2006-2009 Triennium Work Report

October 2009

WORKING COMMITTEE 1: EXPLORATION AND PRODUCTION

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Russia

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SG 1.1 **“**Remaining conventional world gas resources and technological challenges for their development” report

SG 1.2 “Difficult reservoirs and unconventional natural gas resources” report

INTRODUCTION

Reliable natural gas supply becomes more and more important for world energy sector development. Especially this is visible in regions, where old and sophisticated gas infrastructure is a considerable part of regional industry and its stable work is necessary for successful economy development. In the same time such regions often are already poor by conventional gas reserves or have no more such reserves. And there is need for searching new sources of natural gas. This is ***challenge*** for exploration and production of natural gas requiring reviewing strategies of their development in near future. The most important questions are: how much gas still we can get from mature areas (and by what means), and how much gas we can get from difficult reservoirs and unconventional gas sources?

From this point of view IGU Working Committee 1 (Exploration and Production of Natural Gas) has established for the triennium 2006-2009 two Study Groups: **"**Remaining conventional world gas resources and technological challenges for their development" and "Difficult reservoirs and unconventional natural gas resources".

The purposes for the first Group study were to make definition of such important term now using in gas industry like "mature area", to show current situation with reserves and production in mature areas and forecast of future development, situation with modern technologies of produced gas monetization, Arctic gas prospects, special attention was paid to large Shtokman project.

Second Group had also analyzed such important term like "unconventional gas resources", studied current unconventional gas sources and their resources, technologies of their exploration and production and their importance for regional gas industry development (especially in the North America). This is very important issue for global gas industry now, because gas resources of unconventional sources and difficult reservoirs exceed conventional resources many times and they are spread much more wider than conventional resources.

Study Group 1.1 Report

Dominique COPIN (France) – leader

REMAINING CONVENTIONAL WORLD GAS RESOURCES AND TECHNOLOGICAL CHALLENGES FOR THEIR DEVELOPMENT

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INTRODUCTION

Following parts are included into WOC 1 Study Group 1.1 report: mature areas, Arctic developments and gas monetization.

Mature areas: specificities and challenges.

The history of discoveries and production starts has been analysed. The target was to illustrate the “maturity” of different producing areas in the North Sea, South America, South East Asia and Russia.

This work shows that each area has its own specificities. The potential for growth varies considerably from one area to another. The challenges which the industry faces in these areas are broadly described.

Development of Arctic gas resources.

Our report includes descriptions of the most important Arctic developments in the Barents Sea and in the Yamal peninsula, like:

Shtokman in the Barents Sea,
Kruzenshternskoe, Bovanenkovskoe, Kharasavejskoe and Novoportovskoe fields in the Yamal peninsula.

Not only are the geological models of these fields displayed, but the main challenges to overcome are also discussed, like the impact of the Arctic conditions on development schemes and environmental constraints.

Gas monetization.

Our report shows how the perspectives on the different ways of monetizing gas changed during the last years.

Different factors can contribute to these changes such as technological improvements, market conditions, or cost evolutions.

The following technologies or processes are considered:

Gas to Liquids,
Dimethylether,
Methanol,
Ammonia,
Gas to Wire,
Floating LNG,
Compressed Natural Gas Transportation,
Hydrates Transportation.

MATURE AREAS

Introduction

Gas consumption will keep on increasing for some decades. This will be true in almost every country around the world, whether the country has been a significant gas consumer for a long time or not.

The oldest (”mature”) gas consumers have benefited from the fact that they were close to fields bearing significant gas reserves. Reserves of these fields are generally not yet exhausted. But one can expect that, in the areas where these fields are located, the most prolific fields have produced a large share of their reserves, and also that the fields which are still to be discovered may be smaller than the ones which have been producing for a long time. Under these circumstances, the producing area which encompasses these fields can be qualified as “mature”.

These “mature” gas consumers will still be supplied by fields which have produced for many years and which are either close or connected to them through developed pipeline or gas liquefaction infrastructures.

There is a fundamental imbalance between “maturity” in terms of consumption and “maturity” in terms of production. The consumption “maturity” will not result soon in reduction of consumption, while the question of the productions’ ability to match the consumption growth of their markets is worth examining closely.

The following question arises: to which extent will production from these “mature” producing areas meet the increasing demand for gas in the “mature” consuming areas which they are supplying?

This issue is important in terms of the supply and demand equation. It also raises the issue of the increase of the need for gas infrastructures to link high growth potential producing areas to old and new consuming areas. This will depend on many factors, one of them being the capacity of mature producing areas to improve their production profiles.

The purpose of this study is to show the specificities of different important mature areas and to identify the different challenges they will have to meet.

The purpose is certainly not to oppose one country against the others, or one operator against the others, or even to compare them. Comparisons here are used only as a tool to investigate the characteristics of a mature area.

More importantly, the fact that a zone is mature has nothing to do with the attractivity of the area in terms of investments. Many operators can find that mature areas are interesting places to invest in any segment of the exploration and production process. Some elements such as the industrial base, infrastructures, experience of people, proximity of the markets, political stability and many others, can make investment opportunities in these areas attractive for companies.

The purpose of this study is not to tell operators what to do.

We have based our study on Wood Mackenzie data. This data helped us gather very useful information on histories of discoveries and production starts in the different areas.

Conclusions

The areas which are analysed in this work present different characteristics. The challenges that have to be met are very different from one area to another.

A general observation which has important short term consequences for some areas can be made:

> In most areas, the deficit of commercial discoveries versus production increases with time. As with any general rule, there are exceptions. Norway is one of them, because a very important field was discovered in 1995, which frontally encounters the trend. The other exception is an area which should not be regarded as mature: Brazil.

United Kingdom

By many criteria, UK is the most mature area of the group of areas which were studied. The short duration life of its reserves, whether they are commercial or not, and the deficit of discoveries versus production are the main characteristics which qualify this area as mature. This leads to the conclusion that unless an important discovery is made, or a group of discoveries, the decline previously noticed will continue.

Norway

Owing to recent starts of production on very important fields, production will continue increasing in the near future after a period of stability around year 2000. Norway will not see its production decline before long, but it will need new discoveries to increase its production. The coming growth is due to exceptional exploration successes. For production to keep on increasing after 2012, more exploration successes are necessary.

The Netherlands

This area will soon enter a decline period. If we exclude Groningen, the decline will be very strong after 2012. As long as the production plateau in Groningen does not stop, this decline will be somehow mitigated. This plateau might end around 2020. If the deficit of exploration successes which has been observed for the last 20 years does not change, the decline will begin after 2012.

Argentina

Although its production will be stable in the coming years, a decline seems unavoidable in a few years time because of the lack of discoveries and the short reserves duration life. Up to now, the production profiles of the main fields have been such that no decline has been observed yet. If no significant discoveries are made before this period, production will decline.

Brazil

It is not a mature area. Showing the history of Brazil, which is today a small producer when compared to the other areas, illustrates by contrast the differences between a mature area and a growing area.

Malaysia

After a recent period of significant production growth, Malaysia has now entered a period of stabilisation in its production which should last another next 10 years. Like many other areas, it meets a lot of difficulties to renew its production. However, the area benefits from a significant amount of non commercial reserves which could contribute to an increase in production if they are made commercial.

Indonesia

Indonesia's production is growing fast. This will not last for more than a few years if new reserves are not put on production in the next years. This will not concern relatively recent discoveries as the most important ones have already started production, and exploration results during the last years have been quite low. However, making its very significant non commercial reserves commercial will enable Indonesia to enter a new period of growth.

West Siberia

This area contains huge reserves produced today at a low rate which make irrelevant any debate about the decline of the region. The long duration life of its reserves is linked to passed exploration successes and to the demand for gas. However, on the one hand, as demand is expected to grow, huge investments in infrastructure for reaching the markets (pipe, LNG) will be required and, on the other hand, more exploration successes will be needed in the future to sustain a production growth.

Definition of maturity

Mature areas must fulfil the following criteria.

1. All fields and exploration opportunities of a given area must be connected together or can be connected with investments in infrastructure which are incremental compared to the existing infrastructures.
2. The area must be connected to a developed market. This does not exclude the possibility that new investments in infrastructure will have to be developed, but they will be incremental.
3. An area needs to be significant in terms of production and reserves.
4. When an area encompasses several countries, each country will then be regarded as an area if the reserves and production in this country are significant.
5. A trend which shows an increasing imbalance between reserves associated to discoveries during a given period and production during the same period is a clear indication of maturity.
6. A trend which shows an increasing imbalance between reserves associated to production starts during a given period and production during the same period is a clear indication of maturity.

With these different criteria in mind, it can be easily anticipated that production profiles for mature areas will usually show a plateau or a decline. In fact, production from some areas might keep increasing for some years despite the fact that they fulfil most, if not all, of the criteria described above. From a relatively short term point of view at least, maturity does not always mean plateau or decline.

This report will be an opportunity to make distinctions between the future production behaviours of the different areas.

Perspectives and challenges might highly depend on the area analysed.

The ambition of the authors of this report is to show the specificities of the different areas.

Selection of the areas

We initially considered the following areas:

The North Sea (the United Kingdom, Norway, the Netherlands), South America (Argentina, Brazil), South East Asia (Malaysia, Indonesia) and Russia (West Siberia).

For practical reasons, the group decided not to work on the USA. However, a specific presentation will be made on this area in one of our technical sessions.

For all the areas which encompass several countries (the North Sea, South America and South East Asia), we considered that each country could be identified as an area. In fact, we will see in this report that each of them has specificities which are worth being outlined when compared to the others.

The areas we analysed are therefore the following: the United Kingdom, Norway and the Netherlands in the North Sea; Malaysia and Indonesia in South East Asia; Argentina and Brazil in South America, and West Russia.

Comparison of discoveries and production starts with production.

Discoveries versus production

For each area, the cumulative commercial reserves associated with discoveries have been compared to the production. Four 5-year periods have been defined between 1987 and 2006.

A deficit of discoveries versus production, if it occurs every year, is an indication of maturity. An increase of this deficit is an indication that this area is becoming more and more mature. A change from a surplus to a deficit is an indication of an area which is becoming mature.

The impact on production profiles will not be immediate, because time is needed between the discoveries and the production starts. This comparison is an early indicator of maturity.

When considering the first period (1987-1991), two areas showed a deficit of discoveries during that period versus production for the same period: the Netherlands and West Siberia.

When considering the last period (2002-2006), seven areas showed the same kind of deficit. The only exception was Brazil. In the Netherlands and West Siberia, two areas which showed an initial deficit, the deficit has increased, mainly due to the decrease of the amount of discoveries.

This increase in the number of areas showing a deficit of discoveries (two in 1987-1991, and seven in 2002-2006) is an indication that areas are getting more and more mature with time.

The only exception, Brazil, should not be regarded as mature.

If non commercial, or technical[1], reserves are also included in the discoveries, the results are marginally different. Deficits are lower for each area and each period, but the conclusions are basically the same since the Netherlands is the only area to show a deficit in 1987-1991, while the same areas (all areas except Brazil) show a deficit in 2002-2006.

Production starts versus production

The same kind of exercise has been performed as above with reserves associated to production starts replacing the reserves associated with discoveries.

As we can see also in the comparison between reserves associated to discoveries and production, a deficit of reserves associated to production starts versus production is an indicator of maturity. As the impact of a production start on production profiles is almost immediate, this indicator tends to lag behind the one described above (discoveries versus production). In other words, in a given period, there should be more countries with a deficit on discoveries than with a deficit on production starts.

In the first period (1987-1991), no area except West Siberia and the Netherlands showed a deficit in terms of production starts versus production.

[1] Technical reserves are reserves which cannot be regarded as commercial because their development is not economical under the present technological and economic conditions.

In the last period (2002-2006), the Netherlands, the United Kingdom, Argentina and Malaysia showed this deficit.

Between 2007 and 2012, production in these areas will be stable (the Netherlands and Argentina) or will increase by less than 10% (Malaysia), or will decline by more than 20% (United Kingdom).

During the same period, production in the other areas will increase by more than 20% in Norway, Indonesia and Brazil, while it will increase by more than 5% in West Siberia.

United Kingdom

1987-1991 was the only period where discoveries were close to production:
since then, production has increased and discoveries have declined.

Besides, reserves associated with production starts were above or close to the production for most of the period. However, for the 2002-2006 period, reserves associated with production starts have decreased significantly.

Of the different areas considered, UK is probably the area whose behaviour is the closest to a typical mature area: the reserves associated to discoveries have constantly declined for the last 20 years, and the peak of reserves associated to production starts occurred around 10 years ago.

The main discoveries for the different periods were the following:

During the 1987-1991 period, discoveries were close to production: Liverpool Bay in the Manx-Furness Basin (West of Britain) has been the only discovery above 1 Tcf since 1987. The only other discovery above 0.5 Tcf was Shearwater in the Central Graben (Central North Sea). Production in Liverpool Bay started during the 1992-1996 period. Shearwater was put on production during the 1997-2001 period.

During the 1992-1996 period, discoveries were significantly lower than in the previous period, while production increased. A strong deficit is observed: there were two discoveries between 0.5 Tcf and 1 Tcf: Goldeneye in the South Halibut Basin (Central North Sea), and Jade in the Central Graben. They were both put on production during the 2002-2006 period.

During the 1997-2001 period, there was only one discovery between 0.5 Tcf and 1 Tcf: Breagh in the Cleveland Basin (Southern Gas Basin). Its production should start in 2012.

During the last period (2002-2006), there was no discovery above 0.5 Tcf.

Since the beginning of 2007, no discovery above 0.5 Tcf has been reported.

The main production starts were the following:

In 1987-1991: Alwyn area in the East of Shetland Basin (Northern North Sea) with more than 4 Tcf (discovered in 1973), Sole Pit in the Sole Pit Basin (Southern Gas Basin) with more than 1 Tcf (discovered in 1966), and V-Fields in the Indefatigable Shelf (Southern Gas Basin) with more than 1 Tcf (first discovery in 1970).

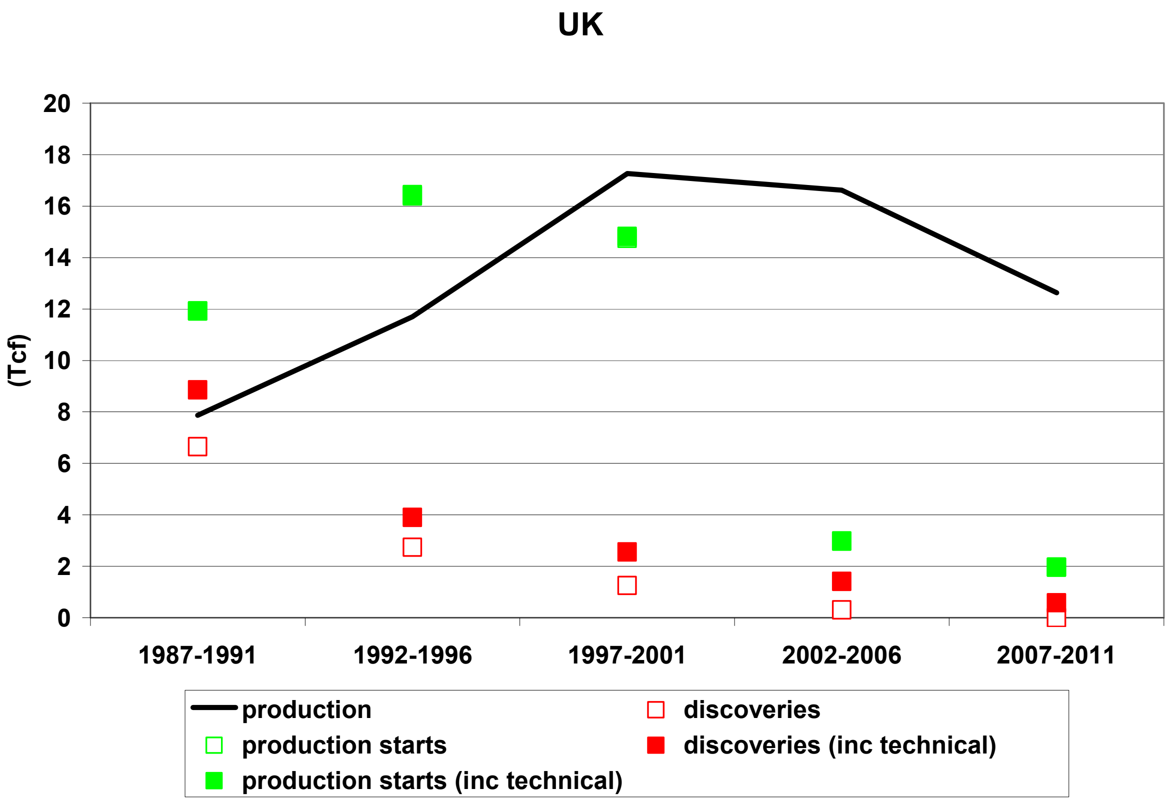
In 1992-1996, in addition to Liverpool Bay, there were two other significant production starts: Bruce in the Viking Graben (Northern North Sea) with close to 3 Tcf (discovered in 1974), and Morecambe North in the Manx-Furness Basin (West of Britain) with more than 1 Tcf (discovered in 1976). This period was the one where the amount of reserves associated to production starts was the highest.

In 1997-2001, the main production starts were Britannia in the Viking Graben Basin (Central North Sea) with more than 3 Tcf (discovered in 1975), Elgin Franklin in the Central Graben (Central North Sea) with more than 2.5 Tcf (discovered in 1985), J block in the

Central Graben (Central North Sea) with more than 1.5 Tcf (discovered in 1981), and Armada in the Viking Graben (Central North Sea) with more than 1 Tcf (discovered in 1980).

The three most important fields where production started between 2002 and 2006 were Rhum in the Viking Graben (Northern North Sea) with more than 0.5 Tcf (discovered in 1973), Goldeneye and Jade.

Since the beginning of 2007, no production was started in fields whose initial reserves were above 0.5 Tcf.



Sources Wood Mackenzie and BP Statistical Review of World Energy

Norway

For the first two periods under study, discoveries were close to production, while for the third one (1997-2001), discoveries were above production. For the last period, however, the deficit of discoveries relative to production was very important.

Reserves associated with production starts were close to the production for 1987-1991 and 1997-2001. But they were considerably higher than production in the 1992-1996 period and significantly lower in the 2002-2006 period.

Norway does not completely fulfil the ideal of a mature area. However, the deficits in discoveries and production starts in the 2002-2006 period might be a hint that Norway will soon become a mature area.

<u>The main discoveries for the different periods are the following:</u>

During the 1987-1991 period, discoveries were slightly lower than production: Gjøa in the Lomre Terrace (Northern North Sea) was the only discovery above 1 Tcf during that period. The only other discovery above 0.5 Tcf was Mikkel in the Halten Terrace (Mid Norway). Production in Gjøa should start in 2010. Mikkel was put on production during the 2002-2006 period.

During the 1992-1996 period, the main discovery was Kvitebjørn in the Viking Graben (Northern North Sea) with more than 2.5 Tcf (production started in the 2002-2006 period). The only other discovery above 0.5 Tcf was Tune in the Viking Graben (production started in the 2002-2006 period).

During the 1997-2001 period, the main discovery, and by far the most important for the whole period in Norway, was Ormen Lange in the Møre Basin (Mid Norway) with 14 Tcf (production start 2007). Skarv in the Halten Terrace (Mid Norway) was a discovery with more than 1.5 Tcf (production should begin in 2012), and Kristin in the Halten Terrace was another discovery of 1 Tcf (production start 2004). Victoria in the Halten Terrace was discovered during that period (more than 3 Tcf), but is still regarded as non commercial for the time being. The Luva discovery in the Vøring Basin (Mid Norway) is also regarded as non commercial for the time being (1 Tcf).

During the 2002-2006 period, no significant commercial discoveries were reported. However, new technical reserves were found with the discovery of Onyx in the Halten Terrace (close to 1 Tcf).

Since the beginning of 2007, no discovery above 0.5 Tcf has been reported.

<u>The main production starts were the following:</u>

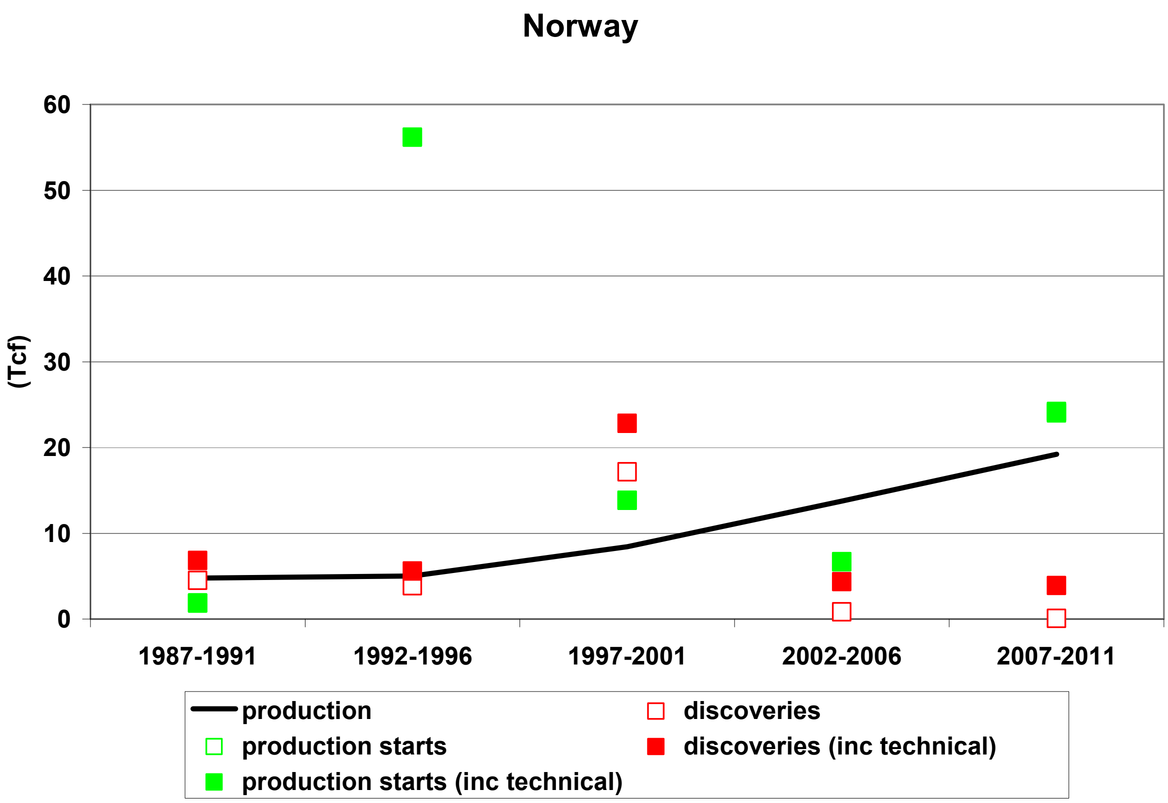
No starts were reported in 1987-1991 on fields with initial reserves above 0.5 Tcf.

In 1992-1996, the most important production start was by far Troll Gas in the Horda Platform (Northern North Sea) with more than 46 Tcf (discovered in 1979). There were three additional production starts on fields with more than 1 Tcf of commercial reserves: Sleipner Vest in the Viking Graben (Northern North Sea) with 4 Tcf (discovered in 1974), Sleipner Øst with 3 Tcf (discovered in 1981), and Heidrun in the Halten Terrace (Mid Norway) with 1.5 Tcf (discovered in 1985).

In 1997-2001, the main production starts were Åsgard in the Halten Terrace with more than 6 Tcf (discovered in 1981), Elofisk II in the Halten Terrace with more than 2 Tcf (discovered in 1969), Visund in the East Shetland Basin (Northern North Sea) with close to 2 Tcf (discovered in 1986), and Gullfaks Sør in the East Shetland Basin with more than 1 Tcf (discovered in 1978).

In 2002-2006, the main production starts were Mikkel (discovered in 1987-1991), Kvitebjorn (discovered in 1992-1996) and Kristin (discovered in 1997-2001).

Since the beginning of 2007, the main production starts have been Ormen Lange (discovered in 1997-2001), and Snøhvit (discovered in 1981) with 6 Tcf in the Hammerfest Basin (Barents Sea). Skarv and Tyrihans in the Halten Terrace (discovered in 1983) and Gjøa in the Horda platform (discovered in 1987-1991) will follow with around 1 Tcf each.



Sources Wood Mackenzie and BP Statistical Review of World Energy

The Netherlands

In each period under study, the deficits of reserves associated to discoveries or production starts were very important.

This area is very mature since production is far from being renewed.

The main discoveries for the different periods are the following:

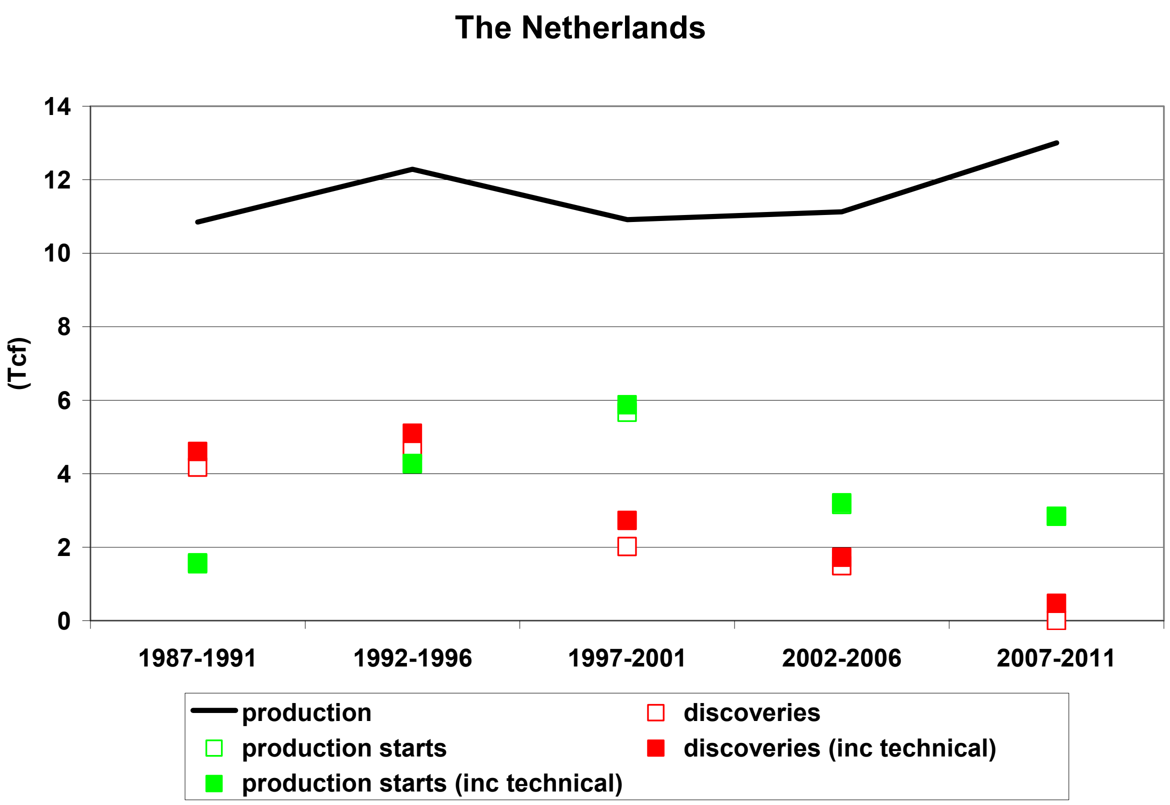
During the 1992-1996 period, main discoveries were L/9AB in the Central Graben (close to 1.5 Tcf) where production started in 1997-2001, and K/4B-K/5A in the Cleaver Bank High (more than 1 Tcf) where production started in 1997-2001.

During the 1992-1996 period, a number of fields were discovered in the Noord Friesland Concession (between 1.5 Tcf and 2 Tcf).

In the other periods, there were no discoveries above 0.5 Tcf.

Since the beginning of 2007, no discovery above 0.5 Tcf has been reported.

From the production start point of view, the only significant fields were L/9AB (discovered in 1992-1996) where production started in 1997-2001, and K/4B-K/5A where production started in 1992-1996.



Sources Wood Mackenzie and BP Statistical Review of World Energy

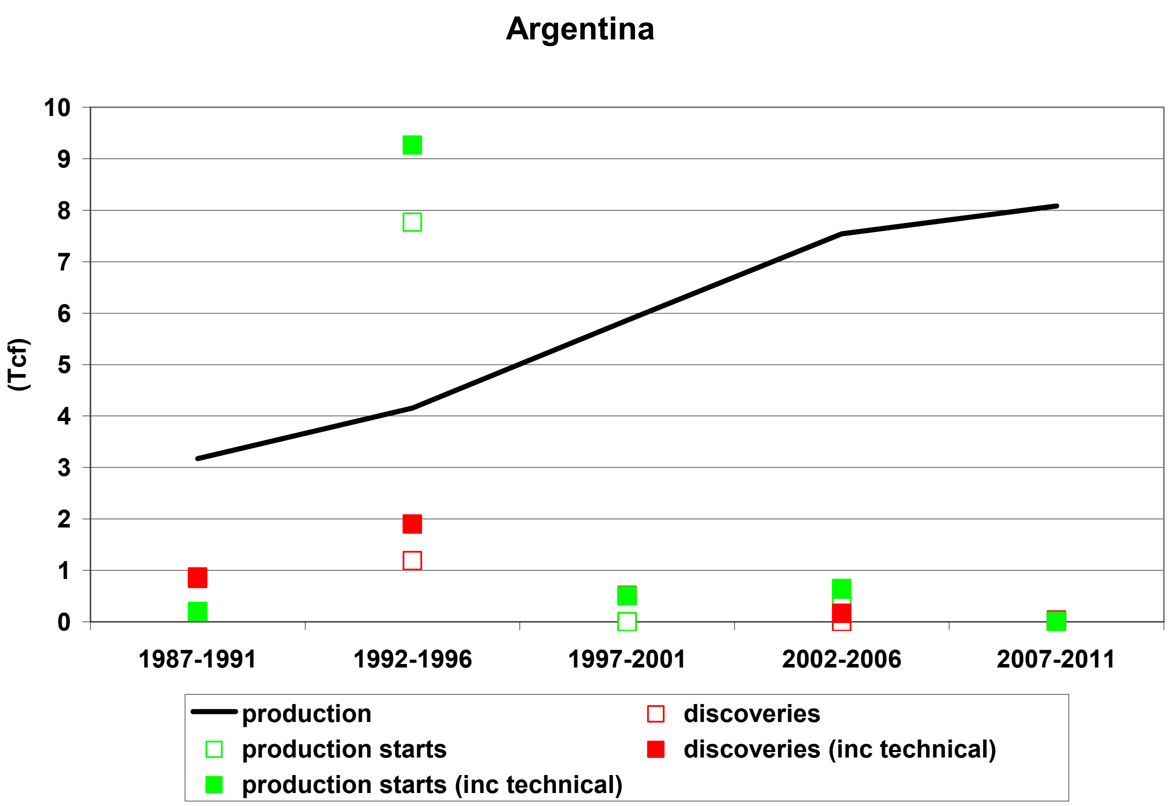
Argentina

For the last two periods (1997-2001 and 2002-2004), the levels of reserves associated to discoveries or production starts were very low.

For the first two periods (1987-1991 and 1992-1996), discoveries and production were more or less balanced, while the surplus of reserves associated to production starts in the period 1992-1996 was very important.

There was no significant discovery for the different periods. There was only one discovery with commercial reserves above 1 Tcf: Sierra Chata in Neuquen, which was discovered in 1993 and whose production started in 1995.

The only period where a significant field was put on production is 1992-1996. In addition to Sierra Chata, two other fields were put on production: Acambuco in Noroeste (3 Tcf including technical reserves) and Aguada Pichana in Neuquen (3.5 Tcf including technical reserves).



Sources Wood Mackenzie and BP Statistical Review of World Energy

Brazil

In this country, a significant surplus of reserves associated to discoveries or to production starts has been recorded for the last 20 years.

The main discoveries for the different periods are the following:

No significant discoveries occurred in the first two periods (1987-1991 and 1992-1996).

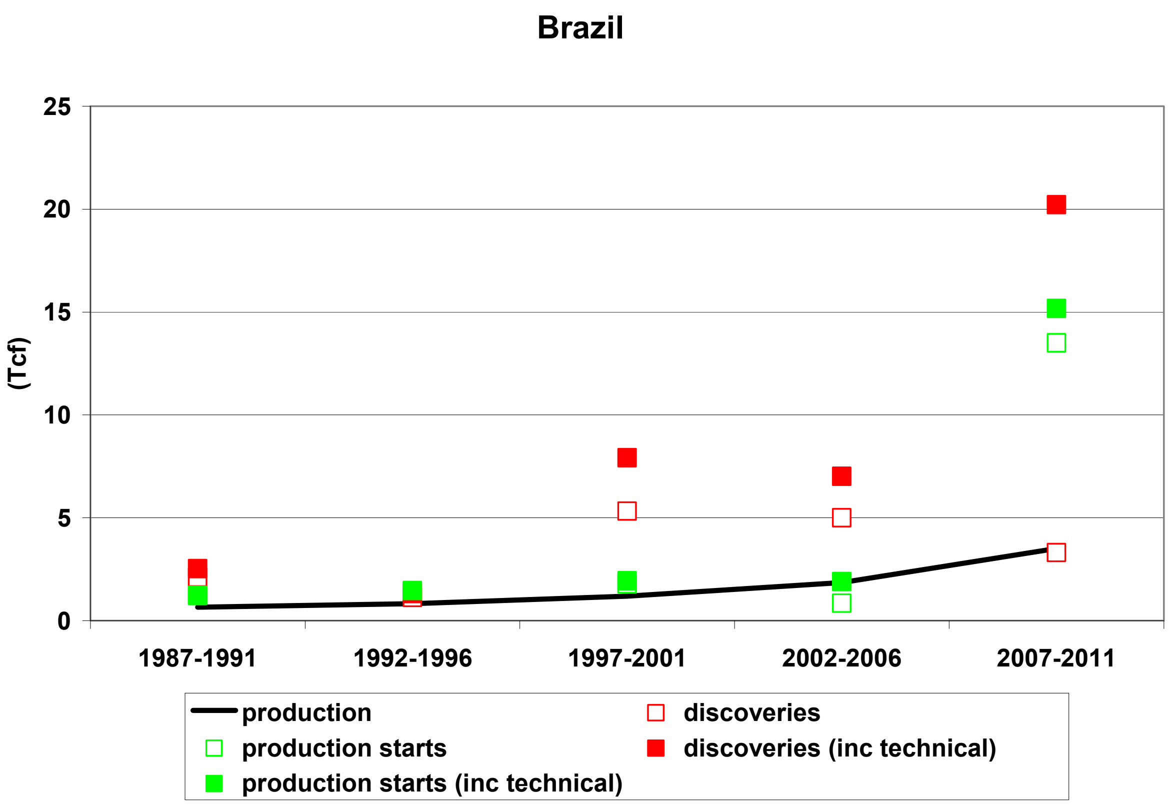
In the 1997-2001 period, there were three significant discoveries. Two were in the Santos Basin: Mexilhão and BS-500 Pole, with cumulative commercial reserves equal to 4 Tcf and one was in the Camamu-Almada Basin: Manati with 1 Tcf. Its production started in 2007.

In 2002-2006, the main discovery was Tupi in the Santos Basin, with more than 4 Tcf of commercial reserves.

These four fields should begin their production in 2007-2011, or have begun their production.

The fields which were put on production during the periods between 1987 and 2006 are much smaller than these four fields.

Since 2007, the main production start has been Manati. In 2009, production will start from Tupi. In 2010, production will start from Mexilhão and BS-500 Pole.



Sources Wood Mackenzie and BP Statistical Review of World Energy

Malaysia

For the first two periods under study, discoveries were above the production, while, for the last two, the deficit of discoveries relative to production was significant, especially if technical reserves are not taken into account.

Reserves associated with production starts were above the production between 1987 and 2001, while, for 2002 to 2006, they were very close to the production.

The main discoveries for the different periods are the following:

During the period 1987-1991, SK10 in the Sarawak Basin was the most important discovery (more than 2 Tcf). Its production started in the 2002-2006 period. PM3 CAA in the Malay Basin was another important discovery (more than 1.5 Tcf). Its production started in the 1997-2001 period. Some significant technical reserves were discovered: PM301 and PM311 (more than 1 Tcf altogether) in the Malay Basin. There is no forecast for the beginning of production from these fields.

During the 1992-1996 period, the main discovery was SK8 in the Sarawak Basin (more than 4 Tcf). Its production started in 2002-2006. Kebabangan in Sabah (more than 4 Tcf) was also a very significant discovery. Its production will not start before a few years.

During the 1997-2001 period, no commercial reserves were identified. However substantial technical reserves were discovered in the Sarawak Basin: K5 (more than 5 Tcf).

During the 2002-2006 period, commercial reserves were identified in SB J in Sabah and PC4 in Sarawak (more than 1 Tcf each). They are being developed. SB K (close to 1 Tcf) in Sabah was discovered during the same period and is currently on stream.

Since the beginning of 2007, no discovery above 0.5 Tcf has been reported.

The main production starts were the following:

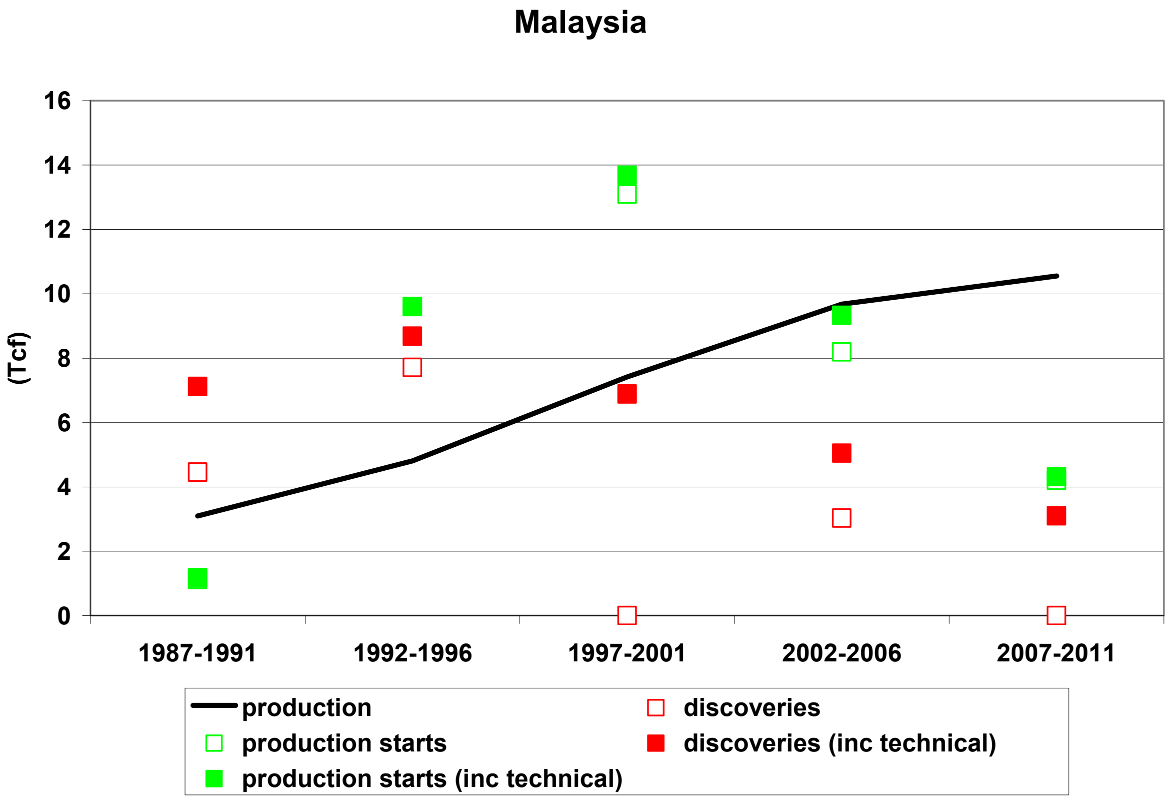
No significant starts were reported in 1987-1991.

In 1992-1996, the main production start was the project in Sarawak: MLNG Dua PSC.

In 1997-2001, the main production start was Gas PSC in the Malay Basin.

SK8, SK10, SK309 and SK311 were the main fields where production started in the 2002-2006 period. SK8 (more than 4 Tcf) and SK10 (more than 2 Tcf) were discovered at the end of the eighties or at the beginning of the nineties, while SK309 and SK311 (1.5 Tcf altogether) were discovered in 1961.

Since the beginning of 2007, production has started on SB K (discovered in 2002-2006). Production is about to start or has started on PC4 (discovered in 2002-2006). And production will start on Kumang Cluster in the Sarawak basin (above 3 Tcf): this field was discovered in 1969.



Sources Wood Mackenzie and BP Statistical Review of World Energy

Indonesia

For the first period under study, discoveries and reserves associated with production starts were slightly above the production. For the other periods, unless technical reserves are taken into account, there was a strong deficit of discoveries and production starts against production. When technical reserves are taken into account, there has been a deficit from the point of view of production starts over the past twenty years, but discoveries have been almost level with production.

<u>The main discoveries for the different periods are the following:</u>

During the 1987-1991 period, Berau PSC in the Bintuni Basin was by far the most important discovery in terms of commercial (more than 7 Tcf) and technical reserves (close to 5.5 Tcf). Berau will start its production in 2009.

Similarly, during the 1992-1996 period, Muturi PSC in the Bintuni Basin was the most important discovery in terms of commercial (more than 2.5 Tcf) and technical reserves (more than 1 Tcf). Wiriagar was a slightly less significant contributor to the results in terms of discovery (2 Tcf for the commercial and technical reserves altogether). As for Berau, these two fields will start production in 2009.

The main event during the 1997-2001 period is the discovery of technical reserves in Abadi in the Timor Basin (14 Tcf). Ganal and Rapak in the Kutei Basin were the most important commercial discoveries (above 4 Tcf altogether) with significant technical reserves (more than 1.5 Tcf altogether). The production starts of these fields are not expected before 2015.

There was no significant discovery between 2002 and 2006.

Since the beginning of 2007, no discovery above 0.5 Tcf has been reported.

<u>The main production starts were the following:</u>

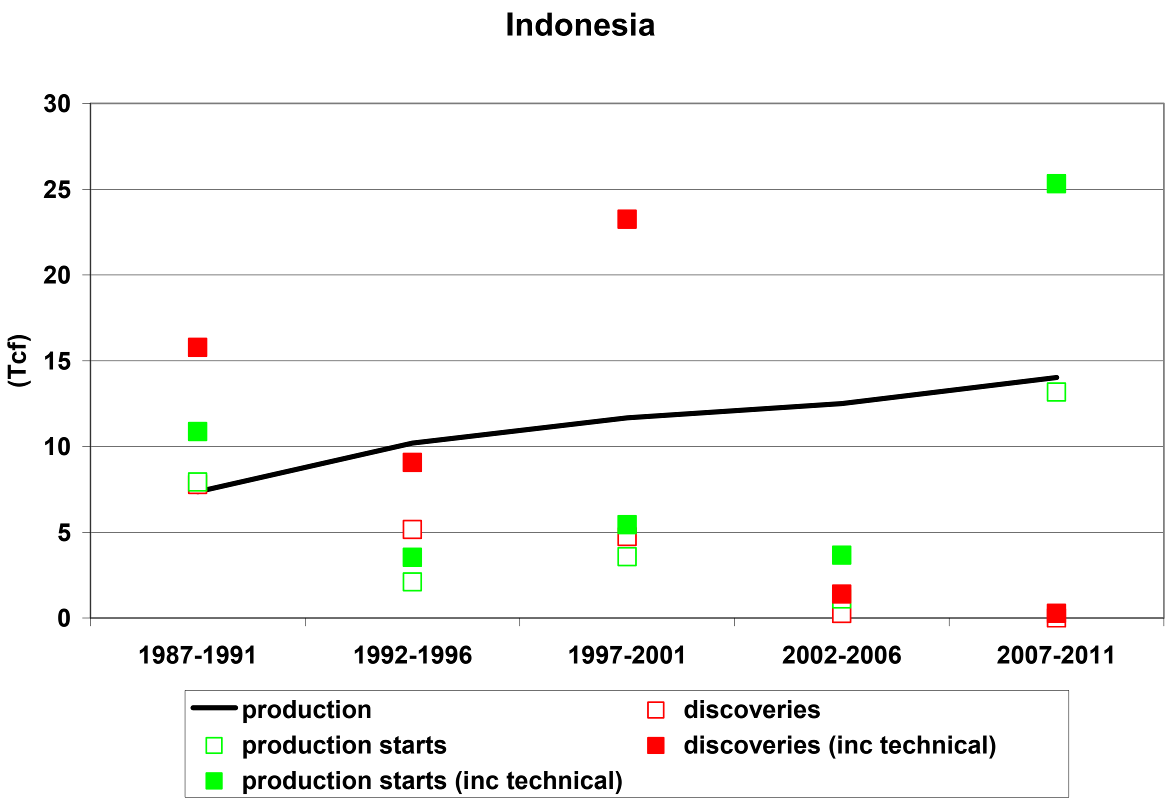
In 1987-1991, during which reserves associated to production starts and production were quite balanced, the main production start was Corridor in South Sumatra Basin (6 Tcf). It was discovered in 1972. Natuna Sea Block A in the West Natuna Basin was also a significant production start (1.5 Tcf). This field was discovered in 1972.

In the following period (1992-1996), the deficit of reserves associated to production starts against production was important and tended to increase. Kangean in East Java Basin started its production at that time (close to 2 Tcf). It was discovered in 1977.

In 1997-2001, the main production start was NSO/NSO Extension PSC in the North Sumatra Basin (close to 2 Tcf, when technical reserves are included). Jabung in the South Sumatra Basin was another significant field whose production started during that period (1.5 Tcf including the technical reserves).

In 2002-2006, the deficit against production was at its highest value for the last 20 years.

During the 2007-2011 period, the production will start on three fields: Berau, Muturi, Wiriagar. The commercial reserves associated with these fields are above 10 Tcf, and the non commercial reserves are close to 8 Tcf.



Sources Wood Mackenzie and BP Statistical Review of World Energy

West Siberia

For the last years, this area has generally witnessed some deficit of discoveries versus production, while the reserves associated with production starts have tended to be close to production.

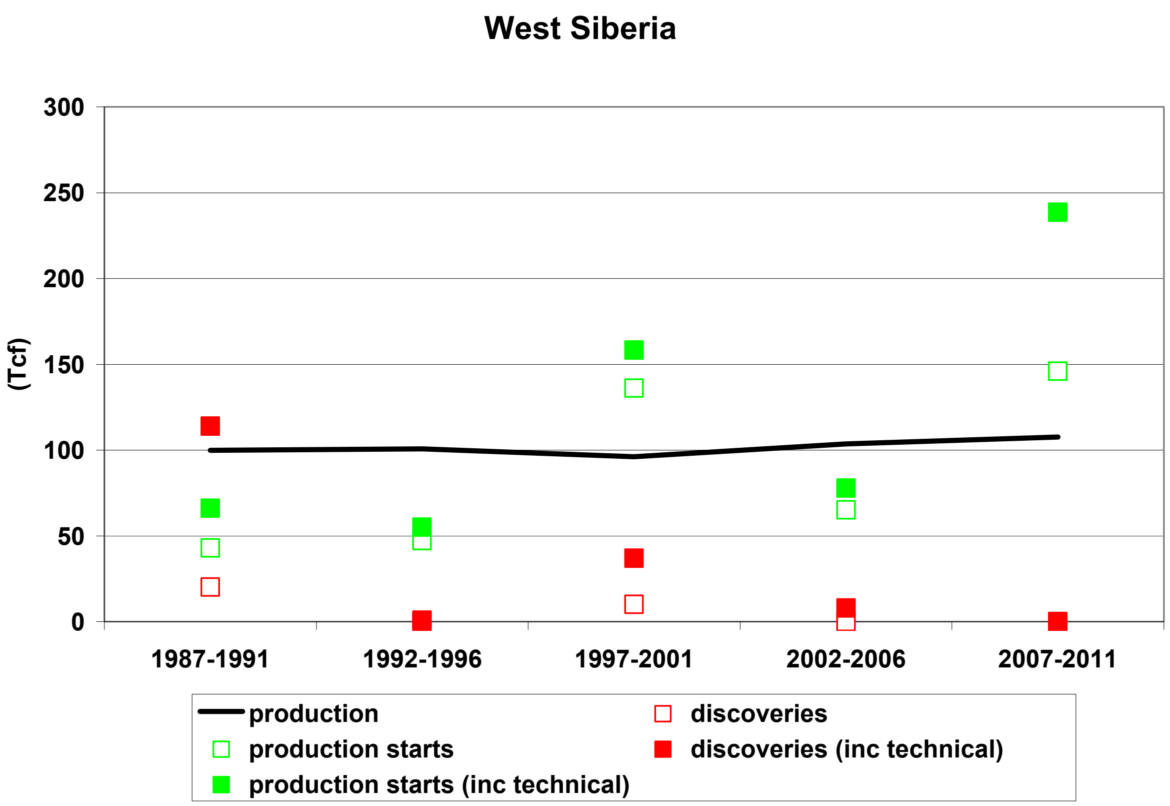
The main discoveries for the different periods are the following:

1987-1991 is the period when reserves associated to discoveries were greater than production if technical reserves are taken into account. If these reserves are not taken into account, the deficit would then be very important. The two fields which bring considerable technical reserves are Leningradskoye and Rusanovskoye in the Kara Sea. Their discoveries brought altogether more than 60 Tcf.

Before 1987, there were important technical discoveries like Tambey group of fields in north-east Yamal peninsula and Kamennomysskoye and Kamennomysskoye-more fields in Ob river Gulf. Their reserves are estimated at 140 Tcf (source: Gazprom).

Although there were other discoveries which would be very significant in any other area, they are quite small when compared to production in this zone.

The largest field whose production started in 1997-2001 is Zapolyarnoye in the Yamal-Nenets region, with reserves exceeding 100 Tcf. It was discovered in 1965. In addition, few other significant fields began their production between 1987 and 2006: Pestsovoye, Yurkharovskoye , Severo-Urengoyskoye, Kharvutinskoye, Yuzhno-Russkoye et al.



Sources Wood Mackenzie and BP Statistical Review of World Energy

Production perspectives

Most of these zones can be regarded as mature by the deficits which most of them show in terms of renewal of production by discovered reserves. However, in the 2007-2012 period, there will be only one area which will show a decrease of production. It is the United Kingdom where production in 2012 will be almost one quarter below production in 2007. In four areas, (the Netherlands, Malaysia, Argentina and West Siberia), the increase will be lower than 10%. Two areas, Norway and Indonesia, will show increases of more than 30%, while Brazil will more than double its production.

However, if we had considered the 2012-2017 period instead of 2007-2012, results would have been quite different. Four countries, instead of one, would show a decrease of production equal or greater than a quarter of the 2012 production. These countries would be UK, which will lose close to half of its 2012 production, the Netherlands, Indonesia and Argentina, which will lose around a quarter of their respective 2012 productions. Norway and Malaysia will decline, but by less than 5%. West Siberia's growth will not change significantly, while Brazil's growth will be less than 10% for this period.

For the 2012-2017 period, one can expect conclusions to be rather pessimistic since they do not take into account either the future discoveries or the fact that some technical reserves might become commercial during the next years, in case of technological innovations and/or more favourable economic conditions. This concern is perfectly valid. However, we will keep on the same track for one main reason: the record of discoveries for the last 20 years does not lead to the conclusion that new discoveries will change the production perspectives very significantly before 2012-2017. This being said, we will comment these points for each area by raising the following questions:

1. what is the historic track in terms of discovery?
2. is the volume of technical reserves such that the production in the 2012-2017 period might be significantly and positively influenced?

If these questions of future discoveries and changes of status of the technical reserves are put aside, the trends in the evolution of production is the same as for the renewal of production by discoveries: as time goes by, more and more areas will see a production decline, in the same way that an increasing number of areas faced difficulties when replacing production with discoveries in the past. It is not surprising that there is a time lag between the deficit of discoveries and the decline of production.

From an analytical point of view, this illustrates the main advantage of the analysis on production versus discoveries and production starts: it shows in advance what will happen in terms of production. This capacity to show the evolutions of production is better when the reserve-to-production ratio is low rather than high. The higher the ratio is, the lower is the influence of results of exploration on near future production. However, this cannot last for long!

United Kingdom

Overall, the decline will be around 25% between 2007 and 2012. This is similar to the performance in 2002-2007.

The decline of on-stream fields is an important issue in this area. The declining fields will lose almost two thirds of their 2007 production between 2007 and 2012.

Decline will come:

- from fields whose production decline began some years ago, like Morecambe South, Brent, ECA, Brae Complex, Bruce, Britannia,
- from fields whose production is just beginning to decline at the end of the production plateau like Liverpool Bay and J block,
- and finally from fields whose production started after the year 2000 like Saturn Area, Atlantic&Cromarty and Goldeneye. The production plateaus of these fields, which were put on production after year 2000, are much shorter than the plateaus of the older fields (less than 5 years).

The two main new producing fields which will contribute to the production are Cygnus and Breagh. Their production will peak in 2012-2013 and decline rapidly afterwards: this means that, after having contributed to the production growth between 2007 and 2012, they will contribute to the decline of the production of UK between 2012 and 2017.

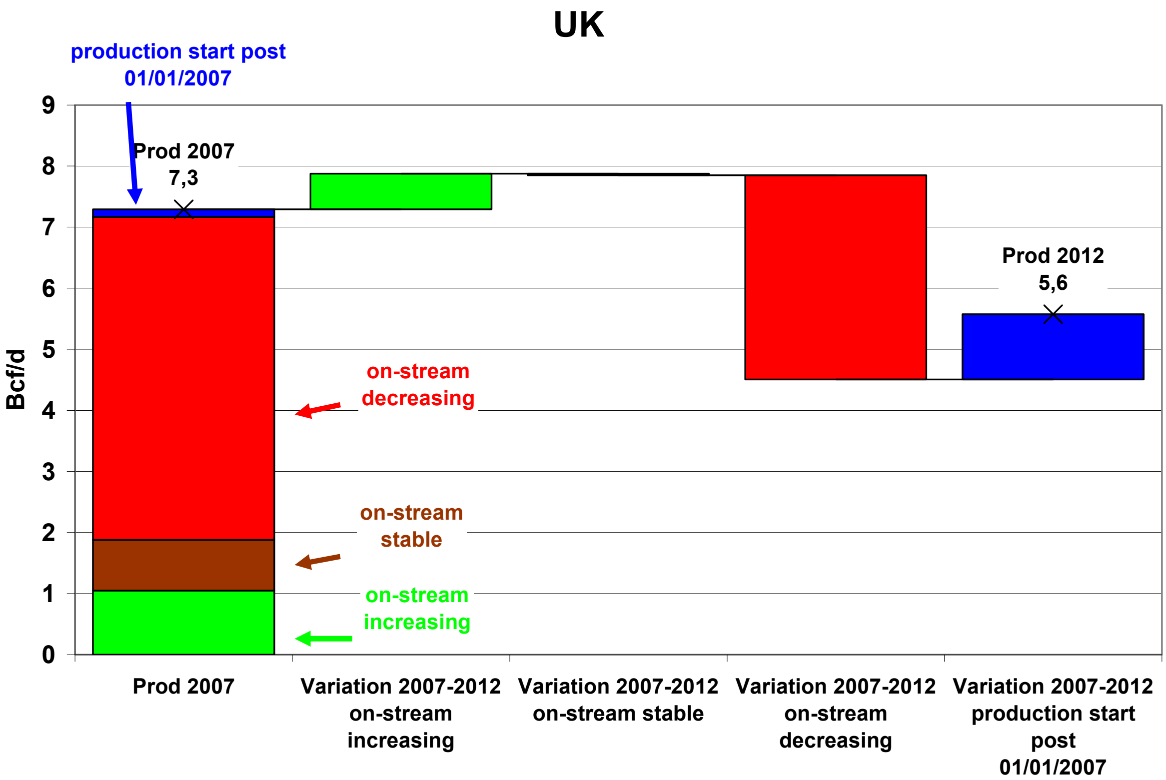
Devenick, Laggan and Harding will start their production after 2012. Their production plateaus are also very short. They will contribute to the increase of production in the period 2012-2017, but, like Cygnus and Breagh, with a difference in timing of a 5-year period, they will contribute to the decline between 2017 and 2022.

There are relatively significant technical reserves in this area. Making these technical reserves commercial would result in an increase of the reserve-to-production ratio of 4 years. Although this does not appear to be a large increase, it is relatively significant when compared with the ratio when technical reserves are not included (around 8 years).

Although the amount of technical reserves is significant, there are no important fields in terms of technical reserves: reserves are shared between many fields, with no reserve above 0.5 Tcf.

Putting these fields on production would contribute to slow a decline which began five years ago.

If nothing stops the trend, the decline of production would accelerate in 2012-2017: the expected decline between these two dates is close to 50% of the 2012 production. Such an increase is a consequence of the low reserve-to-production ratio (8 years excluding the technical reserves).



Source Wood Mackenzie

Norway

The important fact concerning Norway is that it has the highest potential in terms of growth for the next years, thanks to new producing fields such as Ormen Lange, Snøhvit, Gjøa, Tyrihans and Skarv which are all deep offshore. Unlike developments in the UK, the production plateaus of these fields will last for a long period.

Production decline from fields which were on-stream will come for Sleipner Vest and Øst, Gullfaks Sør, Åsgard.

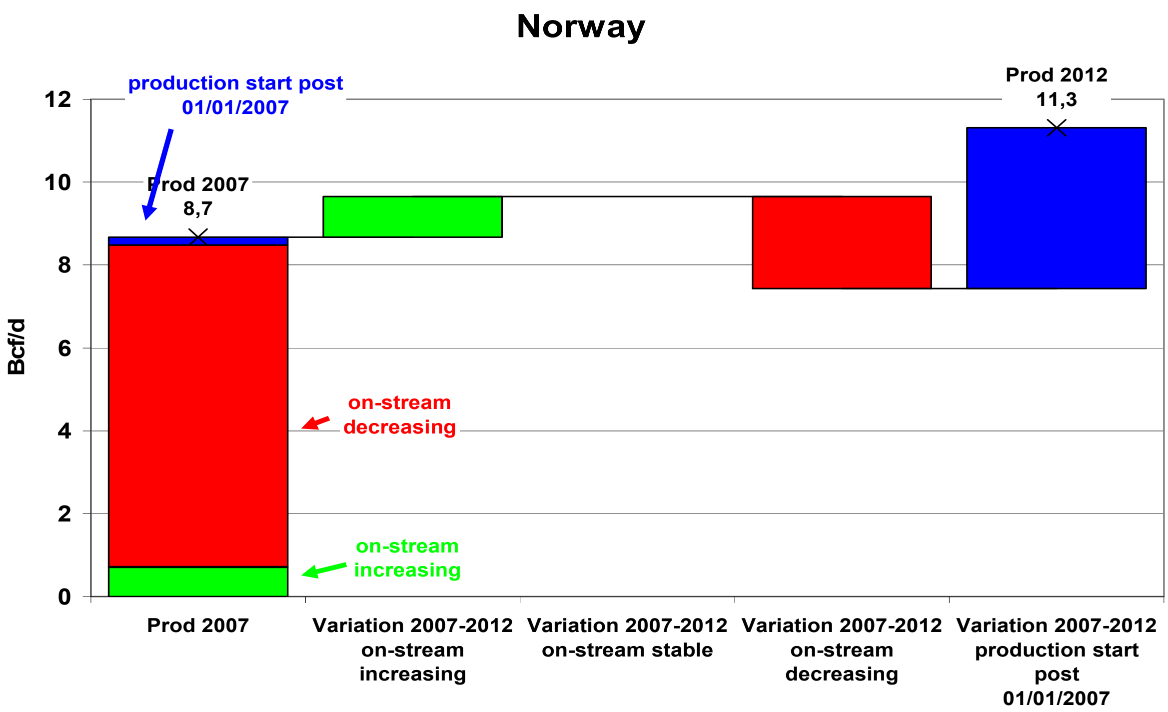
Norway's performance will mostly depend on the build-ups of Ormen Lange, Snøhvit and Gjøa.

For the 2012-2017 period, the contribution of the new productions will be much lower: this is partly the result of the lack of discoveries in recent years.

Norway's reserves are higher than its European neighbours. Its on-stream reserve to production ratio (around 27 years) is second only to Brazil.

Production in 2017 should be equal to that in 2012. Norway will lose its growth potential if no significant discoveries are made. But the decline should not begin before 2017. After this date, with no major new discoveries or development of technical reserves, decline will begin at a rate of 20% per 5-year period.

Victoria (above 3 Tcf), Onyx (close to 1.5 Tcf), both in the Halten Terrace, Luva (above 1 Tcf) in the Vøring Basin and 7226/11-1 (above 1.5 Tcf) in the Nordkapp Basin are the most important technical reserves: their developments would have a significant impact on the production evolutions. This could be critical if there are weak exploration results.



Source Wood Mackenzie

The Netherlands

Although production will not decline between 2007 and 2012, the decline will begin at a significant rate after 2012: this area will lose around a quarter of its 2012 production in the 2012-2017 period.

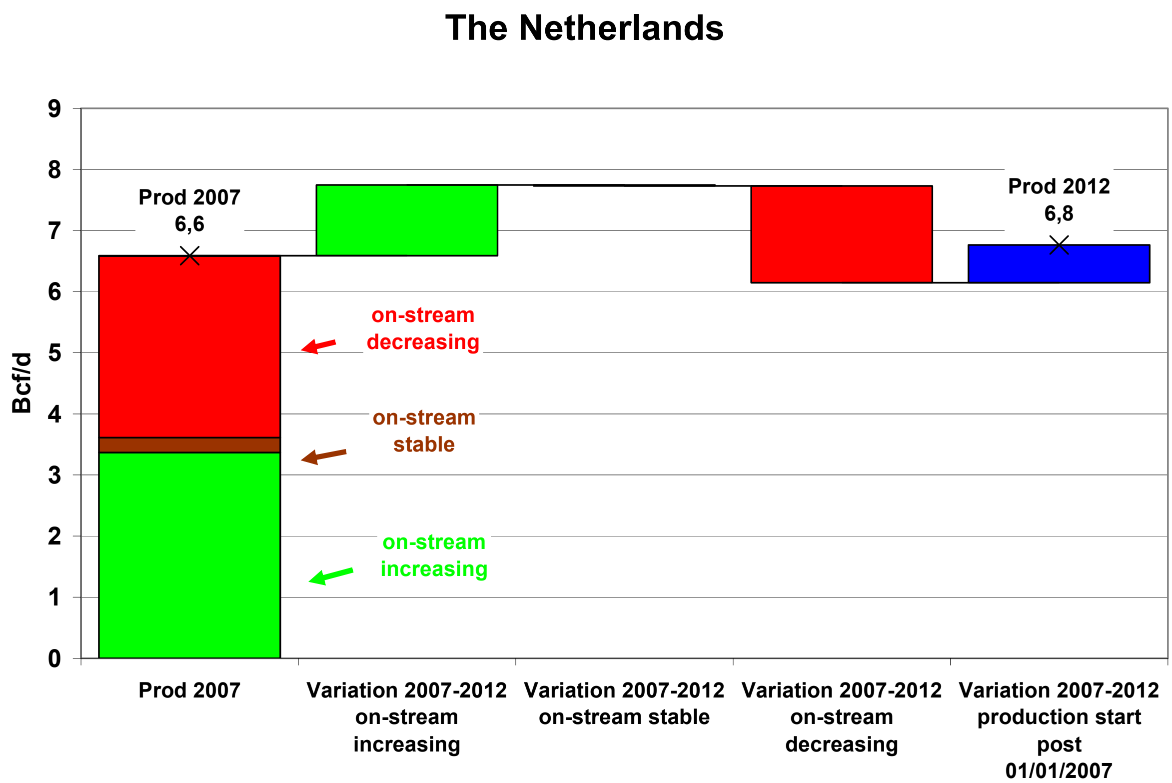
Production in the Netherlands can be divided in two parts with rather different profiles: Groningen and non-Groningen.

The production from fields excluding Groningen will decrease after 2012 at significant rates (they will lose close to two thirds of their 2012 production between 2012 and 2017). Groningen's plateau will hold until 2020.

Production will decrease between 2012 and 2017 (a quarter of the 2012 production).

Excluding UK, the Netherlands is the area with the smallest level of reserves in terms of reserves to production ratio when technical reserves are included (21 years), and, excluding the technical reserves, the ratio is still among the lowest (19 years).

The reserve production life ratios are relatively small, the amount of technical reserves in this area is very small and discoveries have been far from replacing gas production. Groningen will manage to hinder the beginning of decline in this area for some time, but not forever.



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Argentina

Production will be stable in the 2007-2012 period.

No new production is expected at all in Argentina. There were few production starts during the 2002-2007 period.

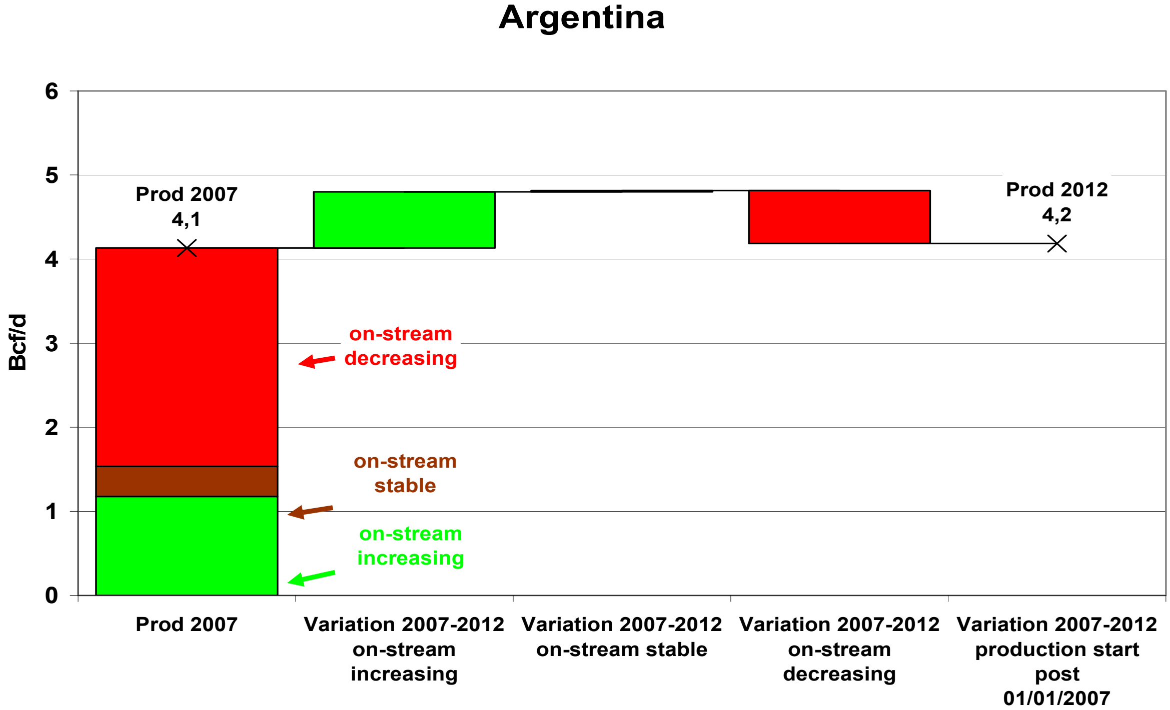
However, the production decline in this area from on-stream fields will be the smallest one among the eight areas. This is due to the fact that some of the most important fields like Loma la lata, Aguada Pichana, Aguada San Roque or Ramos begin their declines after 2009.

Production increases will more than make up for the production declines thanks to Acambuco and Area Magallanes-Poseidón.

A significant decline in production is anticipated after 2012. This is due to the fact that some fields will enter the decline period like El Porton or Area Magallanes-Poseidón, or pursue declines which started in the second half of the 2007-2012 period (Aguada Pichana, San Roque, Santa Cruz, Ramos). The reserve production life ratio is very low (13 years).

In the absence of discoveries, the decline will begin in the years close to 2012. This decline should moreover be quite rapid.

It is very important that technical reserves are made commercial. The main technical reserves are in Ramos in the Noroeste Basin with 4 Tcf, and in Cuenca Marina Austral (more than 1.5 Tcf). It could bring up to 8 years of production. This would be enough to delay or slow down the decline, but not enough to make Argentina come back to growth. Successes in exploration are necessary for this to happen again.



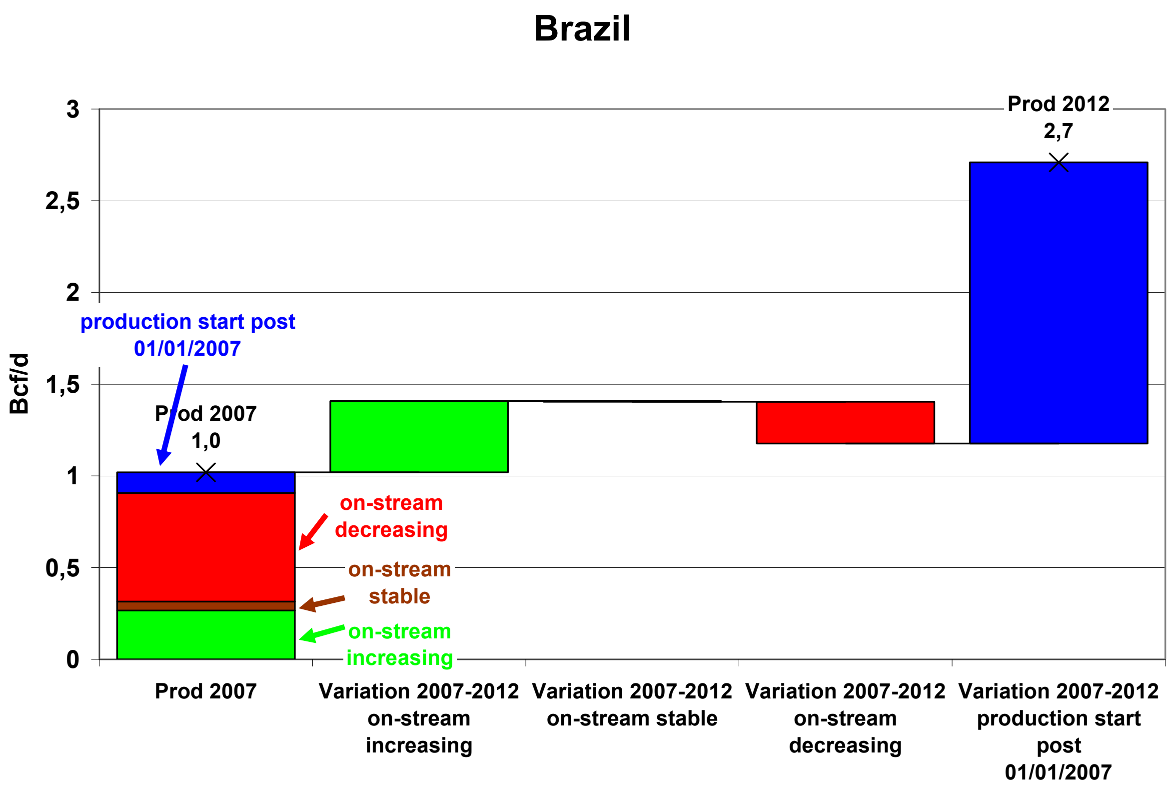
Source Wood Mackenzie

Brazil

At the moment, Brazil is certainly among the selected areas the one which should not be regarded as mature.

Its commercial reserves represent more than 50 years of production. When technical reserves are taken into account, reserves represent more than 100 years of production.

Production will more than double in the next 5 years. This will be mainly due to the production starts of new developments like BS-500 Pole (close to 1.5 Tcf) and Mexilhão Area (0.5 Tcf) in the Santos Basin, Camarupim in the Esperito Santo Basin (close to 0.5 Tcf), Manati in the Camamu-Almada Basin (close to 1 Tcf), Urucu Area in the Solimões Basin (above 1 Tcf).



Source Wood Mackenzie

Malaysia

Malaysia's production will moderately increase between 2007 and 2012, while it increased a lot during the 2002-2007 period.

Before 2007, the starts of SK8 and SK10 were significant contributors to the 2007 production. SK309 & SK311, PC4, SB K and Kumang Cluster are much smaller than SK8 and SK10. Some fields were put on production after 2007 in some fields. Production is yet to start in others.

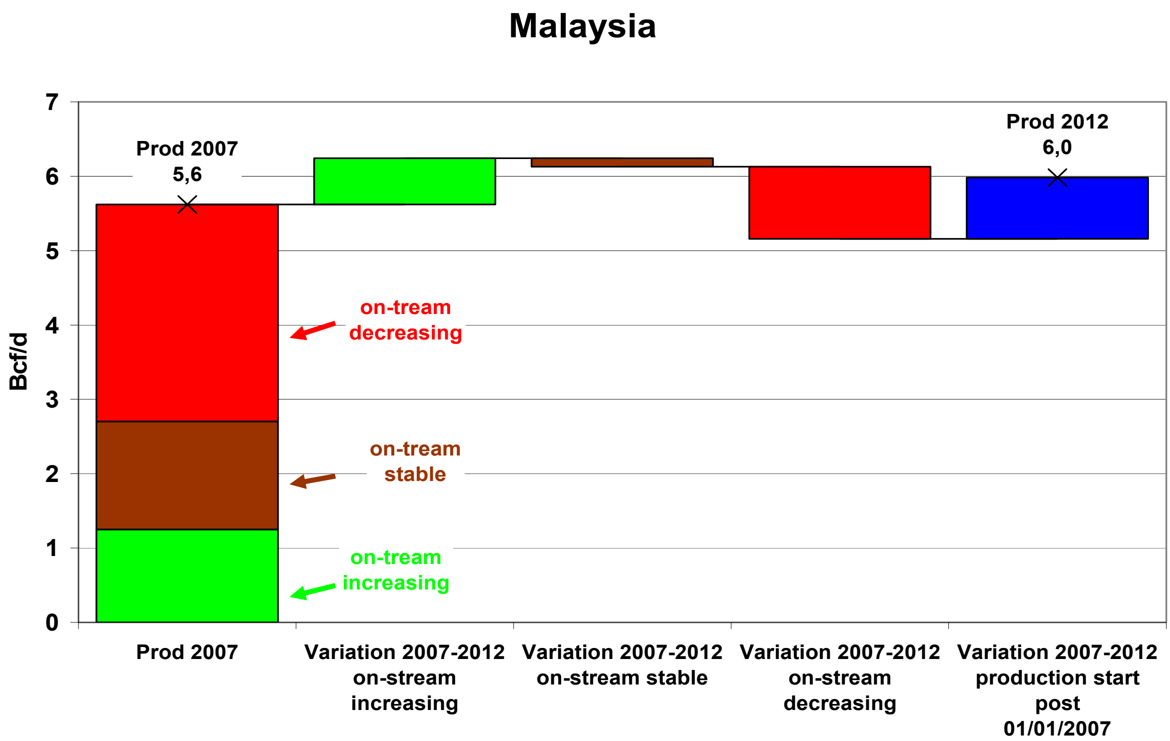
The declines of production from fields which were producing in 2007 are relatively important. This follows relatively low reserves to production ratio (18 years).

The increases of production from fields which were producing in 2007 are quite limited. The main fields where increases of production are expected are Baram Delta, PM3 CAA, Gas PSC.

A moderate decline is anticipated for 2012-2017.

An important issue is to make significant technical reserves commercial.

The ratio of commercial reserves to production is around 18 years, which is one of the smallest ratios among the studied areas. However, in this area, the amount of technical reserves is quite significant: the most important ones are in K4 and K5 in the Sarawak Basin (8 Tcf altogether). Making all these reserves commercial would increase the ratio to more than 30 years: in this case, new periods of significant production growth would occur.



Source Wood Mackenzie

Indonesia

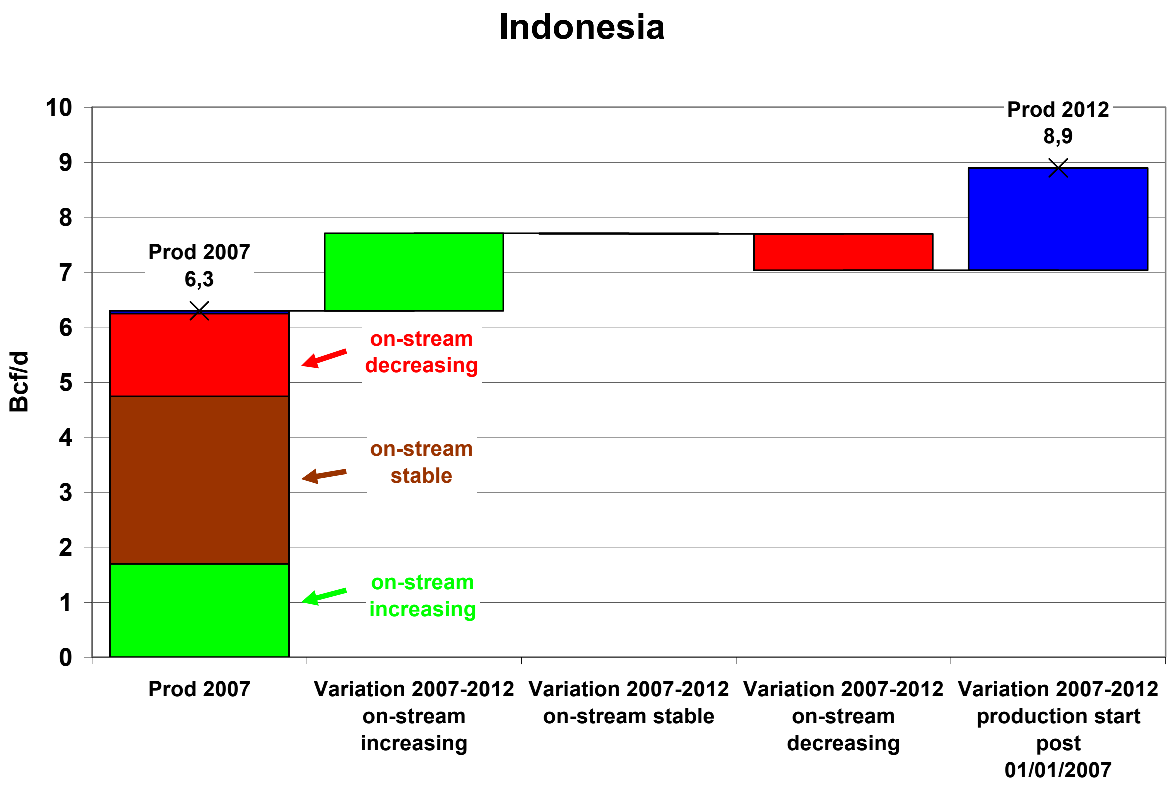
Between 2007 and 2012, the increase of production in Indonesia will be the first one behind Brazil.

This is the result of the production start in Tangguh.

The lack of new production starts resulting from the deficit in terms of discovery should slow down Indonesia's production growth in the next period (2012-2017).

Whereas the ratio of the initial reserves versus production is not one of the largest when technical reserves are not taken into account (around 19 years), it is much more important when technical reserves are included since they potentially could add around 40 years of 2007 production.

These technical reserves are mainly in Natuna D alpha (46 Tcf) in the East Natuna Basin and in Abadi (14 Tcf) in the Timor Sea Basin. Making these reserves commercial would have a very important impact on the production profiles.



Source Wood Mackenzie

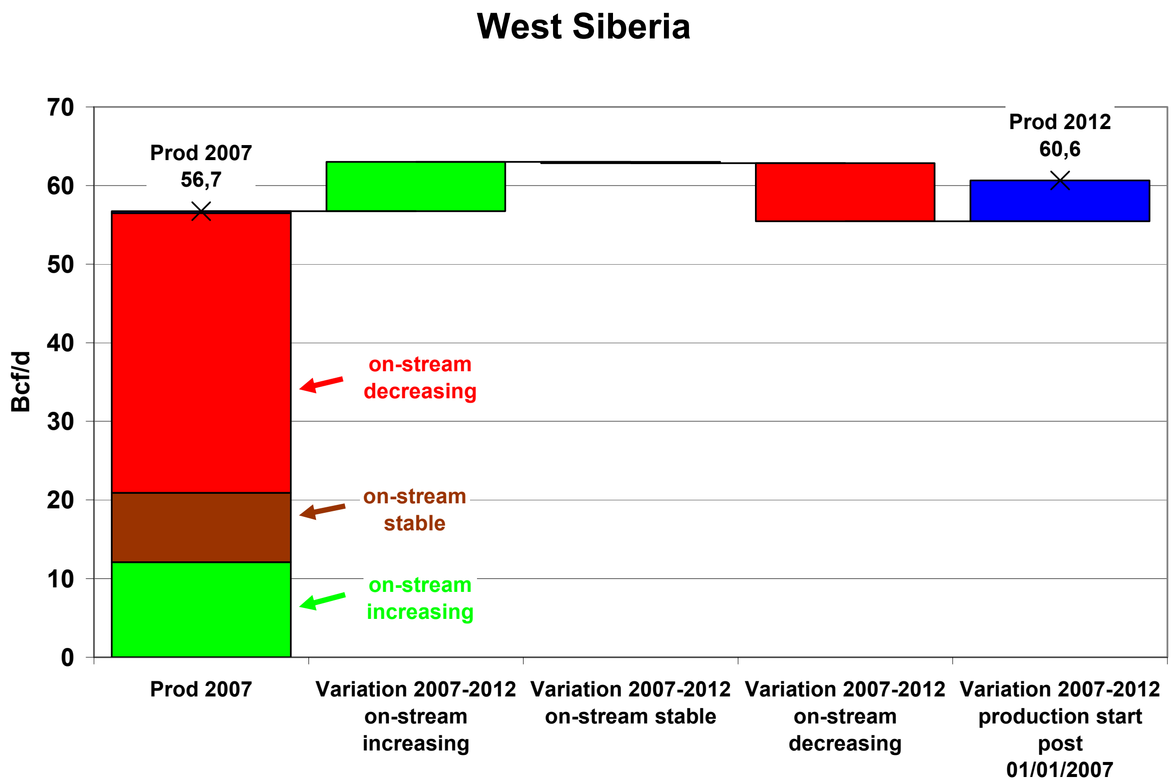
West Siberia

One of the main characteristics of this area is the size of the reserves and the level of production.

Moreover, the reserve- to-production ratios are the highest in this area: 30 years excluding technical reserves, 65 years including them.

The performances of fields like Bonanenkovo and Kharasaveiskoye in Yamal will be a major factor to maintain growth in this area.

Another important aspect is the amount of reserves (more than 700 Tcf including technical reserves) in the Kara Sea Leningradskoye (WS), Russanovskoye) and in Yamal (Malyginskoye, North Tambeiskoye, South Tambeiskoye, Utrenneye). When these reserves become commercial, the growth potential of this area will be strongly improved.



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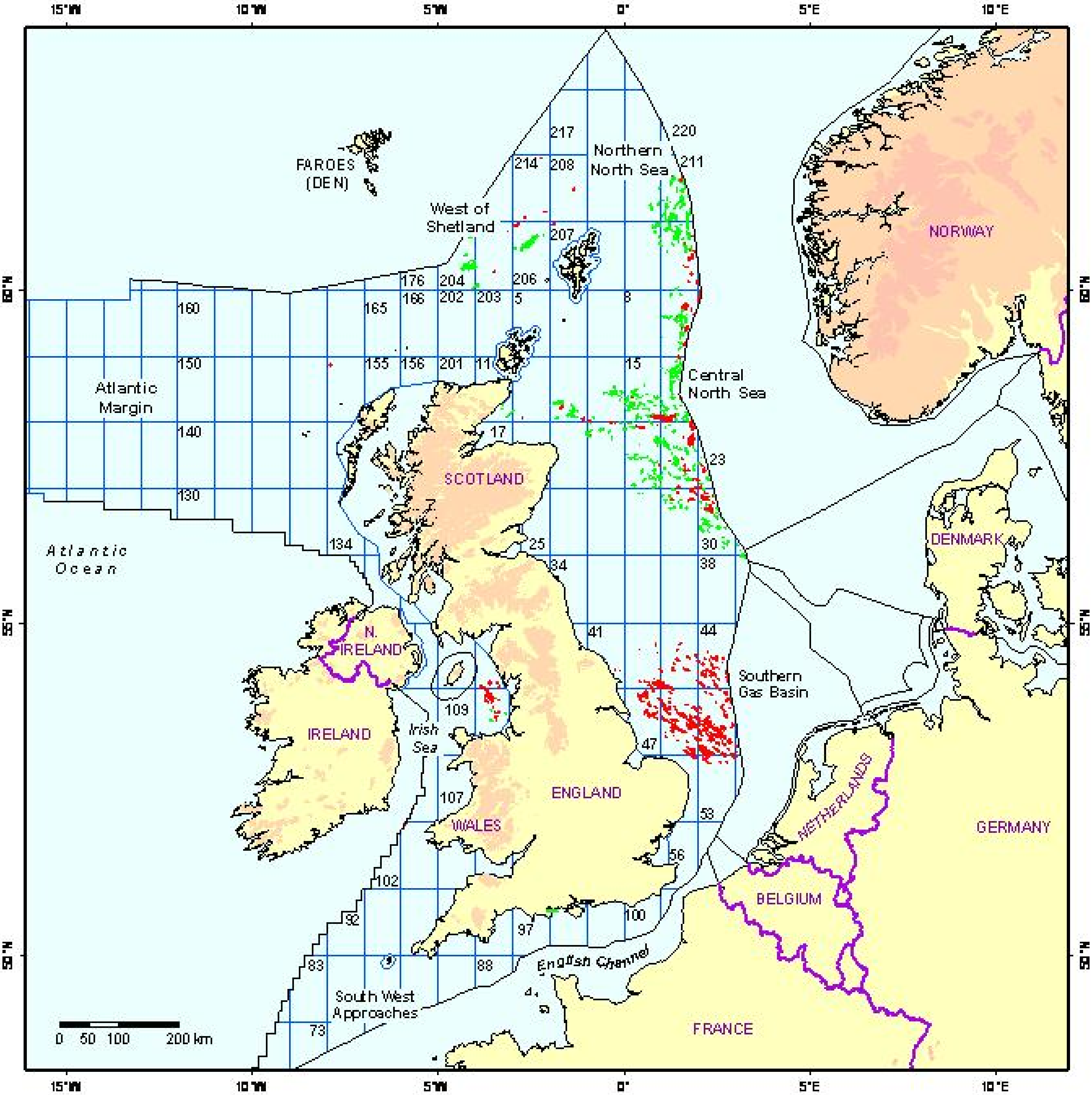
UK



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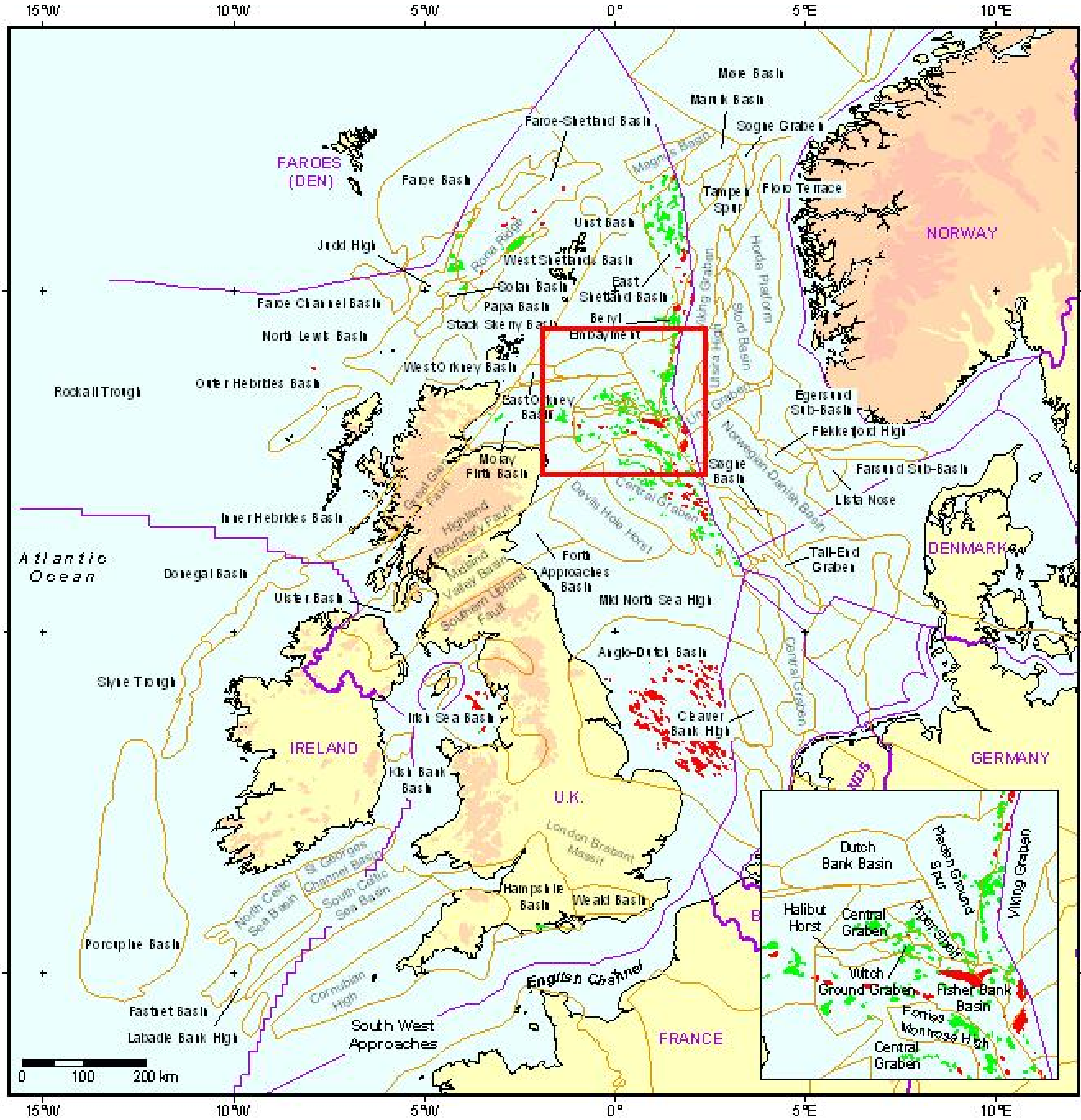
UK Offshore: Basin Map



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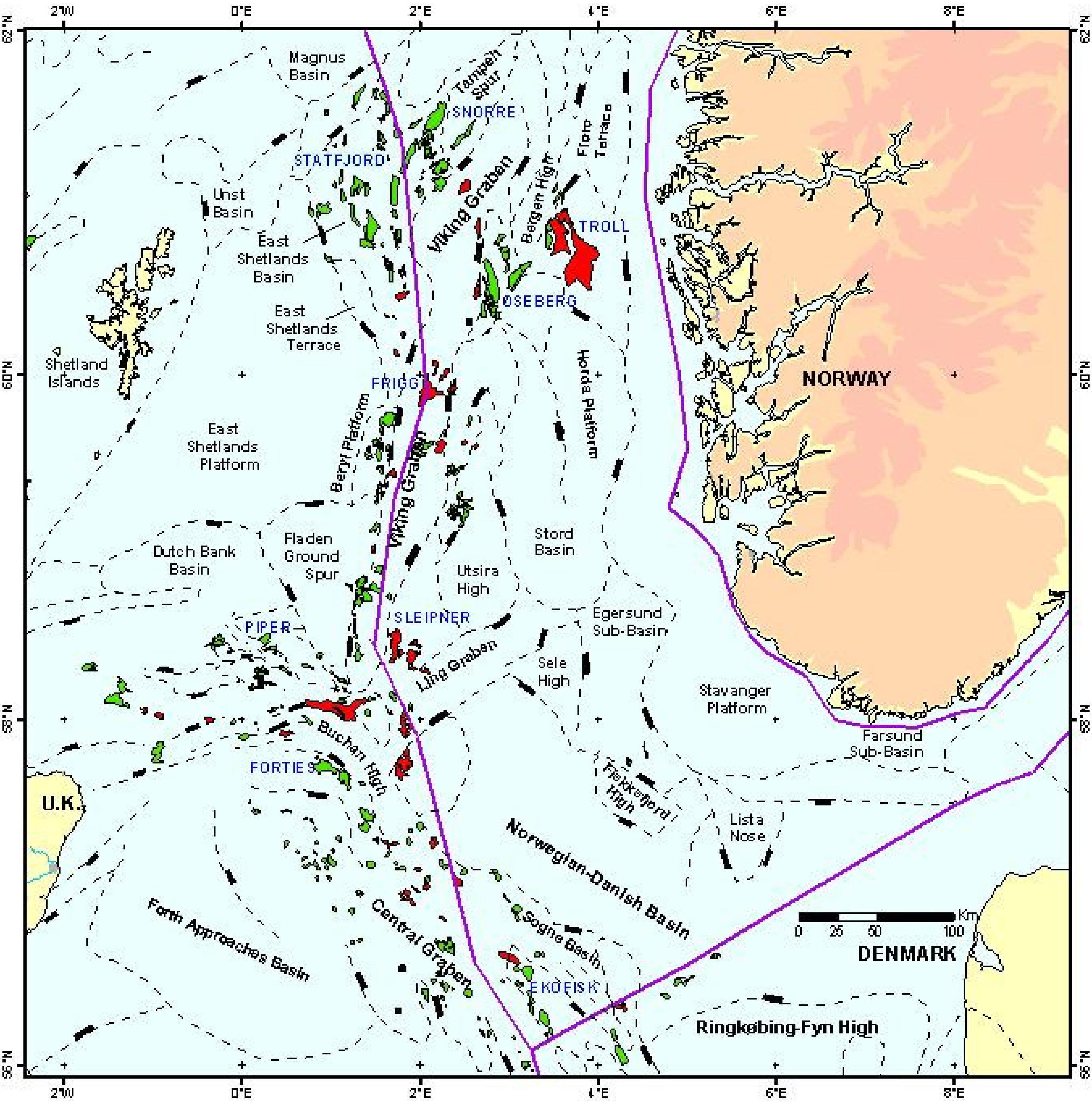
Norway Central & Northern North Sea: Basin Map



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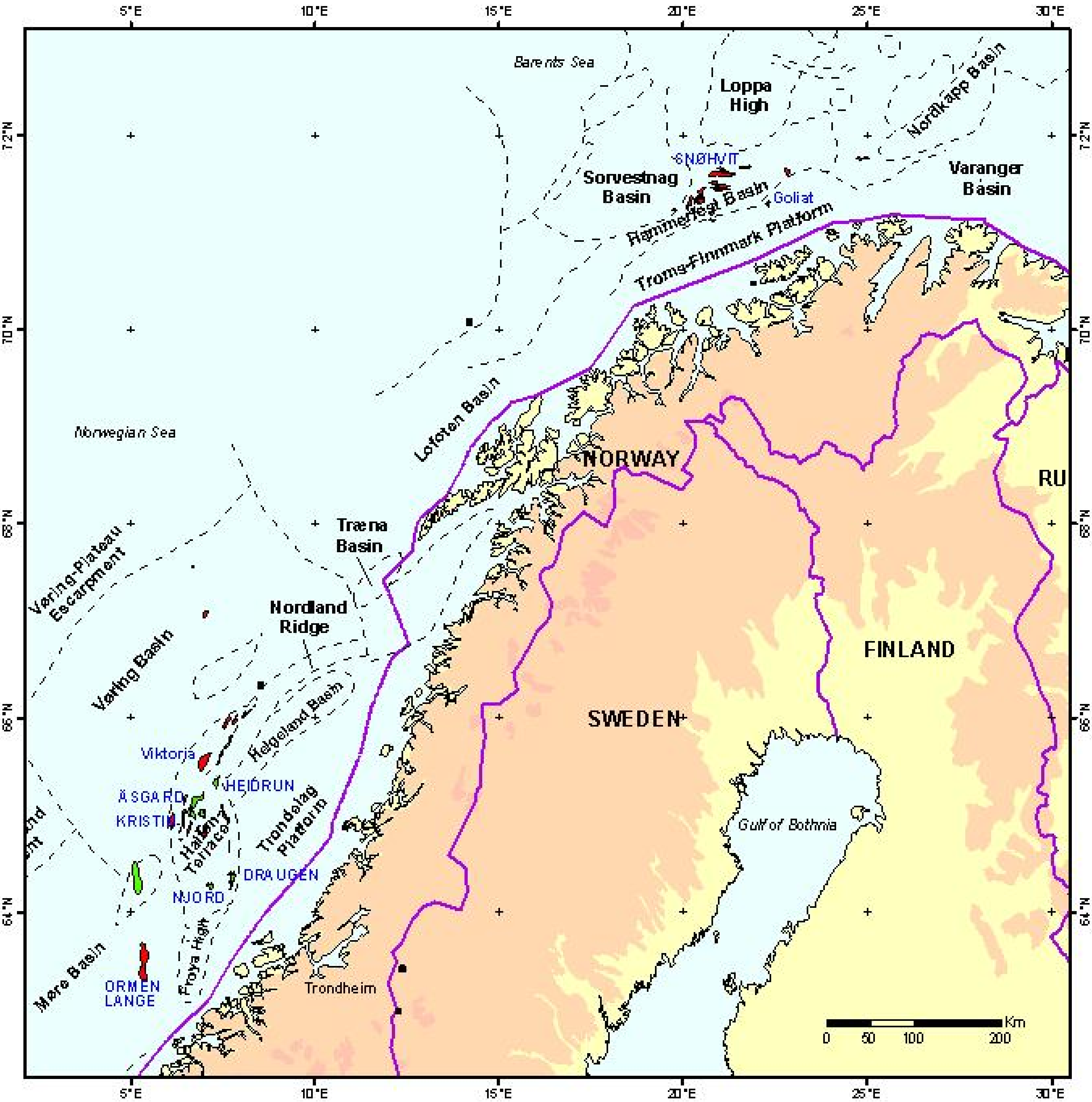
Norwegian Barents Sea: Basin Map



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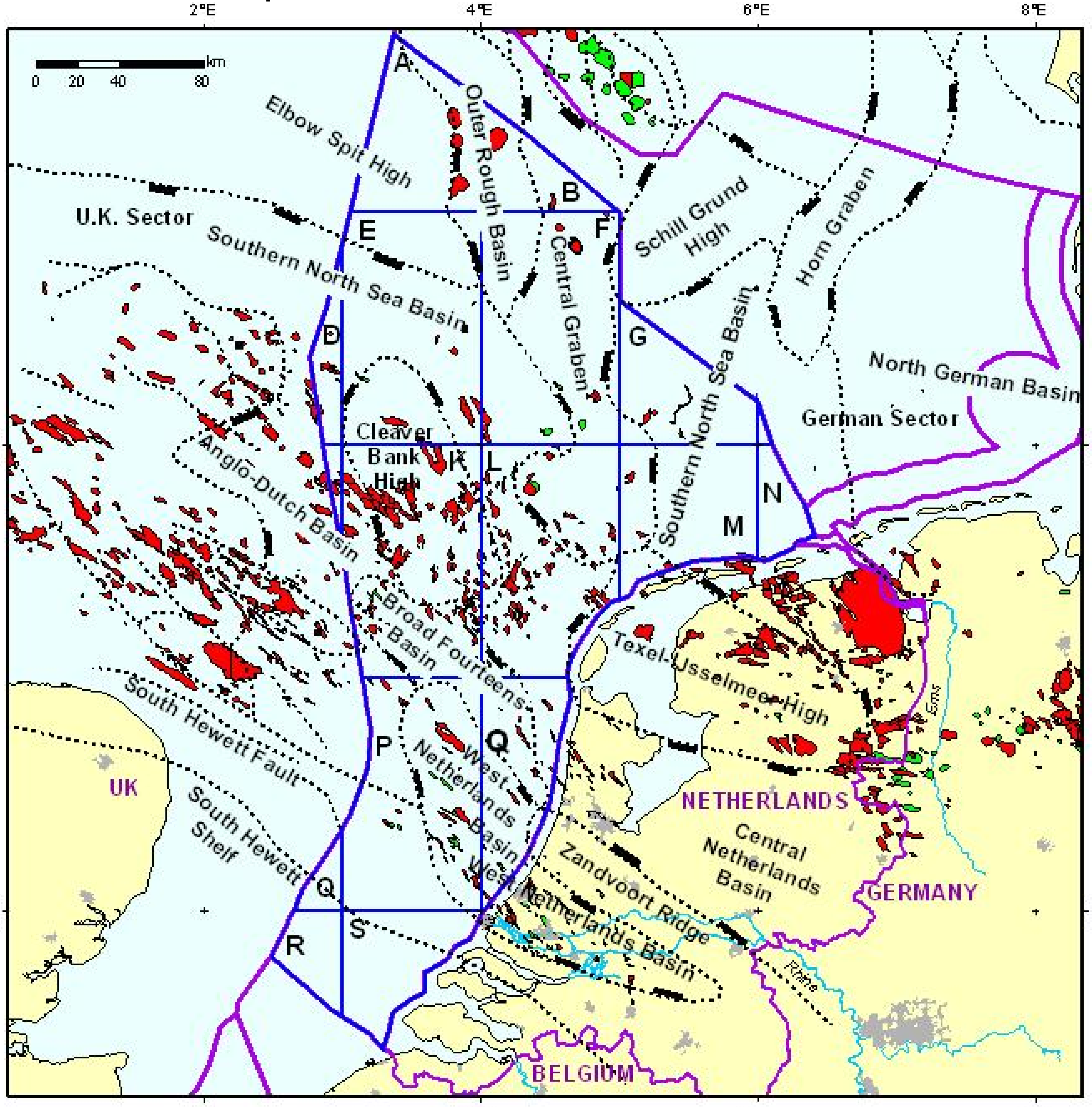
Netherlands: Basin Map



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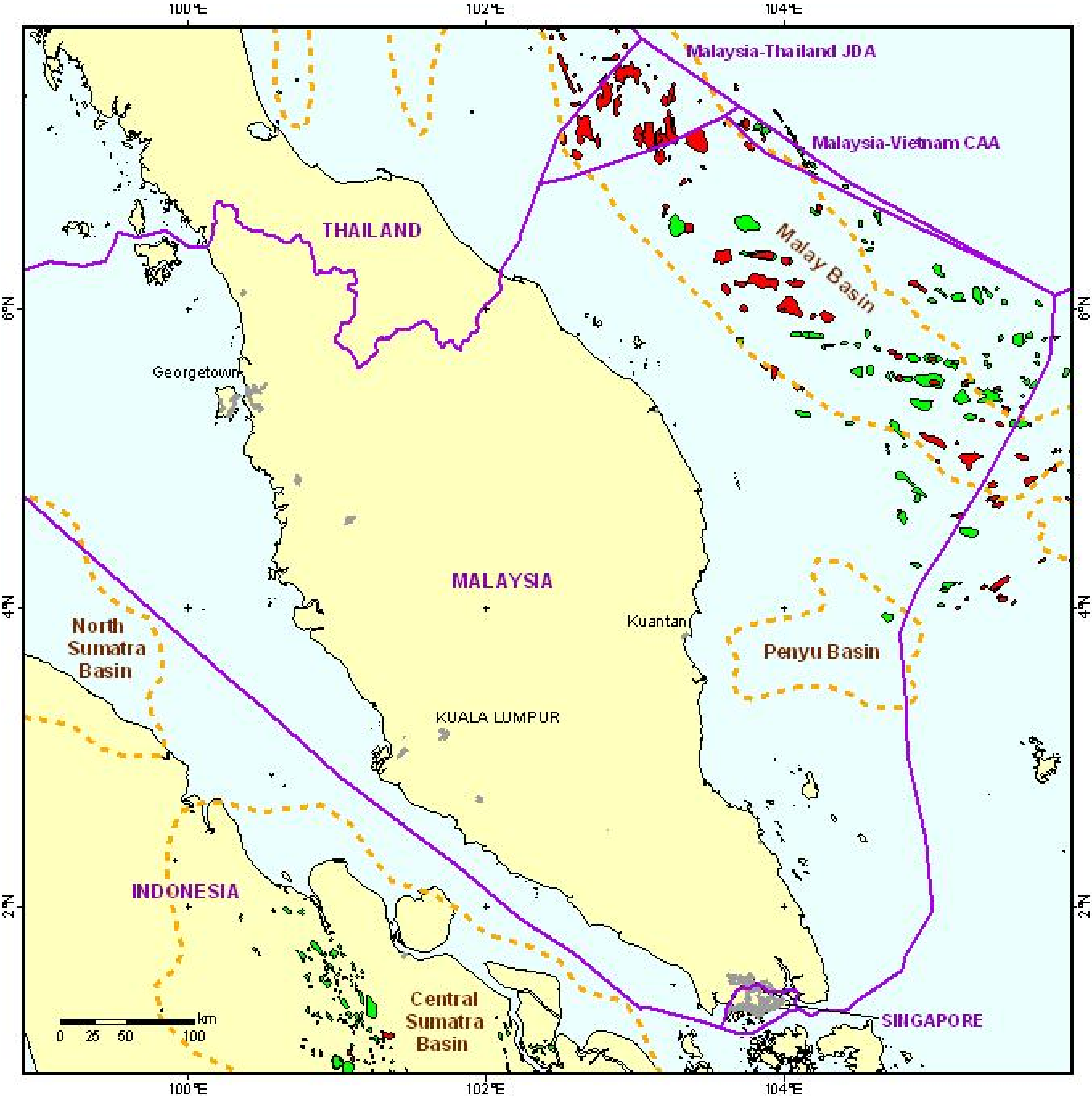
Western Malaysia: Basin Map



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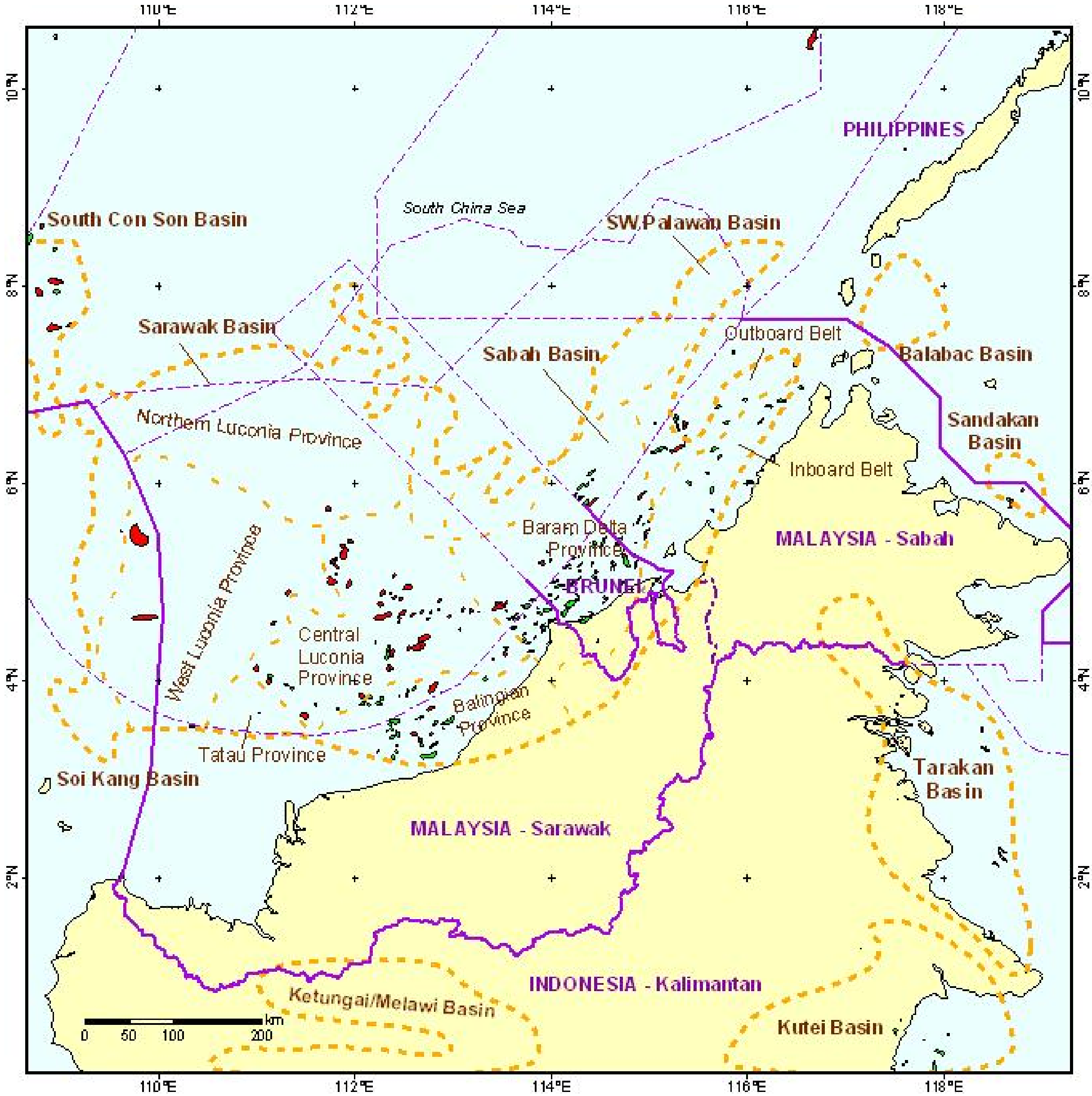
Eastern Malaysia: Basin Map



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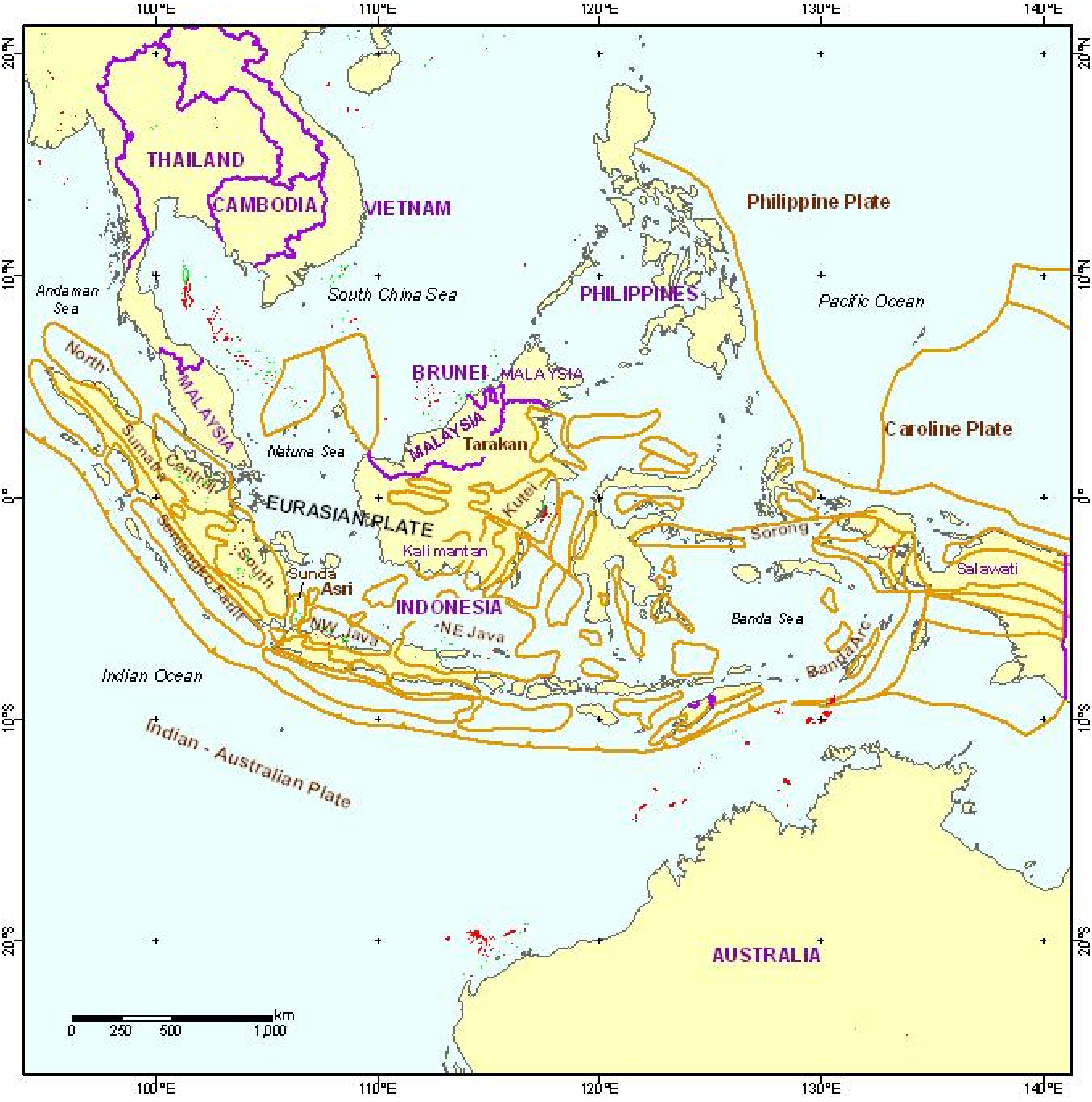
Indonesia: Basin Map

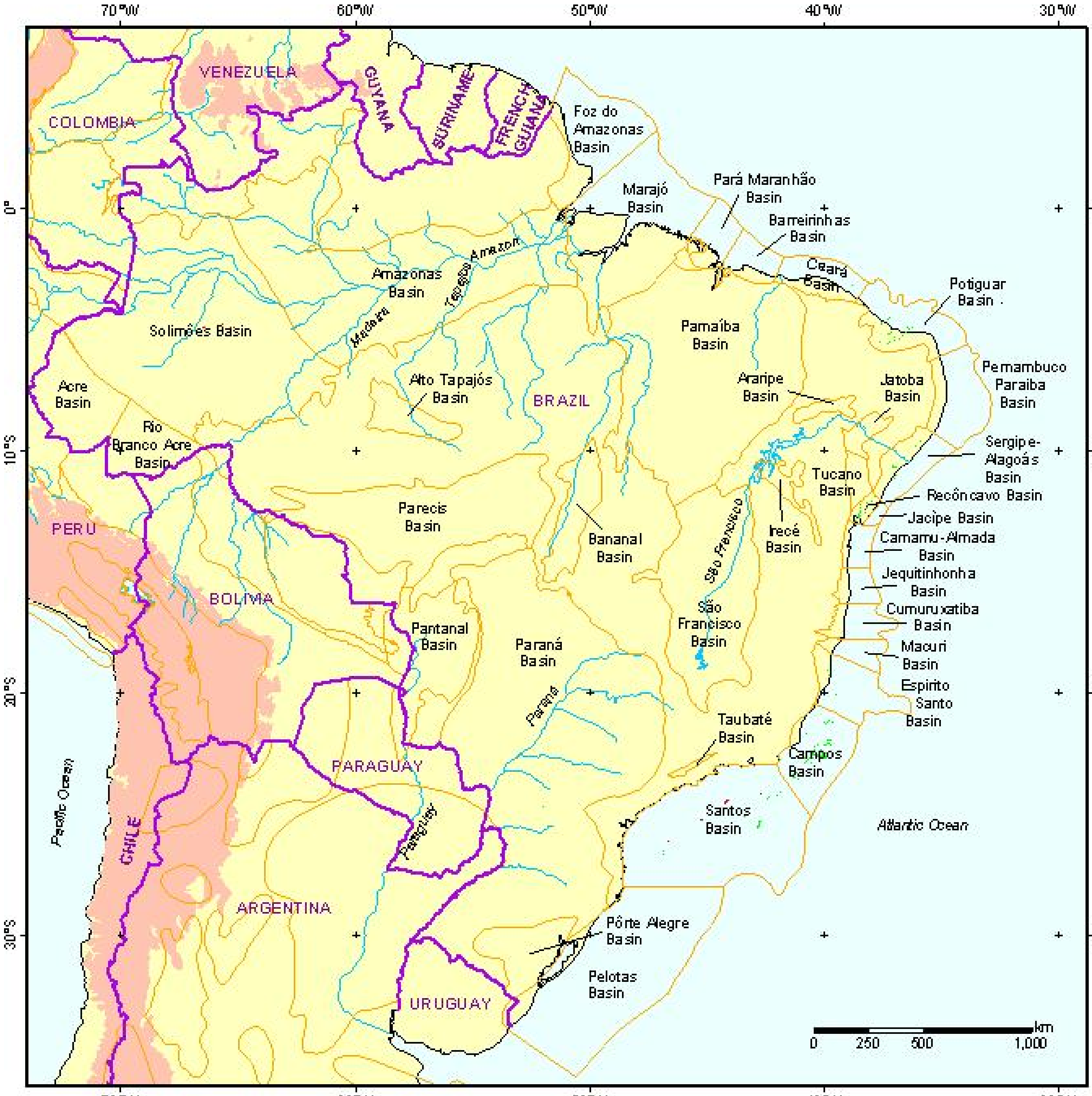


Source Wood Mackenzie

Argentina: Basin Map

Source Wood Mackenzie

Brazil: Basin Map



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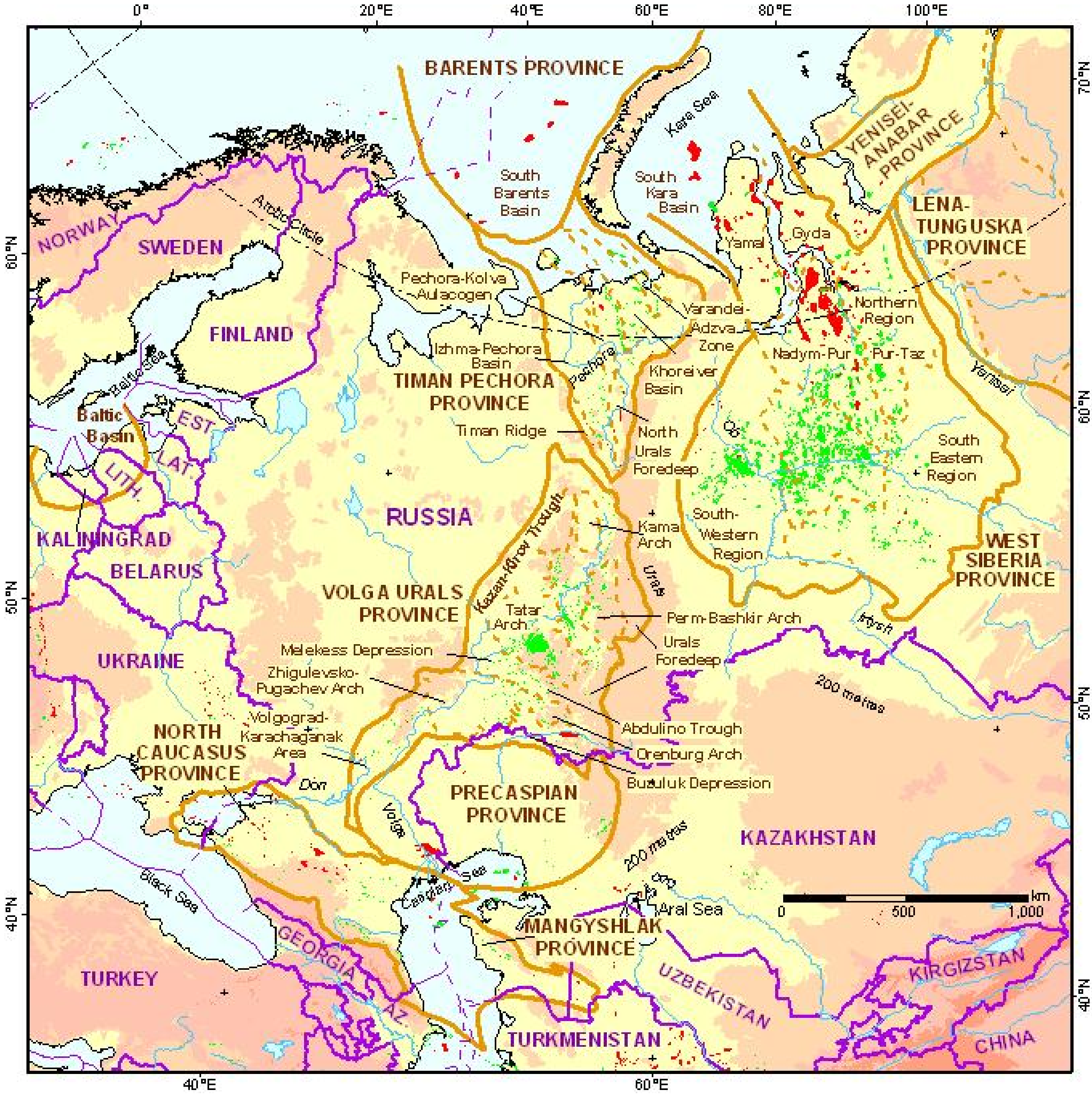
West Russia: Basin Map



Source Wood Mackenzie

ARCTIC DEVELOPMENTS

Development prospects Arctic gas resources

Arctic area usually means territories and seas inside Polar Circle (i.e. 66^o NA). Inside this area only one gas condensate field outside Russia is under operation now – offshore Snohvit gas-condensate field in the South-West part of Barents sea, which production started in 2006. Although few Arctic fields have been discovered in northern part of Canada and Alaska, there are not confirmed plans of their development because of absence of gas pipelines, connecting these fields with consumers. So, only Russia and, partially, Norway have real gas production projects in Arctic areas now. But in Norway last exploration drilling on Tornerose Block near Snohvit was unsuccessful and future Arctic developments in Norway are unpredictable. In Russia main gas production projects are located in Arctic and two of them, Shtokman field in Barents sea and Yamal peninsula fields in the North of West Siberia are giant projects affecting the regional and world gas markets.

Currently (at present time) Arctic shelf is one of the most perspective trends for gas production development in Russia. The majority of total predicted gas resources of Russian seas are concentrated here. High prospects of this region are proven by the discoveries of unique fields such as Shtokman in the Barents sea, Rusanovskoe and Leningradskoye in the Kara sea, Kamennomysskoye in the gulf of Ob (fig. 1).

REVIEW MAP OF ARCTIC SEA SHELF OF RUSSIA

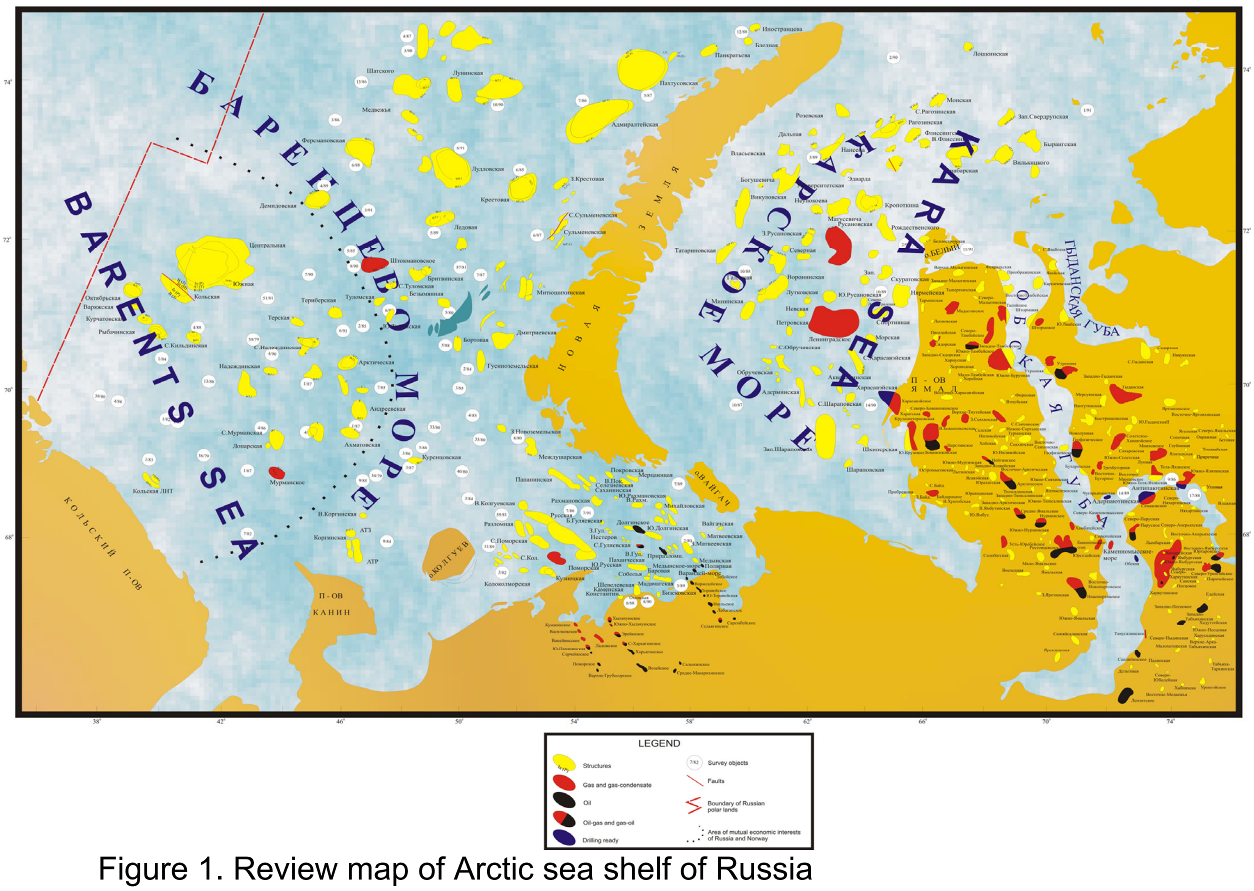


Figure 1. Review map of Arctic sea shelf of Russia

Characteristics and development aspects of Shtokman gas condensate field.

The Shtokman gas-condensate field has been discovered in 1988. It is located in the shelf of Barents sea, at about 600 km to the northeast from Murmansk city. Depth of the sea varies from 320 up to 340 m. Three meters in height waves prevail from October till April. The area is free of ice the year around. Icebergs are possible locally.

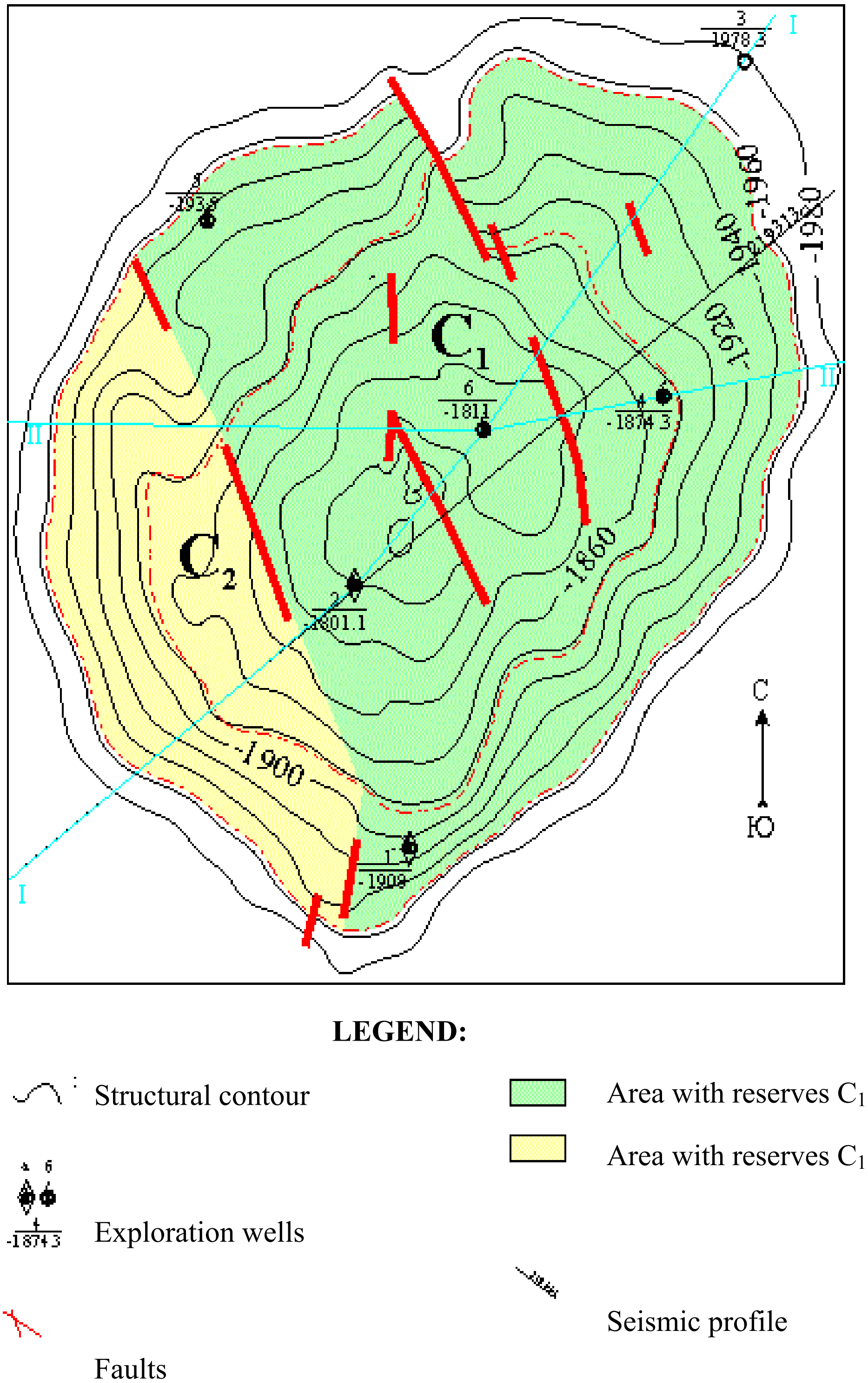


Figure 2. diagram of well spacing pattern

Seven prospecting wells are drilled and 3-D seismic works are carried out on the field. Figure 2 gives the diagram of well spacing pattern.

Four Jurassic productive layers are separated on the field. Basic layers are J_1 and J_2. Figure 3 shows the tentative geological model of the field.

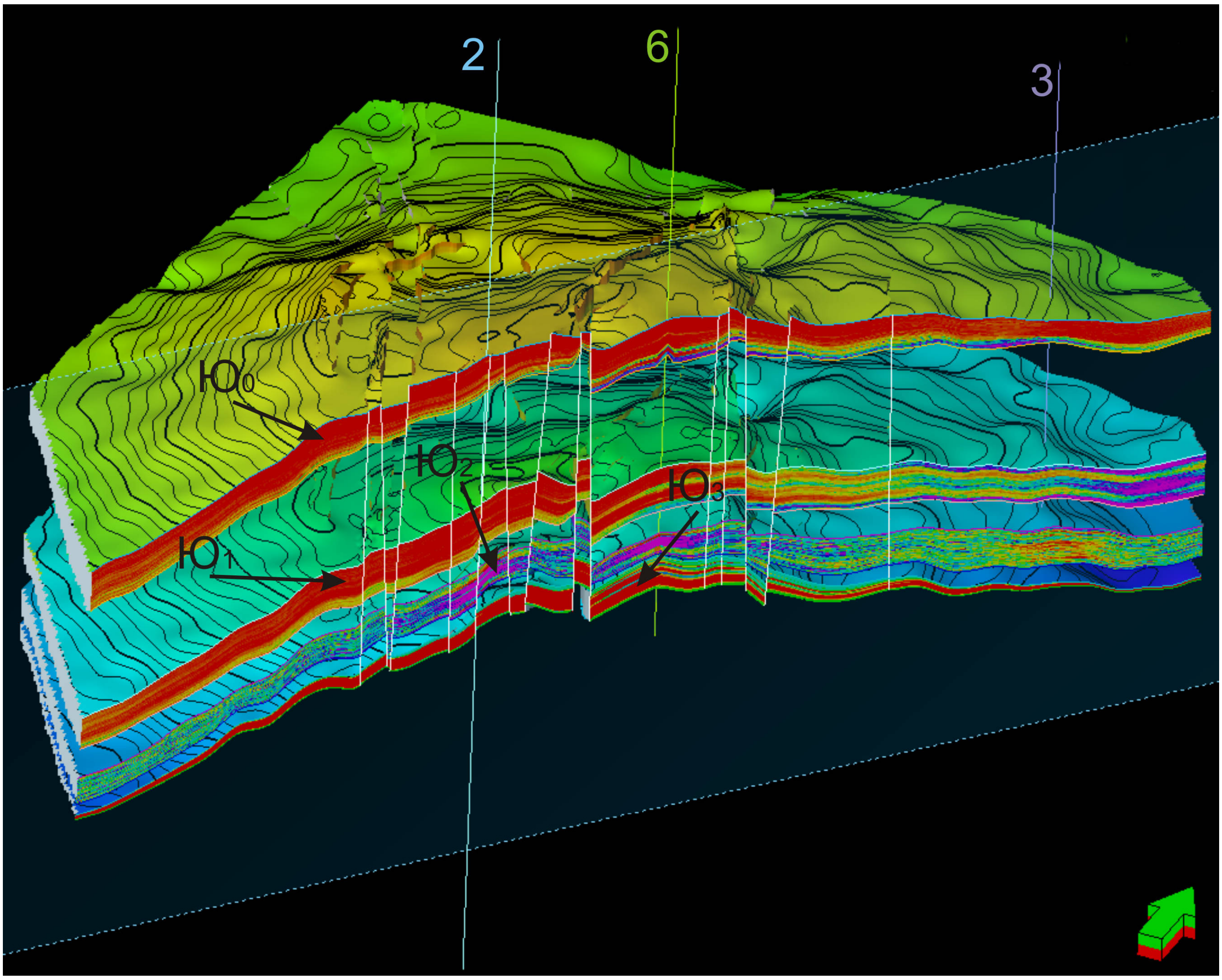


Figure 3. Geological model of the field.

The proved and probable reserves of the field compose 3.8 trillion cubic meters of gas and about 37 million tons of gas condensate.

A number of the problems, which appear during the development of Arctic offshore gas resources, were revealed as a result of studies of the fields' development designing in the region. These problems are related to the following drivers (see presentation in Annex 1 at the end of SG 1.1 report):

- significant distance of the fields from the coast;
- the depths of the seas;
- intricate ice conditions;
- condensate presence in the deposits;
- absence of production and transport infrastructure.

The remote location is one of the most significant factors, which complicate the development of the field. More than 500 km distance from the coast greatly complicates gas transportation to customers. The construction of extensive subsea pipeline and providing of gas flow to such a long distance are required. Applying the number of powerful gas booster stations excludes the possibility of just underwater technologies using and forces to be oriented toward the combination of underwater production complexes and stationary platforms. The condensate presence is also a negative factor, which complicates appreciably the gas transportation up to long distance at low temperatures. As a result the preliminary gas treatment requires additional technological plants on the platform. Generally the gas treatment and necessary pressure for long distance pipeline transportation must be provided on the platform.

The influence of climatic and natural Conditions is determined by the joint effect of sea depths and ice conditions. Requirement for applying of stationary platforms at depth more than 300 m determines type of the platform – with tension legs. And icebergs hazard causes the need for technical solutions, capable to resist ice loads.

Total lack of production and transport infrastructure generates the necessity for additional significant expenditures for its construction.

Development of the Shtokman field is expected to produce of about 70 billion cubic meters of natural gas and 0.6 million tons of gas condensate per year. This is compared with the annual gas production of Norway – one of the most important suppliers in Europe.

The Shtokman gas-condensate field will become the resource base for Russian gas supply to the markets of Atlantic region both through pipelines and with use of LNG technologies.

Sevmorneftegaz LLC (a wholly owned subsidiary company of Gazprom JSC) has a license for search, geological study and production of gas and condensate at the Shtokman field.

Production of 23.7 billion cubic meters of natural gas per year is anticipated at first stage of the field development, beginning of gas supply is planned in 2013, liquefied natural gas - in 2014.

Gazprom JSC and Total signed the Framework Agreement for the Basic Collaboration Conditions at first stage of the Shtokman gas-condensate field development on July 13, 2007. Analogous agreement was signed by Gazprom JSC and StatoilHydro on October 25, 2007.

Development prospects and ecological challenges of Yamal Peninsula.

The Yamal peninsula as perspective gas-extraction region is the unique gas-bearing province of such scale which is available in Russia for a nearest quarter of a century. The total amount of proven reserves of natural gas of peninsula reaches more then 10 trillion m^3.

The distinctive feature of a geological structure of Yamal peninsula is the presence of gas columns, predetermined formation of complex multilayer fields in this region consisting of various deposits of sheet and sheet-massive type with various thermobaric characteristics and occurrence depths of productive layers.

26 gas fields have been discovered onshore the Yamal peninsula and 70 percent of the proven reserves of natural gas for commercial production are concentrated at Kruzenshternskoe, Bovanenkovskoe and Harasavejskoe fields.

The total proven reserves of natural gas of all 26 fields of Yamal region amount to 10,4 trillion m^3; condensate - 228,3 million tons; oil - 291,8 million tons. Gazprom obtained licenses on Bovanenkovskoe, Harasavejskoe and Novoportovskoe fields with total reserves of natural gas amount to 5,9 trillion m^3, a condensate - 100 million tons and oil - 227 million tons. Potential volumes of production of natural gas on specified fields are estimated to 178 billion m^3 per year, liquid hydrocarbons – from 7 to 9 million tons per year.

At the same time no purely oil field have been discovered at the Yamal peninsula.

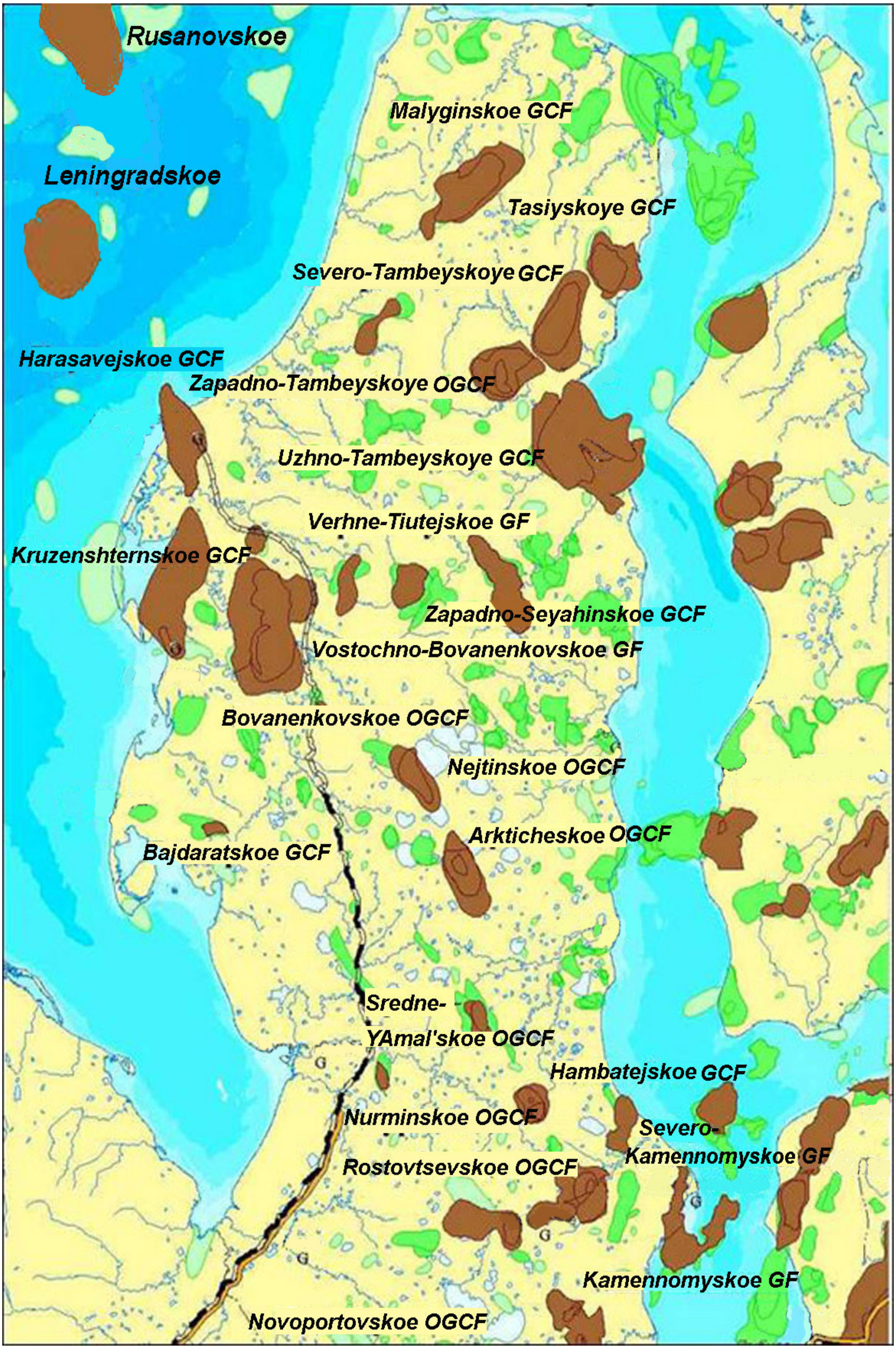


Figure 4. Review map of Yamal peninsula

The list of onshore (and partly onshore) fields of Yamal peninsula.

Name	**Type**
Malyginskoe	Gas-condensate field
Syadorskoe	Gas field
Tasiyskoye	Gas-condensate field
Severo-Tambeyskoye	Gas-condensate field
Zapadno-Tambeyskoye	Oil-gas-condensate field
Uzhno-Tambeyskoye	Gas-condensate field
Zapadno-Seyahinskoe	Gas-condensate field
Harasavejskoe	Gas-condensate field
Bovanenkovskoe	Oil-gas-condensate field
Kruzenshternskoe	Gas-condensate field
YUzhno-Kruzenshternskoe	Gas field
Severo-Bovanenkovskoe	Gas field
Vostochno-Bovanenkovskoe	Gas field
Verhne-Tiutejskoe	Gas field
Bajdaratskoe	Gas-condensate field
Nerstinskoe	Gas field
Nejtinskoe	Oil-gas-condensate field
Arkticheskoe	Oil-gas-condensate field
Sredne-YAmal'skoe	Oil-gas-condensate field
Ust'-YUribeskoe	Gas field
Nurminskoe	Oil-gas-condensate field
Hambatejskoe	Gas-condensate field
Rostovtsevskoe	Oil-gas-condensate field
Kamennomyskoe	Gas field
Malo-YAmal'skoe	Gas-condensate field
Novoportovskoe	Oil-gas-condensate field

Besides certified gas field, two more gas deposits have been discovered in the region: Vostochno-Kharasaveiskoe and Vostochno-Novoportovskoe. The reserves of these fields are not estimated yet.
At present time the top-priority objects for exploration and production at Yamal peninsula are cenomanian-aptian deposits of Bovanenkovskoe oil-gas-condensate field.

Bovanenkovskoe oil-gas-condensate field is located within the bounds of Nurminskiy region of Yamal oil-gas-bearing province and confined to a central part of Bovanenkovskiy bank. Bovanenkovskoe OGC field is a part of largest in Arctic regions of West Siberia gas accumulation node consisting of Bovanenkovskoe field and two super giants - Kharasaveiskoe GC field и Kruzenshternskoe GC field, located correspondently in 75 and 35 km to the north-west and west from the center of Bovanenkovskoe field on the Kara sea coast.

Bovanenkovskoe field was discovered in 1971. During cenomanian formation testing, gas production with flow rate of 650 thousand m3 per day was obtained. Hereinafter gas-bearing capacity of the whole permeable section from top of cenomanian to bottom of Jurassic deposits was reviled. The dimensions of the field are 22.5 x 15 km, amplitude is 200 m. 22 deposits at the depth from 582 to 3075 m were discovered, and among them 2 are of a gas type, 1 – oil-gascondensate and 19 – gas-condensate.

The project extent of production of Bovanenkovskoe field is considered to be about 115 billion m3 per year. Over the longer term it can be increased to 140 billion m3 per year. To deliver gas to unified system of gas supply it is necessary to construct gas transmission system of total length of 2451 km, including new gas transportation corridor from Bovanenkovo to Uchta-city with pipe range of about 1100 km.

According recent decisions, Bovanenkovskoe OGC field is planned to bring into production in 2010-2011.

Kharasaveiskoe gas-condensate field was discovered in 1974 and it is located in the west part of Central-Yamal zone of gas accumulation to the north-west from Bovanenkovskoe oil-gas-condensate field and 480 km to the north from Salekhard city. The north-west part of the field is off-shore at the shelf of Kara Sea. The dimensions of the structure are 44 x 15 km. At present time a section down to Jura sediments at the maximum depth of 4000 m is exposed by drilling. Extra-high gas potential was determined for this region. By the size of reserves this field is attributed to a “super giant” type.

The distinctive feature of Kharasaveiskoe gas-condensate field is the considerably larger thickness of sedimentary section and higher shaliness of section in whole and especially of upper jurassic and neocomian layers in comparison with other fields of Nurminskiy megalithic bank. 22 gas and gas condensate deposits were revealed at the field in the interval of depth from 717-3335 m in cenomanian, aptian, gotterivian – valanginian and middle Jurassic. The gas is essentially methane by composition (90,9 - 97,3 %). The condensate density is 733-780 kg/m^3.

The exploration degree of deposits is extremely irregular. The deposits in upper part of productive section are characterized by high exploration degree and contain the main part of reserves of natural gas (more than 67 % of total reserves of the field) and are prepared for commercial development.

The deposits in more deep layers are of low exploration degree and additional exploration is needed. At that deposits in more deep layers are characterized by complex structure, lithological and petrophysical heterogeneity and as consequence by low reservoir properties. The production characteristics of these layers according to geophysical logging data are interpreted ambiguously and identified by complex of data involving field test’s results.

Exploration works at the field are considered to be completed in whole, as exploratory and delineation well drilling for Jurassic layers won’t lead to discovery of considerable hydrocarbon accumulations. The prospects of gas and condensate reserves growth remain in off-shore part of the field. It is necessary to drill deviated wells up to neocomian layers bottom to complete its exploration.

Abnormally high pore pressures were determined in Jurassic sediments of all fields of Yamal peninsula. But Kharasaveiskoe gas-condensate field is an exception from the indicated rule. Abnormally high pore pressures were determined considerably upper than Jurassic sediments right up to aptian – upper gotterivian layers.

At present time Kharasaveiskoe field is preparing for commercial stage of reservoir development.

Kruzenshternskoe gas-condensate field is located 396 km far to north-west from Noviy Port settlement and it is a part West-Siberian oil-and-gas bearing province. It was discovered in 1976. By the size of reserves this field is attributed to a “super giant” type (the reserves of natural gas of Kruzenshternskoe Gascondensate field amount to 1,67 trillion m^3). The field is confined to Kruzenshternskoe arch, which complicates north-west end of Nurminskiy megalithic bank. The major part of the field is located off-shore at the shelf of Kara Sea. By the top of cenomanian the field represents anticline fold extended in north-south direction. The dimensions of the structure are 24 x 70 km. Productivity were determined in Upper and Lower Cretaceous sediments.

11 gas and gas condensate deposits were revealed at the field in the interval of depth from 655 to 2331 m, and among them there are 7 gas deposits in aptian – cenomanian, albian and neocomian layers and 4 gas condensate deposits in Neocomian layers. The largest deposit by reserves is PK, with the area of 669,2 km^2, gas column thickness is 150 m and gas-water surface at a subsea depth of 796 m. The layer is represented by alteration of sands and sandstones with aleurolites and clays. The type of reservoir is porous and the factor of porosity is 30-35%. The type of deposit is massive-uplifted.

The gas is essentially methane by composition (90 - 95,3 %). The condensate density is 700 kg/m^3.

Novoportovskoe oil-gas-condensate field stands out from the rest of the other fields of the north of West Siberia, first of all due to complex geological structure of section and complex character of oil and gas content. Novoportovskoe field was discovered in 1974 and it is located on south-east of Yamal peninsula in 30 km to north-west from Noviy Port settlement and gulf of Ob of Kara Sea.

The field is confined to a same-name structural high, which complicates Novoportovskiy bank at south-east part of South-Yamal megalithic bank. Upstructure part of the high is complicated by three arches. The most upstanding is central arch. The north and south arches are correspondently 15 and 20 m lower. The high is delineated by structural contour of – 2100 m and vertical closure is 212 m. This high keeps its form within upper layers, but south arch is delineated more distinctively. The metamorphic and sedimentary terrigenous and carbonaceous rocks of deferent level of diversity of pre-jurassic basement and sandshale and also terrigenously silicate formations of sedimentary cover of Jurassic-Cretaceous and Kainozoic age form the geology structure of the field. The thickness of sedimentary cover changes from 2500 m at axial region of Novoportovskiy bank up to 3000-3600 m at the west wing. The basement plunges along step faults down to 5000 m and more to the east and south-east. According to data from seismic surveys, tectonic dislocations of north-west and north-northwest trend were revealed at the field. The presence of assumed tectonic dislocations is also confirmed by drilling data.

At present time 145 wells were drilled at the field and immediate area. The section of platform cover and Paleozoic basement were penetrated. The oil and gas content in the interval of depths from 470 to 3000m (from cenomanian to Paleozoic) were established and 14 deposits. Among them 2 are of a gas type, 2 - oil, 2 – oil-gas-condensate and 8 are of mixed type. The maximum amount of deposits was discovered within the limits of south periclinal and south arch. Further in north direction the Novoportavskaya section is pinching-out and the amount of deposits decreases.

The considerable complexity of geological structure of Jurassic and Novoportovskoe deposits, lack of clean data about pool outline and contacts (OWC) within the limits of some blocks, and also about production capacity of individual deposits, required carrying out of additional scientific researches in the area of structural-lithologic modeling of structure of the field and additional interpretation of available detailed seismic data.

At present time preliminary works for experimental-industrial production of basic deposits have started at the Novoportovskoe oil-gas-condensate field.

Development prospects

At the first stage of development of Yamal peninsula fields Gazprom plans to invest in development of Bovanenkovskoe field about 40 billion dollars in the nearest 25 years. The production at Bovanenkovskoe field is planned to begin in 2011. It will amount 115 billion m^3 per year upon the project. The 1.1 thousand km length pipeline “Bovanenkovo-Uchta” will be constructed.

Besides the Bovanenkovskoe field, Gazprom plans to bring into production Novoportovskoe and Kharasaveiskoe fields and also two subsurface blocks of Tambey group within the frameworks of carrying-out a program of development of Yamal peninsula.

At the second stage it is scheduled to develop the fields of Tambeyskaya group, which total amount of proven reserves of natural gas reaches 3,7 trillion m^3. In total about 70 billion dollars will be spent on realization of complex program of Yamal peninsula development.

Commercial development of Yamal fields will allow to bring the production of natural gas at peninsula up to 250 billion m^3 per year. Thus the Yamal peninsula development is of fundamental importance for security of production growth, which is planned by Gazprom.

As a group of Yamal gas and gas condensate fields make up an important part of the perspective plan of development of Russian fuel and energy sector, their active exploration will likely cause an environmental hazard. Following environmental challenges are possible there:

- Top soil in the vicinity of settlements, compressor stations, central processing facilities is damaged by ordinary trampling down, waste disposal and nitrogen oxides emission.
- Last-mentioned ones when depositing to soil transform to toxic nitrates and ferrum nitrites, which are destroying soil microflora and ground vegetation. Only with the course of time, these substances are redistributing and depositing to geochemical traps.
- Landscape - anthropogenic influence on tundra landscapes. Active exploration of gas fields is accompanied by destruction of unstable biogeocenosis of Yamal's tundra. The natural revegetation of tundra is extremely hindered due to expansion of layer of seasonal freeze cycles and activation in this case of exogenic and associate processes, such as: thermokarst, termoerosion, solifluction, linear erosion. It is necessary to carry out engineering and biological recultivation there.

Flora. The most serious damage to plant cover is inflicted in summer by offroad vehicles. In this respect limnodiums are especially sensitive, when even at single ride of off-road vehicles a grass-mossy surface is not only mechanically damaged, but floristic composition is declining.

Fauna. 12 species of animal and 50 species of birds inhabit area in the vicinity of Bovanenkovskoe field, including 3 red-listed. Already at the exploration stage, due to loss of breeding grounds the bottleneck phenomenon of Bewick's swans and peregrin falcons are observed. All their breeding grounds can be lost when field developing. At this time the area of field facilities overlaps range of population of Polar fox. The Bovanenkovskoe field development fraught with serious consequences to Polar fox population at Yamal peninsular in whole.

In the same way there is a real hazard of air emission and water pollution either as result of accidents or during production processes.

Due to these environmental challenges it was decided to launch a complex ecological monitoring project at Bovanenkovskoe field in frameworks of future development. The cost of the project is estimated by Gazprom to be about 400 million rubles.

The ecological analysis at this area must be organized prior to intensive field development and henceforth at the all stages of field development. It is assumed to carry out the ecological monitoring of atmosphere, water environment, soil covering, flora and fauna. The supposed engineering solutions will guarantee the ecological influence to environment within the limits of maximum permissible environmental load, waste disposal and habitat conservation of animals and fish.

NATURAL GAS MONETIZATION

Since the last World Gas Conference in 2006, natural gas monetization has been in many ways more difficult than before. The key change that occurred in this time was a substantial increase in project costs. This has affected all natural gas monetization projects including LNG, which is not covered in this report. However, in this environment LNG projects have been delayed by cost concerns, and many emerging technologies such as GTL have seen a dramatic drop in prospective supply picture.

In the last half of 2008 and into 2009, the high energy price markets that largely drove the project cost increases have dropped significantly in the face of global recession. The effects of this environment are still being seen in reduced demand and lower prices. While project costs are gradually returning to a lower level – with reductions finally starting to show in early 2009, most energy companies seeking to monetize gas are having to manage their cash flows carefully, leading to continued slowness in gas monetization projects.

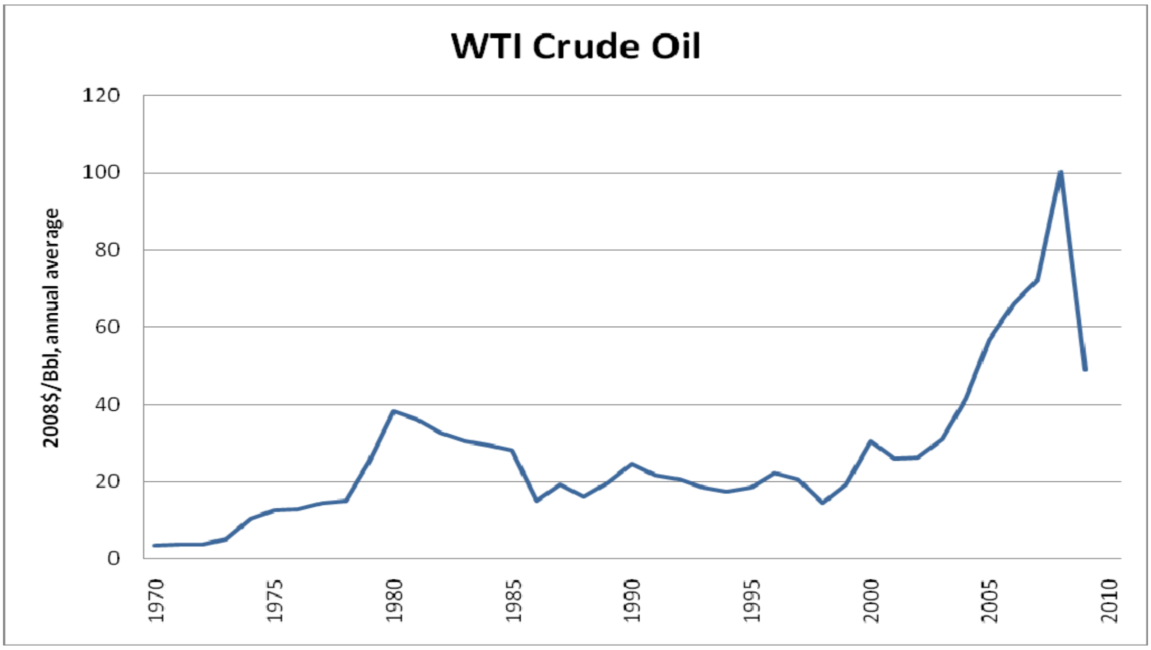
In this report, we will address the project cost issue which is a major factor underlying the evolution of gas monetization in the last years. We will also address the updated status of the major non-LNG monetization routes which have seen commercial development in this time period: GTL, DME, methanol, and petrochemicals. Finally, we will touch on some emerging technologies which are close to commercialization: floating LNG, CNG transportation, and hydrates transportation. As always, there is a lot of research activity in the area of gas-based processes, but these are believed to be the most advanced alternatives.

I. Project Costs

The last years saw an enormous run-up in project costs. The biggest increases were caused by shortages in:

- Equipment (turbines, pumps, and compressors)
- Bulk material (alloy steel, structural steel shapes, and cables)
- Experienced craft labor
- Pressure vessel fabrication
- Trained engineers

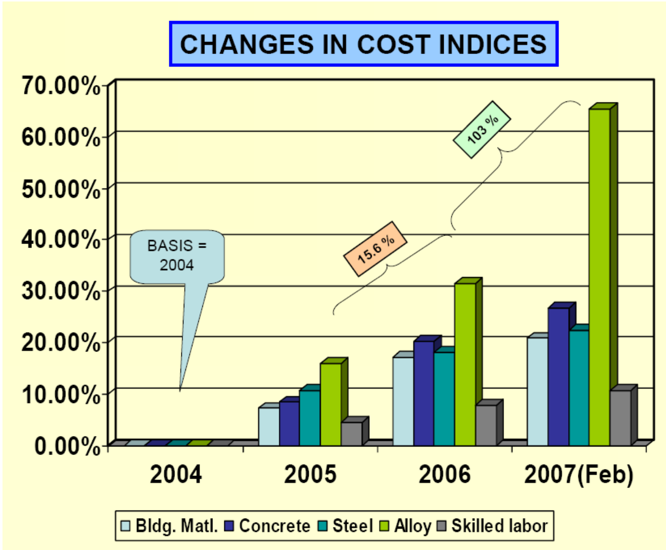
Why this shortage? It is widely held that the primary reason was the rise in crude oil prices. This is supported by the similar rise in project costs during the early 1980's, when crude prices also rose abruptly. In the more recent case, the trend was aggravated by the growth of emerging economies such as China and India. The crude price trend is illustrated below:



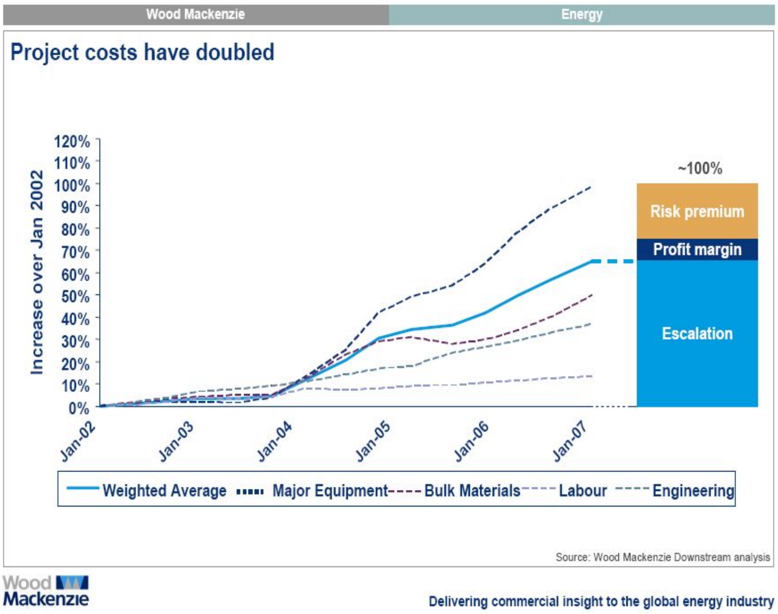
In response to this, worldwide activity in energy and infrastructure rose dramatically. In 2007, the global contracting community was trying to accomplish $450 billion worth of projects, about $150 billion of it in the energy sector. The contracting community was unable to complete all of these projects, and resources were limited for those projects moving ahead. As a consequence, contractor costs increased 60 to 100% during 2003-2006, with contractors including higher margins in their prices. During that time, engineering costs rose 24%, procurement costs increased 54% (largely due to steel prices, shown below), and construction costs increased 35%.

Steel Prices 1995-2007

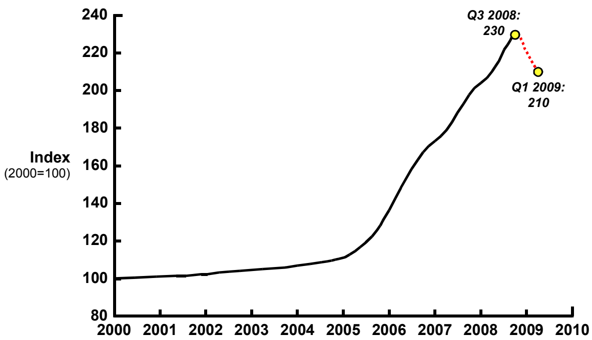
The above changes in project costs are summarized below, from several sources:

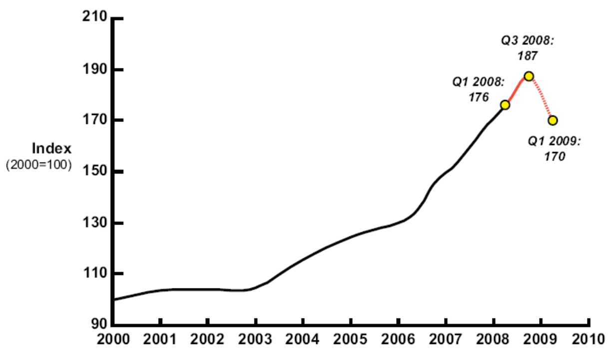


SOURCE: Nelson-Farrar survey, Oil & gas Journal, July 2, 2007, Volume 105.25, pg 65-67



IHS-CERA Upstream Project Cost Index HIS-CERA Downstream Project Cost Index





Source: IHS Cambridge Energy Research Associates.

Because of these cost increases, there were changes in the ways that contractors dealt with projects. For one, they included full risk premiums in their bids. Owners wishing to avoid these premiums began to take on more of the project risks themselves. Contractors were also more selective about projects, sometimes choosing not to bid.

For large, capital-intensive gas monetization schemes the above meant great change. Some projects had difficulty in getting enough bidders for an EPC tender. Cost overruns were common, and sometimes quite large. Finally, many projects chose to delay, in the hope that by contractual strategy or a change in market conditions the project return could be improved. Naturally, these impacts were greatest when the capital intensity of the project was greatest.

In early 2009, the EPC project backlog was sufficiently worked off that project cost indices started dropping. Given the new state of energy costs and the world economy, these indices should continue dropping for some time, leading to new opportunities for capital-intensive gas monetization projects.

II. Gas-to-Liquids

In the past three years, progress in gas-to-liquids technology commercialization slowed considerably. The primary reason is the abrupt rise in major project costs, mentioned above. GTL is usually more capital intensive than the most common monetization alternatives of LNG and pipelines, so it is competitively harmed by the precipitous rise in capital project costs. The effects on the industry can be seen in the following:

1. Qatar has decided that no new major projects should be scheduled for development until further notice. This affects all gas monetization projects contemplated for Qatar, but it has particularly delayed developments which Qatar anticipated would make them the GTL Capital of the world. Project proposals by Marathon, ConocoPhillips, and Sasol Chevron have been shelved.
2. ExxonMobil has indefinitely postponed its very large project for Qatar, citing high project costs.
3. The bid round for a GTL project in Algeria using gas from the Tinrhert Block was cancelled. The Minister of Energy and Mines cited high project costs.

On the positive side:

1. Chevron continues to build its 34,000 barrel per day GTL plant in Nigeria, using Sasol Chevron technology. Ownership is Sasol 10%, NNPC 25%, and Chevron 65%.
2. Shell is building a 70,000 barrel per day GTL plant in Ras Laffan, Qatar. This project is called Pearl GTL. It is to be followed by a second 70,000 barrel per day plant at the same location.
3. World GTL is constructing a 2,250 barrel per day plant at a refinery in Trinidad & Tobago. The plant is intended to help the refinery increase high-quality diesel production.

4. The first major commercial GTL plant, Oryx, was started up in Ras Laffan, Qatar in 2007. It has a capacity of 34,000 barrel per day.

Oryx has proven the marketability of the product, and gets the commercial GTL industry in gear. Previously, the market was being developed by Shell, with the volumes available from their Bintulu, Malaysia plant, which was debottlenecked to 14,700 barrels per day in 2005. Due to the relatively small volumes, Shell's emphasis was generally on niche, premium markets.

Next on line will be Chevron's 34,000 barrel per day plant in Nigeria and Shell's 70,000 barrel per day Pearl Project in Qatar.

There has been much debate about whether or not GTL is helped by higher oil prices. In general it is, but there are so many contrary examples it is more useful to look at particular markets than to rely on a generality.

GTL is generally helped by distance from gas markets, since LNG in particular is more expensive to ship than GTL products.

Also, GTL is favored if the target gas markets are not coupled well with global energy prices. If a gas market has local gas production or its power generation consumers have alternatives such as coal or nuclear power, gas prices can be de-coupled from oil prices. The United States is today a case in point, where the rise of gas production from shales has largely returned the country to gas self-sufficiency. Another example of de-coupling was the nature of LNG contracts in Asia a few years ago, with limited sharing of upside and downside cost changes. However, in the European and Asian markets today gas prices track energy prices quite closely. In contrast to gas, GTL products fit into global liquids markets which are always closely tied to crude oil prices.

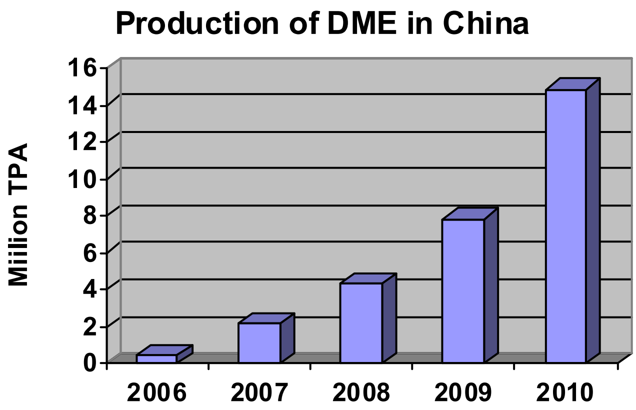
It is hard to see at this time what is next for GTL. On the positive side, project costs are slowly coming down, but have not quite settled to a new level. Also, gas prices have softened as the global recession dampens demand. Monetizing produced gas for gas markets is hard to justify using today's realities. On the negative side, projects continue to experience delays because lower energy prices cause energy companies to manage their cash flows more tightly.

The next wave of synthetic fuel plants may well be in places like China, where national interest and great need combine to make projects move ahead. We will address this in the next section.

III. DME

Dimethyl Ether, or DME, is the simplest ether and a gas at ambient temperature and pressure, but can be stored as a liquid. DME has found use as a refrigerant and a propellant for aerosol products, replacing halogenated hydrocarbons (freons) with an environmentally safer material. However, these uses are relatively small volumes. What has caused a lot of interest for DME in recent years is its potential as an energy source.

DME is considered a leading alternative to petroleum-base fuels and liquefied natural gas. Its physical properties are similar to liquefied petroleum gas (LPG) and it can be stored and delivered using existing land and sea based infrastructures with minor modifications. DME can be prepared from various energy sources including natural gas or coal, as well as biomass. This means that DME is both multi-source and multi-purpose.



Up to now, commercial DME plants have been constructed based on a conventional two-step process. Technology providers of this two-step process include Haldor Topsøe, Lurgi, Toyo, and MGC. On the other hand, KOGAS and JFE Holdings have developed a one-step process which produces DME directly from synthesis gas. KOGAS and JFE have adopted fixed bed and slurry bed reactors in their respective technologies.

The largest market for DME is Asia, where the capacity has steadily increased and will continue to grow with new plants constructed for the domestic fuel market. This has been especially true in China, due to the rapid growth of the economy and aggressive investment in methanol and DME plants. Annual production capacity and production were only 31.8 and 20 TPA, respectively, in 2002, but increased to 480 and 320 MTPA by 2006, with annual increases of around 96 to 97%. DME production has continued to increase sharply since 2006, as illustrated in the graph on the right. Virtually all of the Chinese DME capacity is based on coal, rather than natural gas.

A 3 million TPA DME plant in Inner Mongolia has been approved by the government and will be put into production by 2010, with a gross investment of 21 billion RMB. In the next 3 years, China will continue to construct large DME plants. By 2010, it is estimated that annual production capacity will be15 million TPA. DME production is ready for mass utilization and large-scale market operation in China.*

SOURCE: Huang Zhen, World CTL, 2008

China uses the DME primarily to blend with LPG, extending supplies. LPG has wide uses in China, including domestic use for cooking and heating. The potential market for DME imports as a LPG substitute in Asia is expected to grow from 18 MMTPA in 2012 to 27 MMtpa by 2030. China, Japan, and India are expected to have the largest markets.

Another use of DME is as a diesel fuel replacement. While this has attracted a lot of research interest, it has been hindered commercially because extensive modifications are required to vehicles to use DME. Because of its solvency and physical properties, DME requires changes to the fuel delivery system. Because of higher CO and hydrocarbon emissions, proper tailpipe mitigation measures are required. However, DME has a good cetane (around 55-60) and has lower NO_x and particulate emissions than conventional diesel. Because of this, it has been studied as a potential environmentally clean solution for applications such as city buses.

DME imports to various countries, in million TPA.

	China	Japan	Taiwan	Korea	India	Indonesia	Vietnam	Philippines	**Total**
2012	7.0	4.7	0.5	1.5	3.7	0.0	0.3	0.3	**18.1**
2020	7.6	4.7	0.5	1.6	5.3	1.7	0.1	0.4	**21.9**
2030	8.3	4.7	0.5	1.6	7.6	2.8	0.8	0.5	**26.8**

SOURCE: Gaffney, Cline & Associates Report KK1126, April 2008

Plans for construction of new plants in Japan, Iran, and New Guinea are currently under consideration:

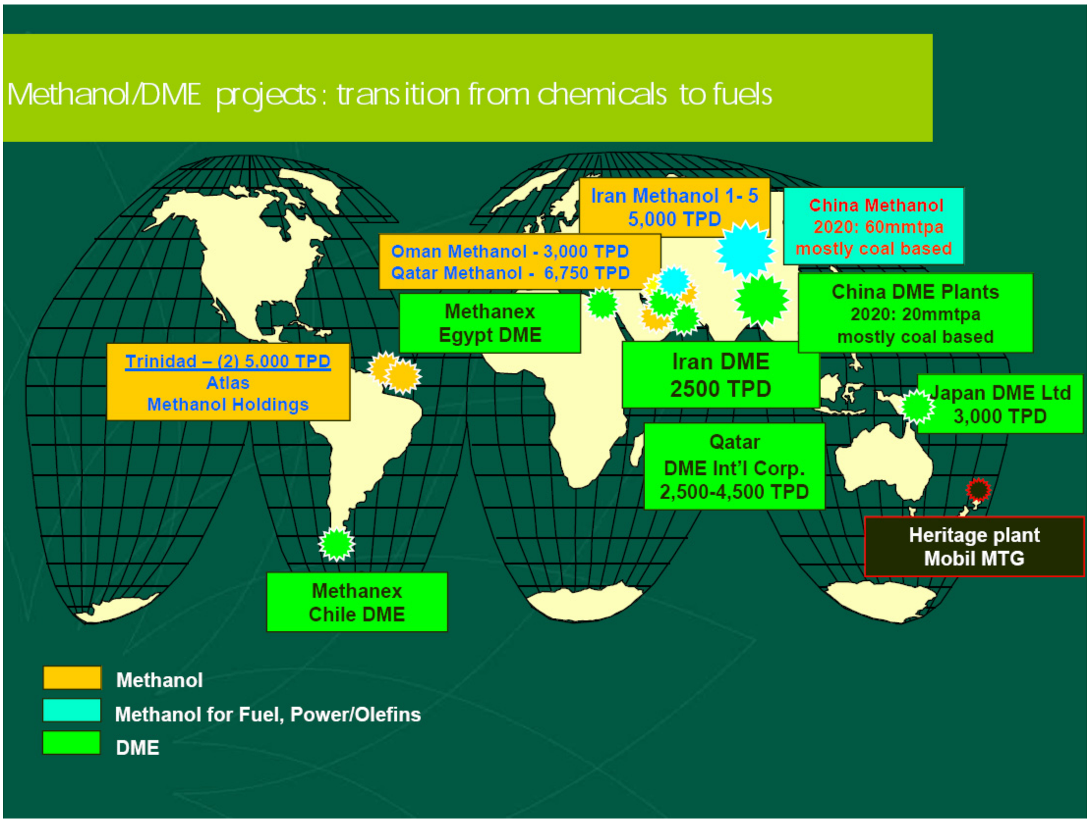
International DME Projects

Company	**Location**	**Capacity**	**Start Up Date**	**Use**
Zagros Petrochemical	Assaluyeh	800,000 MTPA	Will come on stream in 2008	Domestic Fuel
Japan DME*)	Niigata	80,000 MTPA	Onstream June 2008	Aerosol, Domestic Fuel
Japan DME*)	Papua New Guinea	1,000,000 MTPA	Feasibility Study announced March 1, 2007. If commercialized, projected onstream in 2011	Domestic Fuel
KOGAS	SEA	1,000,000 MTPA	Preliminary Feasibility Study finished April 2008. If commercialized, projected onstream in 2013	Domestic Fuel

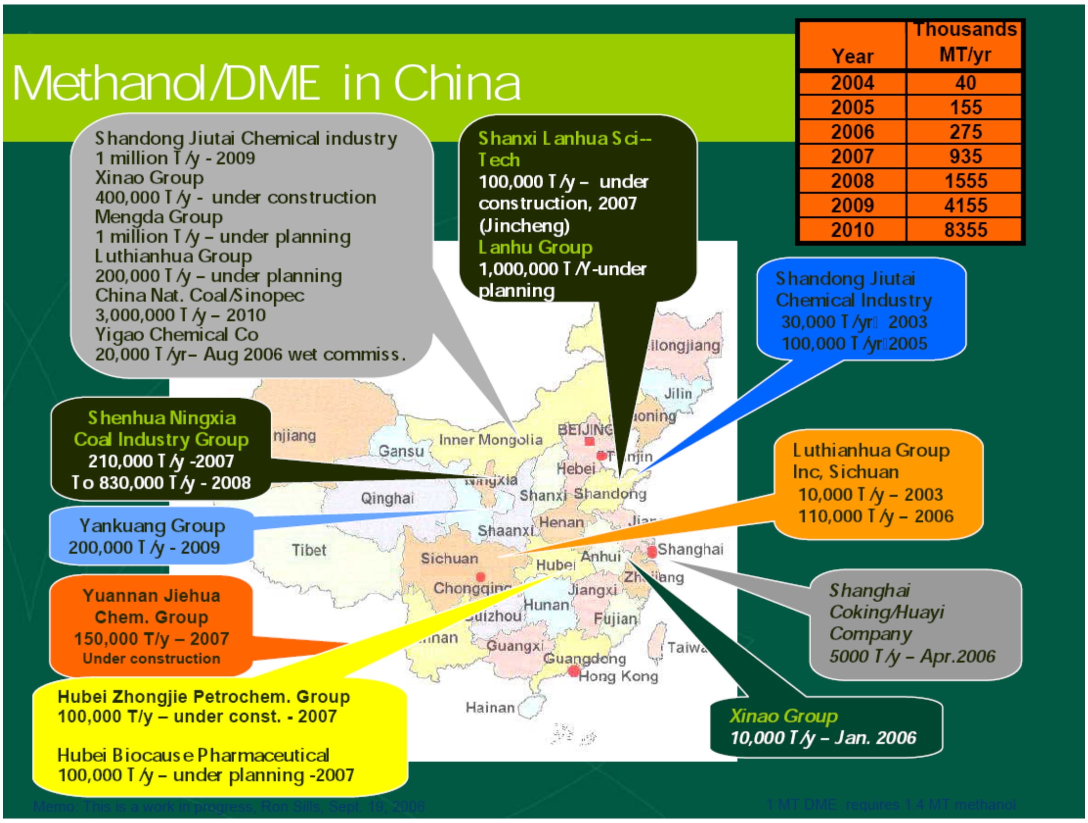
SOURCE: The Catalyst Group, Global Dimethyl Ether Emerging Markets, April 2007

In Korea, KOGAS is developing the DME process using a 10TPD demonstration plant, operating since 2005. Three companies and four research institutes are involved in this effort.

In May 2008, operation of the demonstration plant was started and successfully operated continuously for 2 months. KOGAS will perform the test operation several times to complete operation of the demonstration plant, validating the technology of the one-step DME synthetic process for a 1,000,000 TPA commercial plant. Also, KOGAS completed a preliminary feasibility study for a commercial-scale DME project in April 2008. A plan has been prepared to implement the DME project with a target of year-end 2012 for plant start-up.



SOURCE: Dr. Theo Fleisch et al. NGCS 8 Natal, Brazil, May 2007



SOURCE: Dr. Theo Fleisch et al. NGCS 8 Natal, Brazil, May 2007

Japan DME, Ltd. announced plans in February 2007 to establish a Joint Venture Company for DME production, and to construct an 80,000 TPA DME production plant within Mitsubishi Gas Chemical Company's Niigata Factory. The plant is scheduled to start operation in June 2008, with production capacity expandable to 100,000 TPA. JGC is in charge of the construction of this new production plant, and Mitsubishi Gas Chemical will be operator.

DME remains an interesting possibility for remote gas monetization, but the right opportunity has yet to materialize. The biggest difficulty is that there needs to be a market imperative to drive its use. China has this, but is pursuing a path of self-dependence with cheap DME based on coal. DME can also be used as a turbine feed for power generation, in areas where LNG regasifiers may be impractical. The future promise of DME is that economies come to rely on it, allowing imports from remote gas locations.

IV. Industrial Uses for Natural Gas

Besides using natural gas as a fuel – burned as is, or converted to another fuel – it can be used as an industrial feedstock. Worldwide, about 20% of natural gas use is for industrial non-energy use. On a percentage basis, the most successful country in the stimulation of industrial gas use is Trinidad & Tobago, where around one-third of gas use is destined for petrochemical uses such as methanol and ammonia; a few years ago it had been closer to half, but the large increase of the local LNG business is drawing an ever larger share of the gas produced.

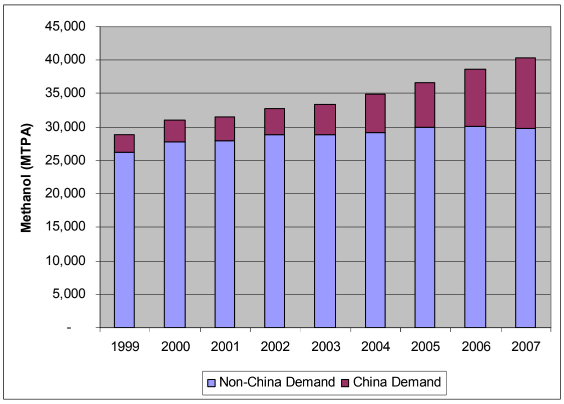
Use of natural gas as an industrial feedstock is generally viewed favorably by host governments. The limitation to its use for gas monetization is the ability to market the products. The target markets are generally small, compared to energy markets. Thus, the energy applications mentioned previously tend to take the greatest share of natural gas production. Following, we will examine the status of the two largest industrial uses: methanol and ammonia

a. Methanol

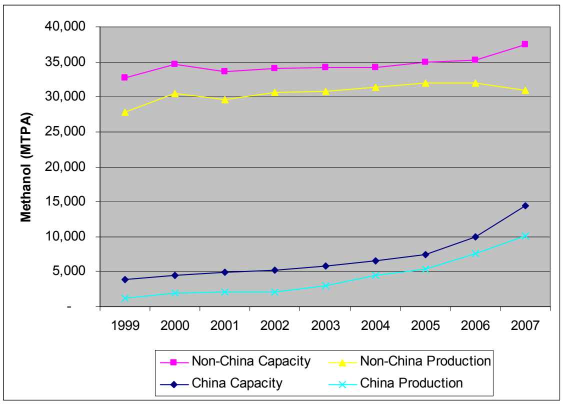
One route used to monetize natural gas is conversion to methanol. This method has been most actively used in Trinidad & Tobago, Chile (using Argentine gas), the Middle East, and Venezuela. In this process, natural gas is converted to a synthesis gas (carbon monoxide and hydrogen), which is then reacted at high pressure to make methanol.

In recent years, the traditional large markets of the United States and Western Europe have seen flat to shrinking demand for methanol. United States demand has been affected mostly by the removal of MTBE from motor gasoline. MTBE, made with methanol, had by the late 1980's become the major chemical derivative using methanol feedstock. In the early 2000's, MTBE was detected in groundwaters in the United States; by early 2006, it was gone from U.S. gasoline supplies. However, China's methanol market has been growing substantially and has doubled its production capacity in the last 3 years. The graphs below show recent trends in methanol demand and production capacity, in and outside of China. The first graph illustrates how the recent methanol demand increase is primarily in China. The second graph shows the response of production capacity in China. As a consequence, Chinese capacity is operating at about 70%, while non-Chinese capacity is at 83%. Chinese methanol production relies more on coal, which is plentiful, rather than natural gas. Thus, methanol production increases in China do not generally affect natural gas markets.

Methanol Demand



Methanol Supply – Production and Capacity



In spite of the overcapacity in the methanol market, plants continue to be announced and built, generally driven by the hope of large gas owners to monetize gas via this route. The Methanol Institute shows this forecast:

METHANOL EXPANSION FORECAST 2007-2010

(000 Metric Tons)

Projects Approved or Under Construction

Name	Location	Ownership	Capacity	Timing	Comments
Togliatti	Russia		500	Q1-2007	Started up Jan, 2007
Zagros-1	Iran	NPC	1650	Q2 2007	Original Schedule 1H 2005
Zagros 2	Iran	NPC	1650	*Late 2007	Comericially available 2008-2009
Shanghai Coking	China	Shanghai Coking	450	Q2-2007	
Oman Methanol	Oman	Oman /MHTL	1000	Q3 2007	
Ar-Razi V.	Saudi Arabia	Sabic/MGC	1750	H1 2008	
Petronas	Malaysia	Petronas	1700	Q1 2009	Was Mid-2008
Atlantic Methanol	Equatorial Guinea	Atlantic Methanol	125	Q3 2007	Timeing uncertain
MCN (Methanor)	The Netherlands	MCN	425	Undetermined	Restarted 425 KTA Dec-2006
Brunei National Petr.	Brunei	MGC/Itochu/Brunei Nat	850	Q4 2009	Commercial Operation Q2, 2010
Various	China	Various	2500	2007-2009	
		Total	12,600		

Jim Jordan & Associates, LLP

As shown above, there are still a number of projects in the Middle East and Asia that seek to produce incremental methanol from natural gas.

b. Ammonia

Besides methanol, another widely used monetization route for natural gas has been for the production of ammonia. While ammonia does not use the methane directly as a feedstock, so much hydrogen is needed to produce ammonia that it has come to be associated with areas where natural gas is available at a relatively low price. The ammonia finds use in a number of chemical uses, but mostly (about 80%) in the production of nitrogen fertilizers. Because of this, ammonia projects generally are most successful where inexpensive gas is available and nitrogen fertilizers can find a market not too far away. In the absence of one or both of these, ammonia is generally difficult as a way to monetize gas.

As is the case for methanol, Chinese production growth dominates the world picture. Since 2002, Chinese production growth of ammonia has ranged from half to nearly all of world growth. At the same time, as gas prices have risen ammonia plants in gas consuming nations such as the United States have gone out of business.

V. Gas-to-Wire

Gas to wire refers to the use of natural gas to fire electric power generation. The gas monetization income is derived from the sale of the electric power. In the past, this has taken the form of local power generation, a concept that is often challenged by the weakness of electric power markets near remote gas sources. In other cases, electric power plants may be built with the deliberate intent of exporting the electric power to a neighboring region, in lieu of exporting the gas. This can be advantageous, say if regulations limit the income from gas sales while power may be regulated differently. The generation project in Uruguaiana, northern Argentina, was an example where the power generated was exported into southern Brazil.

Very few generalities apply to gas-to-wire. Local electric power markets are generally regulated in some form, and the regulations affect projects significantly. One generalization is that in order to make money, the power generated needs to be bought by someone. While apparently obvious, this has been the downfall of many gas-to-wire projects. For example, where there are mature power markets desperate gas producers tend to overbuild generation capacity, leading to a series of unprofitable ventures. Electric power is a distinct and complex market, and requires its own expertise. Gas producers need sound advice before embarking on a gas-to-wire venture. Nevertheless, it is generally easier to distribute electric power to consumers and enhance a market than to build a gas distribution grid and create a market for the gas.

VI. Options Close to Commercialization

The above options are all commercial technologies, being built at commercial scale today. As always, there are a number of new approaches that are approaching the commercial stage but have not yet found commercial application. We will turn our attention to these.

a. Floating LNG

For some time now, various technology providers have attempted to provide solutions for more compact, floating plants to monetize gas. This solves the problem faced by offshore gas discoveries far away from infrastructure. Recently, Shell Oil Company has announced that it is seeking a place to construct a ship containing a gas liquefaction plant. This floating LNG plant could find a number of potential uses, but Shell has particularly expressed interest in Australian applications. Announcements appeared in March and April of 2008, representing an interesting development in gas monetization. When energy prices were high, the lucrative nature of the Asian

LNG market drove the potential for Pacific Basin applications for floating LNG. For example, in October 2008 Wood Mackenzie reported that Inpex was proposing floating LNG as a leading possibility for its Abadi Field in Indonesia. At a Floating LNG conference in London in October 2008, three enterprises claimed to be positioning themselves to provide floating LNG plants: Flex LNG, Hoegh LNG, and Golar LNG. Now that Asian LNG markets are softer and capital projects are being carefully scrutinized, the speed with which floating LNG finds applications may be affected. One promising sign: in January 2009, Shell continued conversations with consortia interested in building a floating LNG facility.

b. CNG Transportation

In terms of gas transportation, some companies have been exploring whether the costs of liquefying and regasifying natural gas could be avoided by transporting it in compressed form. This method does not allow as much gas to be transported per ship load as LNG, but is less capital-intensive. Generally, it provides a way to transport smaller quantities of gas over shorter distances with greater efficiency than LNG. Claims are that CNG is profitable for a transport range of 300 to 2,000 nautical miles with production volumes of 0.5 to 3 billion cubic meters a year (around 50 to 300 million cubic feet per day).

Leaders in this technology appear to be EnerSea (a venture of Mitsui, “K” Line, Tanker Pacific, ABB, Lone Star R.S. Platou, Alan McClure, Amec Paragon, Nippon Steel, and Hyundai) and CETech (a venture of Statoil, Teekay Shipping and Leif Hoegh & Co).

c. Hydrates Transportation

Another way to transport natural gas is to convert it into a hydrate, then recover the gas at the receiving terminal. This is an analogue to LNG, except that instead of cryogenically condensing the methane into a liquid, you convert the gas into a hydrate crystalline structure for transportation. At the receiving end, the methane in the hydrate is released into its gaseous form. By avoiding cryogenic storage and transportation, you can use simpler equipment, simpler storage, and simpler transportation vessels.

Like CNG transportation, hydrates transportation targets smaller fields and production volumes, as well as shorter distances. A proponent of this technology, Mitsui Engineering & Shipbuilding Co., Ltd., indicates a target market of transportation distances less than 3,500 nautical miles. The methane is converted into hydrate pellets and transported on a refrigerated carrier. Equipment on the carrier re-gasifies the pellets. Production volumes used to illustrate the application are in the 40 to 125 MM cubic feet per day range, to serve “medium to small-scale consumers”.

Shtokman project development: environmental and technical challenges

Source: http://www.strategikonferansen.org/2008/
http://www.gazprom.com/

Shtokman field characteristics

- ✓The field was discovered in 1988
- ✓Seven exploratory/delineation wells have been drilled
- ✓Extension of field 48x36 km
- ✓4 producing formations J0, J1, J2 and J3
- ✓Offshore distance is about 600 km
- ✓Sea depth in the field area is up to 350 m
- ✓Gas in Place (C1+C2): 3,8 tcm
- ✓Condensate in Place: 31 mln tons
- ✓Good petrophysical characteristics
- ✓Low CGR – Low CO2 content – No H2S

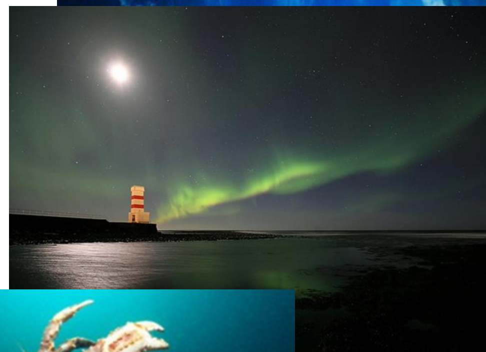
- ✓The Shtokman development project envisages annually producing some 70 bcm of natural gas and 0.6 mln t of gas condensate
- ✓Phase 1 contemplates annually producing 23.7 bcm of natural gas with the startup of gas supply via the gas pipeline due 2013, and liquefied natural gas supply– 2014

Shtokman Development AG

✓Gazprom, Total and StatoilHydro will set up a special purpose vehicle create a special purpose vehicle (Shtokman Development AG) to organize the design, financing, construction and operation of the Shtokman phase one infrastructure.

✓Gazprom has a 51% participating interest in the Shtokman Development AG while Total has 25% and StatoilHydro - 24%.

Environmental challenges



Extreme arctic conditions of Barents sea:

✓cold temperature

✓iceberg and drift ice

✓construction windows limited

✓polar day and night

Essential to preserve the environment in a sensitive ecosystem

Technical Challenges : Offshore Facilities

In July, 2008 construction of the first of two semi-submersible platforms for drilling production wells on the Shtokman field initiated.

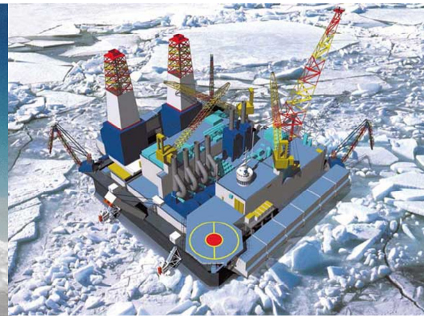
✓Topsides operating weight up to 45 000 tons

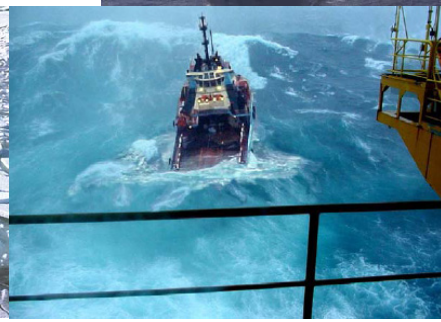
✓Ice conditions

✓Icebergs and drift ice (In 2003, more than 15 icebergs have been observed close to Shtokman, 2 of them weighting more than 3 millions tons)

✓Waves up to 32 m high

=> Two main concepts: **Offshore Facilities have to be ice resistant and disconnectable**

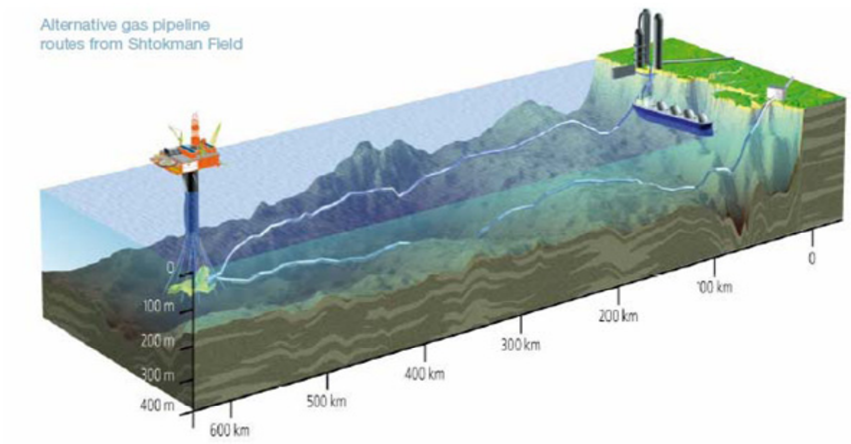




Technical challenges: Export pipeline to shore

The Dry 2 Phase transport challenges:

- ✓ Offshore riser arrangement (high flow rates)
- ✓ Large diameter and high design pressure pipeline
- ✓ Liquid Hold-up in the range 30 – 70 MSm3/d to be managed in operations
- ✓ Size of the phase 2 slug catcher onshore to be optimized
- ✓ Shore approach difficulties
- ✓ Optimization between pipe diameter / inlet & outlet pressure / maximum liquid hold-up / operating conditions (minimum – maximum flow-rates)

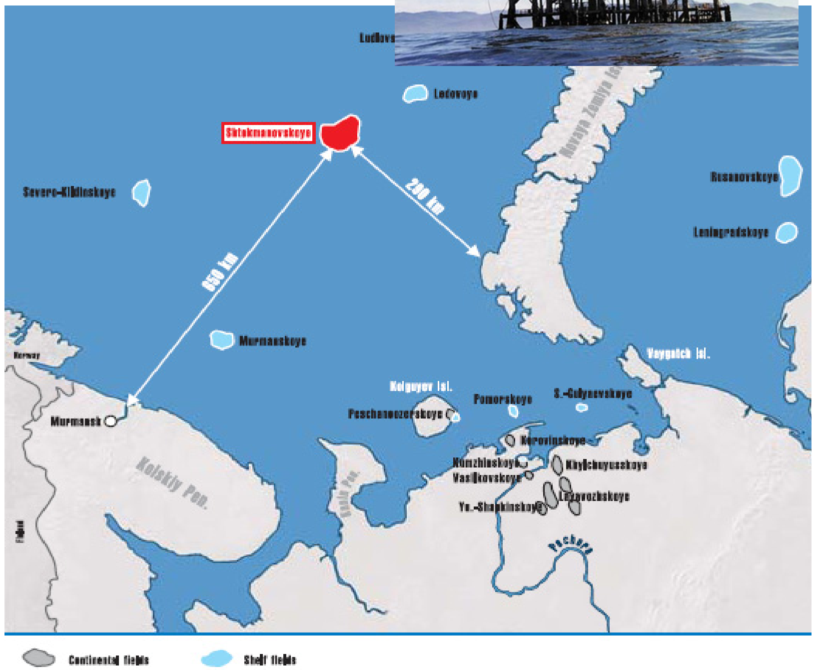


Technical challenges: LNG plant: specific site conditions

- ✓ **Design capacity = 7.5 Mt/year**
- ✓ **Main aspects for optimization and design**:
  - ▪ Arctic climate
  - ▪ Winterization
  - ▪ Construction constraints (stick built / modular)
  - ▪ Appropriate design: number of trains, driver selection, cooling media, reservation for next phases…

Technical challenges: Associated facilities - Logistics

- ✓ **650 km offshore from Murmansk**
- ✓ **Supporting facilities for onshore and offshore installation**
- ✓ **Thousands of construction workers during the construction peak activities**



Conclusion:

General trend in remaining conventional gas reserves is exploration of new reserves in more and more far areas from main consuming regions. Arctic developments are on agenda now. Mature areas in many countries still have enough gas reserves to load existing production infrastructure, but gas production becomes more and more expensive and no hopes for finding of new huge discoveries able to improve economics of gas production in the area.

This situation pushes technologic development of gas production. Gas monetization is a perspective way for more complete exhausting of gas fields in mature areas as well as for remote and difficult reservoirs development. But these technologies often still are in the beginning of development and their application in different situations with gas production requires accurate economic approach.

Study Group 1.2 Report

Kamel Chikhi (Algeria) – leader

Difficult Reservoirs and Unconventional Natural Gas Resources

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INTRODUCTION

Unconventional resources are world-widely distributed. Their development potential can be realized in the mid term. These resources share common characteristics, but also have geographical uniqueness both technically and economically. Their development is still hindered by many obstacles which need to be overcome. The biggest challenge will be to devise a comprehensive policy that encourages development of unconventional gas fields using existing technology and knowledge. Funding and appropriate technology are also required to support exploration and development of these new unconventional resources [1].

The boundary between conventional gas and unconventional gas resources is not well defined, because they result from a continuum of geological conditions. Coal seam, shale and tight gas occur in low permeability rocks and require special treatment for recovery.

Unconventional gas is most broadly defined by the Society of Petroleum Engineers (SPE) as gas contained in formations from which it is difficult to produce without some extraordinary completion and stimulation practices [2]. The most common unconventional gas formations are low permeability sands ("tight gas"), coals containing coalbed methane (CBM), organic-rich shales, and gas hydrates. One trait common to each is an IGU WOC 1 analysis of unconventional gas definitions (2003).

In Russia, unconventional gas source is defined also unofficially as natural gas accumulation, commercial development of which is not possible now due to geologic or technologic reasons. Geological and technological criteria of unconventionality are shown as follows:

- Geologic reasons:
  - Liquid or solid form of natural gas or gas-containing fluid;
  - Large (more than 4500 m) depth;
  - Low permeability of reservoir (less than 1 mD);
- Technologic reasons:
  - Low gas flow rates at wellheads (less than 20 000 m^3/day);
  - Low pressure at wellheads (less than 2 MPa);
  - Expensive materials and facilities for natural gas production.

More precise definition of unconventional gas sources has appeared recently. All known unconventional gas sources (or considered so) were divided into "really unconventional sources and"pseudo-unconventional".

Really unconventional gas source:

> More than 5%* of total gas content (excluding conventional reservoirs) is in the form different from Free State (liquid, solid). These are such sources as coalbed methane, water-dissolved gases or natural gas hydrates.

- Pseudo-unconventional gas source:

  Less than 5%* of total gas content is in the form different from free state, but not economically feasible for development due to geologic or technologic reasons. These are such sources as dense reservoirs, deep fields or permafrost gases.

  (* 5% is approximate maximum share of natural gas adsorbed by mineral surface in a reservoir.)

Japan also has the following criteria:

- Geologic Criteria:
  - Gas in the gaseous state in subsurface conditions is considered conventional and that in other state is considered unconventional
  - Gas contained in low porosity low permeability (generally construed to be less than 0.1 mD) formation is considered unconventional.
- Technologic Criteria:
  - Low permeability (less than 0.1 mD) would be regarded as unconventional if technology to produce in commercial rate is not established.
- Economical Criteria:
  - Where production cost (including transportation cost) exceeds gas price it is considered unconventional. However sometimes commerciality can be established in combination with other products which are simultaneously produced, e.g. iodine production in conjunction with water-dissolved gas production helps commerciality and hence water-dissolved gas is considered part of conventional.

In general, even if there is unconventionality from geological or technological point of view, the source would be considered conventional if economical criteria are historically cleared.

U.K. also has the same technologic criteria of "0.1 mD or below" for "Dense reservoirs (Tight formation)".

In spite of the above-mentioned criteria in Japan and Russia, the definition of the unconventional gas source is still uncertain. The key issues for the definition are listed as follows:

- Criteria of "low permeability": for example, 0.1mD or 1.0 mD;
- How to define the ratio free gas/non-free gas content for the criteria of unconventional gas resources and reserves;
- Necessity of economic criteria and, if yes, how to define it;
- If unconventional gas can be commercially produced, should it be categorized as "conventional gas"?

As Japan considers commercial water-dissolved gas as a part of conventional in the economic criteria for unconventional gas source, most companies include coalbed methane, which is evaluated to be commercially recoverable, into “reserves” category. The SEC definitions in 1979 exclude “natural gas" that may be recovered from coal and other sources from “proved reserves”; however, most companies ignore this requirement. In the SEC guideline in 2000, it is defined that coal bed methane gas can be classified as proved reserves if its recovery is shown to be economically feasible.

USGS definition of some kinds of unconventional gas and difficult reservoirs

The U.S. Geological Survey (USGS) is currently assessing continuous gas resources of the U.S. (including basin-centered gas, shale gas, tight reservoir gas, and coal-bed gas).

Based on geological criteria, a continuous gas accumulation (1) is regional in extent, (2) can have diffuse boundaries, (3) has existing "fields" that commonly merge into a regional accumulation, (4) does not have an obvious seal or trap, (5) does not have a well-defined gas-water contact, (6) has hydrocarbons that are not held in place by hydrodynamics, (7) commonly is abnormally pressured, (8) has a large in-place resource number, but a very low recovery factor, (9) has geological "sweet spots" of production, (10) typically has reservoirs with very low matrix permeabilities, (11) commonly has natural reservoir fracturing, (12) has reservoirs generally in the vicinity of source rocks, (13) has little water production (except for coal-bed gas), (14) has water commonly found updip from gas, (15) has few truly dry holes, and (16) has Estimated Ultimate Recovery (EUR) of wells that are generally lower than EUR's from conventional gas accumulations. The USGS has developed a cell-based methodology for the assessment of continuous gas accumulations, in which a probability distribution of potential untested geologic cells (a cell is related to the drainage area of a well) is paired to a probability distribution of EUR's of untested cells to have a probability distribution for undiscovered resources in a continuous accumulation.

The main distinction between conventional and unconventional gas lies in the frequent need for additional stimulation to gain and maintain commercial production from unconventional resources. Unconventional gas is also often produced at low pressures.

As well, some of the unconventional gas types can be both the source of, and the reservoir for, the natural gas. Finally, the mechanism for storing the natural gas for most unconventional gases is different than for conventional gas reservoirs. The need for stimulation also dictates special needs in drilling and completion technology.

1 RESOURCES BASE – ENDOWMENT

Endowment and recoverable resources are fundamental concepts in any discussion of energy supply.

Endowment refers to the earth's physical store of potential energy sources: tons of coal, cubic meter or feet of natural gas, etc. The endowment of fossil hydrocarbons is fixed: it can be depleted but not replenished.

Recoverable resources are a subset of the hydrocarbon endowment—the portion that can be viably produced and converted to fuel and power.

The natural endowment is the foundation of all supply projections. Although there are many estimates for future producible reserves and production, these are often based on the same resource estimates, principally data compiled by energy companies and governmental agencies.

Current endowment and resource assessments for Unconventional Gas indicate very large in-place volumes and resource potential, several times the cumulative produced volumes and current reserve estimates.

However, physical, technical, commercial and other constraints make only a fraction of any endowment available for extraction. The key consideration for all energy sources is converting the resource endowment to economically and environmentally viable production and delivery.

1.1 DISCOVERY AND DEVELOPMENT CRITERIA

According to 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS), the term "resources" encompasses all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

Resources classification requires the definition of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

A discovery is one petroleum accumulation or several petroleum accumulations collectively for which one or several exploratory wells have established, through testing, sampling, and/or logging, the existence of a significant quantity of potentially moveable hydrocarbons (i.e. sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery). Estimated recoverable quantities shall initially be classified as Contingent Resources with sufficient chance of commercial development to reclassify all, or a portion, as Reserves.

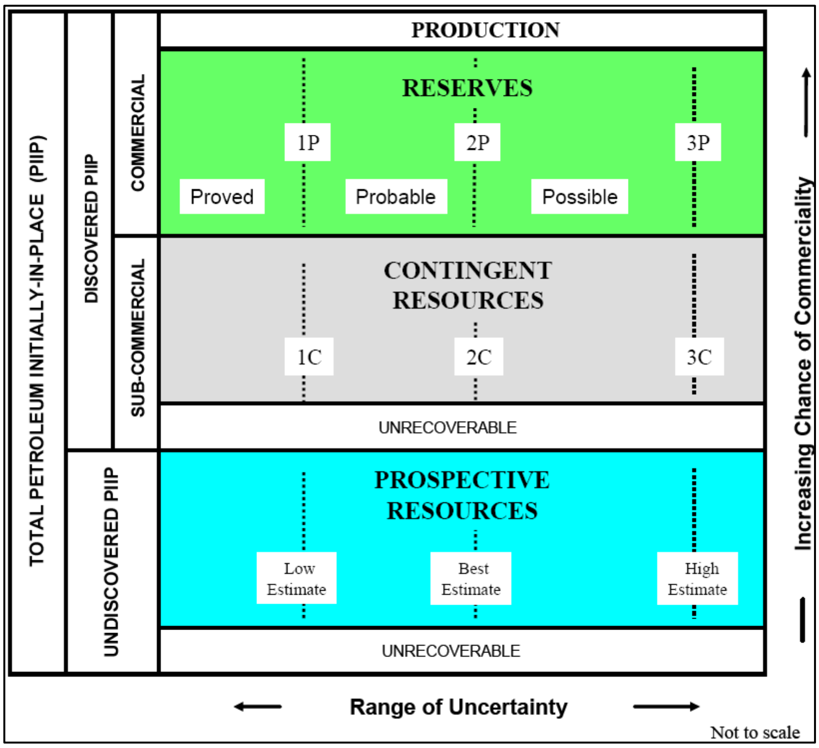


Figure 1-1: Resources Classification Framework.
The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality, that is, the chance that the project that will be developed and reach commercial producing status.

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

• Evidence to support a reasonable timetable for development.

• A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria:

• A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.

• Evidence that the necessary production and transportation facilities are available or can be made available:

• Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

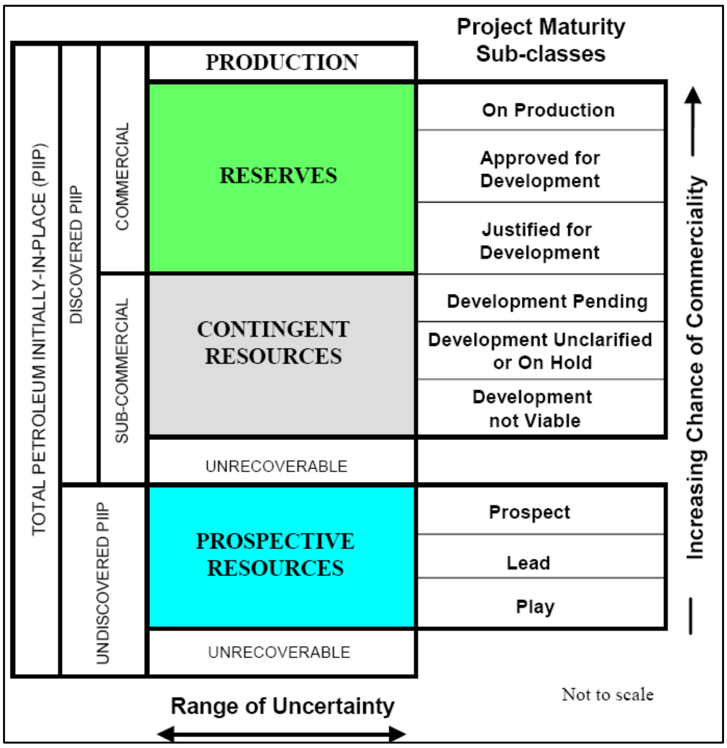


Figure 1-2: Sub-classes based on Project Maturity.
As illustrated , development projects (and their associated recoverable quantities) may be sub-classified according to project maturity levels and the associated actions (business decisions) required to move a project toward commercial production.

1.1.1 Unconventional Resources evaluation approaches

Unconventional Resources require different approaches for their evaluation.

Unconventional Gas resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called “continuous-type deposits”). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrates. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas).

For these petroleum accumulations that are not significantly affected by hydrodynamic influences, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum may not be possible. Thus, there typically is a need for increased sampling density to define uncertainty of in-place volumes, variations in quality of reservoir and hydrocarbons, and their detailed spatial distribution to support detailed design of specialized mining or in-situ extraction programs.

It is intended that the resources definitions, together with the classification system, will be appropriate for all types of petroleum accumulations regardless of their in-place characteristics, extraction method applied, or degree of processing required.

1.1.2 NOC, IOC and Research Institutions estimates

[1]. Unconventional gas reservoirs represent a vast, long-term, global source of natural gas and have not been appraised in any systematic way. Unconventional Gas resources—including tight sands, coalbed methane, and gas shales—constitute some of the largest components of remaining natural gas resources in the United States.
During the last decade, development of unconventional gas reservoirs has occurred in Canada, Australia, Mexico, Venezuela, Argentina, Indonesia, China, Russia, Egypt, and Saudi Arabia.
Many of those who have estimated the volumes of gas in place within unconventional gas reservoirs agree on one aspect: that it is a large resource. Using the United States as an analogy, there is good reason to expect that unconventional gas production will increase significantly around the world in the coming decades for the following reasons:
• A significant number of geological basins around the world contain unconventional gas reservoirs.

1.1.2.1 Rogner Estimates

Rogner estimates that in the world there are around:

- ✓ 256 TCM of gas in place in coalbed methane,
- ✓ 456 TCM of gas in place in shale gas, and
- ✓ 209 TCM of gas in place in tight gas sands.

1.1.2.2 Russia Estimates

Gazprom VNIIGAZ (Russia, 2008) estimates:
Really unconventional:

- ✓ Underground water-dissolved (aquifer) gas (depth up to 4,5 km) – 8000 – 10000 TCM
- ✓ Gas of hydrates (including permafrost metastable hydrates)- 2500 – 21000 TCM
- ✓ Shale gas - 380 – 420 TCM
- ✓ Coalbed methane (up to depth 4,5 km) - 200 – 250 TCM
- ✓ Pseudo – unconventional (difficult reservoirs):
- ✓ Dense reservoirs (Tight sands) gas (depth up to 4,5 km) - 180 – 220 TCM
- ✓ Deep reservoirs (depth 4,5 – 7,0 km) gas - 200 – 300 TCM

• Any reasonable recovery efficiency leads to the conclusion that there is an ample opportunity in the future to develop unconventional gas worldwide.
• Tight gas sand development in the United States, critical to future U.S. gas supply, has to over 0,11 TCM/year and is supported by ongoing technology
• The technology developed in the United States over the past 3 to 4 decades will be available for application around the world.

• New technology is rapidly becoming a worldwide commodity through efforts of major service companies.
• The global need for energy, particularly natural gas, will continue to be an incentive for worldwide unconventional gas resource development.
• Tight gas sands, gas shales, and coalbed methane are already critical to North America today and will be an important energy source worldwide during the 21st Century.

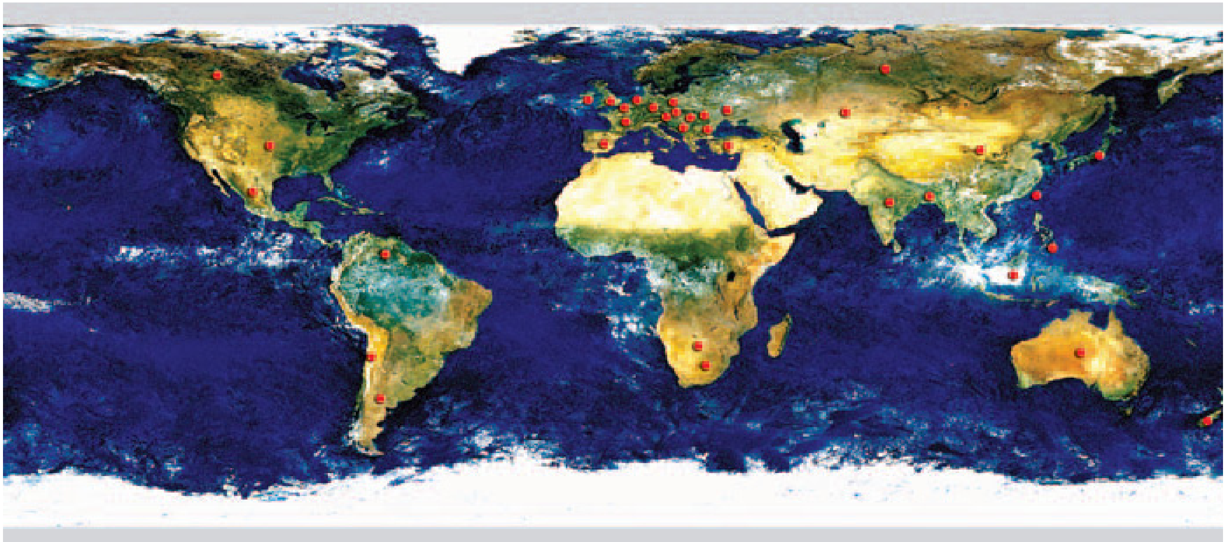


Figure 1-3 Worldwide CBM activity.
(By 2001, 35 (red dots) of the 69 coal-bearing countries had investigated CBM development)t.

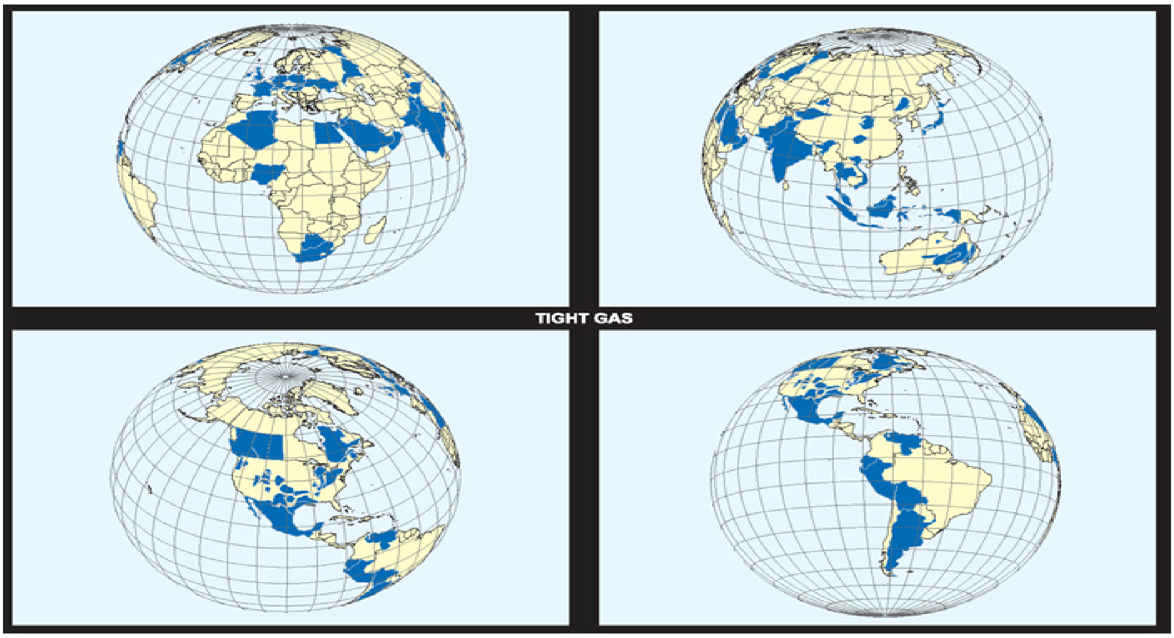
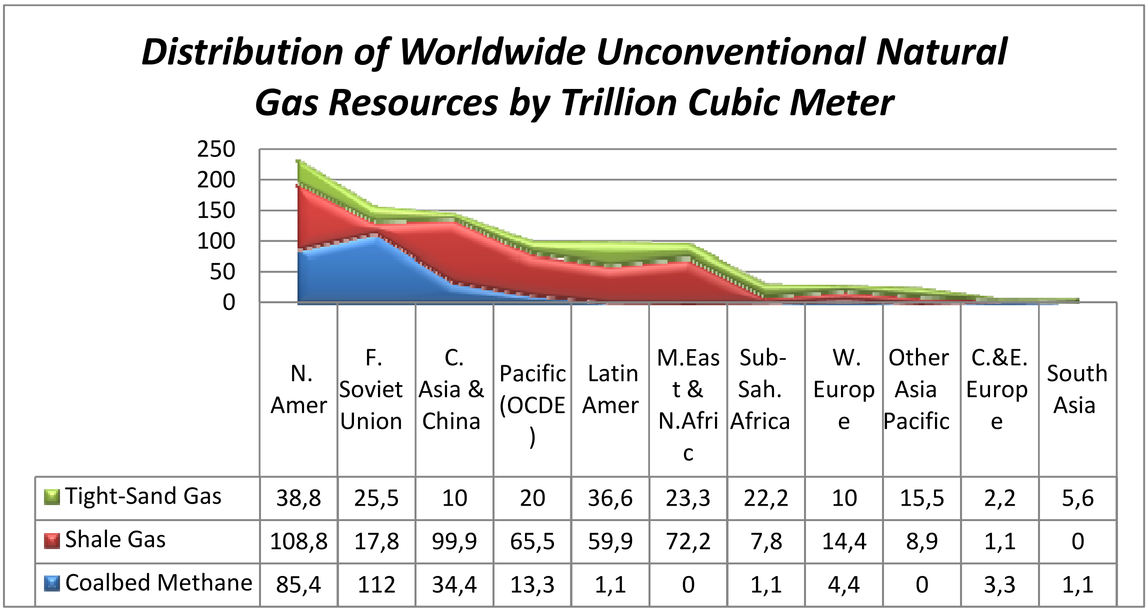


Figure 1-4: Global distribution of tight gas resources (blue).
(Figure courtesy of Wood Mackenzie).

Table 1- Worldwide Unconventional Natural Gas Resources Estimates

Region	Coalbed Methane (TCM)	Shale Gas (TCM)	Tight-Sand Gas (TCM)	Total (TCM)
World	256,3	456,2	209,7	**922,0**
North America	85,4	108,8	38,8	**233,0**
Former Soviet Union	112,0	17,8	25,5	**155,3**
Centrally planned Asia and China	34,4	99,9	10,0	**144,2**
Pacific (Organization for Economic Cooperation and Development)	13,3	65,5	20,0	**98,7**
Latin America	1,1	59,9	36,6	**97,6**
Middle East and North Africa	0,0	72,2	23,3	**95,4**
Sub-Saharan Africa	1,1	7,8	22,2	**31,1**
Western Europe	4,4	14,4	10,0	**28,9**
Other Asia Pacific	0,0	8,9	15,5	**24,4**
Central and Eastern Europe	3,3	1,1	2,2	**6,7**
South Asia	1,1	0,0	5,6	**6,7**

Source: Kawata and Fujita, "Some Predictions of Possible Unconventional Hydrocarbons Availability Until 2100," Society of Petroleum Engineers, SPE Paper 68755, 2001.



	N. Amer	F. Soviet Union	C. Asia & China	Pacific (OCDE)	Latin Amer	M.East & N.Afric	Sub-Sah. Africa	W. Europe	Other Asia Pacific	C.&E. Europe	South Asia
Tight-Sand Gas	38,8	25,5	10	20	36,6	23,3	22,2	10	15,5	2,2	5,6
Shale Gas	108,8	17,8	99,9	65,5	59,9	72,2	7,8	14,4	8,9	1,1	0
Coalbed Methane	85,4	112	34,4	13,3	1,1	0	1,1	4,4	0	3,3	1,1

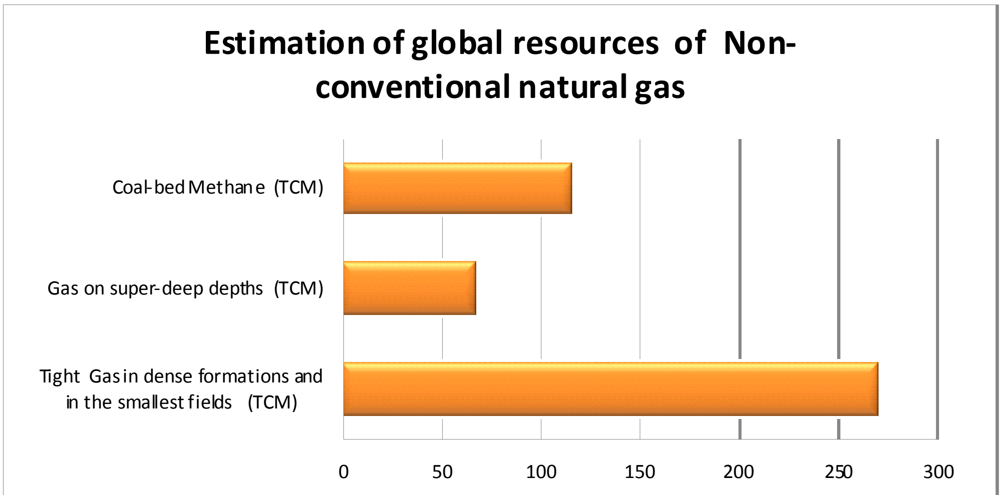
Figure 1-5: Estimation trend of global unconventional gas resources.

The low-permeable gas reservoirs in sedimentary basins of Russia are valued by experts from 80 up to 100 TCM (minimum estimation). The summary resources of gas in the smallest fields of basins of Russia are estimated as 12-15 TCM. The potential resources of methane up to depth 1800 m over all coal-bearing basins are estimated as 25-27 TCM. Thus, the original total gas potential of Russian Federation is valued approximately as 290-320 TCM (without gas-hydrates, gas dissolved in water and oil).

In particular, resources of gas in low-permeable natural reservoirs (dense formations) by the beginning of the 90s were valued as 175 TCM By V.I. Yermakov and V.A. Skorobogatov as per state of materials in 1997 all UCRG of the World (except for gas-hydrates, gas dissolved in oil and water) were valued as 300-320 TCM, and the above-indicated authors considered this estimation as a minimal one.

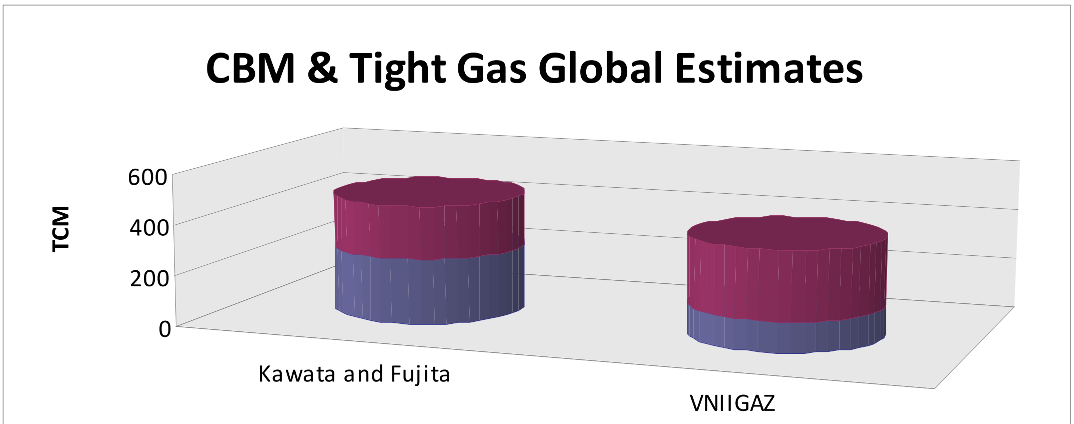
Table 2- Estimation of global resources of Non-conventional natural gas (VNIIGAZ, 2002)

	Estimation of global resources of Non-conventional natural gas
Tight Gas in dense formations (TCM) and in the smallest fields	**270**
Gas on super-deep depths (TCM)	**67**
Coal-bed Methane (TCM)	**115**
Maximum Non-conventional resources (TCM)	**452**



	Tight Gas in dense formations and in the smallest fields (TCM)	Gas on super-deep depths (TCM)	Coal-bed Methane (TCM)
Estimation of global resources of Non-conventional natural gas	270	67	115

Figure 1-6: Estimation of Global Resources of Non-Conventional Natural Gas



	Kawata and Fujita	VNIIGAZ
Tight-Sand Gas	209,7	270
Coalbed Methane	256,3	115

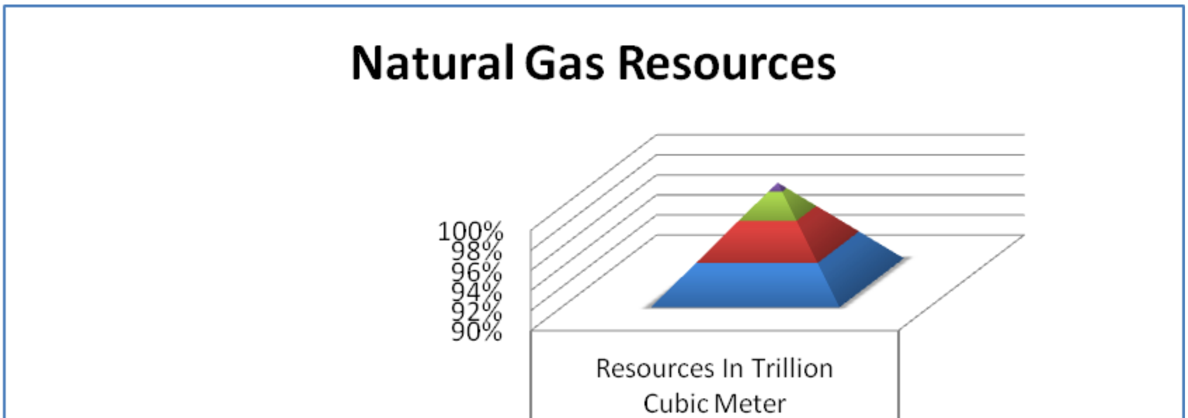
Figure 1-7: Different global sources estimates

1.1.2.3 IFP Estimates

Estimation of Global unconventional gas resources by IFP 2002 it estimates of unconventional gas resources are around 585 TCM and might be ultimately recovered from coal bed methane, tight formation gas, geo-pressured gas, gas from fractured shales and ultra-deep gas. Gas hydrates represent a further resource, which, for some authors, might be equivalent to hundred times present proven reserves.

Gas hydrates—Naturally occurring hydrates can be found in many places, including the continental shelves near Japan, Europe, India, the Gulf of Mexico, the U.S. western seaboard, and Alaska.

Rough estimates of hydrate resources exceed 16 thousand TCM or almost 30 times the conventional gas resource. Under the ocean, hydrate estimates range from 8,5 to 15,5 thousand TCM, and beneath permafrost, the hydrate resource estimates range from 0,14 to 0,34 thousand TCM.



	Resources In Trillion Cubic Meter
Proven Reserves	127,8
Conventional resources	405
Unconventional resources	585
Speculative resources (hydrates)	16200

Figure 1-8: Source IFP 2002 Natural Gas Fundamentals

1.2 UNCONVENTIONAL GAS CLASSIFICATION

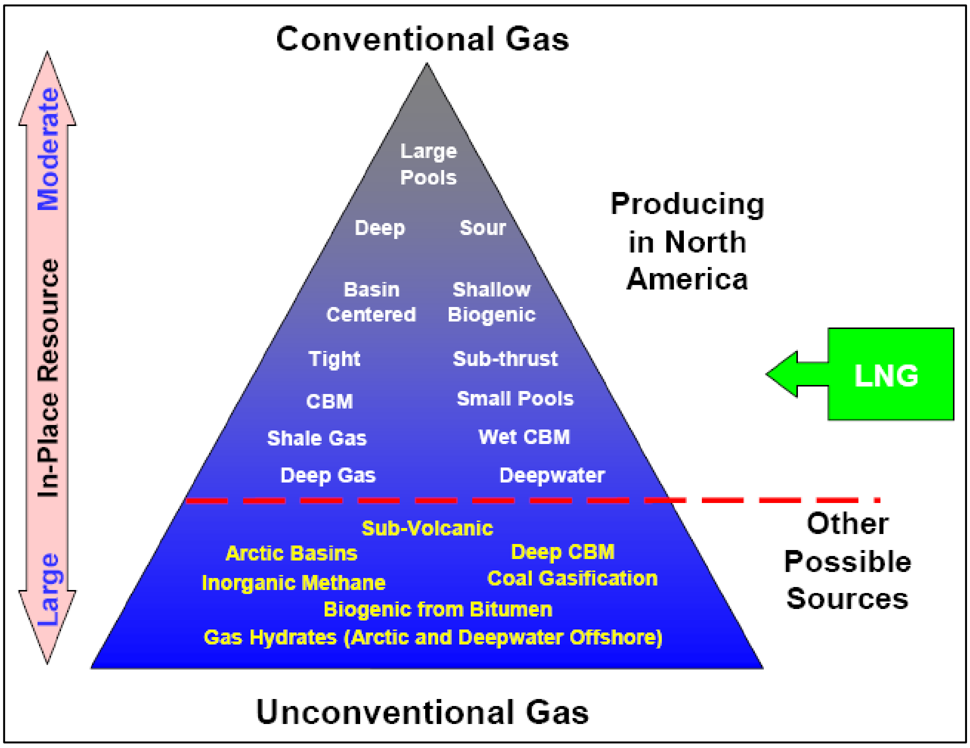


Figure 1-9: Gas Resource Triangle & Remaining Potential
(Source Ziff Energy Group, 2008 report)

Large continuous gas accumulations are sometimes present in low permeability (tight) sandstones, siltstones, shales, sandy carbonates, limestones, dolomites, and chalk. Such gas deposits are commonly classified as unconventional because their reservoir characteristics differ from conventional reservoirs and they require stimulation to be produced economically.

Unconventional natural gas: term commonly used to refer to ***low-permeability*** reservoirs that produce mainly natural gas with little or no associated hydrocarbon liquids.
<u>Really unconventional gas sources</u>
(non-free gas content more than 5% of total gas content in a reservoir)
<u>Pseudo-unconventional gas sources</u>
(non-free gas content less than 5% of total gas content in a reservoir)

- *With reference to the different classifications adopted and/or suggested by gas community, we recommend to set a dedicated workgroup initiated by IGU where WPC, AAPG, SPE and other institutions will be associated to make a proposal for a consensual classification similar to what has been done for hydrocarbon reserves.*

1.2.1 Tight Gas Reservoirs

Gas reservoirs with permeability less than 0.1mD are considered “tight gas” reservoirs [3].

In the petroleum industry, tight gas refers to natural gas that is in underground reservoirs with low porosity and low permeability. In other words, the underground rock layers that hold the gas are very dense, and so the gas does not flow easily toward wells drilled to recover it.

The tight gas is contained in lenticular or blanket reservoirs that are relatively impermeable and can occur downdip from water-saturated rocks and cut across lithological boundaries. They often contain a large amount of in-place gas, but exhibit low recovery rates. Gas can be economically recovered from the better quality continuous tight reservoirs by creating downhole fractures with explosives or hydraulic pumping. The nearly vertical fractures provide a pressure sink and channel for the gas, creating a larger collecting area so that the gas recovery is at a faster rate. Sometimes massive hydraulic fracturing is required, using a 2 thousand cubic meter of gelled fluid and a half million kilogram of sand to keep the fractures open after the fluid has been drained away.

Tight gas present unique problems to reservoir engineers when applying the Material Balance Equation (MBE) to predict the gas-in-place and recovery performance. The use of the conventional material balance in terms of Reservoir pressure and gas deviation factor Z (p/Z plot) is commonly used as a powerful tool for evaluating the performance of gas reservoirs. For a volumetric gas reservoir, the MBE is expressed in different forms that will produce a linear relationship between p/Z and the cumulative gas production Gp.

Unfortunately, the concept of the straight-line p/Z plot as described by the conventional MBE fails to produce this linear behaviour when applied to tight gas reservoirs that had not established a constant drainage area. The early, rapid pressure decline is seen in tight gas reservoirs and is an indication that the use of p/Z plot analysis may be inappropriate.
The main problem with tight gas reservoirs is the difficulty of accurately estimating the average reservoir pressure required for p/Z plots as a function of cumulative Gas production G_P or time.

In tight gas reservoirs, excessive shut-in times of months or years may be required to obtain accurate estimates of average reservoir pressure as shown in Figures 1-10 and 1-11 (Advanced Reservoir Engineering by A. Tarek and D. McKinney).

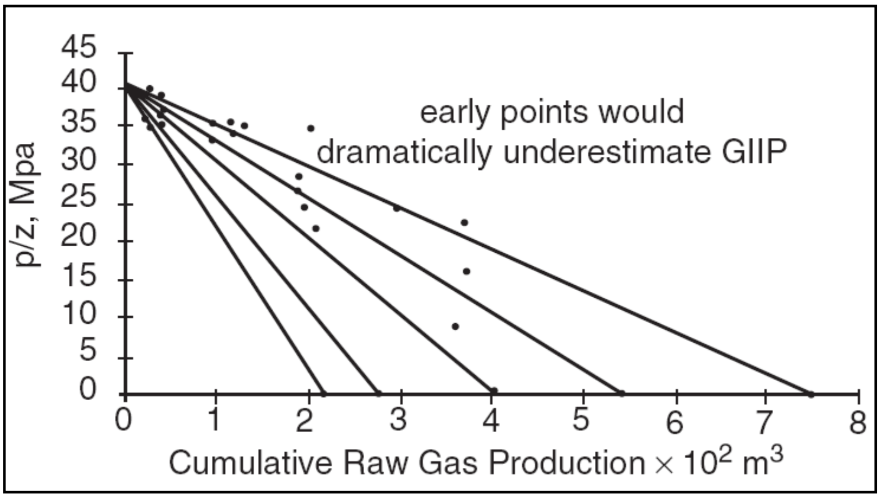


Figure 1-10: Real-life example of p/Z plot from Data in the Waterton Gas Field.
It is clearly apparent that the use of early points would dramatically underestimate GIIP, as shown for the Waterton Gas Field example, with an apparent GIIP of 7.5 BCM
It reveals that the reservoir pressure declines very rapidly as the area surrounding the well cannot be recharged as fast as it is depleted by the well.

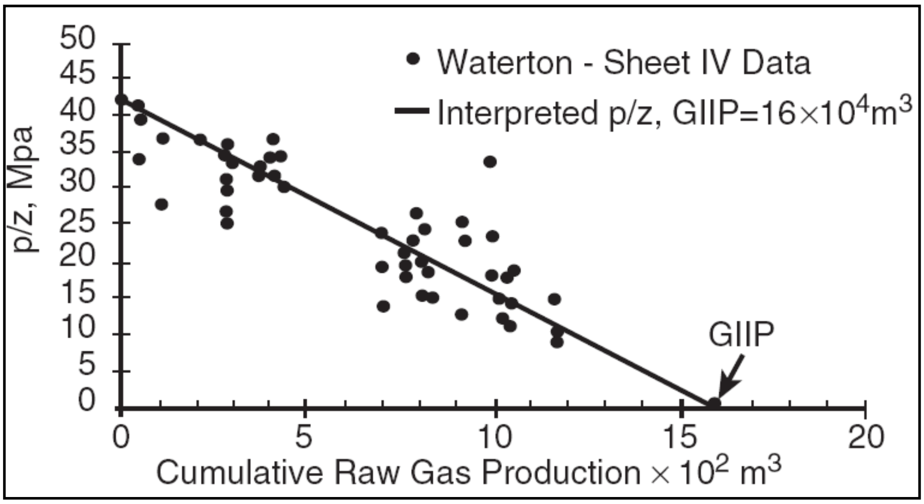


Figure 1-11: Real-life example of p/Z plot from Data in the Waterton Gas Field.
Late-time production and pressure data shows a nearly double GIIP of 16.5 BCM

1.2.2 Coalbed Methane (CBM)

The term “coal” refers to sedimentary rocks that contain more than 50% by weight and more than 70% by volume of organic materials consisting mainly of carbon, hydrogen, and oxygen in addition to inherent moisture [6]. Coals generate an extensive suite of hydrocarbons and non-hydrocarbon components. Although the term “methane” is used frequently in the industry, in reality the produced gas is typically a mixture of C_1, C_2, traces of C_3, and heavier N_2 and CO_2.

Methane, as one such hydrocarbon constituent of coal, is of special interest for two reasons:
(1) Methane is usually present in high concentration in coal, depending on composition, temperature, pressure, and other factors.
(2) Of the many molecular species trapped within coal, methane can be easily liberated by simply reducing the pressure in the bed. Other hydrocarbon components are tightly held and generally can be liberated only through different extraction methods. Coal seam gas well productivity depends mostly on reservoir pressure and water saturation.

Multiwell patterns are necessary to dewater the coal and to establish a favourable pressure gradient. Since the gas is adsorbed on the surface of the coal and trapped by reservoir pressure, initially there is low gas production and high water production.

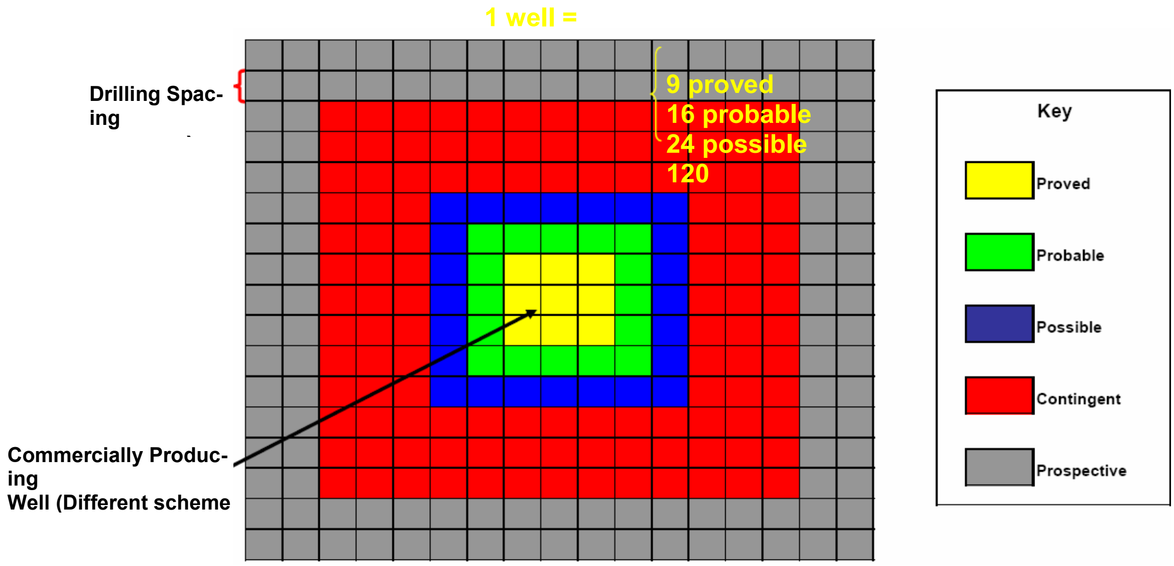


Figure 1-12: Estimation and Classification of CBM Reserves and Resources (by SPEE, 2007)

Most of the key data needed for estimating gas-in-place and performing other performance calculations is obtained mainly from the following core tests:
● Canister desorption tests: These tests are conducted on coal samples to determine:
– the total adsorbed Gas Content (GC) of the coal sample as measured in scf/ton of coal;
– desorption time t that is defined by the time required to disrobe Levine 63% of the total adsorbed gas.
● Proximate tests: These tests are designed to determine coal composition in terms of:
– percentage of ash;
– fixed carbon;
– moisture content;
– volatile matter.

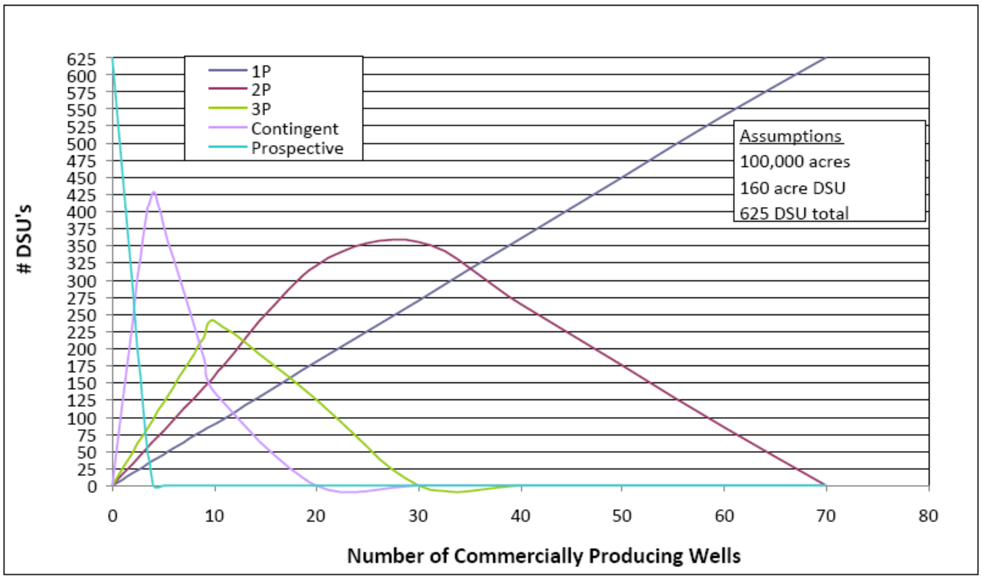


Figure 1-13: Example Application of CBM Reserves Assignment Methodology

Reservoir characteristics of coalbeds are complex because they are naturally fractured reservoirs that are characterized by two distinct porosity systems, i.e. dual-porosity systems.

These are:

(1) Primary porosity system: The matrix primary porosity system in these reservoirs is composed of very fine pores, "micropores," with extremely low permeability.
These micropores contain a large internal surface area on which substantial quantities of gas may be adsorbed. With such low permeability, the primary porosity is both impermeable to gas and inaccessible to water. However, the desorbed gas can flow (transport) through the primary porosity system by the diffusion process. The micropores are essentially responsible for most of the porosity in coal.

(2) Secondary porosity system: The secondary porosity system (macropores) of coal seams consists of the natural fracture network of cracks and fissures inherent in all coals. The macropores, known as cleats, act as a sink to the primary porosity system and provide the permeability for fluid flow. They act as conduits to the production wells as shown in the Figure 1.10 below. The cleats are mainly composed of the following two major components:
(a) The face cleat: The face cleat, as shown conceptually in Figure by Remner et al. (in Advanced Reservoir Engineering by A. Tarek and D. McKinney), is continuous throughout the reservoir and is capable of draining large areas.
(b) The butt cleat: Butt cleats contact a much smaller area of the reservoir and thus are limited in their drainage capacities.

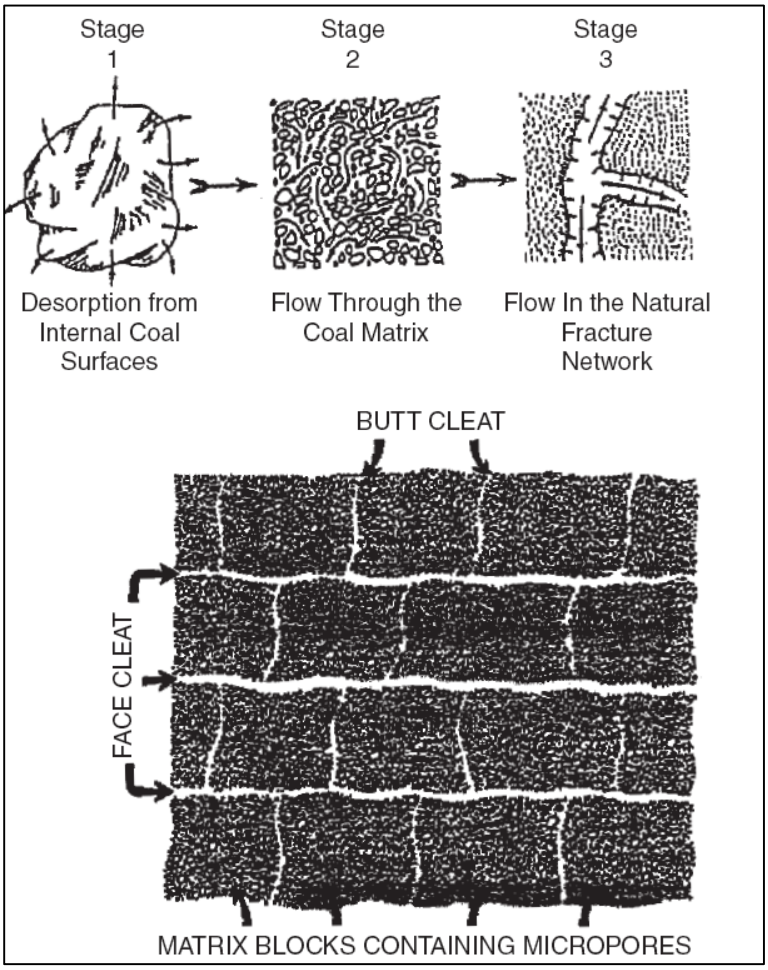


Figure 1-14: Schematic of methane flow dynamics in a coal seam system (After King et al., 1986)

1.2.3 Shale Gas

[2]. Shale gas is natural gas contained within a sequence of predominantly organic-rich, fine-grained rocks and silts dominated by shale.
Gas exploited in this type of deposit is contained in a sequence of fine-grained rock where the Shale predominates.
Natural gas is stocked in the layer in two ways:

1. Adsorbed gas: gas is fixed to the surface of ions or molecules. The portion of adsorbed gas varies between 20% and 85%.
2. Free gas: gas is contained in the matrix porosity (interbedded layers of silt or sandstone in the shale) and in the natural network of fractures.

Contrary to conventional deposits, Shale gas act as a source that generates natural gas and also as reservoir rock for the stocking of gas. The origin of gas can be biogenic (by actions of bacteria) or thermogenic.

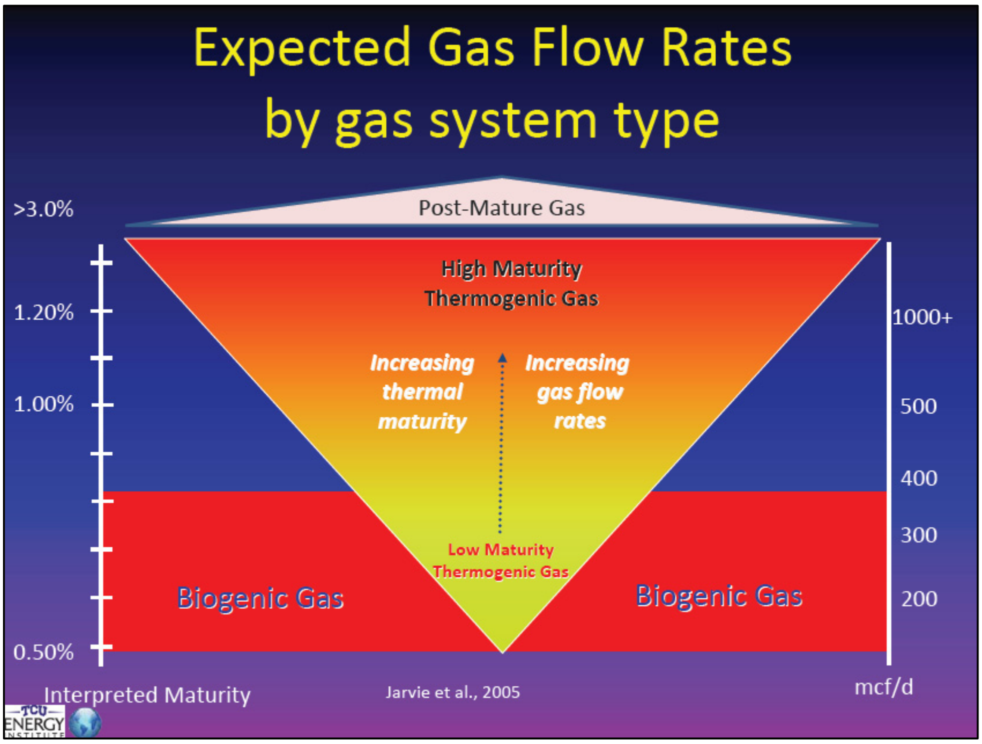


Figure 1-15: Expected Gas Flow Rates by gas system type (Jarvie et al., 2005)

Shale has low matrix permeability, so gas production in commercial quantities requires fractures to provide permeability. Shale gas has been produced for years from shales with natural fractures; the shale gas boom in recent years has been due to modern technology in creating extensive artificial fractures around well bores. Horizontal drilling is often used with shale gas wells.

Shales that host economic quantities of gas have a number of properties in common. They are rich in organic material, and are mature petroleum source rocks in the thermogenic gas window. They are sufficiently brittle and rigid enough to maintain open fractures. In some areas, shale intervals with high natural gamma radiation are the most productive.

Some of the gas produced is held in natural fractures, some in pore spaces, and some is adsorbed onto the organic material [4]. The gas in the fractures is produced immediately; the gas adsorbed onto organic material is released as the formation pressure declines.

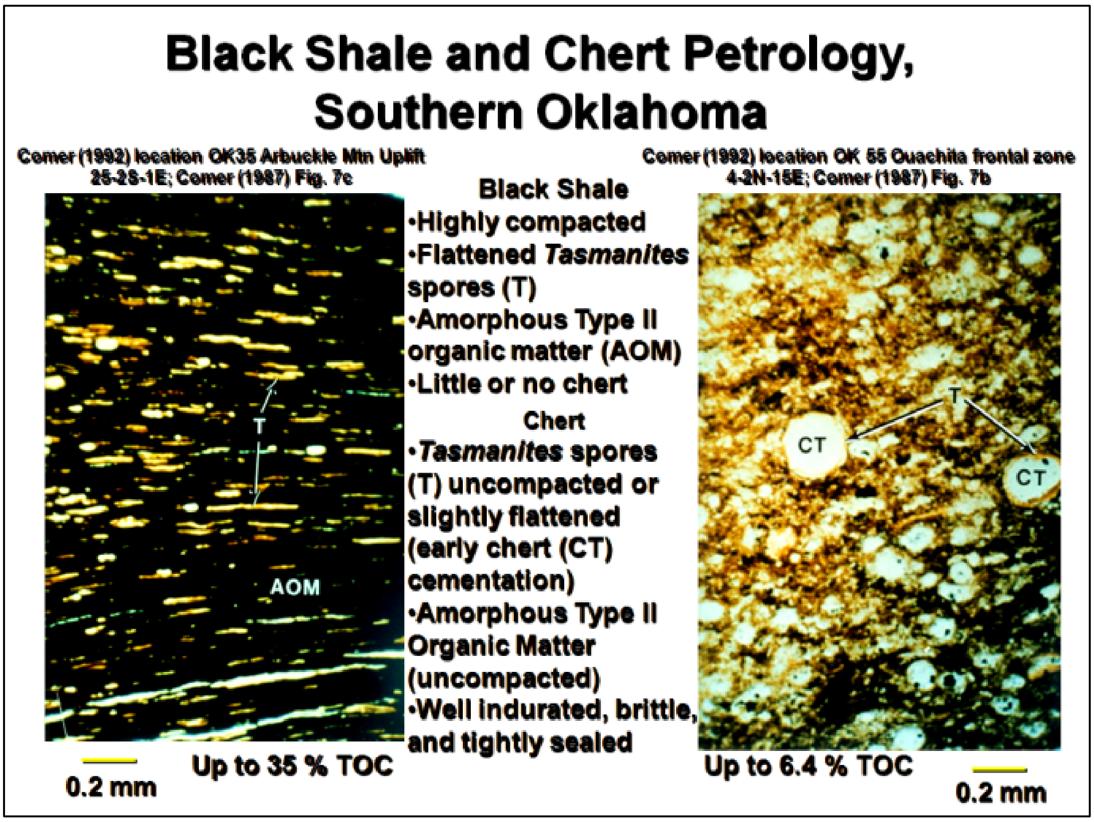


Figure 1-16: Black Shale and Chert Petrology, Southern Oklahoma (J.B. Comer 1992)

1.2.4 Gas Hydrates

Gas hydrates are solid crystalline compounds formed by the physical combination of gas and water under pressure and temperatures considerably above the freezing point of water. In the presence of free water, hydrate will form when the temperature is below a certain degree. Gas hydrate crystals resemble ice or wet snow in appearance but do not have the solid structure of ice. The main framework of the hydrate crystal is formed with water molecules. The gas molecules occupy void spaces (cages) in the water crystal lattice; however, enough cages must be filled with hydrocarbon molecules to stabilize the crystal lattice. When the hydrate "snow" is tossed on the ground, it causes a distinct cracking sound resulting from the escaping of gas molecules as they rupture the crystal lattice of the hydrate molecules.

Two types of hydrate crystal lattices are known, with each containing void spaces of two different sizes:

(1) Structure I of the lattice has voids of the size to accept small molecules such as methane and ethane. These "guest" gas molecules are called "hydrate formers." In general, light components such as C_1, C_2, and CO_2 form structure I hydrates.
(2) Structure II of the lattice has larger voids (i.e., "cages or cavities") that allow the entrapment of the heavier alkanes with medium-sized molecules, such as C_3, $i - C_4$, and $n - C_4$, in addition to methane and ethane, to form structure II hydrates.

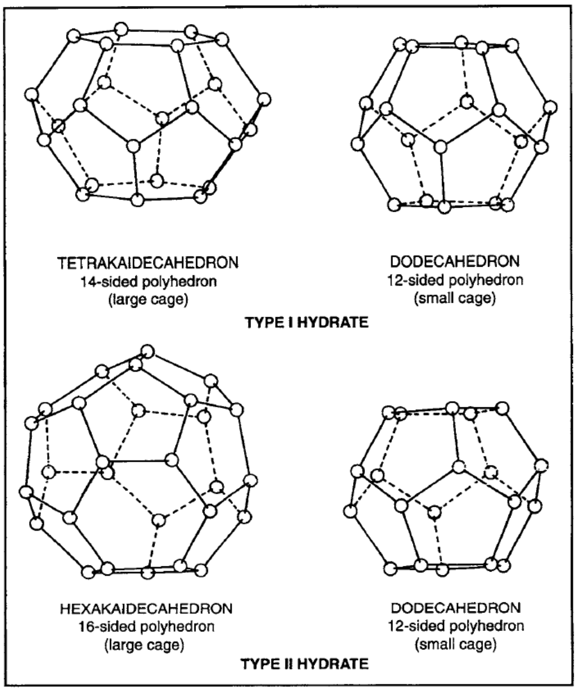


Figure 1-17: The polyhedral cages of Type I and Type II hydrates
(Elsevier Science & Technology Books, John J. Carroll, 2002)

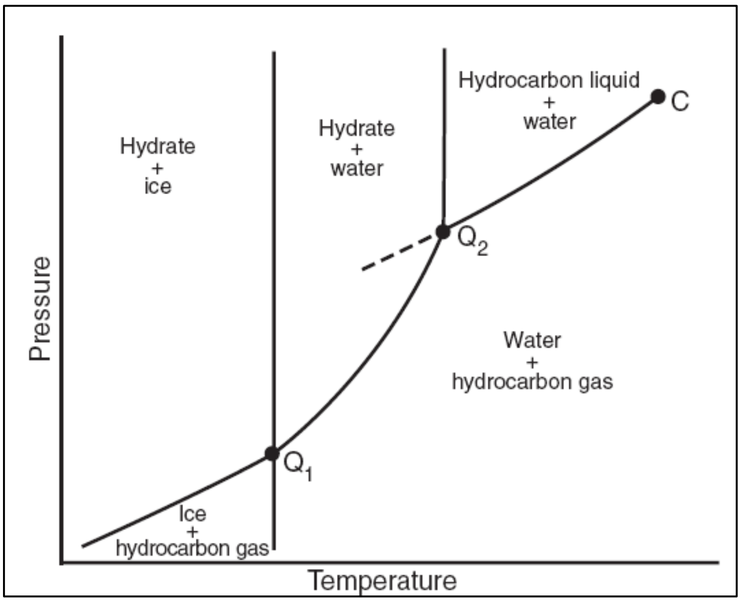


Figure 1-18: Phase diagram for a typical mixture of water and light hydrocarbon *(T.Ahmed & P. D. McKinney, 2005).*

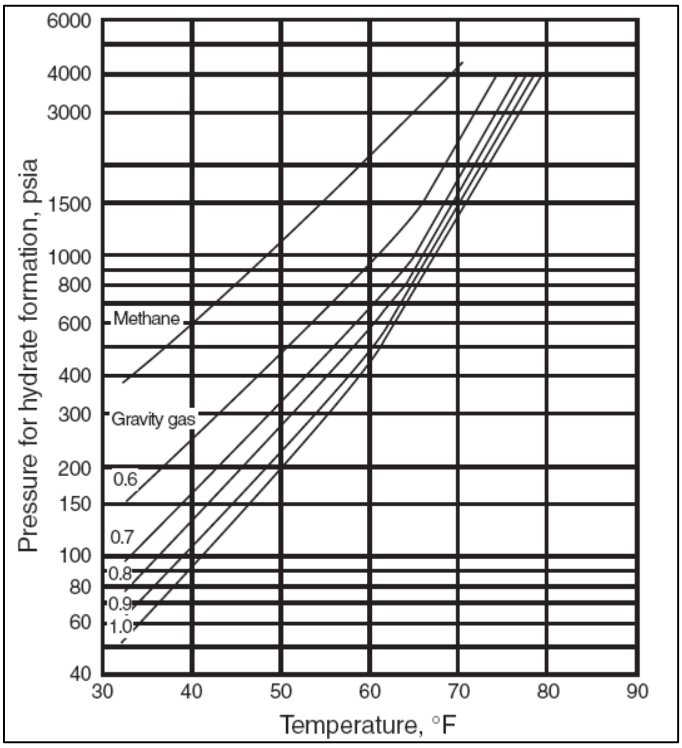


Figure 1-19: Pressure–temperature curves for predicting hydrate
(Courtesy Gas Processors Suppliers Association).

One explanation for hydrate formation is that the entrance of the gaseous molecules into vacant lattice cavities in the liquid water structure causes the water to solidify at temperatures above the freezing point of water.

In general, addition of ethane, propane, and butane raise the hydrate formation temperature for methane. For example, 1% of propane raises the hydrate-forming temperature from 41^o to 49^{o}F at 600 psia. Hydrogen sulfide and carbon dioxide are also relatively significant contributors in causing hydrates.

These solid ice-like mixtures of natural gas and water have been found in formations under deep water along the continental margins of America and beneath the permafrost (i.e., permanently frozen ground) in Arctic basins.

The permafrost occurs where the mean atmospheric temperature is just under 32^{o}F. Muller (1947) suggested that lowering of the earth's temperature took place in early Pleistocene times, "perhaps a million years ago."

If formation natural gases were cooled under pressure in the presence of free water, hydrates would form in the cooling process before ice temperatures were reached. If further lowering of temperature brought the layer into a permafrost condition, then the hydrates would remain as such.

In colder climates (such as Alaska, northern Canada, and Siberia) and beneath the oceans, conditions are appropriate for gas hydrate formation.

The essential condition for gas hydrate stability at a given depth is that the actual earth temperature at that depth is lower than the hydrate-forming temperature corresponding to the pressure and gas composition conditions.

The thickness of a potential hydrate zone can be an important variable in drilling operations where drilling through hydrates requires special precautions. It can also be of significance in determining regions where hydrate occurrences might be sufficiently thick to justify gas recovery.

The existence of a gas hydrate stability condition, however, does not ensure that hydrates exist in that *region*, but only that they can exist. In addition, if gas and water coexist within the hydrate stability zone, then they must exist in gas hydrate form.

The discovery of large gas hydrate accumulations in terrestrial permafrost regions of the Arctic and beneath the sea along the outer continental margins of the world's oceans has heightened interest in gas hydrates as a possible energy resource.

However, significant to potentially insurmountable technical issues must be resolved before gas hydrates can be considered a viable option for affordable supplies of natural gas.

Disagreements over fundamental issues such as the volume of gas stored within delineated gas hydrate accumulations and the concentration of gas hydrates within hydrate-bearing strata have demonstrated that we know little about gas hydrates. Recently, however, several countries, including Japan, India, and the United States, have launched ambitious national projects to further examine the resource potential of gas hydrates. These projects may help answer key questions dealing with the properties of gas hydrate reservoirs, the design of production systems, and, most important, the costs and economics of gas hydrate production.

Current estimates of the amount of gas in the world's marine and permafrost gas hydrate accumulations are in rough accord at about 20,000 TCM.

1.2.4.1 Arctic Hydrates

The combined information from Arctic gas hydrate studies shows that, in permafrost regions, gas hydrates may exist at subsurface depths ranging from about 230 to 2000 m. Metastable (relic) hydrates can be found within ice-bearing permafrost from first meters of depth.

1.2.4.2 Marine Hydrates

The presence of gas hydrates in offshore continental margins has been inferred mainly from anomalous seismic reflectors, known as bottom-simulating reflectors that have been mapped at depths below the sea floor ranging from about 100 to 1100 m.

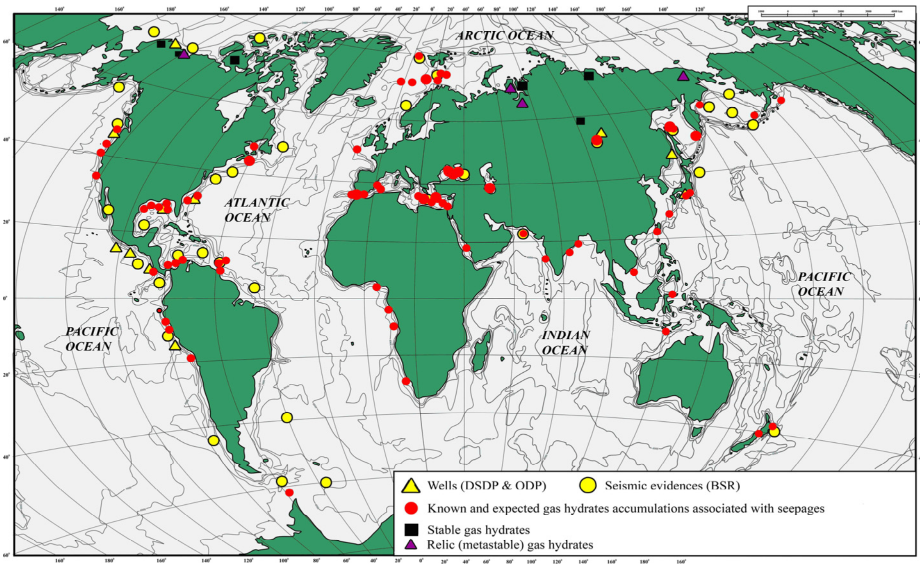


Figure 1-20: Known and inferred hydrate occurrences (Gazprom VNIIGAZ, 2008)

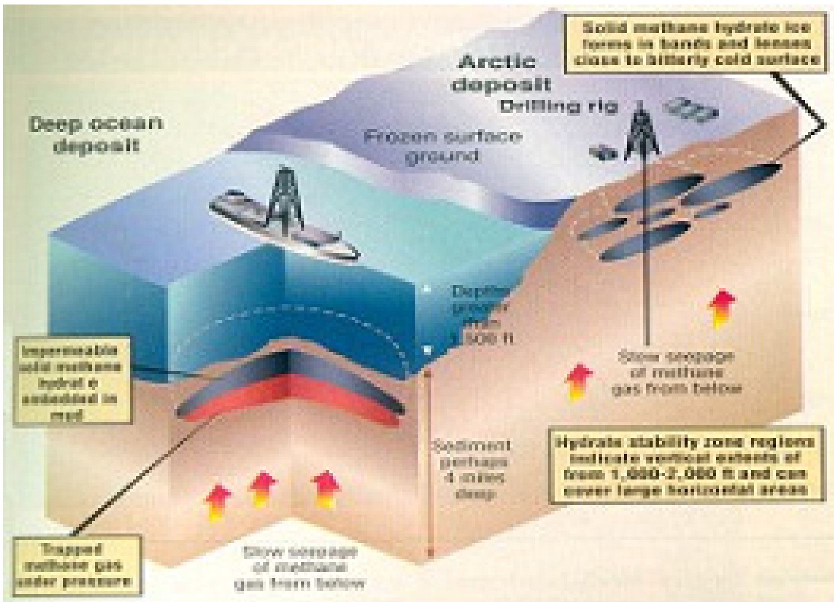


Figure 1-21: Type of gas hydrate deposit

Figure 1-22: Gas hydrate sample from seabed

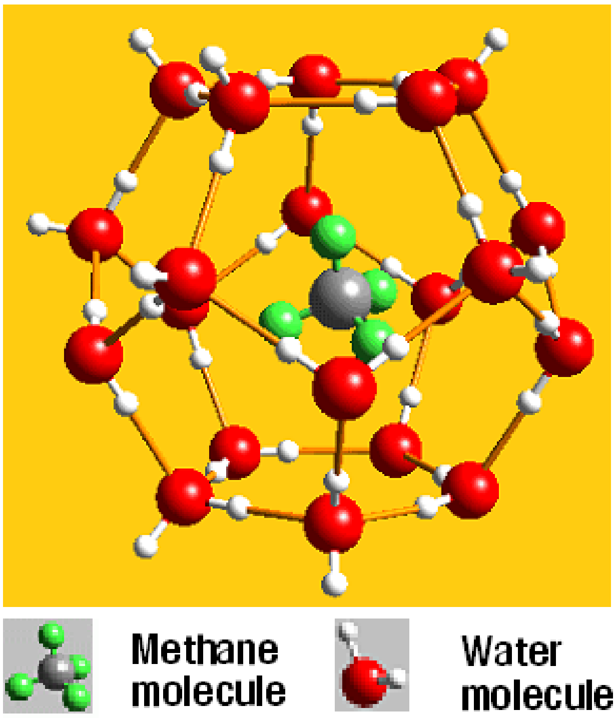


Figure 1-23: Gas hydrate Structure

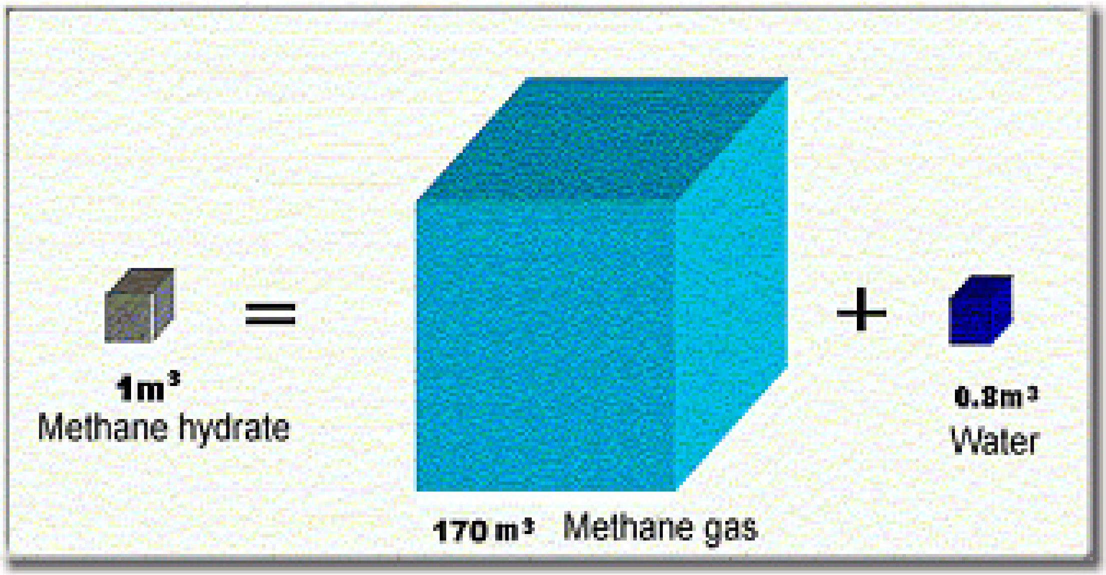


Figure 1-24: Methane hydrate volume ratio

1.3 UNCONVENTIONAL RESERVOIR CHARACTERIZATION

Successful reservoir characterization results in guidelines for reducing the risk in:

- Setting new wells,
- Applying optimal completion and stimulation technologies,
- Recovering bypassed gas because of compartmentalization and prior production.

To reduce time and cost associated with characterizing unconventional gas-producing reservoirs, it helps to identify key parameters that most dramatically affect production and streamline the reservoir characterization workflow to focus on these parameters.

1.3.1 Tight gas sand

The key parameters controlling production are:

• Stratigraphy and Structure;
• Porosity and Permeability;
• Fracturing parameters: length, spacing, connectivity and anisotropy; and
• Mechanical properties.
In the Rockies, channels have not only been shown to be associated with sweet spots in tight sands, but may be linked to elevated natural fracture distribution.

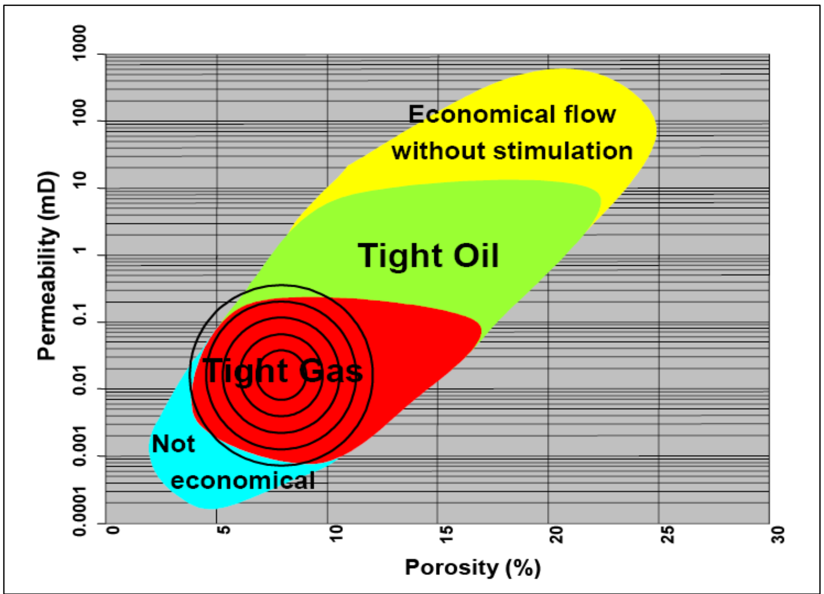


Figure 1-25: Reservoir Characterization of Tight Gas
(The Know-How Series, TOTAL, 2006)

1.3.2 Coalbed methane

For most coalbed methane, regardless of geographic area, the key parameters are:

- Drainage area, thickness of producing zone(s);
- Coal depositional environment and rank, which may correspond to structural trends;
- Cleat porosity;
- Radial permeability;
- Stress state, which coupled with cleat orientation, may indicate a preferred direction for permeability or may influence fracture treatment design;
- Sorption characteristics; (i.e process of taking up and holding by absorption or adsorption). Coal's unique gas-storage mechanism is known as the "sorption" process, whereby gas molecules are packed tightly within the coal-matrix molecular pore system.
- Gas properties; and
- Hydrodynamics.

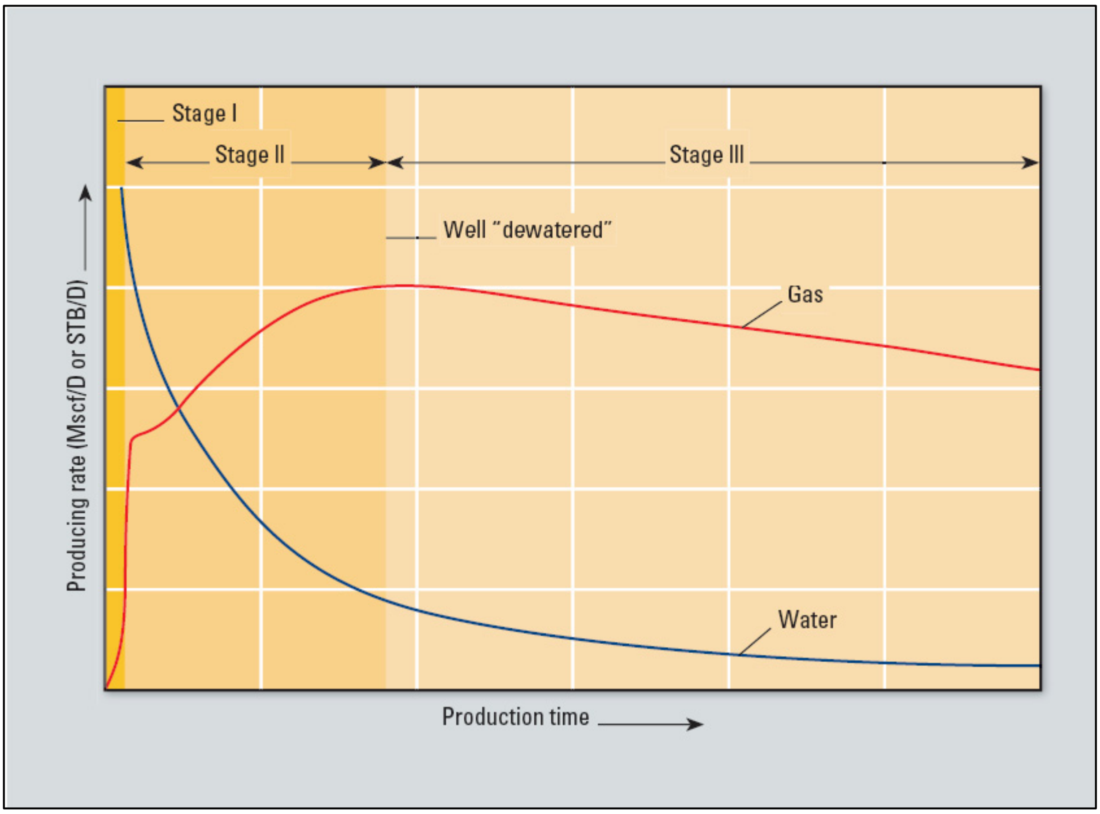


Figure 1-26: Coalbed production characteristics.
(During Stage I, production is dominated by water. Gas production increases during Stage II, as water in the coal is produced and the relative permeability to gas increases. During Stage III, both water and gas production decline.) [5]

1.3.3 Shale Gas

Key parameters affecting production from fractured gas shale include:

- Drainage area size, shape and orientation;
- Fracture vs. matrix porosity;
- Permeability;
- Anisotropy;
- Fracture length, spacing and conductivity;
- Relationship between natural and induced hydraulic fractures; and
- Mechanical properties.

Of these, natural fracture characteristics dominate production control. Since individual fractures may be limited in lateral and vertical extent, multiple fracture sets, forming a three dimensional permeability network, are important for good production
Gas porosity and kerogen content, however, may contribute to productivity.

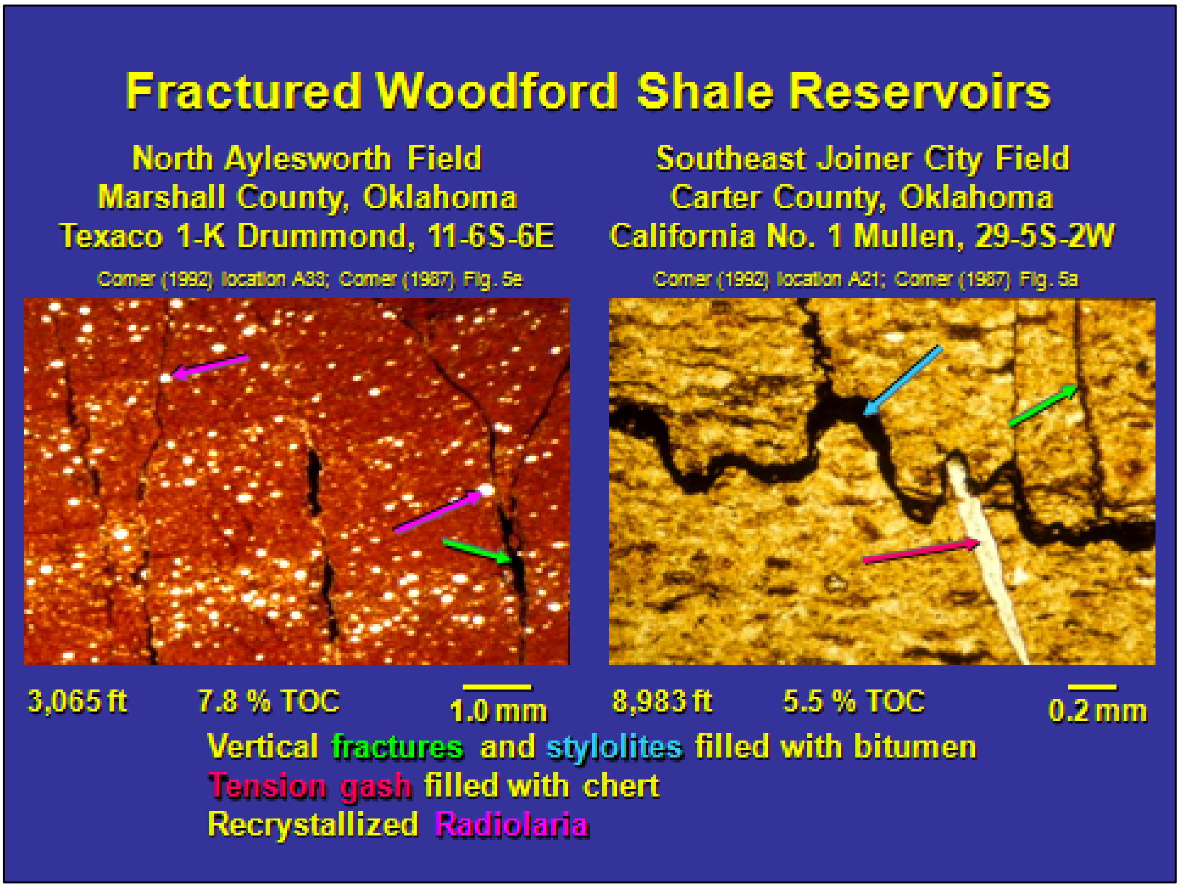


Figure 1-27: Fractured Woodford Shale Reservoirs
(J.B. Comer 1992) [8]

Table 3- Summary of critical data used to appraise coalbed- and shale-gas reservoirs

Analysis	Results
Gas Content	Provides volumes of desorbed gas (from coal samples placed in canisters), residual gas (from crushed coal), and lost gas (calculated). The sum of these is the in-situ gas content of a given coal seam.
Rock-Evaluation Pyrolysis	Assesses the petroleum-generative potential and thermal maturity of organic matter in a sample. Determines the fraction of organic matter already transformed to hydrocarbons and the total amount of hydrocarbons that could be generated by complete thermal conversion.
Total Organic Carbon	Determines the total amount of carbon in the rock including the amount of carbon present in free hydrocarbons and the amount of kerogen.
Gas Composition	Determines the percentage of methane, carbon dioxide, nitrogen, and ethane in the desorbed gas. Used to determine gas purity and to build composite desorption isotherms.
Core Description	Visually captures coal brightness, banding, cleat spacing, mineralogy, coal thickness, and other factors. Provides insights about the composition, permeability, and heterogeneity of a coal seam.
Sorption Isotherm	A relationship, at constant temperature, describing the volume of gas that can be sorbed to a surface as a function of pressure. Describes how much gas a coal seam is capable of storing and how quickly this gas will be liberated.
Proximate Analysis	Provides the percentage of ash, moisture, fixed carbon, and volatile matter. Used to correct gas contents and sorption isotherms to an ash-free basis, correct the isotherms for moisture, and determine the maturity of high-rank coals.
Mineralogical Analyses	Determines bulk mineralogy using petrography and/or X-ray diffraction, and clay mineralogy using X-ray diffraction and/or scanning electron microscopy.
Vitrinite Reflectance	A value indicating the amount of incident light reflected by the vitrinite maceral. This technique is a fast and inexpensive means of determining coal maturity in higher-rank coals.
Calorific Value	The heat produced by combustion of a coal sample. Used to determine coal maturity in lower-rank coals.
Maceral Analysis	Captures the types, abundance, and spatial relationships of various maceral types. These differences can be related to differences in gas-sorption capacity and brittleness, which affect gas content and permeability.
Bulk Density	Relationships between bulk density and other parameters (such as ash content and gas content) can be used to establish a bulk-density cutoff for counting coal and shale thicknesses using a bulk-density log.

Conventional Logs	Self-potential, gamma ray, shallow and deep resistivity, microlog, caliper, density, neutron, and sonic logs. Used to identify coals and shales, and to determine porosity and saturation values in shales.
Special Logs	Image logs to resolve fractures and wireline spectrometry logs to determine in-situ gas content.
Pressure-Transient Tests	Pressure buildup or injection fall-off tests to determine reservoir pressure, permeability, skin factor, and to detect fractured-reservoir behavior.
3D Seismic	Used to determine fault locations, reservoir depths, variations in thickness and lateral continuity, and coal/shale properties.

(JPT • FEBRUARY 2008)

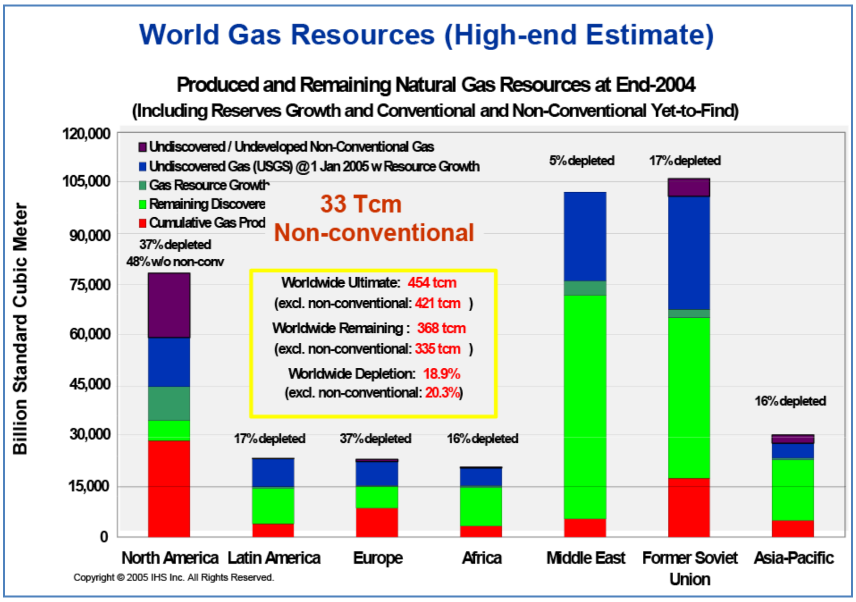
1.4 PLAYS DISTRIBUTION

Unconventional natural gas resources are widespread. They are associated with most "common" petroleum systems across the globe except the particular cases of CBM's and Methane hydrates.

1.4.1 Therefore, the key issue is not discovering the resources, as is the case with conventional hydrocarbons. The central issue is identifying areas where the commercial drivers enable their economic development. New Plays

To date, the majority of unconventional gas E&P activity has been focused on North America, where declining indigenous conventional production has driven up gas prices.
Europe, India and China will be the focus of the next unconventional wave, as current and anticipated market conditions suggest commodity prices will be sufficient to sustain commercial unconventional development.

At this stage, we need to highlight the exploration activity made by some companies for assessing such resources as MOL through its cooperation with ExxonMobil, PetroChina and CUCBM in partnership with CDX, Far East Energy Corp and ConocoPhilips.



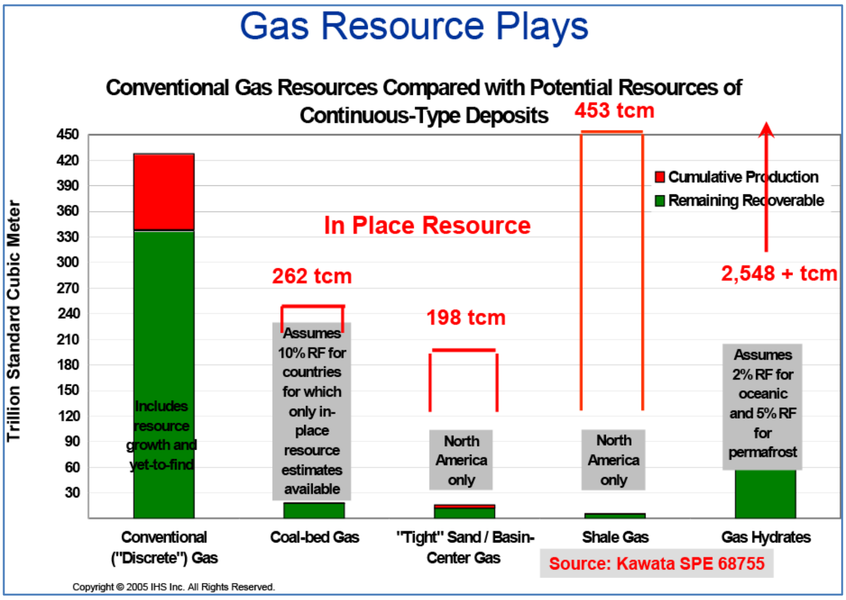


Figure 1-28: World Gas Resources and Gas Resources Plays
(Source IHS, EAGE, Vienna 2006)

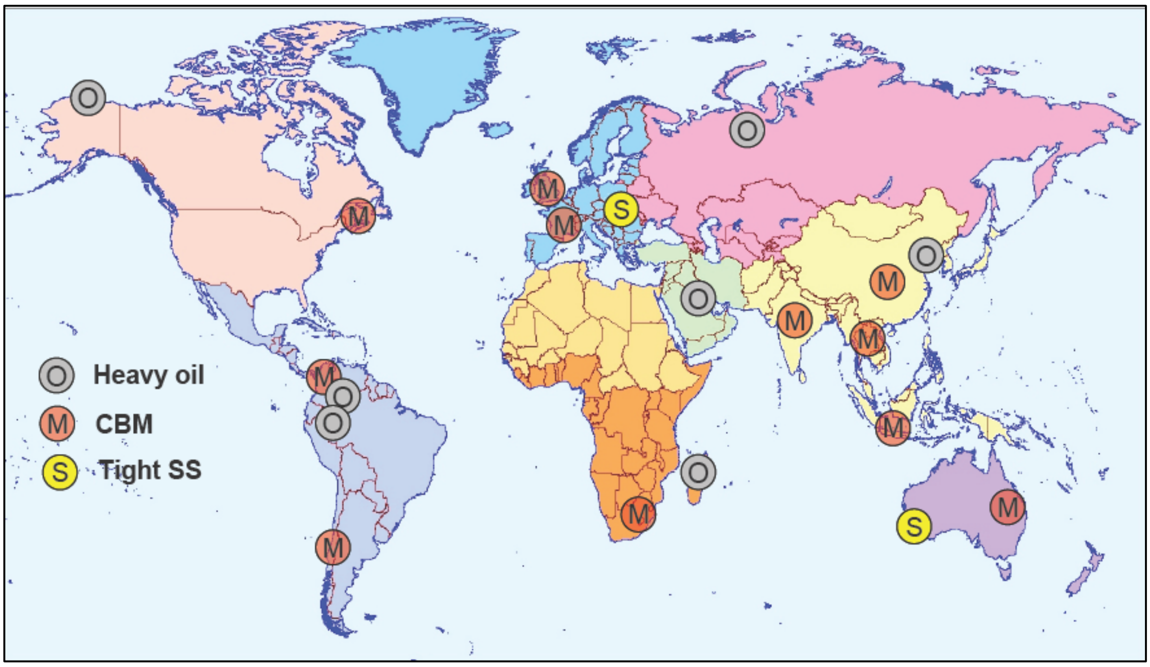


Figure 1-29: Emerging Unconventional Plays
(IHS, NAPE International Forum February 6, 2008)

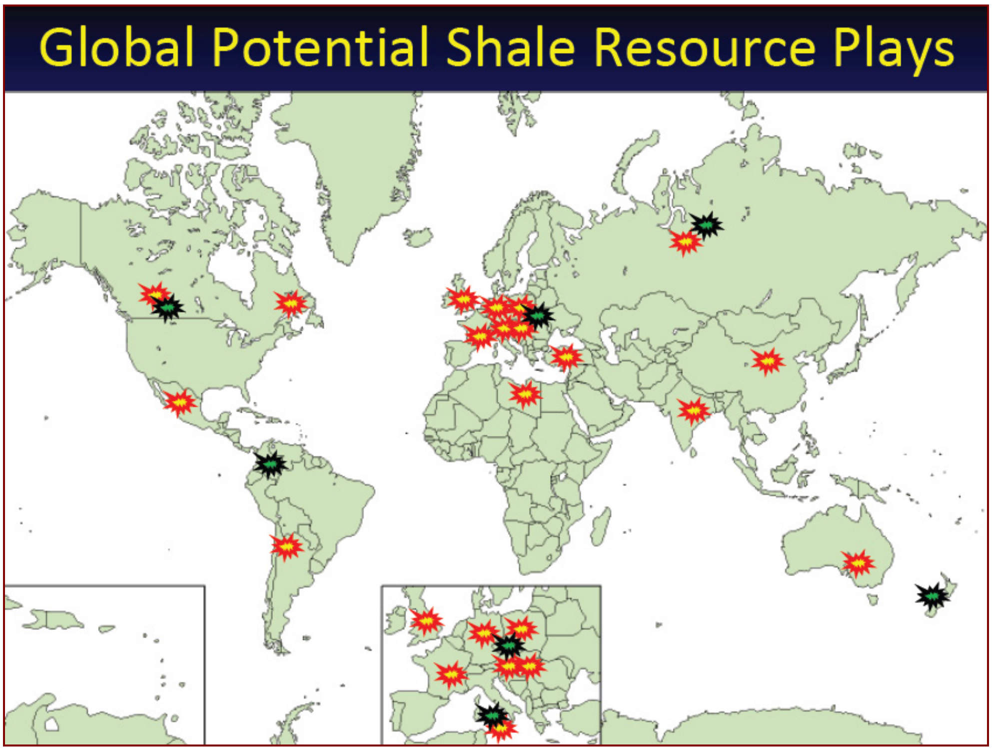


Figure 1-30: Global Potential Shale Resource Plays
(Dan Jarvie, NAPE Forum August 26, 2008)

1.4.1.1 Unconventional gas systems in China

The main targets for unconventional gas exploration in China, source-contacting gas, coal-bed methane and shale gas have great resource potential and preferable development values. Source-contacting gas with saturated gas in the bottom of tight reservoirs is one of the most favorable types for unconventional gas exploration in the Middle and Western basins, such as Ordos basin, Sichuan basin, Turpan-Hami basin, Tarim basin, Junggar basin etc [4].

Coal-bed methane is the representative of absorption gas accumulation, which is significant for natural gas exploration in medium and small sized basins such as Qinshui basin, Chuxiong basin, Southern North basin etc, and the margins of big sized basins, for example the circumference of Bohai Bay basin.

Shale gas with simultaneously free gas and absorption gas exists universally in China, not only in the basins of Northern Chian, for example Junggar basin, Turpan-Hami basin, Ordos basin, Bohai Bay basin, Songliao basin, etc, but also in the remnant sediment areas with different denudation in Southern China, including Sichuan basin. Shale gas may be the important breakthrough for the hydrocarbon exploration in the near future for the Paleozoic sediment areas in Southern China where hydrocarbon resources are expected but where little discoveries have been made so far.

1.4.1.2 Tight gas reservoirs, offshore southeast Korea

The tight gas reservoirs are identified offshore southeast of the Korean Peninsula [11].

The continental shelf off the southeastern part of the Korean Peninsula has largely bipartite prospect groups called Dolgorae (means dolphin) and Gorae (means whale). The Dolgorae prospects are present in the structurally deformed zone consisting of complex thrust faults and associated folds.

The Dolgorae reservoirs are characterized by low permeability of about 0.2 mD, Gases were detected even when Dolgorae wells were drilled, but were not detected during production tests. Consequently, most of the Dolgorae reservoirs can be classified as tight gas reservoir.

In addition, low-permeable reservoir rocks also occur at a depth of below 3,500 m in the Gorae prospects, which are characterized by abnormal overpressure. The overpressure is indicated by a drastic increase in mud weight at about 3,500 m depth. The reservoir rocks have porosity in the range 5-10% and an extremely low permeability of 0.2 mD.

1.4.1.3 Tight gas potential in Indian sedimentary basins

The noticeable perspectives appear to be the Bhuvanagiri Formation (permeability of 0.033mD) and Mandapeta sandstone (permeability of 0.01mD) in the Cauvery and Krishna-Godavari basins both of which are established producers [11].

The Albian Andimadam sandstone (Cauvery Basin) is texturally immature and a low porosity, permeability reservoir. The Mukta and Bassen formations (Mumbai offshore basin) in the wedge out area appear to be tight. The Wadu pay unit embedded in Mandhali member (lower Eocene), Cambay Basin is also inferred to be tight (Kanungo et al, 2003). Similarly significant gas reserves are likely to be locked up in the tight reservoirs in the Vindhyan Basin. The Jabera well flowed gas at 2000 m^3/d, but reservoirs were found tight because of silica fillings and quartz overgrowth. Many other instances of tight reservoirs in other basins have also been identified holding considerable gas resources.

1.4.1.4 Untapped coalbed methane resources in the Philippines

In the Philippines, coalbed methane resources are mainly in the Miocene coal-bearing strata in the central and southern coalfields. There, coalbed methane is present in coals of semi-anthracite, bituminous, and subbituminous rank [11].

The coal-bearing strata are 450 to 2,000 m thick, with individual coal beds as much as 25 m thick incorporated in stacks of coal zones 150-400 m thick and containing as much as 70 m of total coal thickness.

Measurements of sorbed gas storage capacity at constant temperature by high-pressure methane adsorption isotherm analysis for the semi-anthracite coal in the Zamboanga-Sibugay Basin are as much as 23 cubic centimeters per gram (cc/g); bituminous coal isotherms in the Visayan Basin range from 16-21 cc/g; subbituminous coal isotherms in the Mindoro Basin range from 3-7 cc/g; and lignite coal isotherms in the Visayan Basin are about 7 cc/g. Comparison of adsorption isotherms of the Philippine coals to U.S. coals indicates better ideal gas storage capacity.

Desorbed total gas content of Philippine coals ranges from as much as 1.4 cc/g for sub bituminous coal to as much as 4.4 cc/g for semi-anthracite and bituminous coals. An evaluation of the adsorption isotherms and desorbed gas content of subbituminous coal at the same depths and apparent rank to those in the Powder River Basin (PRB), Wyoming and Montana, indicates better gas storage capacity and gas content for the Philippine coals.

1.4.1.5 Gas saturation: Controls and uncertainty in biogenically-derived coalbed methane, examples from New Zealand coal fields

In New Zealand, the Greymouth, Ohai and Huntly coalfields were investigated and all found to be biogenic to mixed biogenic/thermogenic in origin. There was also a wide variance in the degree of gas saturation within and between deposits. The Ohai coalfield has the highest $\delta^{13}C$ isotopes values but is intermediate in rank between the Greymouth and Huntly coals. It is postulated that its relatively high gas saturations (>75%) are the result of gas migration up-dip from more thermally mature coal beds. It should be noted, however, that potentially large uncertainties can exist around gas saturation values [11].

1.4.1.6 Coalbed methane potential of Paraná Basin coals, Brazil

In Brazil the principal coal resources occur in the southern part of the Paraná Basin associated with the Permian age Rio Bonito Formation. Earlier studies identified the Santa Terezinha coalfield, Rio Grande do Sul (RS) as prime candidate for coalbed exploration in Brazil based on coal distribution (coal thickness, lateral continuities of the coal beds), size and depth of reservoir (coal) beds and coal rank [11].

The coals are in general mineral-rich (ash yields range from 28.4 to 92.7 wt. %) and are of high volatile bituminous rank, except where in contact with diabase (semi-anthracite).

1.4.2 Methane Hydrates Plays

Worldwide, only a few dozen boreholes have been drilled to assess marine and Arctic hydrate resources, but still only one hydrate accumulation is explored according to industry requirements Mallik accumulation in MacKenzie Delta in the Northwest Territories of Canada (figure 1.32). It is located in Tertiary under permafrost deposits. Sediment granular composition: sands and gravels (high permeability of rock matrix if no hydrates). Other known worldwide hydrate accumulations marine as well as Arctic were encountered in sediments of different composition and geologic age. The only requirements were: thermodynamic conditions favorable for hydrate formation, water and gas availability and contact and enough permeability.

Figure 1-31: Hydrate-containing drill cores from Mallik gas hydrate deposit
(Uchida T. et. al., 1999)

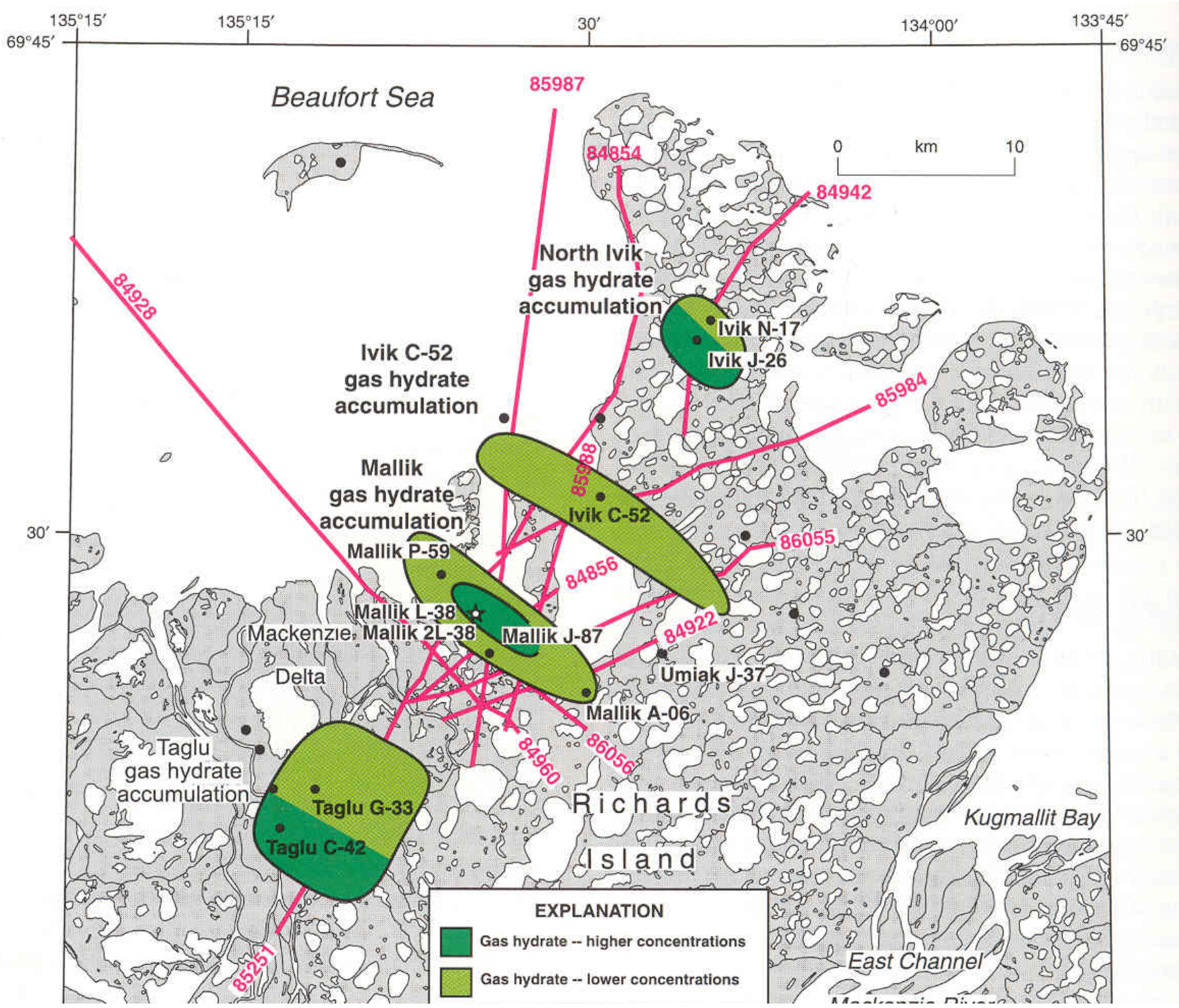


Figure 1-32: Map showing explores and inferred gas hydrate accumulations in Mackenzie Delta
(Collett T.S. and oth., 1999)

Table 4- Estimation of natural gas resources in the four hydrate accumulations in Mackenzie Delta (north Canada) (Collett T.S. and oth., 1999).

Gas hydrate accumulation	Area of gas hydrate accumulation (km^2)	Volume of gas within hydrate per square km ($x\ 10^6\ m^3$)	Total volume of gas within the hydrates of each gas hydrate accumulation ($x\ 10^6\ m^3$)
Mallik	10.27	4835	49 656
	41.08	1469	60 347
			Total 110 003
Ivik C-52	46.61	921	42 928
North Ivik	15.01	1187	17 817
	9.48	531	5034
			Total 22 851
Taglu	26.07	351	9151
	38.71	58	2245
			Total 11 396

According to the exploration of gas hydrate accumulations made in Canada, natural gas hydrate plays have some peculiarities making them attractive for future development comparing with other unconventional gas plays:

1. Shallow depth (first hundreds meter below sediment surface)
2. High specific density of gas resources per one well (see Table)
3. Opportunity to hold up relatively high pressure of gas flow if needed (thermal stimulation).

1.4.3 Gas Hydrate activities in each country

[14]. [15]. [16]. [17]

1.4.3.1 United States

The Gas Hydrate Research and Development Act of 2000 have been operated under the auspices of the U.S. Department of Energy (DOE). A Congressionally sponsored review of the research and development activities was undertaken in 2003 by the National Research Council (NRC, 2004) to review the progress made under the act and to provide advice on future research. Slightly over $29 million dollars was expended in funding hydrate research under the act since its inception up to the time of completion of the NRC report.

The United States government is committed to ensuring clean, dependable, and affordable energy for today and into the future. Gas hydrates represent a potentially significant new source of energy that may provide a sound economic and environmental future as conventional resources are depleted. The volume of natural gas trapped in hydrates in the United States (at or beneath the sea-floor, and in permafrost zones in Alaska) is estimated at more than 320,000 trillion cubic feet (TCF). Hydrates are attracting interest because demand is rising for natural gas while reserve replacement from conventional geological formations declines. Annual U.S. gas consumption is expected to reach 30 TCF by 2015, up from about 22 TCF in 2000. So, production of just one % of the estimated hydrate resource would meet U.S. natural gas demand for the next 100 years. The Methane and Hydrate Research and Development Act became law in May 2000, authorizing $50 million in federal funds for research over five years.

The U.S. Department of Energy (USDOE) in partnership with the U.S Geological Survey (USGS), industry, academia, and other government agencies, are working to ensure a long-term supply of natural gas by developing the knowledge and technology base to allow commercial production of methane from domestic hydrate deposits by the year 2015. USGS and USDOE are committed to participating in international research programs to advance the understanding of natural gas hydrates and the development of these resources for future energy demand.

BP Exploration (Alaska) and the DOE also have undertaken a project to characterize, quantify, and determine the commercial viability of gas hydrates and associated free gas resources in the Prudhoe Bay, Kuparuk River and Milne Point field areas in northern Alaska. The University of Alaska in Fairbanks, the University of Arizona in Tucson, and the USGS also are participating in the Alaska BP project. Several Gulf of Mexico programs are currently under way. The most comprehensive study is a Joint Industry Project (JIP) led by ChevronTexaco, designed to further characterize gas hydrates in the Gulf of Mexico. Participants include ConocoPhillips, Total, Schlumberger, Halliburton Energy Services, U.S. Minerals Management Service (MMS), Japan National Oil Corp. and India's Reliance Industries. The primary concern of U.S.-based energy companies at present appears to be seafloor stability aspects of hydrate in near-seafloor sediments in order to mitigate drilling hazards.

1.4.3.2 Japan

Japan, like many other countries with little indigenous energy resources, imported oil and gas accounts for 99% of Japan's total primary oil and gas supply. High import dependency is one reason why the government of Japan has been caring out a very ambitious research program to develop the technology needed to recover gas from oceanic hydrates. gas hydrate bearing formations are estimated in Nankai Trough, Okushiri Ridge (Offshore Hokkaido), Offshore Okachi-Hidaka, etc. in Japan. In 1999-2000, the Japan National Oil Corporation (JNOC), with funding from the Ministry of International Trade and Industry (MITI; Presently Ministry of Economy, Trade and Industry abbreviated as METI), drilled a series of gas hydrate test wells in the Nankai Trough off the southeastern coast of Japan and discovered distribution of gas hydrate in sandstone layers. Japan Geological Survey (JGC) assessed the resources as 4-6 TCM (1992). There is no commercial natural gas production from gas hydrate-bearing formation.

In 2001, METI has started "Japan's Methane Hydrate Exploitation Program", a 16-year program in which gas hydrate is defined as a future energy resource that is expected to exist in large amounts offshore around Japan. In the program, Mallik is regarded as an important project in collecting necessary data and parameters in preparing future successful offshore gas production from hydrates. The current plan included the following:

- Selection of gas hydrate gas field from the prospective areas and its economic evaluation.
- Production test of gas from the chosen gas hydrate gas fields.
- Establishment of technology for economic production.
- Establishment of development system that is environmentally friendly.

The Japanese are also the only nation currently carrying out assessment drilling of potential hydrate deposits, although their field program is currently in a state of flux. The latest program was carried out based on planning for drilling and coring between 10 and 20 wells in the Nankai Trough off Japan's East Coast. Initial results indicate that their geologic model was incomplete. Produced gas did not behave as anticipated, resulting in an incomplete test program and results that were not completely satisfactory. This result is not an unusual occurrence in a program of testing resource deposits whose actual character and response cannot be known exactly. It is anticipated that the data will lead to improved understanding of the occurrence of gas hydrate in the reservoir. The Japanese program is thus currently going through a stage of reassessment that has set their program back from its planned milestones.

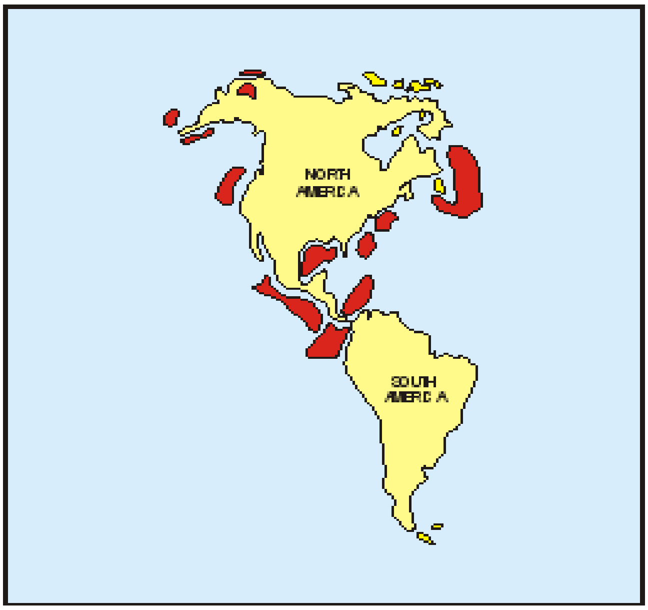


Figure 1-33: US gas hydrate distribution

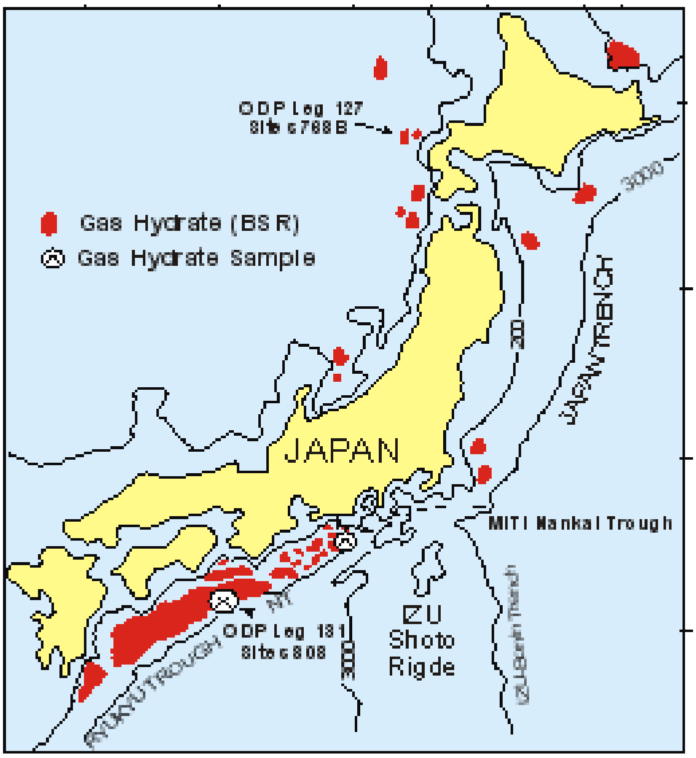


Figure 1-34: Japan gas hydrate distribution

1.4.3.3 Canada

If a future global supply of energy is stored in gas hydrates, then an immense potential occurs in Canada, a northern nation bounded by three oceans. Canada is also the world's third largest producer of natural gas, the most environmentally friendly fossil fuel. Expected North American growth in demand for natural gas provides Canada with opportunities for economic and export growth, while contributing to commitments to a sustainable environment and a vibrant economy in northern communities. Gas hydrates are being evaluated as a potential natural gas source through a new unified research program led by Natural Resources Canada. The total in-situ amount of gas in hydrates of Canada is estimated to be 0.44-8.1 × 10^{14} m^3. This is compared to a conventional Canadian in-situ hydrocarbon gas potential of ~0.27 × 10^{14} m^3.

Early pioneering work in the early 1970s proved the existence of hydrate in permafrost terrane through drilling. Hydrate has been identified in over 250 wells in five areas: (1) the Cascadia margin of western Canada, (2) the Mackenzie Delta and (3) the northern shelf of the Arctic Islands bordering the Arctic Ocean, (4) the western margin of the Labrador, and (5) the Atlantic coast of Canada. Relatively sophisticated estimates of the volume of hydrate in these fields have been made.

Perhaps of greatest boost to understanding the energy potential of gas hydrates is the research since 1997 centered on the Mallik gas hydrate research site in Canada's Mackenzie Delta. The Geological Survey of Canada (GSC) and the Japan National Oil Corporation (JNOC) have led this work. Among the participants are the GSC, JNOC, USGS, DOE, GeoForschungsZentrum Potsdam (GFZ), India Ministry of Petroleum and Natural Gas (MOPNG)/Gas Authority of India (GAIL), and the ChevronTexaco-BP-Burlington joint venture group. The project has also been accepted by the International Scientific Continental Drilling Program, which provided a broadening of the scientific research goal. At present, the Mallik deposit is the best-evaluated hydrate deposit in the world and the only one in which a natural gas production test from hydrate has been attempted.

In early 1998, the JAPEX/JNOC/GSC Mallik 2L-38 gas hydrate well was drilled to a depth of 1,150 m in the Mackenzie Delta. Gas-hydrate rich sandy to pebbly clastic strata were identified at depths between 890 to 1,110 m beneath 640 m of permafrost. Silt and clay-rich sediments such as silts and clays, which separated the main gas hydrate layers, were free of hydrate or contained little hydrate. Typically, hydrate-bearing strata were 10 cm to 1.5 m thick with an estimated porosity of 25 to 35%. Hydrate concentrations were up to 80% of pore saturation. Other wells were drilled and in 2002, a brute-force production test in the 5L-38 well was capable of sustaining a large flare. Although the hydrate conversion test consumed more energy than it produced from an area of hydrate-enriched sediment, continuous conversion of hydrate was demonstrated.

The GSC recently established a new gas hydrate research and development program as part of Natural Resources Canada (NRCan), which is a federal government department specializing in the sustainable development and use of natural resources, energy, minerals and metals, forests and earth sciences. The new science program consolidates GSC hydrate researchers. The focus is on gas hydrates as an environmentally friendly source of fuel for North America. University researchers are funded by a scientific funding agency similar to the U.S. National Science Foundation. Other government agencies appear to operate independently. The mechanism for the coordination of overall hydrate research in Canada is unclear.

A joint international research program that has been largely funded by the Japanese government succeeded in 2002 in carrying out a short production test at Mallik in the Mackenzie delta. This test showed that conversion of hydrate to recoverable gas was a physical possibility and substantiated thermodynamic recovery models. When the gas pipeline to the Mackenzie Delta from Alaska is completed, it is likely that some natural gas from hydrate will be recovered along with the associated conventional gas, even without a hydrate-specific hydrate recovery program.

The Mallik and nearby related fields could be developed for hydrate natural gas on a fast track if required.

1.4.3.4 Russia

Gas hydrate resources in Russia are estimated as 10-100 TCM on land and 100-1000 TCM offshore (hypothetical resources). There is some scientific discussion about natural gas hydrate reservoir production at Messoyakha gas field (north of West Siberia) during the last 30 years, but no direct indications on natural hydrate decomposition during production. The reservoir is situated at the low boundary of the thermodynamic Hydrate Stability Zone in this region, so there were well log indications of hydrates formed around the well bottom due to gas withdrawal during well testing, but still no evidence of natural hydrate existence in quantities able to affect production history.
Scientists in Russia were the first to recognize the energy potential of gas hydrate in its permafrost regions and the first to develop methodology for the in-situ conversion of natural gas hydrate to recoverable gas from permafrost hydrate deposits. Because Russia has such a large resource base of conventional natural gas, however, little emphasis has been placed by any national agency or energy company in Russia on the development of gas hydrate resources, although Gazprom, the State energy company, briefly investigated hydrate resources. Scientific research on hydrate has increased recently as part of individual initiatives and in step with the attention that hydrate is receiving worldwide. However, an integrated national program in hydrate research is apparently not being planned by Russian central or regional governments despite the availability of intellectual resources and experience and the clear evidence for large quantities of permafrost hydrate.

Gas hydrates are discussed in Russia in 2 directions. One is a potential natural gas resource, the other is a factor complicating well drilling and operation in permafrost and offshore regions. Having large conventional natural gas resources and proved reserves, Russia pays low attention to hydrates as a potential natural gas source.
But some accidents at northern wells during drilling through permafrost and under-permafrost layers caused by possible hydrate decomposition resulted to some research efforts on studying shallow intra-permafrost hydrates at the north of West Siberia. Self-preserved gas hydrates can exist in shallow permafrost from a depth of first meters and form free gas accumulations generating blowouts when drilling through. This research trend is planned to develop in future as well as offshore hydrate-containing sediments as foundation for oil and gas production platforms in polar seas.

1.4.3.5 South Korea

Preliminary hydrate research program was initiated in the 1990s in conjunction with the U.S. Naval Research Laboratory. In Korea, there were 2 national R&D projects on the exploration of gas hydrates [6]. One has been carried out by the KOGAS (Korea Gas Corporation) and KIGAM (Korea Institute of Geoscience and Mining) with total budget of 3 million (US) dollars for 5 years from 2000 to 2004, covering 12,000L-km 2D seismic surveys in the way of reconnaissance over 40,000 km^2 area. The other was performed by KNOC (Korea National Oil Corporation) and KIGAM with total budget of 1.8 million (US) dollars for 3 years from 2002 to 2004. KOGAS and KNOC have obtained promising results in its search for gas hydrate in the seabed of the East Sea around Korea Peninsula. It is believed that significant amount of gas hydrate exists below the seabed of the East Sea within the declared Korean territory.

Korean Government intends to lead the project by stage with the ultimate goal of the gas hydrate production in 2015. A research consortium (KGHDO; Korea Gas Hydrate R&D Organization) for gas hydrate resources in Korea was established to undertake research in accordance with an R&D plan prepared by 10-year national gas hydrate exploration program. This consortium was consisted of KOGAS, KNOC, and KIGAM. For 3 years from 2005 to 2007, it is expected that the budget will be about 65 million dollars, of which the share will be 57 million dollars by government and 8 million dollars by KOGAS. For the first stage of 3-year project starting in 2005, its objective is the confirmation of gas hydrates existence over the "Prospect I" on the basis of the compiled results of the previous works, along the additional high resolution seismic surveys and drilling.

November 2007 marked the successful completion of South Korea's first large-scale gas hydrate exploration and drilling expedition in the East Sea: Ulleung Basin Gas Hydrate Expedition 1 (UBGH1), which successfully explored and recovered gas-hydrate-bearing sediments at three different locations in the Ulleung Basin. The five "type" locations drilled in the Ulleung Basin (three of which were cored) will now allow extrapolation of gas hydrate probability to other sites in the Ulleung Basin that have seismic data. The thick gas hydrate accumulation discovered at one of the locations is similar in many ways to that found in the Krishna-Godavari Basin on Indian National Gas Hydrate Program Expedition 1, with many grain-displacing gas hydrate veins in clay, but there are also similarities to the preferential distribution of hydrate in sands found in the interbedded sands and clays drilled on Integrated Ocean Drilling Program Expedition 311 at the Cascadia Margin.
For the 2nd stage from 2008 to 2011, it will be practical the same as the 1st stage with only difference of the target area of "Prospect II". During the final stage, if the economic reserves would be positively defined, intensive studies will be focused on the development & production techniques to put the prospect potentials on a solid foundation for the commercial utilization. The government will take the inititive of the first stage works, supporting the R&D of KOGAS, KNOC, and KIGAM is expected to join the project with its matching fund. In the next stage, a consortium will be formulated consisted of the institutions involved in the 1st stage and private companies at home and abroad.

Figure 1-35: Research vessel (Tamhae-II)

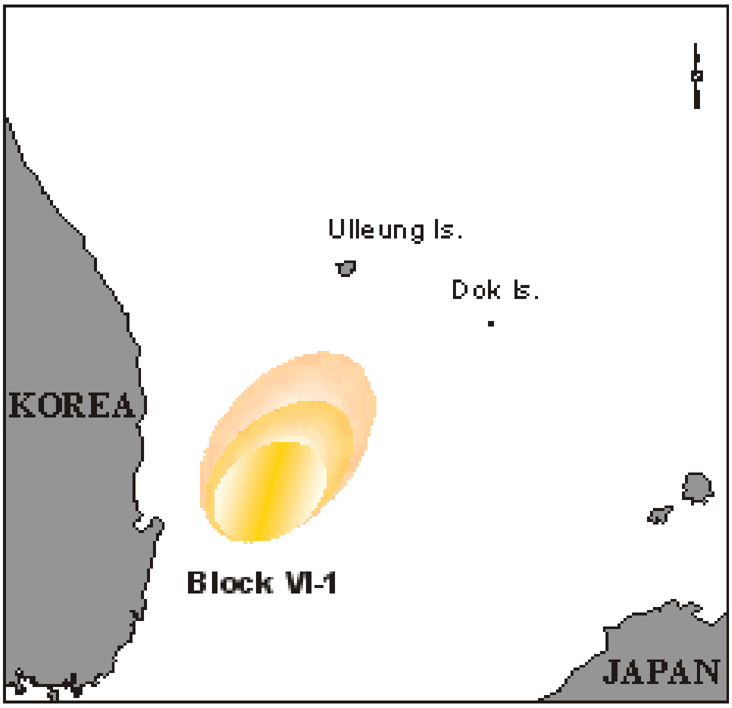


Figure 1-36: Promising area of Korea

Field	preliminary step (2000 ~ 2004)	1st phase (2005 ~ 2007)	2nd phase (2008 ~ 2011)	3rd phase (2012 ~ 2014)
1. Regional Seismic Survey & Basic R&D	■			
2. Prospect I Survey & Drilling (Component research)		■		
3. Prospect II Survey & Drilling (Base technology for production)			■	
4. Test Production & Confirmation of production method				■

Figure 1-37: Long term plan for gas hydrate in Korea

1.4.3.6 India

India, like Japan, has also initiated a very ambitious gas hydrate research program leaded by GAIL (Gas Authority of India Ltd.). In March of 1997, the government of India announced new exploration licensing policies, which included the release of several deep water (>400m) lease blocks along the east coast of India between Madras and Calcutta. The Indian national gas hydrate research program has moved from an early phase of preliminary identification of gas hydrate resources in their offshore area (including along the eastern side of the Bay of Bengal sector of the northern Indian Ocean) to one of focused research.

The Indian Department of Ocean Development (DOD) has announced that large quantities of hydrate have been identified along India's 7,500 km coast. The Institutes of Oceanography and the Institute of Geophysics have identified the Kerala-Konkan offshore region as having significant hydrate shows. Recently acquired seismic data have revealed possible evidence of widespread gas hydrate occurrences throughout the proposed lease blocks. Also announced was a large gas hydrate prospect in the Andaman Sea, between India and Myanmar, which is estimated to contain as much as six trillion cubic meters of gas.

New resources will aid this effort, including a new research ship (at a cost of Rs. 1.55 billion) that is largely dedicated to gas hydrate research. The new research vessel is scheduled to be operational by the beginning of 2006 and is intended to deploy new technology. The vessel will have a 48 m^2 deck, from which equipment can be lowered to the seafloor. It is planned to use advanced engineering seafloor drilling equipment. Drilling of the thickly sedimented submarine fans in the Indian Ocean is being contemplated by the Integrated Ocean Drilling Program (IODP). IODP will provide high-resolution climatic records along with data relevant to the presence of potential source beds for the production of natural gas.
The Indian government is aggressively exploring their hydrate potential resources, and has licensed commercial exploration interests for hydrate as well as conventional gas and oil.

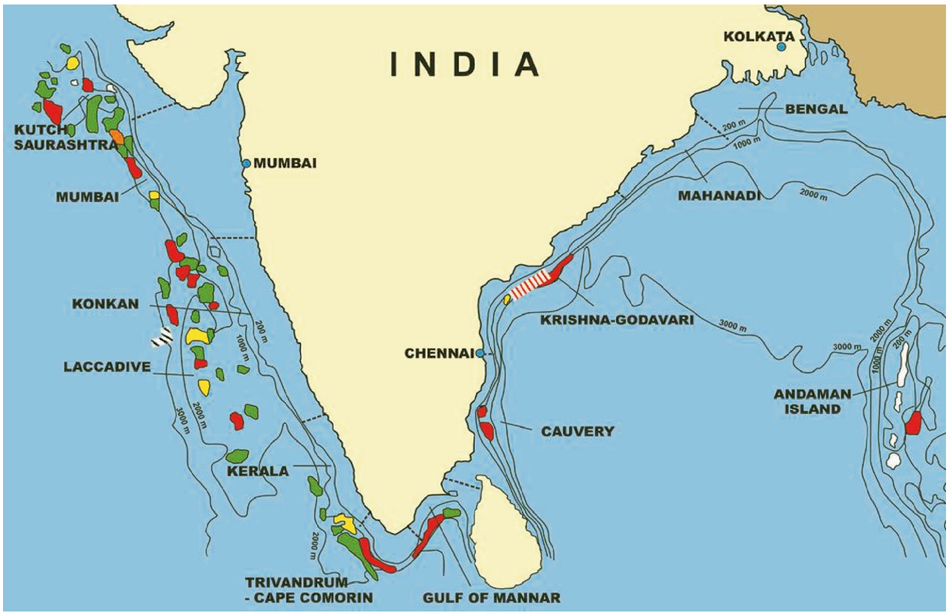


Figure 1-38: India gas hydrate distribution

1.4.3.7 China

In 2000, three national natural science foundations with an interest in different aspects of the gas hydrate system commissioned research focused on gas hydrate. This research built on earlier surveys to identify gas hydrate undertaken in 1999 by the Guangzhou Marine Geological Bureau. In May 2004, the Center for Hydrate and Natural Gas Research was established in the Guangzhou Institute of Energy Conversion (Chinese Academy of Sciences), which is heading multidisciplinary research among academic and company interests.

The Second Institute of Oceanography of the State Oceanic Administration is involved with some gas hydrate research, but has no gas hydrate program. In 2001, a gas hydrate project was established (Second 863 Program), and the Geological Survey of China has initiated a number of marine research projects focusing on the identification of hydrate. In 2002 a national gas hydrate project was initiated with the equivalent of 100 million dollars allocated as start-up funding. The first Chinese scientific program meeting of this project was held in Beijing in November 2003, with mainly Chinese and Japanese scientists attending. First order assessments of sea areas adjacent to China have identified considerable hydrate shows.

Recent seismic surveys and research, including seismic data processing, complex trace analysis, AVO analysis with full waveform inversion, show that indications of gas hydrate occur in the marine sediments of the South China Sea and East China Sea passive margin sediments. BSRs have been recognized in the northern margin in the Xisha Trough and Dongsha regions and on the western slope of Okinawa trough and other areas. The Xisha Trough and Dongsha regions and the western slope of the Okinawa Trough are the principal areas of national gas hydrate interest in China. A deep water gas hydrate investigation has been successfully completed for the Guangzhou Marine Geological Survey (GMGS), China Geological Survey (CGS) and the Ministry of Land and Resources of P. R. China. Drilling expedition GMGS-1 was carried out between April 21st and June 12th 2007 in the Shenhu Area (north slope of South China Sea) from the drill ship SRV Bavenit. Eight sites were drilled in water depths of up to 1500 m, with testing and sampling to 250 m below the seabed. A comprehensive program of borehole logging, coring, sampling and onboard analysis was conducted at five sites. The gas hydrate was found in a disseminated form within the fine-grained foram-rich clay sediments in concentrations ranging from 20 to more than 40% of pore volume. The gas released from the hydrate was found to be more than 99% methane.

1.4.3.8 Taiwan

In 2004, the Central Geological Survey of Taiwan funded a 4-year preliminary gas hydrate research program, which also involves university researchers. It is likely that following the confirmation of very large areas of BSRs so early in the preliminary program, considerable hydrate and subjacent gas is present and that further research and development will follow.

1.4.3.9 Malaysia

In Malaysia, the study to estimate volume of methane hydrate resources is still on-going by PETRONAS. The study is divided into two phases. Phase 1('06. 9 –'08. 3) is to develop standard PETRONAS procedures to estimate potential methane hydrate resources in Malaysia. Gumusut-Kakap field is used as the case study due to availability of good seismics data, and several wells that penetrate directly into the hydrate formation i.e. logs. Two types of gas hydrates deposits identified. The first one is associated with highly faulted/fractured zone acting as gas conduit and linked to active source of gas(high gas hydrate saturation associated to free gas). The second one is associated to passive diffusion of gas extent limited to depositional bodies (low saturation deposits). In case of Phase 2('08. 9 – '10. 9), the procedures are extended to other deep water areas in Sabah and later to the whole Malaysia deep water. No estimate of methane hydrate is available yet for Malaysia (only for Gemusut-Kakap area). However potential of methane hydrate in Malaysia is believed to be significant.

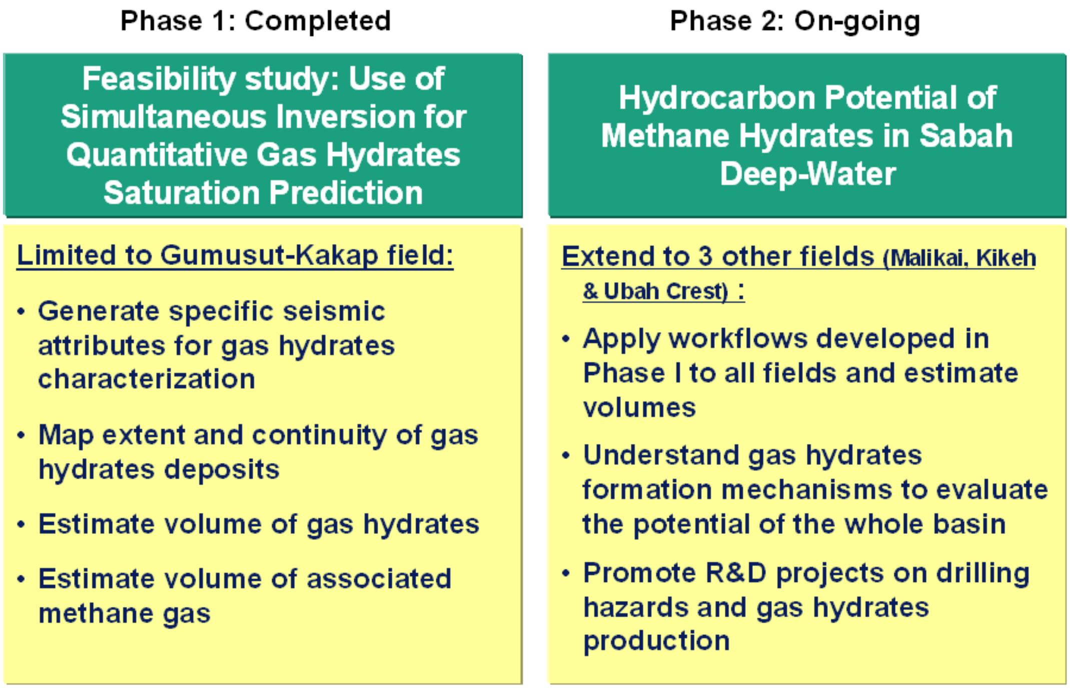


Figure 1-39 Project overview for gas hydrate in Malaysia

1.4.3.10 Indonesia

Scientists at the Center of Technology for Natural Resource Inventory in the Agency for the Assessment and Application of Technology are currently preparing a recommendation to the Indonesian government to carry out technical and economic feasibility to explore hydrate-gas occurrences in the offshore accretionary prism adjacent to Indonesia south of Java and Sumatra.

1.4.3.11 Australia

Australia's ocean territory is about 16 million km^2, about twice as large as its land area. There are considerable thicknesses of continental slope and marginal basinal sediments in which gas hydrate can be expected to form, but exploration to date has focused on conventional hydrocarbon deposits. Australian is emerging as a major supplier of LNG and has recently completed a contract to supply China, amongst other countries.
Reflection seismics have been used to identify hydrate in a number of continental margin slopes and basins. For instance, a bottom-simulating reflector (BSR) has been identified in thick packages of Cretaceous and Tertiary sediment with numerous diapirs that fill the Southern Fairway Basin (SFB) on the Lord Howe Rise (LHR) of the Tasman Sea. Cores confirm the presence of hydrocarbon gases. Hydrate has also been inferred on the NW margin of Australia facing Indonesia. In addition to energy exploration issues, the Petroleum Exploration Society of Australia (PESA) hosted a workshop on seafloor stability aspects of gas hydrate and associated fluids and gases in seafloor sediments in October 2004. As In the U.S., energy companies are concerned about drilling safety and the impact of the hydrate systems on seafloor stability in the deeper water now being explored for hydrocarbon deposits. Australia presently has no national gas hydrate program although there is considerable activity among university earth scientists.

1.4.3.12 New Zealand

The presence of gas hydrates on the Hikurangi Margin east of northern New Zealand was first inferred from BSRs in 1981. BSRs have also been detected on the Fiordland Margin to the southwest of New Zealand. The New Zealand Foundation of Science, Research, and Technology has provided funding for a small gas hydrates project since 1997. This project has so far focused on an analysis of existing seismic data for the presence of BSRs to obtain first estimates of the amount of natural gas that may be stored in New Zealand's gas hydrate deposits. Gas hydrates surveys are planned on the Hikurangi Margin in collaboration with international partners.

1.4.3.13 European Union

With the notable exception of Ireland, European Union appears to be primarily interested in the hazard and the carbon cycle/global climate change aspects of hydrate, or for basic physical chemistry research. French, German, and Italian research vessels are maintaining aggressive marine research programs using state-of-the-art ships and technology in many ocean areas, most notably in Polar regions using icebreaker and ice-capable research vessels superior to anything the United States can field. Individual European universities and research centers, such as the Department of Geology and Geological Mapping, Institute of Geology and Mineral Exploration of Greece, Heriot-Watt University (The Hydrate Group, Institute of Petroleum Engineering) in Scotland, the School of Earth Science, University of Birmingham, and Geotec Ltd, Northants, UK, Geomar in Kiel, Technische Universität Berlin, and GeoForschungsZentrum Potsdam in Germany, the University of Aveiro, Portugal, the Istituto Nazionale di Oceanografia e di Geofisica Sperimentale (OGS) in Trieste, Italy, carry out laboratory and marine research hydrate studies. In southern Europe, in addition to hydrate in the deep Mediterranean Sea, there appears to be hydrate in the Gulf of Cadiz and possibly on the more sediment-poor continental slopes to the north. Northern European continental slopes display many indications of hydrate, especially along the Norwegian and Barents Sea coast.

The European Commission has sponsored and funded four research projects dealing with Gas Hydrate since 1997. The HYACE project (1998-2001) was targeted at developing and testing pressurized core apparatus. Two core-head pressure corers were developed to sample more consolidated sediment containing hydrate. Testing was carried out on and offshore. The HYACINTH project (2001-2004) was intended to put the HYACE system to operational use. The HYACE/HYACINTH system was first used on ODP leg 204 offshore Oregon in 2002. HYDRATECH (2001-2004) is a project that aims to develop techniques to identify acoustically and quantify methane hydrate and to establish relationships between varying amounts of hydrate and its seismic response in sediments. The purpose of the ANAXIMANDER (2002-2005) project is sampling of sediments containing hydrate and a methane-dependent biota in the Anaximander seamountains in the eastern Mediterranean Sea in the vicinity of mud volcanoes.

1.4.3.14 Germany

Beginning in 2004, the Ministry for Education and Research (BMBF) and the German Research Council (DFG) will launch the second phase of EOTECHNOLOGIEN, with special emphasis on "Methane in the Geo/Biosystem". Its five research areas will be: (1) methane gas in gas hydrate provinces, (2) Climate impact of methane, (3) Gas hydrates as GeoBio-Systems, (4) Natural hazards, and (5) Structure and properties of gas hydrates. Of special importance in this context are two methodological thrusts. The first is the monitoring component, which encompasses geochemical properties and secular temperature variations especially in permafrost settings and their influence on atmosphere and climate. The second is the modeling component, where gas hydrate occurrence in time and space (3-D/4-D) willbe addressed. Here, interdisciplinary investigations will study the physics, chemistry and microbiology utilizing evolving natural, experimental and virtual laboratories, taking due consideration of (1) basin evolution- (2) subsurface water flow, (3) biogenic and thermo-genic gas generation and (4) partition and phase behavior in the system water-gas-oil.

1.4.3.15 Ireland

In 1998, the Marine Institute of Ireland published a plan for the scientific and economic development of its large continental shelf and seafloor area. This document identified energy, amongst other issues and opportunities. A framework addressing these issues has been provided in the Productive Sector Operational Program of the National Development Plan (2000-2006) with an indicative budget of over fifty million Euro for marine research and technology developments over the period 2000-2006. These documents are available through the Marine Institute. Two research vessels have been acquired and appropriate scientific and technical resources based in Galway have been staffed. The marine work is coordinated by the Irish Government and includes a seabed survey, which is overseen by the Geological Survey of Ireland. The possibility of hydrate resources in the Irish seabed resulted in a preliminary, in-house assessment in 2003. International contractors providing expert oversight and technology transfer to the Irish resource base began an assessment of existing seismic data during the early part of 2005. Ireland has informally designated ocean areas that might contain hydrate well beyond the 200-mile limit of national interest identified by United Nations Convention on the Law of the Sea (UNCLOS).

1.4.3.16 United Kingdom

There are not any formal estimates of U.K. Natural Gas Hydrate resources and any production plans in the U.K. Some R&D activity has been concerned with methods of forming natural gas hydrates for possible transportation options.

1.4.3.17 Norway

Although there is no formal National Hydrate Program, has strongly supported research through STATOIL, which has carried out considerable research into the energy potential of hydrate both offshore Norway and Nigeria. In particular, the first 3-D seismic survey conducted specifically to assess slope stability and hydrate/gas in marine sediments was carried out in the vicinity of the uppermost Storegga Slide. This slide is one of the largest known mass flows whose generation is thought to be associated with hydrate dissociation. Researchers from the Unversities of Bergen and the University of Tromso, the Geotechnical Institute in Oslo, and the Geological Survey of Norway participate in hydrate research.

1.4.3.18 Belgium

Scientists at the Renard Centre of Marine Geology in Gent have been very active in marine hydrate research and have taken part in cruises and have organized and strongly participated in scientific meetings.

1.4.3.19 Turkey

Turkish scientists are attending hydrate research meetings and are reported as having initiated at least preliminary hydrate assessment programs.

1.4.3.20 Pakistan

Gas hydrates potential has been identified off the coast of Makran. The resource is known to be distributed along 700 km of the coastline of Pakistan. At the moment there is no plan of recovering gas from this resource.

1.4.3.21 Chile

More than 70% of Chile's natural gas is imported from Argentina. Chile's experience has been that during periods of social and economic upheaval in Argentina, their gas supplies are likely to be interrupted. During two of these periods in the recent past, when gas supplies were cut off for weeks, Chile was subject to considerable economic distress because, as with almost every other country, they have no fallbacks for sudden energy shortages. Southern Chile produces a small amount of gas, but most of the long

Chilean margin has not been explored for either conventional gas or hydrate deposits using modem technology.

Gas hydrate investigations to date have been conducted by an international collaboration that includes the Pontificia Universidad Catolica de Valparaiso, the U.S. Naval Research Laboratory, the University of Hawaii, and the Universities of Kiel and Bremen, Gennany. These investigations have included piston coring, heat flow measurements, and collection of both nonnal and deep-tow seismic data. Gas hydrate has been recovered from some of the shallow cores.
Researchers collected the first hydrate-relevant data from Chile and the Universities of Bremen and Kiel (GEOMAR) along the Chilean margin in 2003. In November 2004, the Chilean government approved an expanded program to investigate the national gas hydrate resource potential. The second of two hydrate research cruises in Chilean waters as part of an international consortium led by the Naval Research Laboratory and Pontificia Universidad Catolica de Valparaiso (Chile) took place in the summer of 2004. These cruises involved seafloor sampling, chemical analyses, and high-resolution seismic surveys.

1.4.3.22 Brazil

Brazil has an extensive continental slope with thick marine sediments containing large amounts of organic carbon, a source for petroleum and gas deposits. The Amazon submarine fan bears a strong resemblance to the hydrocarbon-rich marine sediments of the Mississippi River delta, which is currently a focus of U.S. gas hydrate energy research. Indications of gas hydrate and subjacent gas deposits have been identified in the Amazon fan in water depths between 600 and 2,800 m. Brazil is currently supporting considerable exploration and development of its abundant deep-water hydrocarbon resources. There is currently, however, no national gas hydrate research program.

1.4.3.23 Mexico

Indigenous oil and gas production is at a turning point. Two third of the nation's oil production is coming from a single field complex (Cantarell) that will begin a sharp decline in 2006. At present Mexico is a net importer of natural gas. Mexico is now beginning the exploration of its deepwater Gulf of Mexico acreage. The geology of the Mexican deepwater east coast has many similarities to the U.S. Gulf of Mexico, including diapiric and alochthonous salt, although there is no sediment supply on the order of the Mississippi River. Natural oil seeps are present throughout the deepwater area. The Mexican government plans to do all the development themselves rather than open exploration to foreign oil companies.
A conference, which was officially called the "First Forum on Natural Gas Hydrates in Mexico", was organized in the summer of 2004 by PEMEX, the Mexican Ministry of Energy, and the National University. Also associated were the Mexican Association of Exploration Geologists (AMGE) and the Mexican College of Geophysics Engineers (CIGM). This was essentially the first national gas hydrate conference in Mexico. However, there does not appear to be a hydrate research program at this writing, and petroleum remains the primary Mexican exploration objective.

1.4.3.24 West Africa

Gas hydrate has been inferred from reflection seismic records along the southwest African continental margin off the Congo River in originally relatively homogeneous pelagic sediments. These shows of shallow hydrate are associated with pockmarks, high fluid flow from the seafloor, seafloor hydrates and carbonates, and thermal anomalies. There are similarities with seafloor venting of natural gas-rich fluids in the northern Gulf of Mexico. Gas hydrate, in some form, is probably ubiquitous on most continental margins of the world. New identifications and inferences of gas hydrate are now being made with regularity as the spreading knowledge of hydrate means that more researchers are looking for hydrate indicators.

1.4.3.25 South Africa

Widespread BSRs have been identified on multi-channel seismic profiles in the upper continental slope in the southern periphery of the Orange River delta off South Africa. Although no hydrate has been drilled or found on the seafloor in the region, the presence of large quantities of gas hydrate is inferred. The seafloor in the region appears to have many pockmarks and mud volcanoes indicating upwelling of gas-rich fluids.

2 IMPORTANCE OF TECHNOLOGY PROGRESS

The main distinction between conventional and unconventional gas lies in the frequent need for additional stimulation to gain and maintain commercial production from unconventional resources. Unconventional gas is also produced at low pressures.

As well, some of the unconventional gas types can be both the source of, and the reservoir for, the natural gas. Finally, the mechanism for storing the natural gas for most unconventional gases is different than for conventional gas reservoirs. The need for stimulation also dictates special needs in drilling and completion technology.

Unconventional gas resources may require significant technical expenditures to unlock the gas from the reservoir, including artificial stimulation to gain and maintain production.

2.1 ACTUAL RESEARCH AREAS AND REQUIRED TECHNOLOGY ADVANCES

Technology used today or required to be developed to recover unconventional gas depends on these three key areas:

- ➔ Characterization and modeling
- ➔ Drilling and completions
- ➔ Lifting technology and infrastructure

2.1.1 Characterization and Modeling

Characterization and Modeling involves the development of a model of the geological system for the purpose of predicting its behavior in response to changing conditions during stimulation and production. Understanding of the geo-mechanical and geo-chemical characteristics of the resource rock will add to the ability to locate and characterize natural and artificially created fractures.

Gas hydrates are significantly different from the other three unconventional plays and will require largely appropriate practices. Gas hydrates have a unique characteristic that is not shared with the other unconventional gas plays:

- The structure that holds the gas in place is likely to be degraded during gas production, with implications for the stability of surrounding geological structures.

  Two major objectives for longer-term research into all unconventional gas plays will be the identification of sweet spots and means to improve subsurface operations through real-time monitoring.

Finding and producing unconventional resources entails not only the discovery of entirely new plays, but also the re-discovery of previously missed or uneconomic ones.

Known zones of tight gas, shale gas and CBM are now being re-evaluated to identify any missed opportunities (Engler, 2005).

Characterization and modeling techniques are needed for both new discovery and re-discovery, and existing information and knowledge is an invaluable base for developing new practices and technology specifically designed for unconventional gas.

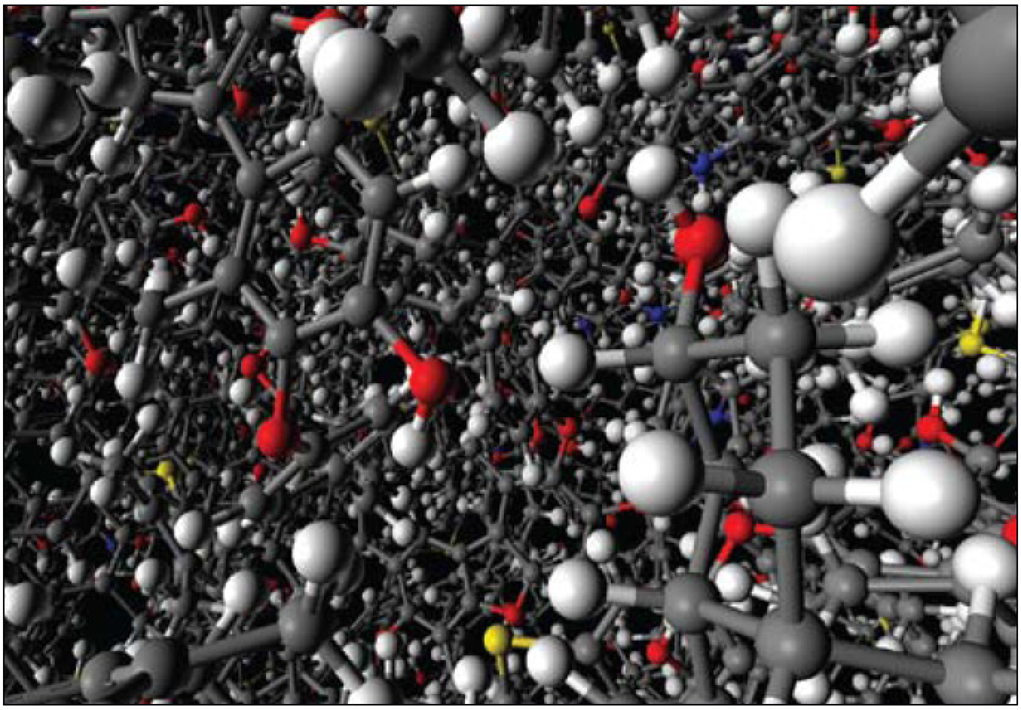


Figure 2-1: Free gas and sorbed gas exist in the coal matrix.
The model image shows a depiction of a typical subbituminous coal at the molecular level (Source Oil&GasJournal, December 17,2007) [18]

Unconventional gas reservoirs are more difficult to model than conventional gas reservoirs because the flow behavior is transient for much longer periods of time before stabilization.

The long-term objective is the development of models for unconventional gas reservoirs at an appropriate scale, which can be used to simulate and predict potential production prior to commercial development.

Table 5- Some key areas of inquiry that require further research

Research Area	Coalbed Methane	Tight Gas	Shale Gas	Gas Hydrates
Permeability and Porosity	✓	✓	✓	✓
Fracture lenght, spacing and conductivity	✓	✓	✓	✓
Cleat orientation and porosity	✓			
Fractures versus porosity		✓	✓	
Anisotropy	✓	✓	✓	✓
Mechanical rock properties	✓	✓	✓	✓
Chemical properties	✓		✓	✓
Trapping mechanisms	✓		✓	✓
Sorption characteristics	✓		✓	
Cap and basal rock and seals				✓
Stress	✓	✓	✓	
Stratigraphy and structure	✓	✓	✓	✓
Pressure and temperature	✓	✓	✓	✓
Fluid saturations and fluid properties	✓	✓	✓	
Permafrost properties				✓
Drainage area: shape, size, thickness and orientation	✓	✓	✓	✓

Source Gagnon and Schmelzl, 2003; Decker, 2004

2.1.2 Drilling and Completions technology

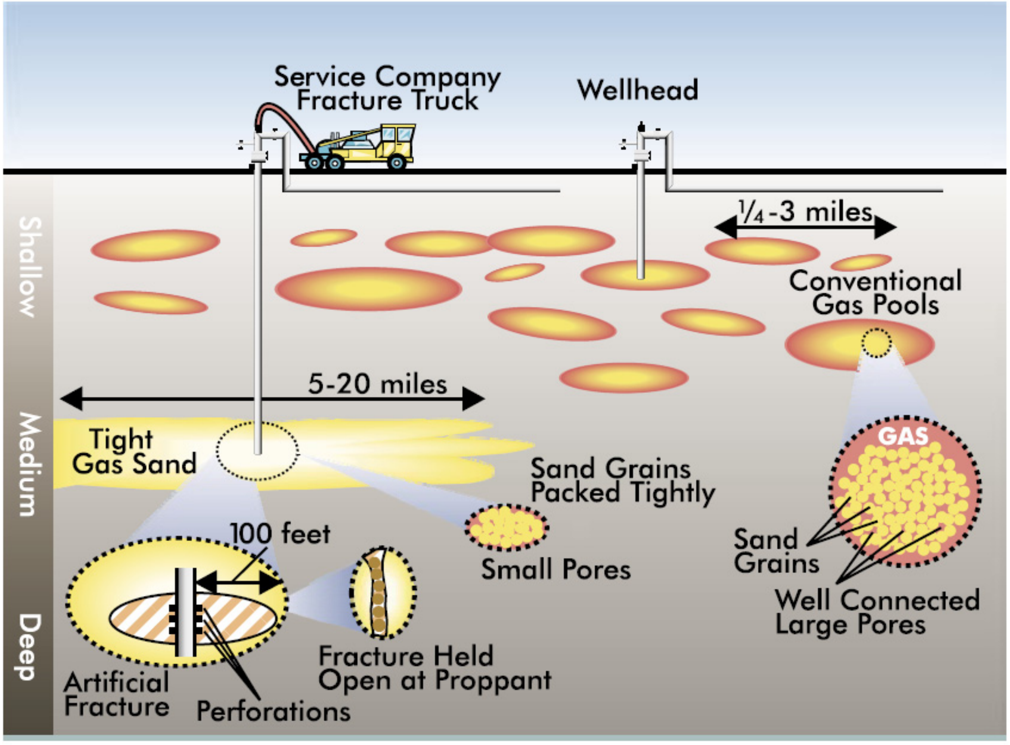
The development of stimulation technology, sometimes in conjunction with artificial means to keep fractures open, is an ongoing challenge. However, in some tight gas plays, careful attention to drilling practices which reduce formation damage may of itself allow an economic approach to development.

Central to the development of future drilling practices for CBM, tight gas, and shale gas, is the optimum application of directional horizontal and lateral drilling, or novel variations. Such improvements not only offer the promise of greater well productivity by intersecting more natural fractures, but also inherently reduce the footprint associated with unconventional gas development. Specific to gas hydrates, low impact Arctic drilling practices will need to be developed.

New cementing technology already under development addresses the special needs for production zone isolation.

Micro-technology in drilling, real-time logging during drilling, and the use of laser cutting will likely lead to major improvements in drilling practices.

Figure 2.2 below illustrates how stimulation can help overcome the major challenge facing unconventional gas Production.



Source: Mauger and Ziff, 2005

Fig-ure 2-2: Need Stimulation to start Production
(PTAC, 2006)

2.1.3 Lifting Technology and Surface Facilities

Lifting technology and surface facilities include the means to produce and gather the lower pressure unconventional gas sources, collect and distribute into existing or new natural gas supply infrastructure, and handle co-produced fluids. Unconventional gas development will need to address three long-term challenges:

- the means to treat and dispose of potentially large co-produced water volumes (especially from CBM production)
- the above-ground footprint from the larger well density
- better compression technology

Long-term research will address entirely new lift mechanisms and even the possibility of sub-surface compression. In addition, new downhole devices may be designed to lift only the gas, separating out unwanted production fluids such as water in the reservoir, for re-injection in lower, safe disposal zones.

The adoption of more horizontal or directional drilling mentioned above will also indirectly assist in reducing the above-ground footprint as a result of fewer drilling and production pads.

Gas hydrates present their own unique challenges. Long-term research will determine if the hydrate structures can be mined and maintained in their natural or modified state for transport.

In addition to applying the best practices used during conventional gas development, high priority will need to be given to environmental challenges unique to unconventional gas. These include mitigation of risk to fresh water aquifers, means to reduce above-ground water production, and the safe treatment of produced water for eventual re-use. In addition, long-term sustainable development will be enhanced by technologies or best practices to reduce the visible footprint associated with the industry.

2.1.4 Unconventional Gas technology under development or anticipated

Table 6- Summary of Currently Developing Technologies for Unconventional Natural Gas from Now to 2030 [3]

Unconventional Gas Technology under development or anticipated by 2010	Research and development required for success	Discussion
Fracture modeling and analysis, full 3D models for new types of treatments	Accelerated	Incorporating new physics for fracture propagation, in naturally fractured reservoirs, fracture-proppant transport, and better models for horizontal and multilateral wells.
New fracturing fluids and proppants	Incremental	Strong, light-weight proppants are needed. Better fluids that do not damage the reservoir and fracture must be developed.
Hydraulic fracturing methods used in horizontal wells	Incremental	Fort Worth basin (Barnett Shale): increased production rate by 2 to 3 times rate of vertical well.
Stimulation methods used in naturally fractured formations	Incremental	Gas shales and coal seam reservoirs are normally naturally fractured. We need a better understanding and better technologies for such reservoirs to include better models to determine gas storage and gas production using multiple gas systems, such as CO2, wet gas, and N2.
Micro-seismic fracture mapping and post-fracture diagnostics	Accelerated	Fort Worth basin (Barnett Shale): improved understanding of hydraulic fracturing in horizontal wells so that designs can be improved.

Data collection and availability during drilling, completions, stimulations, and production	Incremental	Significant data are being generated by increased drilling and new tools and techniques. The ability to handle and use data is being challenged. The data need to be evaluated in detail to learn more about formation evaluation, fracture treatments and production.
Integrated reservoir characterization of geologic, seismic, petrophysical, and engineering data	Accelerated	More complex reservoirs, lower permeability, greater depth and more cost require a more in-depth understanding of reservoir petrophysics. Better models will be required to properly integrate all the data and optimize the drilling and completion methods.
Horizontal drilling and multilateral wellbore capability	Accelerated	Enables development of stacked, thin-bed coal seams and reduces environmental impact. Also need to develop multiple wells from a single pad. This technology is very important in shale-gas reservoirs, and sometimes important in tight-gas reservoirs.
Reservoir characterization through laboratory measurements	Accelerated	We need better core-analysis measurements for basic parameters such as permeability, porosity, and water saturation. In coal seams and shales, we need better methods for estimating sorbed gas volumes and gas-in-place values in the reservoir.
Reservoir imaging tools	Incremental	Understanding the reservoir characteristics is an ongoing challenge and priority for all unconventional reservoirs.
Overall environmental technology	Accelerated	We need to reduce the impact of operations on the environment by reducing waste, reducing noise, using smaller drilling pads and adequate handling of waste water.
Produced water handling, processing and disposal	Accelerated	Coal seams and shale gas continue to produce significant volumes of water. Efficient handling and environmentally safe and low impact disposal are needed.

2020 Technology for Unconventional Gas Reservoirs	Research and development required for success	Discussion
Real-time sweet-spot	Breakthrough	Will allow the steering of the drill bit to the most productive areas of detection while drilling the reservoir.
Coiled tubing drilling for wells less than 5,000 ft.	Accelerated	Will allow the advantages of continuous tubing drilling to be realized (fast drilling, small footprint, and rapid rig moves) for currently difficult drilling areas.

3D seismic applications for imaging layers and natural fractures in shale reservoirs	Accelerated	We could improve recovery efficiency from existing wells if we used well testing methods to better understand the reservoirs.
Produced-water processing	Accelerated	Produced water is processed and utilized such that it no longer is viewed as a waste stream but as a valuable product for agriculture, industrial use, and for all well drilling and completion needs.
Deep drilling	Incremental	We need to determine how deep we can develop coalbed methane, shale gas and other naturally fractured unconventional reservoirs.
Enhanced coalbed methane production via CO2 injection/ sequestration	Accelerated	We need to determine the technological solutions and screening of suitable pairing of deposits and CO2 sources.
Data handling and databases	Incremental	Databases are available and user-friendly allowing access to geologic and engineering data for most North American basins, and are being developed for geologic basins worldwide.

2030 Technology for unconventional gas reservoirs	**Research and development required for success**	**discussion**
Resource characterization and gas.in.place potential	Accelerated	All of the basins worldwide need to be assessed for unconventional gas potential. The results should be recorded in databases and made available to the producing community around the world.
Well drilling and completion	Accelerated	Well drilling technology must be advanced through improvement in downhole drilling systems, better metallurgy and real.time downhole sensors allowing drilling to sweet spots, use of underbalanced drilling where needed, advantages of continuous tubing drilling, and efficient utilization of multilaterals.

Source National Petroleum Council 2007

2.2 TECHNOLOGICAL ADVANCEMENT FOR DIFFICULT RESERVOIRS

2.2.1 Drilling, Completion, and Production Methods for coalbed methane and shale gas

[9] With recent improvements in downhole technology and associated reductions in cost, **horizontal drilling** has become an attractive alternative. The first large-scale application of single-wellbore horizontal wells in a coalbed reservoir was in the mid-1990s in the Arkoma basin of Oklahoma, USA.

Subsequently, a **multilateral technique** was developed in the central Appalachian basin of West Virginia, USA, consisting of an initial vertical well followed by a **horizontal well steered** to intersect the vertical well in the coal seam of interest (Von Schoenfeldt et al. 2004).

From the horizontal wellbore, multiple laterals then are drilled to generate a **pinnate pattern**, similar to the vein pattern on a leaf. Typically, the horizontal laterals are completed openhole, and a pump is placed in the vertical well. Other multilateral configurations have evolved since the pinnate system was introduced and are being tested in several basins. The use of horizontal and multilateral techniques in shale-gas reservoirs also has been expanding rapidly, especially in the Barnett shale in which more than 90% of all new wells are horizontal.

A wide variety of **fracture-stimulation designs** are used in coalbed reservoirs. In the Raton basin of New Mexico, USA, multiple cased-hole, coiled-tubing fracture stimulations are conducted on thin individual seams by use of gelled fluids, with sand as proppant. In the Powder River basin of Wyoming, USA, where coal-seam permeability is high, wells are completed openhole and coals are flushed with water at rates of <5 bbl/min to flush out coal fines, open the cleats, and effectively connect the wellbore to the coal reservoir.

The Horseshoe Canyon coals in Alberta, Canada, which produce no water, are stimulated with **nitrogen-only fracturing treatments** to keep liquids from damaging the coals by clay swelling, fines migration, or other mechanisms.

Overall, cased and perforated wellbores with single- or **multistage hydraulic fractures** are the most common form of completion in coalbed wells.Shale-gas wells almost universally rely on hydraulic fracturing to connect natural fractures to the wellbore.

Although several horizontal openhole wells have been attempted in the New Albany shale of the Illinois basin, USA, most shale gas horizontal wells are cased, cemented, and perforated with multistage treatments pumped along the length of the horizontal section.

To monitor these treatments and adjust the fracture-stimulation pumping schedule in real time, new technologies, including **tiltmeters and microseismics**, are used. These technologies are especially important in the Barnett shale, in which it is critical to avoid fracture growth into the underlying wet rocks of the Ellenburger group.

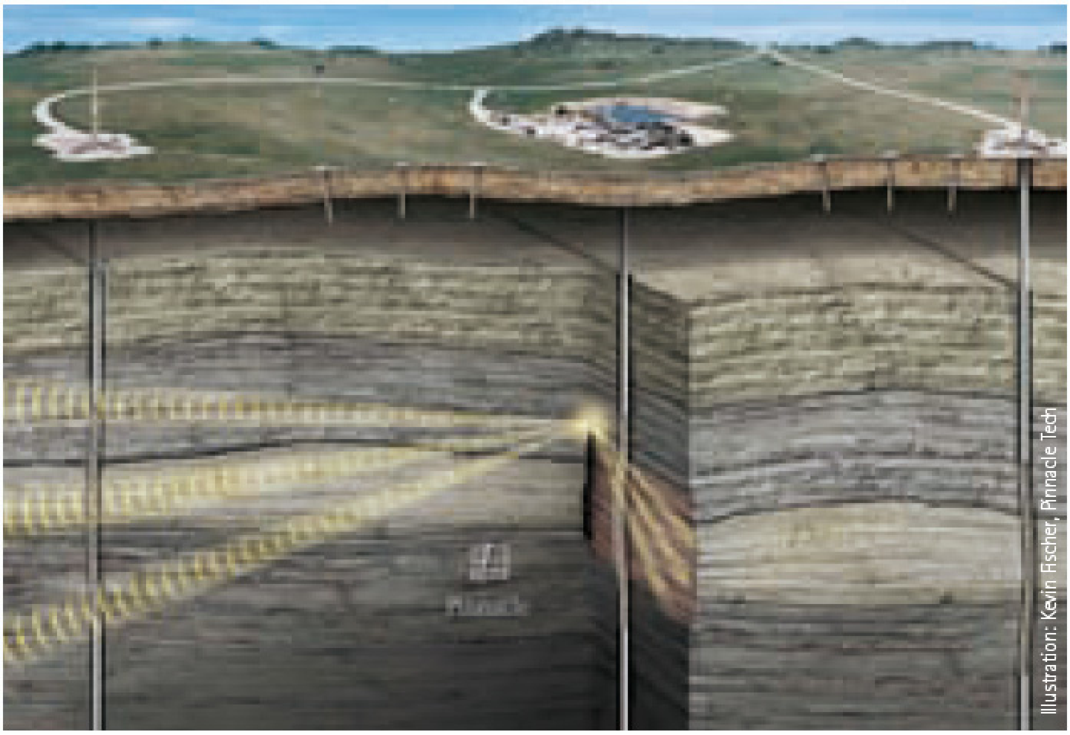


Figure 2-3: Surface tiltmeter arrays measure surface deformation. (GEO ExPro March 2007)

Figure 2-3 above shows the downhole tiltmeters measure deformation patterns in adjacent well bores. Sensitive geophones measure micro-earthquakes caused by the fracture treatment.

One production characteristic common to all coalbed- and shale-gas reservoirs is a high variability in productivity. An example is a 23-well coalbed-gas development in a 1-sq mile area of the Black Warrior basin of Alabama, USA. All of the wells were drilled and completed in essentially the same way in a single coal seam, but there was still significant variation in gas productivity (Fig.2-4). Local changes in permeability, as a result of both fracture intensity and fracture-aperture width, are thought to be the primary causes of this variability (Weida et al. 2005).

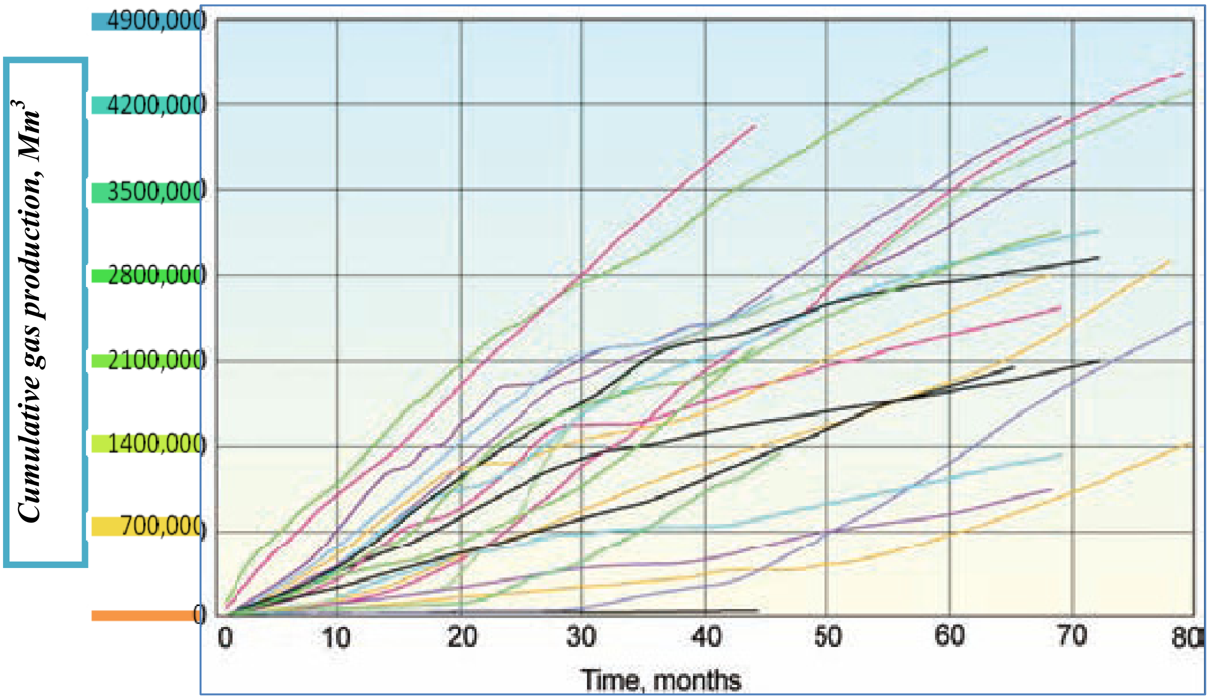


Figure 2-4: Variability in coalbed-methane well performance from a 23-well field in the Black Warrior basin, Alabama, USA
(courtesy of Schlumberger).

Table 7- Critical technology needs and applications for coalbed- and shale-gas reservoirs [9]

Primary Technology Areas	Technology Needs	Technology Applications
Reservoir Characterization	Quantify fracture systems and variability Identify areas with high permeabilities	3D and 4D seismic
		Wellbore imaging tools
		Surface geochemistry
	Sorbed-gas content measurements	Downhole spectroscopic analysis
		Geochemical logging
	Permeability measurements	Pre- and post-closure minifrac analysis
		Wireline-conveyed isolation/injection systems
	Identification of behind-pipe reservoirs	Through-casing analysis
		Improved interpretive algorithms
Drilling Operations	Rapid, reduced-cost drilling	High-pressure, jet-assisted coiled-tubing systems
		Telemetric and composite drillpipe
		Nondamaging, environmentally benign fluids
	Reduced drilling "footprint"	Multilateral wells
		Below-reservoir extraction
	Horizontal-well stability	Combination drill and liner systems
		Mechanical liner systems
Completion Operations	Nondamaging cementing	Ultralightweight cement
	Formation access	Jet-assisted hydrojetting
		High-energy laser perforating
	Increased hydraulic-fracturing effectiveness	Coiled-tubing-conveyed systems with horizontal-well application
		Fracture diagnostics, including microseismic and tiltmeters
		Environmentally benign fluids
		Ultralightweight proppants
Production Operations	Artificial lift/water disposal	Downhole gas/water separation and reinjection
		Improved filtration and/or sequestration of contaminants
		Surface-modifi cation agents
		Smart-well and expert systems
	Enhanced production	Carbon dioxide or nitrogen injection
		Enhanced horizontal-wellbore configurations
		Microbial-enhanced gas generation

(JPT, February 2008)

2.3 IMPACT OF UNCONVENTIONAL GAS TECHNOLOGY

Technological progress, as represented in the National Energy Modeling System (NEMS), affects the projections of unconventional natural gas production and wellhead prices in the Annual Energy Outlook 2000 (AEO2000) [18].

2.3.1 Exploration technologies

Exploration technologies are assumed to accelerate the discovery of hypothetical plays in un-assessed areas, shorten the development time for emerging plays, and increase the success of development.

2.3.1.1 Basin Assessments:

Basin assessments increase the available resource base through:

a) Reducing the time in which hypothetical plays in currently un-assessed areas will become available for development and,

b) Increasing the play probability for hypothetical plays - that portion of a given area that is likely to be productive.

2.3.1.2 Play Specific, Extended Reservoir Characterizations:

Extended reservoir characterizations increase the pace of new development by accelerating the pace of development for emerging plays, where projects are assumed to require extra years for full development compared to plays currently under development.

2.3.1.3 Advanced Exploration and Natural Fracture Detection R&D:

Exploration and natural fracture detection R&D increases the success of development by a) improving exploration/development drilling success rates for all plays and b) improving the ability to find the best prospects and areas.

2.3.2 Drilling and completion technologies

2.3.2.1 Geology Technology Modeling and Matching:

Geology/technology modeling and matching matches the "best available technology" to a given play with the result that the expected ultimate recovery (EUR) per well is increased.

2.3.2.2 More Effective, Lower Damage Well Completion and Stimulation Technology:

Improved drilling and completion technology improves fracture length and conductivity, resulting in increased EUR's per well.

2.3.2.3 Targeted Drilling and Hydraulic Fracturing R&D:

Targeted drilling and hydraulic fracturing R&D results in more efficient drilling and stimulation which lowers well drilling and stimulation costs.

2.3.2.4 Advanced Well Completion Technologies such as Cavitation, Horizontal Drilling, and Multi-lateral Wells:

R&D in advanced well completion technologies a) defines applicable plays, thereby accelerating the date such technologies are available and b) introduces an improved version of the particular technology, which increases EUR per well.

2.3.3 Production technologies

2.3.3.1 Advanced Well Performance Diagnosis and Remediation:

Well performance diagnosis and remediation expand the resource base by increasing reserve growth for already existing reserves.

2.3.3.2 New Practices and Technology for Gas and Water Treatment:

New practices and technology for gas and water treatment result in more efficient gas separation and water disposal which lowers water and gas treatment operation and maintenance (O&M) costs.

2.3.3.3 Other Unconventional Gas Technologies, such as Enhanced Coalbed Methane and Enhanced Gas Shales Recovery:

Other unconventional gas technologies introduce dramatically new recovery methods that a) increase EUR per well and b) become available at dates accelerated by increased R&D with c) increased operation and maintenance (O&M) costs (in the case of Coalbed Methane) for the incremental gas produced.

2.3.3.4 Mitigation of Environmental Constraints:

Environmental mitigation removes development constraints in environmentally sensitive basins, resulting in an increase in basin areas available for development.

3 UNCONVENTIONAL GAS SUPPLY – PRESENT STATUS

There are considerable uncertainties with respect to the amount of non-conventional natural gas that can be recovered. Global reserves of unconventional natural gas are estimated at just 2 TCM because the technologies to recover these potential reserves are only available for coal-bed methane and tight gas. Moreover, the conditions necessary for economic production only exist in relatively small regions.

According to BGR Annual Report 2007, unconventional natural gas resources (not including gas hydrates and aquifer gas) were estimated at 220 TCM, which is about half of the estimated ultimate recovery of conventional natural gas. The 1 to 100 ratio of original reserves to resources reflects the low degree of exploration. This ratio is about 1 to 1.2 for conventional natural gas and about 1 to 0.5 for conventional oil [18].

The amount of gas that can possibly be recovered from gas hydrates (500 trillion m³) and aquifers (800 TCM) are more than the EUR of conventional natural gas. Significant commercial production of aquifer gas is unlikely in the near future. Worldwide, there are a number of ambitious projects going on, focusing on commercial production of gas hydrates after 2020.

Table 8- Reserves and resources of unconventional gas in 2006 and 2007 [in TCM] [20]

	Reserves		Resources	
	2006	**2007**	**2006**	**2007**
Tight gas	1	1	90	90
Coal-bed methane	1	1	143	143
Aquifer gas	-	-	800	800
Gas hydrates	-	-	500	500
Non-conventional natural gas	ca. 2	ca. 2	1,533	1,533

Table 9- Regional distribution of reserves and resources of unconventional gas (Tight gas, Coal Bed Methane, Aquifer Gas) in 2007 [in TCM] [20]

Region	Reserves	Resources [1]
Europe	0,21	58,99
CIS	0,11	191,67
Africa	0,00	87,24
Middle East	0,00	115,17
Austral-Asia	0,11	252,87
North America	1,58	184,68
Latin America [2]	0,00	143,91
WORLD	**2,00**	1034,51
OECD	1,74	317,47
EU-27	0,11	37,06
OPEC-13	0,11	174,24

Source Federal Institute for Geosciences and Natural Resources (2008)

[1]Not including gas hydrates (19,000 EJ ~ 499,7 TCM), because they cannot be assigned to one of the regions,
[2] Including AntArctica
EJ Exajoule 1 EJ = 10^{18} J = 278.109 kWh = $34,1.10^6$ tce
1 G.m³ Giga cubic meter = 10^9 m³
1 EJ (10^{18} J): 34,1 Mtce = 23,9 Mtoe = 26,3 G. m³ natural gas = 278 TWh

3.1 KEY REGIONS AND MAJORS PROJECTS

Worldwide demand for natural gas is growing: technological advancements, together with natural gas environmental benefits, have made natural gas a vitally important component of the world's primary energy supply.

Natural gas is becoming a preferred fuel in the industrialized world, especially North America.

[18]. Natural gas from unconventional reservoirs is being targeted to contribute a greater share of the world's natural gas supply in the next two decades. Independent producers are helping develop many of the new technologies and well-site strategies necessary to ensure that as much unconventional gas as possible will be available by 2025, when it will amount to about 44% of US domestic gas production. The objectives of technologies being used in unconventional reservoirs include enhanced productivity

through increased exposure of the reservoir to the well bore; improved fluid-handling and disposal; reduced process-cycle times; declining materials and services costs; and better management of environmental risks and compliance.

Although UCG resources exceed conventional resources by several times, the technology necessary to recover tight sands and coal bed methane economically has not yet been well developed. Converting the remaining resources into reserves requires a combination of technological improvement, an appropriate regulatory environment, and a high level of industry-government cooperation.

Coal-bed methane (CBM) resources represent an additional volume estimated at 100 to 250 TCM. Gas shales and tight gas sands resources also harbor very high and still largely unidentified potential. The industry has mastered the recovery of coal-bed methane and gas from tight sands or shales. In the United States for instance, CBM and tight gas production currently account for about 30% of total gas produced every year. Although no technique to develop and produce hydrate potential (20 000 to 25 000 TCM offshore?) has been tested on an industrial scale, hydrates are also often touted as a valid alternative, offering a cleaner energy source than hydrocarbons.

3.1.1 Russia

The prospects for the expansion of the gas industry raw material base in the XXI century for Western Siberian region, as well as for Russia as a whole, are related to the development of the tight gas. The geological gas resources in low permeable beds and in parts of different tight gas natural reservoirs in Aptian section (Yamal and Gydan) are the roof of Pre-Jurassic rocks (throughout) by the most conservative estimates total not less than 65-70 TCM with unconventional resources contained in Jurassic rocks considerably exceeding conventional resources. Specifically, initial “conventional” gas in-place found in lower Middle Jurassic tight gas of the Urengoi field is estimated at 17,8 TCM.

As to the unique Yamal’s Bovanenkovo gas field with Jurassic gas reserves, no less than 180-200 BCM are accumulated in tight gas zones with the initial production rates being up to 50 000 m^3/d, although in state balances they are considered as recoverable ones.

The production of free gas from tight gas saturated rocks in Western Siberia is not currently profitable. However, by 2015-2020, an ultimate gas production from tight reservoirs may reach 40-50 BCM, i.e. 7-8% of the total gas production in the region.

3.1.2 China

The CBM production will approach 40 billion m^3/y in 2020; It is expected that, by 2020, the production scale of shale gas and biomass gas will be similar to that of CBM. Expected un-conventional gas production in China, 2020, 80-90 BCM/y

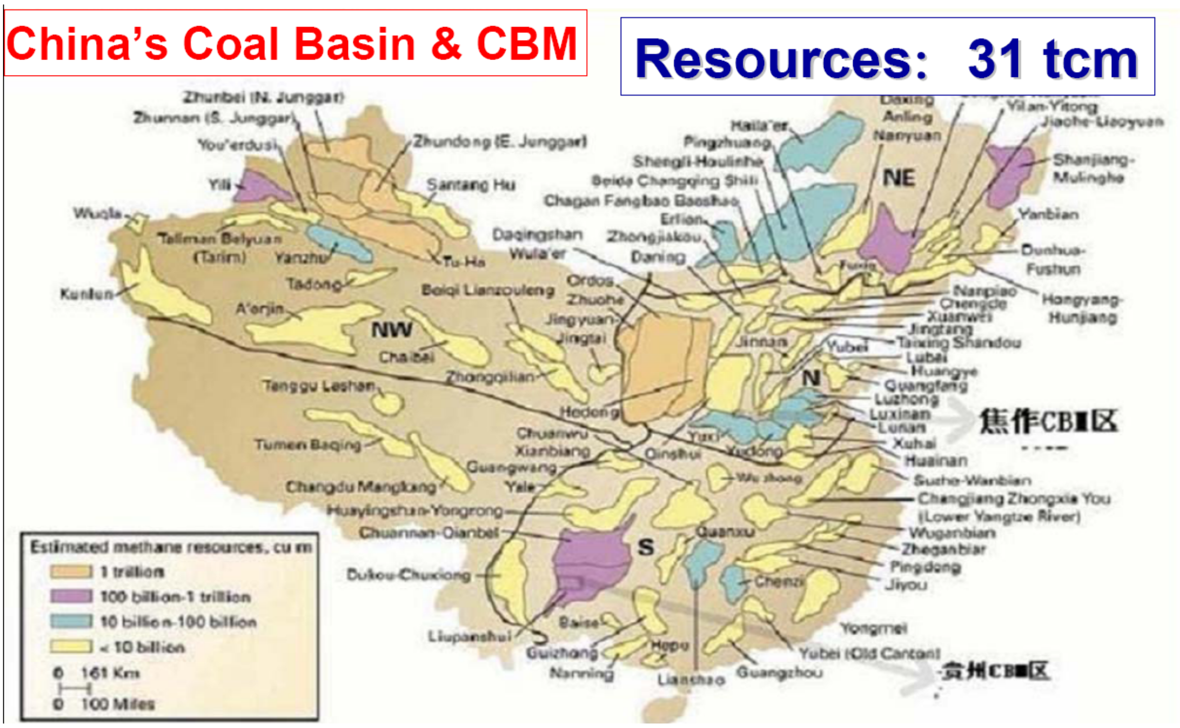


Figure 3-1 Resources of China's CBM (Research Center for Natural Gas, South China University of Technology September. 4, 2008 Hong Kong)

3.1.3 Australia

Development of coalbed methane (CBM) reserves in Queensland and News South Wales is progressing rapidly, with production from fiscal years 2000-2001 to 2005-2006 growing by 30% per year on average and accounting for roughly 5% of production and 8% of consumption in 2005 and 2006 [21]. Production from CBM represents a higher percentage of total natural gas consumption than total production, because no CBM is being exported currently. That may change, however, as four LNG projects have been proposed with CBM as the feed gas.

3.1.4 North America

In OECD North America, the United States has historically been both the largest producer and the largest consumer of natural gas, and Canada has been the primary source of U.S. natural gas imports. In 2005, Canada provided 86 % of gross U.S. imports of natural gas [21]. Although Canada's unconventional production is expected to increase over the projection period and LNG imports into Canada are projected to begin by the end of the decade, the combined increases in supply are not sufficient to offset a decline in conventional production in Canada's largest producing basin, the Western Canadian Sedimentary Basin. Increasing costs are expected to prevent the development of Canada's McKenzie Delta natural gas resource in the reference case, and Canada's production is projected to decline steadily, at an average annual rate of 0.8%. U.S. gross imports of LNG are projected to exceed gross pipeline imports from Canada after 2017, and Canada's share of U.S. gross imports is projected to decline to 32% in 2030.

A large portion of North America's remaining technically recoverable natural gas resource base consists of unconventional sources, which include tight sands, shale, and coalbed methane. With most of the large onshore conventional fields in the United States already having been discovered, the United States, like Canada, must look to these costlier sources of supply to make up for declines in conventional production. Unconventional production is expected to be a significant source of U.S. incremental supply, increasing from 223.7 BCM (44% of total domestic production) in 2005 to 269 BCM (49%) in 2030. With the increases in unconventional production and production from Alaska more than offsetting the decline in conventional production, U.S. production grows by an average of 0.2% per year.

3.2 ROLE OF UNCONVENTIONAL GAS GROWING AS IT SPREADS TO INTERNATIONAL STRATEGY

In January 2007 BP announced that it had been awarded a tight gas block in Oman.
The 2,800 km^2 block is located in central Oman. It includes two fields, Khazzan and Makarem, which were discovered in 1993 but have remained undeveloped [21].

A multi-year appraisal program is anticipated before initial production in 2010. While reserve estimates are obviously preliminary, this project is noteworthy for its potential size (as much as 566 to 849 BCM of recoverable reserves).

At the same time BP announced plans to spend up to US$2.4 billion to recover an estimated 53,8 BCM of additional coalbed methane gas from its San Juan Basin operations in the US.

This and Shell's long-deferred Changbei tight gas project in China's Ordos Basin are two examples of the potential spread of unconventional technologies common in North America to previously untapped areas. The Changbei project startup was announced in mid-2005.

Plans call for initial Changbei output of Our Perspective 3,25 Million cubic meter/day to markets in Beijing, Shandong, Hebei and Tianjin by 2007, rising to 8,21 Million cubic meter/ day by 2008. Plateau output is expected to be sustainable for up to 17 years from an early estimate of 70,8 BCM of recoverable reserves.

Shell is estimated to have a 50% share in the project.

Total upstream development costs for the Changbei project will be about US$ 600 million. These costs include construction of the central processing facilities, inter-field pipelines and development drilling of about 50 horizontal and multilateral wells over an estimated 10 year period. However, total costs of US$3 billion were originally reported to be necessary once transportation and power generation investments are included. This estimate dates to 2000 and, therefore, is likely to be increased.

The BP and Shell tight gas projects are not the first unconventional gas initiatives outside North America.

Burlington Resources signed a sales and purchase agreement in May 2002 to provide gas from its 100% working interest in the Chuanzhong Block which included the Bajiaochang field.

Potentially recovereable tight gas reserves estimates at the time ranged as high as “several TCF”. However, Chuanzhong production rates have remained very modest and it is reported that ConocoPhillips is interested in selling its interest.
While unconventional gas is booming in North America, the long-term prospects for these types of unconventional projects in other parts of the world are unclear.

In North America, a substantial portion of tight gas captures what, by international standards, is a very high price. It is likely to be difficult to realize the same value of tight gas reserves in most of the developing world.

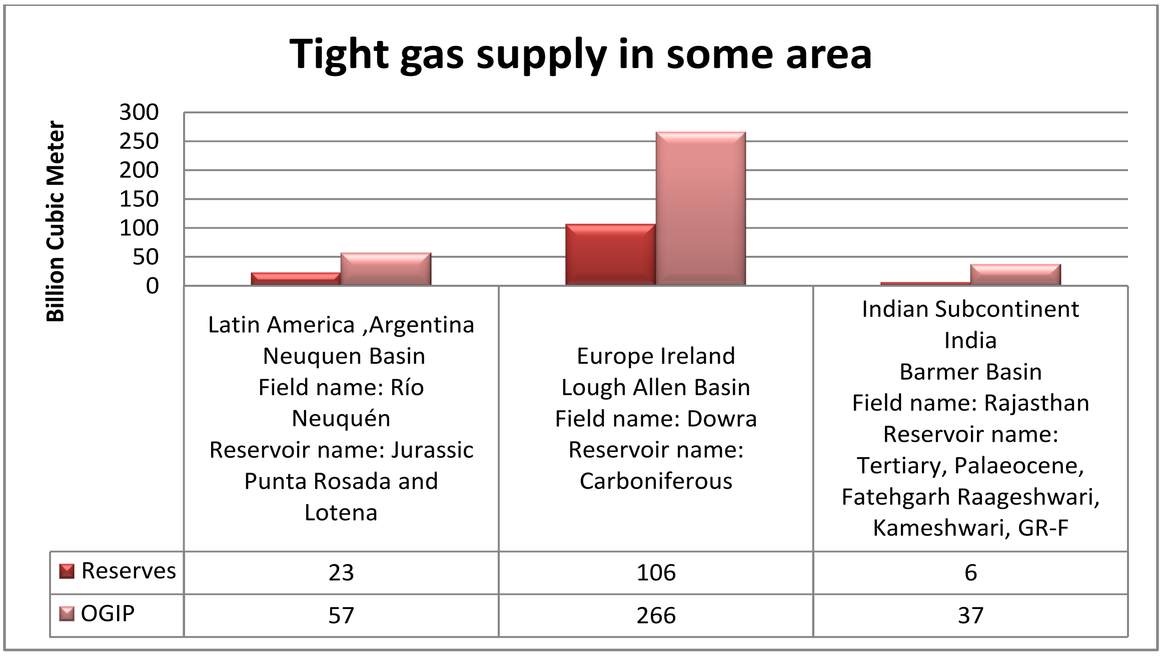


Figure 3-2: (Tight Gas Supply in Some area, courtesy Wood Mckenzie)

4 ECONOMICS

4.1 UNCONVENTIONAL GAS RESOURCES: KEY FACTOR'S DEVELOPMENT

The economics of unconventional natural gas production:

Although unconventional gas resources are abundant, they are costly to recover.

The drive to greater reliance on natural gas will be based in part on economics. However, government regulatory and taxation policy will also affect the viability of certain energy commodities, such as gas hydrate. In the recent past, government subsidies for unconventional gas resources such as coal bed methane bolstered their technical and economic viability. Similar forms of government support could have a significant impact on the resource viability of gas hydrates [21].

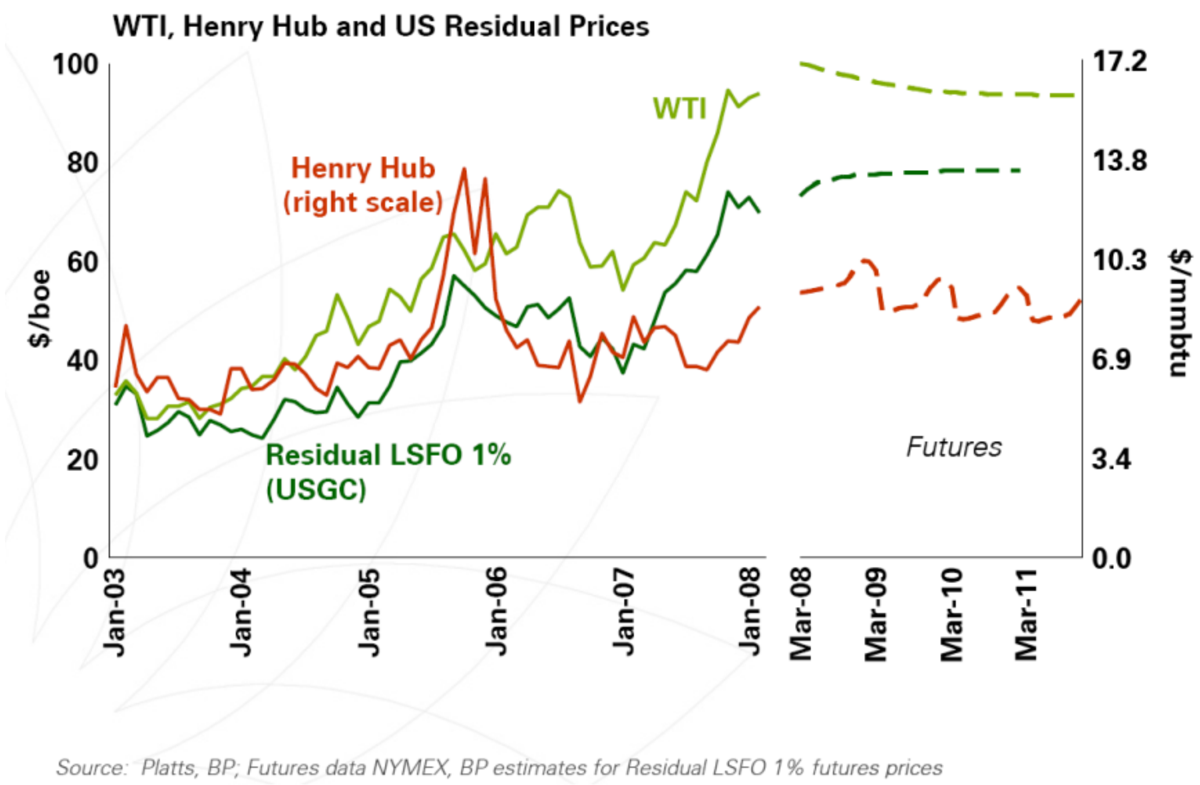


Figure 4-1: US gas prices: disconnected from oil price

4.1.1 Market Trends

4.1.1.1 Coalbed-Gas

Annual natural-gas production from coalbed-gas reservoirs in the US is approximately 48 BCM, which represents 9% of total natural-gas production. This gas comes from approximately more than 40,000 coalbed gas wells completed in at least 20 different basins [9].

Outside the US, more than 40 countries have investigated the potential of coalbed gas, resulting in commercial projects in Australia, Canada, China, and India.

The expansion of coalbed-gas development to countries outside the US continues to be slow because of various factors including unfavorable reservoir characteristics, inadequate infrastructure, and competition with conventional gas reservoirs. In some cases, leases changed hands several times before an operator with the right combination of corporate size, technical know-how, and contractual terms achieved a successful project.

Fruitland Coalbed Gas, San Juan Basin, USA.

This area is the most prolific coalbed-gas basin in the world, producing more than 70,8 million cubic meter/day from coals of the Cretaceous Fruitland formation and accounting for approximately 60% of the annual US coalbed-gas production [9].

Typical production from a fairway well is 170 thousand cubic meter/day, with peak rates reported at more than thousand cubic meter/day. Non fairway production is typically 2,8 to 11,3 thousand cubic meter/day.

Development in the basin continues, with more than 700 wells being drilled in 2006, in part to take advantage of a reduced well-spacing allowance of 32,5 ha vs. the previous 65 ha.

Fort Union Coalbed Gas, Powder River Basin, USA.

The Powder River basin is the most active coalbed-gas play in the US, with an estimated 3,000 wells drilled in 2006 [9].

By the end of 2005, more than 16,000 wells were producing a combined 25,5 million cubic meter/day.

Table 10- Comparison of characteristics from selected commercial coalbed-gas projects

Basin	Field	Area (Km^2)	Coal Thick. (m)	Coal Rank	Gas Cont. (m^3/ton)	Perm. (md)	Well Spac. (Ha)	Well Count	Gas Rate/ Well (Mm^3/D)	OGIP (Bm^3)	RF (% OGIP)	Res. (MMm^3 /well)
San Juan (US)	Ignacio Blanco	155	12–21	Bitu-minous	8,5–17	5–50+	24–129,5	130	42,5	50	66	80–420
Uinta (US)	Drunkard's Wash	311	1–14	Bitu-minous	12	5–20	65	450	14,1	44,5	57	40–110
Black Warrior (US)	Cedar Cove	168	7–9	Bitu-minous	7–14	1–25	32	520	2,8	23	53	10–40
Powder River (US)	Recluse Rawhide Butte	194	12–27	Subbitu-minous	0,85–2	5+	32	600	4,2	8	62	5–14
West. Can. Sed. (Alberta)	Horseshoe Canyon	1605	10–33	Subbitu-minous	1,5–3	0.1–100	32–65	3,300	1,2	124,5	28	7–14
Bowen Basin (Aust.)	Fairview	1113	15–30	Bitu-minous	5,66–11,32	100	101	80	19,8	12,5	60	70–99
Qinshui Basin (China)	Yangcheng-Qinshui	57	6–12	Anthra-cite	8,5–25,5	<1–5	32	40	1,9–3,9	3	20	11–22

(Source Distinguished Author Series, JPT February 2008) [9]

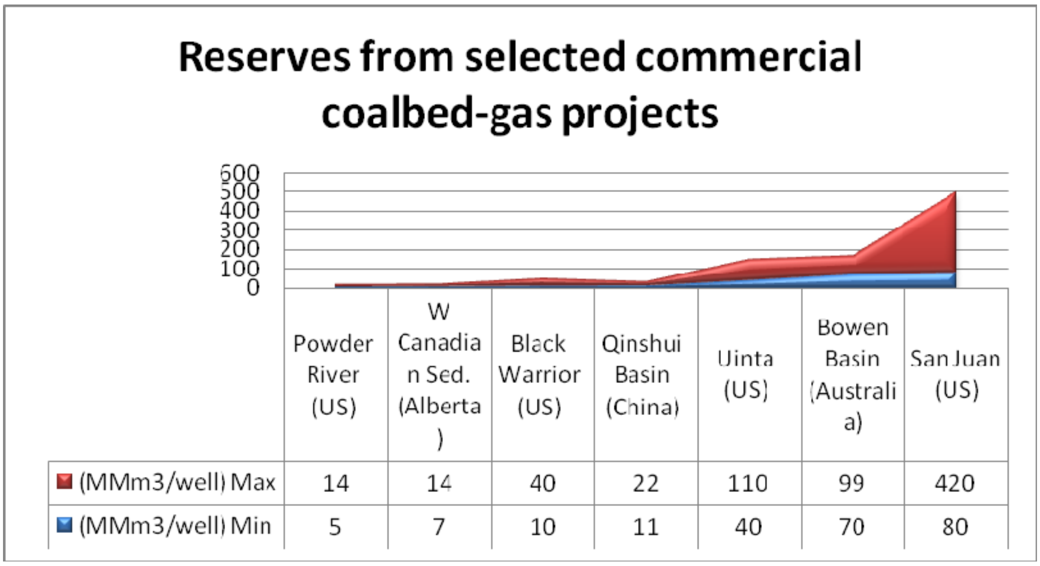


Figure 4-2: Reserves from selected commercial coalbed-gas projects

The combination of shallow drilling depths (75 to 450 m), thick coal seams (up to 90 m cumulative), high permeability (100 md to 2+ darcies), and low drilling and completion costs (<USD 100,000/well) compensates for the low gas content and results in reserves of 2,8 to 14,1 million cubic meter/well, which are recovered in 5 to 8 years at a 16- to 32-hectares well spacing.
Wells take less than 1 week to drill and complete, and they reach highly variable peak gas rates of 0,85 thousand cubic meter/day to greater than 28,3 thousand cubic meter /day within 1 year. Initial water rates are very high and may exceed 159 m^3/D.

Fortunately, the water quality is such that it can be inexpensively discharged at the surface, which helps reduce lease operating costs to less than USD 10,6/ thousand cubic meter. Wells commonly retain their peak gas rate for 9 to 12 months before declining at a rate of approximately 20%/yr. Total recovered gas to date is approximately 56,6 BCM, with estimates of total recoverable gas ranging from 0,5 to 1 TCM.

4.1.1.2 Shale Gas

Annual natural-gas production from shale-gas reservoirs in the US is approximately 28,3 BCM, which represents 6% of total natural-gas production [9]. The gas comes from more than 40,000 shale gas wells completed in five primary basins. While the pace of coalbed-gas drilling is starting to slow, shale gas continues to be one of the hottest plays in the US, and drilling is expanding rapidly, especially in the south-central US (the Barnett shale and its equivalents), the Appalachian basin, and numerous Rocky Mountain basins.
No commercial shale-gas projects currently exist outside of the US, but work continues to identify both new shale-gas reservoirs and to add incremental shale-gas production in existing reservoirs.

The Mississippian Barnett shale is the largest gas-producing field in Texas, with more than 6,600 wells producing a combined 59,5 x 10^6 m^3/day. Potential reserves estimated at more than 0,85 TCM [9].

Gas in the Barnett shale is thermogenically derived, and the shale is gas-saturated, so there is no initial water production.

Nearly all wells are fracture stimulated. The Barnett shale is found at depths of 1980 to 2590 m, and vertical wells cost USD 700,000 to USD 1.5 million. Horizontal wells, with laterals varying from 152 to 1066+ m in length, cost approximately twice as much as vertical wells, but their gas rates and recoveries are 2 to 4 times those of a vertical well.

Table 11- Comparison of characteristics from selected commercial shale-gas projects in the US

Shale Play	Basin	Net Thick. (m)	Gas Cont. (m^3/ton)	*kh* (md-m)	Res. Pres. (psia)	Well Spac. (ha)	Gas Rate/ Well ($10m^3$/D)	Water Rate/ Well (m^3/D)	OGIP (MMm^3/Km^2)	RF (% OGIP)	Res. (10^6 m^3/ well)
Antrim	Michigan	21–36	1–2,8	1–1524	400	12–65	0,5–15,5	0,8–238	54–382	20–60	5,6–51
Ohio	Appalachian	9–30	1,7–2,8	0.2–15	500–2,000	16–65	0,8–14,1	0	54–109	10–20	4,2–17
New Albany	Illinois	15–45	1–2	1–548	300–700	32	0,8–2,8	0,8–159	76–109	10–20	4,2–17
Barnett	Fort Worth	15–60	4,2–9,9	0.01–0,6	3,000–4,000	32–65	2,8–84,9	0	328–437	5–20	14–85
Lewis	San Juan	60–90	0,4–1,2	6–122	1,000–1,500	32–129	2,8–14,1	0	87–546	5–15	17–56,6

[MODIFIED FROM CURTIS (2002)] (Source Distinguished Author Series, JPT February 2008) [9]

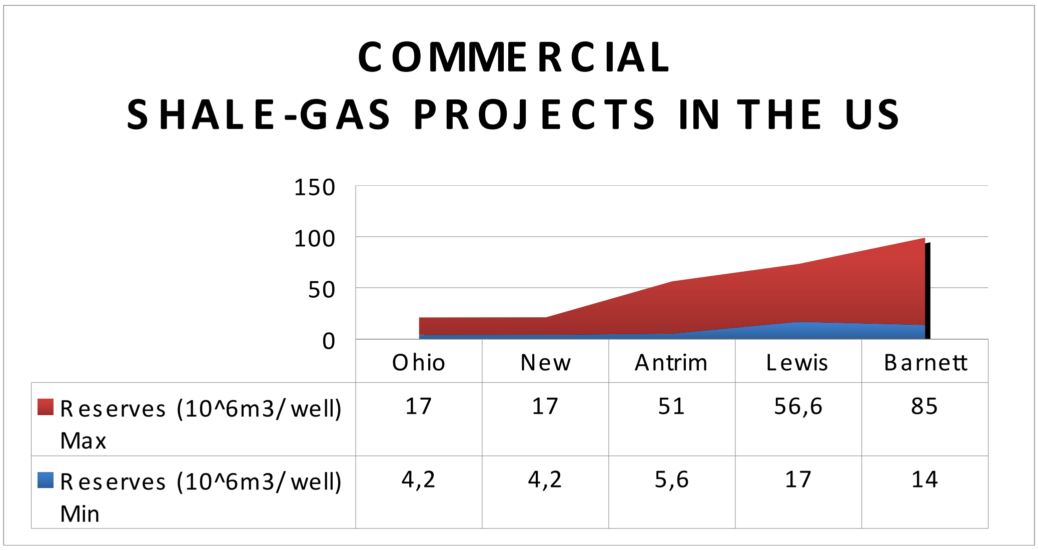


Figure 4-3: Commercial Shale-Gas Projects in the US

Barnett Shale Gas, Fort Worth Basin, USA.

Initial gas rates for horizontal wells typically range from 28,32 to 85 10^3 m^3/day, with reserves of 42,5 to 85 10^6 m^3/well based on a 30-year well life.

Antrim Shale Gas, Michigan Basin, USA.

Gas in the Antrim is of biogenic origin and is primarily sorbed gas with a concentration ranging from 1,4 to 2,8 m^3/ton [9]. The Antrim play saw rapid development from 1990 through 1992, spurred by a US federal-tax credit. Annual gas production peaked in 1998 at 5,6 BCM.

In 2005, more than 8,300 wells produced a combined 4,2 BCM of gas and 12 million cubic meter of water; the average per-well rate was approximately 1,4 thousand cubic meter of gas / day and 4 cubic meter of water / day. Per-well gas rates are highly variable, ranging from 141 to more than 14158 cubic meter / day /well, with the gas stream averaging 10 to 20% carbon dioxide. Drilling continues, with more than 400 new wells completed within the past year. Total gas production to date is approximately 56 BCM, with estimates of technically recoverable gas resources ranging from 141 to 283 BCM.

Antrim shale wells are 120 to 610 m deep, and gas production typically is 3,5 to 5,6 thousand cubic meter / day after 6 to 12 months of dewatering, during which time water rates can exceed 79 cubic meter of water / day.

A peak gas rate is reached in approximately 2 years, followed by an average decline of approximately 8%/yr for 20 years, resulting in a cumulative gas production of 11 to 22 million cubic meter. Well spacing varies from 12 to more than 65 acres/well, with initial gas-in-place estimates ranging from 54 to more than $382x10^6$ m^3/km^2.

Although wells initially were completed open hole, most operators now use cased-hole operations and two-stage nitrogen-foam hydraulic-fracturing treatments. The cost to drill and complete a well is less than USD 250,000, and there is increasing interest in trying horizontal wells in the Antrim shale.
Operating costs are relatively high because of the need to lift water and inject it into disposal wells.

4.1.2 Production Trends- The Global Fuel Mix

Historic fuel mix [21]
•Mid 1980s through 1990s natural gas was the preferred fuel
•Average annual growth rate 3%
Market share
•Gas has gained market share from coal in power generation
Recent trends
•Coal has regained market share driven by China’s insatiable desire for energy
•Nuclear debate being renewed –security of supply concerns Forecast
•Gas to grow at 2.0% CAGR between 2004 and 2030 (*Source: EIA)*

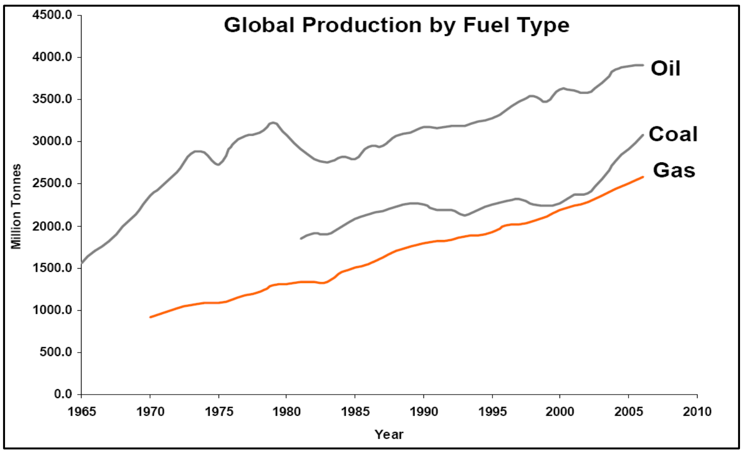


Figure 4-4: Global Production by fuel Type
(Source: BP Statistics Review of World Energy, 2007)

4.1.3 Unconventional Gas in the US Market

Compensates the Decline in Conventional Gas US Unconventional Gas Growth [25]
• Tight gas sands dominate –> 141,5 BCM produced in 2005
• CBM –produced 48,1 BCM in 2005
• Shale gas –produced 19,8 BCM in 2005
• Technological drive has intensified as conventional resources deplete
• Fiscal policies have driven exploration for unconventional gas

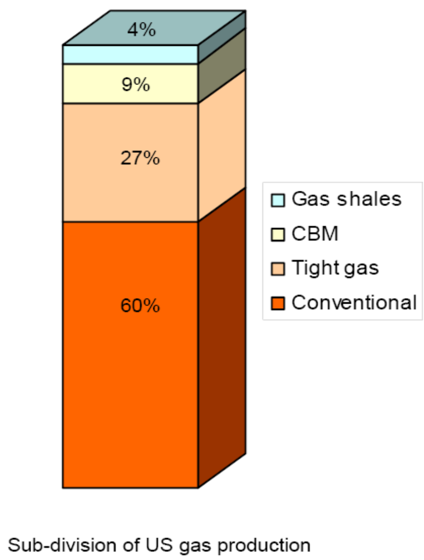


Figure 4-5: 2010–2030: Domestic unconventional gas replacing large conventional gas in US.

4.2 THE ECONOMICS OF UNCONVENTIONAL NATURAL GAS PRODUCTION OF UNCONVENTIONAL GAS PLAYS (ROCKY MOUNTAIN CASE STUDY).

Table 12- Economic Performance of Three Established Unconventional Gas Plays [21]

		Tight Gas Sands Williams Fork/Mesaverde S. Piceance Basin	Coalbed Methane Big George Powder River Basin	Tight Gas Sands Wasatch/Mesaverde Uinta Basin
Realized Gas Price [1]		$7.58	$6.34	$6.80
Less:	Production Taxes	(0.45)	(0.93)	(0.39)
	LOE/Other	(0.86)	(1.95)	(0.52)
	F&D Costs	(2.34) [2]	(0.71) [3]	(1.43) [4]
Net Margin		$3.93	$2.75	$4.46
ROR		36%	53%	52%
Min. Required CIG Gas Price		**$4.50**	**$3.00**	**$3.90**

1 Mid-2007 Rockies strip with BTU/sales adjustment
2 Assumes net EUR of 23 000 m^3/well and D&C costs of $1.9 million
3 Assumes net EUR of 8 000 m^3 /well and D&C costs of $0.2 million
4 Assumes net EUR of 59 500 m^3/well and D&C costs of $3 million

But recently forecast for unconventional gas has been changed by EIA and according to 2009 EIA Outlook, unconventional gas can exceed 50% in total domestic gas production in USA already in 2010. This is attributed to accelerated production of shale gas last 2 years. So by 2030 unconventional gas can replace imported gas and take more than 60% of domestic gas production.

4.3 EFFICIENCIES IN UNCONVENTIONAL GAS DEVELOPMENT AND COAL BED METHANE GLOBAL MARKET POTENTIAL

4.3.1 Australia

Demand for eastern Australian gas would double within a decade and prices would rise as the arbitrage between export and domestic markets closed, driving both conventional and unconventional reserves growth [21].

A comparison of conventional LNG projects with coal seam gas projects by Deutsche Bank analysts illustrated the differences neatly. They compared Woodside's Pluto project with Santos' Gladstone LNG (GLNG) project, which will source gas from its Fairview resource.

Pluto will drill five wells to support its initial LNG production. GLNG will drill 540. Pluto will increase its number of wells to 8, while GLNG will be adding about 60 wells a year.

The ramp up period to first production is about five days for Pluto, but two years for GLNG, while production per well is about 3,4 million cubic meter of gas a day for Pluto and only about 0,028 million cubic meter per well for Fairview. Total production for Pluto would be around 17,4 million cubic meter where Fairview is expected to produce 14,9 million cubic meter.

So, at face value, coal seam gas involves far more drilling for significantly less production and, because coal seam gas contains no liquids, significantly less valuable production. The capital expenditure on the upstream phase of the development to bring Pluto into production, however, is about $5 billion, whereas Fairview will cost only about $1.2 billion – that's the difference between an offshore development and an onshore project.

Moreover, where Pluto faces a petroleum resource rent tax rate of 40 per cent, as an onshore project Fairview will only pay royalties of 10 per cent – the upstream tax take, the analysts say, will be $6.7 billion for Pluto but only $2.3 billion for Fairview.

The growth in Australian coal seam gas production is following a similar path to coal seam gas in the US, although average production from the Queensland fields is substantially greater than from the average well in the US.

With four export LNG plants planned in Queensland, the market for the gas would become a global one. Exports of the gas as LNG will generate greater value and pull domestic prices up to narrow the arbitrage opportunity, putting a rising floor under the economics of the coal seam gas sector and bringing other unconventional sources of gas into play.

4.3.2 Hungary

Hungary's MOL oil and gas company has entered into a partnership with ExxonMobil of the United States and Falcon Oil & Gas of British Columbia, Canada, to develop the gas deposits in Hungary's Mako Trough. With this project, North American energy companies are directly entering the hydrocarbon production sector in Central Europe for the first time. The agreements just signed are a follow-up to the preliminary ones signed in 2007, when the companies ascertained the presence of sizeable deposits of unconventional gas in that area [21].

The Mako Trough is located in the Pannonian depression in southeastern Hungary, near the point where the borders of Hungary, Romania and Serbia intersect. The Mako Trough holds an estimated 1.2 TCM of gas, including 340 BCM susceptible to commercial development. These recent estimates by the Scotia Group consultancies are in line with MOL's preceding estimates. Drilling is scheduled to start before the end of 2008, with exploration wells eventually reaching a depth of 6,000 m. Commercial production is anticipated to begin in 2011, with a potential to reach 10 BCM annually by 2012 and thereafter.

MOL and ExxonMobil each hold 40.4% of the acreage in the Mako contract area, with Falcon holding the remainder of 19.2%. The total investment is estimated at up to $24 billion for the project's lifetime of up to 30 years. Within the overall project, ExxonMobil signed separate parallel agreements last month with MOL and with Falcon for joint exploration and development of particular portions of the project area. ExxonMobil shares those acreage portions half and half with MOL and 67% to 33% with Falcon.

The companies envisage supplying Hungary's internal market as well as nearby countries with gas from the Mako deposits. At present, Hungary relies on Russian gas for some 80% of its gas requirements. The dependence level is similarly high in several countries in the region.

The Mako deposits contain "tight gas," which is one of several forms of "unconventional gas." While technically complex, the extraction of unconventional gas is rapidly becoming attractive commercially due to rapidly rising prices for the product and uncertain access in the main producing countries beyond Europe and North America. Within these two continents, unconventional gas is now recognized as the main basis for potential growth in extraction. In Germany, for example, BASF/Wintershall and Gaz de France are jointly developing tight gas deposits in the Ostfriesland basin.

Tight gas such as that in the Mako Trough is trapped in low-permeability, low-porosity rock, limestone, or sandstone formations. It necessitates advanced techniques and expensive processes for fracturing those formations, opening up a passage for the gas to the borehole, and possibly for dehydration of the gas. ExxonMobil brings its unconventional gas production technology to Hungary. For its part, Falcon has a niche capability in Canada for extraction of unconventional gas.

4.3.3 Mexico

Free gas is limited mainly to the Burgos Basin where PEMEX is already producing from tight formations to help bridge the supply gap. Mexico has also recently started receiving LNG imports [21].
While Mexico's indigenous production could rise in the future, the volume and timing of the increase are highly uncertain. This is highly dependent on exploration success in offshore acreage, especially in deep water. The government is eager to increase production from the Burgos Basin and is in the process of tendering its third round of Multiple Service Contracts (MSCs) (renamed Financed Public Works Contracts (FPWCs). However, this service contract structure limits the commercial attractiveness of Mexico for prospective international investors.

4.3.4 Argentina

During the past three years Argentina's gas production has struggled to meet domestic demand (especially in winter) and export commitments to Chile, Brazil and Uruguay. Many of the supply issues stem from the pesoficación of domestic gas sales contracts in January 2002, which drastically lowered domestic prices. As a result, operators cut investment in gas production between 2002 – 2004, while gas sales increased dramatically [21].
In response to rising domestic demand, the Argentinean government has periodically curtailed exports to Chile. The country also began importing small volumes from Bolivia.

These imports are expected to increase, with Argentina and Bolivia negotiating over construction of a new pipeline (GNEA) connecting the countries.

The market situation could provide an opportunity for tight gas if gas domestic gas prices are allowed to rise. Residential prices remain frozen at about US$0.33/$10^6$Btu whilst industrial prices have inched up to about US$1.46/$10^6$Btu. In the near term, there may be a gradual shift to higher prices, as evidenced by the willingness of the government to pay up to US$4.86/$10^6$Btu for Bolivian gas imports.

Once domestic prices rise, operators are likely to invest initially in their existing conventional assets. However, production is not expected to rise substantially due to the increasing maturity of Argentina's conventional gas plays. The medium-to-long term supply picture indicates a continuing supply squeeze and rising prices. These conditions may encourage operators to develop tight gas.

4.3.5 Venezuela

Despite holding the largest gas reserves in Latin America (4,98 TCM – 2P), Venezuela is currently facing a tight supply-demand balance [21].

The Venezuela government plans to increase gas utilisation for power generation, refinery projects and steam injection for the next phase of heavy oil projects. Without new, non-associated, gas supply, it is unlikely that it will be able to supply these projects. This supply/demand situation bodes well for the development of tight gas. However domestic gas prices remain regulated; residential prices range from US$0.41 to 0.82/$10^6$Btu and industrial from US$0.92 to 1.27/$10^6$Btu. Some companies have negotiated prices above the regulated price but only to US$1,94/$10^6$Btu.

In the near term, there are no plans to raise these prices, as the Venezuela government currently views gas as a means to develop the country, and not a business in itself. Without higher prices, exploitation of tight gas in Venezuela will remain unlikely, unless the government offers incentives for its development.

4.3.6 China

China is permitting private companies to develop small-medium gas fields [23]:

- China has a large number of small—medium gas fields with low abundance and low permeable oil-gas fields.

- Encouraging private companies to exploit these resources through "on-site" liquefaction into LNG and transport via tankers.

- With the lower taxes rate and financial allowance support, these projects would be able to enter domestic LNG trade market.

China is speeding up coal-bed methane, shale gas development and rational utilization:

- Chinese very abundant coal-bed methane and shale gas resources; ranked top 3 or 4 in the world

- State Proposals: Strengthen and standardize supervision in order to avoid waste of resource. Coal-bed methane and shale gas for power generation, particularly through the ordinary boiler should be strictly prohibited. Government should work out corresponding policy to promote development and utilization of unconventional natural gas.

5 ENVIRONMENT

5.1 ENVIRONMENTAL ISSUES AND OTHER CHALLENGES

Environmentally-based challenges will be addressed by specifically targeted technology, or indirectly through new recovery practices.

Coal Mine Methane

Coal mine methane (CMM) is a relatively large and undeveloped resource, but its utilisation is garnering increasing attention as a method for reducing greenhouse gas emissions [21].
China, Russia, Poland and the United States account for over 77% of coal mine methane emissions. Emissions are projected to grow 20% from 2000 to 2020, with China increasing its share of worldwide emissions from 40% to 45%. By 2020, it is estimated that methane emissions from coal mining activities will be 449 mt CO_2e
Currently only a fraction of the CMM resource is recovered in a suitable form to be used for heat or power production.

5.1.1 Water Management Practices

Water management takes a number of forms, particularly in relation to CBM [2].

5.1.2 Surface Impact

The footprint in unconventional gas operations is greater than for conventional gas, because the low permeability of such resources leads to a higher well density and associated aboveground infrastructure to produce the gas at economic rates.

5.1.3 Noise

Unconventional gas resources produce at low surface pressures and therefore require multiple stage compression. Combined with the higher well density, this creates a higher noise level than is the case with conventional gas production from higher pressure wells.

5.1.4 Air Quality

The principal emissions (other than greenhouse gases) arise from flaring and venting, especially prior to individual well tie-ins to gas collecting infrastructure.

5.1.5 Greenhouse Gas Emissions

There are three possible sources for greenhouse gas emissions in unconventional gas development.

1. Variable CO_2 content in produced gases, including possibly in gas hydrates,
2. Potentially major source of greenhouse gases is fugitive methane emissions during normal operation, and during venting prior to tie-ins.
3. The high level of power consumption from compression is an indirect source of CO_2 emissions.

5.1.6 Methane Migration

There is a need for the industry to work with government regulatory authorities to investigate if there is methane migration from CBM developments and other shallow gas operations to adjacent zones.

5.1.7 Fluid Management and Disposal

The industry, in cooperation with other bodies, needs to investigate whether the fluids used in unconventional gas drilling and completion practices could affect adjacent or overlying aquifers.

5.1.8 Shallow Fracture Containment

In particular, care needs to be taken in stimulation techniques to ensure no damage is done to above-ground structures, nor to fresh water aquifers used to supply water for irrigation, livestock, and human consumption.

5.1.9 Destabilization of Land or Seafloor

In the future development of gas hydrates, a significant challenge to the seafloor, tundra, or muskeg is posed by gas hydrate destabilization.

6 OUTLOOK AT 2030

6.1 PROFIT AND DISADVANTAGES OF UNCONVENTIONAL RESOURCES EXPLOITATION

Profit In the short to medium term, unconventional hydrocarbon development will be driven primarily by commodity prices. Wood Mackenzie's medium term gas price ($5.06/106Btu Henry Hub flat real) points to a favorable environment for the exploitation of unconventional outside of the existing North America areas. This assumes a softening in the current cost inflation and on-going technology advances.

Disadvantages Dark Clouds have begun to appear on the horizon for unconventional gas. In North America and for many years, technological advances did allow to counter resource depletion, holding the key performance measure, reserves added per well, relatively constant. This, unfortunately, is no longer the case with reductions in R&D and technology investments. As a result, from the period of 1996 to 2000, reserves per well for all three of the unconventional gas resources have declined sharply.

Annual growth world gas production, demand and reserves

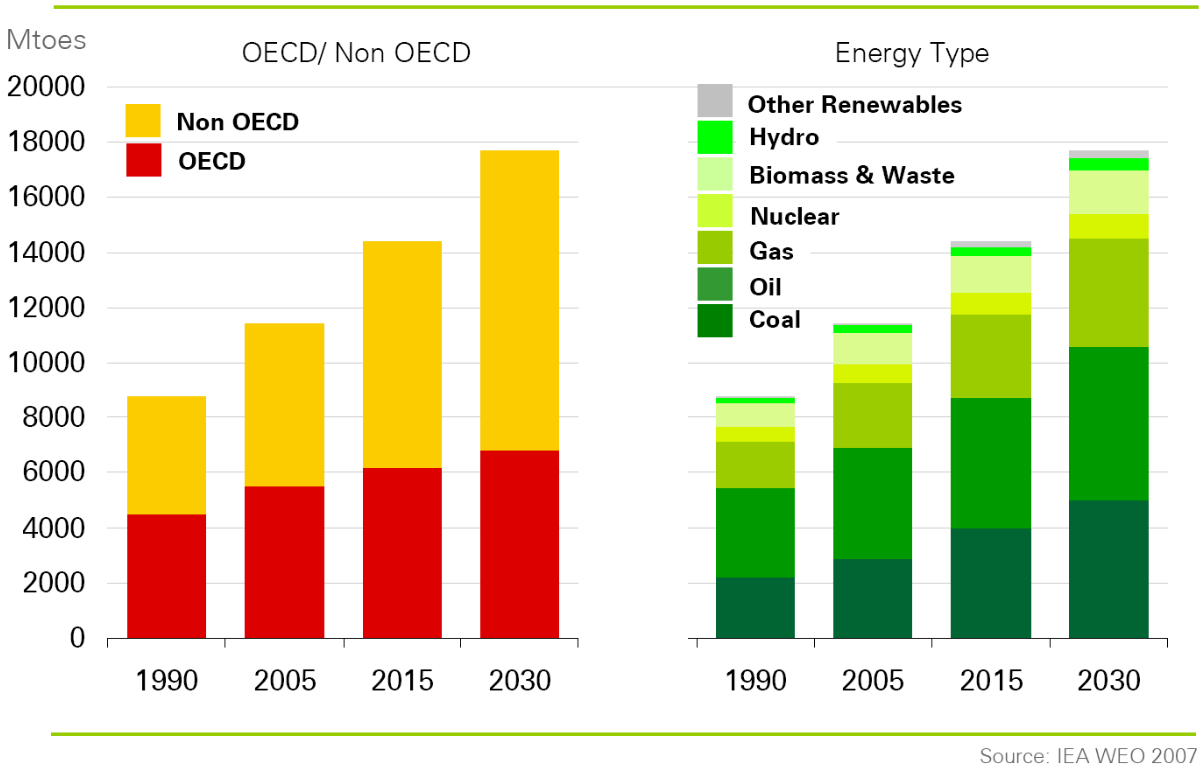


Figure 6-1: Global energy demand

6.2 REGIONAL AND TEMPORAL DISTRIBUTION OF PRODUCTION PEAKS

North American Gas Production

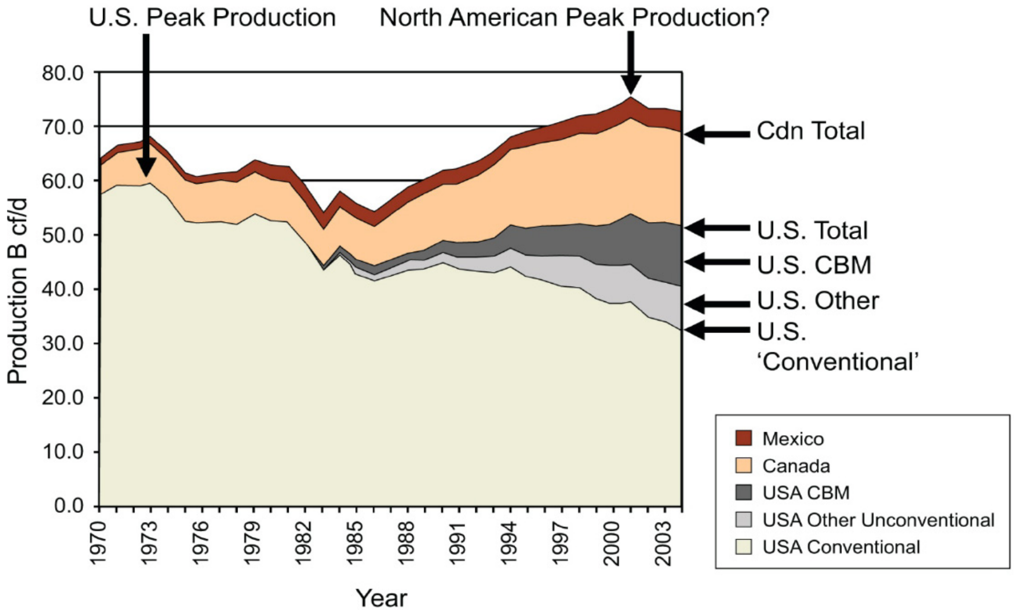


Figure 6-2: Source BP 2005 and others

6.3 UNCONVENTIONAL GAS SUPPLY OUTLOOK AT 2030

There is a big gap between what has been achieved so far in North America and the rest of the world.

This gap will be reduced significantly for some types of unconventional gas as tight gas considering that many companies are fully involved in the E&P of such plays. Consequently, a significant increase is expected.

For CBM, the situation is more complex where strong environmental implication takes place. Thus, the development of such resource will differ from countries according to their environmental policies.

As a result, an important increase would happen in Asia and Africa.
Concerning Methane Hydrates, and following the status of the research projects, no considerable commercial production is expected prior to 2030.

Annual Energy Outlook 2008 reference case indicates that through 2030, future growth in U.S. natural gas supplies depends on unconventional domestic production [21].

In conclusion, and among the 4,5 TCM global natural gas wich will be produced in 2030, the ratio of unconventional gas could be estimated to 12 – 15%, slightly higher than the one recorded today ~ 10 – 12%.

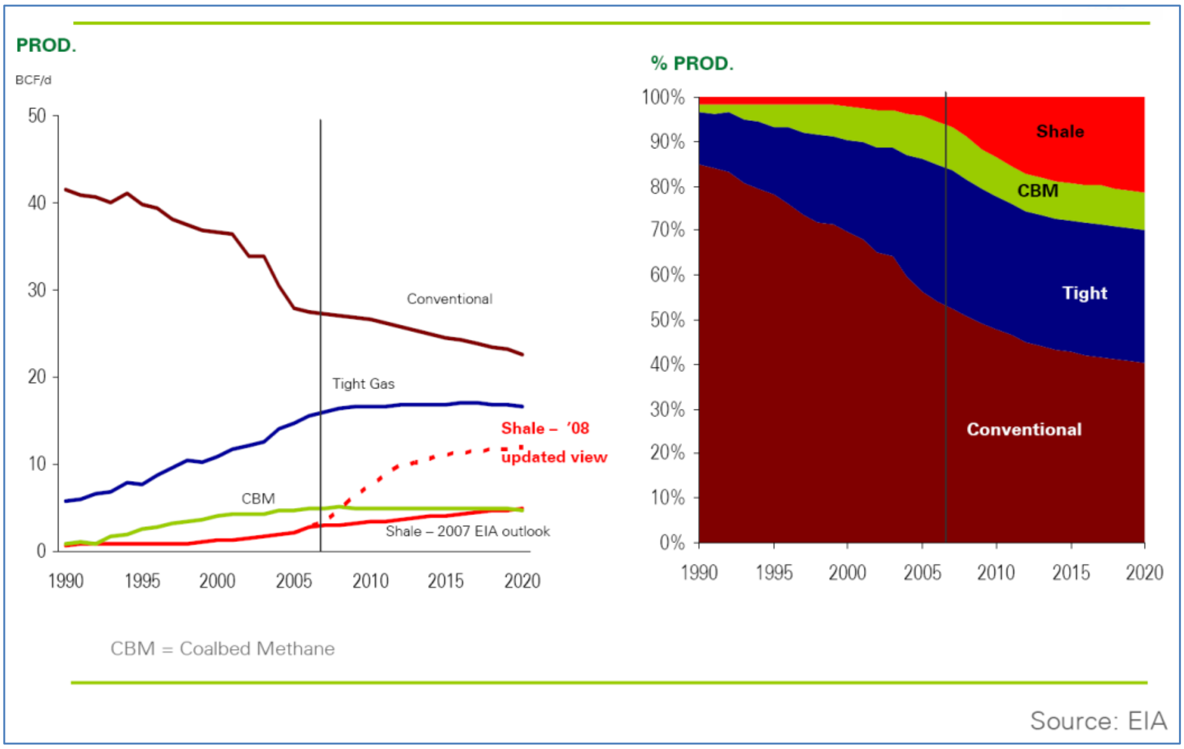


Figure 6-3: North America Gas – unconventional

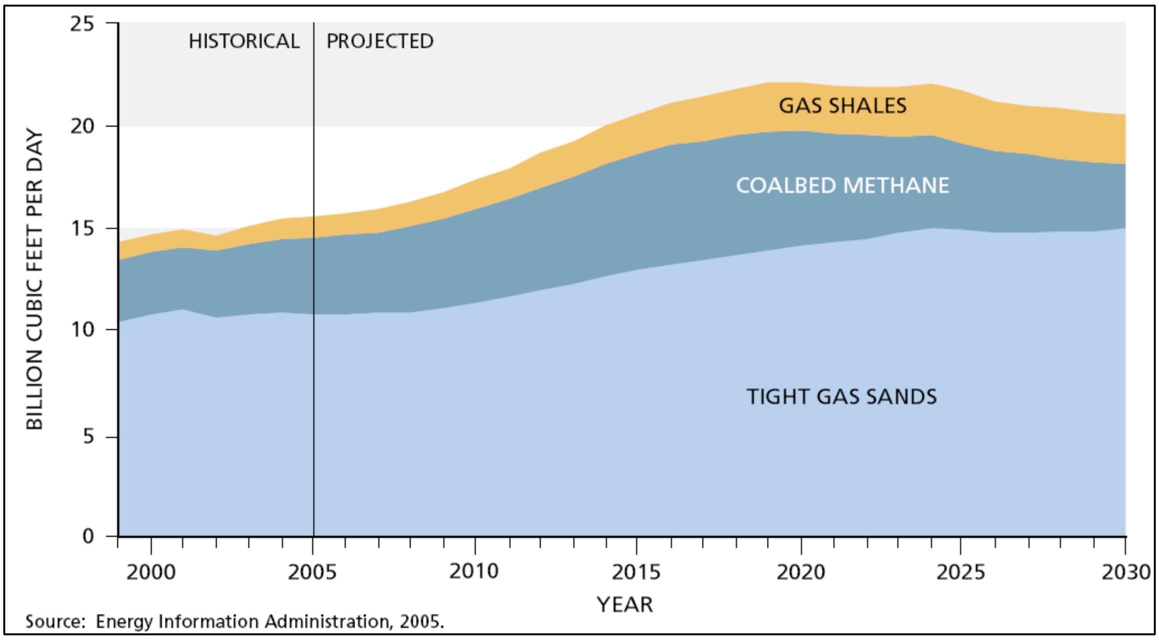


Figure 6-4: U.S. Unconventional Natural Gas Production and Future Projection

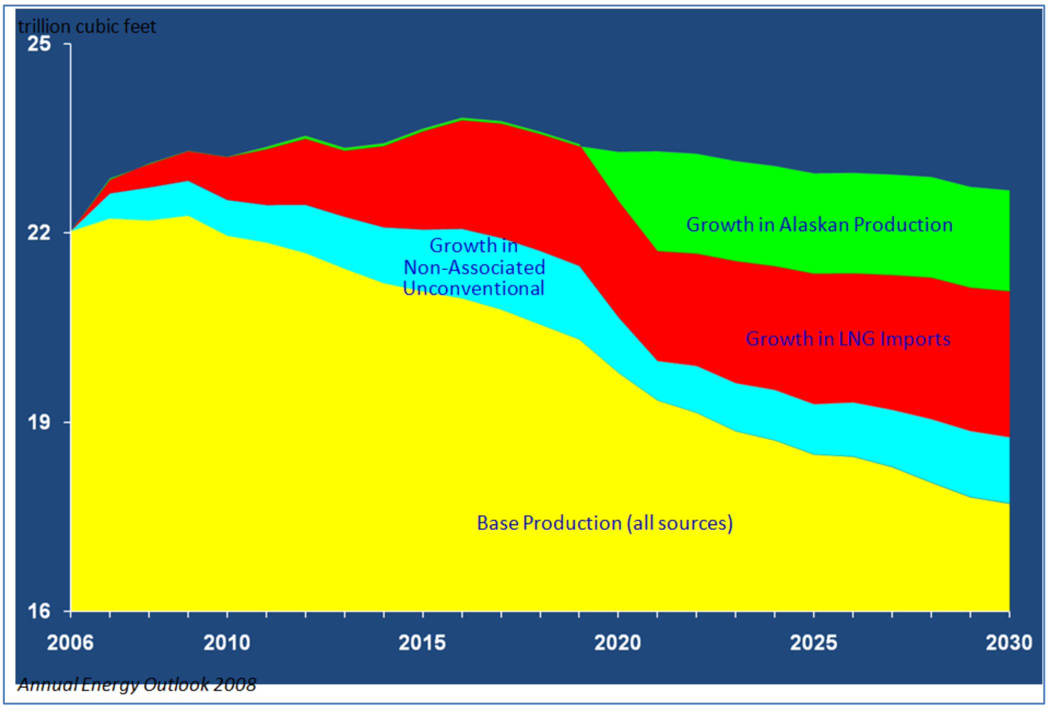


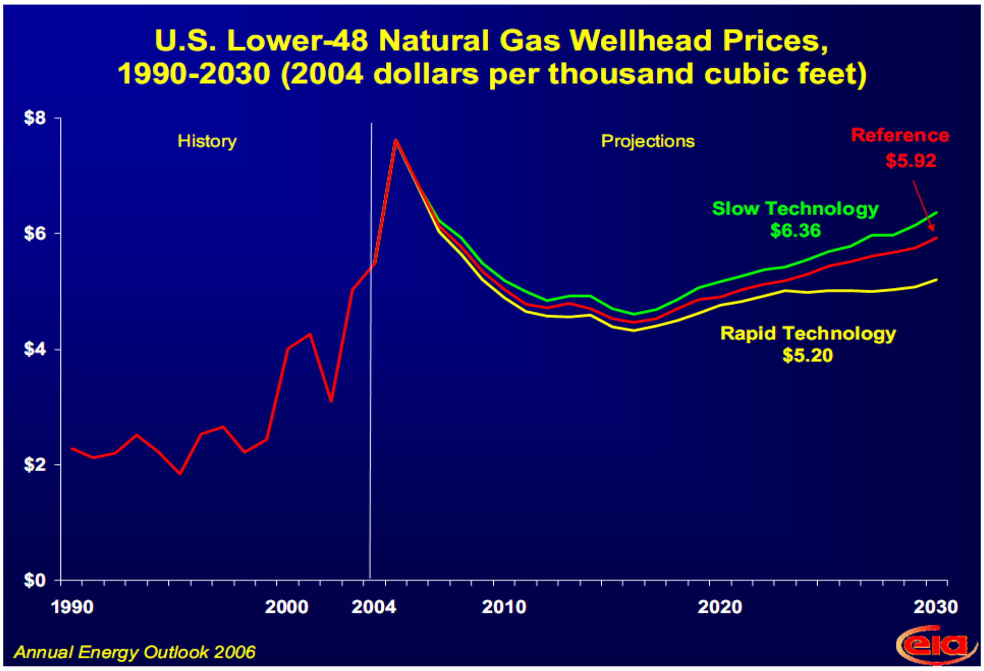
Figure 6-5: The major sources of incremental U.S. natural gas supply will be unconventional gas, Alaska, and LNG
Tight sands formations will dominate unconventional gas production, but shales grow rapidly

In Russia, after 2010 in many old gas-producing regions on land there will be an active development of resources of unconventional sources: accumulations of gas in dense low-permeable reservoirs at middle- and, mainly, great (4-7 km) depths, methane of coal-bearing beds in industrially coal-bearing ("opened") and oil-gas-bearing ("closed") basins, the smallest accumulations, and after 2030-2040 - also gas-hydrates [22].

It seems quite real and geologically justified, that the summary annual production of natural gas from unconventional (according to modern concepts) sources will be in 2050 not less than 170-200 BCM. By the end of the 21st century the share of "unconventional" gas in total production in Russia, including water areas of the seas, will reach (as per various estimations), 70-80%, because of considerable exhaustion of reserves and resources of "usual" gas at depths, accessible to development.

6.4 UNCONVENTIONAL GAS PRICE OUTLOOK AT 2030

Average real natural gas wellhead prices are projected to fall from today's high levels to just under \$5 per thousand cubic feet (mcf) (2005 dollars) (1000 ft^3= 28,31 m^3) by 2013 as increased drilling brings on new supplies and new import sources become available. After 2013, natural gas wellhead prices are projected to increase gradually, to about \$6 per mcf in 2030 (equivalent to \$9.63 per mcf in nominal dollars) [21].



Note : The economically recoverable CBM gas in the Powder River Basin doubles when the well-head price is raised from $3 to $7

Figure 6-6: US Lower-48 Natural Gas Wellhead Prices, 1990-2030

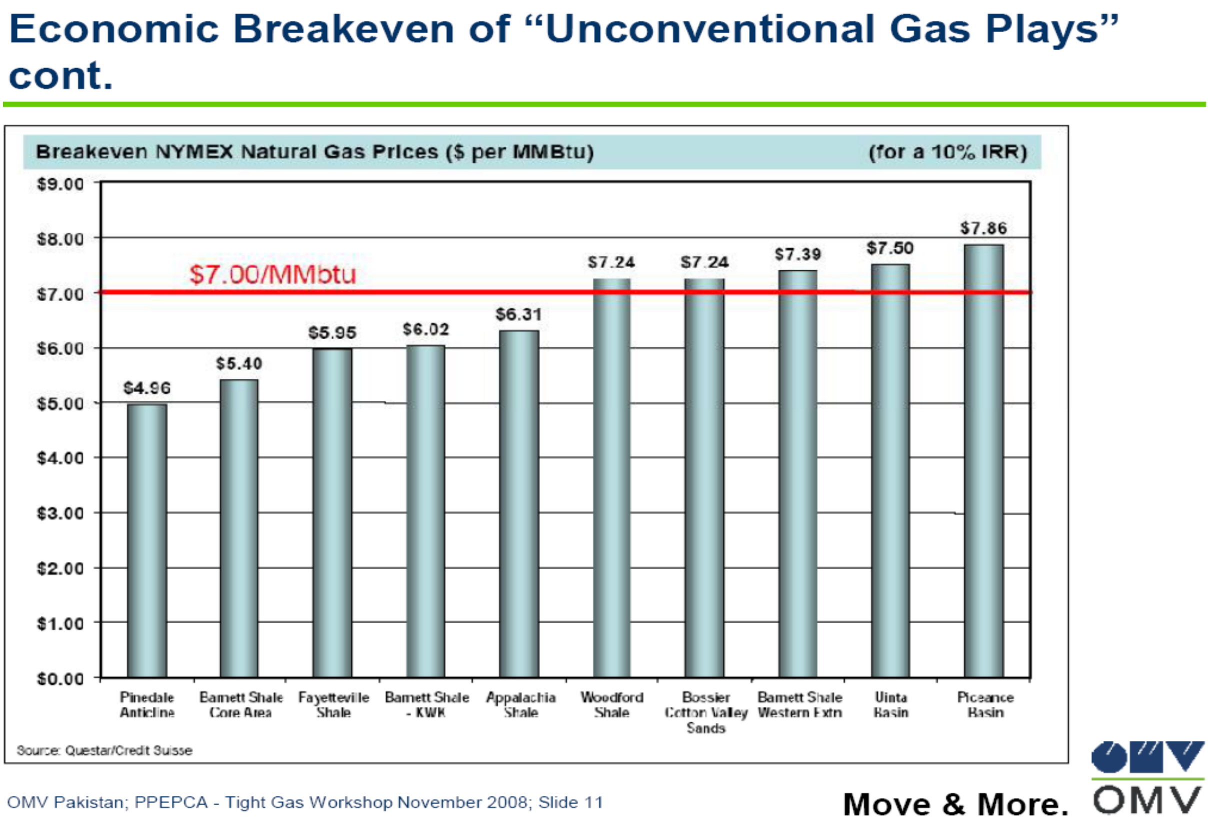
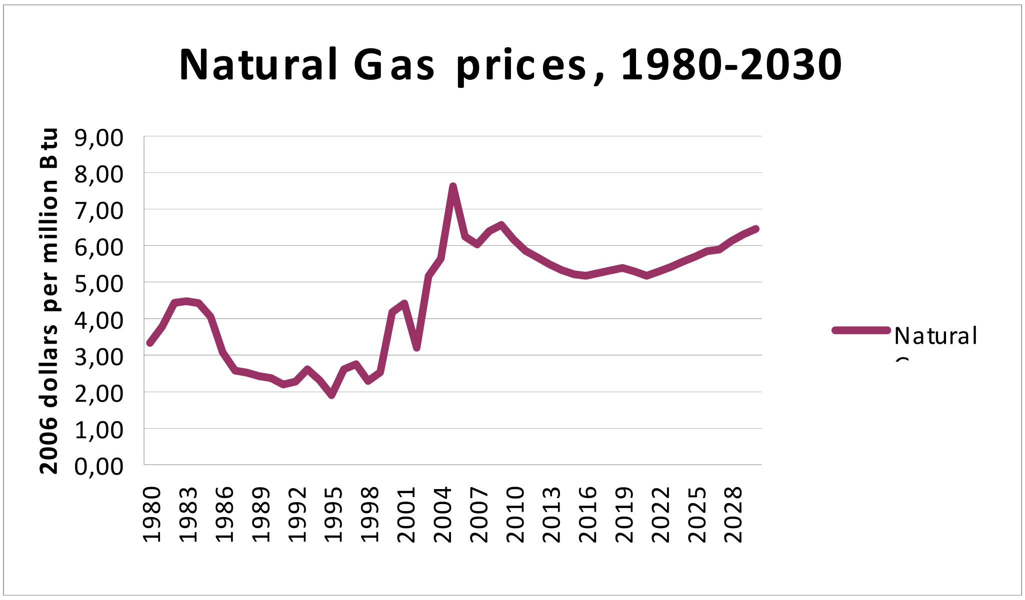


Figure 6-7: Economic Breakeven of "Unconventional Gas Play"

High production costs to extract unconventional gas (estimated in a range between 5US$/MMbtu and 7US$/MMBtu) involve high market prices to underpin production. Below 7US$/MMBtu, producers could start decreasing drilling activity (currently at its historical peak) and CAPEX. In such a case, the growth of US domestic production should be rapidly curtailed [21].



Source WEO2008.

Figure 6-8 : Natural Gas Prices, 1980-2030

The price of natural gas also is higher in the AEO2008 reference case. The real wellhead price of natural gas (in 2006 dollars) declines from current levels through 2016, as new supplies enter the market. After some fluctuations through 2021, real natural gas prices rise to $6.5 per million Btu in 2030 ($10.35 per million Btu in nominal dollars). The higher natural gas prices also are supported by higher oil prices.

According to these two graphs, it is appearing that the price levels needed to stimulate the development of difficult reservoirs and unconventional gas resources will not be economic until 2025.

7 CONCLUSION

IGU, through this study, try to have vision of current and potential of the Unconventional Gas by including country profiles, major project case studies, and new technology research.

Taking into consideration both reserves and resources, many of those who have estimated the volumes of natural gas in place within unconventional gas reservoirs agree that it is a large resource . The situation for Unconventional Gas is therefore favourable. Hence, it is expected that Unconventional Gas will be available for many decades to meet the global demand.

Development of unconventional sources requires significantly increased investment levels, continued technology advancements, and potentially large carbon management infrastructure.

However, there are large differences in the occurrence of Unconventional Gas reserves with respect to the gas markets. For example, the European natural gas market is in a comfortable position due to relatively easy access to neighbouring regions rich in natural gas reserves. These are in particular Russia and other CIS countries, North Africa and the Middle East.

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