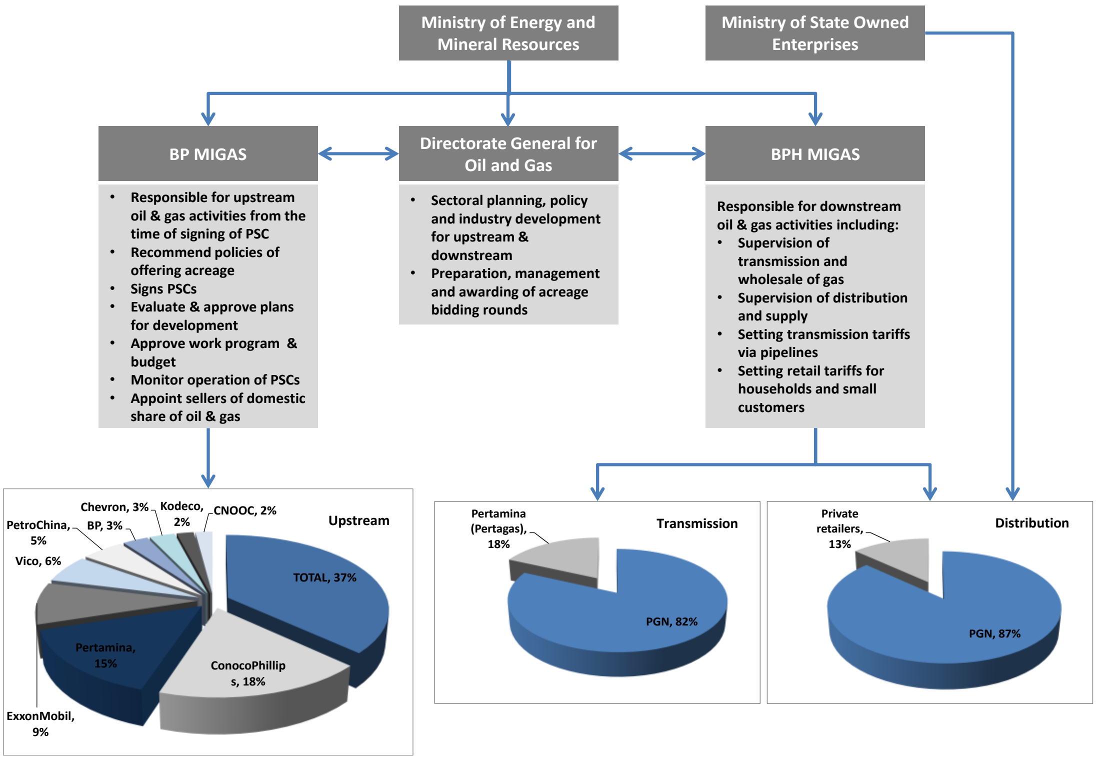
After the reform and the implementation of the Oil and Gas Law No.22/2001, two new regulatory bodies were established: BP MIGAS to regulate upstream activities and BPH MIGAS to regulate downstream activities. Both regulators reports to the MEMR. Figure 44 summarises the regulatory structure of Indonesia's gas sector.

BP MIGAS is the executive agency that signs the PSCs with production companies, and is responsible for monitoring the operation of PSCs, evaluating and approving plans for development and work programmes and budgets. BP MIGAS also provides policy advice and recommendations to DGO&G.

BPH MIGAS regulates the operations of downstream activities, including setting tariffs for gas transmission and distributions to households and small customers.

Another player in the regulatory structure is the Ministry of State Owned Enterprises (MSOE), which is responsible for supervision and monitoring of the operations of state-owned enterprises in the gas sector, including Pertamina and PGN.

Figure 44 Indonesia Gas Sector Regulatory Structure



Source: adapted from International Energy Agency (IEA), Energy Policy Review of Indonesia, 2008

8.7. *Similarities to Israel*

There are similarities between Indonesia and Israel:

- Indonesia and Israel have a similar primary energy consumption fuel mix with both being dependent on oil as the main energy source

- Both Indonesia and Israel are looking to increase their gas consumption and reduce their dependency on oil. Indonesia aims to increase gas consumption to 30% of total energy consumption by 2025, while Israel aims to increase gas consumption by threefold by 2015
- Both Indonesia and Israel will need to increase investments in domestic gas infrastructure. The Indonesian domestic market is under developed due to the lack of investments in infrastructure. Israel on the other hand, has only started gas development in 2003 and the current energy infrastructures are not fully geared towards gas consumption outside the power sector.
- Indonesia has improved the investment climate somewhat, however further policy clarification and more importantly, aligning domestic prices with international prices are necessary to attract more investments in infrastructure. Similarly, Israel needs to improve the investment climate in the gas sector to meet increasing domestic demand

8.8. Differences to Israel

There are differences between Indonesia and Israel:

- Indonesia has been a gas producing and exporting country for around 30 years, and has never imported natural gas. Israel was and still is a gas importing country
- Indonesia is an archipelago, which makes development of gas pipelines difficult and therefore relies mostly on LNG terminals to transport gas. Israel has land borders with other countries, which makes export or imports of gas possible by pipelines

8.9. Lessons Leant

The following are the main lessons:

- Indonesian gas production is geared towards export in the form of LNG, with less than 50% of production supplied to the domestic market.
- Increasing domestic usage due to high oil prices coupled with Government's policies to increase domestic consumption (such as the Domestic Market Obligation or DMO) has caused problems in terms of meeting LNG export obligations, and has slowed down investments in further gas development, also because of low domestic prices.
- As domestic prices are low compared to international or export prices, developers are reluctant to increase their gas production since around 25% of production will have to be sold to domestic buyers under the DMO. Export contracts are needed to undertake new investments
- The lesson to be learnt is that domestic gas market obligations should be accompanied with cost reflective domestic prices. Setting domestic

prices close to export prices will give incentives to gas producers to meet both export and domestic market demands.

9. Libya

9.1. Key Issues

Libya has significant gas reserves, the fourth largest in Africa. The country's potential gas reserves are however still largely unexploited and are less explored than its oil reserves. Proven gas reserves currently stand at 1,549 bcm but Libyan experts believe it is considerably larger, possibly 1,982 -2,832 bcm or more. Libya's National Oil Corporation (NOC) said they could be approximately 3,398 bcm. Compared with other countries with similar or less gas reserves quantity, Libya's gas production and exports are quite low.

Political restrictions arising from international sanctions on Libya limited the growth of the gas industry and the full capacity utilization of the Marsa El Brega LNG plant. The huge potential for hydrocarbons discoveries that was expected following the lifting of the previous round of international sanctions in 2003-04 was not realised under the Qadhafi regime. Libya was also severely affected by the recent civil war, with gas production and exports grinding to a halt for several months. Although, oil and gas production is gradually recovering to the pre-conflict level, the Economist Intelligence Unit posits that expansion of production in the sector is still likely to be slow once output has recovered from the effects of the war.

9.2. Basic Data

9.2.1. Proven Reserves

As at 31 December 2010 Libya had 1,549 bcm of proven gas reserves which compares with 1,208 bcm as at 31 December 1990.

9.2.2. Exports

Total exports in 2010 were 9.75 bcm of which 9.41 bcm were via pipeline and 0.34 bcm were via LNG. The two largest export markets were Italy (9.41 bcm) and Spain (0.34 bcm).

9.2.3. Production

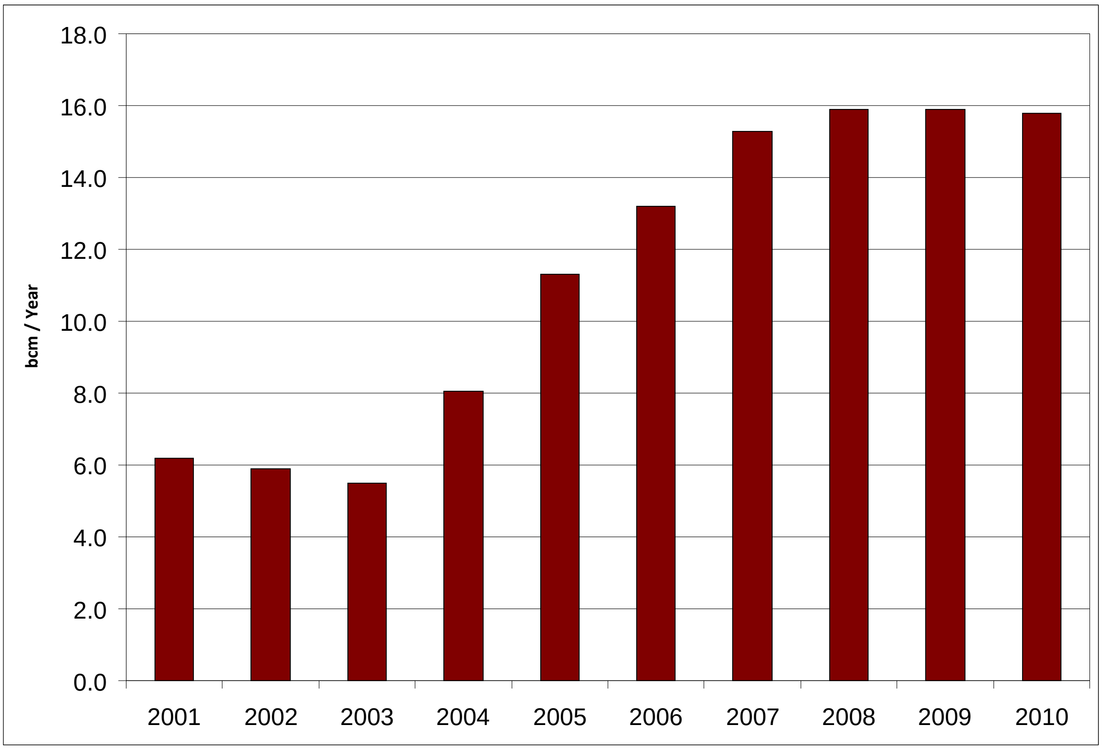
Gas production in 2010 was 15.8 bcm. It has increased steadily over the last six years but has reached a plateau since 2008. Details of the production are shown in Table 22 and Figure 45.

Table 22 Libya Gas Production (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
6.2	5.9	5.5	8.1	11.3	13.2	15.3	15.9	15.9	15.8

Source: BP Statistical Review of World Energy, June 2011

Figure 45 Libya Gas Production



Source: BP Statistical Review of World Energy, June 2011

9.2.4. Consumption

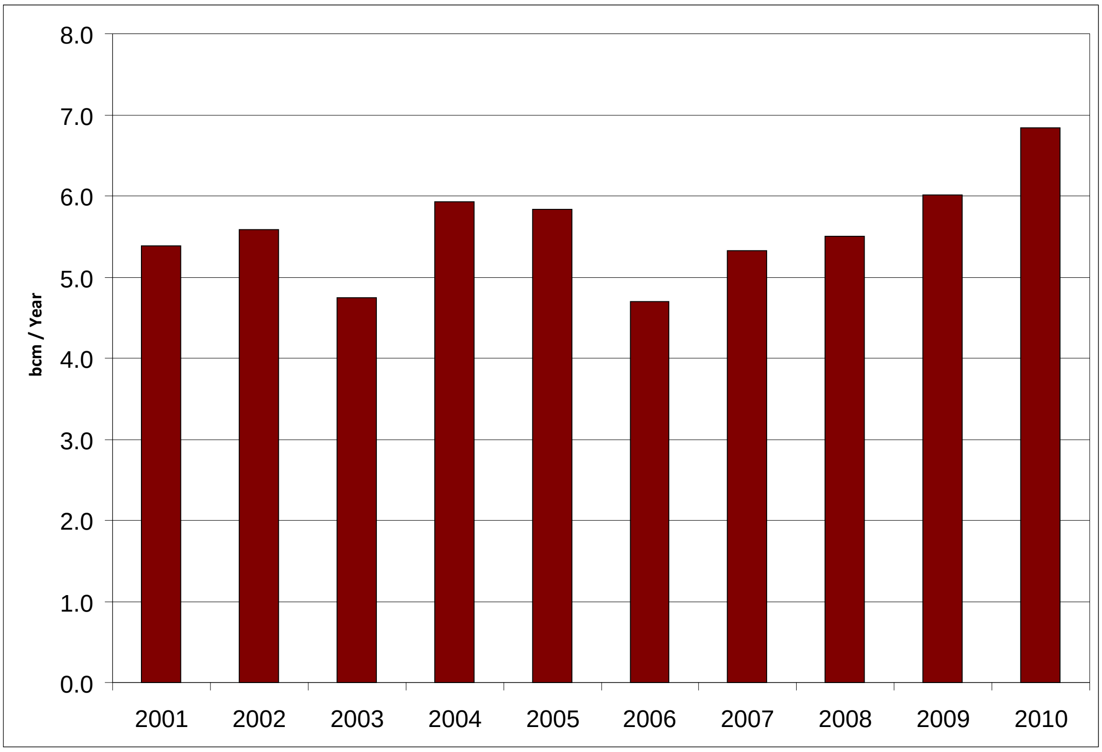
Gas consumption in 2010 was 22.0 bcm and consumption has been growing steadily as shown in Table 23 and Figure 46.

Table 23 Libya Gas Consumption (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
5.4	5.6	4.8	5.9	5.8	4.7	5.3	5.5	6.0	6.8

Source: EIA, International Energy Statistics

Figure 46 Libya Gas Consumption



Source: EIA, International Energy Statistics

9.2.5. Reserves/Production

The reserves/production ratio is 1549/15.8 = 98 years.

9.2.6. Reserves/Consumption

The reserves/consumption ratio is 1549/6.8 = 226 years.

9.2.7. Natural Gas Rents (% of GDP)

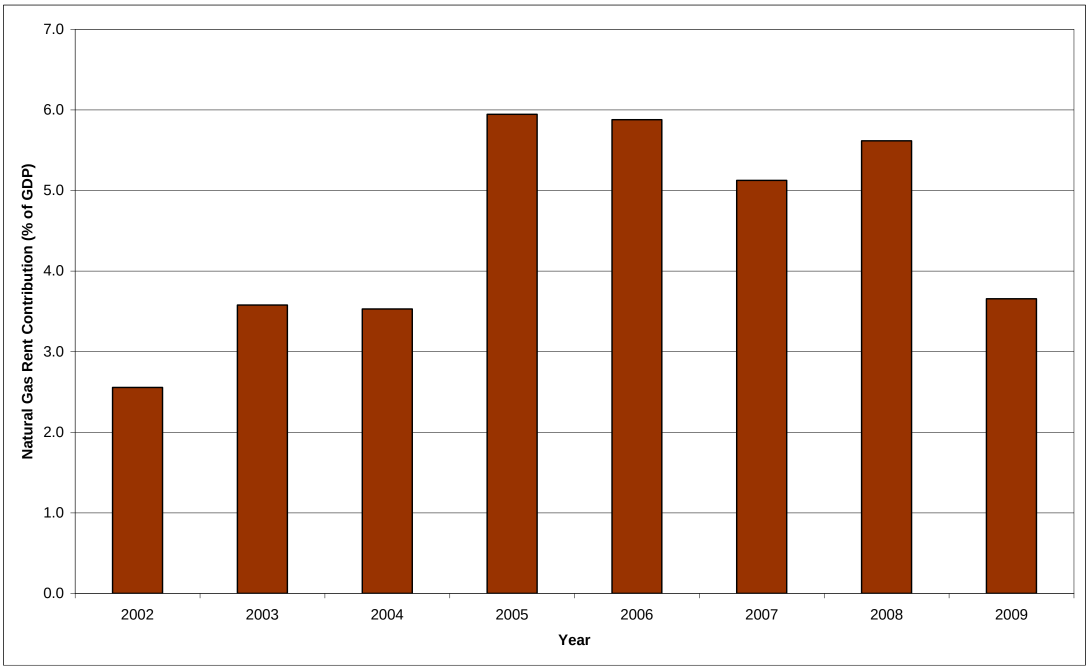
Natural gas contributes to Libya's GDP as shown in Table 24 and Figure 47.

Table 24 Libya Natural Gas Rents (% of GDP)

2002	2003	2004	2005	2006	2007	2008	2009
2.6	3.6	3.5	5.9	5.9	5.1	5.6	3.7

Source: World Bank

Figure 47 Libya Natural Gas Rents (% of GDP)



Source: World Bank

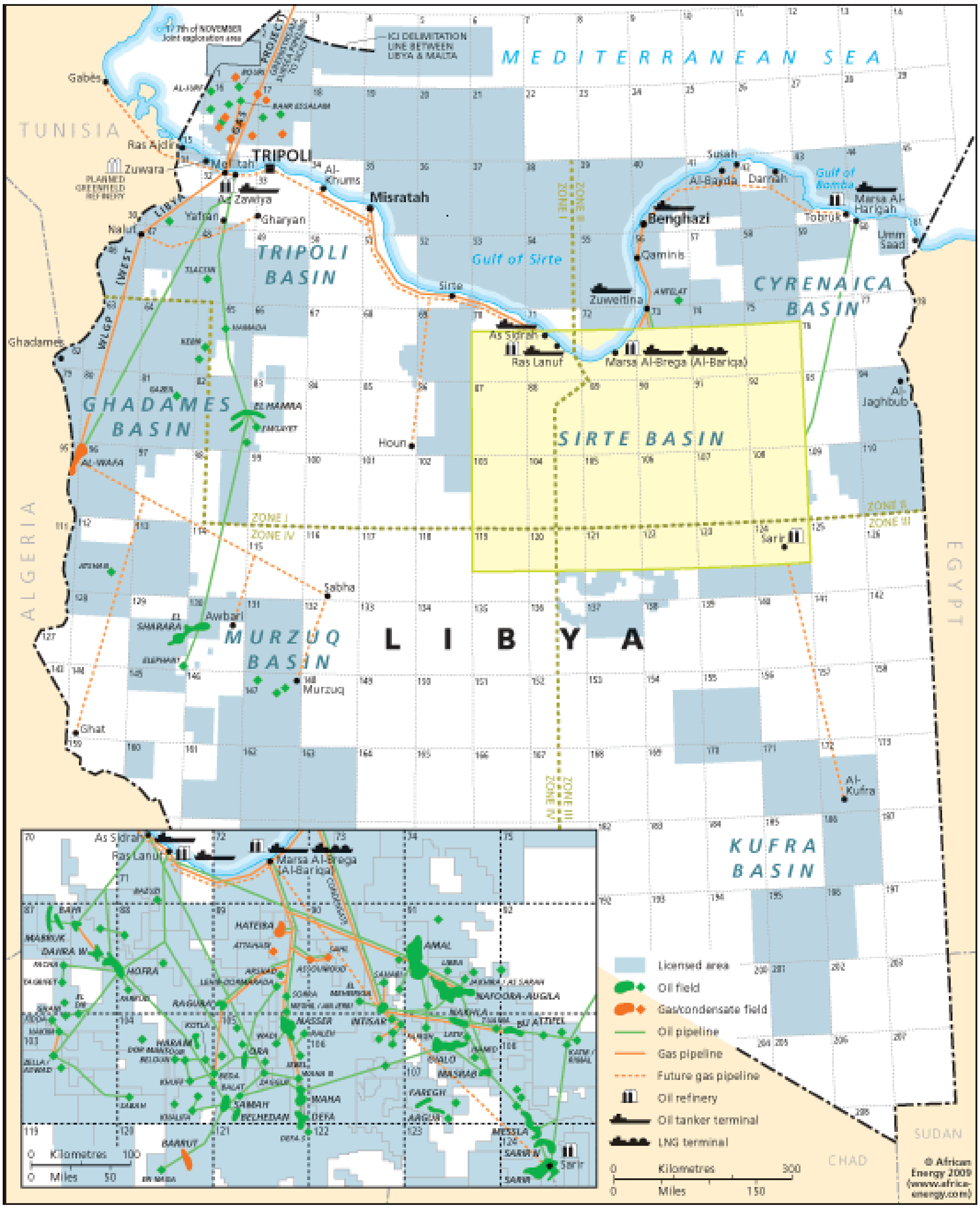
9.3. Gas Production Facilities

About 80% of Libya's gas reserves are located in the Sitre basin while the remainder lies in the Ghadames basin and Pelagian shelf. Major producing gas fields include Attahaddi, Hatieba, Defa-Waha, Zelten, Assoumoud and Sahl. Libya commenced associated gas production in the 1960s and natural gas production was about 8 bcm in 2004.

Production rose significantly with the coming on stream of the Western Libya Gas Project. Sirte Oil Company (SOC) produces about 10 bcm per year of gas from Assoumoud, Nasser, Hatieba and Sahl fields. Eni and Arabian Gulf Oil Company (Agoco) also produce gas from the Bu' Attifel, Nafoora, Sarir, Bahr Essalam and Wafa fields[74]. The location of the gas fields and domestic pipelines can be seen (in red) in Figure 48.

[74] http://www.menas.co.uk/localcontent/home.aspx?country=73&tab=industry

Figure 48 Libya Oil and Gas Production Facilities



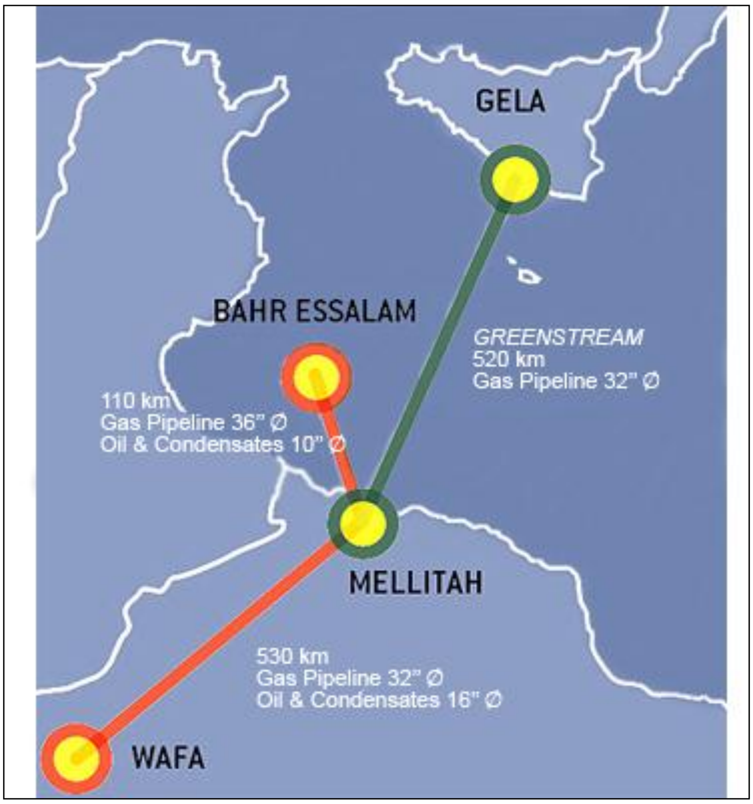
Source: African Energy 2011 (www.africa-energy.com)

9.4. Gas Export and Import Facilities

96% of Libya's gas exports go to Europe through the Greenstream pipeline, which extends from Melitah to Sicily. The Greenstream pipeline is an underwater gas pipeline that crosses the Mediterranean. It is part of the WLGP. Natural gas is piped from the Wafa concession and the offshore Bahr es Salam fields to Melitah, where it is treated for export. From Sicily, the natural gas flows to the Italian mainland. The Greenstream pipeline came online in 2004 and is operated by Eni in partnership with NOC[75].

The Greenstream pipeline is shown Figure 49.

Figure 49 Libya Greenstream Pipeline



Source: Eni

Libya's LNG plant in Marsa El Brega was built in the late 1960s by Esso and has a nameplate capacity of about 3.54 bcm per year. Libya was the second country in the world (after Algeria in 1964) to export LNG in 1971. However, U.S. sanctions prevented Libya from obtaining necessary technology to separate out LPG from the natural gas, thereby limiting the plant's output by over half of capacity. In 2010 LNG exports decreased to 0.34 bcm, all of which was exported to Spain[76].

In May 2005 Shell signed a long-term gas exploration and development deal with NOC for the upgrade of the existing LNG plant at Marsa El Brega. Long-delayed plans to rejuvenate and upgrade the plant by Shell may be revived

[75] http://www.eia.gov/countries/cab.cfm?fips=LY
[76] http://www.eia.gov/countries/cab.cfm?fips=LY

under the new regime. Shell had also agreed to build a new LNG plant if it found enough gas, but the company's exploration efforts were unsuccessful[77].

9.5. *Industry Organisation*

Libya's natural gas industry is mostly state-run, although a number of international firms participate in the sector. The NOC has overseen the oil and gas sector since 2006, when Colonel Qadhafi dissolved the Ministry of Oil.

NOC operates through several subsidiaries, the most significant being[78]:

- Arabian Gulf Oil Company (Agoco), formed by NOC in 1979 to take over the assets of the BP and Hunt joint venture, as well as Amoseas (the Chevron and Texaco JV). Agoco's production comes from the Sarir, Nafoora and Messla fields.

- Waha Oil Company (WOC), the largest of NOC's subsidiaries and was created by NOC to take over the operations of the US Oasis consortium - of Conoco, Marathon, Amerada Hess - when it was forced to abandon Libya due to sanctions. WOC operates the Sidra terminal.

- Sirte Oil Company (SOC), established in 1981 to takeover Exxon's Libyan holdings, but later also took Grace Petroleum's assets when it departed Libya in 1986. Its assets include the Marsa El Brega LNG plant and it operates the Nasser, Raguba, Attahaddi and Assoumoud fields.

- Zueitina Oil Company (ZOC) , created after the departure of Occidental Petroleum in 1986 to operate the five Intisar fields in the Sirte Basin, plus other interests previous held by Occidental. ZOC also operates the Zueitina terminal. ZOC is now owned by NOC (87.5 %) and OMV (12.5 %).

NOC controls the gas industry and is responsible for gas exploration and production, processing, transmission, distribution and exports of gas and liquids. Gas production is mostly undertaken by SOC on behalf of NOC's Gas Projects Department, but WOC and Agoco also control significant reserves.

NOC also has participation agreements with international companies and such agreements have developed into exploration and production sharing agreements. International companies that participate in exploration, production, and transportation of natural gas in Libya include Eni, BP, Shell, ExxonMobil and others.

[77] http://www.eiu.com/index.asp?layout=ib3Article&article_id=1868551171&pubtypeid=1142462499&country_id=1200000320&category_id=775133077&rf=0
[78] http://www.menas.co.uk/localcontent/home.aspx?country=73&tab=industry

9.6. Gas Regulatory Structure

NOC has overseen the oil and gas industry since 2006 and is responsible for implementing the Exploration and Production Sharing Agreements (EPSA) with international oil companies (IOCs). NOC is also responsible for field development and improvements as well as downstream activities.

The National Transitional Council (NTC) of Libya plans to establish a new oil ministry, which will share control of the hydrocarbons sector with the NOC. Under the new set-up, the ministry will formulate policy in the sector while the NOC will play a purely commercial role[79].

A priority policy concern for the Libyan government is to significantly increase the country's natural gas production. Libya plans to use more natural gas domestically for power generation in order to free up more oil for exports. It also wants to expand existing pipeline and LNG exports, particularly to Europe, by exploring its large gas reserves. These objectives will be met by further promoting the development of existing and new discoveries, while at the same time reducing the volumes of flared natural gas (estimated at 3.54 bcm in 2009)[80].

9.7. Similarities to Israel

There are similarities between Libya and Israel:

- Israel and Libya both have national policies on developing natural gas as a primary energy source for electricity generation.
- Both countries' reserves are dominated by non-associated gas fields.

9.8. Differences to Israel

There are some differences between Libya and Israel:

- Israel's potential gas reserves are just a little higher than Libya's proven reserves.
- Libya is favourably located with respect to the gas markets in Europe and is connected directly by a major pipeline system to Europe
- Libyan state backed NOC has played an active role in exploring and producing gas unlike the situation in Israel where the state role has been confined to the development of a gas transportation system
- Libya does not import natural gas while Israel imports gas from Egypt.

9.9. Lessons Leant

The following are the main lessons:

---

[79] http://www.eiu.com/index.asp?layout=ib3Article&article_id=1868551171&pubtypeid=1142462499&country_id=1200000320&category_id=775133077&rf=0
[80] http://www.eia.gov/countries/cab.cfm?fips=LY

- Libya has failed to capitalise on the potential for gas production and exports through the political problems of the previous regime
- There is limited private involvement in the gas industry in Libya which has limited access to modern technology.

10. Malaysia

10.1. Key Issues

Malaysia is the world's tenth largest holder of natural gas reserves, with proven reserves of 2,400 bcm, and is the third largest exporter of LNG in the world after Qatar and Indonesia in 2010, exporting over 30 bcm of LNG, which accounted for 10% of total world LNG exports.

Domestic consumption has been increasing over the years, reaching 35.7 bcm, or just over 50% of production in 2010. Most of the domestic demand came from industries and commercial entities in Peninsular Malaysia, while the largest reserves are located offshore of Sarawak and Sabah, and are mostly reserved for LNG exports. This unique geographical issue has led to a shortfall in domestic supply to the Peninsular Malaysian demand.

Malaysia's three LNG plants are located at Bintulu in Sarawak. Gas feedstock is provided by a cluster of fields about 200 kilometres offshore in the South China Sea and is entirely committed under LNG contracts with customers mainly in Japan, Korea and Taiwan.

Even if Malaysia could spare gas from some of these fields for the domestic market there is no pipeline connection with the Malaysian Peninsula, where almost three quarters of the country's 28 million people reside. Smaller gas fields offshore from the Malaysian Peninsula are rapidly depleting.

The other issue to consider is that Malaysia's domestic prices are considerably lower than export or international LNG prices. Therefore, producers do not have the incentives to sell to the domestic market and prefer to continue to export LNG.

To fill the growing shortfall in domestic supply, Petronas is constructing a floating LNG import terminal, with capacity of 5.2 bcm per year, off the coast from Malacca, south of Kuala Lumpur. This LNG terminal is expected to come online in 2012. In addition, Petronas recently announced plans for a second import terminal as part of a new petrochemical complex at Pengerang in southern Johor[81].
LNG import deals have been made with Australia, Qatar and GDF Suez of France. Gladstone LNG venture (GLNG) of Australia signed an accord to sell 2.7 bcm a year of the fuel to its partner Petronas for 20 years beginning in

[81] http://www.seaaoc.com/news-old/qatar-lng-to-southeast-asia

2014, with an option for an additional 1.3 bcm[82]. Petronas has also recently struck an LNG import deal with Qatar to buy 2 bcm per year from 2013 for at least 20 years[83].

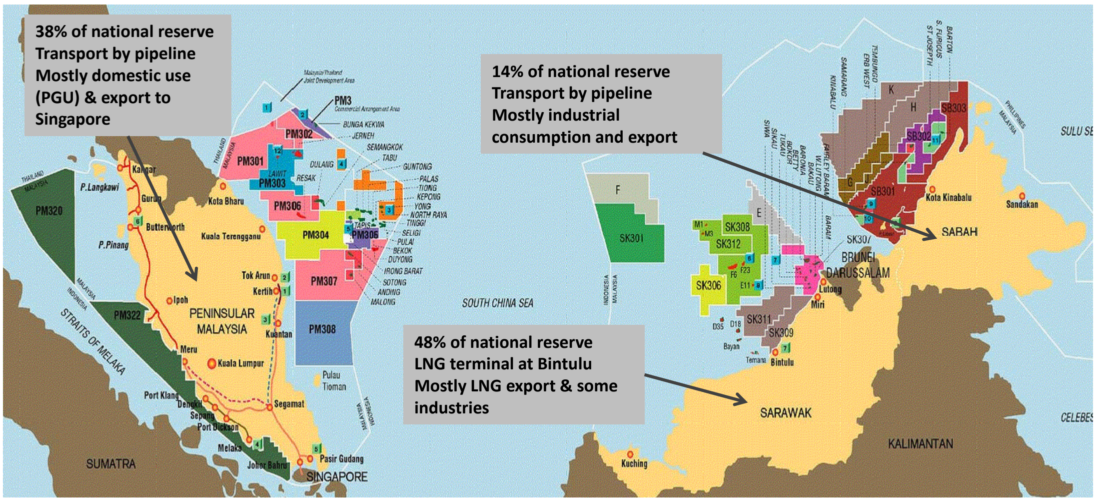
In addition, GDF Suez has entered into an agreement with Petronas LNG, a wholly owned subsidiary of Petronas, under which, GDF Suez will supply Petronas LNG with 3.4 bcm of LNG from August 2012 over a 3.5 year period[84].

10.2. Basic Data

10.2.1. Proven Reserves

Malaysia was the world's tenth largest holder of natural gas reserve, with proven reserve of 2,400 bcm as at 31 December 2010 compared to 1,600 bcm as at 31 December 1990. The largest reserves are offshore Sarawak, amounting to 48% of the national reserves. The second largest reserves are on the east coast of Peninsular Malaysia, at 38% of national reserves. The west coast of Sabah holds the rest (14%) of national reserves[85]. Figure 50 shows the locations of Malaysia's gas reserves.

Figure 50 Malaysia Gas Reserves



Source: Energy Commission, Natural Gas Utilization in Malaysia, presentation slides, undated

10.2.2. Exports

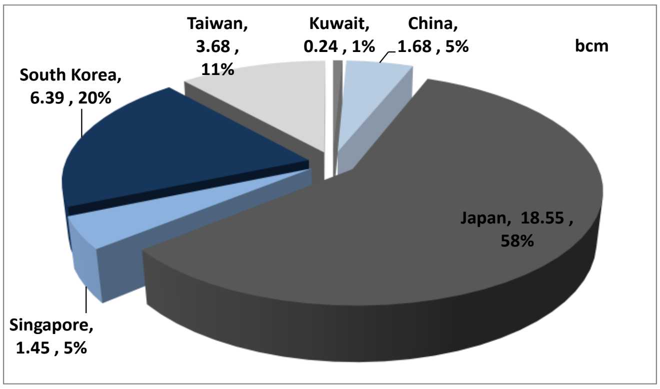
Malaysia is the third largest exporter of LNG in the world after Qatar and Indonesia in 2010, exporting over 30 bcm of LNG, which accounted for 10%

[82] http://www.lngpedia.com/2009/06/20/malaysia-will-import-gas-from-australia-to-meet-local-demand/
[83] http://arabnews.com/economy/article497893.ece
[84] http://www.lngworldnews.com/gdf-suez-petronas-sign-lng-deal/
[85] Petronas, The Gas Industry in Malaysia, 2008

of total world LNG exports. Japan, South Korea, and Taiwan were the three primary purchasers. Malaysia also exports around 1.5 bcm per year of natural gas via pipeline to Singapore. Figure 51 shows Malaysia's export destinations.

Malaysia has several long term (15-20 years) LNG supply contracts with Japan, with several of those being renewed contracts which have expired in late 2000s. South Korea and Taiwan also has long term and medium term LNG supply contract starting from mid-1990s[86]. In addition, Malaysia signed a 25-year supply contract with China in 2006[87].

Figure 51 Malaysia Gas Export, 2010



Source: BP Statistical Review of World Energy, June 2011

10.2.3. Production

Natural gas production has been rising steadily, reaching 66.5 bcm in 2010. However, growth in production has slowed since 2005 as shown in Table 25 and Figure 52.

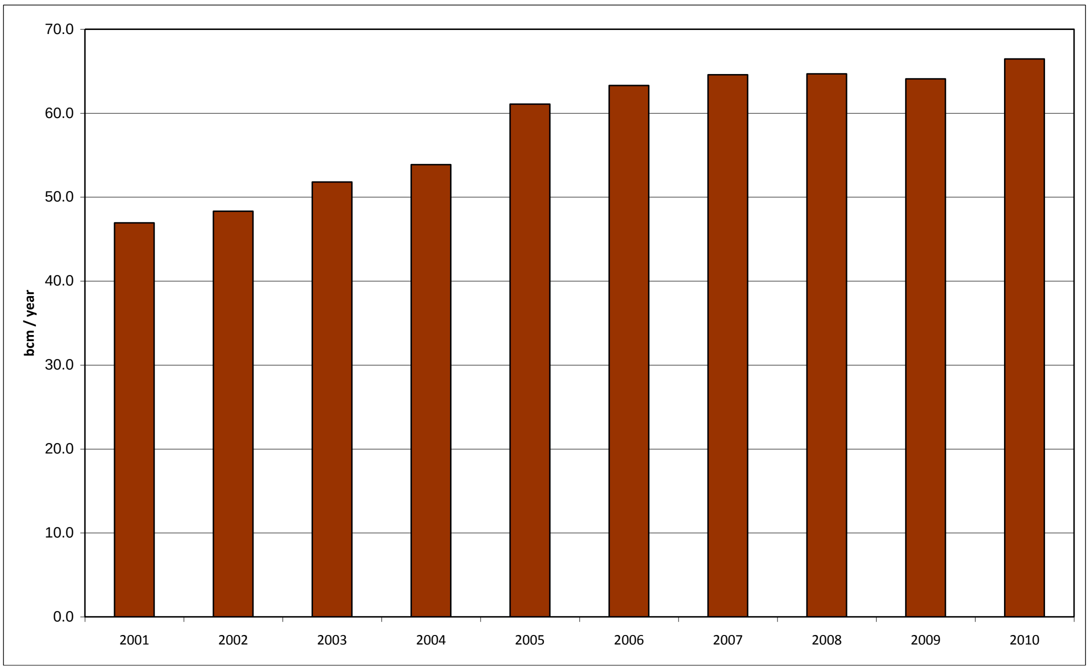
Table 25 Malaysia Gas Production (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
46.9	48.3	51.8	53.9	61.1	63.3	64.6	64.7	64.1	66.5

Source: BP Statistical Review of World Energy, June 2011

[86] http://www.mlng.com.my/Milestones.html
[87] http://www.zoomchina.com.cn/new/content/view/17105/81/

Figure 52 Malaysia Gas Production



Source: BP Statistical Review of World Energy, June 2011

10.2.4. Consumption

Malaysia was initially an importer of natural gas. As domestic production started, consumption rose steadily, reaching almost 36 bcm in 2010. Most domestic consumption use gas produced from offshore fields on the east of Peninsular Malaysia. The Peninsular Gas Utilisation (PGU) project, completed in 1997, supplies natural gas via its pipeline network mostly to the power sector (around 60% of gas transported through the PGU network), and other industrial and petrochemical users (around 32%). The remaining 8% is exported to Singapore via pipelines[88].

Demand from industrial and power sector customers in Peninsular Malaysia have been increasing, leading to Malaysia importing natural gas from Indonesia (since 2002), Vietnam (since 2003) and Thailand (since 2005). To date about 20% of Peninsular Malaysia's gas demand is met by import sources[89].

Furthermore, other import deals have been made. Beginning in 2014 the country will import over 2.7 bcm per annum of LNG from Australia to meet the rising domestic demands and to counter the dwindling domestic discoveries[90]. An LNG import deal with Qatar to import 2 bcm per annum from 2013 has

[88] Petronas, The Gas Industry in Malaysia, 2008
[89] http://www.gasmalaysia.com/about_gas/future_gas_industry.htm
[90] http://www.lngpedia.com/2009/06/20/malaysia-will-import-gas-from-australia-to-meet-local-demand/

been recently made[91]. Most recently in mid-2011, an agreement with GDF Suez has been struck, in which GDF Suez will supply Petronas with 3.4 bcm of LNG from August 2012 over a 3.5 year period.

Natural gas consumption in Sarawak and Sabah (East Malaysia) is mostly for fertiliser industries and as feedstock to petrochemical industries. All of the LNG produced in the facility in Sarawak is exported.

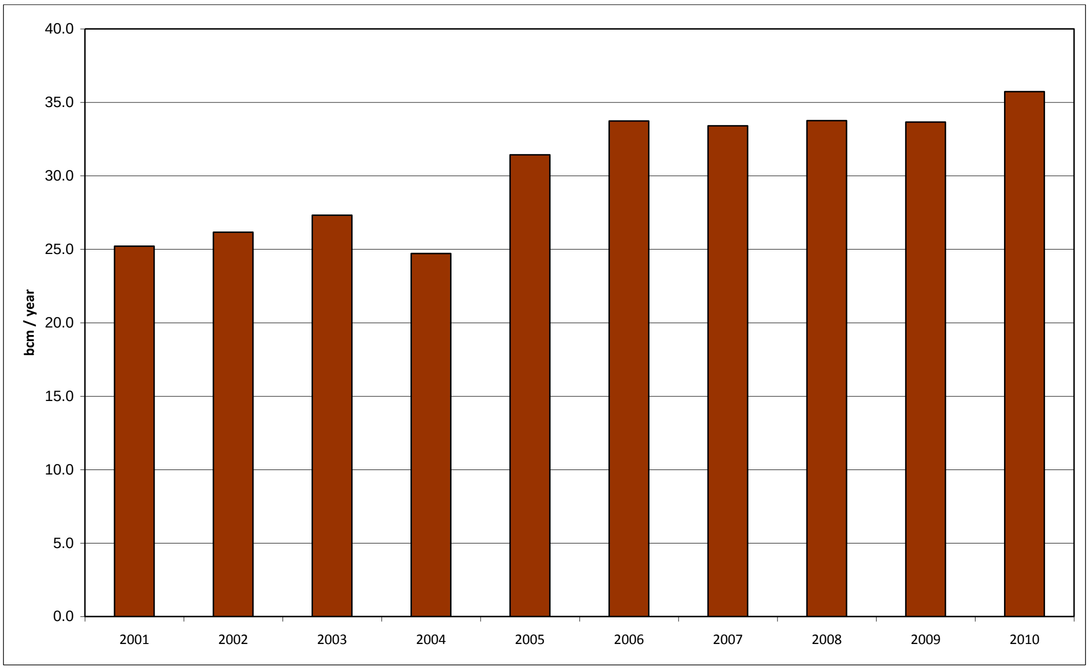
Details of consumption are shown in Table 26 and Figure 53.

Table 26 Malaysia Gas Consumption (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
25.2	26.2	27.3	24.7	31.4	33.7	33.4	33.8	33.7	35.7

Source: BP Statistical Review of World Energy, June 2011

Figure 53 Malaysia Gas Consumption



Source: BP Statistical Review of World Energy, June 2011

10.2.5. Reserves/Production

The proven reserve/production ratio in 2010 is 2397/66.5 = 36 years.

10.2.6. Reserve/Consumption

The proven reserve/production ration in 2010 is 2397/35.7 = 67 years.

[91] http://arabnews.com/economy/article497893.ece

10.2.7. Natural Gas Rents (% of GDP)

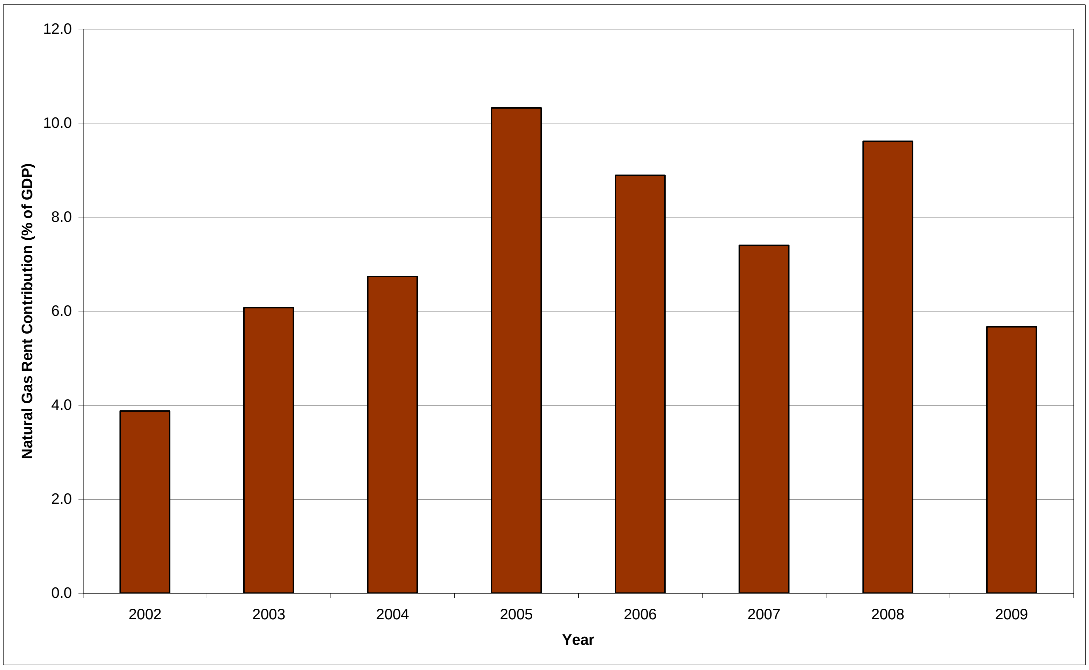
Contributions of natural gas rents to Malaysia's GDP are as shown in Table 27 and Figure 54.

Table 27 Malaysia Natural Gas Rents (% of GDP)

2002	2003	2004	2005	2006	2007	2008	2009
3.9	6.1	6.7	10.3	8.9	7.4	9.6	5.7

Source: World Bank

Figure 54 Malaysia Natural Gas Rents (% of GDP)



Source: World Bank

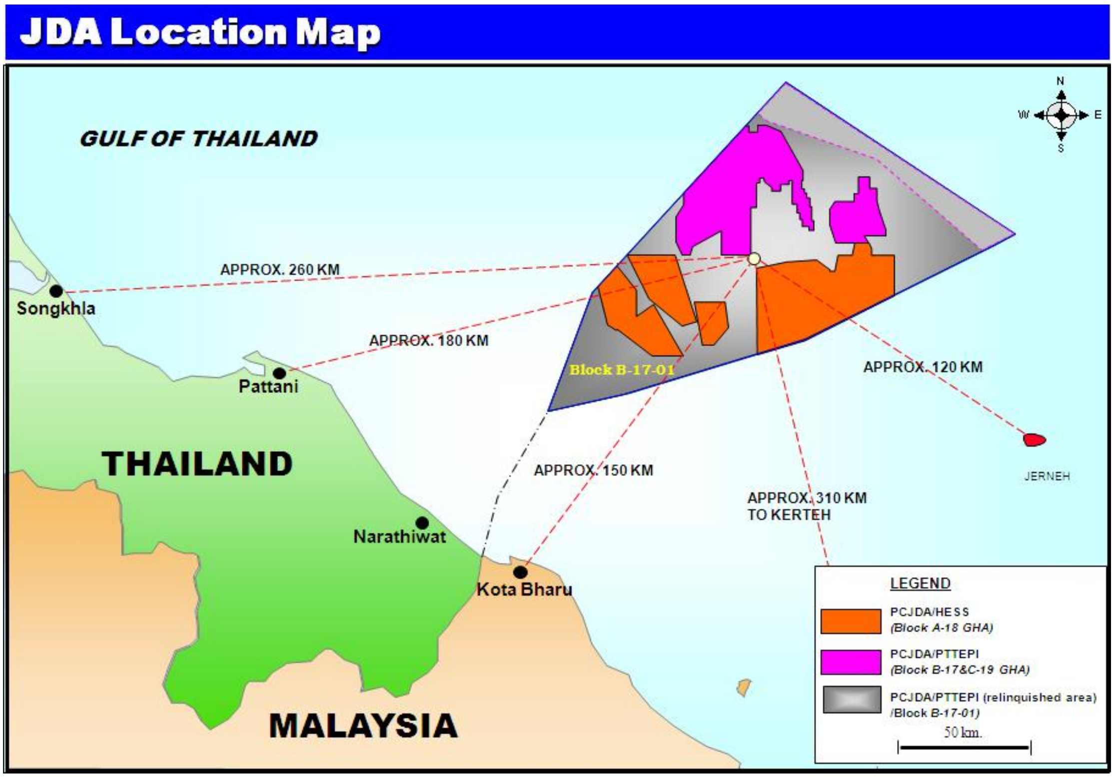
10.3. Gas Production Facilities

One of the most active areas for natural gas exploration and production is the Malaysia-Thailand Joint Development Area (JDA), located in the lower part of the Gulf of Thailand (see Figure 55). The JDA reportedly holds 300 bcm of proved plus probable gas reserves. The area was divided into three blocks, Block A-18, Block B-17, and Block C-19, and is administered by the Malaysia-Thailand Joint Authority (MTJA), with each country owning 50% of the JDA's hydrocarbon resources.

The exploration period for Blocks A-18, B-17 and C-19 expired on 20 April 2002. Current contractors retain the Gas Holding Areas (GHA) in these blocks. Those areas that were relinquished to MTJA have been merged as a new block in the JDA. The production sharing contract for the new Block B-

17-01 was signed between MTJA and contractors on 30 September 2004 for the right to explore and exploit petroleum in the JDA.

Figure 55 Malaysia – Thailand Joint Development Area



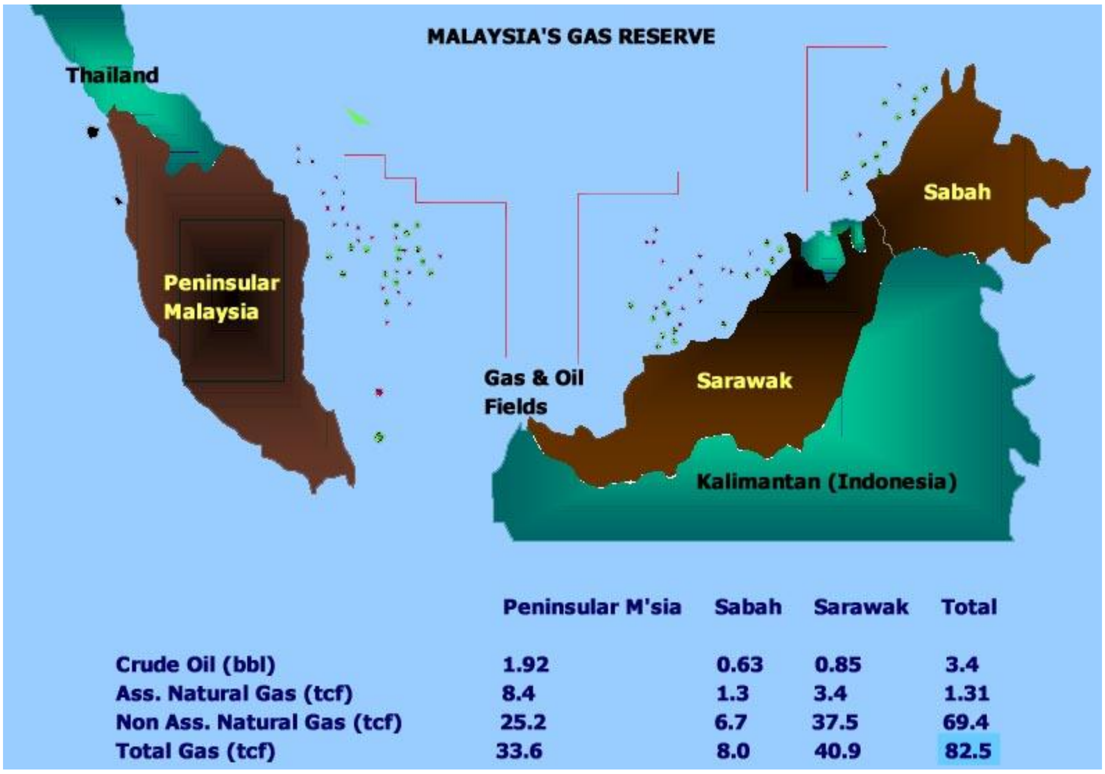
Source: MTJA website

Block B18 phase 1 came online in 2005, and in September 2009, production was reported to have reached 0.028 bcm per day. Block B17 came online in 2009. In October 2010, B17 gas shipments reportedly reached 0.009 bcm per day, with half going to Thailand and half to Malaysia[92].

Production from offshore Sarawak and Sabah fields is mostly used for LNG export (see Figure 56).

[92] http://www.eia.gov/countries/cab.cfm?fips=MY

Figure 56 Malaysia Gas Fields



	Peninsular M'sia	Sabah	Sarawak	Total
Crude Oil (bbl)	1.92	0.63	0.85	3.4
Ass. Natural Gas (tcf)	8.4	1.3	3.4	1.31
Non Ass. Natural Gas (tcf)	25.2	6.7	37.5	69.4
Total Gas (tcf)	33.6	8.0	40.9	82.5

Source: Petronas Gas Berhad website

Several new gas projects include[93]:

- Block SK309 & SK311 – located 137 miles offshore Sarawak, developed by Murphy Oil and Petronas, end of 2010 will produce 0.007 bcm per day for the next 5 years. Phase 2 could produce 0.01 bcm per day for another 10 years. Gas to be processed in Bintulu for LNG export
- The Kumang Cluster in Block SK306 – a major gas field offshore Sarawak, developed by Petronas, Phase 1 is expected to provide 0.014 bcm per day to the Bintulu LNG terminal
- Three new gas fields in Block SK 308 – 124 miles offshore Sarawak, are being jointly developed by Shell and Petronas. They are projected to produce first gas of 0.0025 bcm per day in 2012

10.4. Gas Export and Import Facilities

The Bintulu LNG complex on Sarawak is the main hub for Malaysia's natural gas industry. The Bintulu facility is the largest LNG complex in the world, with 3 LNG processing plants, 8 production trains, and a total liquefaction capacity of 30.8 bcm per year.

[93] As above

LNG is primarily transported by Malaysia International Shipping Corporation (MISC), which owns and operates 27 LNG tankers, the single largest LNG tanker fleet in the world by volume of LNG carried. MISC is 62% owned by Petronas.

Construction began on the Sabah Oil and Gas Terminal in 2007 and it is expected to be completed by 2012. It will have handling capacity of 0.037 bcm per day of natural gas per day and will primarily serve Malaysia's export markets. The Sabah-Sarawak Gas Pipeline project is part of this development. This pipeline will connect the gas producing areas and will be able to transport gas from Sabah to Bintulu LNG processing and export terminal.

10.5. Industry Organisation

Malaysia’s national oil and gas company, Petroleam Nasional Berhad (Petronas), holds exclusive ownership rights to all oil and gas exploration and production projects in Malaysia and is the single largest contributor of Malaysian government revenues, almost half in 2009, by way of dividends and taxes.

The company has a monopoly on all upstream natural gas developments, and also plays a leading role in downstream activities and the LNG trade. Most natural gas production comes from production sharing agreements operated by foreign companies in conjunction with Petronas.

Petronas operates the Peninsular Gas Utilisation system (see Figure 57) through its majority-owned subsidiary, Petronas Gas Berhad which involves six processing plants and approximately 2,505 kilometres of pipelines to process and transmit gas to end-users in the power, industrial and commercial sectors in Peninsular Malaysia and Singapore.

Figure 57 Malaysia Peninsular Gas Utilisation System

Source: Gas Malaysia website

The distribution network of natural gas is vested with PGB, which is responsible for processing and distributing the gas to customers. To date, there are only two other companies licensed by the Energy Commission to distribute gas¸ which are Gas Malaysia Sdn Bhd in Peninsular Malaysia and Sabah Energy Corporation Sdn Bhd for Sabah.

Malaysian International Shipping Company Berhad (MISC) serves as Petronas' primary LNG transportation provider. MISC transports LNG from the Bintulu LNG facility to export destinations.

Bintulu port is the only export gateway for Malaysia's LNG and is under the jurisdiction of the Bintulu Port Authority (BPA), a Federal statutory body under the purview of the Ministry of Transport. BPA's responsibilities include the overall supervisions of all the activities at Bintulu port, including the utilisation of port utilities and operations and acting as trade facilitator.

10.6. Gas Regulatory Structure

As prescribed by the Petroleum Development Act 1974, the entire ownership inclusive of the privilege rights for exploring, exploiting, winning and obtaining petroleum is vested solely on Petronas, with direct purview of the Prime Minister. Nonetheless, the rights may be delegated to the interested entities by contracting the production sharing agreements with Petronas and authentication by the Petroleum Authority. Effectively, Petronas also acts as the regulator in the upstream gas sector, while it also plays a significant role in the downstream sector.

In January 1991, the Act was amended and the responsibility to regulate all activities in the downstream sector of the petroleum industry is to be shared by the Ministry of Domestic Trade and Consumer Affairs (“MDTCA”) and the Ministry of International Trade and Industry (“MITI”) Thereafter, MITI is responsible for the issuance of licences for the processing and refining of petroleum and the manufacture of petrochemical products, whilst MDTCA issues licences for the marketing and distribution of petroleum products. A licence for retail of LNG is issued by MDTCA.

The Gas Supply Act 1993, on the other hand, is gazetted to provide local guidelines for the licensing of the supply of gas for domestic consumers, and the price, installation and appliances with respect to transportation and gas consumption. The Energy Commission is empowered to enforce the Act and to ensure that the interest of the consumer is safeguarded besides carrying on all requisite tasks such as to secure the licence, regulate the composition, pressure, purity and volume of gas supplied through pipelines.

The Energy Commission of Malaysia, created under the Energy Commission Act 2001, is responsible for all matters relating to the supply of gas through pipelines and the use of gas as provided under the Gas Supply Act.

10.7. Similarities to Israel

There are similarities between Malaysia and Israel:

- Both countries have offshore gas fields that border with other countries. Malaysia’s experience with dealing with offshore gas fields may be relevant to Israel in the future.
- Both countries have neighbouring countries which can export or import gas
- Both Malaysia and Israel have offshore gas fields that straddle borders with other countries. Malaysia has formed an agreement with Thailand to develop a defined gas field area together. The Memorandum of Understanding (MOU) was signed in 1979 between the two Governments on the establishment of a Joint Authority for the exploration and exploitation of the resources. Israel has a joint field with Cyprus

10.8. Differences to Israel

There are differences between Malaysia and Israel:

- Although both Malaysia and Israel were initially net gas importing countries, Malaysia's initial gas consumption was very low at around 1 bcm per annum, and when gas production activities begun, it was geared towards export.
- Primary energy consumption fuel mix of the two countries is also quite different with Israel using a significantly higher proportion of coal than Malaysia.

10.9. Lessons Leant

The following are the main lessons:

- Malaysia's unique geographical location presents difficulties in diverting offshore gas production from Sarawak and Sabah to where domestic demand is the highest, in Peninsular Malaysia, creating a shortfall in domestic supply. This problem is enhanced by the low domestic prices, which further provide disincentives for producers to sell to the domestic market and encourage LNG imports, despite being the world's third largest LNG exporter.
- Connecting domestic demand with supply is essential to ensure domestic demands are met.
- Setting domestic prices close to export prices will give incentive to gas producers to meet both export and domestic market demands.

11. Netherlands

11.1. Key Issues

After the discovery and development of the Groningen field in the early 1960s, which is one of the largest gas fields in Continental Europe, the Netherlands became one of the biggest gas producing countries in Europe. Today Dutch gas reserves account for approximately 29% of all the European natural gas reserves and 0.7% of global natural gas reserves[94].

Although domestic gas production (73.7 bcm) could easily cover the national gas requirements (45.3 bcm), only 46.4% of the Dutch natural gas requirements are met through domestic natural gas production as a result of the large exports. Approximately 52.7 bcm of 73.7 bcm natural gas produced is exported.

Back in 1963, the Government of the Netherlands (GoN) was under the impression that nuclear power would become the dominant source of energy

[94] Global Legal Group (2011) The International Comparative Guide to: Gas regulation 2011, available at: http://www.iclg.co.uk/khadmin/Publications/pdf/4168.pdf

generation, replacing natural gas. In that respect, GoN decided to export a significant part of the reserves, without worrying about the depletion of gas reserves. However, in 1974, when it was clear that energy generation could not depend on nuclear energy alone, the small fields policy was adopted in order to increase the life of the Groningen gas field and domestic production for as long as possible. After this, Groningen was no longer allowed to export gas.

Nederlandse Aardolie Maatschappij (NAM), an ExxonMobil-Shell joint venture, initiated the exploration of potential smaller fields and succeeded in discovering dozens of new gas fields[95]. The strategy followed by the Netherlands in order to prolong the lifespan of the current gas resources, and continue the transformation of the country into a net importer was to rely primarily on the small fields for the domestic production of gas. At the same time the Groningen field has been kept as a swing producer to account for any seasonal fluctuations. As a result, only a third of the domestic gas consumption now comes from the Groningen field.

It is estimated that most of the reserves in the, non-Groningen, small fields will be depleted by 2040, as shown in Figure 58. The Groningen field will not be depleted by that time, but it will not be able to act as swing producer. With no further action taken, the Netherlands may become a net importer of gas within 15 years[96]. With that in mind, the Netherlands is taking steps to ensure greater sustainability of domestic gas resources, as well as making the necessary preparations for the time when, to meet gas demand, it will need to import from outside the EU.

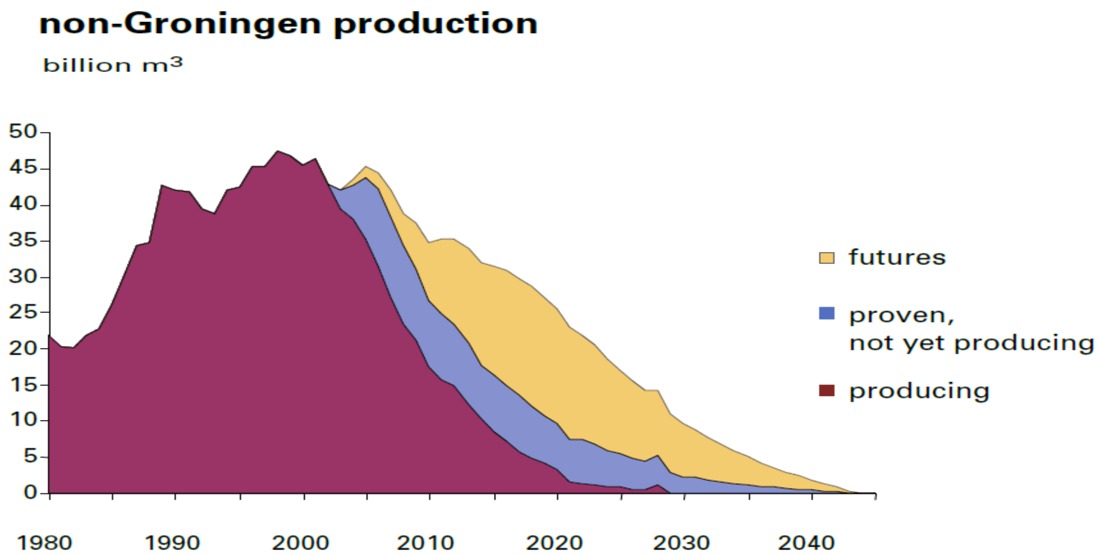
The preparations for large-scale imports of gas from Russia are partly bilateral, for instance by Gasunie (the publicly owned natural gas company of Netherlands) entering into contracts with the Russian company Gazprom. Another action taken to ensure adequate gas supply is the construction of LNG terminals, started in 2009, for the import of LNG in the future.

A major problem that Netherlands faced right after the discovery of the Groningen field was the accompanying appreciation of the currency, which reduced the profitability of manufacturing and service exports, known as Dutch Disease. Total exports from the Netherlands decreased markedly relative to GDP during the 1960s. However, the problem proved short-lived; from 1960s onwards, exports of goods and services have increase from less

[95] NAM website (2011) Natural gas in the Netherlands, available at: http://www.nam.nl/home/content/nam-en/general/natural_gas_in_the_netherlands/
[96] Ministry of Economic Affairs, Dutch Government (2009) Gas production in the Netherlands, available at: http://www.sodm.nl/sites/default/files/redactie/gas_letter_eng.pdf

than 40% of GDP to 65%[97], and therefore the fears of de-industrialisation did not materialise.

Figure 58 Netherlands Gas Production: Small Fields



Source: Dutch Ministry of Economic Affairs (2009)[98]

11.2. Basic Data

11.2.1. Proven Reserves

The Netherlands is one of the biggest gas producing countries in the world. Proven reserves are 1,200 bcm as at 31 December 2010 compared to 1,800 bcm as at 31 December 1990. The majority of the reserves, around 75%, are contained in the Groningen gas field whose original reserves were 2,800 bcm, making it the largest field in Europe. The total proven reserves in various small fields, both offshore and onshore, amount to approximately 300 bcm. In addition to the current proven reserves, the future producible reserves (i.e. reserves that can be expected on the basis of seismic surveys, but have not been confirmed by drilling), are estimated to add another 200-570 bcm. Out of the estimated future reserves one third is estimated to be located onshore and two thirds offshore.

11.2.2. Exports

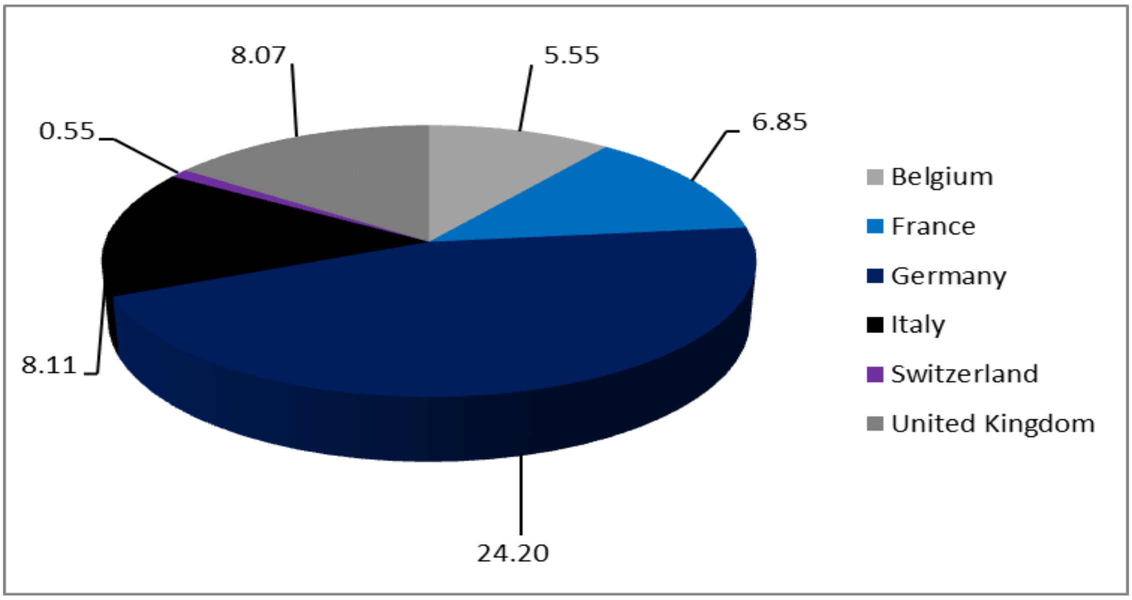
Total exports in 2010 were 53.33 bcm, all of which were via pipeline. Approximately 44% of the exported volumes in 2010 went to Germany, followed by Italy (15%) and UK (14.5%) as shown in Figure 59. The

[97] Institute of Economic Studies (2001), Lessons from the Dutch Disease: Causes, Treatment, and Cures, Working paper series W01:06, available at: https://ioes.hi.is/publications/wp/w0106.pdf
[98] Ministry of Economic Affairs, Dutch Government (2009) Gas production in the Netherlands, available at: http://www.sodm.nl/sites/default/files/redactie/gas_letter_eng.pdf

production of gas from the Groningen field was used to absorb seasonal fluctuations[99]. All of the excess gas produced was exported to EU countries.

Even though domestic production always exceeded domestic gas consumption needs, Gasunie has decided to import gas. This was because the commitments agreed for exports and domestic consumption structurally exceeded the average production ceiling of 80 bcm[100]. This ceiling was set by the third Energy Policy Paper, in 1995, and concerns all Dutch fields. Since the production from the Groningen field was the difference between the national production ceiling and the expected production from the small fields, the ceiling acted as a production limit for the Groningen field. The production ceiling was part of the small fields policy to prolong the life of the Groningen gas field.

Figure 59 Netherlands Gas Export Markets

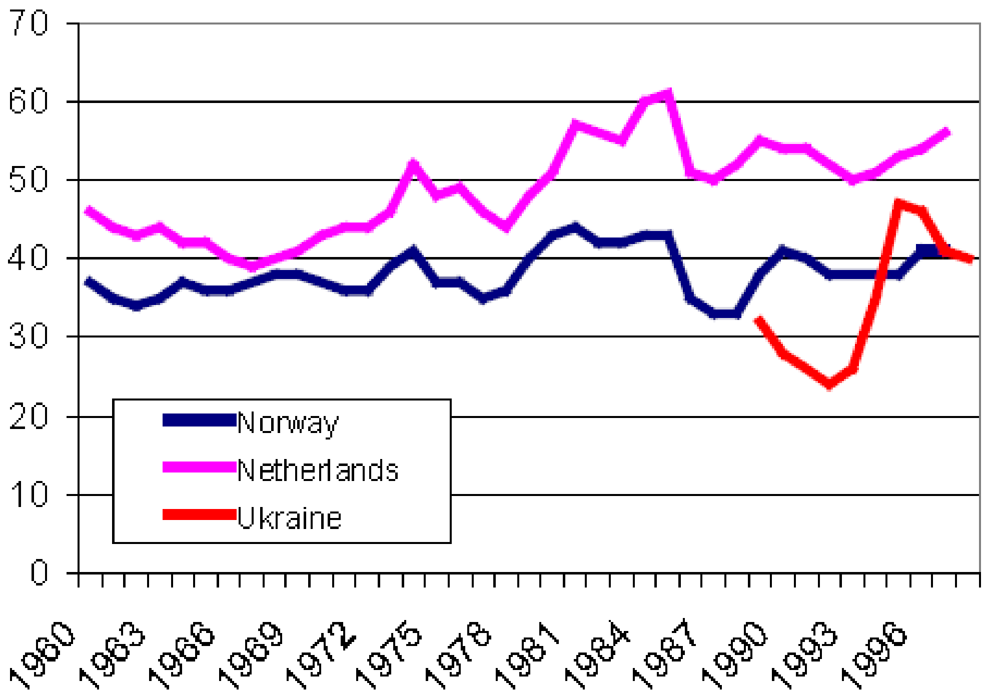


Source: BP Statistical Review of World Energy, June 2011

Exports of total goods and services increased from less than 40% of GDP in the 1960s to 65% in the 1980s, as shown in Figure 60[101].

[99] Ministry of Economic Affairs, Dutch Government (2009) Gas production in the Netherlands, available at: http://www.sodm.nl/sites/default/files/redactie/gas_letter_eng.pdf
[100] Ministry of Economic Affairs, Dutch Government (2009) Gas production in the Netherlands, available at: http://www.sodm.nl/sites/default/files/redactie/gas_letter_eng.pdf
[101] T Gylfason, 2001, Natural resources and economic growth what is the connection, available at: https://notendur.hi.is/gylfason/pdf/kievshort.pdf

Figure 60 Exports of Goods and Services in the Netherlands, 1960-1996



11.2.3. Production

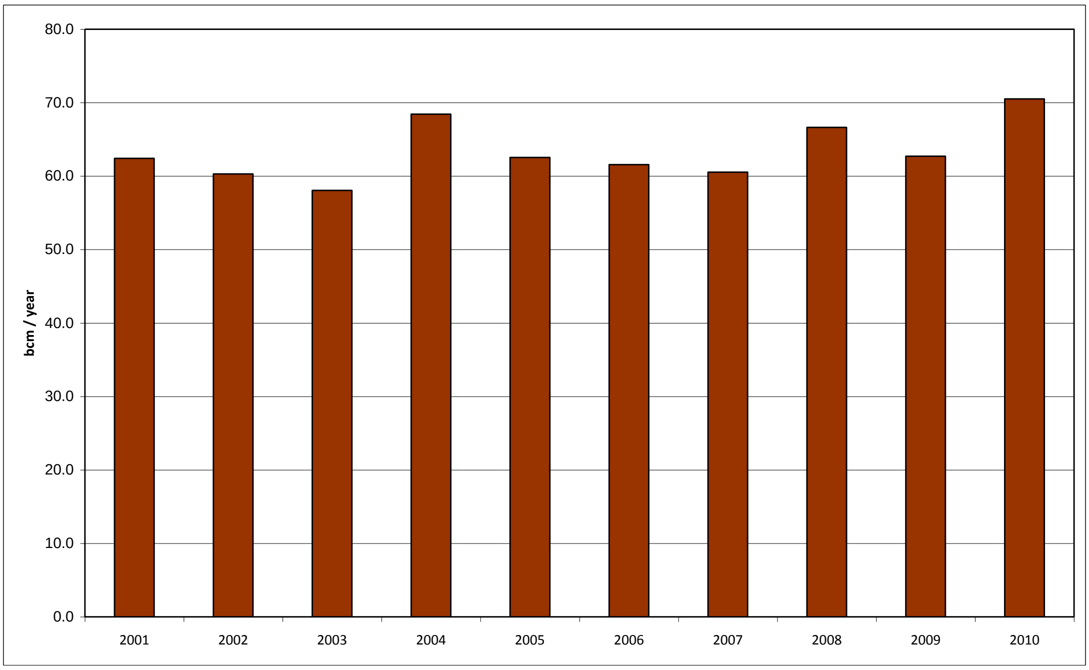
Gas production in the Netherlands was 71 bcm in 2010. Gas production was at relatively low levels in 1970, but during the following seven years production increased almost exponentially reaching more than 80 bcm in 1976. However, after 1977, production was falling gradually reaching 55 bcm in 1988. Thereafter, production of gas increased gradually reaching a high level of 77 bcm in 1996, while remaining stable around 60 cm from 2000 until 2009, as shown in Table 28 and Figure 61.

Table 28 Netherlands Gas Production (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
62.4	60.3	58.1	68.5	62.5	61.6	60.5	66.6	62.7	70.5

Source: BP Statistical Review of World Energy, June 2011

Figure 61 Netherlands Gas Production



Source: BP Statistical Review of World Energy, June 2011

11.2.4. Consumption

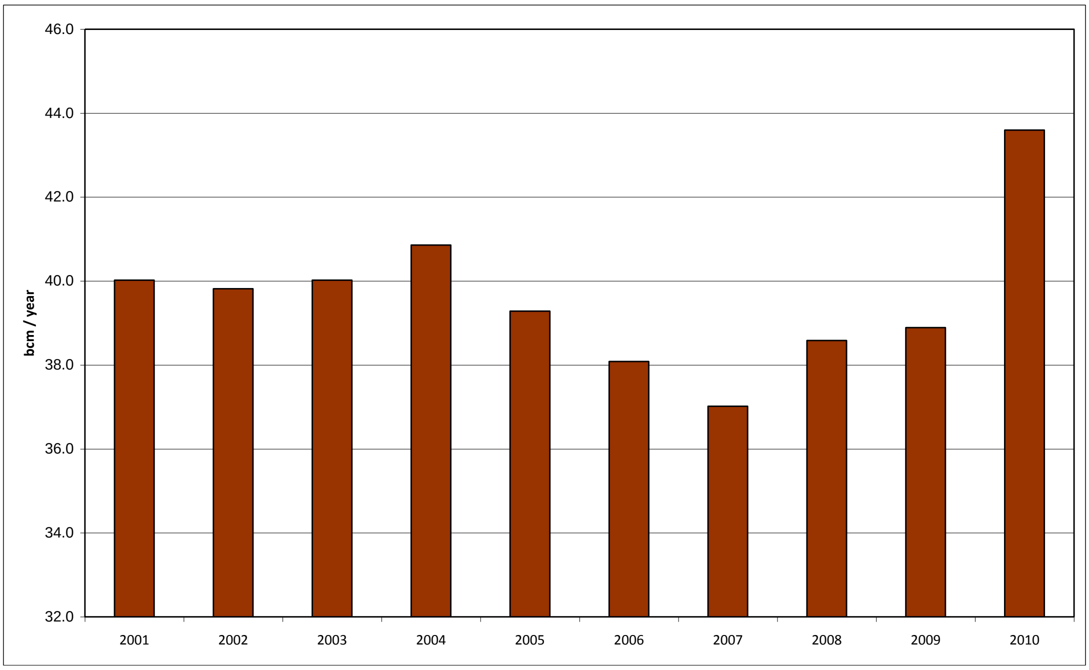
Gas consumption in 2010 was 44 bcm, which represents an increase of 13% compared to the 2000 consumption level (39 bcm). The change in gas consumption in the Netherlands is shown in Table 29 and Figure 62. The biggest gas consumer is the power generation sector.

Table 29 Netherlands Gas Consumption (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
40.0	39.8	40.0	40.9	39.3	38.1	37.0	38.6	38.9	43.6

Source: BP Statistical Review of World Energy, June 2011

Figure 62 Netherlands Gas Consumption



Source: BP Statistical Review of World Energy, June 2011

11.2.5. Reserves/Production

The reserves/production ratio is 1200/70.5 = 17 years.

11.2.6. Reserves/Consumption

The reserves/consumption ratio is 1200/ 43.6 = 28 years

11.2.7. Natural Gas Rents (% of GDP)

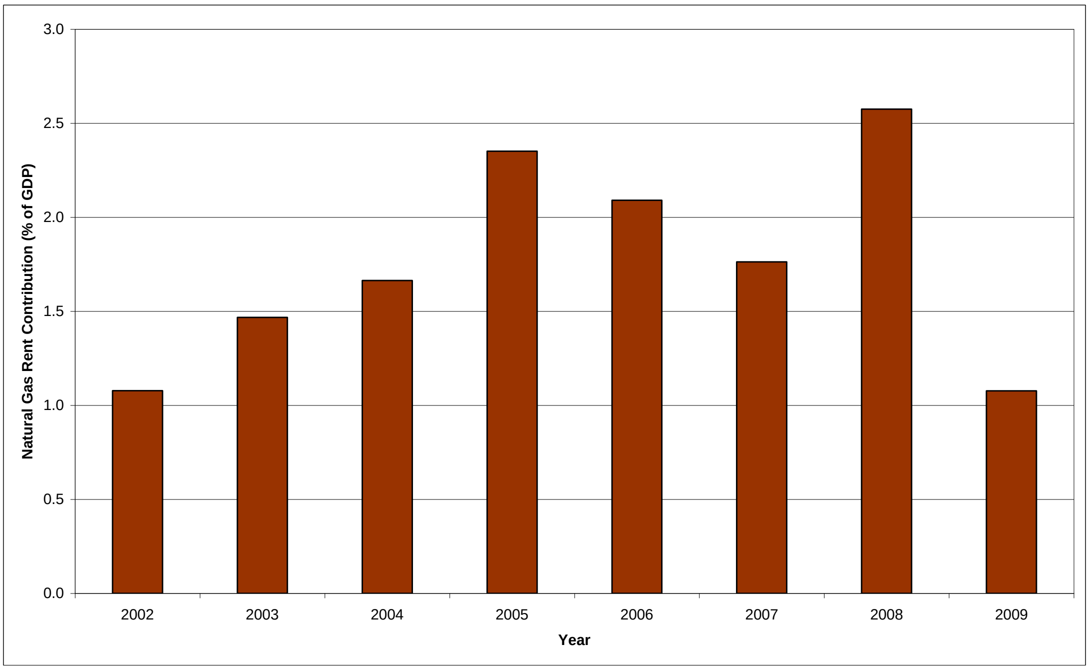
Contributions of natural gas rents to Netherlands' GDP are as shown in Table 30 and Figure 63.

Table 30 Netherlands Natural Gas Rents (% of GDP)

2002	2003	2004	2005	2006	2007	2008	2009
1.1	1.5	1.7	2.4	2.1	1.8	2.6	1.1

Source: World Bank

Figure 63 Netherlands Natural Gas Rents (% of GDP)



Source: World Bank

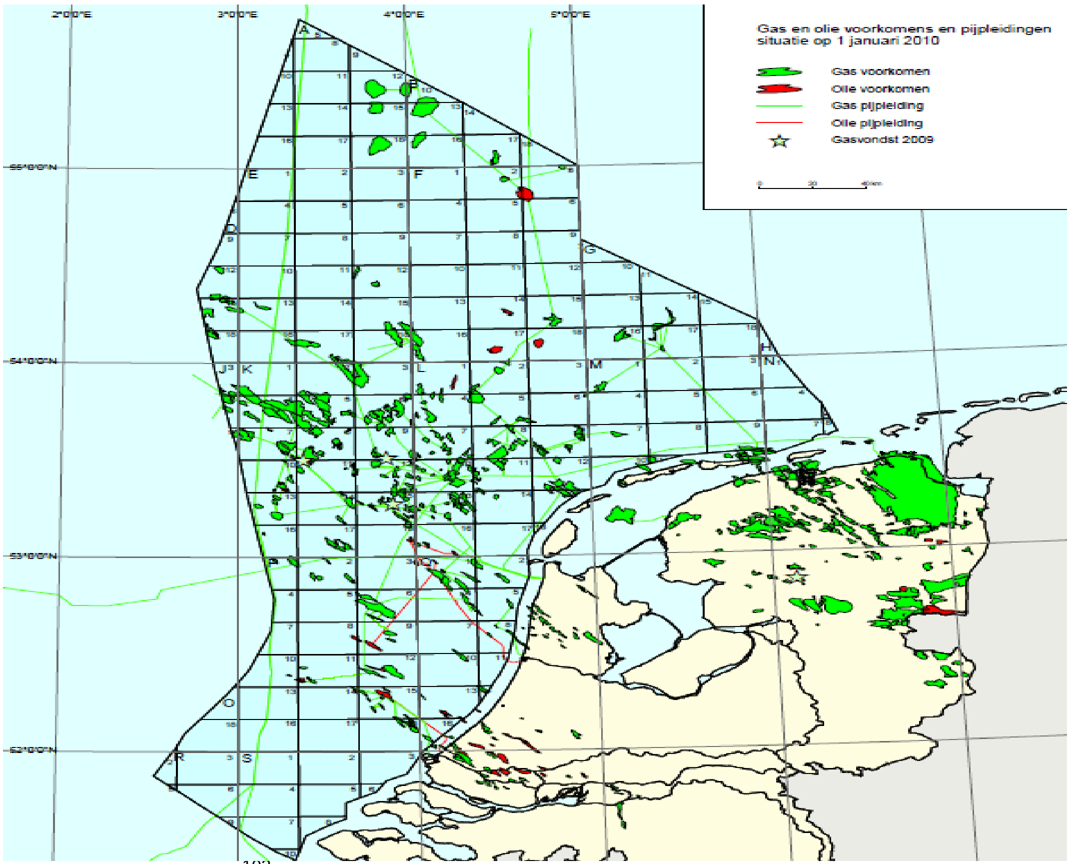
11.3. Gas Production Facilities

Since the start of gas production in the Netherlands 3,000 bcm of gas has been produced. Despite this, the reserves and resource base remains large; this is largely explained by the vast size of the Groningen gas field[102].

The distribution of gas fields and their areal extent can be seen in Figure 64.

[102] EBN (2011) Focus on Dutch gas, available at: http://www.ebn.nl/files/2011_06_01_ebn_focus_on_dutch_gas_2011.pdf

Figure 64 Netherlands Gas Fields



Source: NAM (2011)[103]

Given the discovery of the Groningen field in 1959, Dutch gas production was almost entirely concentrated in this gas field. However, a growing awareness of the need to preserve this field[104] and the necessity for exploration of smaller fields led to the development of the small fields policy. This policy was formalised in the Gas Act which obliges Gasunie to purchase all gas produced from small fields[105]. This regime acts as a safety net for oil companies by assuring them that they will be able to sell their gas at market prices and also providing them with a choice to either sell their gas to Gasunie or to another buyer. The Groningen field acts as a buffer stock, balancing the differences in supply and demand, as well as seasonal differences.

The high dependence on small fields for Dutch gas production is shown by the fact that, approximately two thirds of the total gas currently produced comes from small fields. The small fields policy has lowered the risk of gas

[103] Available at: http://www.nlog.nl/resources/Jaarverslag2009/NL/2009_map_gas_oil_reservoirs_NL.pdf
[104] Not only because of its size but also its good capabilities for acting as a flexible producer to balance supply and demand
[105] Ministry of Economic Affairs, Dutch Government (2011) Gas production in the Netherlands, available at: http://www.sodm.nl/sites/default/files/redactie/gas_letter_eng.pdf

supply in the Netherlands. Given the same analogy of small fields and the Groningen field usage, both onshore and offshore, the Netherlands will be able to continue production at the same rate until approximately 2030.

11.4. Gas Export and Import Facilities

Since the beginning of gas production in the Netherlands, the level of production was around twice the level of consumption. The Netherlands have always been a gas exporting country and more than 55 bcm were exported to other EU member states in 2010.

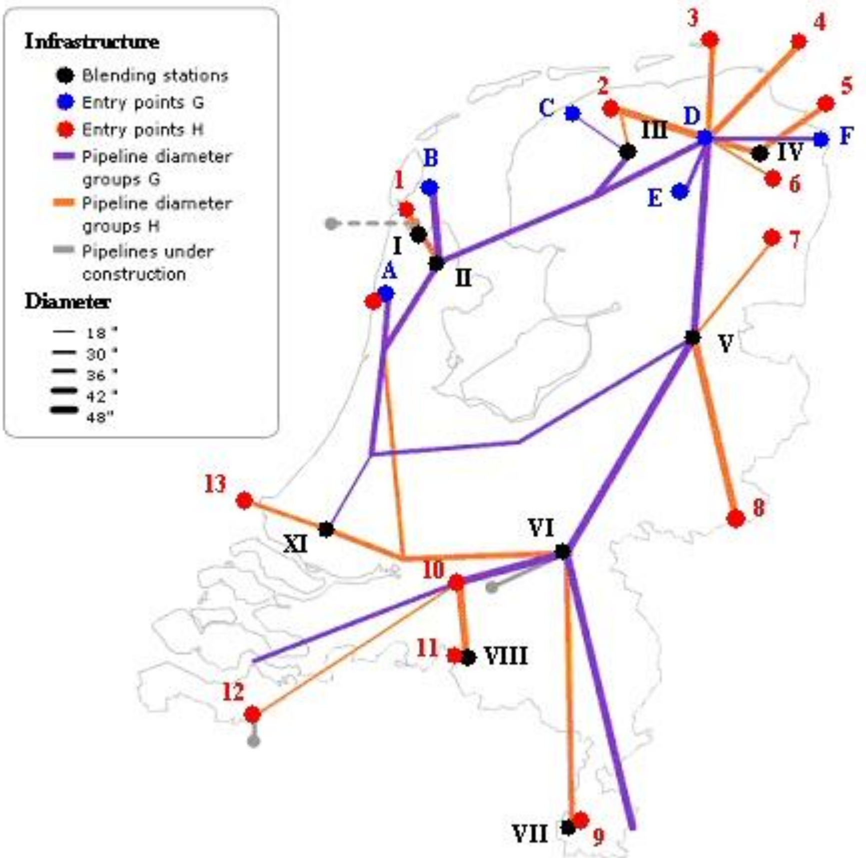
There are three import and export points:

- Germany interconnector (Trans Europa Naturgas Pipeline, capacity 15.5 bcm)
- Belgium interconnector (WEDAL, capacity 10 bcm)
- Uk interconnector (Bacton-Balgzand Line, capacity 16 bcm)

Gas Transport Services (GTS) is responsible for these interconnectors. An ‘entry/exit’ system applies to the gas transportation system. The entry and exit licences are granted on an individual basis, without the need to report the specific transport route for the gas. In this way, the system is more accessible, which facilitates the trading of gas.

Gasunie is responsible for the operation of the high- pressure transmission which is illustrated in Figure 65. The network consists of 11,500 km of pipeline.

Figure 65 Netherlands Gas Pipeline System



Source: ECN

The key position of the Netherlands in the gas market is attributed to its existing infrastructure, the rich gas supplies and its central location within Europe. In 2010 gas imports amounted to approximately 17 bcm, the transit volumes being a significant part of this[106]. The main suppliers of gas imports are Norway (48% of imports in 2010) and Russia (24% of imports).

Netherlands does not currently possess any operating LNG terminal. However, an LNG terminal, for importing purposes, with a 12 bcm annual potential is under construction near Rotterdam. A number of foreign companies – Dong Energy, OMV Gas International, Essent and E.On Ruhrgas – have each taken a 5% share in the terminal[107].

11.5. Industry Organisation

The gas market in the Netherlands is divided into the production sector of the natural gas industry, which is privately owned, and the wholesale sector which

[106] Ministry of Economic Affairs, Dutch Government (2009) Gas production in the Netherlands, available at: http://www.sodm.nl/sites/default/files/redactie/gas_letter_eng.pdf
[107] Global Legal Group (2011) The International Comparative Guide to: Gas regulation 2011, available at: http://www.iclg.co.uk/khadmin/Publications/pdf/4168.pdf

is partly private and partly state owned. The structure of the production of natural gas, in 2008, was characterised by monopolistic competition. The market was controlled by eleven producers with the dominant player being NAM accounting for about 75% of the domestic market[108].

GasTerra, a half state owned company (Shell 25% and Esso 25%) is responsible for buying gas from all NAM fields and selling the produced gas to downstream companies.

The high-transmission transport network is owned by Gas Transport Services (GTS, 100% state owned). The gas market comprises of sixteen registered regional network operators, the majority of which were state owned (51%), and the rest privately owned (49%). The network and trading activities are legally unbundled, while tariffs are regulated by the Dutch regulator (DTe)[109].

Energie Beheer Nederland B.V. (EBN) which is fully state owned plays an important role in the upstream sector. EBN is always the designated joint venture partner of any private company in the gas production sector and 40% of production activities belong to EBN. EBN has also the right to participate in exploration activities of off shore fields, given the request from the exploration company[110].

The downstream gas sector in the Netherlands is fully regulated by the market, since 2004, with no state intervention. There are approximately thirty parties currently involved in this market, but Essent, Eneco, Nuon and Delta together represent 85% of retail market share and are the dominant players.

11.6. Gas Regulatory Structure

The Dutch gas system is often referred to as the ‘Gas Building’ (Gasgebouw). The Gas Building was first established given the discovery of the Groningen field and its vast size. A production licence for the Groningen field was issued to NAM under the obligation that NAM would enter into a general partnership (the Maatschap Groningen) with EBN[111]. NAM has the majority of financial shares of the partnership (60%), but the voting rights are shared equally between the partners. The Maatschap Groningen entered into a gas sales agreement with Gasunie, which was a joint venture of Shell and ExxonMobil

[108] Energy Delta Institute (2011) Country Gas Profile: Netherlands, available at: http://www.energydelta.org/mainmenu/edi-intelligence-2/our-services/Country-gas-profiles/country-gas-profile-netherlands
[109] Energy Delta Institute (2011) Country Gas Profile: Netherlands, available at: http://www.energydelta.org/mainmenu/edi-intelligence-2/our-services/Country-gas-profiles/country-gas-profile-netherlands
[110] Dutch Ministry of Economic and Agricultural Affairs (2010) Economic Impact of the Dutch Gas Hub Strategy on the Netherlands, available at: http://www.brattle.com/_documents/UploadLibrary/Upload899.pdf
[111] Global Legal Group (2011) The International Comparative Guide to: Gas regulation 2011, available at: http://www.iclg.co.uk/khadmin/Publications/pdf/4168.pdf

(each 25%) and the state of Netherlands (50%), which covers the whole level of production from the Groningen field.

The exploration and production activities of gas in the Netherlands are dictated by the Mining Act, which came into effect in 2003. According to the Act, exploration and production of Dutch gas should be done with the participation of EBN, which has a 40% share in the production of gas[112].

Concerning the transmission of gas, GTS is fully responsible for the maintenance and operation of the national high pressure transmission network. GTS is now fully state owned, given its unbundling from Gas Terra in 2005[113].

The regional gas networks are operated by 12 regional network operators. In most cases these operators are held by the original energy distribution companies, which in turn are held by regional authorities. The Gas Act dictates the access to the networks.

In 1970s the Small Field Policy (SFP) became the regulatory framework which called for the maximisation of production from small fields. According to SFP, Gasunie was obliged to buy gas from any producer of a small gas field at a high load factor at a reasonable price related to the market value of gas and producers were obliged to sell the gas to Gasunie. Since 1996, the producers' obligation changed into an option, Gasunie (and since 2006 GasTerra, 50% state owned, Shell 25% and ExxonMobil 25%), however, still has the obligation to offer a market value price for all Dutch small fields. Gasunie started importing gas through long-term contracts in 1980s, price based on coal-parity. The SFP has proven to be highly successful.

11.7. Similarities to Israel

There are similarities between the Netherlands and Israel:

- Gas demand in both countries is growing rapidly primarily through increased use of gas for power generation
- The population density of the Netherlands is very similar to that of Israel although the population level in the Netherlands is about twice that of Israel
- Both Israel and the Netherlands have a state-owned gas transmission system
- Large gas discoveries early on vastly exceeded domestic requirements. The value of gas exports is (potentially in the case of Israel) very large in relation to the economy and can have a deleterious

[112] Global Legal Group (2011) The International Comparative Guide to: Gas regulation 2011, available at: http://www.iclg.co.uk/khadmin/Publications/pdf/4168.pdf
[113] Global Legal Group (2011) The International Comparative Guide to: Gas regulation 2011, available at: http://www.iclg.co.uk/khadmin/Publications/pdf/4168.pdf

impact on other industries through the effect on exchange rates ('Dutch disease')

11.8. Differences to Israel

There are differences between the Netherlands and Israel:

- Gas plays a much more important role in the economy of the Netherlands than does in Israel. Looking at the energy mix of Israel and the Netherlands gas represented 20% of Israel's energy mix in 2010, while the relevant figure for the Netherlands was 39%.
- The Netherlands has open borders between it and its neighbours in the European Union allowing it freely to export and import gas and acting as a European gas trading hub

11.9. Lessons Leant

The following are the main lessons:

- The use of a large field (Groningen) in the Netherlands as initially and exporter and later a swing producer may have some relevance for the potential development of the large Leviathan field in Israel
- Exports – as in the small fields policy - are needed to encourage further exploration when reserves are already high, together with designating a strategic reserve
- Although initially the Netherlands took no action in conserving its gas supplies and commenced exporting, eventually the small fields policy has succeeded in prolonging the life of Dutch gas production
- Despite the initial currency appreciation that resulted from gas exports, which initially reduced the competitiveness of manufacturing and service exports (i.e. Dutch Disease), empirical evidence suggests that the increase in gas exports did not have a long lasting negative effect on economic growth, nor on total exports. Exports of total goods and services increased from less than 40% of GDP in the 1960s to 65% in the 1980s

12. Norway

12.1. Key Issues

Norway is a major producer and exporter of gas, but not a large consumer. Norway is the second largest gas exporter in Europe (2010). Norway provides much of Western Europe's gas requirements[114].Domestic use of gas amounts to a very small percentage of the country's gas production (around 5%)[115].Consumption of natural gas in Norway is limited to offshore power

[114] Kingdom of Norway, U.S Department of State, July 2011
[115] Norway Oil and Gas Security, IEA, 2011.

generation (3.5 bcm) and onshore methanol production and gas processing (1 bcm).

Norway has an abundance of two forms of energy: hydroelectric power and petroleum resources. The former provides the bulk of domestic energy use while the latter is exported. About half of Norway's 65,000 largest lakes are situated at elevations of at least 1,650 feet (500 metres); about one-fifth of the country lies 2,950 feet (900 metres) or more above sea level; and predominantly westerly winds create abundant precipitation. As a result, Norway has tremendous hydroelectric potential[116] and hydroelectricity meets virtually all Norway's electrical consumption needs.

12.2. Basic Data

12.2.1. Proven Reserves

As at 31 December 2010 Norway had 2000 bcm of proven gas reserves which compares with 1700 bcm as at 31 December 1990.

12.2.2. Exports

Total exports in 2010 were 100.59 bcm of which 95.88 bcm were via pipeline and 4.71 bcm were via LNG. The two largest export markets were United Kingdom (26.57 bcm via pipelines and LNG) and France (14.15 bcm via pipelines and LNG).

12.2.3. Production

Gas production in 2010 was 106.4 bcm and has doubled over the last ten years. Details of the production are shown in Table 31 and Figure 66

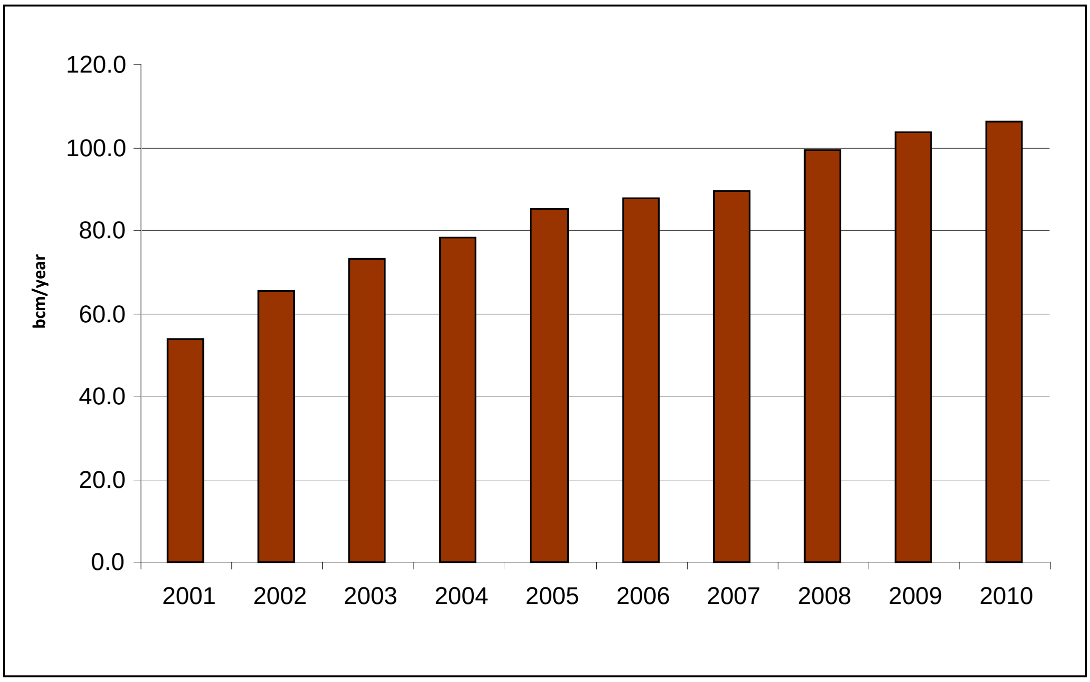
Table 31 Norway Gas Production (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
53.9	65.5	73.1	78.5	85.0	87.6	89.7	99.3	103.7	106.4

Source: BP Statistical Review of World Energy, June 2011

[116] Norway Encyclopaedia Britannica

Figure 66 Norway Gas Production



Source: BP Statistical Review of World Energy, June 2011

12.2.4. Consumption

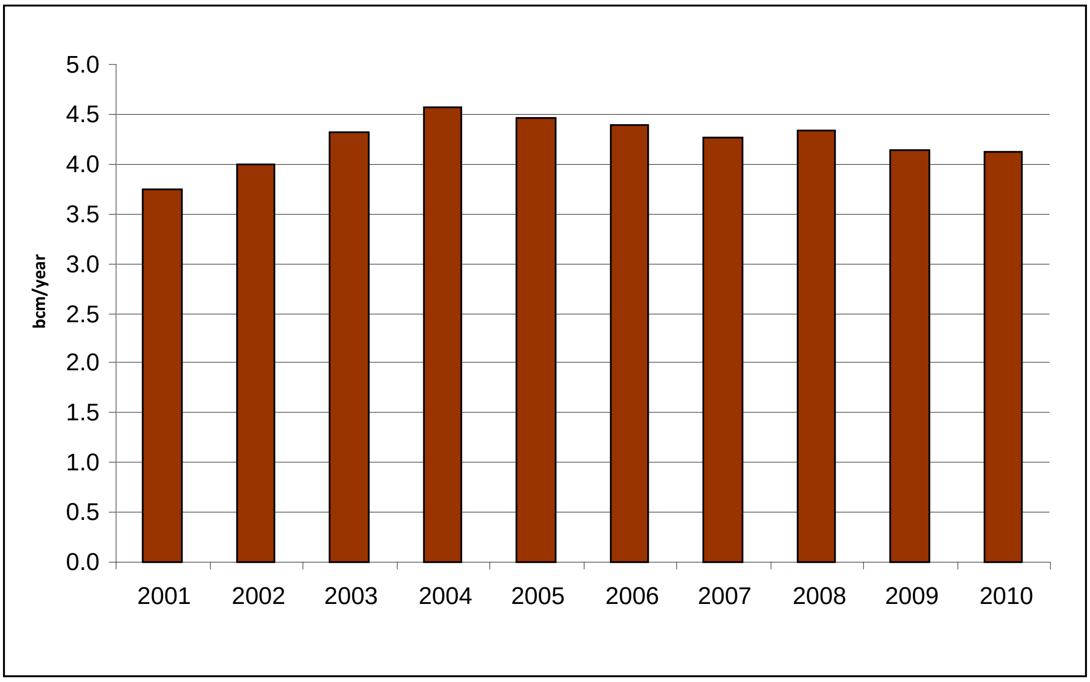
Gas consumption in 2010 was 4.1 bcm and consumption has been reasonably stable since 2001 as shown in Table 32 and Figure 67.

Table 32 Norway Gas Consumption (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
3.8	4.0	4.3	4.6	4.5	4.4	4.3	4.3	4.1	4.1

Source: BP Statistical Review of World Energy, June 2011

Figure 67 Norway Gas Consumption



Source: BP Statistical Review of World Energy, June 2011

12.2.5. Reserves/Production

The reserves/production ratio is 2000/106.4 = 19 years.

12.2.6. Reserves/Consumption

The reserves/consumption ratio is 2000/4.1 = 488 years

12.2.7. Natural Gas Rents (% of GDP)

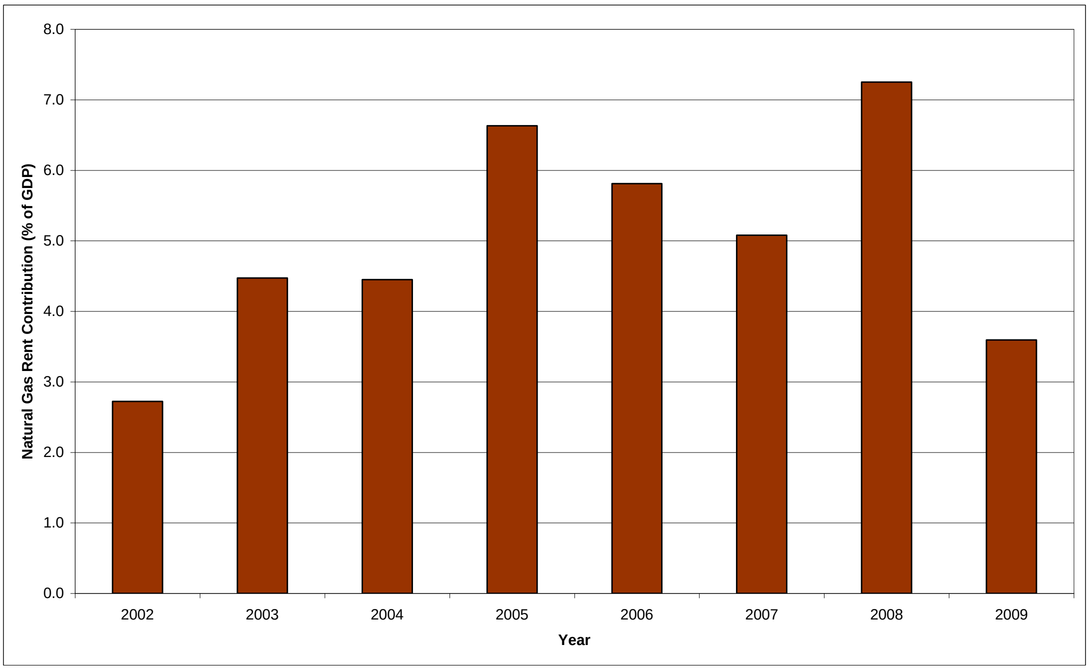
Contributions from natural gas rents to Norway's GDP are as shown in Table 33 and Figure 68.

Table 33 Norway Natural Gas Rents (% of GDP)

2002	2003	2004	2005	2006	2007	2008	2009
2.7	4.5	4.4	6.6	5.8	5.1	7.3	3.6

Source: World Bank

Figure 68 Norway Natural Gas Rents (% of GDP)



Source: World Bank

12.3. Gas Production Facilities

All of the oil and gas production in Norway is offshore. The gas is transported by pipeline to land-based receiving terminals for processing before further transport to Continental Europe. In a few instances the gas is processed offshore and transported directly to the UK and the Netherlands.

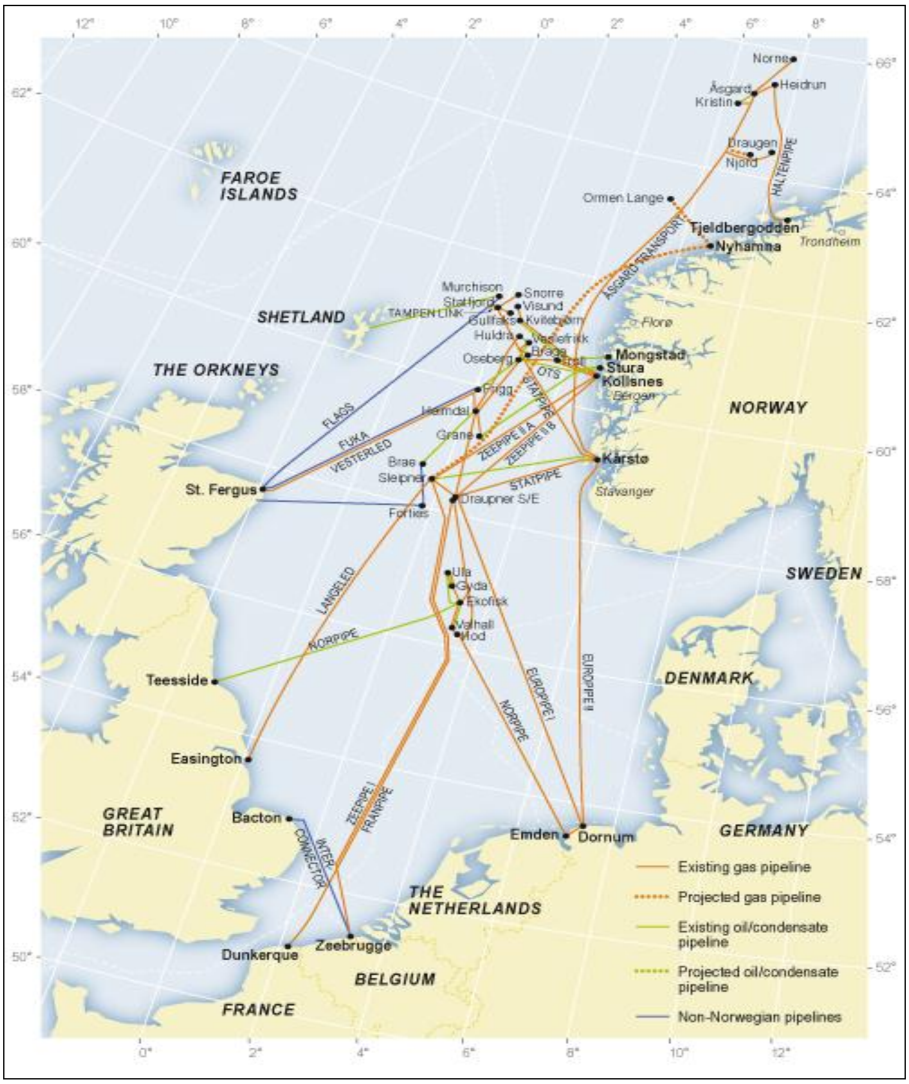
There are three major receiving terminals in Norway, at Kårstø north of Stavanger, at Kollsnes west of Bergen and Tjeldbergodden some distance west of Trondheim. The Kårstø terminal is the oldest and largest and processes natural gas and gas condensate. The Kollsnes terminal processes natural gas from the very large Troll-field (non-associated gas field). The Tjeldbergodden terminal receives natural gas from the Heidrun field and is the site of a methanol plant. Natural gas to Continental Europe is compressed and transported from Kårstø and Kollsnes[117].

12.4. Gas Export and Import Facilities

The Norwegian gas transportation system is shown in Figure 69. The Norwegian gas transport system is extensive and consists of a network of seven 800 km of pipelines with a capacity of about 120 bcm.

[117] Ministry of Petroleum and Energy; Natural Gas in Norway and the Mid-Nordic Gas Pipeline Study, Jon Steinar Guomundsson. 2001

Figure 69 Norway Gas Pipeline System



Source: Norwegian Petroleum Directorate

The Frigg field was discovered in May 1971 and came on stream six years later[118]. The Norpipe system's gas line from Ekofisk to Emden in Germany began operating in 1977, initiating Norwegian natural gas exports to continental Europe. Norway consistently exports almost 95% of its gas production. Exports have traditionally been to Europe by direct pipeline (to the United Kingdom, France, Belgium and Germany)[119].

Gas activities make up a growing share of the petroleum sector, and provide the State with considerable revenues. Norwegian gas is important for the European energy supply and is exported to all the major consumer countries

---

[118] Norwegian Oil History in Brief; http://www.regjeringen.no/upload/kilde/oed/bro/2004/0006/ddd/pdfv/204702-factsog0104.pdf

[119] Norway Oil and Gas Security, IEA, 2011.

in Western Europe. Norwegian gas export covers close to 20% of European gas consumption. Most of the exports go to Germany, the UK, Belgium and France, where Norwegian gas accounts for between 20-35% of the total gas consumption. Producing companies on the Norwegian continental shelf have gas sales agreements with buyers in Germany, France, the UK, Belgium, the Netherlands, Italy, Spain, the Czech Republic, Austria and Denmark[120].

There are six receiving terminals for Norwegian gas to Europe: two in Germany, two in the UK, one in Belgium and one in France. Between Norway and the countries that have landing sites for gas there are treaties developed to govern rights and obligations[121].

The UK-Norway Vesterled pipeline link connects St Fergus in Scotland to both the Frigg gas field, a jointly operated offshore gas field straddling UK and Norwegian waters, and to facilities on Norway's Heimdal field. This has a capacity of 11bcm a year[122].

The Langeled pipeline is an underwater pipeline transporting Norwegian natural gas to the United Kingdom. It has a total capacity equivalent to one fifth of the United Kingdom's gas consumption[123]. The Langeled pipeline is the second longest subsea pipeline in the world[124]. The annual capacity of the Langeled pipeline is 25.5 bcm. The owner of the Langeled pipeline is Gassled. The operator for Langeled is Gassco and technical service provider is Statoil. Statoil also runs the gas export project[125].

With the opening of the LNG plant at Melkøya in northern Norway in 2007, Norwegian gas now reaches markets outside Europe for the first time. The export facility in the Barents Sea is Europe's first for LNG, and has an annual capacity of 5.7 bcm[126].The Snøhvit facility delivers LNG to countries including the US, Brazil, South Korea, Turkey and several countries in the EU area. With the opening of the Snøhvit LNG terminal, Norway's exports will be further diversified.

12.5. Industry Organisation

Gassco is the operator of the integrated gas transport system from the Norwegian continental shelf to other European countries. The creation of Gassco forms part of an extensive reorganisation of the Norwegian oil and gas sector since 2001. Before that date, gas transport was provided by a

[120] Gas Export from the Norwegian Shelf, Norwegian Petroleum directorate.
[121] Norway Gas Profile, Energy Gas Institute, Energy Business School, 2011
[122] The Future of UK Gas Supplies, Parliamentary Office of Science and Technology, Oct 2004
[123] Norway Gas Profile, Energy Gas Institute, Energy Business School, 2011
[124] Nord Stream Passes Ships and Bombs, The Moscow Times. Bloomberg, May 2005
[125] "Statoil to Provide Technical Services to Langeled Pipeline System". Downstream Today, Sept 2006
[126] Gas Export from the Norwegian Shelf, Norwegian Petroleum Directorate

number of companies. The Norwegian Administration also indicates that Gassco serves as operator for the gas receiving terminals in Dunkerque (France), Zeebrugge (Belgium), Emden and Dornum (Germany)[127].

One of Gassco's tasks is to coordinate the processes for further development of the upstream network of gas pipelines. Although they do not invest in infrastructure themselves, they can recommend solutions. Being a neutral party, Gassco ensures that all users of the gas transmission system have equal rights when it comes to making use of the system and to the consideration of capacity increases[128].

All licensees on the Norwegian continental shelf are responsible for selling their own gas. StatoilHydro sells the State's oil and gas together with its own petroleum, in accordance with the Ministry's instruction concerning marketing and sale of oil and gas[129].

The transport system for Norwegian gas is mainly owned by the Gassled partnership. Gassled encompasses all gas facilities that are currently in use or that are planned to be used by parties other than the owners.

12.6. Gas Regulatory Structure

Systems for transporting natural gas intended to deliver to natural gas undertakings in another region, cannot be constructed or operated without a licence pursuant to the Natural Gas Act.

The licensing authorities are the bodies responsible for processing licence applications and for issuing licences. They include the Parliament, the Government, the Ministry of Petroleum and Energy and the Norwegian Water Resources and Energy Directorate (NVE). The distribution of the licensing authority varies according to the nature and size of the project. Nevertheless, common for all cases is that the NVE has a central role in the procedure[130].

Gas transport tariffs are governed by special regulations to ensure that economic returns are earned from producing fields instead of from the transportation system. To secure good resource management, transport rights can be transferred between users[131].

The Petroleum Fund of Norway was set up in 1990 and changed its name in January 2006 to The Government Pension Fund Global. The change in the

---

[127] Norway Oil and Gas Security, IEA, 2011
[128] http://www.energydelta.org/mainmenu/edi-intelligence-2/our-services/Country-gas-profiles/country-gas-profile-norway
[129] Petroleum and Energy; Gas Infrastructure, May 2008.
[130] http://www.regjeringen.no/en/dep/oed/Subject/Energy-in-Norway/Licensing-procedures.html?id=440496
[131] http://www.energydelta.org/mainmenu/edi-intelligence-2/our-services/Country-gas-profiles/country-gas-profile-norway

fund's name highlights its role in saving government revenue to finance an expected increase in future public pension costs. However, the fund has no formal pension liabilities and no political decision has been made as to when the fund may be used to cover future pension costs. The fund also serves as a fiscal policy tool to support long-term management of Norway's petroleum revenue and to enable the government manoeuvre its fiscal policy when oil price drops or the economy contracts. It was designed to be invested for the long term, but in a way that made it possible to draw on when required.

The fund is fully integrated with the state budget with its capital inflows consisting of all government petroleum revenue, net financial transactions related to petroleum activities, net of what is spent to balance the state's non-oil budget deficit. The fiscal policy guideline is that over time, the structural, non-oil budget deficit shall correspond to the real return on the fund, estimated at 4%. The fund is broadly based as a response to the problems of the Dutch disease described earlier in Section 11.1.

Norges Bank Investment Management (NBIM) manages the fund on behalf of the Ministry of Finance, which owns the funds and determines the investment strategy, following advice from NBIM and discussions in Parliament. The fund is invested abroad in international equity (60% of assets), fixed-income markets (35-40%) and real estate (up to 5%) with the aim of having a diversified portfolio that will give the highest possible risk-adjusted return within the guidelines set by the ministry. They currently do not invest in private equity and the guidelines also restrict investments in tobacco producers, companies involved in human rights abuses, environmental damage or production of weapons that through their normal use may violate fundamental humanitarian principles. The fund is currently valued at about $560 billion[132].

12.7. Similarities to Israel

There are some similarities between Norway and Israel:

- Both countries have their main gas fields in deep water at a significant distance from land and require high technology solutions
- Subsea technology plays a significant role in the development of these resources in each country
- A significant proportion of Norwegian gas is not landed and processed in Norway which is likely to be the position in Israel
- Although both countries have private companies involved in the gas industry Norway has important state ownership of both resources and transportation; Israel has a state owned gas transportation system
- Both Norway and Israel have relatively small populations with regard to the size of their gas reserves

[132] http://www.nbim.no/en/

12.8. Differences to Israel

There are some differences between Norway and Israel:

- Norway has a partly state owned oil and gas company which is not the case in Israel which only has private companies involved in exploration and production
- Norway has been able to develop its oil and gas reserves initially without them being landed in Norway; this is not the case in Israel but it may be in the future
- Norway has clearly demarcated marine boundaries unlike Israel which has yet to agree all its marine borders
- Norway has established a sovereign fund for oil and gas revenues which is not currently being discussed in Israel

12.9. Lessons Leant

The following are the main lessons:

- Norway developed its initial gas reserves by landing them at a terminal in the UK even though the UK was developing its own gas reserves. This indicates that the option for Israel to land gas, for example, in Cyprus has good international parallels
- The state has played an important role in the development of Norway's gas resources and has allowed Norway to become a significant gas exporter. In Israel the state currently only has influence through the licensing process and its ownership of the gas transportation system.
- Consideration should be given to the establishing for an Israel sovereign fund for oil and gas revenues

13. Tanzania

13.1. Key Issues

The Tanzanian gas industry is based around the Songo Songo gas field with total reserves of around 28.3 bcm. The field was discovered in 1974 but was only put into production in 2004. The relatively low demand for gas in Tanzania has meant that the field has only partially developed. There is a large undrilled prospect Songo Songo West which is only 2.5 km to the west of the field. There is also a large discovery in Mwanzi Bay to the south of Tanzania with total reserves of around 18.1 bcm which has only been partially developed in order to generate electricity. The capacity of the production facilities and the pipelines for Songo Songo has been limited.

The recent offshore gas discoveries are likely to be dedicated to the production of LNG. The large development costs could not be supported by the low price for gas for power generation which is the major consumer of gas in Tanzania. If some of the new gas is to be provided to the domestic market there may have to be cross-subsidisation from the more valuable LNG exports.

13.2. Basic Data

13.2.1. Proven Reserves

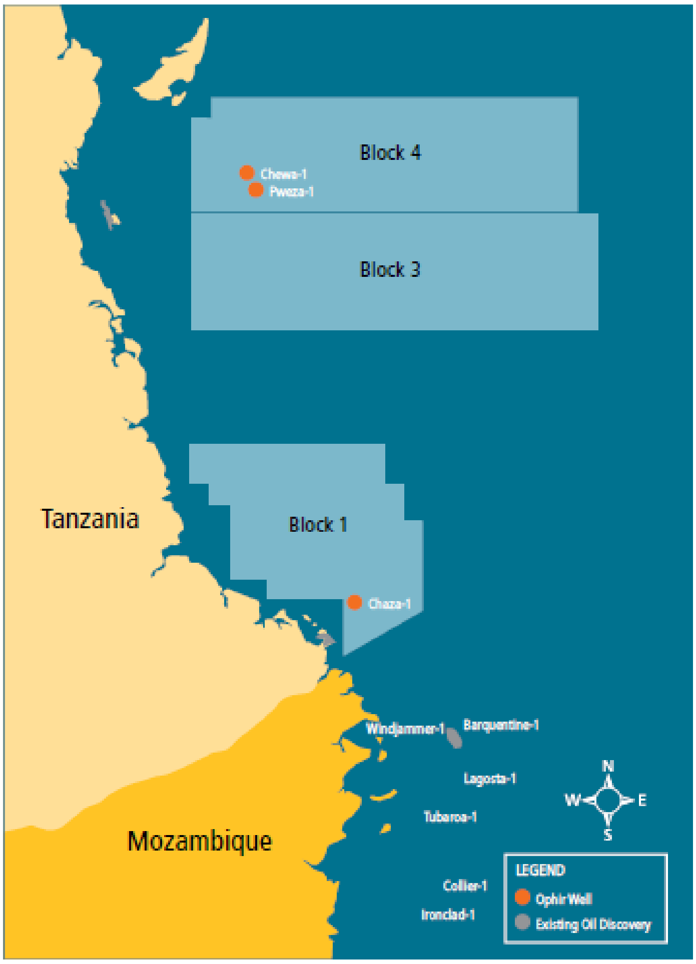
As at 31 December 2010 Tanzania had 19.51 bcm of remaining recoverable proven reserves[133]. These reserves are in the Songo Songo field offshore Tanzania.

However further major gas reserves have been discovered in deep water Blocks 1 and 4 offshore Tanzania as shown in Figure 70. These discoveries are now operated by BG who farmed into the licence before the wells were drilled taking over operatorship and 60% interest. No official estimates of the size of the discoveries has been given however Tanzania's Energy and Minerals Minister has suggested that they will increase the country's reserves to 283 bcm[134].

These recent discoveries have given a major boost to exploration in Tanzania. Petrobras has spudded Zeta-1 in deepwater Block 5 in August 2011 as part of two well programme and ExxonMobil has farmed into this block taking a 35% interest. Statoil will also be drilling a well in their deepwater Block 2 and Shell farmed into this block to take a 50% interest. Finally BG will be drilling further wells in Blocks 1, 3 and 4.

133 Orca Exploration Group, 2010 Annual Report
134 Reuters Africa, 23 September 2011

Figure 70 Tanzania Offshore Gas Discoveries



Source: Ophir Annual Report

13.2.2. Exports

There are currently no gas exports from Tanzania, but it is expected that LNG will be exported from the new discoveries.

13.2.3. Production

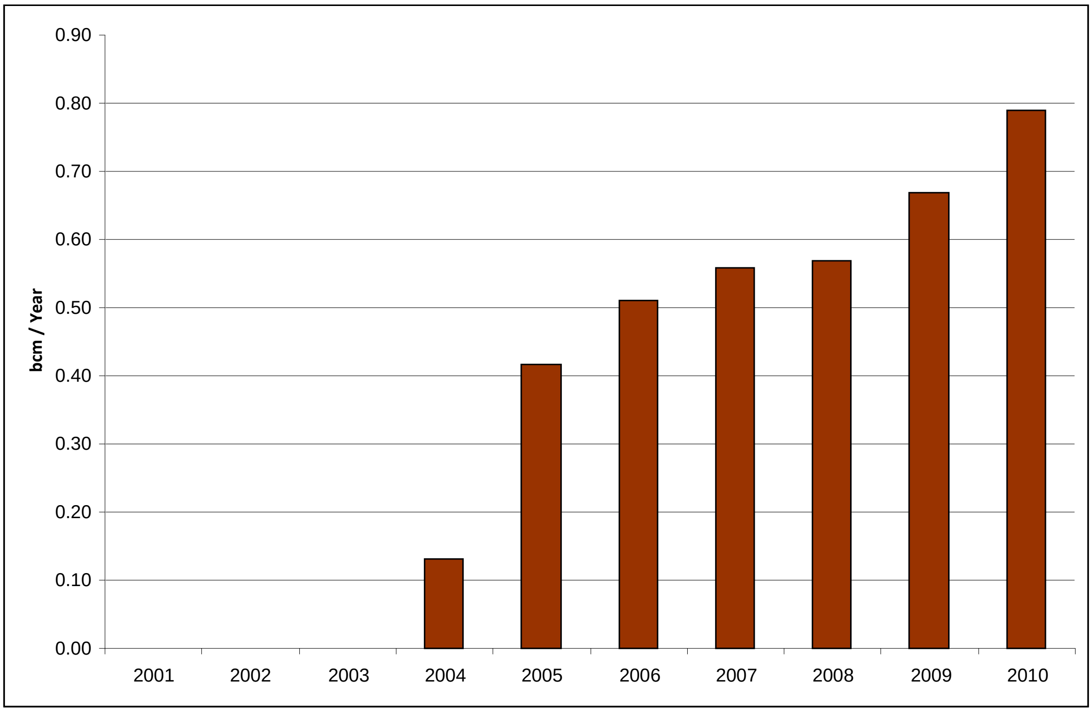
Gas production in 2010 was 0.79 bcm and it has increased steadily since 2004. Details of the production are shown in Table 34 and Figure 71.

Table 34 Tanzania Gas Production (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
0.00	0.00	0.00	0.13	0.42	0.51	0.56	0.57	0.67	0.79

Source: EIA, International Energy Statistics

Figure 71 Tanzania Gas Production



Source: EIA, International Energy Statistics

13.2.4. Consumption

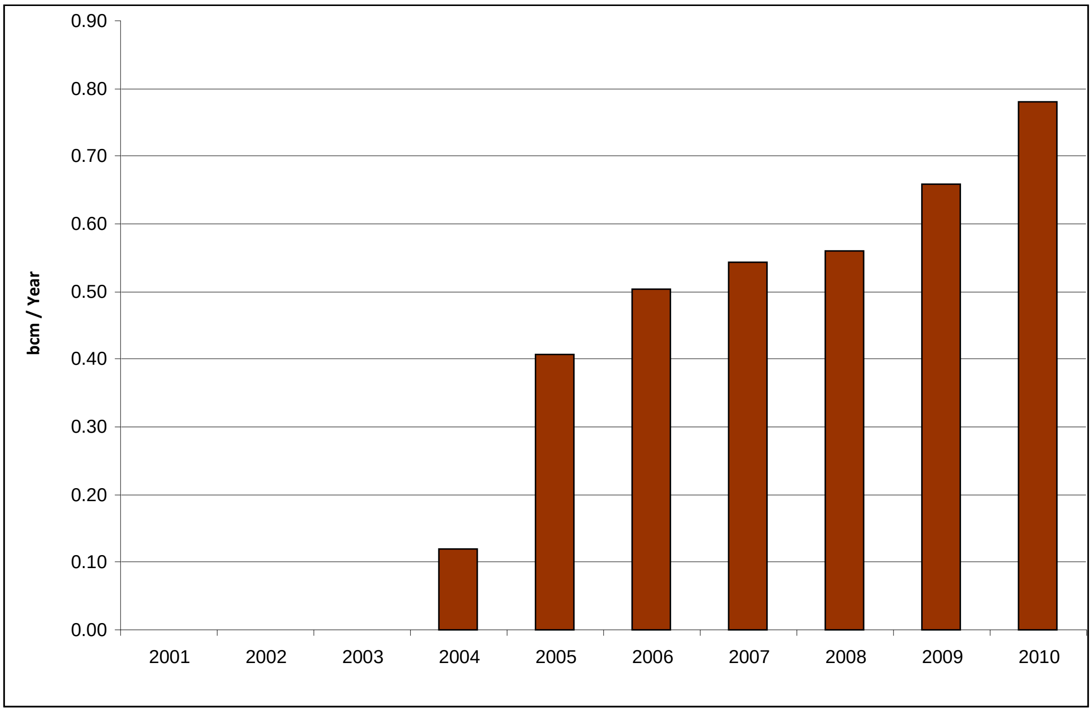
Gas consumption in 2010 was 0.78 bcm and consumption has been growing steadily as shown in Table 35 and Figure 72.

Table 35 Tanzania Gas Consumption (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
0.00	0.00	0.00	0.12	0.41	0.50	0.54	0.56	0.66	0.78

Source: EIA, International Energy Statistics

Figure 72 Tanzania Gas Consumption



Source: EIA, International Energy Statistics

13.2.5. Reserves/Production

The reserves/production ratio is 19.51/0.79 = 24.6 years.

13.2.6. Reserves/Consumption

The reserves/consumption ratio is 19.51/0.78 = 25.0 years

13.2.7. Natural Gas Rents (% of GDP)

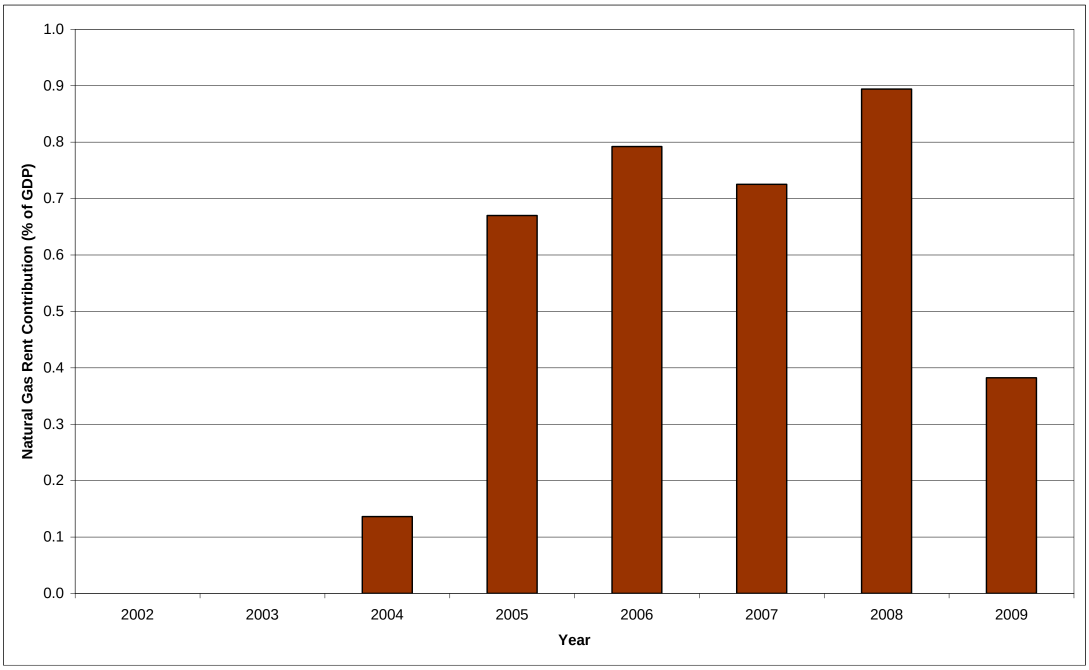
Contributions from natural gas rents to Tanzania's GDP are as shown in Table 36 and Figure 73.

Table 36 Tanzania Natural Gas Rents (% of GDP)

2002	2003	2004	2005	2006	2007	2008	2009
0.0	0.0	0.1	0.7	0.8	0.7	0.9	0.4

Source: World Bank

Figure 73 Tanzania Natural Gas Rents (% of GDP)



Source: World Bank

13.3. *Gas Production Facilities*

The main production facilities are located at the Songo Songo field which although offshore is produced from Songo Songo Island (see Figure 74). Details of the gas production volumes and sales prices are shown below for 2nd quarter 2011 (see Table 37).

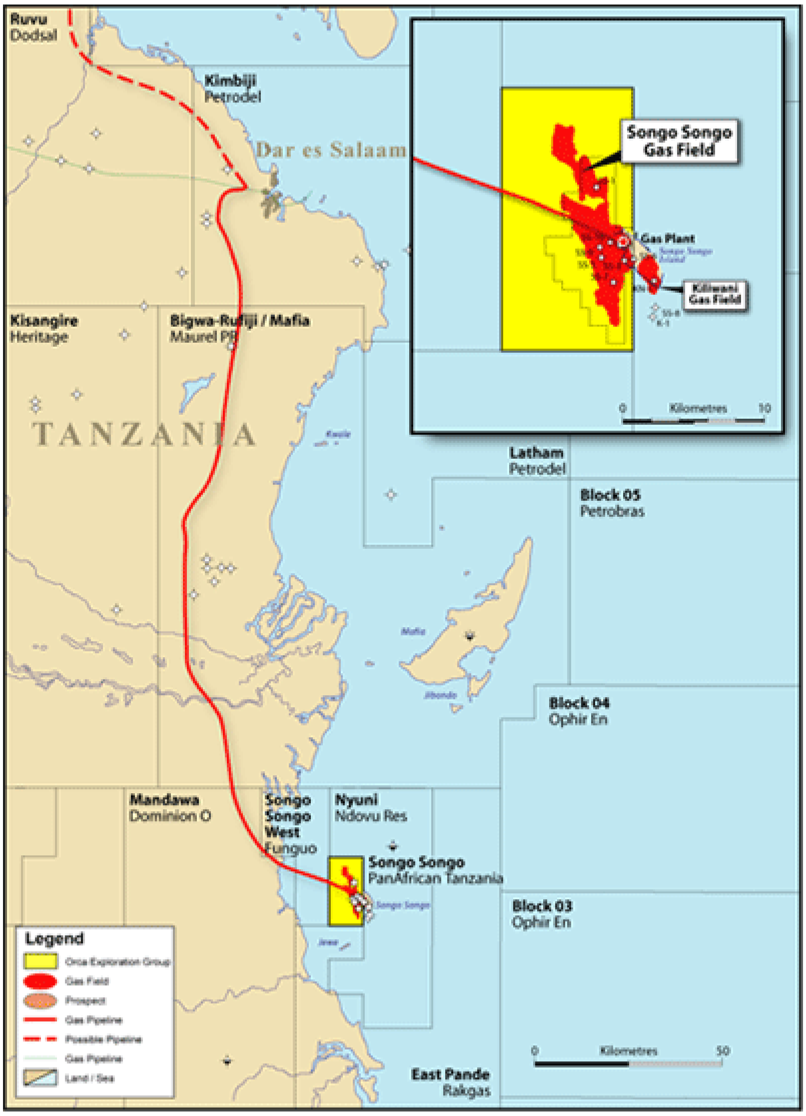
Table 37 Tanzania Gas Sales

Sector	Volume (bcm per day)	Price ($/MMBTU)
Power generation – protected sector	0.0012	2.02
Power generation – additional sales	0.0009	2.64
Industrial – additional sales	0.0002	10.28

Source: Orca Financial Report 2nd quarter 2011

This is very typical of a developing gas economy where power generation volumes are large but the price is low. Conversely the industrial volumes are low but the prices are higher reflecting a link to heavy fuel oil prices.

Figure 74 Tanzania Gas Infrastructure



Source: Orca Exploration

13.4. Gas Export and Import Facilities

There are currently no export or import facilities although there will be LNG exports in the future.

13.5. Industry Organisation

The industry was composed of mid-sized oil and gas companies. However, recently a number of major companies such as BG, Shell and ExxonMobil have farmed into offshore blocks.

13.6. Gas Regulatory Structure

Petroleum exploration and development in Tanzania is governed by the Petroleum (Exploration and Production) Act 1980. This Act vests title to petroleum deposits within Tanzania to the State.

The Act expressly permits the Government to enter into a petroleum agreement under which an oil company may be granted exclusive rights to explore for and produce petroleum. Under the production sharing agreement arrangements currently in place in Tanzania, the state owned Tanzania Petroleum Development Corporation (TPDC) is granted the licences under the Act with the Government and TPDC entering into production sharing agreements with the oil companies. The terms of the production sharing agreements form the basis of the licences and are negotiable. The legislative framework offers considerable flexibility to the Government in negotiating acceptable terms with oil companies.

TPDC has a right to back into developments for up to 20% after paying past costs.

13.7. Similarities to Israel

There are some similarities between Tanzania and Israel:

- Both Israel and Tanzania have developed a small-scale gas industry based on limited amounts of gas and driven mainly by power generation
- Both Israel and Tanzania have experienced large scale gas discoveries which needed to be assessed in an overall framework that takes account both of domestic needs and exports
- Neither Israel nor Tanzania are currently gas exporters although the potential for exports from both countries is high

13.8. Differences to Israel

There are some differences between Tanzania and Israel:

- Israeli is a developed economy unlike Tanzania which is a developing economy
- The per capita use of electricity in Tanzania is very low and very few people are connected to the grid; Israel has a well developed modern power industry

13.9. Lessons Leant

There are probably few lessons to be learnt from the Tanzanian experience although it will have to tackle the same problems of balancing domestic requirements and gas exports that apply to Israel.

14. Trinidad & Tobago

14.1. Key Issues

Over the past decade, there has been a dramatic increase in Trinidad's gas production and exports of LNG have facilitated this. Gas production has overtaken oil as the government's largest source of revenue, through the sale of LNG[135]. Trinidad is the sixth largest supplier of LNG in the world by 2010 estimates[136]. LNG exports account for about 60% of Trinidad's total gas production and the downstream industrial sector makes up the bulk of local gas consumption.

Petrochemicals and metals production account for approximately 75% of domestic gas demand and power generation being 18% of domestic demand[137]. Trinidad is the number one global exporter of methanol and ammonia in the world[138]. Major gas based industrial plants in Trinidad are detailed in Table 38. It should be noted that gas prices for these plants were low with a US government report on gas pricing indicating that the price was $1.60/MMBTU in 2005.[139]

[135]http://www.eiu.com/index.asp?layout=ib3Article&article_id=637743448&pubtypeid=1142462499&country_id=700000070&category_id=775133077 and http://www.eia.gov/countries/cab.cfm?fips=TD
[136] BP Statistical Review of World Energy, June 2011
[137] http://www.energy.gov.tt/energy_resources.php?mid=51
[138] http://www.dnv.com/resources/publications/dnv_forum/2009/forum_2_2009/trinidadandtobagoexploreformore.asp
[139] US GAO Report, 13 February

Table 38 Trinidad and Tobago Industrial Plants

Plant	Start-up Year	Annual Capacity (MT)	Product
Yara Trinidad Limited	1959	285,000	Ammonia
Tringen I	1977	500,000	Ammonia
PCS 01	1981	445,000	Ammonia
PCS 02	1981	445,000	Ammonia
Tringen II	1988	495,000	Ammonia
PCS 03	1996	250,000	Ammonia
PCS 04	1998	650,000	Ammonia
Point Lisas Nitrogen Limited (PLNL)	1998	650,000	Ammonia
Caribbean Nitrogen Company (CNC)	2002	650,000	Ammonia
Nitrogen 2000 (N2K) Unlimited	2004	650,000	Ammonia
AUM Ammonia	2009	650,000	Ammonia
TTMC I (M1)	1984	480,000	Methanol
CMC (M2)	1993	550,000	Methanol
TTMC II (M3)	1996	570,000	Methanol
Methanol IV (M4)	1998	580,000	Methanol
Methanex Titan	1999	860,000	Methanol
Atlas	2004	1,650,000	Methanol
M5000 (M5)	2005	1,890,000	Methanol
PCS Nitrogen (Urea)	1982	600,000	Urea
Nu-Iron Unlimited	2007	1,500,000	Iron Ore

Source: Ministry of Energy and Energy Affairs Trinidad & Tobago

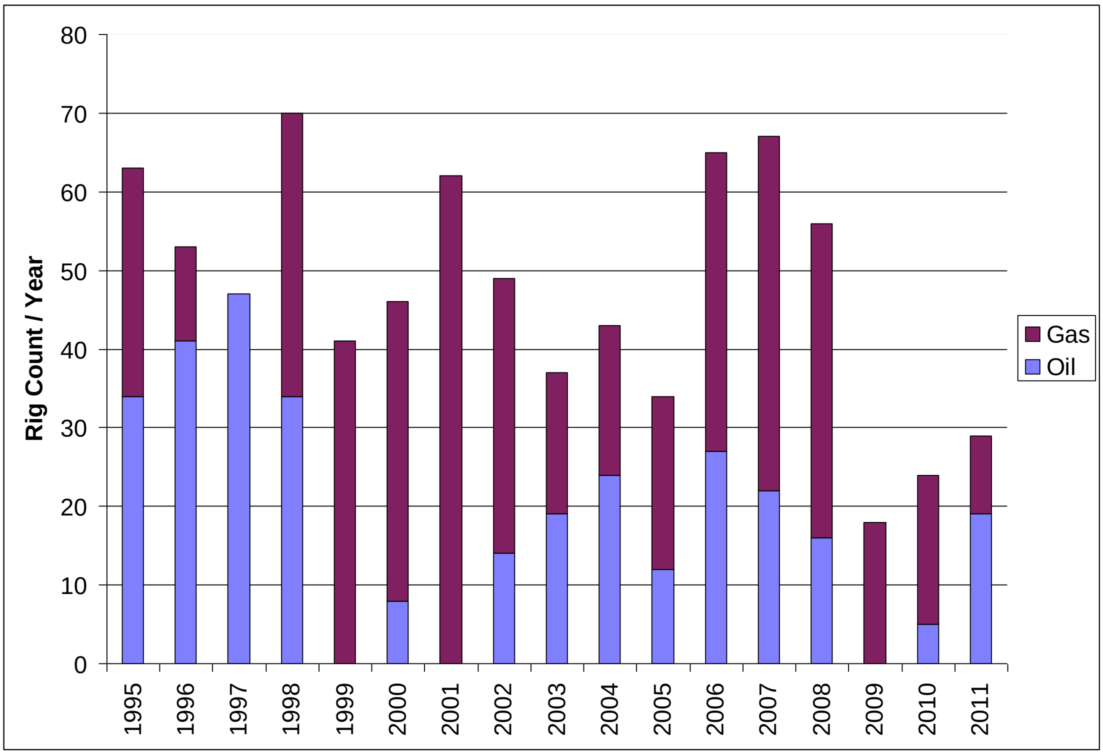
Given the fact that gas reserves to production ratio is quite low (9 years) and Trinidad is a major gas-based industrial economy (majorly petrochemicals), a key issue has been concerns about energy security and assurance of future supply to meet domestic gas demand[140]. The government of Trinidad also does not have any domestic gas reservation policy[141].

There are, however efforts to encourage exploration into deepwater acreages in order to increase reserves and gas supply following the unsuccessful deepwater bid round of 2006[142] and the limited success achieved in the 2010 bid round[143]. Of the 11 blocks on offer in the 2010 bid round, 3 were bid on and only BP was awarded two deepwater exploration blocks[144]. In order to attract investment to the deepwater acreages and ensure more successful bid rounds in the future, Trinidad's Ministry of Energy has made amendments to the country's PSC terms and fiscal regime. There has been a reduction in

140 http://www.upstreamonline.com/live/article271548.ece?WT.mc_id=rechargenews_rss
141 http://www.news.gov.tt/index.php?news=8899
142 http://www.ihs.com/News/WW-News/news-2006/Trinidads-Ultra-Deepwater-One-Bid.htm
143 http://www.energy.tt/index.php?categoryid=1&p2001_articleid=1091
144 http://www.energy.gov.tt/media_centre.php?mid=98&eid=81

Petroleum Profits Tax from 50% to 35% along with 40% uplift and the elimination of signature bonus payments as well as state participation[145]. Deepwater acreage is also allowed a higher rate of cost recovery – 60%. Figure 75 shows a large decline in drilling activity in Trinidad and Tobago in 2009.

Figure 75 Drilling Activity in Trinidad & Tobago



Source: Baker Hughes

14.2. Basic Data

14.2.1. Proven Reserves

As at 31 December 2010 Trinidad had 364.7 bcm of proven gas reserves which compares with 252 bcm as at 31 December 1990.

14.2.2. Exports

Total exports in 2010 were 20.38 bcm all of which were via LNG. The two largest export markets were the United States (5.38 bcm) and Spain (3.32 bcm).

[145] http://www.energy.tt/index.php?categoryid=1&p2001_articleid=1091

14.2.3. Production

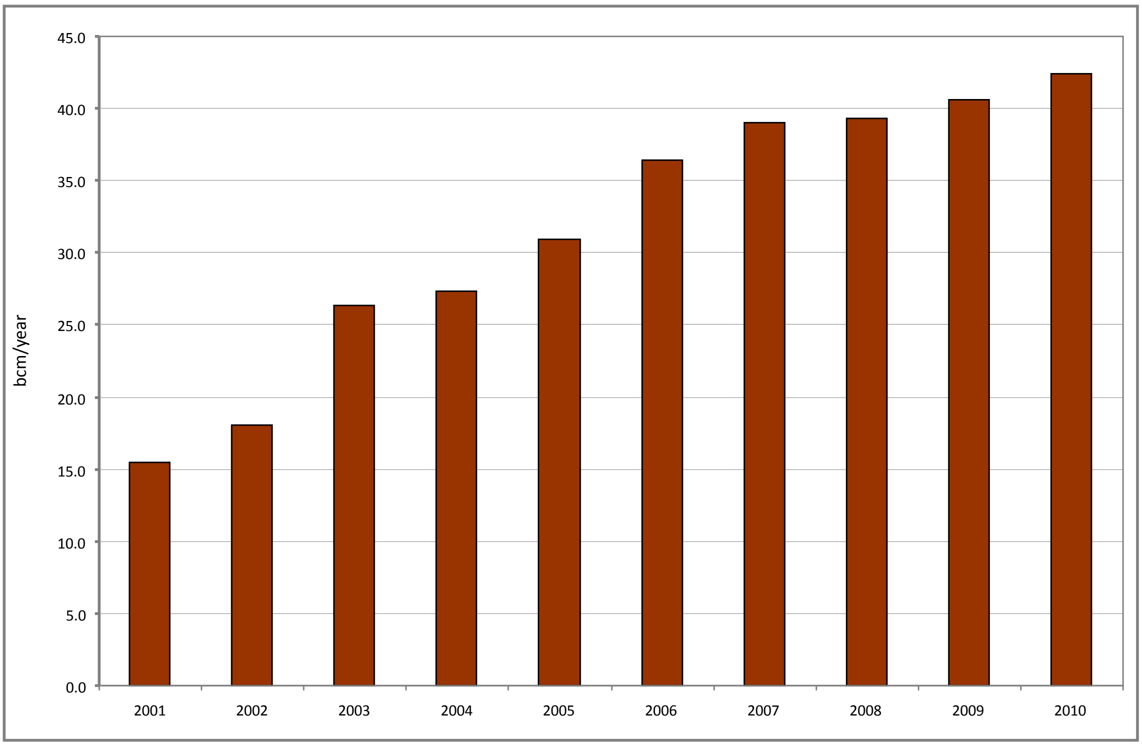
Gas production in 2010 was 42.4 bcm and it has increased dramatically over the last ten years. Details of the production are shown in Table 39 and Figure 76.

Table 39 Trinidad and Tobago Gas Production (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
15.5	18.0	26.3	27.3	31.0	36.4	39.0	39.3	40.6	42.4

Source: BP Statistical Review of World Energy, June 2011

Figure 76 Trinidad and Tobago Gas Production



Source: BP Statistical Review of World Energy, June 2011

14.2.4. Consumption

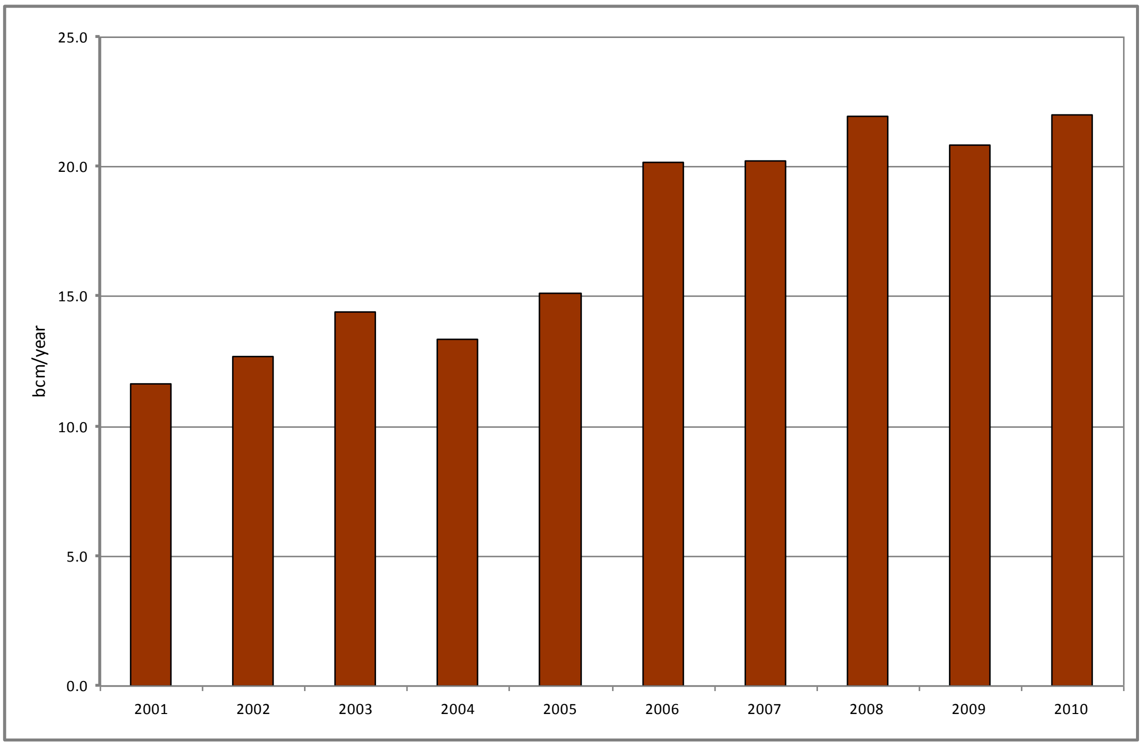
Gas consumption in 2010 was 22.0 bcm and consumption has been growing steadily as shown in Table 40 and Figure 77.

Table 40 Trinidad and Tobago Gas Consumption (bcm)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
11.6	12.7	14.4	13.4	15.1	20.2	20.3	21.9	20.9	22.0

Source: BP Statistical Review of World Energy, June 2011

Figure 77 Trinidad and Tobago Gas Consumption



Source: BP Statistical Review of World Energy, June 2011

14.2.5. Reserves/Production

The reserves/production ratio is 364.7/42.4 = 8.6 years.

14.2.6. Reserves/Consumption

The reserves/consumption ratio is 364.7/22 = 16.6 years.

14.2.7. Natural Gas Rents (% of GDP)

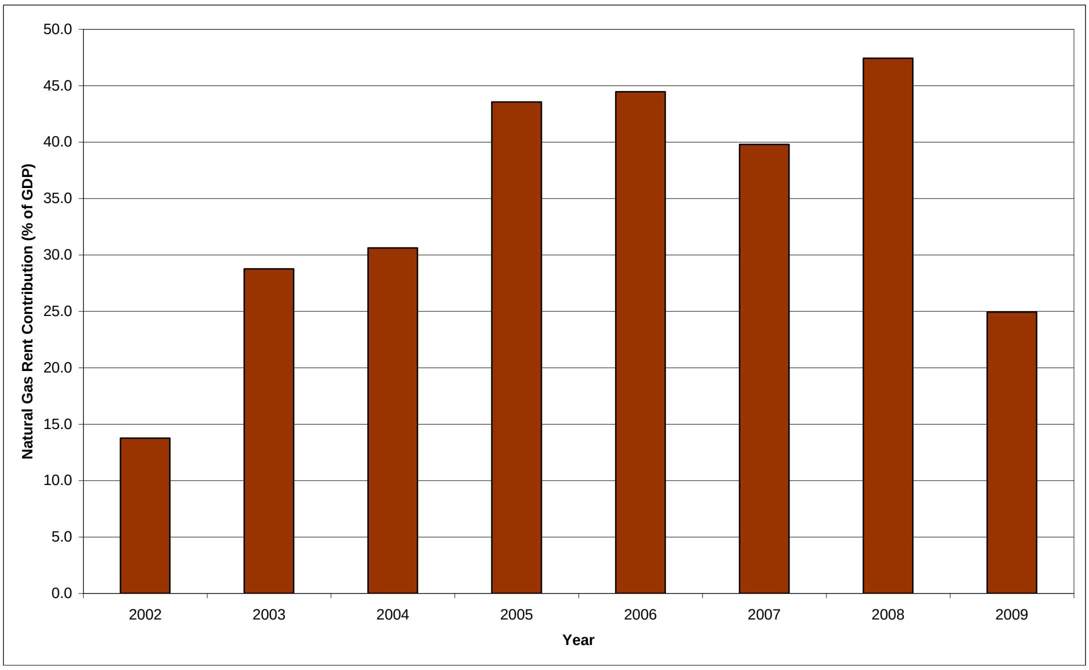
Natural gas rents contributions to Trinidad and Tobago's GDP are as shown in Table 41 and Figure 78Figure 73.

Table 41 Trinidad and Tobago Natural Gas Rents (% of GDP)

2002	2003	2004	2005	2006	2007	2008	2009
13.8	28.8	30.6	43.6	44.5	39.8	47.4	24.9

Source: World Bank

Figure 78 Trinidad and Tobago Natural Gas Rents (% of GDP)



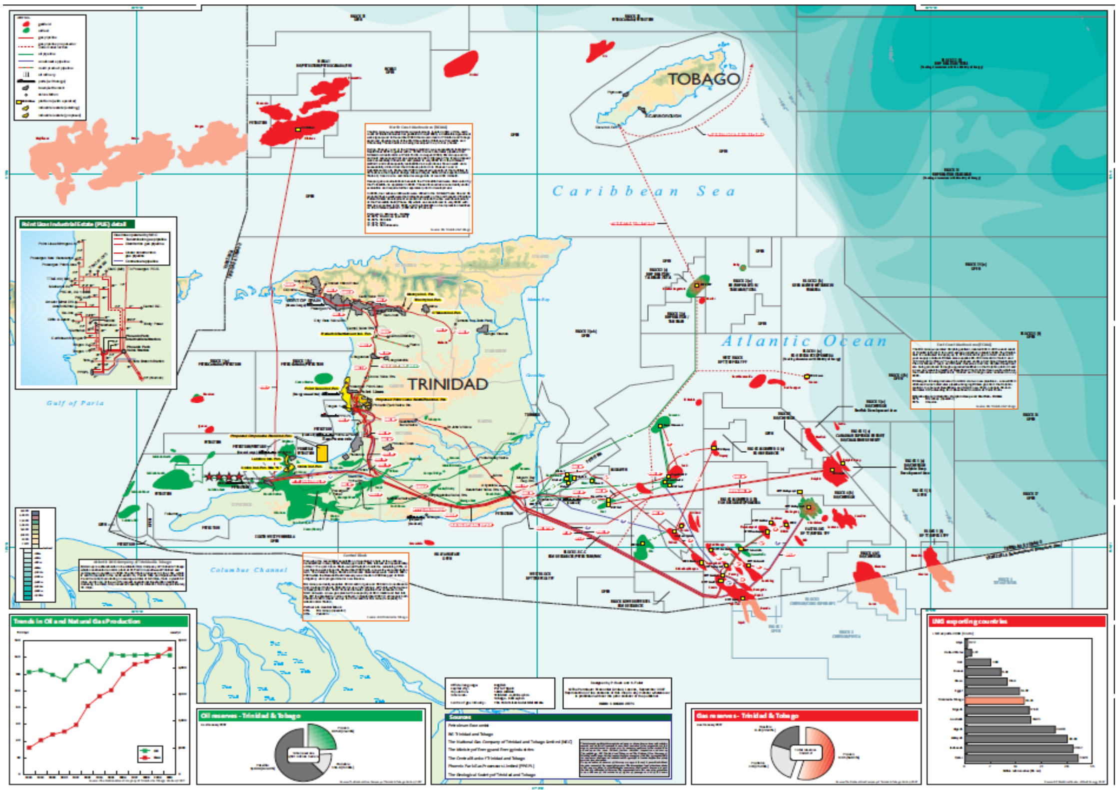
Source: World Bank

14.3. Gas Production Facilities

Gas is produced mainly from offshore fields in the North Coast Marine Area (NCMA) and East Coast Marine Area (ECMA). There are also gas production facilities in the onshore Central Block and in offshore fields in the Gulf of Paria[146]. BP and BG are the largest gas producers and they operate most of the producing facilities. Other producers are EOG, BHP, Repsol and Petrotrin[147]. Figure 79 shows the gas production facilities in Trinidad and Tobago.

[146] Energy Map of Trinidad and Tobago 2007
[147] http://www.energy.gov.tt/data_and_publications.php?mid=114

Figure 79 Trinidad and Tobago Gas Production Facilities



Source: Energy Map of Trinidad and Tobago 2007

BP produces gas from offshore assets in the Samaan, SEG and EM blocks in the ECMA. They operate a hub and spoke basin development model in which their processing facilities and other infrastructure are shared. BP's offshore production assets comprise 13 platforms. Hydrocarbons are transported ashore by pipeline from the eastern gas fields via two major offshore gas transmission service systems, each owned and operated by BP and Trinidad's National Gas Company (NGC).

BG, through a 50:50 partnership with Chevron, produces gas under a Combined Development Plan from the Dolphin, Dolphin deep and Starfish fields in the ECMA. Production is delivered from the Dolphin field through 13 platform wells and the Dolphin Deep field from 2 sub-sea wells, which are tied back to facilities on the Dolphin platform. Dolphin is contracted to supply 0.007 bcm per day of gas to NGC under a 20-year supply contract together with 0.0028 bcm per day to Atlantic LNG Train 3 and 0.0034 bcm per day to Atlantic LNG Train 4. A new production contract to supply 0.0062 bcm per day of gas to NGC for up to 15 years commenced in 2009 following the drilling of five further development wells in the Dolphin field. ECMA gas is delivered to NGC via a pipeline to the Poui platform where it connects to the domestic network. Gas is delivered to Atlantic LNG through a second offshore pipeline bringing gas from the Dolphin platform to shore at the Beachfield receiving terminal. It then connects to NGC's 76 kilometre onshore Cross Island Pipeline extending from Beachfield to Atlantic LNG at Point Fortin.

BG is in partnership with Petrotrin, Eni and NSGP (Ensign) to develop gas prospects in the BG-operated NCMA. The NCMA development includes the Hibiscus, Poinsettia and Chaconia gas fields and the fields are being developed in up to 4 phases to supply gas to Atlantic LNG Trains 2, 3 and 4. The Hibiscus platform is linked to the Atlantic LNG at Point Fortin via a pipeline from NCMA. NCMA is contracted to supply 0.0068 bcm per day gas to Train 2 for up to 20 years, in addition to 0.0013 bcm per day to Train 3 and approximately 0.0023 bcm per day for 10 years to Train 4.

14.4. Gas Export and Import Facilities

There are currently no imports of natural gas into Trinidad and Tobago as approximately 90% of energy needs is met directly by natural gas[148].

All of Trinidad's gas exports are transported as LNG and they account for about 60% of Trinidad's total gas production. The export facilities are located at the Atlantic LNG liquefaction terminal at Point Fortin in south-west Trinidad. The Atlantic LNG is owned and operated by a consortium of the NGC, BG, BP, Repsol and GDF Suez. Atlantic LNG is made up of 4 trains with an annual aggregate supply of about 20.7 bcm of LNG to subsidiary companies of the consortium members. Train 1 has an annual LNG capacity of 4.28 bcm, trains 2 and 3 both supply 4.7 bcm of LNG annually and train 4 supplies 7.2 bcm[149].

Figure 80 shows the main LNG export routes.

[148] Gas Regulation 2009
[149] http://www.bg-group.com/OurBusiness/WhereWeOperate/Pages/TrinidadandTobago.aspx

Figure 80 Trinidad and Tobago LNG Export Routes

Source: Energy Map of Trinidad and Tobago 2007

14.5. Industry Organisation

The state-owned Petroleum Company of Trinidad and Tobago (Petrotrin) is an integrated oil company involved in exploration and production on-shore and off-shore (some in partnership with IOCs), refining, marketing and storage. Other state owned companies are National Energy Corporation of Trinidad and Tobago, which is responsible for downstream industrial development and the National Gas Company of Trinidad and Tobago (NGC), which is responsible for the purchase, transport, sale and marketing of natural gas to local downstream industries. The NGC owns and operates the country's natural gas transmission and distribution network covering approximately 795km. The network comprises both offshore and onshore pipelines, with a current overall maximum installed transportation capacity of approximately 0.125 bcm per day. BP, BG and EOG account for about 60%, 24% and 11%[150] of the country's natural gas production respectively and other producers include BHP, Repsol and Petrotrin. Other operators like Chevron, Total, ENI, Centrica (NSGP Ensign) have working interests in some of the gas fields.

14.6. Gas Regulatory Structure

Trinidad's Ministry of Energy and Energy Affairs (MEEA), the NGC and the NEC set the government's gas policy. Since the 1970s, the government's policy has been 'resource-based industrialization' which focuses on using gas

[150] Energy Map of Trinidad and Tobago 2007

as a means of accomplishing economic development and diversification[151]. The policy favoured the establishment of gas-based energy, metals and petrochemical industries and saw the emergence of state-sponsored, gas-based investments in ammonia, methanol, iron and steel production and power generation. There was also focus on using surplus petroleum revenues to develop port facilities and industrial estate to diversify the economy[152].

With growth in gas resources and a decline in the oil sector, the government's focus leaned towards developing natural gas as a premium energy resource and potential source of foreign exchange. This signalled a policy change towards monetizing the natural gas resources and the growth of LNG export market[153]. According to the MEEA, "Government's priority for utilization of natural gas resources is targeted at the domestic market in the first instance and then exports. Subject to this policy the Government will be amenable to the pursuit of new LNG opportunities[154]." Thus efforts are geared towards attracting foreign direct investment to the nation's gas based energy sector, maintaining an investor-friendly regulatory and fiscal regime, strong leasing programs and a competitive gas pricing structure.

Ownership of gas reserves is vested in the state which issues exploration and production licenses. Natural gas production facilities are mainly privately operated and government derives value from gas production through the collection of royalties, petroleum taxes, surface rents, dividends from state companies and other taxes and levies.

NGC monopolizes the purchase, transportation and sale of natural gas produced by upstream producers for resale to local downstream gas-based industries (excluding the LNG industry). Trading markets/commodity sales for natural gas do not exist. Gas is sold between NGC and buyers by private, take-or-pay[155] contracts which are usually long-term. Differential pricing regimes are used for different end-uses and sectors. In the petrochemicals sector for instance, a product-related pricing mechanism applies by which NGC shares the market price risks with the petrochemical customers by allowing the gas price to fluctuate with commodity (e.g. ammonia and methanol) prices[156].

[151] Gas Regulation 2009
[152] http://www.ogj.com/articles/2002/03/trinidad-and-tobago-banking-its-future-on-natural-gas-but-energy-policy-still-evolving.html
[153] http://www.ogj.com/articles/2002/03/trinidad-and-tobago-banking-its-future-on-natural-gas-but-energy-policy-still-evolving.html
[154] http://www.energy.gov.tt/energy_industry.php?mid=120
[155] Take-or-pay means that the buyer is obliged to pay for a specified annual quantity of gas regardless of whether they take delivery and NGC is obligated to supply. On expiry, the contract is open to more years of renewal (Methanex Corporation Annual Information Form, March 2008).
[156] http://www.sice.oas.org/ctyindex/tto/wto/s151r1_4_e.doc

NGC owns onshore and offshore gas transmission and distribution networks and sells gas in a bundled package to buyers (i.e. payment for gas and transportation). In most cases, pipelines transporting gas from offshore gas platforms are owned by the upstream producers and gas title passes to NGC on delivery to their pipelines.

The Atlantic LNG is owned through joint venture agreements. Government issues the required authorizations to build and operate LNG facilities and relevant state corporations like NGC and NEC enter into project agreements with investors and financiers. Atlantic supplies LNG on contract to buyers that are subsidiaries of the shareholding companies. There are no spot market transactions[157] and no regulation of prices and terms of service in the LNG sector[158]. LNG price is linked directly with gas prices in major consuming markets: both the f.o.b. (sale) and producer (wellhead) prices of Atlantic LNG gas are determined by netback pricing based on prevailing prices in the United States and Europe (Spain)[159].

14.7. Similarities to Israel

There are some similarities between Trinidad and Israel:

- Both Israel and Trinidad have national policies on developing natural gas as a primary energy source.
- NGC and Israel Natural Gas Lines (INGL) are state-owned companies that own and operate national gas transmission networks and they both monopolize gas transmission.
- Natural gas supply is dominated by private enterprises in both countries.

14.8. Differences to Israel

There are some differences between Trinidad and Israel:

- Trinidad does not import natural gas while Israel imports gas from Egypt.
- About 60% of Trinidad's gas production is exported and petrochemicals and metal industries account for the highest share of domestic demand, about 75%. All of Israel's gas production is consumed locally and electricity generation accounts for 90% of demand.
- INGL only engages in national gas transmission and not in the sale or local distribution of gas while NGC owns and operates gas networks and also engages in sales and distribution of gas to consumers.
- Israel's gas import is via pipelines while Trinidad only exports LNG.
- Israel promotes private-sector driven development along the natural gas value chain except in the national gas transmission network which

[157] http://www.atlanticlng.com/v2/?page_id=14
[158] Gas Regulation 2009
[159] http://www.sice.oas.org/ctyindex/tto/wto/s151r1_4_e.doc

is controlled by state owned INGL. Trinidad promotes both state-sponsored and private-sector investments along the gas value chain from upstream production to downstream petrochemicals and derivatives.

14.9. Lessons Leant

The following are the main lessons:

- Whilst it is possible to build a petrochemical industry by providing cheap gas ultimately that leads to resource exhaustion as has been the case in Trinidad
- There is an imminent shortage of gas being developed in Trinidad and Tobago and the government has left it too late to stimulate exploration and development and there is a low take-up of exploration blocks

15. Main Lessons Learnt

The main lessons learnt cover:

- Reservation policy
- Exploration incentives as applied to domestic requirements
- Low domestic prices
- Transit arrangements
- Sovereign funds
- Ammonia and methanol plants

15.1. Reservation Policy

Six of the countries reviewed have a domestic reservation policy.

15.1.1. Australia

There is no federal policy on gas reservation although both Western Australia and Queensland have such policies. Western Australia which is the most gas dependent government has had such a policy since 2006 and this requires that 15% of every project should be reserved for domestic consumption. It has been suggested that this policy should be more flexible as the reserves are expensive to develop and the best prices for development will be world export prices. In addition new domestic processing plants are costly and only relatively small load increments are need to meet domestic requirements which would not justify the investment.

In 2011 Queensland introduced a Prospective Gas Production Land Reservation Policy to secure Queensland's future domestic gas requirements. As a result of the amendments, a future call for tenders for petroleum exploration acreage may stipulate that the licence is subject to an "Australian market supply condition". This is a condition that gas produced from a resulting production licence must be supplied exclusively to the domestic market. There are certain exemptions to the domestic supply requirement, including if market analysis indicates that sufficient gas may be produced from existing and proposed Queensland gas developments to supply both the domestic market and export demand.

15.1.2. Azerbaijan

The State Oil Company of Azerbaijan is reserving 30% of its production for domestic consumption.

15.1.3. Canada

The province of Alberta maintained a policy of protecting its own gas consumption by requiring a reserve of 30 years to be kept. This policy was in force from 1953-88 and was only ended when Canada and the USA formed a free trade area. Public pressure in the early days of the industry forced producers only to export gas when domestic markets were ensured.

15.1.4. Egypt

The Government in 1999 decided to allow exports of gas but restricted it to 25% of production and only allowed foreign investors permission provided that they invested in local gas distribution companies. The strategy was revised in 2000 so gas exports were limited to 33% of the gas reserve base with the remaining gas reserve being split between domestic consumption (33%) and strategic reserve (33%).

Egypt has also restricted the development of additional export facilities, the most important being the expansion of the LNG export plant at Damietta.

15.1.5. Indonesia

The Government in 2001 introduced a Domestic Market Obligation whereby 25% of any gas produced has to be set aside for the domestic market although the Constitutional Court ruled in 2004 that this should be 25% or more. However producers are reluctant to supply at low domestic prices and this is inhibiting gas development as a whole.

The Donggi-Senoro LNG terminal plans received government approval only after 30% of the output was designated for domestic consumption. Similarly, a third of the output from Inpex's planned Masela floating LNG liquefaction terminal will be designated for the domestic market. In addition, recently the Government announced that it will allocate all output from the massive Natuna D-Alpha field for domestic use only.

15.1.6. Netherlands

In 1963 the Government decided to export a significant part of the reserves of the huge Groningen field, without worrying about the depletion of gas reserves. However in 1974, the small fields policy (SFP) was adopted in order to increase the life of the gas fields for as long as possible. This requires the

state gas company to buy gas from small fields at market prices. As there is a production ceiling this means that production from the large Groningen field is restricted and acts as a strategic reserve.   Trinidad and Tobago
Trinidad and Tobago does not have a domestic obligation and it has been unable to encourage exploration in the last few years with the result that its reserves/production ratio has fallen to 8.6 years. Government policy was to keep this ratio at 25 years but it failed to attract further exploration in a number of licensing rounds.

15.2. Domestic Supply Incentives

A number of the study countries have attempted to improve exploration incentives to provide for domestic supply security with varying degrees of success.

15.2.1. Australia

The State of Queensland has just introduced a provision that would allow tenders of production sharing licences to require an Australian market condition that would require in certain cases dedication of production to the domestic market.

15.2.2. Egypt

In 2008 Egypt stopped the development of export facilities and this is one of the principal causes of a significant slow-down in exploration activity.

15.2.3. Indonesia

Although there is a domestic market obligation the low prices in the domestic market has caused a slow down in investment in further gas development. In addition there is now spare capacity in the export facilities.

15.2.4. The Netherlands

The Netherlands developed the small fields policy to expand its reserves; exploration and development was encouraged by allowing the new fields to export their production while reserving the large Groningen field for domestic use.

15.2.5. Trinidad and Tobago

In order to increase its reserves the government has reduced the petroleum profits tax from 50% to 35%, allowed 40% uplift on investments and has eliminated signature bonuses as well as state participation. However this has had only a minor affect on exploration activity with the low domestic price being a problem.

15.3. Low Domestic Prices

Low domestic prices in a number of the study countries make it difficult to encourage development of domestic supply.

15.3.1. Egypt

The purchase price for domestic gas is significantly lower than export prices and coupled with a ban on further exports this will result in lower exploration activity.

15.3.2. Indonesia

The domestic market obligation with a low price is having a negative effect on investment for further gas development.

15.3.3. Malaysia

Domestic prices are lower than export prices and gas production in Malaysia has reached a plateau which will limit expansion of the domestic market. Malaysia, despite being the world’s third largest LNG exporter, is now developing several LNG import projects to meet domestic demand

15.4. Transit Arrangements

A number of the study countries were required to negotiate transit arrangements for their gas which involved state involvement.

15.4.1. Algeria

Algeria had to negotiate transit arrangements through both Morocco and Tunisia and these arrangements were made through bilateral state agreements.

15.4.2. Azerbaijan

Azerbaijan has required access through Georgia and Turkey for its gas exports. The arrangements for gas transit through Turkey have been made through bilateral state agreement (Inter-Government Agreements).

15.4.3. Norway

In the initial phase of gas development no gas was landed in Norway both because of the lack of a domestic market and physical problems in laying pipe over the Norwegian Trench. Bilateral arrangements were made between Norway and the UK, France and Germany.

15.5. Sovereign Funds

15.5.1. Azerbaijan

The State Oil Fund of Azerbaijan was set up in 1999 to accumulate and manage Azerbaijan oil and gas revenues. As at 31 December 2010 the Fund was $22.8 billion.

15.5.2. Norway

The Petroleum Fund of Norway was set up in 1990 and changed its name in January 2006 to The Government Pension Fund Global. The fund is currently valued at about $560 billion.

15.6. Ammonia and Methanol Plants

Trinidad and Tobago is the largest exporter of ammonia and methanol in the world. However the industry is subsidised with the gas supply price being around $1.6/MMBTU in 2005.