2012-2015 Triennium Work Reports

Working Committee 1

Natural gas exploration and production

Chairman: Denis Krambeck Dinelli

June 2015

2012-2015 Triennium Work Report
June 2015

Working Committee 1

Natural gas exploration and production

Chairman: Denis Krambeck Dinelli
Secretary: Marcos de Freitas Sugaya

Produced by:
International Gas Union

Abstract

In the current IGU triennium (2012-2015), WOC 1 Natural Gas Exploration and Production selected three themes to develop, having set up three study groups accordingly: (1) Technological advances in gas exploration and production, (2) Assessment of global reserves and resources and (3) Gas rent and mineral property rights.

The first study was motivated by the fact that the production of natural gas has become significantly more expensive over the last years, not only because the new reserves are more difficult to develop than the previous, but also because the cost of the services and products consumed by the industry increased substantially over the last years.

Thanks to the development of new technologies, however, productivity has also improved significantly, and thanks to that gas continues to be one of the most abundant and affordable fuels in the world.

As new opportunities arise, however, new technological frontiers must be consolidated. The study group has covered all such challenges, starting from a revision of the technologies and standards that have become mandatory in the development of upstream projects, aiming at the consolidation of best practices for both conventional and unconventional gas, especially those related with the preservation of the environment.

Building on the list started in the previous triennium, new technologies that have recently emerged via R&D were highlighted and presented according to the conventional life cycle of E&P projects, i.e., exploration, appraisal, development and production.

The second study group promoted an assessment of conventional and unconventional gas reserves and resources. Some of the most important projects under development were described, and their potential impact in the availability of natural gas from both regional and global standpoints was inferred.

Exploratory hotspots and new frontiers were highlighted, and the most important trends, opportunities, uncertainties and threats to be faced by the upstream segment of the gas industry were described and analysed.

The third study group compared some of the most important models in use to balance the interest of upstream investors and governments. Looking at the maximisation of their intakes, governmental regulators must create and maintain an attractive atmosphere for business which will actually develop a win-win situation for themselves and upstream investors.

Concession, sharing, buy-back and transfer of rights contracts have been analysed, together with the large arsenal of fiscal instruments used by regulators and policy makers, including signature bonuses, royalties and taxes on profits of varied nature.

Governments must ensure a proper balance of risks and rewards to promote the development of their projects, but conditions have been found to vary dramatically from country to country.

Topics of interest covered by the study included the identification of regulatory tendencies, the assessment of business models for exploration and production of gas, critical analyses of fiscal instruments and the development of upstream policies for gas rent.

In the end, a number of best practices are described as a means to help the industry, policy makers and regulators in securing a reliable and affordable supply of natural gas to the consumers.

WOC 1 Triennial Report

2012-2015

STUDY GROUP 1.1

TECHNOLOGICAL ADVANCES IN NATURAL GAS E&P

Study Group Leader

Adif Zulkifli (Petronas, Malaysia)

Study Group Members

Lin Shiguo	Petrochina	China
Yang Li	Petrochina	China
Wang Guangjun	Petrochina	China
Lee Seungho	Kogas	Korea
Ilya Shireen Harith	Petronas	Malaysia
Im Xaxanuhani Zulkifli	Petronas	Malaysia
Lenny Marlina Omar	Petronas	Malaysia
Datin Rashidah Abdul Karim	Petronas	Malaysia (chief editor)
Nazri Idzlan Abdul Malek	Petronas	Malaysia
Andrey Kniazev	Gazprom	Russian Federation
Ekaterina Litvinova	Gazprom	Russian Federation
Boris Sharipov	Gazprom	Russian Federation
Chalermkiat Tongtaow	PTT E&P	Thailand
Phathompat Boonyasaknanon	PTT E&P	Thailand
Yassine Mestiri	ATPG	Tunisia

Paris

June 2015

Table of Contents

1 TECHNOLOGICAL ADVANCES IN NATURAL GAS E&P

Executive Summary

This report was compiled to analyse the present state of knowledge of the most important technologies in use for the exploration and production of conventional and unconventional natural gas.

Reservoir characterization

As fields mature beyond primary depletion and the perception that more needs to be done to maximize extraction out of existing reservoirs, a renewed impetus and drive on understanding reservoir characteristics has grown, gradually at first and rapidly later.

Reservoir characterization seeks to derive all the pertinent information that is required to adequately describe a reservoir in terms of its ability to store and produce hydrocarbons over time. This entails knowing the complete reservoir architecture, including the internal and external geometry, the distribution of reservoir properties and the flow of fluids within the reservoir.

Focus over the years have been on seeing better through seismic and electro-magnetic methods, pore and log scale derivation of reservoir properties, understanding reservoir geometry and continuity, including flow baffles such as fault dynamics, properties and modelling.

Recent advances have led nevertheless to increasing success in exploring for gas fields through better definition of the subsurface and the power of predictive modelling. These two factors have allowed operators to harness subsurface clues to hunt for gas and to utilize the power of computing for describing the unseen subsurface to great details in order to reduce uncertainties during field development and production.

The development of predictive models to simulate subsurface phenomena is extremely useful, but it requires the integration of a full suite of geophysical, geological, reservoir engineering and drilling skills.

Unconventionals

Technology continues to be a game changer for businesses, and one important example in that direction lies in the entry of new players in the production of shale gas, especially in countries seeking to reduce their dependence on foreign energy supplies.

The original breakthrough technologies have now spun off numerous innovations to manage the impacts on the environment through lesser use of water for fracking, produced water recycling, lower vibration while drilling and faster operations.

Under the current scenario of low oil prices, the impetus to find technologies to lower cost of production of unconventional oil and gas has also impacted the production of conventional hydrocarbons, especially in regions where reserves are dwindling and facilities are ageing.

Best practices for the production of unconventional gas are pointed out in the last part of this report, where the experience accumulated with the production of shale gas in the North Montney prospect is shared as key factors for success.

The production of gas from hydrates has also experienced formidable progress in the last years, including a demonstration unit in Japan, which was able to reach an average rate of 20,000 m^3 for six days.

Gas flaring and venting reduction

According to the 2014 report of the Intergovernmental Panel on Climate Change (IPCC), the total anthropogenic greenhouse gas (GHG) emissions have continued to increase, in spite of the growing number of climate change mitigation policies. From 1970 to 2010, annual GHG emissions grew by approximately 0.4 Gt CO_{2eq}, which is about 1.3% per year, while from 2000 to 2010, they grew to approximately 1.0 Gt CO_{2eq}, which is about 2.2% per year.

Actions to reduce carbon-dioxide emissions have long been viewed as fundamentally opposed to economic growth, but in a recent report the Global Commission on the Economy and Climate (GCEC) refuted this reasoning. Far from being a detriment to economic growth, the commission concluded that efforts to combat climate change could boost growth considerably and relatively soon (GCEC, 2014).

Before that the industry had already moved ahead, embarking on innovations that could yield a significant reduction of upstream emissions, in spite of gas prices that have not always been attractive.

Mid-stream monetization players have also made a breakthrough in the upstream space with the offering of floating and modular processing facilities that can have an important impact on the inhibition of flaring and venting in small, remote and offshore fields. While floating LNG has progressed to a second wave of new builts, micro-GTL and gas to chemicals are starting now to acquire a more important recognition.

Production of gas in remote areas and harsh environments

Automation, new materials and robotic innovation could also become game changers in the future as players seek to cut operating base costs and ensure profitability while increasing their affordability for higher risk exploration ventures. The final part of this report brings case studies that illustrate the application of technological solutions in the Canadian shale of North Montney and the Russian Artic.

1.1 Introduction

Technology has played a key role in the upstream and downstream segments of the gas sector, ensuring cost, competitiveness, environmental sustainability and operational excellence (Figure 1.1 and Table 1.1).

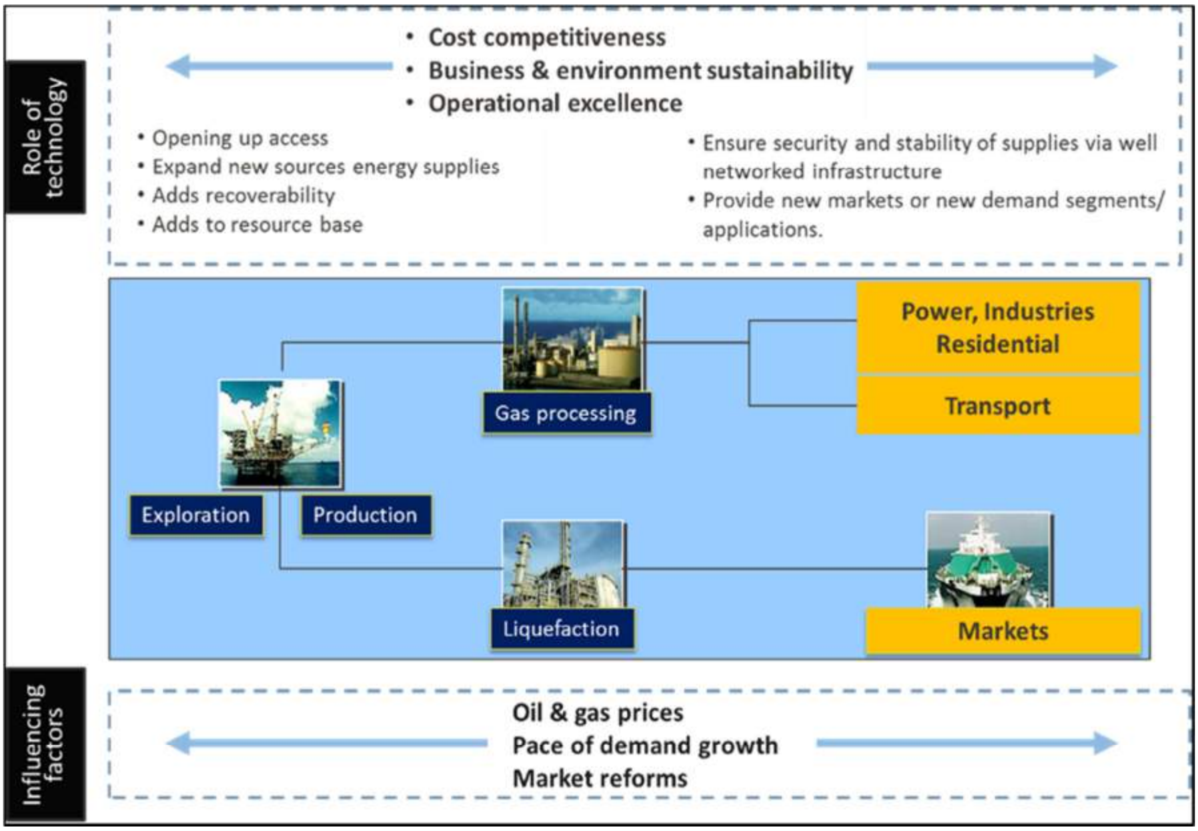


Figure 1.1 The role of technology in the production of natural gas.

Table 1.1 Statistics on upstream technology (www.naturalgas.org/environment).

- 22,000 fewer wells are needed on an annual basis to develop the same amount of oil and gas reserves as compared to 1985.
- Twice as much wells would be required to produce the same amount of oil and natural gas, ad technology remained constant since 1985.
- Drilling wastes have decreased by as much as 148 million barrels due to increased productivity and fewer wells.
- The drilling footprint of well pads has decreased by as much as 70 percent due to advanced drilling technology, which is particularly important in sensitive areas.

- By using modular drilling rigs and slim holes, the size and weight of drilling rigs have been reduced by up to 75 percent, reducing surface impact.
- Had technology and thus drilling footprints remained at 1985 levels, today's drilling footprints would take up an additional 17,000 acres of land.
- New exploration techniques and vibrational sources mean less reliance on explosives, reducing the impact in the environment.

The supermajors are among the most important R&D spenders, as advancements in technology are key for them to access to premium acreages, with higher productivity, reduced costs and other important advantages (Figure 1.2).

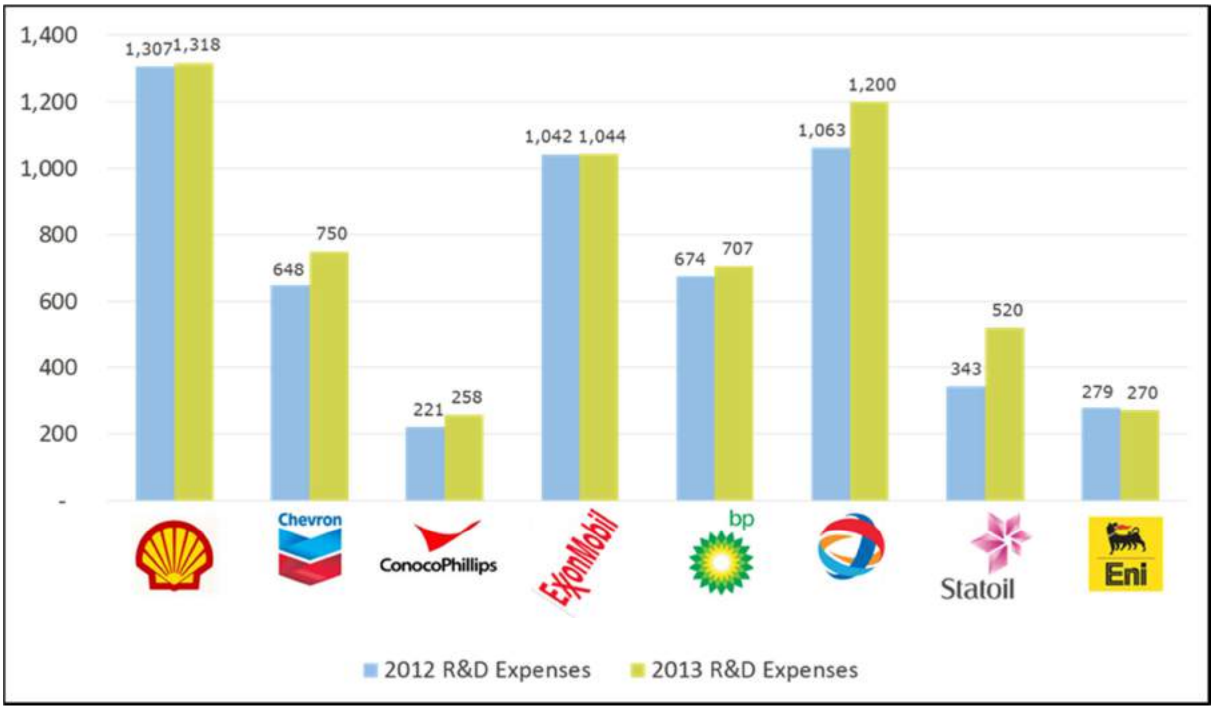


Figure 1.2 R&D expenditure of selected majors in 2012 and 2013.

While oil and gas companies generally acknowledge that technology takes an important part in their businesses, however, they rank relatively low when compared to other industries such as pharmaceuticals and biotechnology. In 2014, for example, the Industrial R&D Investment Scoreboard of the European Union ranked the oil and gas sector at the 12th position, behind health care and leisure goods, and not far from telecoms and banks (Figure 1.3).

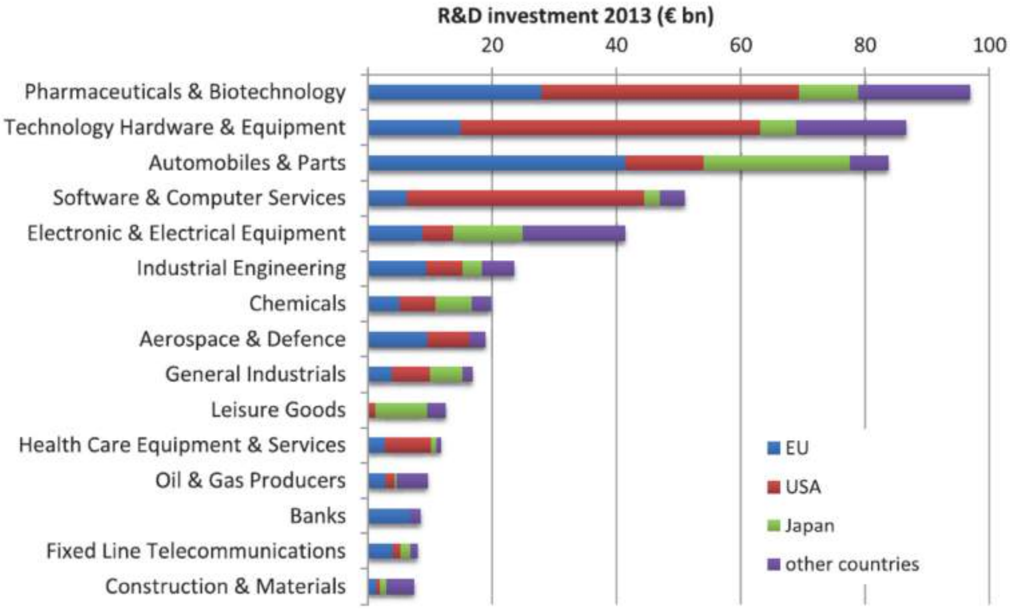


Figure 1.3 R&D ranking of industrial sectors and share of main world regions for the world's top 2500 companies (Hernandez et al., 2014).

In spite of that, technology is gaining a higher prominence in the production of oil and gas, as it has become imperative to shift the production into technically challenging areas such as deep waters, deep reservoirs, unconventional resources and harsh areas such as the Arctic Circle (Figure 1.4).

Figure 1.4 The relative importance of challenging areas is increasing.

Hydraulic fracturing has been a key factor in the exploitation of shale resources. The technology has been around since the middle of last decade, but the increasing scale and intensity of its usage has now resulted in greater scrutiny, particularly with regards to the quantity of chemicals and water used in the process and issues related to water contamination and earth tremors. Lured by the US success history, many gas importing countries are now assessing the possibilities of their local resources, and by 2025 there could be as many as 15 new shale gas producing countries (Wood Mackenzie, 2013).

The relative importance of deep water areas is also increasing, driven by recent discoveries and the emergence of prolific areas such as the East Mediterranean (Levantine), East Africa (Rovuma basin), offshore West Australia (Carnarvon basins) and Latin America Equatorial Margin (Guyana basin), to name just a few (Figure 1.5).

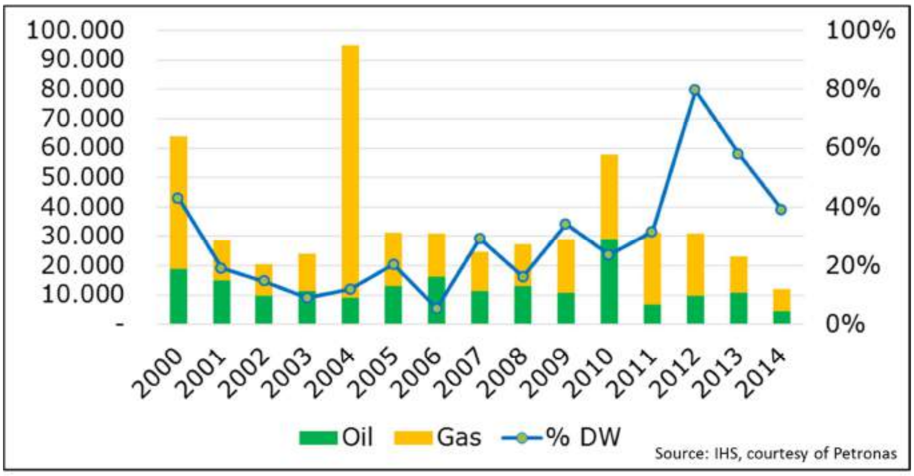


Figure 1.5 Trends in oil and gas discoveries (IHS, 2014).

LNG is one of the clear choices to monetize gas discoveries, particularly in areas of low gas demand, and the industry has already started to develop floating plants and other innovative solutions, not only to take advantage of the huge potential that exists in this area, but also to reduce the flaring and increase the overall efficiency of the operation (Figure 1.6).

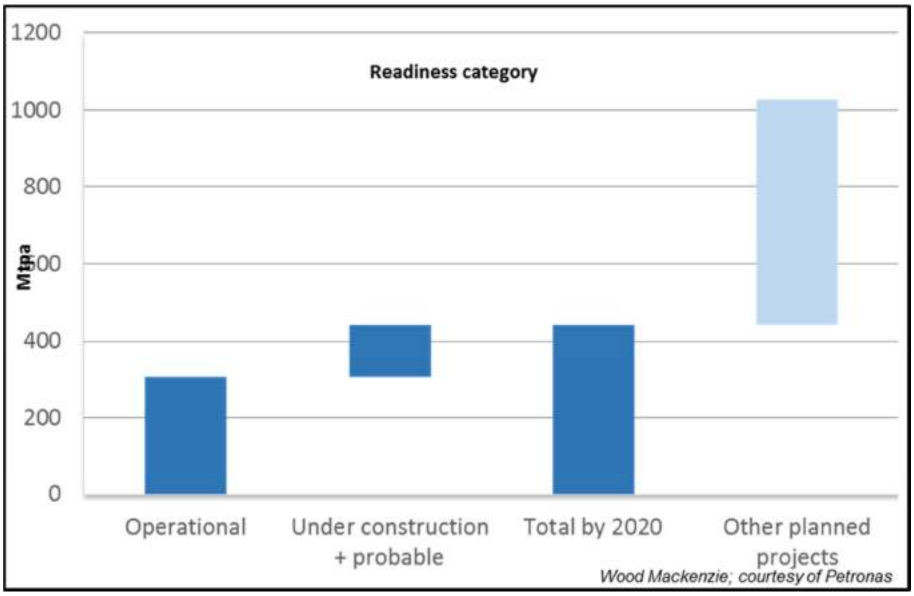


Figure 1.6 LNG liquefaction plants (mtpa).

Significant progress has also been made in methane hydrates. Efforts to produce them have been around for decades, but in March 2013 Japan announced its first successful offshore production test, marking the feasibility of commercial production, which is now targeted for 2018.

Last but not least, the industry will also need to move the technology curve up into other challenging areas such as high temperature and high pressure (HPHT) fields, high CO_2 reservoirs, ultra deep waters and production under harsh climate conditions, following on the foundations that have already been acquired through decades of testing and experimenting (Figure 1.7).

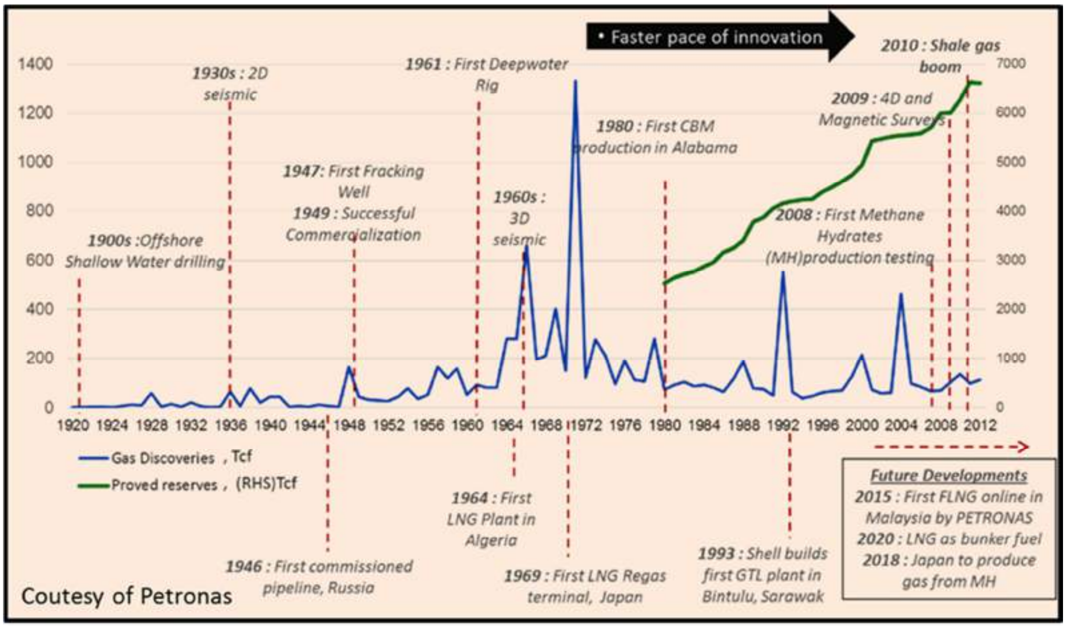


Figure 1.7 Progressive technological development in the production of natural gas.

Prices will be key to incentivise investments in R&D, therefore driving the industry towards a greater pace of innovation, unlocking frontiers and opening up new and alternative resources.

1.2 Technologies for gas reservoir characterization

Reservoir characterization has attracted remarkable research efforts particularly over the past 20 years. Advanced instruments have improved the gathering, processing and monitoring of data, thereby improving their overall quality and reliability to unprecedented levels. On top of that, the development of related technologies such as computing and data mining has allowed for a more comprehensive integration of outcrop analogues, seismic, geological information and well logs. Finally, advances in subsurface digital 3D visualisation have been important for the development of reservoir models that are much richer in information and facilitate the development of production strategies.

1.2.1 Gas cloud imaging

Gas clouds are accumulations trapped as overburdens that lower P-wave velocities (Vp) and frequencies in the seismic, disrupting transmitted energy and obscuring events beneath it. Such anomalies can be formed by biogenic and thermogenic processes, which produce local gases such as methane, ethane or CO_2.

A related phenomenon is the formation of diagenetic zones in channels bends (Figure 1.8) or pockmarks (if the gas escapes to the seabed surface). The seepage of gas bubbles making their way through a leaking fault system is usually large enough to be visible in the form of gas chimneys in the seismic image (Figure 1.9). Depending on the geological structure, the gases may also get trapped and saturate as shallow gas complexes.

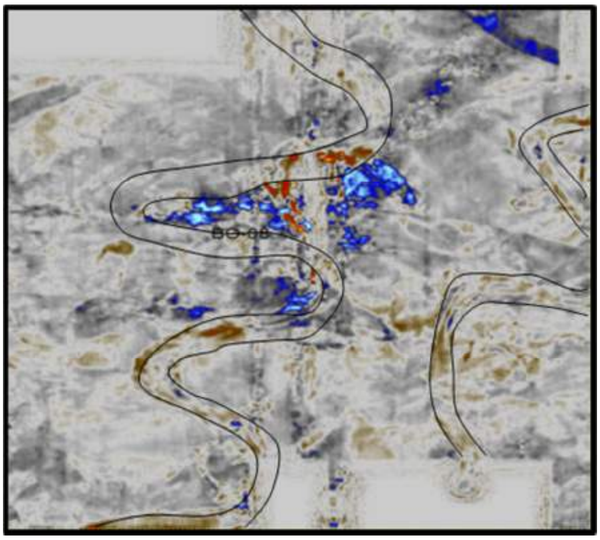


Figure 1.8 Gas anomalies (blue) in channel systems.

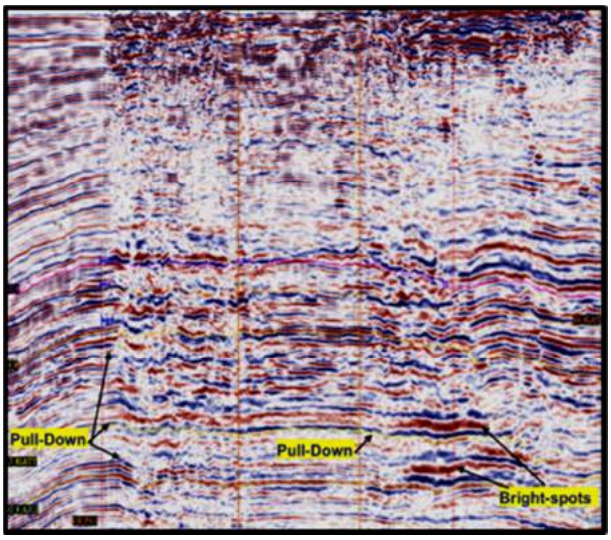


Figure 1.9 Gas seepage effects seen on the seismic as chimneys.

The presence of gas in the shallow overburden causes multiple scattering in the thinly layered heterogeneous media and was first described by Anstey (1971). A nonlinear full waveform re-datuming method proposed by Ghazali (2011) utilized a multiple scattering phenomena that described the overburden as a complex scattering and translated it into a transmission correction operator. Since it is a nonlinear full waveform inversion method (FWI), it is important to characterize the rock properties in the gas clouds to identify the factors that caused the formation of the shallow overburden in order to constrain non-linear inversion results. Complex seismic wave propagation in the heterogeneous media due to multiple scattering of complex wave fields also leads to amplitude attenuation.

Arntsen (2007) modeled the connected fracture network above a reservoir with a finite difference model whose outcome was a gas chimney that closely mirrored the artifacts seen on the original seismic section (Figure 1.10). This particular approach has been used to remove imprints from the reflections below the overburdens, rendering true imaging of structures and fluids through nonlinear full waveform inversion (FWI) and re-datuming, as proposed by Ghazali (Figure 1.11).

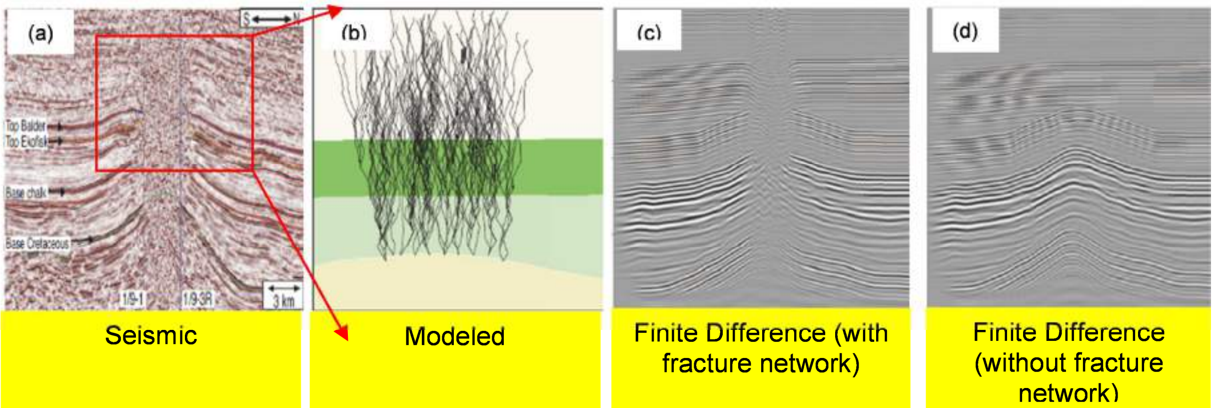


Figure 1.10 A seismic section of a Tommelitan alpha field (a), modelling of the connected fracture network located above the reservoir (b) and finite difference results (c, d). From Arntsen *et al.*, 20007 – courtesy of Petronas.

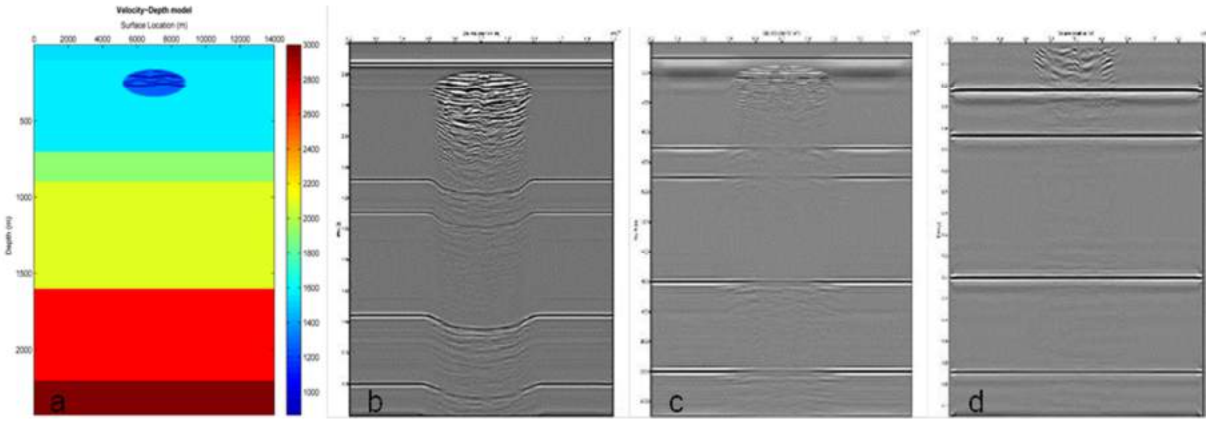


Figure 1.11 A velocity-depth model with shallow overburden (a), a stack section from an acoustical finite difference model showing a time sag (b), pre-SDM result of the model after solving for effective medium of shallow overburden via FWI (c) and the stack section after full waveform re-datuming, showing better definition of the target horizons (d). From Ghazali, 2011 – courtesy of Petronas.

The problem of imaging through gas clouds is experienced in many basins. Ultimately, better reservoir imaging can be obtained through coupling of an appropriate data acquisition method with an advanced seismic processing workflow. Four components ocean bottom seismic data acquisition coupled with powerful seismic processing algorithms yields enhanced imagery in most cases.

Ocean bottom seismic (OBS) is a well-established technology which resolves many of the known limitations of towed streamer seismic acquisition technologies, which are often unable to provide any meaningful data over the central part of a structure due to the presence of gas in the overburden and inadequacy of the PP data. By contrast, 4C OBS provides PS data that is insensitive to the presence of low saturations of gas in the overburden (Figure 1.12).

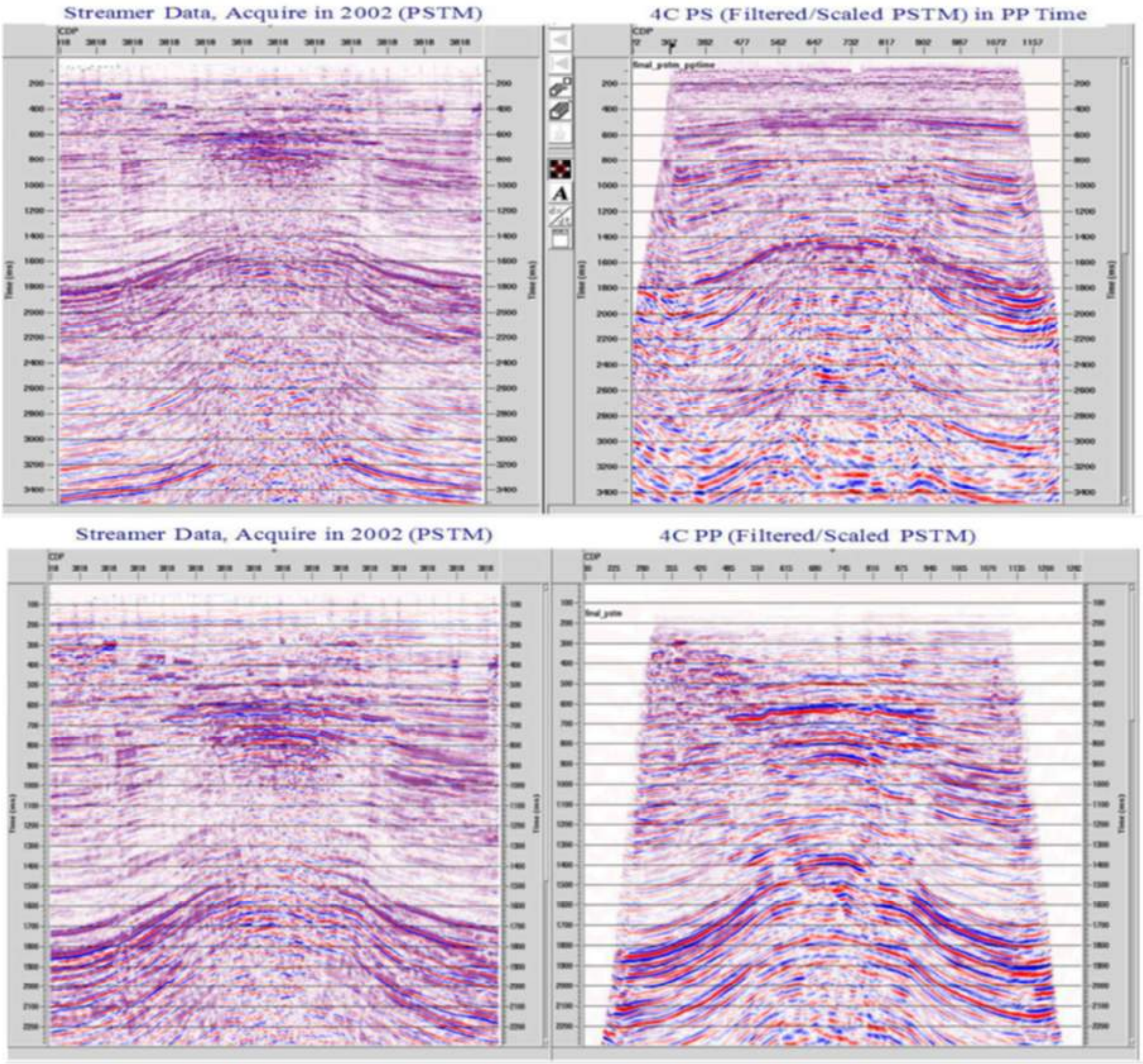


Figure 1.12 Imaging comparison for a gas area between PP and PS (Courtesy of Petronas).

Among the main benefits of the 4C-OBC seismic methods are:

- Broader signal band-width achieved through dual sensor summation.
- Better P-wave imaging through wide azimuth coverage (3D-4C).
- Improved seismic imaging below gas invaded zone.
- Better lithological discrimination using Vp/Vs ratio.
- Fracture identification and characterization by studying the shear wave splitting in an anisotropic medium.

The challenge to make the seismic acquisition cost effective, especially for smaller fields, involves the use of non-vessel based equipment and running acquisition in campaigns to minimize costs of mobilisation and demobilisation. When multiple surveys are required for fluid front monitoring, permanent ocean bottom installations can be justified as the onetime costs of equipment are defrayed over several on demand seismic data acquisition runs.

1.2.2 Reservoir modelling[1]

Digital reservoir models are built as a means to unite the geophysicist and geologist in the creation of fit-for-purpose reservoir models that improve decision-making and maximise the recovery factor.

Model-driven interpretations allow geoscientists to guide and update a 3D, geolocially consistent structural model directly from the data. Geoscientists create suites of model realizations that satisfy many external constraints, from well picks and zone logs to velocity uncertainties and horizon or fault positional uncertainties. These model realizations allow to quantify uncertainty in subsurface parameters.

Furthermore, model driven interpretation provides a forum for cross-disciplinary interactions: geophysicists, with a strong understanding of the complexities of seismic data, can work together with geologists, with their understanding of the lithologies and facies.

Multiple models, responsive workflows, capturing the limitations of the data and quantifying geological risks early help to increase reservoir recovery factors and commercial success. Uncertainty maps can be used to investigate key risks in the prospect, or areas can be quickly identified for more study. The possibilities are wide and varied, but the fact remains that by capturing uncertainty at the beginning of the geoscience workflow, operators gain the best possible picture of their subsurface risks (Figure 1.13).

[1] Includes public domain material from Roxar's and Tracero's websites.

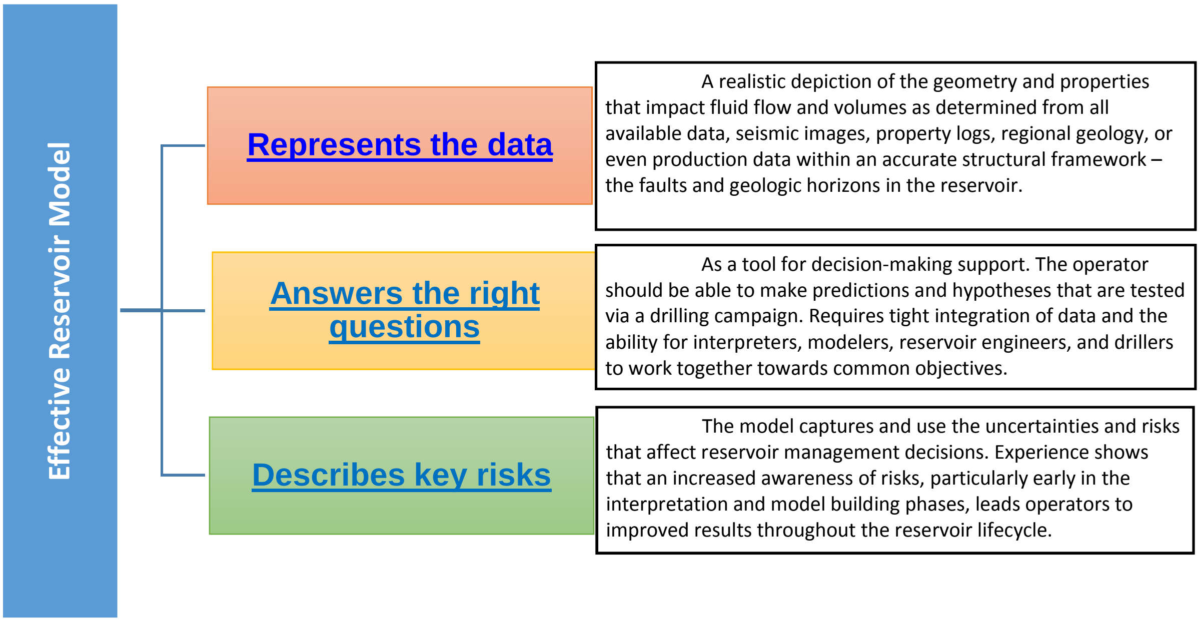


Figure 1.13 Effective reservoir model guide

There are several pitfalls in reservoir modelling as follows:

- Over-dependence on single model

Conventional industry workflows in geosciences still remain geared towards producing a single model or scenario, even though it is widely accepted that multiple scenarios fit the data better. The result is that many alternative hypotheses are discarded and not carried through to decision-making.

- Disjointed and time-consuming workflows

At many companies, workflows are segmented and 'siloed'. Geophysicists interpret thousands of points at seismic scale, and geomodellers do the best they can to fit the model to the interpretation. Iteration and quality control is time consuming and resource intensive. Too often data are ignored, or, in the case of poor seismic data, interpretations may be overestimated and the data quality forgotten.

- Ambiguity of the data

All subsurface data are uncertain to various degrees. Whether it is trajectory uncertainty associated with a well log or bandwidth limitations of seismic data, ambiguous measurements result in uncertain estimates of horizon or fault locations. Many configurations or scenarios are therefore possible, but cannot be distinguished by the data alone.

- Uncertainty in static reservoir properties

The static reservoir properties (for example, the structure or interpretation, depth conversion, fault model, or facies distributions) are the largest contributors to the commerciality of a prospect. These factors must be integrated to obtain risked estimates for decision support.

1.2.3 Fluid flow

Knowledge of subsurface fluid flow provides valuable information to a reservoir field development team during hydrocarbon recovery. This information can be used to ensure effective reservoir displacement to maximise hydrocarbon extraction efficiency.

In cases where there is uncertainty in the contributions from each reservoir zone, tracer technology can be used to detect fluid flows for each completed producing zone. Similarly, tracer technology can be used to identify where injection water would breakthrough into the well (Figure 1.14).

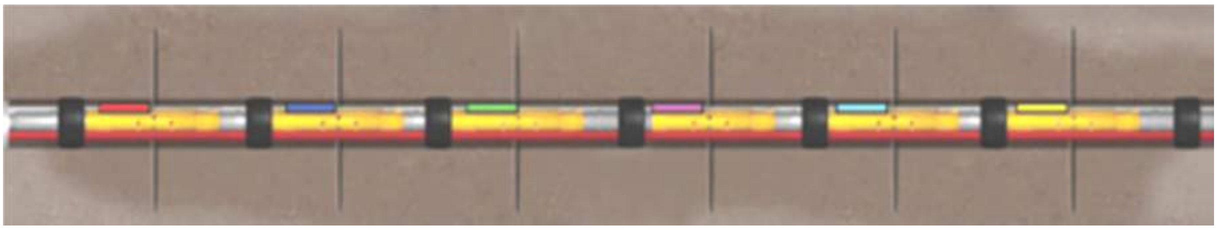


Figure 1.14 Monitoring in-flow oil production through a sliding sleeve completion for chemical tracer technology applications.

Controlled release chemical tracer technology can provide the operator with valuable inflow data without the need for well intervention. These techniques are applied in many development stages from drilling wells to field development and also in late field life to monitor the effectiveness of tertiary recovery operations.

In a production reservoir model, it is sometimes necessary to validate the fluid flow reservoir simulation models. Tracers can be used to detect where flows are entering the borehole at the different completion stages and in cases where multilateral wells are used, the maximisation of oil production over water requires the understanding of the order of flow of water and oil in different parts of the wells (Figure 1.15).

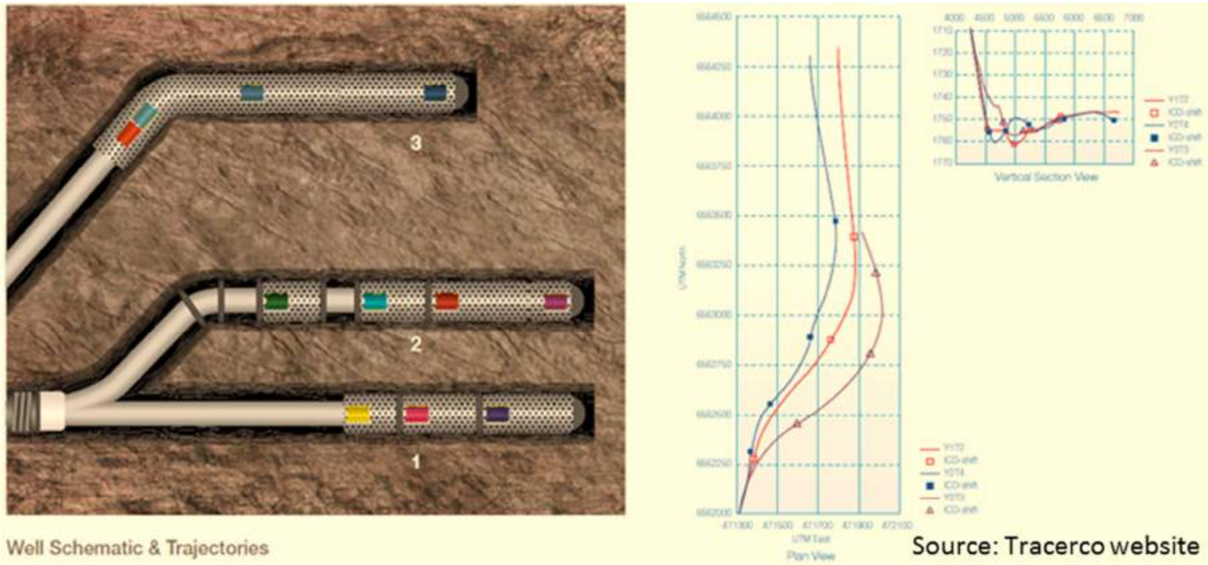


Figure 1.15 Monitoring the sequence of hydrocarbon and water flows in multilateral wells.

1.3 Technologies for the production of unconventional gas

The hunt for unconventional hydrocarbons is driven by the premise that sustainability into the immediate future requires cleaner forms of hydrocarbons as the world's population continue to increase and concentrate into cities necessitating the creation of jobs and energy for economic growth. As gas is cleaner, it is in a prime position to surpass coal to become a foundation fuel.

While methane hydrates have been touted as a future source of hydrocarbons, being plentiful and accessible both onshore and offshore, many technical and environmental issues will need to be handled before commercial production of this voluminous resource can become mainstream. There has been exciting progress made in recent years and this section will highlight some of the recent achievements and the challenges going forward.

1.3.1 Shale gas[2]

The economical extraction of shale gas more than doubled the projected production potential of natural gas, from 125 years to over 250 years. The fulfilment of this outlook requires cost effective technologies to create a positive balance for operators producing through the swings in the market price of gas.

By contrast to conventional gas reservoirs, shale gas reservoirs have very low permeability due to the fine-grained nature of the original sediments (gas does not flow easily out of the rock), fairly low porosities (relatively few spaces for the gas to be stored, generally less than 10% of the total volume), and low recovery rates (because the gas can be trapped in disconnected spaces within the rock or stuck to its surface).

The last two factors (low porosity and low recovery) are responsible for the fact that the volume of recoverable hydrocarbons per surface area is usually an order of magnitude smaller than for conventional gas. The low permeability reservoirs require pervasive natural fractures to be present or to be artificially created before the absorbed gas can be released to flow into the wellbore.

As producers are focused on continuous technological improvement, costs are expected to continue to decline, but the associated production of liquids has been a boost to profits, especially during sluggish market conditions. They have opened up a frenzy of acquisitions.

Primary technological breakthroughs in horizontal drilling and multi stage fracturing have allowed economic development, but advances in artificial stimulations, product slurries

[2] Based on presentations performed at IGU WOC 1 meetings; courtesy of CNPC and DrillingInfo

and highly efficient drilling operations for high well density drilling campaigns known as 'factory operations' have contributed to a healthier bottom line. The "shale gas factory" concept drives down costs significantly and is rapidly spreading to new shale plays outside of the US to UK and Europe, leading to some pilot testing in China.

The principles of lean manufacturing are applied to the shale gas factory to eliminate the waste of time, natural resources, people and assets while improving the quality of the wells. Working several wells at once is a key component of the job, both in drilling and fracturing.

A typical well site operation consists of multi-horizontal wells drilled from centralized well pads that are subsequently fractured. The well site includes a skidding rig, truck mounted drilling rig, coiled tubing truck, fracturing truck, slush pump, mud and water tanks (Figure 1.16).

Figure 1.16 A typical shale drilling operation.

Pad drilling

Pad drilling is the practice of drilling multiple wellbores from a single surface location and is one of the most important innovations from an economic standpoint. Prior to that, an operator would drill a single well, disassemble the drilling rig, move it to a new location, and then repeat the process.

Through pad drilling, 4, 10, 20 or more wells can be drilled from a single, compact piece of land. Doing so saves time and money that would be spent packing and moving the rig and preparing a new drilling site. It also means a smaller impact on the area landscape. (Figure 1.17 and Figure 1.18).

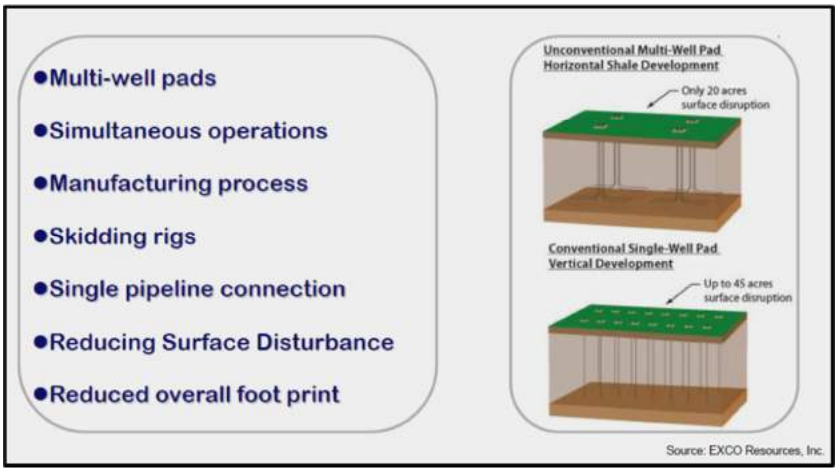


Figure 1.17 Factors for minimizing operating costs and surface footprints.

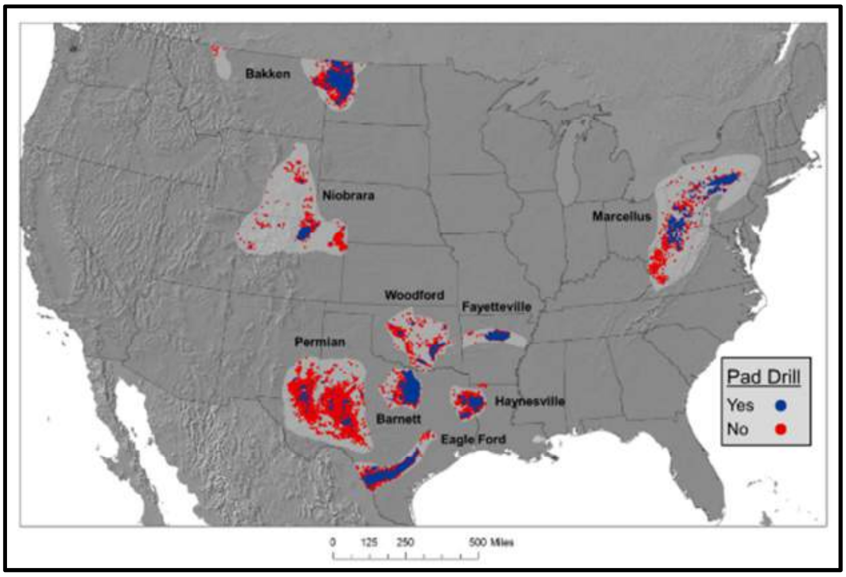


Figure 1.18 Location of wells perforated from 2004 in nine plays in the USA (DrillingInfo, 2014).

The fracking process involves significant challenges in managing fracking fluids, pumps and well pressures in order to obtain fractures with the correct dimensions and orientations (Figure 1.19), but the shale gas factory concept saves land and reduces surface disturbance dramatically (Figure 1.20).

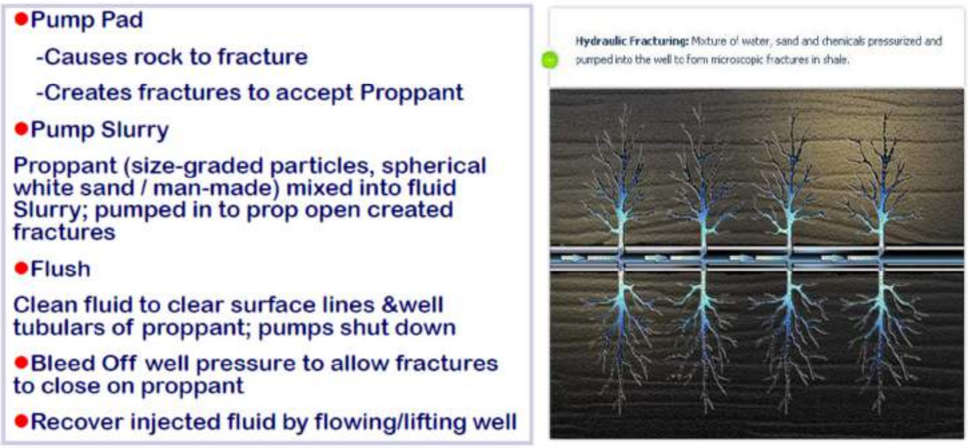


Figure 1.19 Fracturing process (courtesy of CNPC).

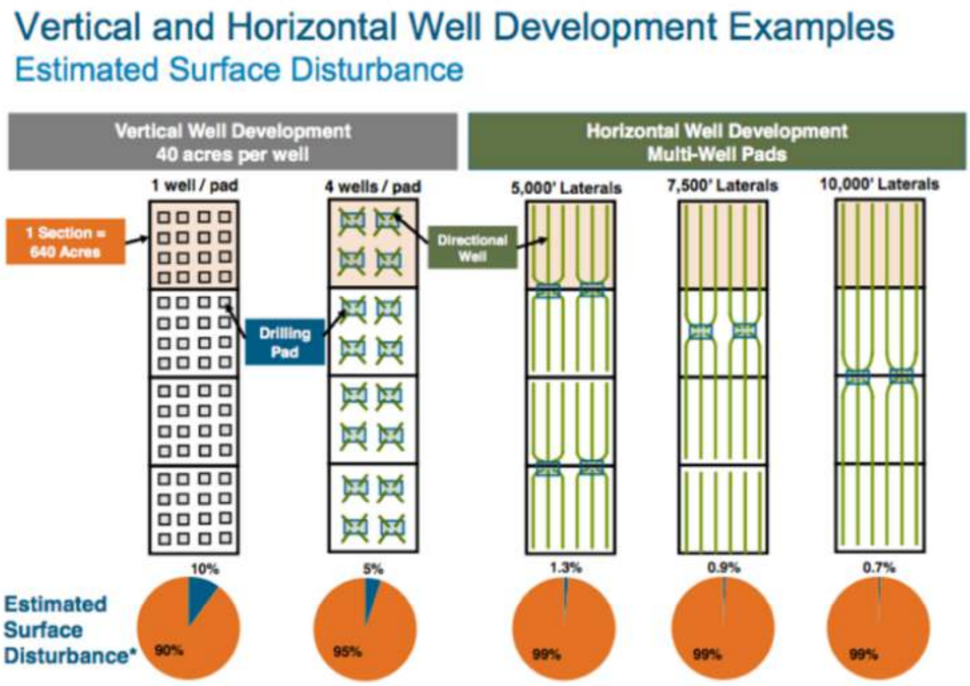


Figure 1.20 The impact of different wells on the surface footprint (courtesy of CNPC).

A 6+ well pad, for example, requires only 8.5 acres for horizontal drilling, which means that only 0.7% of the land is initially disturbed, and this is further reduced upon completion of the development. On top of that, the factory concept paves the way to equipment maximisation and efficient use of the work force available (Figure 1.21).

Figure 1.21 Efficient subsurface penetration and minimal surface impact as a result of the multi well pad system (courtesy of CNPC).

Further optimisation of the land use is obtained by ensuring the proximity of the wells to the process trains, regardless of the mode of well fracking: zipper mode or simultaneous operations (Figure 1.22 and Figure 1.23).

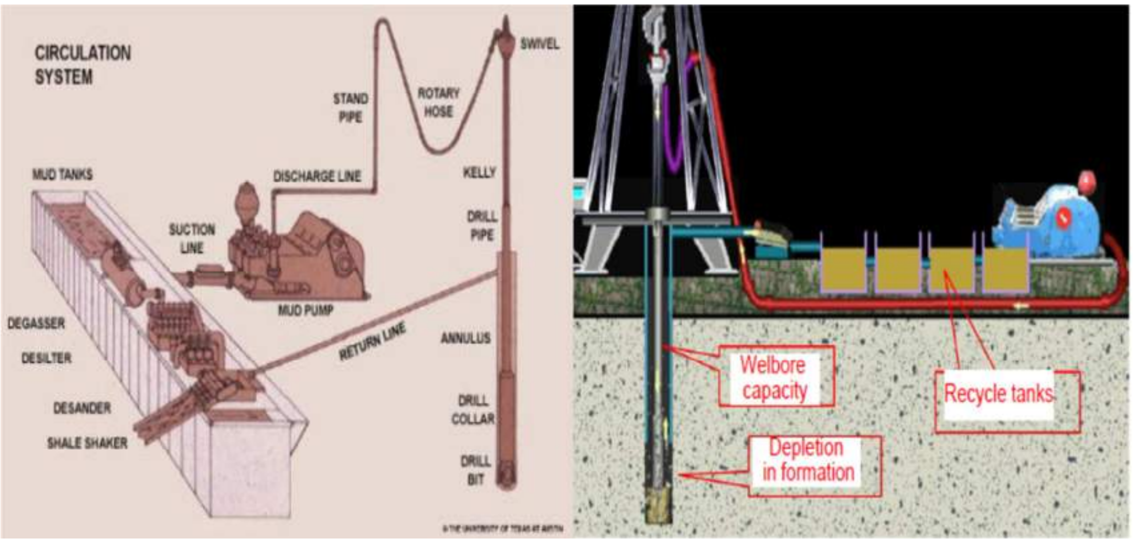


Figure 1.22 The proximity of the wells to the process train minimises the surface footprint (courtesy of CNPC).

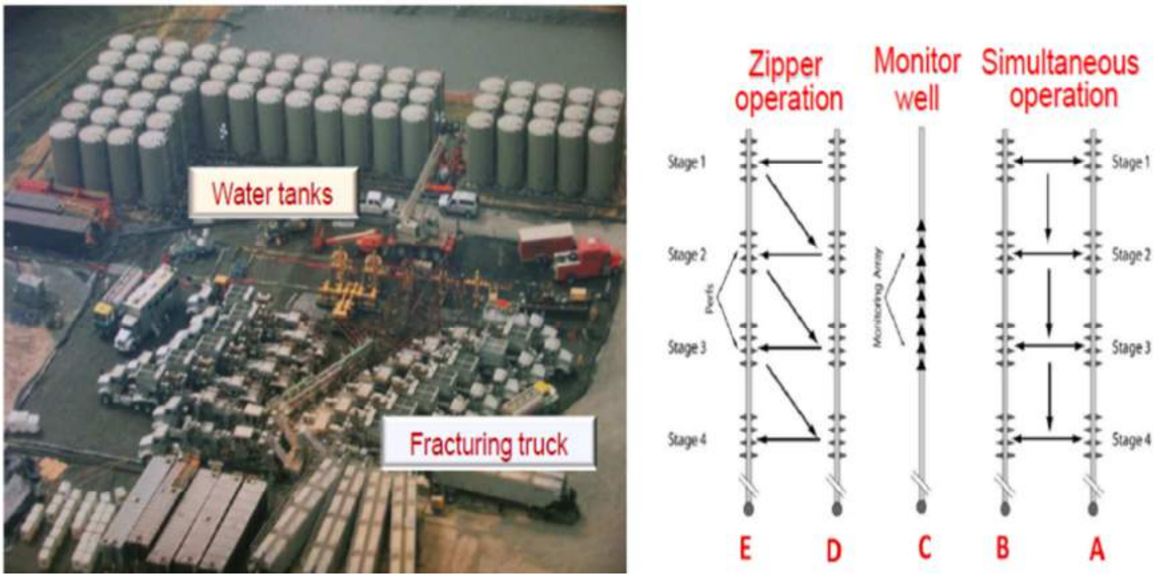


Figure 1.23 Options to maximise the use of fracking equipment.

Treatment and disposal of waste water has always been an important issue in the production of unconventionals, but companies have found new ways to recycle it. After collection and several steps of purification, the water can be reused for future fracking and even for drilling (Figure 1.24).

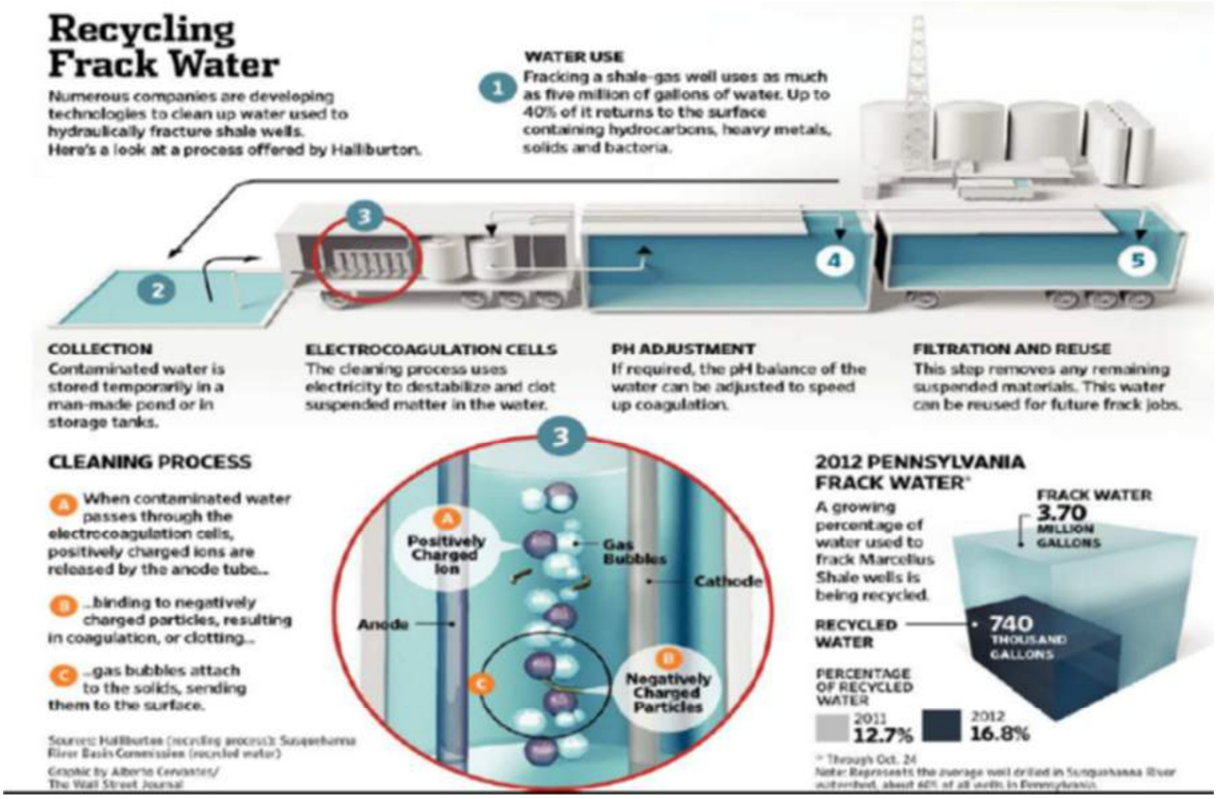


Figure 1.24 Water treating for re-use and decreasing sewage for environmental requirements (courtes of CNPC).

Well interference

Well interference occurs when two or more wells attempt to drain the same reservoir volume. In general, the individual well productivity is reduced when the wellbore spacing is reduced, but the total production rate is increased.

The effect of infill drilling on well productivity is difficult to measure, due to the number of variables involved. Differences in geology, drilling and completion practices, and production strategies all have an impact on both initial and long-term well productivity. On top of that, benchmarking is complicated because interference can be present at different levels during the life of the wells.

Many operators in the USA are developing fields with wellbore spacings of 300-600 feet in plays such as the Bakken, Eagle Ford and Marcellus, but it is important to understand the phenomenon because it affects the drilling strategy and the long long-term productivity of the play.

For that purpose, it is useful to look at neighbouring wells that started production apart from each other in time. As an example, Figure 1.25 and Figure 1.26 compare production rates obtained in the Barnett formation in the USA using six and twelve month cumulative values, respectively. As can be seen, the individual productivity declines significantly as the wellbore spacing is reduced, especially when the time increases.

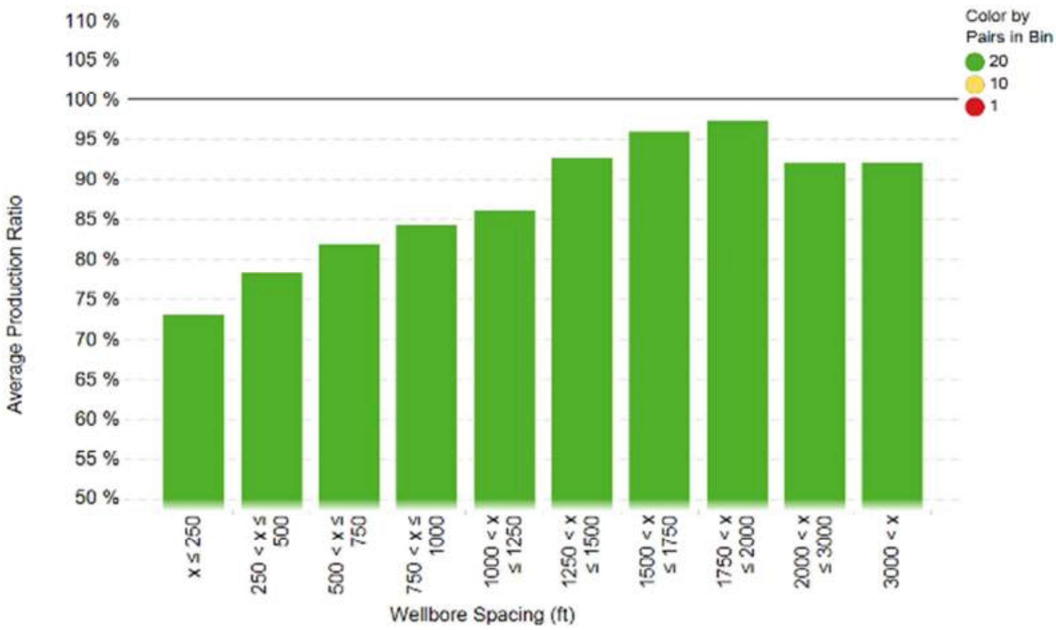


Figure 1.25 Analysis of well interference using six month cumulative production values (DrillingInfo, 2014).

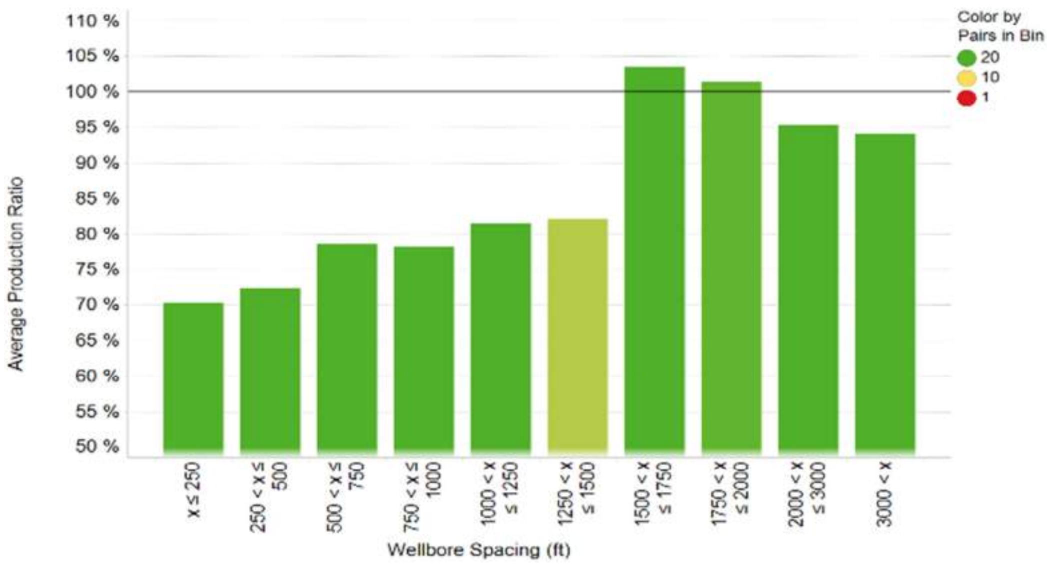


Figure 1.26 Analysis of well interference using twelve month cumulative production values (DrillingInfo, 2014).

Shale gas acreages are different in terms of reservoir productivity and hence longevity of wells, but results such as these indicated here are useful for operators to balance on well productivity and the total production rate that they should have. There is much work currently being pursued to understand the mechanisms involved in the release of natural gas.

1.3.2 Methane Hydrates[3]

Methane hydrates are ice-like materials composed of methane and water molecules under high-pressure and low-temperature conditions and as such expected to be an important hydrocarbon energy resource in the future.

The formation and stability in the subsurface of these structures are constrained by a relatively narrow range of high pressure and low temperature and depend on the influx of free gas and the amount of gas dissolved.

Global estimates of in-place methane gas as oceanic hydrates is at about 1-5 x 10^{15} m^3, which is approximately 2-10 times larger than the ultimate recoverable conventional natural gas resources available on Earth (Milkov, 2004). Assuming that new technologies can be developed to recover about 10 percent from these hydrates, this would allow for 30-170 years of an additional supply to the world.

Methane hydrates are abundantly found in the top few hundred meters of sediment beneath continental margins at water depths between a few hundred and a few thousand feet. They are present to a lesser extent in permafrost sediments in Arctic areas.

In the marine environment the gas hydrate stability is determined by water depth, seafloor temperature, pore pressure, thermal gradient and the gas and fluid composition. The base of the zone in which hydrate can exist is limited by the increase in temperature with depth beneath the seabed.

In 2001, the Japanese Ministry of Economy Trade and Industry (METI) launched an ambitious R&D programme for developing naturally occurring gas hydrate deposits in marine sediments around Japan. The Research Consortium for Methane Hydrate Resources (MH21) was then formed to accomplish the tasks defined in this programme, in which the most important organizations involved are the Japan Oil, Gas and Metals National Corporation (JOGMEC) and the National Institute of Advanced Industrial Science and Technology (AIST).

The programme consists of three phases, and the final goal is to establish a technology platform for the commercial production from offshore hydrates by 2018:

[3] Based on published papers courtesy of JOGMEC

- Phase 1: from fiscal year 2001 through 2008
- Phase 2: from fiscal 2009 through 2015
- Phase 3: from fiscal year 2016 through 2018.

Technologies for the assessment of resource availability

Resource assessment involves identifying hydrate bearing sediments through seismic signatures recognized on seismic profiles such as [A] bottom simulating reflectors (BSR), [B] turbidite sand sequences above BSRs identified on 3D seismic visualization, [C] strong seismic reflectors, and [D] seismic high velocities (Figure 1.27).

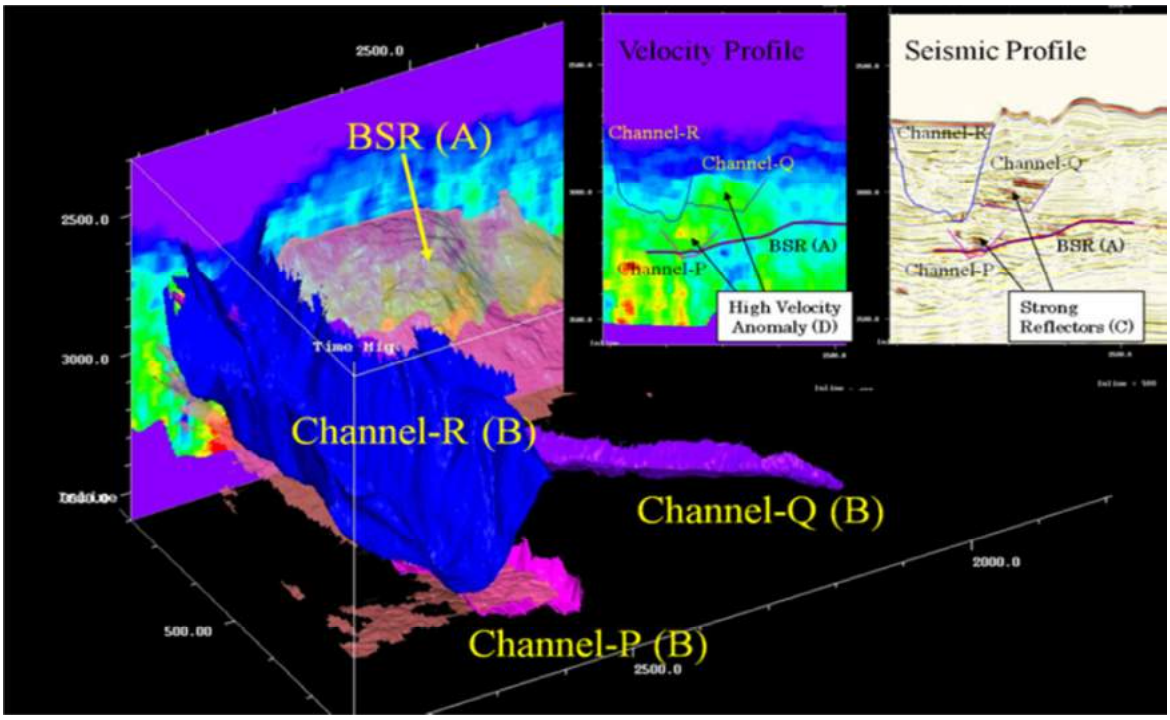


Figure 1.27 Seismic visualization of a methane hydrates accumulation (courtesy of JOGMEC).

The occurrence of hydrates can be estimated in well logs, in particular electrical resistivity and sonic logs. Gas hydrate bearing sediments show anomalously high electrical resistivity and high acoustic velocities. At the base of the gas-hydrate stability zone, which marks the contact between gas-hydrate and free-gas-bearing sediments, a distinct drop in acoustic velocity often characterizes the acoustic log.

Currently, the principal indicator of marine methane hydrates is the detection of bottom-simulating reflectors (BSR) on seismic data. Unfortunately, in older data these may have been processed away as they were not recognized for what they are. Reprocessing existing data, concentrating on the shallow section and the BSR should improve the estimates of the extent of this resource.

Probabilistic estimates have been conducted using gross rock volume, net to gross ratios, methane hydrate saturation, porosity, cage occupancy and formation volume factors.

Production technology

Two gas hydrate dissociation methods were tested at the Mallik 5L-38 well drilled by JAPEX/JNOC/GSC in 2002, thermal stimulation and depressurization. A modular formation dynamic test (MDT) showed encouraging results, and further laboratory and numerical modelling with the MH 21-HYDRES simulator suggested possible continuous and sustained gas flow in the reservoir with depressurization.

Depressurization is a gas production method to dissociate hydrates by lowering the wellbore pressure below the hydrate stability threshold (Figure 1.28). After completing a well in the hydrate sediment, gas production is water-lifted using an electrical submersible pump (ESP). Then the bottom hole pressure is decreased at the wellbore and this pressure reduction propagates into the hydrate formation. Hydrate dissociation is endothermic process, so the temperature goes down with dissociation, but geothermal heat is naturally supplied continue the process.

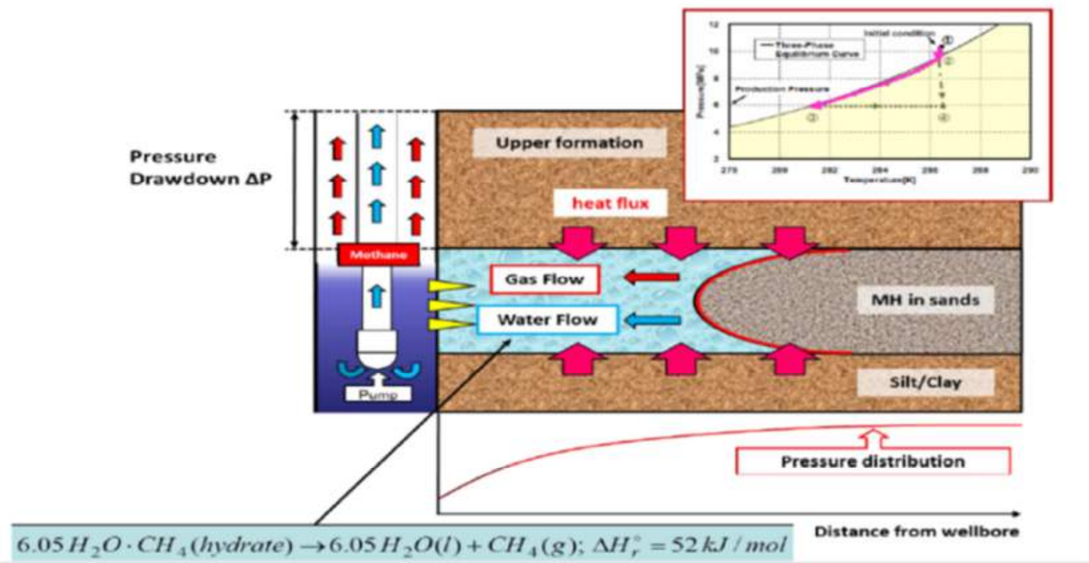


Figure 1.28 Concept of gas production method

Following a number of onshore trials, JOGMEC drilled the world's first offshore gas production well from hydrates on the Daini Atsumi Knoll in the Nankai Trough in water depths of 1000m, where the top of the hydrates zone was around 300 m below sea floor (Figure 1.29).

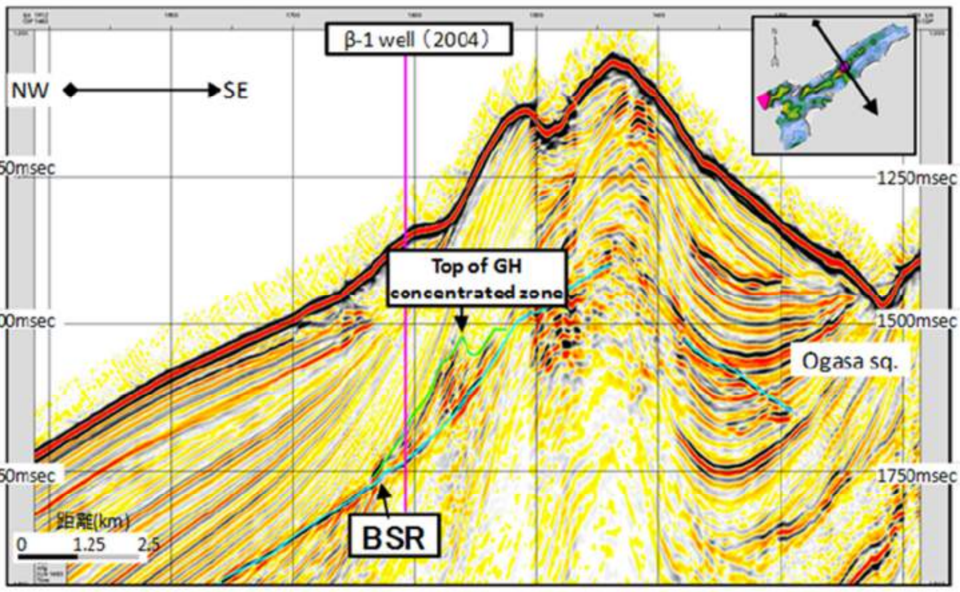


Figure 1.29 Seismic profile near to production test site

From late 2011 to early 2013, two monitoring and a producer well were drilled. Loging, coring and production completions using gravel packing were then undertaken (Figure 1.30).

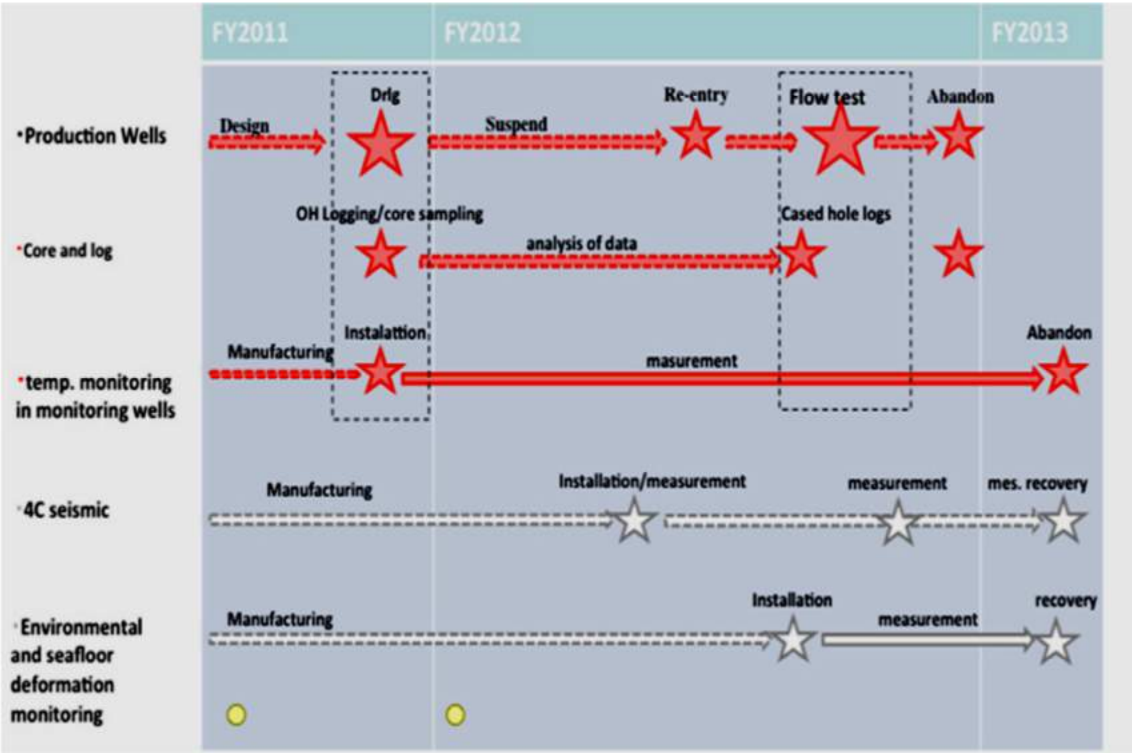


Figure 1.30 Production operations schedule for the world's first offshore hydrates well.

The extensive monitoring program designed to understand the dissociation and production behaviours included 4C/4D seismic, distributed and resistance temperature sensing, environmental and sea floor deformation monitoring. The cores recovered were analysed for mechanical properties and confirmation of the distribution of hydrate saturation in the target formation.

The producer well was completed as a 8.5" open hole with gravel packs in 2013. BOP and riser pipes were then run down to the production well, in which a 36" conductor pipe and a 13.375" casing pipe section had already been drilled in 2012. A 12.25" hole section was drilled to the bottom of a silty formation above the methane hydrate concentration zone (MHCZ), and a 9.625" casing was set.

There was some risk that the methane in the sediments could flow into the well and riser pipe, reaching the surface, but no significant free gas was observed. A sand control device was set in the open hole section to prevent that.

Subsequently, downhole production devices were run into the holes with electrical and optical cable splicing. A six-day cumulative production of 120,000 m^3 (4.2 mmcf) was obtained at an average rate of 20,000 m^3/d (706 mcf/d). Production had to be terminated at the sixth day due to an unexpected occurrence of sand, but important results were accomplished, i.e., the productivity, stability and integrity of the wells were confirmed, and the monitoring technologies implemented were effective to collect information on the dissociative behaviour of the hydrates. Much remains to be done in order to assure a stable, long term production, and to monitor and control the dissociation of the hydrates.

1.4 Technologies for the reduction of gas flaring and venting

It is widely acknowledged that flaring and venting of associated or solution gas contributes significantly to greenhouse gas emissions and has negative impacts on the environment.

The World Bank has estimated annual volumes of about 150 billion cubic meters being flared, which is enough to provide for the annual consumption of Germany and France together. Flaring in Africa alone produce 200 TWh, which is enough to provide for about 50% of the consumption of the entire continent.

Fewer than 20 countries account for more than 70 percent of the gas flaring and venting. And just four countries together flare about 70 billion cubic meters of associated gas (Figure 1.31 and Figure 1.32).

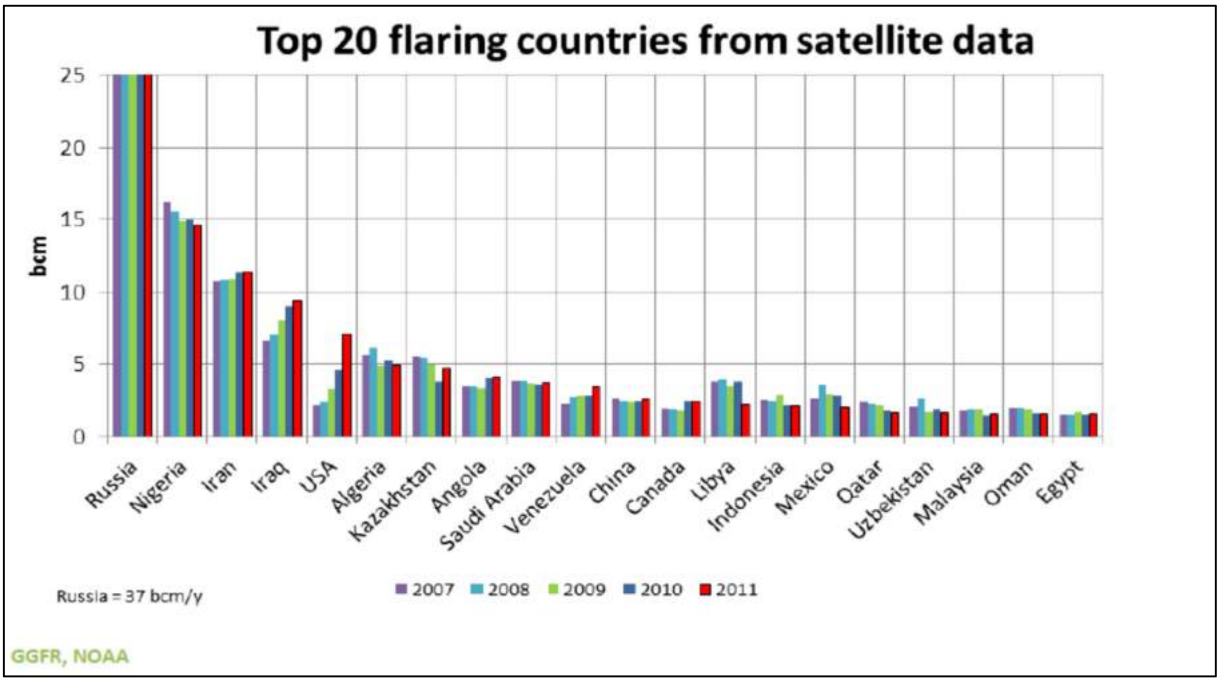


Figure 1.31. Top 20 flaring countries from satellite data.

Figure 1.32 Satellite detection of gas flares (GGFR, 2013).

1.4.1 Beyond technology and regulations

Before starting the description of the technologies that could be useful to the reduction of gas flaring and venting, it is important to mention two other instruments that are equally important and must be considered simultaneously.

Standards

International bodies such as the World Bank have encouraged and supported countries in the adoption of zero continuous flaring and venting policies as a standard by the year 2030.

In that direction, it is important to supplement the current gas flaring and venting regulations with national or international standards that can cover aspects not easily tackled by regulatory compliance regimes.

Such standards would be particularly important in setting targets for the reduction of emissions, and would also allow for operators to be benchmarked. For that purpose, metrics of flaring and venting intensity (FVI) should be adopted, e.g., tons of CO_{2eq} flared per ton of carbon extracted from the reservoir.

The FVI is above all a measure of a loss of opportunity, and could be used to accredit good performers.

Financial incentives and disincentives

In many countries, gas development projects are often hindered by the low value attributed to the natural gas, as compared to other energy sources such as oil and even coal.

Moreover, governments have aimed at the diversification of their energy sources to increase supply security and reduce environmental footprint, and this often results in subsidies and other advantages to make renewables more competitive.

Nevertheless, the economic value of the associated gas is the factor that ultimately encourages an operator to use, flare or vent its natural gas.

Many developing countries focus on the production of crude oil, and often consider the development of infrastructure to market the associated gas as burden. That could change if the benefits of using the gas were higher than its production costs.

Governments have adopted varied strategies in the development of royalties, taxes, duties and other fiscal instruments to discourage flaring and venting. It is worthy to mention a few:

- Promote the production of gas with larger fiscal incentives relatively to oil as a means to encourage oil field operators to market associated gas;
- Apply royalty waivers to improve the economics of associated gas;
- Adopt tax regimes that discourage flaring and venting of associated gas;
- Use the pilot auction facility (PAF) developed by the World Bank.

The latter is an innovative finance model that is expected to set a floor price for future carbon credits in the form of tradable put options. It has a capitalization target of $100 million, and is backed by several governments, which have already introduced carbon prices in the economic evaluation of projects (Figure 1.33).

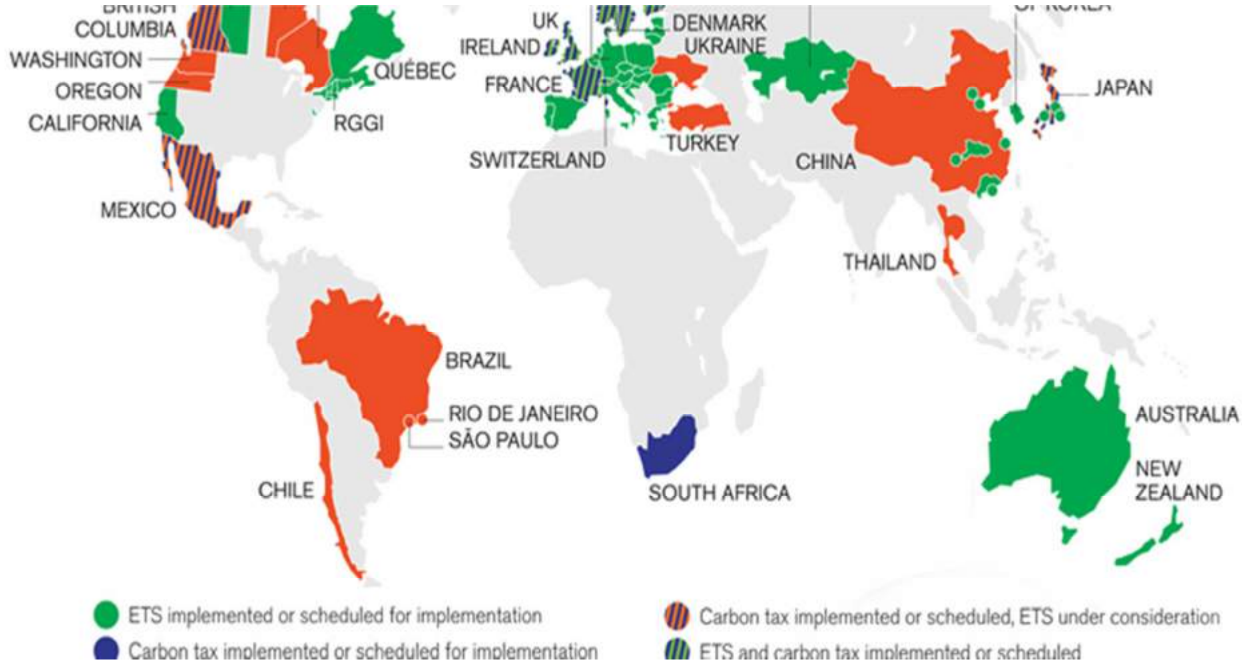


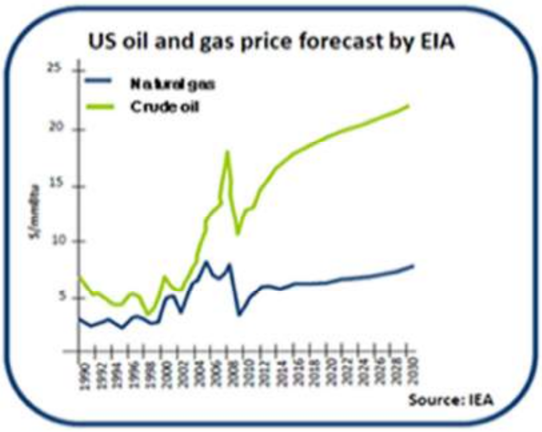
Figure 1.33 Global growth of carbon pricing (GGFR, 2014).

1.4.2 Mini gas-to-liquids technologies

Gas-to-liquid conversion (GTL) refers to the process of converting natural gas to synthetic oil. This has been done commercially for many years now (Table 1.2), but more recently mini or compact GTL technologies started to be developed for small scale fields and floating applications, offering the opportunity to extinguish flares. They become more attractive when a large difference between oil and gas prices occur (Figure 1.34).

Table 1.2 GTL project status.

Project	Country	Scale (bpd)	Start-up
Shell Bintulu GTL	Malaysia	14,700	1993
PetroSA Mossgas GTL	South Africa	36,000	1993
Sasol/QP ORYX GTL	Qatar	34,000	2007
Shell Pearl GTL	Qatar	140,000	2011
Chevron Escravos GTL	Nigeria	34,000	2013
Total		258,700	



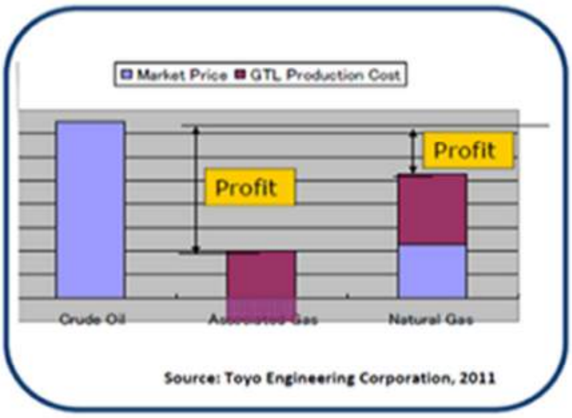


Figure 1.34. US oil and gas price forecast by EIA and GTL Economy (Fonseca *et al.,* 2012).

The engineering of mini GTL plants focuses on modular design, efficiency, simplicity, compactness, mobility and robustness (Figure 1.35). Over twenty five mini GTL technologies are currently under development at different levels of readiness, ranging from laboratory research to actual commercial offers (Figure 1.36).

Figure 1.35 A floating Mini GTL technology.

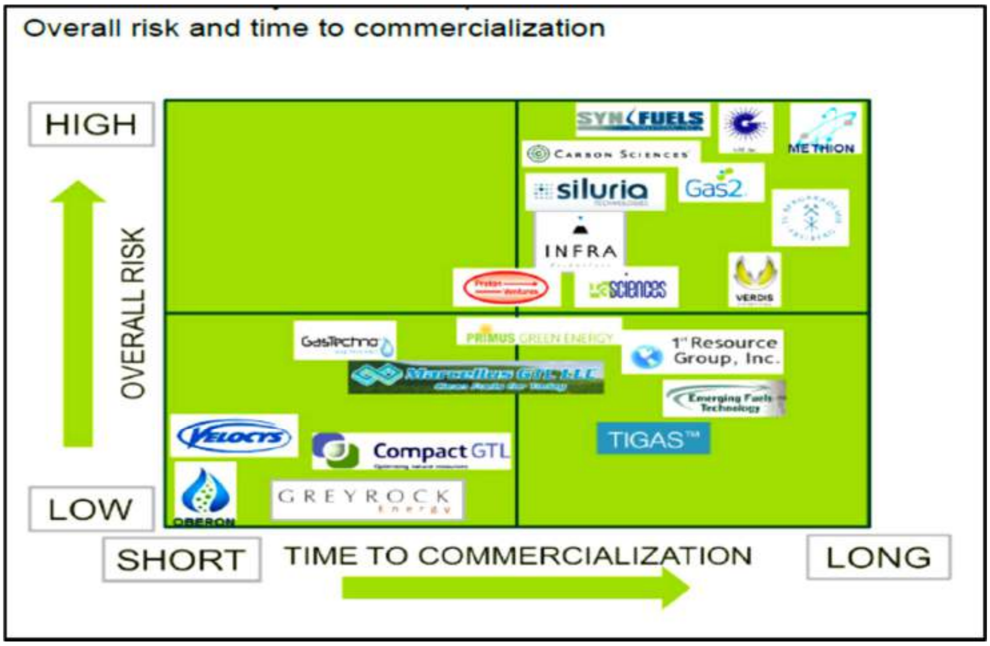


Figure 1.36 An assessment of mini GTL technologies.

Technologies oriented towards the production of gasoline, diesel and other products typically produced in oil refineries are more common, but other possibilities such as methanol and fertilizers are also feasible. The production of ammonia is particularly interesting in rural areas where gas flaring or venting occurs (Proton Ventures, 2012).

Velocys

This company seems to have taken the lead in developing commercial GTL-FT projects with an innovative micro channel reactor design, but a project from a competitor could change this situation quickly. Operation of a 6 bpd plant started in 2012 in Brazil in cooperation with Petrobras, Modec and Toyo Engineering.

Oberon Fuels

The first phase of a DME plant is operational in Imperial Valley, California, producing 4500 gallons per day (110 bpd) of DME from methanol. The fully integrated plant, including a reformer and a methanol production unit, was expected to be completed by 3Q 2014.

A partnership between Oberon Fuels, Volvo Truck and Safeway was recently announced to introduce DME as a clean diesel alternative. Two Volvo trucks operated by Safeway were expected to run on Oberon DME in Safeway's commercial operations during 2014. Commercial scale production of DME powered trucks would then commence in 2015. Volvo has identified DME as the cleanest, most promising diesel alternative for the future.

GasTechno

A pilot plant processing associated gas from an oil field in Michigan successfully demonstrated that the reactor system was capable of converting C1-C6 hydrocarbons from a flare to alcohols and aldehydes. GasTechno offers low capex plants for very small gas volumes, not readily addressed by other technologies (Figure 1.37 and Figure 1.38).

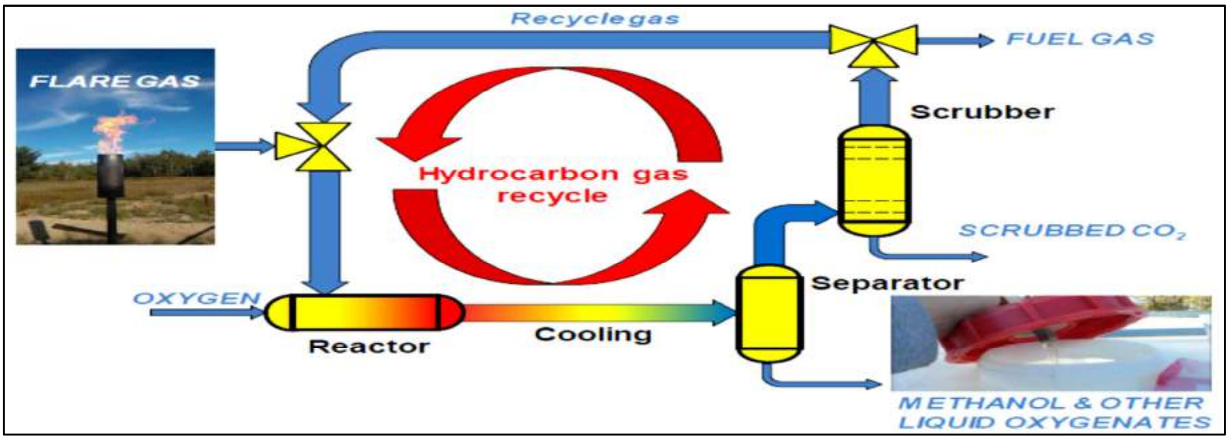


Figure 1.37 Conversion of flare gas to liquid oxygenates.

Figure 1.38 GasTechno's "GTL in a box".

Compact GTL

Compact GTL incorporate conventional reform and modular Fischer-Tropsch (FT) technologies in a single design. This hybrid process offer lower Capex and the potential to move up to larger production scales (up to 15,000 bpd), but commercial applications are still awaited. Pilot operation was completed with the application of a 20 BPSD plant with Petrobras in 2011 (Figure 1.39).

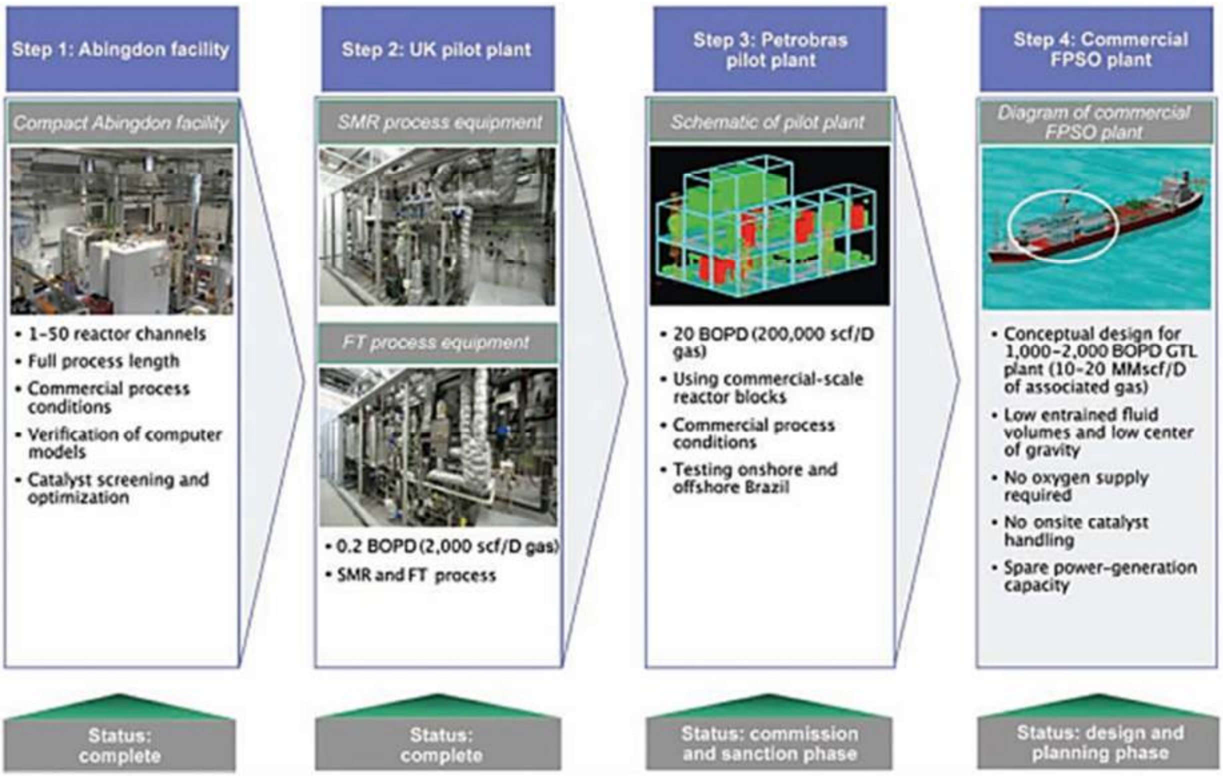


Figure 1.39. COMPACT GTL roadmap to a modular GTL plant.

1.4.3 Recycling of associated gas

PETRONAS is exploring the possibility of recycling associated gas to the reservoir cap in places where the gas demand is low and variable, in order to reduce greenhouse gas emissions (Figure 1.37).

1.4.4 Gas ejectors

Gas ejectors can use high pressure gas (HP) to safely and economically compress low pressure gas (LP) that would otherwise be flared or vented (Figure 1.40).

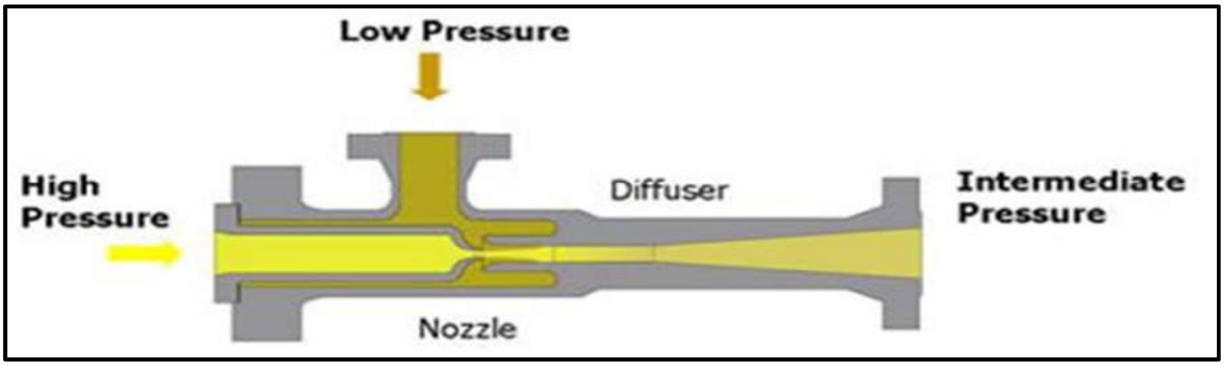


Figure 1.40 A gas ejector.

1.4.5 Multiphase pumps

Multiphase pumps can move flow streams containing variable amounts of gas and liquid by means of centrifugal or positive displacement methods. They eliminate the need for submarine separation facilities and can be useful to reduce gas flaring and venting by dispensing expensive compression facilities (Figure 1.41).

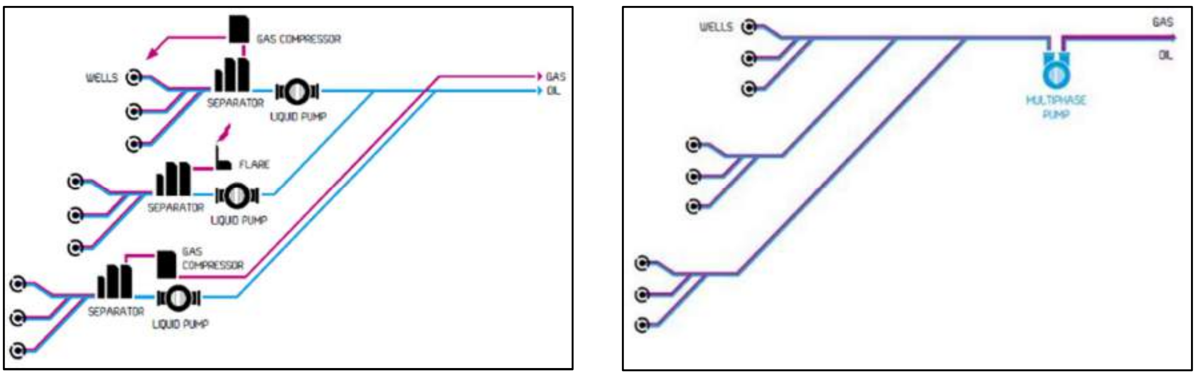


Figure 1.41 A multiphase pump eliminates the need for submarine separation facilities.

One interesting example is the twin screw pump, which is formed by two inter-meshing screws set to work with no metal to metal contact. Fluid mixtures of up to 97% gas content can be constantly pumped without overheating. For that purpose, the necessary liquid is stored in an enlarged housing and is partly recirculated to the inlet, assuring a convenient distribution of temperatures and heat transfer to the environment.

1.5 Case studies

1.5.1 Production of gas in Siberia

Gas production has been moving into more unconventional geographies, and Siberia can be considered to be one of them as it is a huge territory with varied geology and harsh tundra conditions (Figure 1.42).

Approximately 70 percent of the oil and 90 percent of the gas produced in Russia comes from there now. After more than 30 years, a valuable experience has been gathered there from developing and producing under harsh environmental conditions. It is expected that some of it will be applicable to operations performed in places with similar climate conditions, especially in North America.

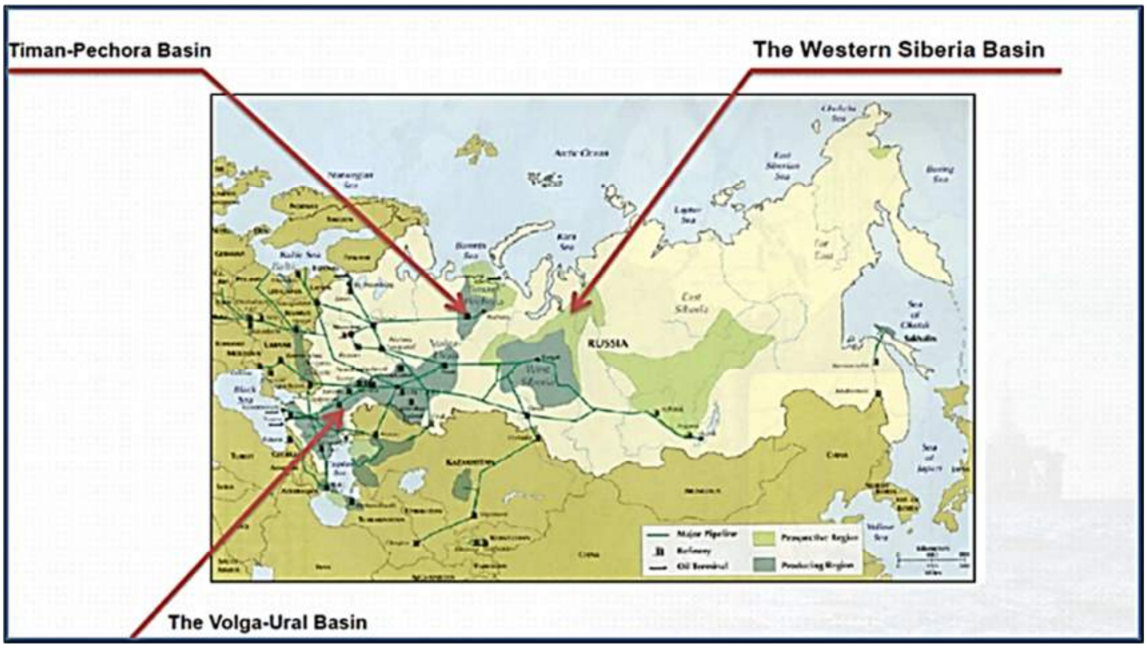


Figure 1.42 The largest hydrocarbon provinces of the Russian Federation.

The Yamalo-Nenetsky hydrocarbon province

The Yamalo-Nenetsky autonomous district is an important area for the prospection of hydrocarbons. It comprises a vast area of 750 thousand km^2 with only 515,000 inhabitants (0.7 persons per km^2).

Yamal produces about 90% of the natural gas in Russia, which is almost a quarter of world production, and about 15% of Russian oil and gas condensate. Hence, the area has an enormous importance to the Russian economy.

Important opportunities still await industrial development. One of them is the development of additional gas resources discovered in the peninsula and in the Kara Sea offshore, where 11 gas fields and 15 oil and gas condensate fields are already operated by Gazprom. The potential reserves are estimated at more than 50 billion m^3 of gas and 5 billion tons of liquid hydrocarbons.

Structure of hydrocarbon reserves

The most important hydrocarbon reserves and producing areas in Western Siberia are from the Cenomanian, but exploration targets also extends to the Jurassic (Figure 1.43). Turonian gas plays are shallower than the Cenomanian gas plays (800 meters deep against Cenomanian deposits ranging from 900 to 1,700 m), but they are harder to produce due to lower permeabilities, abnormally higher reservoir pressures and large variabilities, resulting in lower gas rates and lower reservoir temperatures, due to the proximity to permafrost formations.

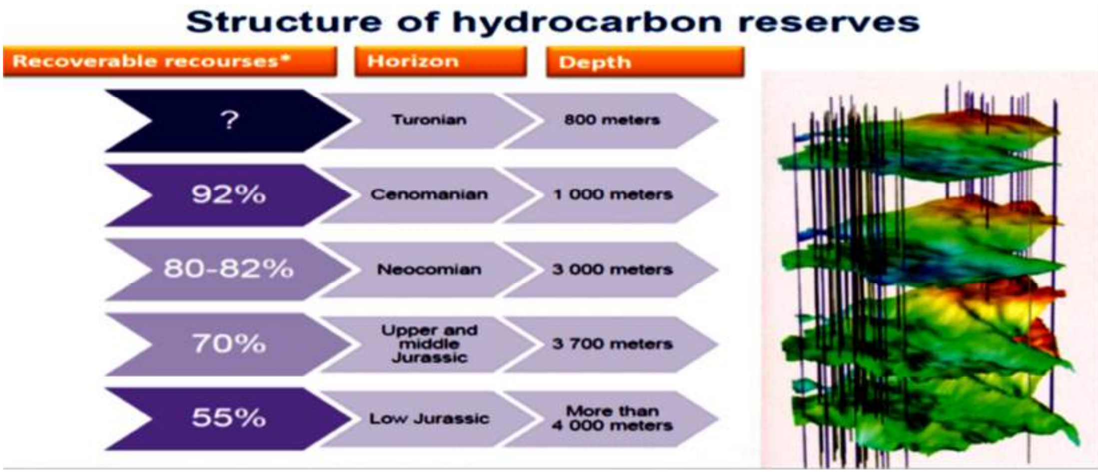


Figure 1.43 Known productive stratigraphic horizons

Geographic conditions

This region is characterized by a unique combination of severe climatic conditions, natural resources, an extremely vulnerable environment, and a multi-ethnic population stretching east from the Urals up to the western back of the Yenisei River.

Broadly speaking, the landscape is largely flat for most parts, with large winding rivers that flow for thousands of km to the Artic seas, bounded within large swamplands under permafrost conditions (Figure 1.44).

Figure 1.44 Taiga biome in Western Siberia.

The winter lasts eight months, and the temperature can be as low as -45°C, making the production of hydrocarbons a huge challenge (Figure 1.45).

Figure 1.45 Geographic realities of Western Siberia.

Other than minerals, the area also possesses the world's largest stock of reindeers (600,000), a third of the world reserves of white fish in the Ob River Basin and one tenth of it is occupied by a protected natural zone.

The Khanty and Mansi communities living there are herders who roam every two to three days in summer while in winter they stay put for up to one week as reindeers feed on lichen. This basic staple grows very slowly at about 3-5 mm per year, requiring a nomadic lifestyle. For many years aviation has been the only reliable way of communication, but now roads and trains are available.

History of development

The year of 1965 became a milestone in the history of region as the Samotlor oil field, Berezovo gas fields and Zapolyarnoye gas condensate field were discovered in succession. A year after that, the Urengoy oil and gas condensate field was added to the discoveries. It was the largest condensate field in the World. The discovery of the Nadymskoye and Medvezhye gas fields followed in 1967 and the discovery of the giant Yamburg gas condensate field came in 1969 (Figure 1.46).

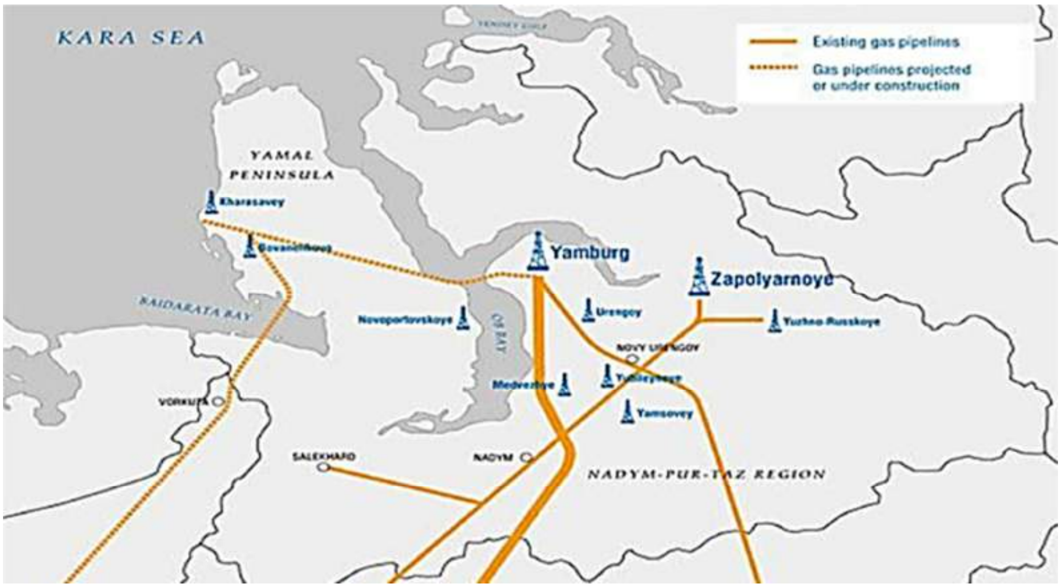


Figure 1.46 Major oil and Gas Fields of Western Siberia

In 1980, the town of Novy Urengoy was established as a support base for development of the gas fields located in the transpolar districts of Yamal. This development was quickly followed by the construction of a gas pipeline from Urengoy to Uzhgorod and the opening of a transcontinental gas pipeline from Western Siberia to Western Europe. This was a 142 cm diameter pipeline of 20,000 km designed to export gas to Germany, France, Italy, Holland, Belgium and other countries.

Today Russia owns two-thirds of the largest gas fields in the world. The majority of these reserves are located in Siberia, with the Yamburg, Urengoy, Medvezhye and Zapolyarnoe fields alone accounting for about 45 % of Russia's total reserves.

Oil and gas operations

The remoteness of the area and its climatic conditions pose challenges to the construction of facilities and pipelines, operations and maintenance (Figure 1.47). Due to the vastly uninhabited areas of taiga and tundra, operations normally begin with the construction of working and living quarters for labourers. A system of regular shifts and transportation from cities to base camp is required, with shifts of several weeks to several months in duration.

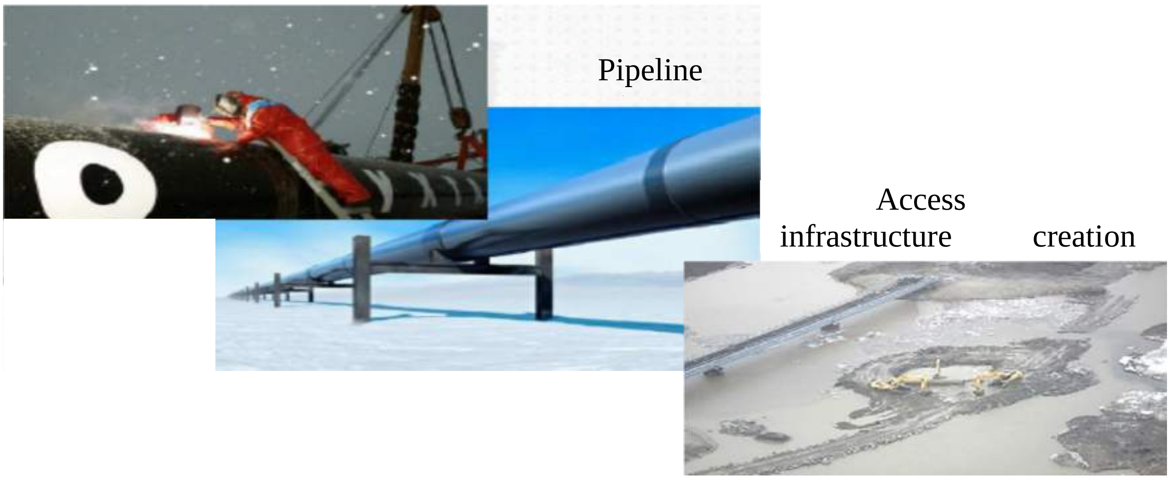


Figure 1.47 Development challenges

Construction under permafrost conditions

One of the requirements for construction in this region involves the use of piles to sustain pipelines and buildings. Pipes containing Freon-22 serve as heat accumulators and stabilizers that prevent permafrost from thawing.

Well design

Producing wells are normally grouped into several well clusters. They are designed considering:

- The use of extra heavy well conductor in cryolite areas;
- The use of heavy well tubing in these areas and at packer zones, for enhancing well reliability;
- The use of complex in-tubing downhole equipment for gas lifting;
- In most cases, a gap of 15-20 m is used between the bottom hole and the lifting pipe to prevent the entrainment of water in the gas;

- The use of cementing slurries lightened with alumina-silicate microspheres in conductor and lifting column to allow lifting up to the surface;
- Heat insulated pipes in well construction and operation;
- Combined monitoring to reduce the number of monitoring wells.

Environmental considerations in field development

A number of activities have been set to protect the environment by preventing and minimizing the impact caused by construction and operation. These include:

- Sustained environmental monitoring during field pre-development and operations;
- Planning of technological and special-purpose activities to mitigate impacts on the surface air;
- Utilization of water recycling systems that prevent surface reservoirs and soils to be polluted;
- Application of special technologies to reduce thermal and mechanical impacts on frozen ground;
- Elaboration of environmentally friendly regimes for area development;
- Utilization of technology to minimise technical and biological reclamation of areas;
- Prohibition of construction during the bird nesting season in spring;
- Use of systems to protect fish at water intakes;
- Prevention of obstructions that could affect the migration of reindeer herds.

Gas gathering system

Producing wells are prone to the formation of hydrates not only during winter but also at their initial stages of production. At start up, production requires the borehole environment to be warmed up. Gas gathering systems comprising manifold and pipelines running from gas well clusters and also gas conditioning units can operate under hydrate formation conditions.

To prevent and remove hydrates from gas gathering systems, a centralized supply of concentrated methanol is used. Downstream the gathering network, gas follows to a comprehensive gas treatment unit (CGTU) for purification and dehydration before delivery to the Unified as Supply System (UGSS) that feeds Russian customers and European countries.

Modern gas processing plants (GPP) such as Astrakhan, Orenburg, Sosnogorsk, the Urengoy condensate treatment plant and the Surgut condensate stabilization plant usually comprise a collection and treatment unit for gas and condensate, compressor stations, processing facilities for removal of acids, gas stripping and drying, separation of C2+, production of sulphur, gas condensate stabilization and auxiliary facilities, including tank farms, water, steam and power supply systems. Process operations can also include deep dehydration and extraction of light hydrocarbons by cold distillation, with the production of helium and ethane, and absorption of acid components and mercaptans.

The Unified Gas Supply System (UGSS)

Russia is the largest holder of gas resources in the world, and contributes to more than 40 % of the international trade of gas. Natural gas from West Siberia is transferred via compression units and pipelines totalling 4,100 km. The three most important arteries are the Southern, Central and Northern Transportation Corridors. Considerable distances are therefore travelled to the consumption centres located in Western and Central Europe.

By to the end of 2012, the total length of trunk pipelines and branch pipes owned by Gazprom and its gas transportation subsidiaries in Russia was 1,683,000 km. The Gas Transportation System included 222 stations with 3,738 compressors (Figure 1.48).

Figure 1.48 A gas gathering system in Western Siberia.

New technologies and advanced experiences

During the development of the region, locally developed new technologies, technological solutions and considerable experience were applied, of which some of the most significant were:

- The utilization of integrated production infrastructures for gas extraction from the Cenomanian - Aptian deposits;
- The application of heat-insulated pipes for well construction and operating conditions to prevent permafrost thawing;
- The reduction of monitoring wells by means of combined arrangements;
- The application highly resistant 1,420 mm pipes of K65 (X80) steel with smooth interior coating designed for 11.8 MPa (120 Ata) of working pressure, as well as new welding technologies and materials;
- The application of energy saving equipments to raise efficiency to 36-40 percent.

1.5.2 Shale gas production in North Montney

Lying within the Western Canadian Sedimentary Basin (WCSB), North Montney is the closest resource to the west coast of Canada (Figure 1.49). The acreage includes both conventional and unconventional hydrocarbon zones. The thick and geographically extensive siltstones of the Montney Formation are expected to contain 12,719 billion m^3 (449 Tcf) of marketable natural gas, 2,308 million m^3 (14,521 million barrels) of marketable NGLs, and 179 million m^3 (1,125 million barrels) of marketable oil according to a recent estimate performed by the National Energy Board, the British Columbia Oil and Gas Commission, the Alberta Energy Regulator, and the British Columbia Ministry of Natural Gas Development (2013). Progress Energy is the largest landholder, with over 50Tcf of resource over contiguous land. Its 2013 capital expenditure was USD 1.8Bn.

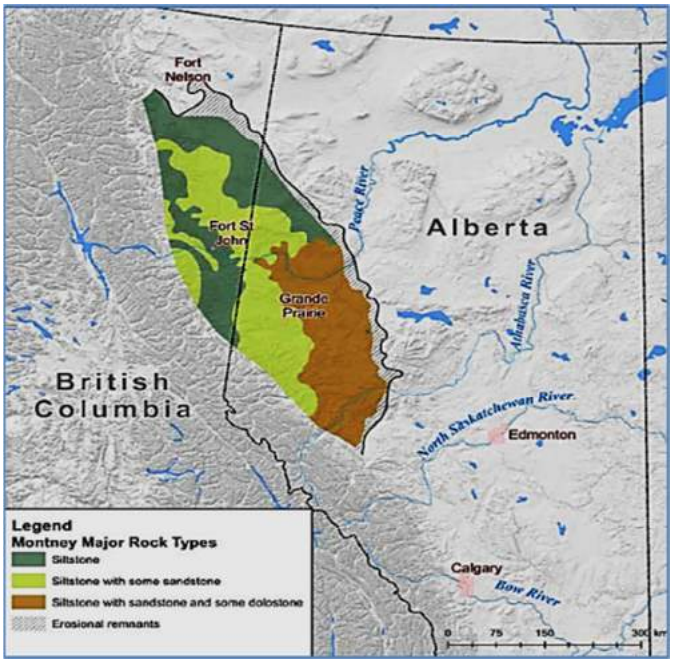


Figure 1.49 The Montney Formation extends from Alberta to British Columbia.

Evolution of hydrocarbon exploration and production

This formation has been the target of oil and gas exploration since the 1950s, with industry traditionally focusing on conventional sandstone and dolostone reservoirs. These conventional reservoirs are encased in siltstone, which represents a far greater volume of rock within the formation and also contains oil and gas. However, Montney siltstones remained undeveloped until 2005, when advances in horizontal drilling and multi-stage hydraulic fracturing made it possible to economically produce from this extensive, unconventional siltstone resource.

In late 2008, the first North Montney vertical test was undertaken and was swiftly followed up by a horizontal test. This lead to the first developments at Town and Farrell (Figure 1.50). By 2012, a 250 producing horizontal wells in 9 commercial developments had been carried out by two international joint ventures. The participation of foreign oil companies in the Canadian oil sector has risen rapidly. At this time, Petronas acquired Progress Energy, who had operations in the North Montney and Deep Basins.

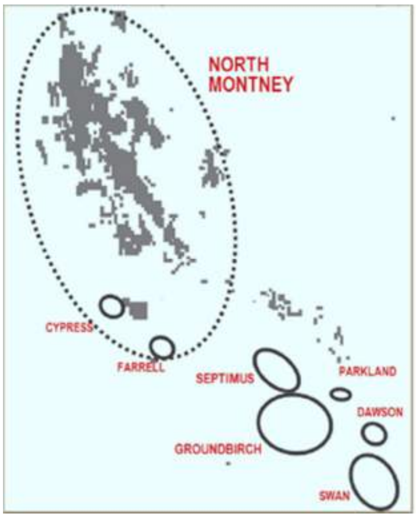


Figure 1.50 Developments in the North Montney and Deep Basins.

Subsequent to this, Progress Energy Canada Limited (PECL) formed a partnership with Sasol to further expand its landholdings through the Progress Sasol Montney Partnership (PSMP) with the acquisition of assets from Talisman. PECL had aggressive development plans to deliver 2.0 Bcf/d of natural gas to the Pacific NorthWest LNG at Prince Rupert Island by the end of 2018.

Geology

The Lower Triassic Montney formation is aerially extensive, covering approximately 130,000 km² (Figure 1.51). It is also thick, typically ranging from 100 m to 300 m, though thins to zero at its Eastern and Northeastern edges, while increasing to over 300 m on its Western side before outcropping in the Rocky Mountains. Most of the formation consists of siltstone with small amounts of sandstone originally collected at the bottom of a deep sea, whereas more porous sandstones and shell beds were deposited in shallower water environments to the east. The depth of the formation also increases from northeast to southwest, generally along with increasing reservoir pressures and decreasing liquid contents (NGL and oil). Thus, reservoir characteristics vary widely across the formation.

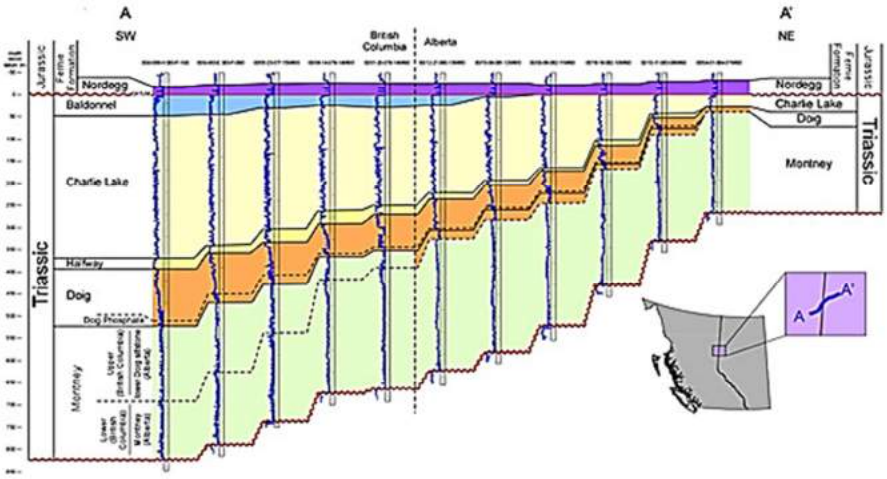


Figure 1.51 Cross section of the Montney formation.

Plans and Targets

PECL had put into place an ambitious programme to arrive at a final investment decision (FID) by late 2014 in order to timely supply the Pacific Northwest LNG plant. It was undertaking development and production in two phases as follows:

- Appraisal Phase (2012-2015): Target of 15 Tcf Reserves by Q4 2014 (FID)
  - ✓ Maximize reserve growth;
  - ✓ Operational ramp up to about 25 rigs;
  - ✓ Step-out drilling.

- Development Phase (2015-2018): Target of 2 Bcf/d by Q4 2018 (1st LNG export)
  - ✓ Maximize production growth;
  - ✓ Continue adding reserves;
  - ✓ Pad drilling.

Drilling operations

The decline behaviour of the shale gas reservoirs call for a certain number of wells to be drilled every year in order to sustain and grow the production. Uncertainty in well performance requires sufficient wells to be drilled and “proved up” before moving into full development. Placement of wells is key to unlock the optimum resource from the shale, each of them is drilled horizontally with several stages of reservoir fracturing for maximum contact in order to enable flow into the production casing (Figure 1.52).

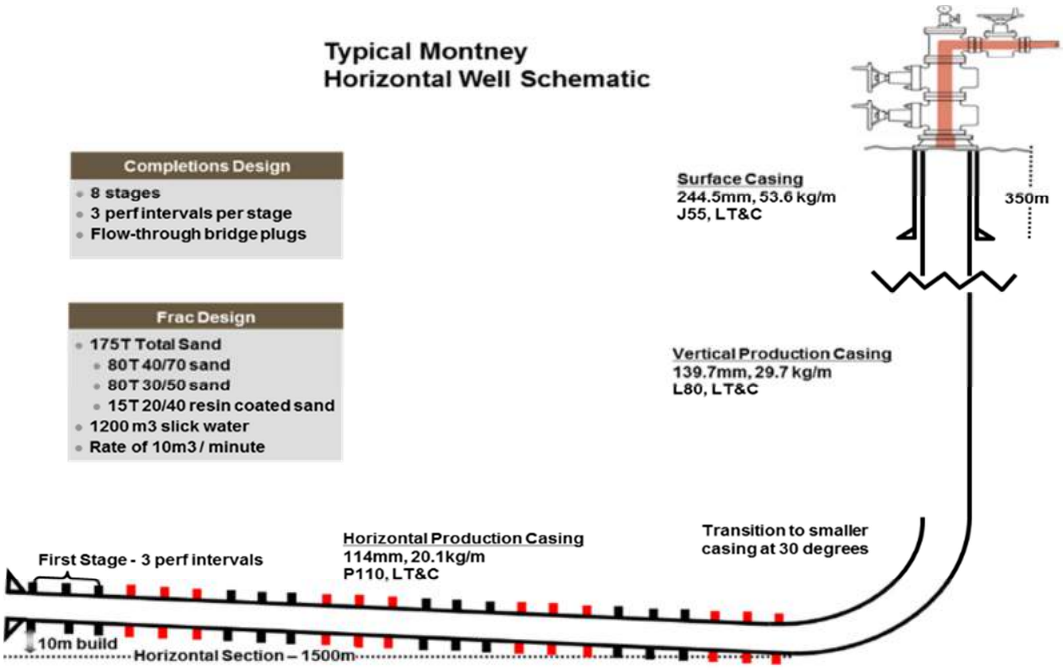


Figure 1.52 Horizontal well schematic

The typical cost for drilling shale gas wells range from US$ 6 to 8 million per well. With a drilling track record in excess of 700 wells over the past 10 years, PECL is well poised to deliver the targeted production. To date, PECL has identified 13,000 drilling locations and drilled 315 horizontal wells in 2014 by operating 16 to 25 rigs per calendar quarter.

Fracking innovations

A typical fracking operation requires integrated logistical handling of water, sand trucking and fracking fluids and a real-time monitoring of the fracturing operations. Good road access is critical and an area away from dense population is ideal for the size of the operations.

A combination of fresh water and produced water is continuously pumped at the well site during fracturing. In winter, this water is heated with natural gas by means of a portable system (Figure 1.53). Flowback water is then pumped back the central site for storage and re-use. The sand used for fracture stimulation is on the order of 1500 tonnes per well.

Figure 1.53 Water handling for fracking.

As a result of the experience accumulated in the Deep Basin of Alberta, PECL developed a fracking system that uses a recyclable oil to reduce formation damage and ensure longevity of production.

Development concepts

A standard modular facility is used to scale up the facility according to the demand, reducing installation time, oversizing and negative impacts on footprint and capital expenditure. Given the nature of the siltstones, sand from erosion can be expected and facilities should be designed to take that into account. Heating for continuous uninterrupted operations in winter is also necessary (Figure 1.53). A typical modular facility process is shown in Figure 1.54.

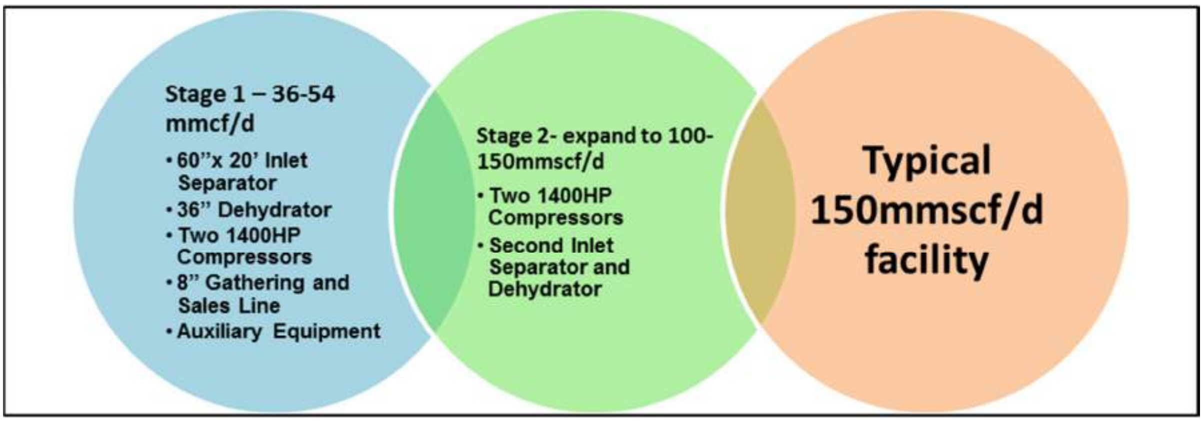


Figure 1.54 A typical modular production facility process.

Key factors for success

PECL has benefited from several technical, economic and fiscal factors. From a technical standpoint, its acreages lie within the thickest part of the basin where the over pressured siltstones yield a liquids-rich gas stream of the order of 8 to 30bbls per mmscf of gas produced, yielding a significant revenue lift. This world class resource yields high heat content gas and liquids ranging 1100-1260 mmbtu/scf with practically zero content of hydrogen sulphide and minimal carbon dioxide content. It further enjoys a deep drilling credit from the British Columbia government in form of time based royalties. In terms of logistics, the acreage under operation benefits from an existing 3rd party pipeline access with all season access via the Alaska Highway. Its above ground risks are minimal with just a few surface stakeholders.

PECL fosters good community relations with the First Nation communities of Halfway River, Prophet River, West Moberly and Blueberry, subscribing to principles of respect, trust and commitment to enhance the future and traditional well-being of the Aboriginal people and all other communities potentially impacted by the operations. This is being accomplished by

- Soliciting feedback to improve cultural awareness and understanding of treaty rights;
- Sharing development plans with First Nations;
- Maintaining an in-depth consultation process in regards to upcoming projects;
- Supporting First Nation Economic Opportunities;
- Building economic, social and business paths for aboriginal people to find jobs, establish and sustain businesses, and participate in joint ventures.

Given the size of the operations and the variability in reservoir quality and uncertainties in production behaviour, the conventional organisation of the work around discipline based teams was considered unlikely to succeed. Some key principles that PECL adhered to in order operate successfully can be listed as follows:

- Subsurface and fracturing teams must evaluate fracturing efficiency in an integrated manner in order to define sweet spots from micro-seismic analyses;
- Close collaboration with fracking service providers to continuously uphold the Hydraulic Fracturing Principles of BC;
- Real time monitoring to ensure quick decisions;
- Use of modular facilities to reduce capex and installation time;
- Use of multiple drilling pads and POD production to reduce environmental footprint;
- Recycle water and fracture fluids to reduce completion costs and safeguard the environment;
- Keep equipment standards across areas;
- Keeping equipment reliability by designing with sand erosion in mind;
- Incorporate sand filters and wet meters at well sites;
- Build a long term relationship with key service providers;

- Maintain a capable, stable and professional workforce with an average of 15.6 years experience leading to considerable in-house experience.

An innovative production process flow was adopted where each process train serves as a hub for multiple well pads delivering raw gas, which is compressed and dehydrated to produce condensates, water and gas. The dehydrated gas is then piped to the gas plant for further separation and processing to meet sales specifications and for the production of natural gas liquids (NGLs) containing C3+ components (Figure 1.55). PECL has successfully constructed and brought online over 20 compressor stations and 3 gas plants.

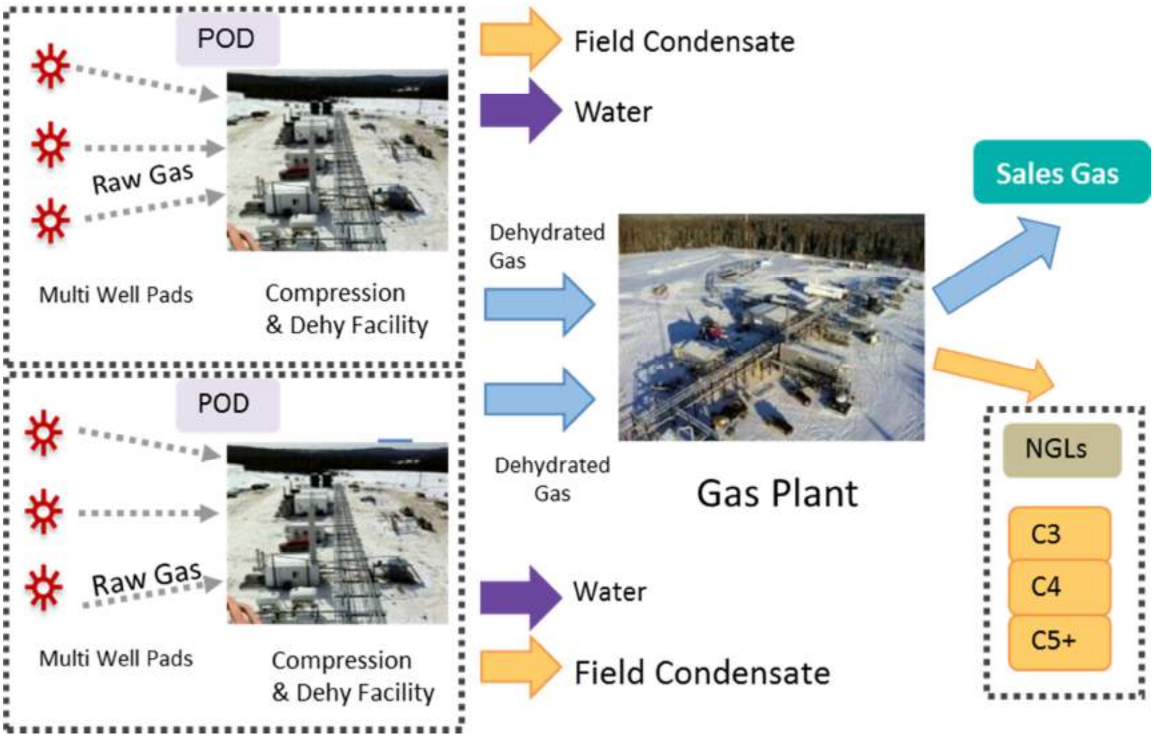


Figure 1.55 Production operations using POD concept.

References

Ailin Jia, Dongbo He and Chengye Jia (2012).Dr. Imran Ahmad Dar (Ed.), ISBN: 978-953-307-861-8 InTech,

Almeida, L. C.; Echave, F. J.; Sanz, O.; Centeno, M. A.; Arzamendi, G.; Gandía, L. M.; Sousa-Aguiar, E. F.; 12 Odriozola, J. A.; Montes, M. Chem. Eng. J. 2011, 167, 536.

Almeida, L. C.; et.al Chem. Eng. J. 2011, 167, 536.

Almeida, L. C.; Sanz, O.; D'olhaberriague, J.; Yunes, S.; Montes, M. Fuel 2013, 110, 171.

Almeida, L. C.; Sanz, O.; D'olhaberriague, J.; Yunes, S.; Montes, M. Fuel 2013, 110, 171

Ang, C.T., Othman, H., Zahir, M.H., and Adnan, A.G., (2013)

Anstey N.A. and O'Doherty R.F., [1971], Geophysical Prospecting, 19, 430 – 458

Arntsen B., Wensaas.L, et.al, [2007], Geophysics 72, 251-259

Associated Gas Monetization via miniGTL, Conversion of flared gas into liquid fuels & chemicals, Update January 2014 by GGFR

Atkinson, D. Biofuels, Bioproducts and Biorefining 2010, 4, 12.

Atkinson, D. Biofuels, Bioproducts and Biorefining 2010, 4, 12.

CNPC, 2013. A presentation to IGU WOC 1.1, Kota Kinabalu, Malaysia 2013

Dieckel et al. Energy Charter Secretariat, 2007

Dry, M. E. Catal. Today 2002, 71, 227.

Fonseca, A.; Bidart, A.; Passarelli, F.; Nunes, G.; Oliveira, R. In World Gas Conference, 2012

Fonseca, A.; Bidart, A.; Passarelli, F.; Nunes, G.; Oliveira, R. In World Gas Conference2012.

Fonseca, A.; Bidart, A.; Passarelli, F.; Nunes, G.; Oliveira, R. In World Gas Conference 2012

Gazprom, 2013.A presentation to IGU WOC 1.1, Kota Kinabalu, Malaysia 2013

GCEC, "The New Climate Economy: Better Growth, Better Climate, 2014

Ghazali A.R., [2011], Ph.D. thesis, Delft University of Technology, 8-9

Growth in the New Climate Economy- Michael Spence, a Nobel laureate in economics

Ha, K.-S.; Kwak, G.; Jun, K.-W.; Hwang, J.; Lee, J. Chem. Commun. 2013, 49, 5141.

Hernandez H. et al., The 2014 EU Industrial R&D Investment Scoreboard, European Comission

Hopper, C. Journal of Petroleum Technology 2009, 26.

Hopper, C. Journal of Petroleum Technology 2009, 26.

IPCC, 2014: Summary for Policymakers

Khalilpour, R.; Karimi, I. A. Energy 2012, 40, 317.

LeViness, S.; Deshmukh, S.; Richard, L.; Robota, H. Top. Catal. 2013, 1.

LeViness, S.; Deshmukh, S.; Richard, L.; Robota, H. Top. Catal. 2013, 1.

Maver, K.G. 2011, First Break volume 29 December

McFarland, E. Science 2012, 338, 340.

National Energy Board, the British Columbia Oil and Gas Comm, the Alberta Energy Regulator, and the British Columbia Ministry of Natural Gas Development, Energy Briefing Note, 2013

Onwukwe Stanley, I. Journal of Natural Gas Science and Engineering 2009, 1, 190.

Petrus, L.; Noordermeer, M. A. Green Chemistry 2006, 8, 861.

Schulz, H. Applied Catalysis A: General 1999, 186, 3.

Sousa-Aguiar, E. F.; Noronha, F. B.; Faro, J. A. Catalysis Sci & Tech 2011, 1, 698.

Van Der Laan, G. P.; Beenackers, A. A. C. M. Catalysis Reviews 1999, 41, 255.

Williams, R. H.; Larson, E. D.; Liu, G.; Kreutz, T. G. Energy Procedia 2009, 1, 4379.

Wood Mackenzie, Energy Briefing, September 2013.

Wood Mackenzie, Global Gas Service, H2 (2013).

Wood, D. A.; Nwaoha, C.; Towler, B. F. J of Nat Gas Science and Engineering 2012, 9, 196.

Appendices

A List of Tables

B List of Figures

C Glossary and Acronyms

CNPC	China National Petroleum Corporation
EIA	Energy Information Administration
FWI	Full waveform inversion
GGFR	Global gas flaring reduction forum
GTL	Gas to liquids
JOGMEC	Japan Oil, Gas and Metals Corporation
PP	Primary wave to primary wave
PS	Primary wave to secondary wave
SDM	Stack depth migration

WOC 1 Triennial Report

2012-2015

STUDY GROUP 1.2

GLOBAL RESERVES AND RESOURCES OF NATURAL GAS

Study Group Leader

Mohamed Kaced (Sonatrach, Algeria)

Study Group Members

Abdelouahad Belmouloud	Sonatrach	Algeria
Faiçal Belaid	Sonatrach	Algeria
Said Chelbeb	Sonatrach	Algeria
Fernando Bado	Tenaris	Argentina
Denis Krambeck Dinelli	Petrobras	Brazil
Bernard Seiller	Total	France
Richard Migeon	Total	France
Vincent Trocme	GDF Suez	France
Gholamreza Bahmannia	NIGC	Iran
Krit Limbanyen	PTT E&P	Thailand
Montri Silpa-Archa	PTT E&P	Thailand
Naruepon Lecksiwilai	PTT E&P	Thailand
Andres Gabriel Weissfeld	Tenaris	USA

Paris

June 2015

Table of Contents

2 GLOBAL RESERVES AND RESOURCES

Executive Summary

In the middle of the so called unconventional gas revolution, one of the most important challenges faced by the industry is the development of reliable estimates for both conventional and unconventional gas reserves and resources.

Most of the international organisations have pointed out that natural gas resources can now be found in many different regions of the world, and they are enough for more than 250 years of use. Natural gas will continue to be the most accessible and secure energy source for many years to come.

In light of these statements, this report provides a global assessment for both conventional and unconventional gas reserves and resources, including subtle traps in mature basins, exploration of frontier areas and unconventional sources associated with tight gas, shale gas, coal bed methane and gas hydrates.

It looks first at the most important projects under development, and their potential impact in the future availability of natural gas, from both regional and global standpoints. After that, exploratory hotspots and new frontiers for natural gas are highlighted, and the most important trends, uncertainties, opportunities and threats to be faced by the upstream segment of the gas industry are analysed.

Conventional oil and gas discoveries have recently fallen to their lowest level since 1952, in spite of a significant increase in the exploratory activity, whose success has declined. The media has given a higher degree of attention to unconventional resources, which is expected to account for more than 50% of US supply by 2020.

Advances in drilling and well completion technologies, including hydraulic fracturing, has opened plays up in a number of different basins, which were considered to be unattractive from an economic standpoint. Nevertheless, the North American success is not easy to replicate elsewhere.

The hydraulic fracturing treatments used to stimulate gas production have stirred environmental concerns over excessive water consumption, drinking water contamination, and surface water contamination from both drilling activities and fracturing fluid disposal. Political opposition is expected to slow or even prevent development in many areas, including Northern Europe.

An EIA/ARI study of June 2013 identified a total shale gas in place of 31,138 TCF (880 TCM) along 41 countries, excluding the USA. Of this total, approximately 6,634 TCF (188 TCM) are considered to be technically recoverable.

In summary, the full potential for natural gas is certainly huge, but its exacts extents still remain relatively unknown, as the assessment of undiscovered quantities remains impregnated with significant uncertainties, especially in the case of unconventional resources. New discoveries of natural gas are expected to continue to predominate relatively to oil, and the business portfolio of many independent, national and international oil companies is expected to reflect that.

2.1 Introduction

As the world's major source of energy, petroleum will continue to play a key role in the development of the world’s economies for many decades to come. This statement was recently reinforced by the development of unconventional resources in North America, which has triggered the assessment of similar formations in a variety of basins around the world.

A clear appraisal of oil and gas reserves is of considerable importance to the global energy industry, but volumes commonly labeled as “reserves”, “resources”, “oil in place” and “ultimate recovery” would not mean much without a proper definition of these terms, as is often pointed out in the literature (e.g. Petrobjects, 2003).

The most widely used definitions come from the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC) and the Society of Petroleum Evaluation Engineers (SPEE). These organizations have jointly developed a resources management system to which all evaluators are expected to conform, while keeping up with evolving technologies and business models, as described next.

2.1.1 Classification of hydrocarbon resources

For the organizations mentioned above, the term “resources” encompasses all quantities of hydrocarbons naturally occurring on or within the Earth’s crust, discovered or undiscovered, recoverable or unrecoverable, conventional or unconventional, and even quantities already produced.

In Figure 2.1 hydrocarbon resources are classified as (1) production, (2) reserves, (3) contingent resources, (4) prospective resources and (5) unrecoverable (SPE et al., 2007). The corresponding description can be found in Table 2.1 next.

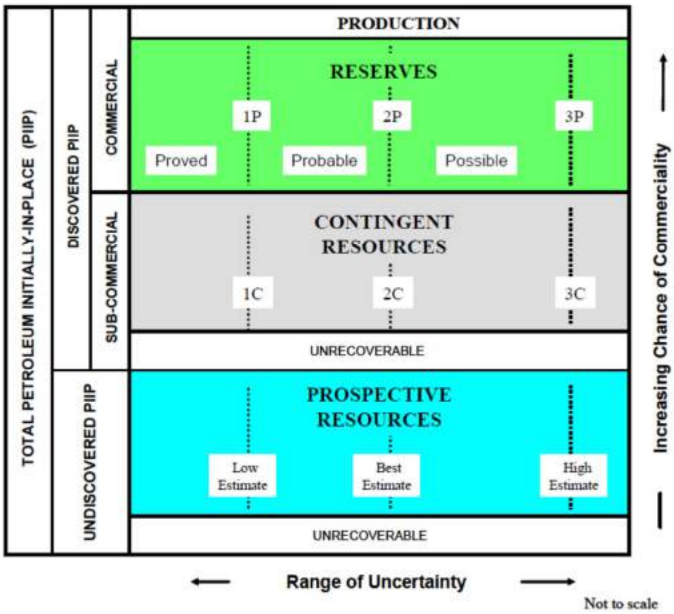


Figure 2.1 Resources classification framework (SPE *et al.*, 2007).

Table 2.1 Resource classes (adapted from SPE *et al.*, 2007).

Total hydrocarbons initially in place (total resources)	The quantity of oil and gas that is estimated to exist originally in naturally occurring accumulations. It includes the quantities estimated to be contained in known accumulations, those already produced and those estimated in accumulations yet to be discovered.
Discovered hydrocarbons initially in place	The quantity of hydrocarbons that is estimated to be contained in known accumulations prior to production. It can be subdivided into commercial and sub-commercial, with the estimated potentially recoverable portion being classified as **reserves** and **contingent resources** respectively.
Reserves	The hydrocarbons that are anticipated to be commercially recoverable by the application of development projects to known accumulations. **Proved reserves** are the quantities that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under current conditions, while **probable** and **possible** reserves are subjected to growing degrees of uncertainty.
Contingent resources	Quantities potentially recoverable as of a given date from known accumulations, but which are not currently considered to be commercially recoverable due to one or more contingencies. This definition includes the projects for which there is currently no viable market, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

Undiscovered hydrocarbons initially in place	Quantities that are estimated, on a given date, to be contained in accumulations yet to be discovered. The estimated potentially recoverable portion of the undiscovered hydrocarbons initially in place is classified as **prospective resources**.
Prospective resources	Quantities estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by the application of future development projects. These resources have both (1) a chance of discovery and (2) a chance of development.

While describing the definitions contained in Table 2.1, the SPE and its partners explain that the expression estimated ultimate recovery (EUR) does not refer to a category of resources, but to accumulations of hydrocarbons, discovered or undiscovered, that are estimated on a given date to be potentially recoverable under defined technical and commercial conditions, including the quantities already produced therefrom (SPE et al., 2007).

Resources in accumulations producible with current recovery technology but without reference to economic profitability are called technically recoverable resources by the U.S. Geological Survey. These change as technology evolves (e.g. when horizontal drilling is combined with hydraulic fracturing).

A description of conventional and unconventional resources is given in Table 2.2. The reader is referred to SPE et al. (2007) for additional information on the classification of hydrocarbon resources, including aggregation methods, range of uncertainty and project maturity sub classes.

Table 2.2 A classification of conventional and unconventional resources (SPE *et al.*, 2007).

Resource class	Definition
Conventional	Discrete accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water. The hydrocarbons are recovered through wellbores and typically require minimal processing prior to sale.
Unconventional	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, natural bitumen, and oil shale deposits. Typically require specialized extraction technology (e.g. dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted hydrocarbons may require significant processing prior to sale (e.g. bitumen upgraders).

2.2 Conventional gas

Over the last years the media has been dominated by a general excitement with the potential of unconventional gas and oil, with special attention to the environmental issues that could hinder the development of production.

Meanwhile, IHS Energy decided to investigate the whereabouts of conventional oil and gas discoveries, coming up with the results indicated in Figure 2.2.

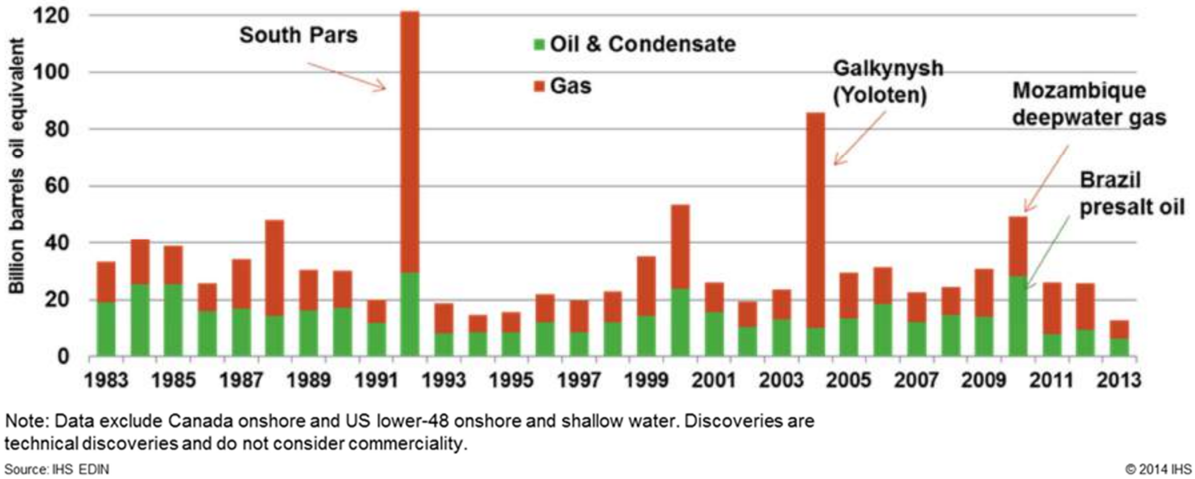


Figure 2.2 Discoveries of conventional oil and gas. Source: IHS Inc. The use of this content was authorized in advance by IHS. Any further use or redistribution of this content is strictly prohibited without written permission by IHS. All rights reserved.

Conventional oil and gas discoveries outside North America have fallen in 2013 to their lowest level since 1952, in spite of a significant increase in the exploratory activity, whose success has declined. For 2014 expectations were even lower, based on discovery results observed during the first semester (~3 billion boe).

Another interesting result indicated in Figure 2.2 is the fact that gas discoveries continue to predominate relatively to oil. Indeed, the importance of gas is increasing in the business portfolio of many international oil companies, as indicated further ahead in this report.

2.2.1 Global potential

The current reserves of natural gas have been estimated at 6,558 TCF or 186 TCM (BP, 2014). For a full picture of the total amount available in the planet, however, it is necessary to account for the quantities that remain to be discovered, and those made available by advances in the appraisal technology and economic conditions.

The United States Geological Survey (USGS) continues to be the only provider of publicly available estimates of undiscovered and technically recoverable gas on a worldwide basis. The latest assessment performed by this organization revealed 6,392 TCF of conventional gas resources yet to be discovered, of which 5,606 TCF are outside the USA (Robertson, 2012).

Table 2.3 USGS assessments of undiscovered hydrocarbons outside the USA.

	1994	2000	2012
Oil	539 billion barrels	649 billion barrels	565 billion barrels
Natural gas liquids	90 billion barrels	207 billion barrels	167 billion barrels
Natural gas	4563 TCF	3880 TCF	5606 TCF

Advances in the technology and economic changes are also important for additional resources to be regarded as technically recoverable, but in the USGS statistics these come out as **reserves growth**. In 2000 the USGS estimated them at 612 billion barrels of oil, 42 billion barrels of natural gas liquids and 2,748 TCF of natural gas, numbers that are almost as large as their undiscovered counterparts in Table 2.3.

The quantities indicated above are significant. A brief comparison with the current consumption of natural gas (120 TCF per year) allows the reader to quickly conclude that natural gas continues to be one of the most abundant energy sources in the world.

2.2.2 Regional analyses

The large availability of gas mentioned in the previous section is briefly detailed along the various regions of the globe in this section, which enlists the most relevant facts in the exploration and production of natural gas over the last three years.

North America

Gas developments in this region have been marked by shale gas, and more recently by the huge volumes of associated gas coming from tight oil plays. This trend towards unconventional sources is expected to continue in the long term, as the reserves are abundant and the necessary technology has been unlocked.

Nevertheless, the production of conventional gas will continue remain significant for many years to come (Figure 2.3), and in the more distant future additional conventional resources can still be developed from challenging environments such as the Arctic and deep areas located in the Gulf of Mexico.

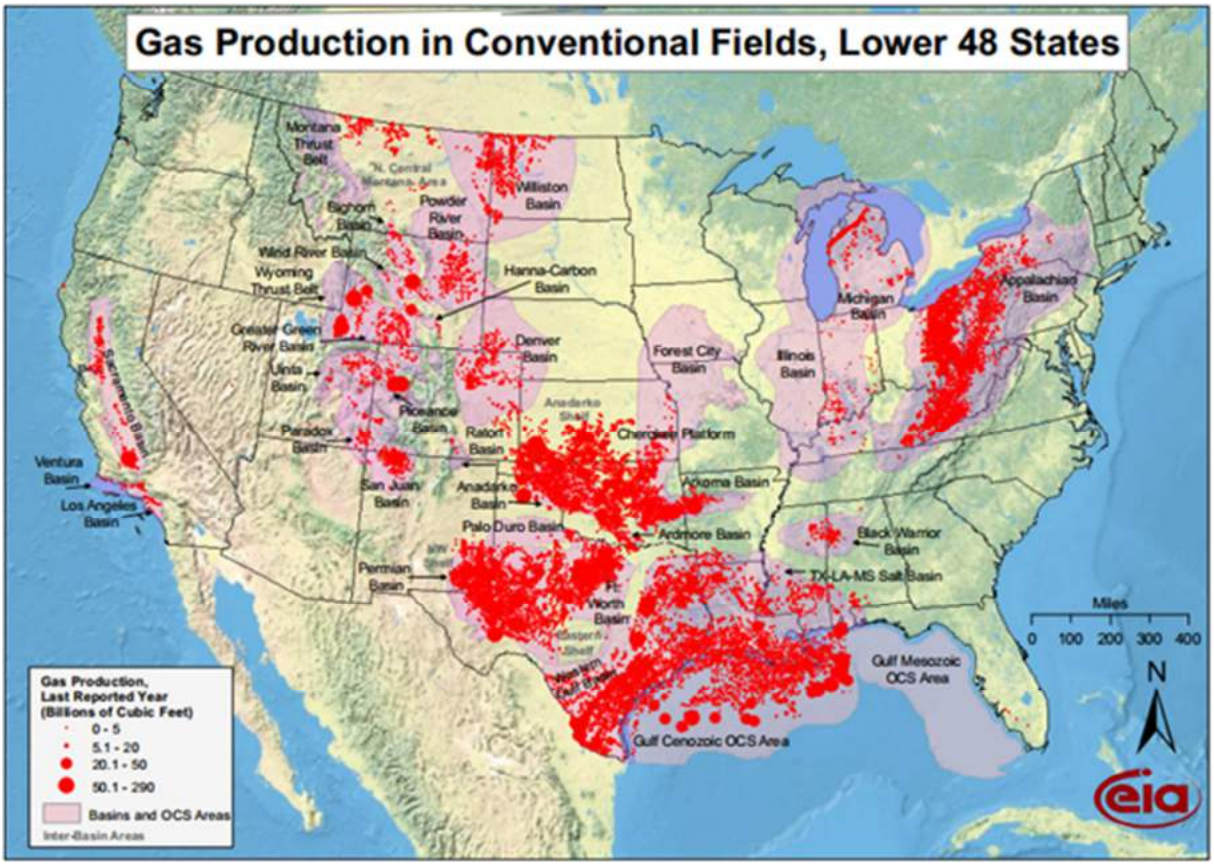


Figure 2.3 Gas Production in Conventional Fields, Lower 48 States (Source: EIA based on data from USGS Geological Survey).

The North American Arctic

The Alaska North Slope holds about 5.5 TCM of potential gas resources in areas such as Prudhoe Bay and Point Thomson.

The former could be an anchor for a potential gas pipeline to the lower 48 states, as currently 60 - 80 BCM/y (6-8 Bcf/d) are being cycled into the reservoir to pressurize, increase and accelerate the production of oil.

With time, Prudhoe Bay will become a gas field with associated liquids, rather than the opposite. By the end of the current decade, natural gas from the region could reach the North American and Asian markets.

More on the North American Arctic is described in section 2.4.1.

Deep gas

Deep natural gas resources can be classified as such below 4,500m (15,000 feet), and ultra-deep below 7,500m (25,000 feet). Their geological characteristics can be diverse but in general there is no correlation between reservoir quality and depth.

There has been a historical trend of progress into deeper horizons, where targets are often characterized by high pressure and high temperature, but the presence of CO_2 and H_2S is also common.

The presence of salt layers can also be relevant, as additional problems may arise from the seismic, drilling mud circulation and lower temperatures.

In the USA the first deep well was drilled in 1920, but the first major production came on stream only during the 1960s. Today deep gas wells are distributed all over the country, but the largest numbers occur in the Mid-Continent, the Permian Basin, the Rocky Mountains and the Gulf of Mexico. In the latter case, most of the wells are concentrated in shallow plays that can be considered as an extension of counterparts located on shore.

In the Gulf of Mexico, deep natural gas resources remain relatively unexplored in the Outer Continental Shelf (OCS). Under the current price environment, however, they have to be deemed as unfeasible.

South America and the Caribbean

Using a geology based assessment methodology, the US Geological Survey estimated in 2012 the existence of 679 TCF (19 BCM) of undiscovered natural gas resources in 31 geologic provinces of South America and the Caribbean.

The methodology for the assessment included a complete geologic framework description for each province, based mainly on published literature. There are many basins in this region that have been maturely explored, such as Maracaibo (Venezuela), Neuquen (Argentina), Magallanes and Llanos (Colombia), whereas several others have had few or no discoveries, such as Salado-Punta del Este (Uruguay), Parnaiba (Brazil) and Bahama Platform (Figure 2.4).

Figure 2.4 Provinces in SA assessed by the World Petroleum Resources Project of the USGS.

About 55% of the total is estimated to be located in only five provinces: Santos Basin (210 TCF; 6 TCM), Falklands Plateau (51 TCF; 1.5 TCM), Parnaiba basin (42 TCF; 1.2 TCM), East Venezuela Basin (40 TCF; 1.1 TCM) and the Guyana-Suriname Province (32 TCF; 0.9 TCM).

In Brazil, the Jupiter field is located in the ultra-deep waters of the Santos basin, 290 km off the coast of Rio de Janeiro and 37 km from the Lula field. Petrobras made an oil and gas discovery in the pre-salt layers of the field in January 2008, and drilling of a second well identified a 176-metre oil column in 2012. Jupiter is estimated to hold 930 million barrels of oil and 30 TCF (0.85 TCM) of natural gas with 15% of CO_2. Petrobras and partner Galp are fast tracking the appraisal programme and plan to spud back to back wells from the third quarter of 2014 to start-up operations in 2019.

In Venezuela, the Cardón IV block is located in the Gulf of Venezuela, approximately 80 km Northwest of the Paraguaná peninsula. Production will be jointly run by PDVSA (60%) Eni (20%) and Repsol (20%) under a 30-year concession. This is one of the 29 blocks that compose the Rafael Urdaneta project, which aims at the development of gas reservoirs in the Gulf of Venezuela.

In September 2009 a major gas discovery was made at the Perla field in Cardón IV, and a declaration of commerciality was submitted in August 2012. The field covers an area of approximately 33 square kilometres and lies in a water depth of 60 m.

Perla has proven gas reserves of 17 TCF (0.5 TCM) of gas and 170 million barrels of condensate. It will be developed in three stages. A gas production of 154.5 MCF/d is expected in December 2014, ramping up to 450 MCF/d with the completion of the first phase in May 2015. The project's second and third phases envision a gas production of 800 MCF/d and 1.2 TCF/d, respectively.

In Peru, the Camisea natural gas fields of Pagoreni, San Martin and Cashiriari were discovered by Shell in 1986, but development started only in the mid-nineties. The Camisea gas project is one of the largest energy projects in Peru and is central to the economy of the country, with investments of US$ 2.7 billion. These gas fields are located in the Peruvian Amazon jungle and hold natural gas reserves of 0.4 TCM. The project is operated by Pluspetrol. To maintain an overall production of 16 BCM/y, contributions made by the three fields are balanced to optimize the drainage of the reservoirs.

In Argentina, the Vega Pleyade offshore gas field is located in the Cuenca Marina Austral 1 (CMA-1) permit, near the Carina-Aries fields. Additional reserves have been found at Vega Pleyade, where Total (operator) has shot 3D seismics and drilled two appraisal wells. The project encompasses an unmanned wellhead platform, connected to three production wells, with a capacity of 10 million m3/d of gas. Total and its partners plan to invest US$ 850 million in the project. In June 2014 Total began drilling the first well, with production slated to begin in the second half of 2016.

In Bolivia, the Aquio and Ipati blocks are located southwest of Santa Cruz in the Sub Andino oil and gas basin at the foothills of the Andes Mountains. The Incahuasi gas field, which straddles both blocks, was discovered in 2004 and its reserves are estimated at 176.3 BCM of gas and 133.4 million barrels of condensate. Incahuasi features high-pressure, high-temperature reservoirs located at a depth of 5,000 metres. The first development phase involves three wells, one on the Aquio Block and two on the Ipati Block, a gas treatment plant with a capacity of 229.5 MCF/d (6.5 MCM/d) and exportation pipelines. Production will be exported to Argentina and Brazil via two new pipelines that will connect to the existing pipeline network. In July 2014, Total finalised a farm-out agreement with Gazprom, in which the French company will hold a 60% interest in the Incahuasi field while Gazprom and Tecpetrol will each hold a 20% interest. Start-up is expected for 2016.

In Trinidad & Tobago, BP announced in August 2014 the sanction of its Juniper offshore gas project, which will take gas from the Corallita and Lantana fields located 50 miles off the south east coast of Trinidad, in water depths of approximately 360 feet. Juniper, estimated to contain 1.2 TCF of gas, lies offshore Trinidad and Tobago’s east coast on the continental shelf where BP produces 2 BCF/d of gas. The development includes five subsea wells and will have a production capacity of approximately 590 MCF/d. Gas from Juniper will flow to the Mahogany B hub through a new flow line of 10 km. Drilling is due to commence in 2015 and the first gas from the facility is expected by 2017.

Europe

Arctic developments

More than 100 exploration wells have already been drilled in the European Arctic, but Snøhvit remains as a milestone because of its complexity, with high carbon dioxide contents and a difficult location.

Multiphase pipeline transportation was key to reduce costs, as offshore separation and multi pipe-laying were deemed too expensive. At the time it was completed, Snøhvit had the largest multiphase transport system in the world (145 km).

The development of reliable subsea compression technology is now crucial for new projects in the area, particularly below the ice and areas where icebergs are prevalent. Sub-sea separation of water will also be essential to handle the production, but additional developments in multiphase transport technology are also important to increase the distances over which transport can be carried out.

Thorough studies have been carried out for Snøhvit considering either a second LNG train or a combination of a dew point plant and gas pipeline, but a final investment decision appears to depend also on the availability of new gas at reasonable production costs.

More on the European Arctic is described in section 2.4.1.

Deepwaters

In 2007, production started in Ormen Lange after significant technological challenges, including the design of sub-sea completion systems and pipelines for an uneven, rugged seabed, located in an area submitted to extensive avalanche slides, where it was necessary to assure flow in temperatures of minus 1.2 ºC at depths of approximately 1,000 m, challenging waves and winds. In addition to that, it was necessary to provide 120 km of multiphase transportation to the shore and 1,200 km of pipelines to the UK.

Norway has the longest integrated subsea gas transport system, and plans were submitted in 2013 to extend the network to the North of the Arctic Circle. This would open up new fields in the Norwegian Sea, prompting fresh questions on how long it might be to link the fields located in the Barents Sea and even the Russian Arctic to the European markets.

The new 480 km Polarled pipeline (formerly Norwegian Sea Gas Infrastructure project) will cost nearly US$ 4.5 billion. By 2017 it will be brought under the control of the state company Gassco to increase its network from 7,975 km to over 8,500 km, including extra spurs.

The concept behind Polarled paralleled other gas fields located off mid-Norway, whose development hinged on having a viable transport system. In fact, the Polarled project was unveiled simultaneously with the plans to develop the Aasta Hansteen field, whose first gas is expected for the third quarter of 2017. Total recoverable reserves there were estimated at 47 BCM, with a plateau output forecast of 7.6 BCM/year (735 Mcf/d).

Polarled will be ready a little before that, in late 2016, with a capacity of 25.5 BCM/y, to include the production from smaller Norwegian sea fields such as Linnorm and Zidane, whose approval for development and production by 2017 is still pending (Figure 2.5).

Figure 2.5 The Polarled pipeline project (statoil.com).

Polarled will run to the Nyhamna gas processing terminal in mid-Norway, where Shell has awarded contracts for a US$ 2 billion upgrade. From Nyhamna the UK can be reached via the 1,170 km Langeled pipeline, completed in 2007 in tandem with Ormen Lange. Gas can also be headed to mainland Europe via the Sleipner offshore hub, midway along Langeled.

These examples illustrate how Norway is constantly adding resilience and flexibility to its subsea systems.

Middle East and North Africa

Proven natural gas reserves in the Middle East, currently estimated at 88 BCM, are concentrated in Qatar and Iran, as indicated in Table 2.4. Gas output in the region is expected to remain broadly stable in the near future (IMF, 2014).

Table 2.4 Proven Natural Gas Reserves (BCM) in Middle East and North Africa (BP Statistical Review of World Energy, 2014).

Proven Natural Gas Reserves (BCM)														
Bahrain	Iran	Iraq	Kuwait	Oman	Qatar	Saudi Arabia	Syria	UAE	Yemen	Others ME	Algeria	Egypt	Libya	Total
191	33.780	3.588	1.784	950	24.678	8.234	285	6.091	479	230	4.504	1.846	1.549	88.188

With 38 TCM of proven reserves, the largest non-associated gas field in the world continues to be shared between Iran and Qatar. North Field (Qatar) is planned to have 16 development phases and South Pars (Iran) 30 more. By 2015 the total production is expected to reach 500 BCM/y (50 Bcf/d), of which around 50% for LNG exports.

Discovered in 2006, the Karan field has been developed in Saudi Arabia to meet the Kingdom's demand for sales gas and industrial feedstock for water desalination and electric power generation. With a capacity of 18 BCM/year, it was the first non-associated offshore development in Saudi Arabia. Production started in July 2011, one year ahead of schedule and under budget.

Meanwhile, when this report was written, Shah, the first sour gas field in the UAE (H_2S content of 23%), was still expected to produce 10 BCM/year for about US$ 10 billion.

In Israeli waters of the Mediterranean Sea several discoveries have recently increased the estimated volumes of resources of the Levant basin to 980 BCM. Production of 3 BCM/year already started in the Tamar field in April 2013, but a lot more could come from the Leviathan field, which is expected to hold 500 BCM of gas (almost the double of Tamar). Investments of 7.5 US$ billion would be required.

In Algeria, more than 100 discoveries had been made in the Sahara since the 1950s, but the gas was considered too remote from any sizeable market, until advances in technology have made some of them economically feasible.

The producing fields were then connected by 400km of gas pipelines. The gas deposits comprise two tight, thin reservoirs at depths between 2000 to 4000 meters. They have low porosity and low permeability, but the appraisal program indicated excellent lateral continuity in the reservoirs, so large areas could be produced with relatively few wells, long-reach horizontal-drilling being an important factor. Separation and storage of CO2 into the gas formation was also included in the investment.

The North Reggane gas fields in Algeria, including Kahlouche, South Kahlouche, Sali, Raggane, Azrafil and Tioliline, located in blocks 351c and 352c, approximately 1,500km southwest of Algiers, will be developed by Repsol, Sonatrach and RWE. The project includes the construction of gas treatment and accumulation facilities, a pipeline for exportation and auxiliary infrastructure (runway, electrical systems, etc). Preliminary estimates indicate a total of 104 wells to be drilled, distributed across the six development areas indicated. Production is expected to span for 25 years from 2017 and the consortium anticipates achieving a stable production rate of 8 MCM/d of gas during the first 12 years..

In Algeria, the Touat gas field is expected to reach a peak production of 4.5 BCM/y in the south-west of the country. At the time of the award (2002), gas reserves had been estimated at 60-120 BCM. The first phase of the project will cover the construction of a gas-processing plant with a capacity of 500 MCF/d and will also include a link into the central gas transport grid of Sonatrach by means of a 100 km interconnection. A total of 25 gas wells will be drilled in the first phase of the development by operator GDF Suez. The project involves the development of 10 fields covering a 3,000 km^2 area, and production is expected to start in 2016.

In Tunisia, the BG projects of Miskar and Hasdrubal have been important to the country. Both consist of complex carbonate reservoirs which are trapped in a combination of structural and stratigraphic traps, with wide variations in non-hydrocarbon components, such as CO_2, H_2S and N_2.

Hasdrubal is a US$ 1.2 billion project that has turned ETAP and BG into the largest producers of gas, LPG and liquids in Tunisia. The plant encompasses gas separation, mercury removal, gas dehydration, H_2S and CO_2 removal, gas compression, stabilization and export.

In Egypt, BP signed an agreement to develop concessions in North Alexandria and the deep waters of the East Mediterranean. The first phase will cover 0.2 TCM of gas and associated condensate from sub-sea facilities covering five offshore fields into a new gas plant located in the Mediterranean coast of Egypt. First gas is expected for late 2014.

In April 2014, the Raven gas field has been incorporated into the West Nile Delta Development. It is expected to produce 1 BCF/d from a water depth of 650m. Most probably, the field will be developed with subsea wells feeding gas to a second liquefied natural gas plant proposed at Damietta. Raven has HP/HT reservoirs, temperatures of up to 350 ºC and pressures as high as 15,000 psi. Raven has reserves of up to 4 TCF of gas and 50 million barrels of condensate.

Asia Pacific and South Asia

In the Asia Pacific, the largest reserves of natural gas occur in Australia, China and Indonesia (Table 2.5). Over the last three years, a large number of events has taken place in the exploration and production of natural, especially in China and Australia, as indicated next.

Table 2.5 Proven natural gas reserves in the Asia Pacific (BP, 2014).

Proven Natural Gas Reserves (BCM)													
Australia	Bangladesh	Brunei	China	India	Indonesia	Malaysia	Myanmar	Pakistan	Papua New Guinea	Thailand	Vietnam	Other Asia Pacific	Total
3.677	276	288	3.272	1.355	2.927	1.091	283	644	155	285	617	326	15.195

In China, where resources of Liwan 3-1 are estimated at 2 TCM, Husky has agreed to operate the deep water portion, including the development of drilling and completions, subsea equipment , controls and tiebacks, while its domestic partner CNOOC will operate the shallow water portion of the project, including a platform, approximately 270 km subsea pipeline and a processing plant located onshore.

Production is still ramping up in the Sulige gas field and is expected to reach 23 BCM/y by 2015. Located in the Ordos Basin in inner Mongolia, it holds over 1 TCF of proven gas reserves. Nearly 2,000 development wells could be drilled over the life of the field along 25 years. Sulige is a low permeability, low pressure gas field with a reservoir depth of 3,200 to 3,500 meters. Around 450 wells will be drilled before the gas block reaches a stable annual output of 3 BCM/y. PetroChina and Total started production at Sulige South in May 2012.

The Yuanba gas field in Sichuan is the deepest gas field in marine strata ever found in China, with deposits reaching 6,950 meters. The field contains 220 BCM of reserves in an area of 155 km^2, and the output capacity will reach 3.4 BCM/y by 2015. The first phase of the project involves 11 gas gathering stations, 130 km of gas pipelines and a processing plant. Sinopec expects to complete the processing plant and start production by the end of 2014.

In India, the Krishna Godavari offshore basin is likely to become a world class area for gas production. The KG-DWN-98/2 block, which sits adjacent to the producing KG-DWN-98/3 block, has a targeted production of 7 BCM/year. However, discoveries are scattered across the basin in both deep waters and shallow waters. ONGC plans to invest 8 US$ billion to develop its gas fields in the KG basin to pump up to 11 BCM/y (1 BCF/d) of gas from these blocks by 2016/17.

The Dhirubhai-34 discovery, known as the R-Series gas field, has recoverable gas reserves of 1.2 - 1.4 TCF. The field could produce 518 MCF/d from 11 wells for a period of eight years. The field is located in the KG-D6 block and could be developed together with the Dhirubhai-29, 30 and 31 discoveries, if their combined reserves of 506 BCF are proven to be commercial. Reliance has confirmed that the development will be dependent on the price of natural gas. However, the planned investment is subject to an increase of regulated prices, which was announced by the government in October 2014, though fall short of markets expectations (increase of ~50% vs. ~100% pretended by Reliance).

The Daman offshore project involves the development of the shallow water B-12 and C-24 marginal fields, located in the Tapti-Daman block in the Mumbai offshore area. In place reserves are estimated at 96 BCM with potential recoverable reserves of 42 BCM. The fields are expected to produce 295 MCF/d of gas and 9 kboe/d of condensate. They are located approximately 60 km from the C-Series fields, in water depths of 100 m. The fields are expected to produce gas for 15 years starting from 2016.

In Australia, Shell continues the US$ 10 billion Prelude FLNG, the first floating LNG facility in the world. It is expected to tap 1 TCM of resources from the Prelude and Concerto fields, with the first production shipping out in 2016. The FLNG facility will stay permanently moored at the Prelude gas field for 25 years, and in later development phases it will produce from other fields in the area. Shell has announced that in Australian waters alone there is an estimated 4 TCM of "stranded" gas to be extracted.

Prelude FLNG will open up development of gas fields that previously were too small or too remote; yet future FLNG applications are unlikely to be universal as marine conditions, hefty investments and commercial issues are likely to limit the activity to companies that are large enough to manage the risk.

Also in Australia it is estimated that about 3.4 million t/y of CO_2 will be reinjected underground at Gorgon, totaling more than 120 million tons over the life of the project, three times as much as any other greenhouse gas storage project worldwide.

Gas from the offshore fields that feed the Gorgon Project contains on average about 14% of CO_2. The Gorgon Joint Venture will capture, compresses, transport and inject it into the Dupuy Saline Formation, 2000 m deep under the eastern coast of Barrow Island.

This project also sets some precedents, being the first to be subject to specific greenhouse gas storage legislation. It is also the first to undergo detailed environmental impact assessment, including public review and comment, and will set new standards in the public availability of monitoring data.

In Malaysia, Shell is leading the development of the 1 TCM Kebabangan cluster and the 0.5 TCM deepwater gas fields of Kamunsu East, as well as the 670 million boe Gumust-Kakap project, all of which are expected to come on stream over the next years.

In Indonesia, the Abadi gas field, located in the Masela Block in the Arafura Sea, lies in water depths ranging from 300 to 1,000 meters. Discovered in 2000 by the Abadi-1 well (making it the first discovery of hydrocarbons in the Indonesian Arafura Sea), Abadi was further appraised by six wells, confirming the sufficient volumes of gas reserves for an LNG development project. Abadi is believed to contain more than 3 TCM of natural gas reserves.

Sub-Saharan Africa

The largest reserves in this region occur in Angola, Cameroon, Mozambique and Namibia (Figure 2.6), but much is taking place in Mozambique and Tanzania now, following the recent discoveries in the Rovuma Basin.

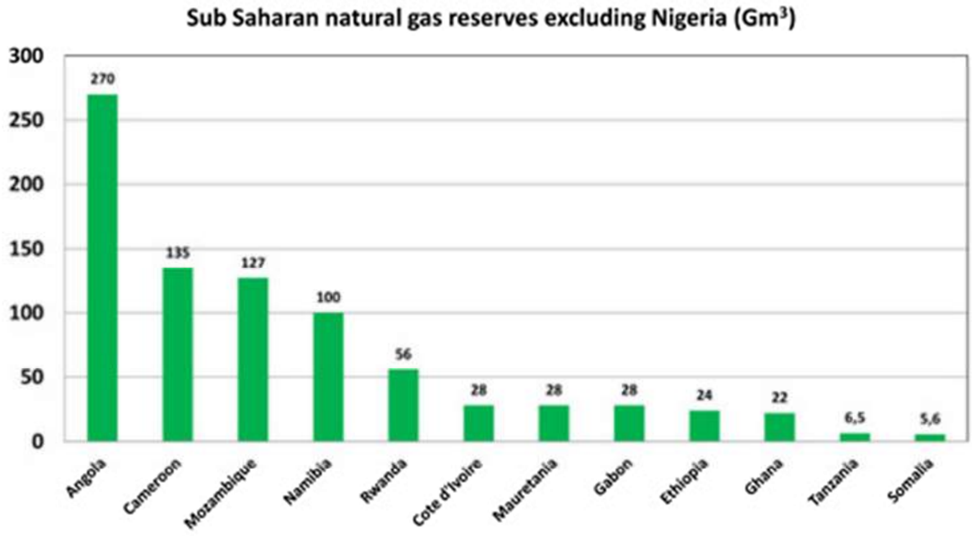


Figure 2.6 Sub Saharan natural gas reserves excluding Nigeria (The World Factbook, IEA, BP).

In Mozambique, the Mamba Complex in Offshore Area 4 covers a surface area of 17,646 km^2 in water depths of up to 2,600 meters, with estimated 2.5 TCM of gas-in-place. The development plan for the field calls for the use of a FLNG vessel to exploit the gas reserves at the block and the feedstock for the vessel is expected to come from the Coral field. Area 4's initial subsea system is expected to include more than 30 subsea wells. Operator Eni was expected to start a design contest covering the development of the subsea production systems during the second half of 2014.

Meanwhile, Offshore Area-1 covers approximately 2.6 million acres in the deep waters of the Rovuma Basin. The Prosperidade complex is estimated to hold recoverable resources of 480-850 BCM of natural gas, including the discoveries of Windjammer, Barquentine, Lagosta and Camarão.

Field development will initially see gas from 30 to 35 subsea production wells fed to a two-train liquefaction plant in the Cabo Delgado province, and this may rise to as many as 60 soon after that. However, the country seems to be behind in providing the legal framework necessary to assure the liquefaction and exportation of the production. This could delay the first gas from 2018 to 2020 or further.

Russia and Central Asia

Over the last three years, a large number of important events has taken place in the Russian Federation and Central Asia, where large reserves and resources of natural gas exist (Figure 2.7).

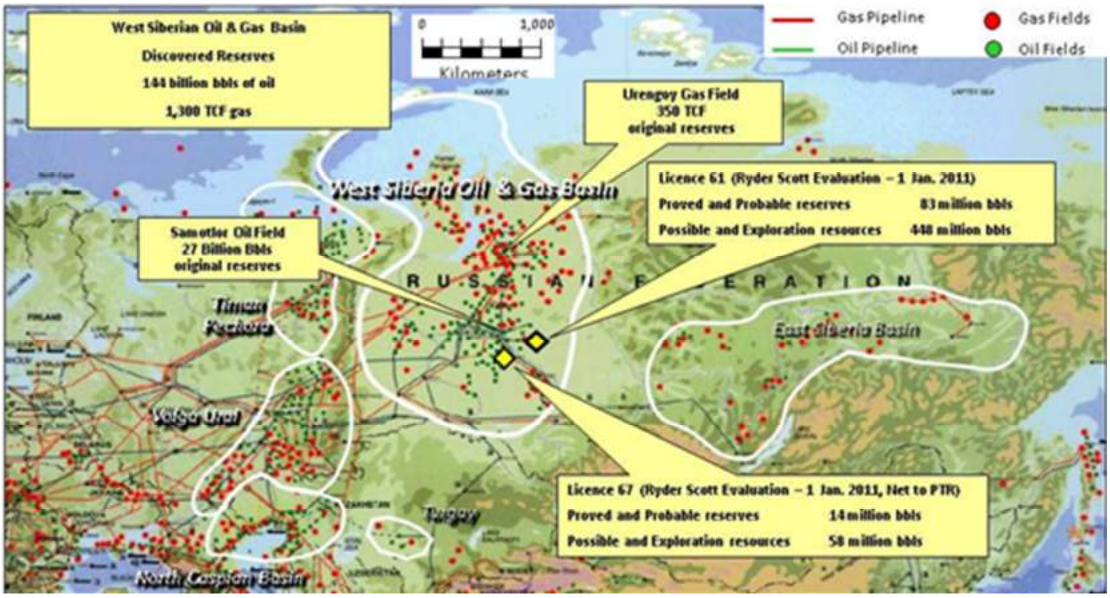


Figure 2.7 West Siberian Oil & Gas Basins (Oil & Gas Journal).

The Russian Arctic and West Siberia

The hydrocarbon resources estimated to exist in the Arctic shelf of Russia amount to approximately 18% of the potential available in other ocean shelves.

In spite of the large potential available at Prirazlomnoye and Severo-Kamennomysskoe, the largest and most promising field in the region is still Shtokman.

It was discovered in 1988 and is located 600 km offshore. After more than two decades, and despite the challenges, the absence of transit countries on the way to markets was a key factor in deciding to prioritize this project. In 2013, Gazprom revived it after work was suspended in 2012, following major concerns over cost and economics. Phase 1 of the project is expected to cost over US$ 40 billion to produce 17.3 million tons/y of LNG after 2019. The resumption of work on this huge gas project has been underlined by a new tender issued for the LNG terminal, locate onshore. Lead operator Gazprom is basing the project on two LNG trains capable of processing 23.4 BCM/y of gas for export and 2.3 BCM/y for the surrounding Murmansk region.

In the Yamal peninsula, 26 inland and 5 offshore fields have been discovered since the 1960s. Total natural gas resources are currently estimated at 22 TCM, and a production of 300 BCM/y (30 Bcf/d) could be reached by 2030. One of the most promising fields is Bovanenkovo, which was prioritized for development due to the fact that it holds the largest amount of reserves in the area, 5 TCM. Gas production from this field is projected to peak at 140 BCM/y (14 Bcf/d).

More on the Russian Arctic can be found in section 2.4.1.

Central Asia

In Azerbaijan, Shah Deniz II is expected to produce 16 BCM/y (1.6 Bcf/d) by 2017, of which 10 BCM/y would be marketed to the EU. The development will target gas and condensate from the deep water portion of the field. The water depth is 550 meters, while the pressure in the reservoir exceeds 5000 psi. The Trans Adriatic Pipeline (TAP) has been selected by the Shah Deniz II consortium to transport gas from Azerbaijan to Europe starting in 2018.

In Turkmenistan, production at the giant Galkynysh gas cluster, formerly known as South Yolotan, started in 2013, but new developments are possible in the future, including a pipeline to Europe, with an annual capacity of up to 40 BCM. Once the field is running at full capacity, it is expected to produce around 25 BCM/y of natural gas. At the moment, output from Galkynysh will mainly be exported to China through the Central Asia - China Pipeline, to which two new lines are being added. The third section of the pipeline is currently under construction, and will run parallel to the existing lines from Turkmenistan, via Kazakhstan and Uzbekistan.

2.3 Unconventional gas

Nearly 10 years have already passed ever since the revolution of unconventional gas and oil started to completely change the energy scenario in North America, but significant difficulties continue to prevent its reproduction in other parts of the globe, where the accumulated drilling activity for unconventionals has been estimated to represent only 10% of the annual figure for the USA alone (Stoppard, 2013).

A first complete assessment of unconventional resources is still being developed by the United States Geological Survey (USGS), but some results are already available. Before that, however, it is important to clearly state a few definitions and concepts.

2.3.1 Definitions and concepts

The three most common types of unconventional gas resources are tight sands, coal bed methane (CBM) and gas shales (Figure 2.8 and Figure 2.9). In these formations, gas is often sourced from the reservoir rock itself, but due to the low permeability it is necessary to stimulate the reservoir by creating a network of fractures to yield enough surface area and permeability (Green, 2013).

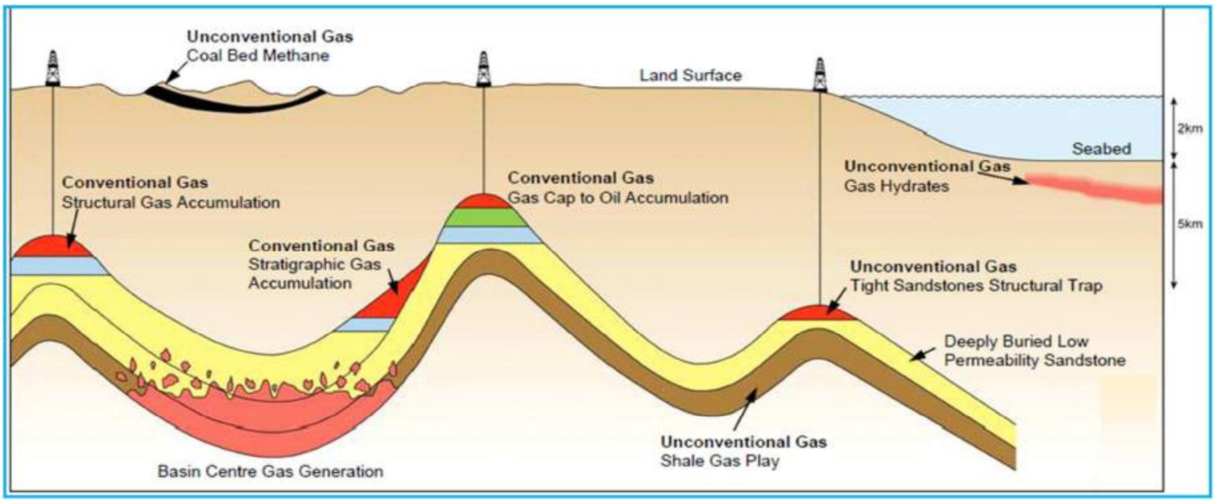


Figure 2.8 A graphic description of the most common unconventional resources (EIA *apud* BG, 2013).

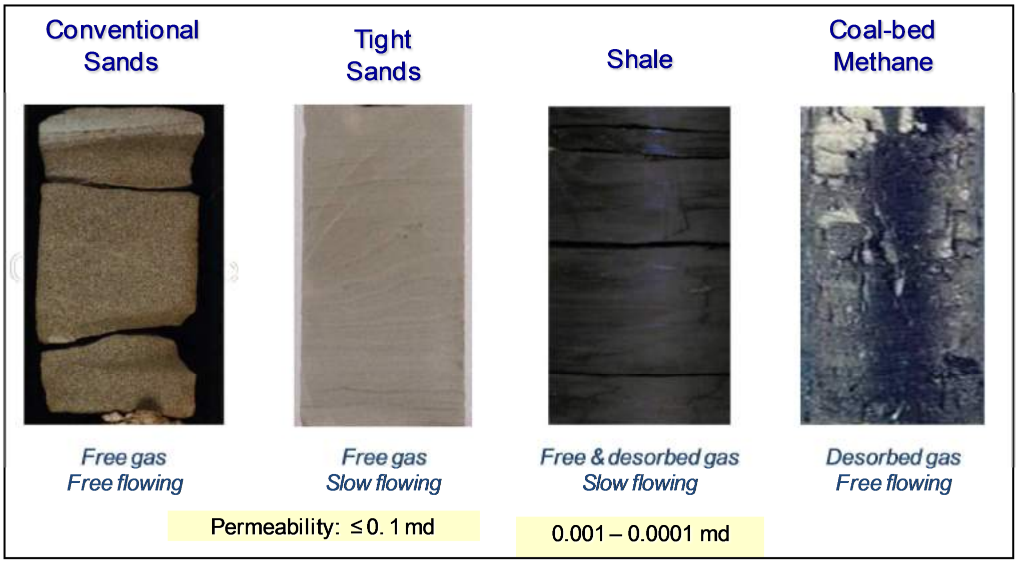


Figure 2.9 A close view comparing the structural details of some reservoirs (BP *apud* Bustin, 2009).

Shale gas

Green (2013) described shale as “a sedimentary rock that is predominantly comprised of very fine-grained clay particles deposited in a thinly laminated texture. These rocks were originally deposited as mud in low energy depositional environments, such as tidal flats and swamps, where the clay particles fall out of suspension. During the deposition of these sediments, organic matter is also deposited, which is measured when quoting the Total Organic Content (TOC). Deep burial of this mud results in a layered rock called “Shale”, which actually describes the very fine grains and laminar nature of the sediment, not rock composition, which can differ significantly between shales”. The natural gas is stored in fracture porosity, within the micropores of the shale itself, or adsorbed onto it.

In addition to their laminated texture, shales are also distinguished from other tight gas formations by their ultra-low permeability (0.001-0.0001md). Unfortunately, a certain confusion subsists in languages such as French, Spanish and Portuguese, as the word “shale” is often translated as “xiste” or “xisto”, which would actually be the equivalent to “schist” in English. The latter is not a sedimentary, but a metamorphic rock (Figure 2.10).

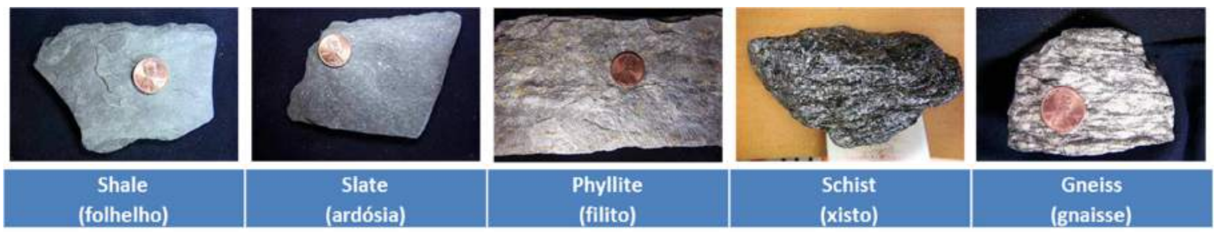


Figure 2.10 Barrovian metamorphic rock changes in English and Portuguese (adapted from Fichter, 2000).

Tight gas

This is a generic expression that is still used to designate natural gas produced from reservoir rocks with such a low permeability that stimulation methods are necessary to produce at economic rates.

Shale gas would therefore be a specific variety of tight gas, but people in the industry often distinguish it as a separate class of unconventional gas, as indicated in numerous presentations and reports published in the literature, where the expression “tight gas” is usually reserved for the natural gas that is sourced elsewhere and then migrated into sandstones, carbonates or other non-shale structures over geological time (Table 2.6).

Table 2.6 Shale vs. tight gas (Hall, 2011).

	Shale gas	Tight gas
Grain-size	Mostly mud	Substantially silt or fine sand
Porosity	up to 6%	up to 8%
TOC	up to 10%	up to 7%
Permeability	up to 0.001 mD	up to 1 mD
Source	Mostly self-sourced	Mostly extra-formation
Trap	None	Facies and hydrodynamic
Gas	Substantially adsorbed	Almost all in pore space
Silica	Biogenic, crypto-crystalline	Detrital quartz
Brittleness	From silica	From carbonate cement

Basin-centered gas

Some tight gas reservoirs have also been found to be sourced from underlying coal and shale source rocks, in the so called basin centered gas accumulations (BCG), which were defined by Law and Curtis (2002) as abnormally pressured, gas-saturated accumulation in low-permeability reservoirs lacking a down-dip water contact.

A less technical but perhaps more useful definition is attributed to Schmoker (1995), who referred to them as “large single fields having spatial dimensions equal to or exceeding those of conventional plays. They cannot be represented in terms of discrete, countable units delineated by downdip hydrocarbon-water contacts (as are conventional fields). The definition of continuous accumulations is based on geology rather than on government regulations defining low permeability (tight) gas. Common geologic and production characteristics of continuous accumulations include their occurrence down-dip from water-saturated rocks, lack of obvious trap or seal, relatively low matrix permeability, abnormal pressures, large in-place hydrocarbon volumes, and low recovery factors” (Nuccio et al., 2000).

Coal bed methane (CBM)

This expression refers to the gas that is associated and produced from coal seams. Methane predominates, but it can also include other constituents such as ethane, carbon dioxide, nitrogen and hydrogen.

Coal seams act both as source and reservoir for the natural gas, whose majority is stored in adsorbed state. Because coal has such a large internal surface area, it can store large volumes of natural gas, six or seven times as much as a conventional reservoir.

Economic reservoirs are normally shallow, as the coal matrix tends to have insufficient strength to maintain porosity at depth. The wells often produce significant quantities of water in the early stages of production.

Gas hydrates

Gas hydrates are often called methane hydrates or methane clathrates. They are an ice like crystalline solid consisting of methane, ethane or other molecules surrounded by a cage of water.

Estimates of the amount of carbon bound in gas hydrates are almost twice the amount of carbon found in all known fossil fuels on Earth; hence, hydrates represent a dominant unconventional energy resource.

It is believed that they are formed by the migration of gas from depth along geological faults, followed by precipitation or crystallization on contact of the rising gas stream with the icy cold water from the sea. These conditions are common in the continental margins and below about 200 m depth in permafrost areas.

2.3.2 Global resources of shale and tight gas

It is interesting to note that the first commercial gas well in the USA, drilled in New York State in 1821, many years before Drake's pioneer oil well, was in fact a shale gas well. Subsequently, limited amounts of gas were produced from shallow, fractured shale formations, notably in the Appalachian and Michigan basins.

The contemporary interest in developing shales initiated at the Barnett play in Central Texas, where production reached 5 BCF/d of production just a few years ago (Figure 2.11).

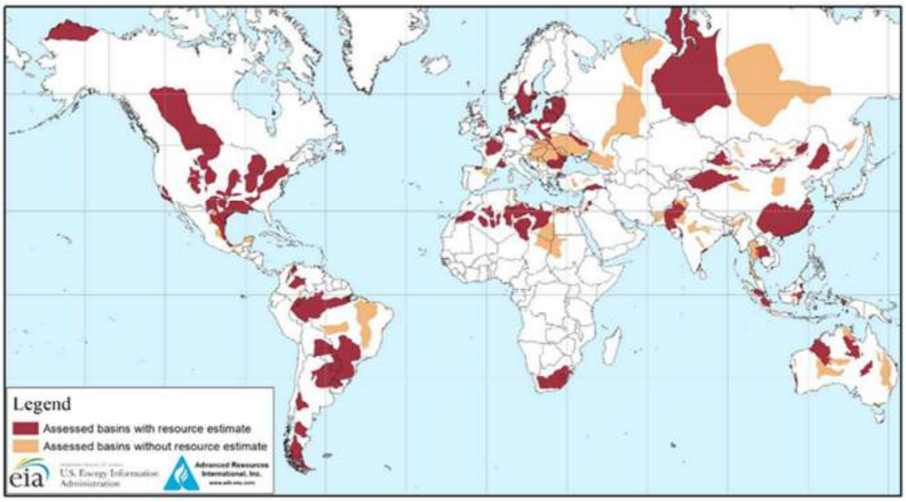


Figure 2.11 Map of basins with assessed shale oil and shale gas formations as of May 2013.

A study sponsored by the Energy Information Administration (EIA) recently identified a total risked shale gas in place of 31,138 TCF (880 TCM) in 41 countries outside the USA, of which approximately 6,634 TCF (188 TCM) were considered to be technically recoverable, as indicated in Table 2.7.

Table 2.7 In place and technically recoverable shale gas (EIA/ARI, 2013).

Continent	Risked Gas In-Place (Tcf)	Risked Technically Recoverable (Tcf)
North America (Ex. U.S.)	4,647	1,118
Australia	2,046	437
South America	6,390	1,431
Europe	4,895	883
Africa	6,664	1,361
Asia	6,495	1,403
Sub-Total	**31,138**	**6,634**
U.S.	4,644	1,161
TOTAL	**35,782**	**7,795**

The top countries with highest assessed resources include China (1,115 TCF; 32 TCM), Argentina (802 TCF; 22.7 TCM), Algeria (707 TCF; 20 TCM), USA (665 TCF; 18.8 TCM) and Canada (573 TCF; 16.2 TCM).

North America

USA

Different studies have shown the potential of shale resources in the USA. According to Advanced Resources International (ARI), the USA has over 1,100 TCF (31 TCM) of natural gas reserves and resources yet to be developed. At current consumption levels this represents 45 years of supply.

These volumes are spread between 70 distinct plays in several regions, the Northeast being the most notable with Marcellus and Utica as key plays, while Haynsville and Fayetville in the Southeast also hold relevant resources. Eagle Ford has also become relevant during the last years as a growing play given its massive resources of both shale oil and shale gas.

Table 2.8 Remaining reserves and undeveloped resources in USA (EIA/ARI, 2013).

Region / Basin	Distinct plays	Remaining reserves and undeveloped resources
	[#]	*[Tcf]*
Northeast		
Marcellus	8	369
Utica	3	111
Other	3	29
Southeast		
Haynesville	4	161
Bossier	2	57
Fayetville	4	48
Mid Continent		
Woodford	9	77
Antrim	1	5
New Albany	1	2
Texas		
Eagle Ford	6	119
Barnett	5	72
Permian	9	34
Rockies / Great Plains		
Niobara	8	57
Lewis	1	1
Bakken / Three Forks	6	19
Total	**70**	**1,161**

Notes: Woodford includes Ardmore, Arkoma and Anadarko (Cana) basins
Barnett includes the Barnett Combo
Permian includes Avalon, Cline and Wolfcamp shales
Niobrara Shale play includes Denver, Piceance and Powder River basins

The Barnett shale is well known for being the first play to see commercial development. Favored by high gas prices before the financial crisis of 2008, other shale gas plays followed, thanks to the particular dynamic of the US industry, were operators and service companies act fast to accommodate market needs. These included Haynesville/Bossier, Antrim, Fayetville and the Marcellus.

Increased gas supply from shale plays ended up affecting prices, and operators turned their attention to liquid rich plays such as the Bakken, Eagle Ford and Permian. As a consequence, the supply of gas kept increasing, and gas prices in the 3.50 – 4.50 US$/MBtu range resulted as consequence.

Gas supply from shale plays is expected to increase further, and there are estimates that it could cover as much as 50% of the US needs by 2025 (Figure 2.12).

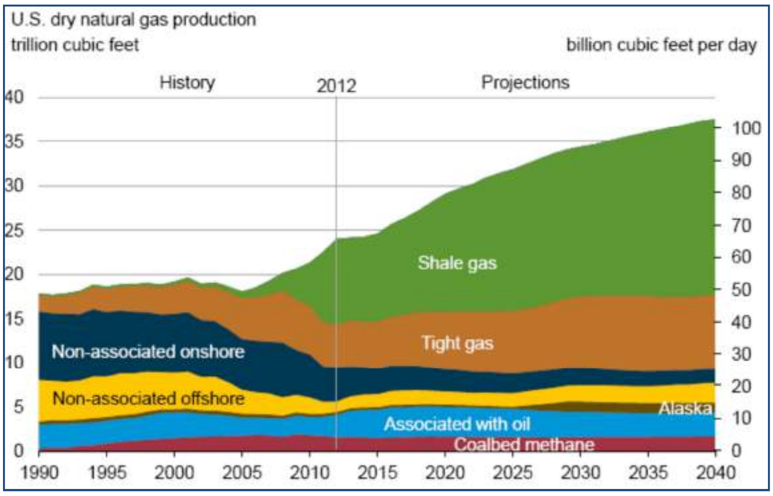


Figure 2.12 Shale gas is expected to reach half of the total production by 2040 (EIA, 2014).

Canada

Canada has significant shale resources of natural gas, close to 60% of all technically recoverable resources located in north-western part of the country, according to ARI (Table 2.9). In addition to that, the region holds significant tight sands resources in Montney and Doig. The Alberta region also holds considerable amounts of shale gas in place, while in the eastern region shale resources are mostly liquids rich, with the exception of Quebec, which is an extension of the Utica shale in the USA.

Table 2.9 Shale gas resources in Canada (ARI, 2013)

Region / Basin (formation)	Risked Gas in Place	Risked Technically Recoverable Resources
	[Tcf]	*[Tcf]*
British Columbia / Northwest Territories		
Horn River (Muskwa / Otter Park)	376	94
Horn River (Evie / Klua)	154	39
Cordova (Muskwa / Otter Park)	81	20
Liard (Lower Besa River)	526	158
Deep (Doig Phosphate)	101	25
Alberta		
Alberta (Banff / Exshaw)	5	0
E/W Shale (Duvernay)	483	113
Deep Basin (Nordegg)	72	13
N.W. Alberta (Muskwa)	142	31
S. Alberta (Colorado)	286	43
Saskatchewan / Manitoba		
Willliston (Bakken)	16	2
Quebec		
App Fold Belt (Utica)	155	31
Nova Scotia		
Windsor (Horton Bluff)	17	3
Total	**2,413**	**573**

Companies in Canada are also focusing on liquid rich plays and unconventional oil to create a more balanced hydrocarbon portfolio in light of the broad spreads between oil and gas prices.

Strong efficiency gains, similar to those achieved in the USA, are improving economics. Drilling times are shrinking with pad drilling increasingly employed in the Montney play, and parts of the Horn River basin. Costs per well are falling, despite of increase in service costs. Some companies are estimating Montney wells to be economical at gas prices as low as US$ 1.5 per million Btu at the best acreage.

Part of the Montney play stretches into Alberta, and there are several other resource plays that have attracted interest. Among them is the Duvernay liquid-rich shale, which is touted as the source rock for the oil reserves of the Western Canadian Sedimentary Basin (WCSB).

The gas in Horn River and Montney should be considered “stranded” due to the fact that these plays are relatively isolated in the Northwest of the country, as compared to conventional sources and shale resources located in Alberta, where a significant infrastructure is already in place. More than 17 LNG projects have been proposed in Western Canada, but none had a final investment decision taken yet. First cargoes should not be expected before 2020.

The Canadian Association of Petroleum Producers outlooks a combined production potential of around 40 BCM/y by 2020 for Montney and Horn River, which more than compensates the expected decline of the domestic conventional production.

South America

Argentina

Argentina's shale gas resources are not only vast in their volume, but are also considered of high quality, particularly at the Vaca Muerta formation in the Neuquén province. Another important formation in Neuquén is Los Molles, which is stacked below Vaca Muerta at depth ranging from 8,000 ft to 16,400 ft (Table 2.10).

Table 2.10 Shale gas resources in Argentina (EIA/ARI, 2013)

Basin / Formation	Risked Gas in Place	Risked Technically Recoverable Resources
	[Tcf]	[Tcf]
Neuquen		
Los Molles	982	275
Vaca Muerta	1,202	308
San Jorge		
Aguada Bandera	254	51
D-129	184	35
Austral Magallanes		
L. Inoceramus - Magnas Verdes	606	130
Parana		
Ponta Grosa	16	3
Total	**3,244**	**802**

Exploratory activity in Vaca Muerta has confirmed its potential, and some areas are already being developed, with more than 400 wells drilled so far. Argentina is expected to be the first country outside North America to massively develop its shale resources, due to the favourable conditions below and above ground.

A decade long a cap on prices led to underinvestment and decline in the production, moving the country from net exporter to net importer of gas. The energy bill for imported energy has grown over the last years, reaching a US$ 7 billion deficit in 2013, affecting budget and the overall economy.

Since 2008 some incentives have been put in place to develop tight gas and in 2013 better conditions were also created for investment in any type of new gas. Several projects have been developed under these conditions, but there was no success in reversing the current decline. In late 2014 a new hydrocarbons law was passed, setting new grounds for a better investment environment, and this is expected to attract more foreign capital now.

So far YPF has been the most active operator, mainly in Loma Campana (with Chevron), El Orejano (with Dow) and La Amarga Chicablock (with Dow and Petronas). A lot of exploratory activity is also in place, with wells being drilled by several companies, including ExxonMobil, Shell, Total, BP (PanAmerican Energy) and Petrobras.

Europe

Around fifty companies are currently performing exploratory activities in Europe, where significant resources exist, but there is consensus that unconventional developments in Europe are unlikely to render a significant contribution until 2020 (Figure 2.13 and Table 2.11).

Figure 2.13 Shale gas and CBM potential in Europe (IEA, 2012).

Table 2.11 Shale gas resources in Europe (ARI, 2013)

Country / Basin (formation)	Risked Gas in Place	Risked Technically Recoverable Resources
	[Tcf]	[Tcf]
Poland	**739**	**145**
Baltic Basin/Warsaw Trough	532	105
Lublin	46	9
Podlasie	54	10
Fore Sudetic	107	21
Romania / Bulgaria	**148**	**37**
Moesian Platform	148	37
UK	**134**	**26**
N. UK Carboniferous Shale Region	126	25
S. UK Jurassic Shale Region	8	1
France	**727**	**136**
Paris Basin	690	129
Southeast Basin	37	7
Germany	**80**	**17**
Lower Saxony / Posidonia	78	17
Lower Saxony / Wealden	2	0
Netherlands	**152**	**26**
West Netherlands / Epen	94	15
West Netherlands / Geverik	51	10
West Netherlands / Posidonia	7	1
Sweden	**49**	**10**
Alum Shale	49	10
Denmark	**159**	**32**
Alum Shale	159	32
Total	**2,188**	**429**

Production in Europe has been challenged by a number of factors:

- Limited access to land – the European population density is much higher than in the USA;
- Geology - the combined favourable characteristics of the plays in the United States, are not easily found in Europe. In particular, the large continuous unstructured accumulations compares with smaller and more complex European plays, where a high level of heterogeneity within plays, on a smaller scale basis, often takes place, requiring more research and data gathering to be performed;
- Water management – insufficient infrastructure to transport water and dispose of waste in the drilling sites;
- Limited availability of services and equipment, especially rigs;
- The pipeline grid density varies considerably in Europe, from 45 km/1000 km^2 in the UK to 1 km/1000 km^2 in Sweden, while in the USA an average of 62 km/1000 km^2 predominates;

Eastern Europe

Poland has some of the most favourable infrastructure for shale development in Europe, and a fairly good public support as well.

Risked, technically recoverable shale resources are estimated at 146 TCF (4.1 TCM) of shale gas and 1.8 billion barrels of tight oil in four assessed basins (Table 2.11).

The Baltic Basin in the north remains the most prospective region, with a relatively simple structural setting. Meanwhile, the Podlasie and Lublin basins also have potential but are structurally more complex, with closely spaced faults, which may limit horizontal drilling.

As fracking is less restricted than in France and Germany, and the country wishes to move out from imported gas, the country is often referred to as a leading case in Europe. First works started only recently, however, and full developments are not expected to mature before the next decade.

Exploration of the Lubocino-1 well located in Wejherowo area has identified a significant amounts of unconventionals, while the development proposed for the Yuzovsky field in the eastern Donetsk and Kharkiv regions seeks the extraction of conventional, shale and tight gas. The Yuzivske field is estimated to contain about 3 to 3.5 TCM of gas deposits, and drilling was expected to start in 2014. As many as 15 wells will have to be drilled to complete the initial exploration and appraisal stage.

Bulgaria, Romania and Ukraine also have significant unconventional gas and oil resources in Dniepr-Donets, the Carpathian Foreland and the Moesian Platform. Shale exploration is underway in Ukraine and Romania, but in Bulgaria a moratorium on shale development is in place. The total risked, technically recoverable resource potential for the three basins is estimated at 195 TCF (5.5 TCM) of shale gas and 1.6 billion barrels of oil and condensate.

Shale resource assessments are reported to be under way in these countries, but no official assessment has been published yet. To date, only one shale focused exploration core well has been drilled in the region, but no production testing has occurred. In Ukraine, Shell recently signed a production sharing agreement for the Dniepr-Donets Basin, committing at least US$ 200 million for exploration, while Chevron has been negotiating a block in the Ukrainian portion of the Carpathian Foreland Basin. Chevron's shale blocks in Romania and Bulgaria were put on hold.

United Kingdom

The risked, technically recoverable shale resources of the UK are estimated at 26 TCF (0.7 TCM) of shale gas and 0.7 billion barrels of tight oil and condensate (ARI, 2013). Compared with North America, the shale geology of the UK is considerably more complex, while drilling and completion costs are substantially higher.

Shale testing is still at an early phase in the UK. In a temporary setback, the first shale well to be hydraulically stimulated triggered a series of minor earthquakes related to a nearby fault. Following an 18-month moratorium, the government concluded that the environmental risks of shale exploration were small and manageable. Shale drilling was allowed to resume in December 2012 as a consequence, albeit with stricter monitoring controls.

The Bowland Sub-basin, the only active shale drilling region in the UK, has had five shale exploration wells drilled to date.

Northwestern Europe

Numerous shale basins and formations occur in Northern and Western Europe, such as the Paris and South-East basins in France, the Lower Saxony Basin in Germany, the West Netherland Basin and the Alum in Scandinavia. The risked shale gas in-place for the five Northern and Western European basins is estimated to be 1,165 TCF (33 TCM), with 221 TCF (6.2 TCM) as the risked, technically recoverable shale gas resource (ARI, 2013).

Most of the exploratory activity in the Paris Basin has targeted the Jurassic Lias play, but Elixir Petroleum has acquired data on the Moselle and its permian-carboniferous resource interval. While the terms of the lease do not require the company to drill, Elixir has publically stated that it intends to investigate the unconventional gas potential of its lease.

A number of firms are beginning to examine the shale potential of the South-East Basin; the initial permit award was delayed due to the large number of applications submited. The French Ministry of Energy and the Environment awarded several exploration permits, covering over 4,000 mi^2, to companies interested in investing in the drilling and exploration of shale formations in the South-East Basin.

ExxonMobil has been a leading company in the Lower Saxony Basin of Germany. It has drilled a series of test wells on its exploratory leases, and at least three of them are reported to be testing the shale gas potential. After a lengthy period of study, the German government issued in late February 2013 a draft legislation what would allow the development of shale and the use of hydraulic stimulation under environmental safeguards.

In the Netherlands, beyond the earlier exploratory wells that helped to define the shale resources in the West Netherland Basin, there is no recent shale gas or oil developments.

Of the numerous companies that have applied for exploration licenses in Sweden, Shell has been the most active. Three wells were drilled, albeit uneconomic. In Denmark, Total is exploring for deep shale gas in two license areas. The work program for the first exploration well, Vendsyssel-1, was submitted in late 2012, and there are plans for a six year program to determine whether their lease areas contain sufficient shale gas resources to warrant further development.

Russia and Central Asia

For the Bazhenov Shale there is an estimated 1,920 TCF (54.4 TCM) of risked gas in-place, with technically recoverable resources of 285 TCF (8.1 TCM) (ARI, 2013). A marine shale rich in TOC, the upper Jurassic Bazhenov Shale is considered to be the main source rock for the Western Siberian Basin's conventional oil reservoirs, and has been selectively drilled, providing shows and variable quantities of oil (Table 2.12).

Table 2.12 Shale gas resources in Russia / Central Asia (ARI, 2013)

Country / Basin (formation)	Risked Gas in Place	Risked Technically Recoverable Resources
	[Tcf]	*[Tcf]*
Russia	**1.921**	**285**
West Siberian / Bazhenov Central	1.196	144
West Siberian / Bazhenov North	725	141
Ukraine	**722**	**158**
Carpatian Foreland / Silurian	362	72
Dnieper - Donets	312	76
Moesian Platform / Silurian	48	10
Lithuania	**24**	**2**
Baltic Basin	24	2
Total	**2.667**	**445**

The oldest fields have been producing since the 1940s. Their rates are therefore declining, even with new technologies in place for secondary recovery and hydro-fracturing. Exploration for conventional oil and gas is now concentrated in the more remote East Siberian Basin and in the Arctic.

Russian oil companies are becoming more interested in the drilling and production techniques used in the USA to develop their unconventional oil and gas resources. Rosneft, Russia's national oil company, has signed agreements with ExxonMobil and Statoil with the aim of using horizontal drilling and large scale stimulation techniques to unlock the vast shale gas and oil resources available in Russia.

Development of the Bazhenov Shale is hindered by the current tax regime, which is geared towards conventional reservoirs. The Russian government is currently working on a proposal to change the mineral extraction tax (MET) for tight oil reservoirs.

North Africa

Ghadames (Berkine) is a large extensional basin underlying eastern Algeria, southern Tunisia and western Libya. Recent discoveries have helped the production of oil and natural gas in Algeria and Tunisia. The basin contains two major organic-rich shale formations that were mapped to establish prospective areas. The basins in North Africa (Algeria, Tunisia, Libya) contain approximately 5,150 TCF (146 TCM) of risked shale gas in-place, with 975 TCF (27.6 TCM) as the risked, technically recoverable shale gas resource (Table 2.13).

Table 2.13 Shale gas resources in North Africa (ARI, 2013).

Country / Basin (formation)	Risked Gas in Place	Risked Technically Recoverable Resources
	[Tcf]	*[Tcf]*
Algeria	**3,418**	**707**
Ghadames / Berkine	1,227	282
Illizi	304	56
Moudyr	48	10
Ahnet	306	60
Timimoun	762	152
Reggane	636	121
Tindouf	135	26
Libya	**943**	**122**
Ghadames	276	47
Sirte	648	73
Murzuq	19	2
Tunisia	**114**	**23**
Ghadames	114	23
Total	**4,475**	**852**

In Algeria, Sonatrach has undertaken a comprehensive effort to define the size and quality of its shale gas (and oil) resources. To date, the company has established a data base of older cores, logs and other data and complemented this with information from new shale well logs in the main shale basins of Algeria. Next in the plan is to drill a series of pilot wells to test the productivity of the high priority basins, targeting shale formations with high TOC (>2%) and thick pay (>20m) at moderate depths (<3,000 m). International energy companies such as Statoil and Repsol have also undertaken geological and reservoir characterization studies of Algeria's shales.

In Tunisia, Cygam Energy has acquired four permits in the Ghadames Basin totalling 1.6 million net acres. Cygam's exploration program involves 200 km of 3D seismic and two deep exploration wells. To date, no information has been provided on test results. In addition to the shale gas and oil potential in the Ghadames Basin, Tunisia may also have shale resource potential in the less defined Pelagian Basin, located in the eastern portion of the country and extending into the offshore.

South Africa

South Africa has one major sedimentary basin that contains thick, organic-rich shales, the Karoo Basin, located in central and southern South Africa. A number of major and independent companies have signed Technical Cooperation Permits (TCPs) to pursue shale gas in the Karoo Basin, including Royal Dutch Shell, the Falcon Oil & Gas/Chevron joint venture, the Sasol/Chesapeake/Statoil joint venture, Sunset Energy Ltd. of Australia and Anglo Coal of South Africa. Recently, Chevron announced that it would partner with Falcon Oil & Gas to pursue the shale resources of the Karoo Basin, starting with seismic studies.

Table 2.14 Shale gas resources in South Africa (ARI, 2013).

Country / Basin (formation)	Risked Gas in Place	Risked Technically Recoverable Resources
	[Tcf]	*[Tcf]*
South Africa / Karoo Basin		
Prince Albert	385	96
Whitehill	845	211
Collingham	328	82
Total	**1,558**	**389**

Asia Pacific

China

Resources of unconventional gas in China are deemed to be huge, at around 80 TCM. A reassessment of a previous analysis (CNPA 2007) recently indicated that the production could triple by 2030 at the Bohai Bay, Ordos, and Sichuan basins. Sources for this rapid increase of supply would include coalbed methane, shale gas, and synthetic natural gas (SNG).

China has an estimated 1,115 TCF (31.5 TCM) of risked, technically recoverable shale gas, mainly in marine- and lacustrine-deposited source rock shales in the Sichuan (627 TCF; 17.8 TCM), Tarim (212 TCF; 6 TCM), Junggar (36 TCF; 1 TCM), and Songliao (16 TCF, 0.5 TCM) basins. Additional risked, technically recoverable shale gas resources totaling 222 TCF (6.3 TCM) exist in the smaller, structurally more complex Yangtze Platform, Jianghan and Subei basins. The risked shale gas in-place for China is estimated at 4,745 TCF (134 TCM; Table 2.15).

Table 2.15 Shale gas resources in Asia Pacific (ARI, 2013).

Country / Basin (formation)	Risked Gas in Place	Risked Technically Recoverable Resources
	[Tcf]	*[Tcf]*
China	**4.745**	**1.113**
Sichuan Basin	2.361	627
Yangtze Platform	596	149
Jianghan Basin	114	28
Greater Subei	181	45
Tarim Basin	979	212
Junggar Basin	359	36
Songliao Basin	155	16
India	**584**	**97**
Cambay Basin	146	30
Krishna-Godavari	381	57
Cauvery Basin	30	5
Damodar Valley	27	5
Australia	**2.046**	**437**
Cooper	325	93
Maryborough	64	19
Perth	168	33
Canning	1.227	235
Georgina	68	13
Betaloo	194	44
Total	**7.375**	**1.647**

Shale gas developments in China underwent important breakthroughs in the last triennium. To date, more than 130 shale gas wells have been drilled. Among these, several have displayed significant gas flows, including the Ning-201 and Jiaoye-1 in the southern Sichuan basin. Initial gas production for both wells was at about 200 thousand m3/d.

The Sichuan Basin is by far the most active shale area for leasing and drilling. Drilling programs are currently underway by PetroChina, Sinopec and Shell, while numerous other Chinese and foreign companies are negotiating initial lease positions. ConocoPhillips was recently awarded two shale exploration blocks in the Sichuan Basin. Chevron is conducting a Joint Study with Sinopec of the Qiannan shale gas block in the Yangtze Platform. BP, ConocoPhillips, ENI, ExxonMobil, Statoil, and TOTAL have also reported interest in leasing shale gas blocks in the Sichuan or Yangtze Platform.

China should see 5 BCM of shale gas production by 2015, which is slightly less than the target of 6.5 BCM suggested by the government's "Shale Gas Development Planning 2011-2015." Technological advances and more investment could increase the production of shale gas to 60 BCM by 2030.

CBM production increased to 2.57 BCM/y in 2012 from 0.13 BCM/y in 2006. Current capacity reached 7 BCM/y recently, but it could be increased to 10 BCM with the production of 6 BCM/y by 2015.

Coal-based syngas is also being discussed. At present, the government has approved four large-scale syngas projects with a total investment of $16.2 billion. Once completed, these projects will produce 15 BCM/y.

India

India is a country where interests for unconventional gas developments are high, due to the rapidly growing gas markets and the increasing dependency on LNG imports. Estimates of risked shale gas-in-place are of 584 TCF (16.5 TCM), while risked, technically recoverable shale gas resource are estimated at 96 TCF (2.7 TCM) (ARI, 2013).

Although the shales in the Cambay Basin have been identified as a priority by India, no plans for exploring them have yet been publically announced. However, two shallower conventional exploration wells penetrated and tested the Cambay Black Shale while targeting the oil-bearing intervals.

Along with the Cambay, the Damodar Valley Basin has been set as a priority for shale gas exploration by the Indian government. In late September 2010, the Indian National Oil and Gas Company (ONGC) spudded the country’s first shale gas well, RNSG-1, in the Raniganj sub-basin of the Damodar Valley. The well was completed mid-January 2011.

CBM gas resources are estimated to be 3.4 TCM. Current production levels are very low (0.05 BCM/y); but potential for increase is high as a total of 33 CBM Blocks are due to be awarded in 4 Rounds. The target is to reach around 2 BCM/y by 2015.

Several basins in India –including: Cambay, Gondwana, Cauvery, Damodhar, Assam-Arakan, Bengal- are known to hold shale gas resources. However, the country faces hurdles related to dense population, land acquisition, availability of water and pollution of lands.

Australia

With geologic and industry conditions resembling those of the USA and Canada, Australia has the potential to be one of the next countries with commercially viable shale gas and shale oil production. As in the USA, small independents have led the way, assembling the geological data and exploring the high potential shale basins of Australia.

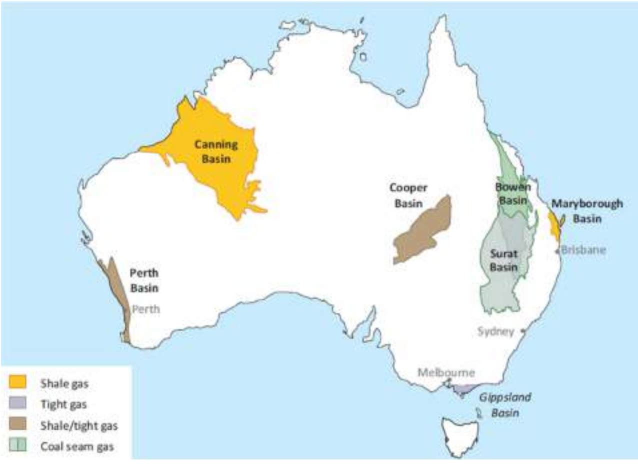


Figure 2.14 Unconventional gas basins in Australia (Energy Delta Institute, 2012).

International majors are now forming JV partnerships with these independent producers, bringing capital investment to develop these areas. However, with the remoteness of many of Australia's shale gas and shale oil basins, development is likely to proceed at a moderate pace.

The shale gas and oil basins of Australia hold an estimated 2,046 TCF (58 TCM) of risked shale gas in-place, of which 437 TCF (12.4 TCM) technically recoverable (ARI, 2013). The Cooper Basin, Australia's main onshore gas-producing basin, with its existing gas processing facilities and transportation infrastructure, could be the first commercial source. Beach Energy, Senex, DrillSearch Energy and Santos have active shale gas and oil exploration and evaluation programs underway.

Unconventional gas in Australia is dominated by coal seam gas (CSG), which currently represents around 25% of the Australian gas production, as described in the next section.

2.3.3 Global resources of coal bed methane

Estimates of the remaining technically recoverable resources of coal bed methane (CBM) are presented in Table 2.16.

Table 2.16 Major World Coal Bed Methane Resources (Energy Tribune, 2008)

Rank	Country	CBM (trillion cubic feet)
1	Russia	600 – 4,000
2	China	1,000 – 1,250
3	Canada	200 – 2,700
4	US	400
5	Australia	300 - 500
6	Germany	100
7	Poland	100
8	UK	60
9	Ukraine	60
10	Kazakhstan	40
	World Total	**2,980 – 9,260**

North America

APF Energy (2004) refers to data from GSC and the BC Government to indicate the total reserve potential of CBM in Western Canada at 182-553 TCF (5.2 – 15.7 TCM), of which 115-352 TCF (3.3 – 10 TCM) in the Alberta Plains (Figure 2.15). The resources available in the USA are also large (Figure 2.16).

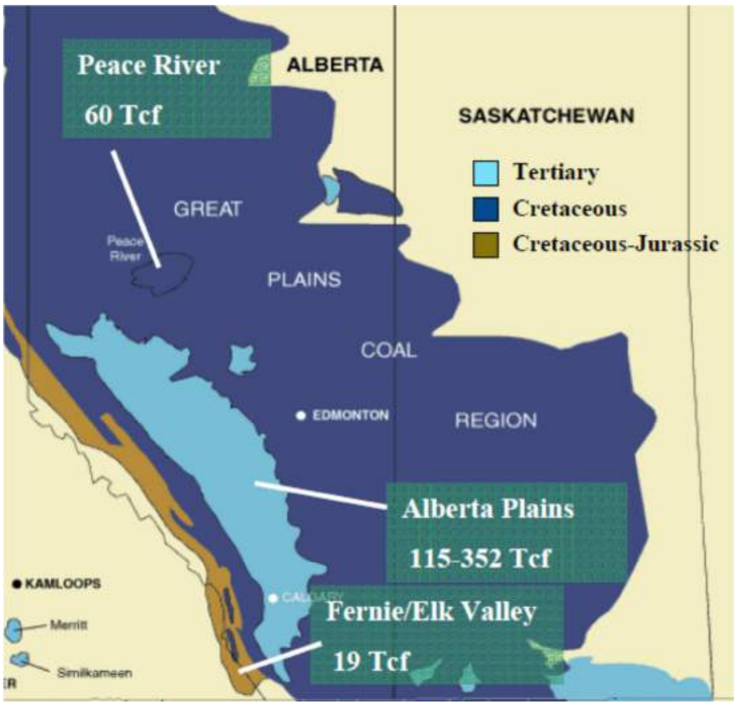


Figure 2.15 The CBM potential in Western Canada is concentrated in the Alberta Plains (APF Energy, 2004).

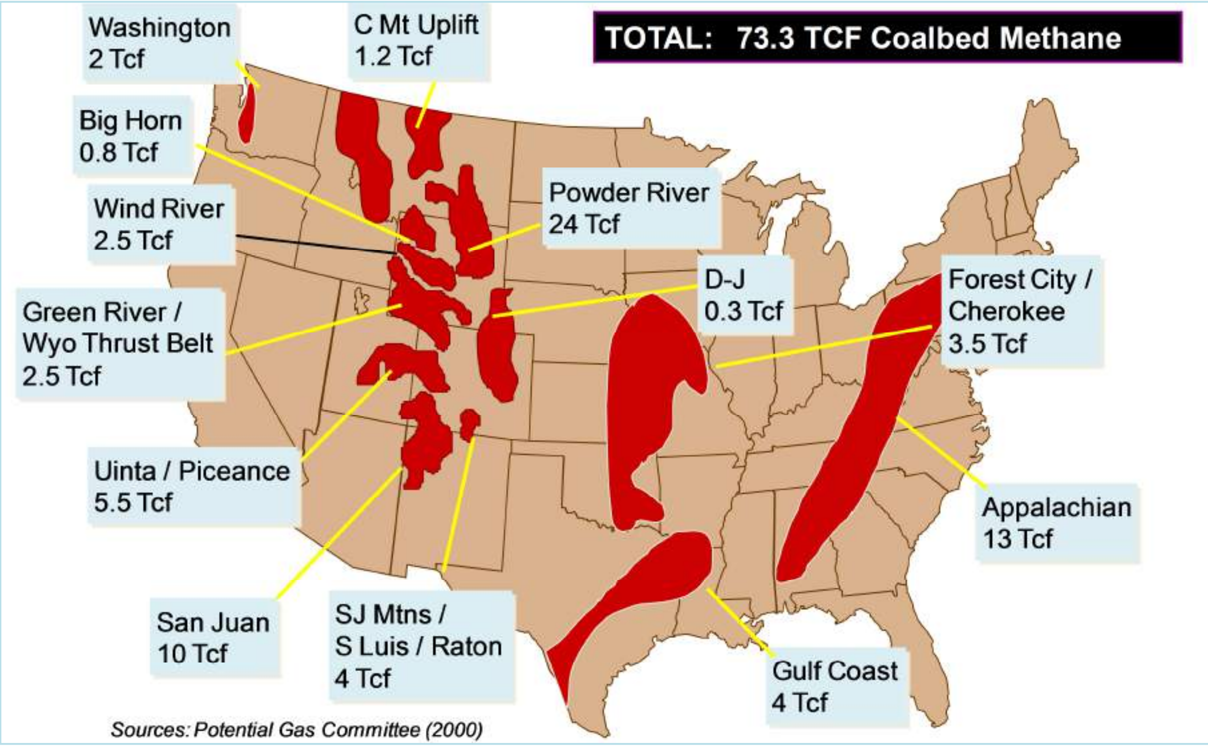


Figure 2.16 US CBM Resources (Potential Gas Committee, 2000).

Australia

Coal bed methane in Australia, or coal seam gas (CSG), is a burgeoning market and an important resource for supplying Australian LNG capacity. Current estimate for CSG resources are between 300 – 500 TCF (8.5 – 14.3 TCM).

The most important Australian coal seam gas basins are Surat and Bowen, where the first commercial production of CSG took place in Australia. These large-bearing basins have substantial resources at depths suitable for methane extraction and have provided the majority of the CSG mapped to date, with provable reserves increasing steadily.

Challenges in the Australian market are similar to those found in other parts of the world. Protecting the environment, managing produced water, building the infrastructure to transport the gas and finding the people, power and technology to run it are vital before massive production can happen.

A challenge unique to the Australian market is the issue of ramp gas produced as the fields are being drilled and dewatered in preparation for production. Some of the gas can feed LNG capacity, but not at sustained levels. Since CSG wells cannot be turned on and off at random, the gas produced during ramp up must be stored or used somewhere, flaring being no longer an option.

In late 2010 and early 2011, the two first world class CSG to LNG projects were sanctioned and went into construction in the east coast, where the industry is relatively more mature than in the rest of the country. Although CSG to LNG had never been tried before, the prospects looked appealing as the technology was proven. When this report was written, BG was about to start the operations at the Queensland Curtis LNG in Australia, after a US$ 15 billion investment to produce 8.5 million ton/y, and a Santos led consortium was also expected to start operations in 2015 after a US$ 16 billion project in the Gladstone LNG project.

2.3.4 Global resources of natural gas hydrates

Lorenson and Kvenvolden (2001) refer to natural gas hydrates to "occur worldwide in oceanic sediment of continental and insular slopes and rises of active and passive margins, in deep-water sediment of inland lakes and seas, and in polar sediment on both continents and continental shelves. In aquatic sediment, where water depths exceed about 300 m and bottom water temperatures approach 0° C, gas hydrate is found at the seafloor to sediment depths of about 1100 m. In polar continental regions, gas hydrate can be present in sediment at depths between about 150 and 2000 m. Thus, natural gas hydrate is restricted to the shallow geosphere where its presence affects the physical and chemical properties of near-surface sediment".

They developed a global inventory report that included 113 regions where the presence of gas hydrate has been inferred from geophysical, geochemical, and geological evidence. A potential of about 10 exagrams (10,000 gigatons) of methane carbon would be available globally.

So far, Arctic gas hydrate reservoirs are deemed to be of higher quality than those in marine environment, as some important Arctic accumulations have good porosity and good gas saturation, and are predominantly found in coarse sands that have high intrinsic permeability. Overlying permafrost may provide a low permeability barrier to gas leakage during extraction. These factors are favorable for production.

There is a hypothesis that some fields in West Siberia have produced methane from hydrates (v. g. Messoyakha), but there are no commercial developments so far on a worldwide basis.

There are different technologies of gas production from hydrates under development based on three methods and their combinations: depressurization of reservoirs, heat injection and chemical inhibition.

The resources in Alaska North Slope were assessed under the depressurization technique, which appears to be the most promising method, according to the USGS. The cost of natural gas production from hydrates is strongly dependent on production/well which is ultimate dependent on the geological structure and hydrate content of the reservoir.

2.4 Frontier exploration areas

In the previous report of WOC-1, a frontier basin or play was defined as one in which a significant part of the hydrocarbons remain undiscovered due to an exploratory activity that is deemed to be insufficient. This definition translates into significant geological risk and uncertainty of success to include the following areas (WOC-1, 2012):

- Remote or difficult to reach;
- Hard to operate due to harsh environmental conditions;
- Exportation infrastructure insufficient or absent;
- Previously unavailable because of too stringent regulations;
- Unlocked by new technologies.

They received significant attention from WOC-1 in the previous triennium, as at that time the focus of exploration seemed to be shifting towards riskier plays, but a completely different scenario is in place today, where aversion to risk predominates. Nevertheless, it is still interesting to briefly verify some the latest developments in these areas.

2.4.1 The Arctic

The Arctic holds 13 important basins located in five countries, along the most extensive continental shelves of any ocean basin.

Drilling density is extremely low, which means the area remains largely unknown, especially Eastern Siberia, Eastern and Western Greenland. Nevertheless, using a probabilistic methodology, the USGS concluded that about 30% of the world undiscovered gas could be found there, mostly offshore, under less than 500 m of water (Gautier *et al*., 2009).

Norway

The Barents Sea is still regarded as the most prospective area for natural gas in Norway. After the Havis and King Lear discoveries announced in 2012, the more recent Ghota (Lundin Petroleum) and Wisting Central (OMV) wells revealed new plays in the region, the first one in a Triassic source rock, as opposed to the current Jurassic plays under development.

There has been a discussion on how to monetise these new discoveries, either by an expansion of the Snohvit LNG facilities or by a new pipeline to the European market. Both options are expensive, and the recent changes in the petroleum tax system reduced the attractiveness of new field developments (the capital uplift was reduced from 30% to 22%, as explained in the third part of this report).

Russia

Hydrocarbon resources in the Russian Continental Shelf would add up to some 100 billion tons of oil equivalent, of which 80 per cent would be gas. About 70% would be concentrated in the Barents, Pechora and Kara Seas, with gas and condensate prevailing in the Barents and Kara Seas, oil in the Pechora Sea.

The development of the Shtokman gas and condensate field is strategic for Gazprom. Project implementation is a pivotal point to form a new producing region in the Arctic Shelf. This field will become a resource base for building up Russian pipeline and liquefied supplies to domestic and foreign markets.

The South Kara Sea remains largely under explored, with already mapped but undrilled structures around the two giant gas discoveries of Leningradskoye and Rusanovskoye, which are considered to hold over 280 TCF (8 TCM) each.

The development of these mega projects will act as an anchor to develop the resources in the nearby areas. Additional resources are already identified in undrilled "smaller" structures around these projects.

Apart from these high grade exploration areas, there are other basins, that also have a large interest to explore, but that are unlikely to be developed before 2030. These include the Laptev Sea, the East Siberian Sea and the Chuchi Sea Basins, which are located in poorly known areas, with no offshore wells and only a few shallow wells onshore. The seismic is very limited or nonexistent. The exploration of these basins, further away from export routes and with harsh ice and climatic conditions, will require more time.

Alaska (USA)

In 2013 a fiscal overhaul immediately boosted the value of fields located in the North Slope and also raised the interest in the Alaska LNG project, in spite of a pending referendum, which took place only during the primary elections of 2014. A few successful wells have been drilled at Qugruk (Repsol), National Petroleum Reserve (ConocoPhillips) and Cook Inlet (Hilcorp Energy and others).

Canada

The main restraint for exploration in the Canadian Artic continues to be the absence of a gas export infrastructure. The Mackenzie Valley pipeline remains halted by economic and environmental reasons, keeping trapped Taglu, Parsons Lake, Niglintgak and other important areas located in the North West Territories and Yukon.

Greenland (Denmark)

The Southwest Basin is considered to be one of the more promising yet under-explored frontiers for oil and gas. Cost can be expected to be very high, as there is no infrastructure to support the subsea to shore facilities that will be required. On top of that, the basin is located in an iceberg prone region, which requires drilling equipment to be moved quickly to avoid collisions.

2.4.2 Middle East

The Middle East area is still considered as being the second most important region for gas reserves (either already discovered or still to explore) after former soviet Union.

According to the USGS evaluations, most of the gas undiscovered resources are situated in the deeper Paleozoic levels, which in total form account for more than 800tcf of undiscovered resources in this region.

Obviously, the 1990's and the beginning of the 21st century proved extremely successful for the gas exploration in Middle East, and in particular in Arabian peninsula and Iran. This period coincided with the extension of exploration, appreciation and production of the Permo-Triassic carbonates levels (Khuff and equivalent).

This play, believed to be sourced by the prolific Silurian hot shales, is still proving to have significant potential and to be able to add large quantities of new reserves for exploration, especially due to the thickness of the reservoirs. As a matter of fact, discoveries were recently announced in the Iranian Zagros Foldbelt (Sefid Ba'ghoun (4.4 TCF; 0.1 TCM), and Halegan (8 TCF; 0.2 TCM), in the Arabo-Persian gulf (Forouz (17.5 TCF; 0.5 TCM), Karan (9 TCF; 0.2 TCM), which are attributed to this target.

Although it cannot be considered as a new exploration target, there is still a number of identified but undrilled prospects at this target, especially in the Iranian Zagros Foldbelt, in the Central Arabian uplifts and in salt related structures of the Arab Persian Gulf. There are also large areas virtually unexplored in the Western Iraqi desert and in the Rub'al Khali basin.

In addition to this target, since the beginning of the century there has also been a move in the exploration of the Petroleum system in Arabian Peninsula to the deeper clastic reservoir of the Lower Paleozoic section. These deeper levels proved to add rich hydrocarbon resource, also sourced by the Silurian Qusaiba "hot shale". It contained oil and gas in various reservoirs throughout Central, Northern, and Eastern Saudi Arabia, but also in Bahrain, Turkey, Jordan and Iraq.

Recent discoveries from this Lower Paleozoic clastic interval include Sirayyan, Sanaman, Dirwazah or Nujayman (Lower Permian) or Kassab & Rabib (Devonian). Most of the discoveries are situated in the Greater Ghawar uplift area, but this play is also recognized to be present in the Arab-Persian Gulf, offshore UAE, Saudi Arabia and in Bahrain. There are most likely still quite a lot of discoveries to make in these layers, whether in already identified structures undrilled at these levels or in new targets.

Finally, a significant effort was made towards the exploration and understanding of tighter Lower Paleozoic succession. This was thought to be able to hold huge quantities of hydrocarbon (mainly gas), in this pile of thousand meters of still poorly known siliclastic succession. The nature of the clastics varies considerably across Arabian Peninsula, either in nature (depending on depositional settings and erosive events) or in properties (from conventional properties to unconventional tight properties).

Near future exploration will likely be targeted to validate this expected potential. The discovery of new plays and large reserves will, however, be strongly linked to the local policies and international environment.

In particular, the last exploration results in the Rub al Khali, opened to IOC's for exploration since 2003, proved largely disappointing for the four ventures, finding no new commercial quantities of gas. This raised concerns about the diminishing rate of increase of the gas reserves of Saudi Arabia. Although 3 of the 4 ventures decided to embark on new periods (exploration or appraisal), it is considered that without significant incentives, exploration won't be sustained, especially given the high exploration and development costs in this harsh environment. Exploration might only be spurred by raising the gas prices and return conditions to attract more investment.

In other countries, the problem is different. In Iraq, there is a strong commitment to the acceleration of the production of the already discovered fields, and a primary focus on the oil-prone areas of the Zagros and Mesopotamian basin. Gas exploration, especially to the more desertic areas of the West is likely to be deferred for some time.

In Iran, there is quite a lot of hurdles that are delaying any further projects. The present international sanctions prevent any major investment in the country, and although there are already numerous giant gas discoveries identified, the country lacks the financial capacity to translate it into developments.

2.4.3 Australian Offshore

Australia is proving from the last ten years to be one of the most prolific basin for gas worldwide. Year after year, new giant fields are discovered onshore, accounting for 50 TCF (1.4 TCM) of new reserves in the last decade. The main focus for exploration remains the western Australian sedimentary basins, in particular the Jurassic and Triassic sandstones of North Carnarvon Basin, the Jurassic and Permian targets in the Perth Basin, but attention is also currently concentrating on Cretaceous and Triassic formations in the Browse Basin and on the Permian formations in the Bonaparte Basin.

Offshore exploration already identified more than 160 TCF (4.5 TCM) of gas in the Carnarvon, Browse and Bonaparte Basins. Major recent finds include Poseidon (7 TCF; 0.2 TCM), Acme, Alaric, Brederode, Kentish Knock, Greater Gorgon Area (11 fields, including the wildcat wells of Geryon-1 (1999), Orthrus-1 (1999), Urania-1 (2000), Maenad-1 (2000), Jansz-1 (2000), Io (2001), Chandon-1 (2006), and Achilles (2009), Satyr (2009) estimated at more than 40 TCF (1.1 TCM), discovered in the Carnarvon basin but also Ichtys (12.8 TCF; 0.4 TCM) in the Browse basin.

Western Australia will certainly continue to attract this high interest for the next 20 years. This interest is sustained by a concentration of favorable conditions.

The political risk of the country is considered as one of the lowest, providing high visibility on the investments. The authorities set in place a clear fiscal regime, designed to encourage exploration, in particular in frontier basins. In addition, there is a policy of transparency and sharing of information that promotes innovation and encourages new ideas for exploration.

Finally, Western Australia's proximity to Asian markets places it in an ideal position to meet growing expected gas demand. This demand was forecasted because of the increasing developments and needs of the Asian countries (China being the first), but was lately reinforced by the probable consequences of the Fukushima accident, shifting energy policy away from Nuclear Power.

To meet this future demand, in the last years there was fierce competition between operators to launch LNG projects. In particular we can cite Gorgon, Pluto, Browse LNG, Wheatstone projects. We can see these projects as opportunities for exploration in the area, as supply is following the increasing demand, still expected to be rising in following years. This situation is particularly exemplified by the latest major LNG gas purchase agreements signed by Sinopec and South Korea, of 85b$ each. The densification of these LNG projects will concur to unlock the vast stranded potential of Australia, as commercial developments were blocked by the lack of infrastructures and the distance to export solutions.

Another favorable factor is the development of new Floating LNG technologies that are designed to produce gas fields that are either too small, or too far away from the shore to be economically viable to be developed by a classical onshore LNG facilities. Shell's Prelude/Concerto project and Santos's Bonaparte projects are currently under way. These new technologies will certainly allow to reconsider what is currently considered as stranded reserves (140 TCF or 4 TCM according to CSIRO in Australia).

2.4.4 East Africa

Given the historic levels of oil and gas exploration in the region, East Africa can still be considered to be a frontier zone. It has only recently emerged as a new frontier for gas due to the current progress in deep water technologies.

Anadarko found significant reserves of gas while drilling its first wildcat in 2010 at the Rovuma offshore in Mozambique near the border with Tanzania. This discovery was followed by others in Barquentine and Lagosta, which suggested huge amounts in place at the Windjammer and Tubarão areas.

The EIA has estimated 32-65 TCF (0.9 – 1.8 TCM) of recoverable resource in this region (Area 1), and 75 TCF (2.2 TCM) more in Area 4, where ENI is performing a work program to develop a production of gas with partners KOGAS and GALP.

A letter of intention was requested from prospective companies willing to perform front end engineering design studies, aiming at a final investment decision by 2015. The major difficulties pointed out would be related to the absence of a significant gas market in the region, and the distance from the major gas trading routes.

Nevertheless, these discoveries created a regional acceleration of investments, and attracted the interest of additional players, which are also preparing exploratory campaigns for blocks in Mozambique and Tanzania (e.g. Statoil).

Meanwhile, East Africa is expected to continue to experience a number of farm-ins, mergers and acquisitions to consolidate smaller players. LNG exports are not expected to start before 2018, FLNG being one of the options under consideration.

2.4.5 Central Asia

The Central Asian region, and in particular the Caspian Sea region, has been expected to become one of the most promising area for world gas exploration since the 1990's. Indeed, after a first period of declining exploration and production following the collapse of the Soviet Union, there was an upward trend of exploration and production in the area. Some countries managed successfully to attract foreign investment (in particular Azerbaidjan and Kazhkstan), which led to world class discoveries and major project developments. We can cite Karachaganak, Tengiz, Shah-Deniz as one of these world scale projects launched since the collapse of FSU.

In support of the development of this zone, new export routes have already debottlenecked the Caspian Area. The Caspian Pipeline Consortium (CPC) capacity between Tengiz and black sea coast is planned to be doubled by 2015. However the area still needs further developments and expansion of direct export routes to Europe. Nabucco, ITGI, TAP pipeline projects or AGRI (LNG) project via the black sea that are currently discussed, are such solutions, but they are still not fully concrete and require strong state support.

Although the area is perceived as a fantastic area for exploration, the situation is quite contrasted in the countries of this region, depending on the maturity of the exploration area, and the opening to foreign investment.

Prior to 1999, exploration in offshore Caspian area was very limited, with only a few activities close to the coast of southern Dagestan. First major exploration began in 1999, with discoveries of Khvalynskoye and Yuri Korchagin, rapidly followed by Rakushechnoye, Sarmatskoye and Filanovsky. Accurate reserve estimates are lacking in the area, but it is described as 'significant'. According to BP , proved reserves in the area are in the range of 450 TCF (12.7 TCM).

Kazakhstan is one of the most promising countries in Central Asia, and considered as rather under explored. Although several giant oil discoveries were made in the Northern Caspian area, natural gas exploration has clearly lagged behind oil due to the lack of domestic pipeline infrastructure, linking the western gas producing regions to the eastern consuming (industrial) regions. Gas potential in this country should be considered as promising, presently sustained by key partnerships with Russia and China. Major undiscovered resources should be considered to be offshore, and dedicated to major companies due to the development scale, but onshore exploration and appraisal activities are benefiting from smaller players involvement (BNBn Tethys Petroleum, Max Petroleum) and are still adding significant resources.

In Azerbaijan, historic exploration focused on onshore plays that are now thoroughly explored. The remaining undiscovered hydrocarbons should mostly be located offshore, in very challenging environments. In particular, the reservoirs from deltaic origin are highly overpressured due to the very quick deposition of the overlying sediments. In addition, the depths to reach are very important, requiring high technology drilling.

The late exploration results were somewhat mixed. Of the 10 deep offshore wells drilled by foreign companies in the last 10 years, only one major discovery had been made (Shah Deniz estimated between 22.5 to 42 TCF; 0.6 – 1.2 TCM). In contrast, numerous structures were disappointing (Araz Deniz, Oguz, Lenkoran Talysh, Kurdashi, Inam,…). The conjunction of high costs and limited success explains the low number exploration in the area. The difficult geological environment necessitates state of the art drilling and completion technologies. Even with that, some of the targets could not be reached (eg. Inam, Yanan Tava and Zafar Mashal) and some of the structures remain yet to be properly tested. It has to be noted that the recent announcement on Absheron-2X might add another significant exploration success.

In Turkmenistan, the latest decade results were less spectacular with 200 wells finding only 5.3 TCF (0.2 TCM) in 17 gas fields, until discovery and reassessment of the giant South Iolotan (now Galkynysh) field (est. around 925 TCF; 26.2 TCM), although a lot of uncertainty still exists on the proper reserves). It allowed the country to jump as one of the world's new gas reserve holder. The Galkynysh reserves, along with the developments of the reserves in the sub-salt Jurassic layers, allowed to consider major export project, directed to the East. The Turkmenistan-China gas pipeline progressed with first stages of construction of the Uzbek and Kazakh sections.

There is a question as to whether other countries like Kyrgyzstan and Uzbekistan might become major players in the area. The reserves are presently considered as of a lesser extent of their neighbors. Uzbekistan is however having a good position, being the 3rd largest producer of natural gas in the FSU after the Russian Federation and Turkmenistan. According to the BP Statistical Review of World Energy 2014, Uzbekistan's proven natural gas reserves are 38 TCF (1.1 TCM), mainly in the Amudarya basin and the Murabek area in the southwest of Uzbekistan. Recently exploration focused on the Aral sea region, with first announced successes.

Kyrgyzstan is also seeking development of its gas reserves with involvement of foreign companies. Successes of the exploration in these two countries are, however, dependant from the local incentives, to open market, to promote private sector and to establish convertibility of currencies.

2.5 Upstream business trends

Over the last years, a significant inflation has affected the upstream industry. New discoveries have become more expensive to develop, and a general decline has been observed in the exploratory success, especially in remote or technically challenging areas (Figure 2.2).

Plays where production can be easily developed have been preferred, but many traditional gas importers have also started to pursue opportunities in the development of unconventional resources.

They were not only interested in accessing a cheap, abundant and reliable supply of natural gas, but also in learning the technology, hoping to replicate it elsewhere. And they have played an important role there, as nearly 20% of the US$ 133.7 billion invested in U.S. tight oil and shale gas from 2008 to 2012 came from abroad.

In a second stage of the unconventional gas revolution, a number upstream companies located in North America are now providing services and equipment to operate overseas, where gas prices remain much higher than in the USA.

2.5.1 Gas pricing and exploratory risk

In spite of growing reasoning in the open literature concerning the possibility of higher prices in the USA, so far the linkage with oil continues to remain shattered (Figure 2.17).

Figure 2.17 Gas and oil prices in the USA and Europe.

Over the last years, hub pricing or gas on gas competition (GOG) seems to be gradually replacing oil indexation or escalation (OPE) as a pricing mechanism, as indicated in Table 2.17 (Bowden, 2012).

Table 2.17 In Europe hub pricing (GOG) is replacing contracts indexed in oil (OPE).

European gas - sales method. Volumes in Bscm

	OPE	GOG	BIM	NET	RCS	RSP	RBC	NP	NK	Total
2005	457.8	87.7	9.9	0.8	1.8	17.8	0.0	4.0	0.0	579.8
2007	417.7	126.1	9.0	0.9	2.3	17.3	0.0	4.2	0.0	577.4
2009	378.7	152.4	2.3	1.0	0.0	18.6	0.4	4.6	0.0	557.9
2010	349.4	217.2	2.4	1.0	12.4	5.8	0.5	4.7	0.9	594.3

Volume change	OPE	GOG
2005-7	-40.1	38.4
2007-10	-68.3	91.1

% of gas under:	OPE	GOG
2005	79%	15%
2007	72%	22%
2010	59%	37%

source: Nexant

According to Stern (2013), about half of the European gas would be currently sold at hub prices, but Komlev (2013) has presented statistics where hub priced gas would account for only 30% of the final consumption in this region (Figure 2.18).

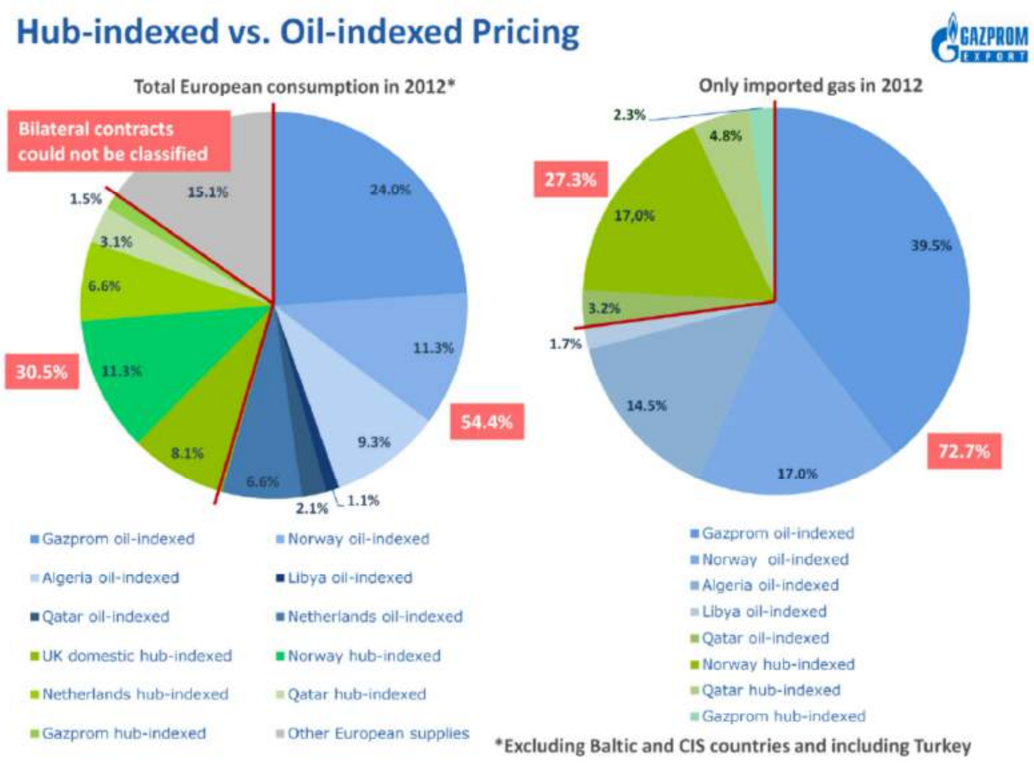


Figure 2.18 Hub vs. oil indexation in Europe (Komlev, 2013).

Whatever the correct value, there is a growing discussion on the development of trading hubs in other parts of the world, at the expense of the traditional long term contracts indexed in oil.

Unfortunately, many still believe that hub pricing always translates into cheaper gas, which is just not true, as pointed out by Bowden (2012) and many other authors. Indeed, hub pricing transfers market and other downstream risks to the producers of gas, and in the long term a higher premium must be paid to them as a consequence. As the current prices for gas remain relatively low, a major challenge for upstream business subsists.

2.5.2 The growing role of natural gas

Important IOCs and NOCs have substantially increased the relative participation of natural gas in their business portfolios over the last years. For many of them the production of gas is now equivalent to the production of oil, as indicated in Figure 2.19.

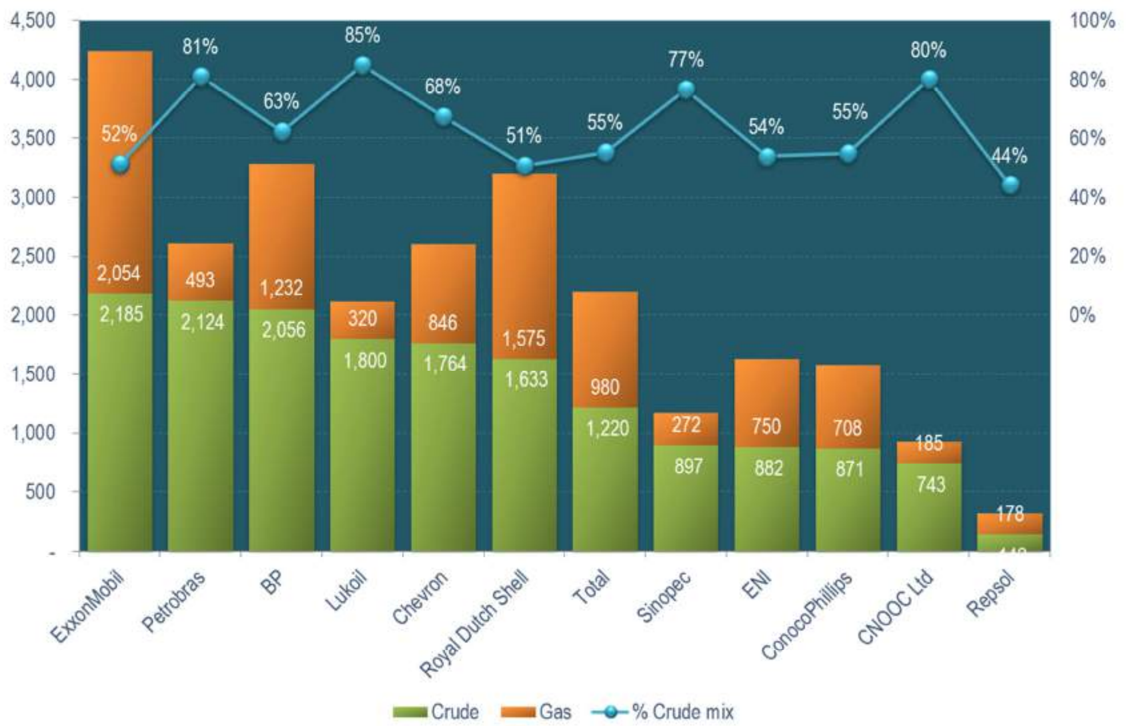


Figure 2.19 Oil and gas production (in thousands of barrels per day) from some of the largest oil companies (Monteiro, 2013).

2.5.3 Independent producers

The name independent producer is usually attributed to a non-integrated company receiving the vast majority of its revenues from the wellhead production, with minimum refining or marketing operations.

In the USA the name is often associated with a small production. Section 613A(d)(2) of the Inland Revenue Code (IRC) defines as independent “a producer who does not have more than US$ 5 million in retail sales of oil or gas in a year (a retailer) and who does not refine more than 50,000 barrels of crude oil on any day during the year (a refiner)”.

Many have less than 20 employees, but a significant number of them have recently evolved to become large and publically held corporations. This was caused by the exploratory shift taken by the major integrated companies, which decided to invest abroad or in deep offshore areas as a response to shareholder expectations in view maturing onshore areas.

Production in onshore areas was left to the independents, and they were largely successful in the development of hydraulic fracturing for the exploitation of unconventional hydrocarbons. Independent producers account today for about 70% of the oil and 80% of the gas produced in the USA, and as of today 95% of all wells in the USA are drilled by them (IPAA, 2014). The USA is often said to be on the verge of becoming the top world oil producer, and that could happen by 2015 (IEA, 2013).

This independence revolution is not restricted to the USA. Internationally, a large number of independent producers have consistently appeared as the most admired exploring companies in a traditional survey that is regularly performed by Wood Mackenzie (Figure 2.20).

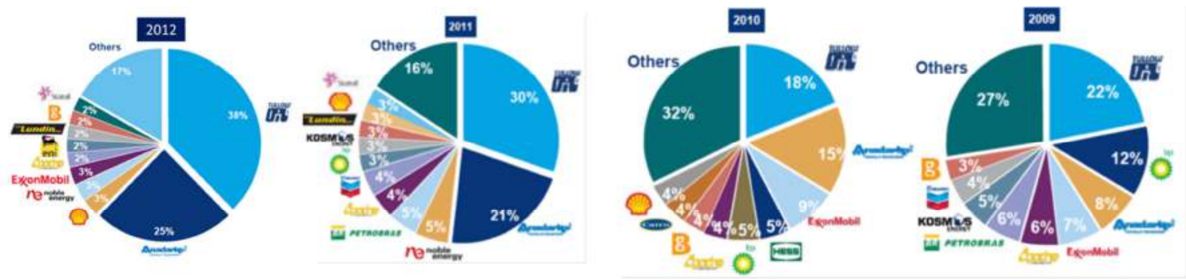


Figure 2.20. Most admired explorers in the world (Wood Mackenzie, 2012).

As an example, Tullow Oil has been consistently appointed the number one for its technical strength, vision and persistence, while Anadarko is often mentioned for its ability to solidly move into completely new areas, always sustained by sound geological work. The first has a strong presence in Africa, while latter has operations in the USA, Algeria, Ghana, Mozambique and China, among other locations. In the meantime, important IOCs and NOCs such as BP, Petrobras, Exxon Mobil, Shell and Statoil seem to be losing ground in the exploratory shop window.

2.5.4 New gas discoveries

In the previous IGU triennium, WOC-1 pointed out North Australia as the “hottest” conventional gas play, as the Carnarvon, Browse and Bonaparte basins contributed with 17% of the global gas volumes discovered between 2000 and 2009.

During the same period, gas discoveries in excess of 4 billion boe (technical) were discovered in Kazakhstan (Pre-Caspian Basin), Egypt (Nile Delta), Brazil (Santos Basin) and China (Sichuan Basin).

More recently, however, the most important discoveries took place in deep waters, especially in East Africa, and the percentage of gas in new discoveries has increased significantly as well. Mozambique is one of the new stars, with 50 TCF (1.4 TCM) added within a couple of years, followed by Angola and Tanzania.

2.6 Conclusions

After analyzing the different types of natural gas accumulations, their regional spread and the technologies available in the market, our first conclusion is that gas reserves and resources are abundant and will continue to play a key role in the energy markets with a high potential to increase its share given not only its availability but also for being a more environmentally friendly alternative to other fossil fuels.

The frontier areas briefly described in this report may add substantial reserve growth and new potential, but the current imbalance between production costs and market value requires upstream investors to reduce their exposure to risk. On top of that, conventional frontier exploration continues to face competition from unconventional exploration. As a consequence of this scenario, most of the new exploratory activity is expected to focus in existing plays.

Deep water plays have yield most of the conventional volumes discovered in the last years, and nothing is expected to revert this historic tendency. Onshore and shallow water discoveries reached an all-time record low of 20% in 2012.

Regulatory authorities remain the best promoters of new exploratory activity. It is worthy to repeat here one of the conclusions presented in a previous report of WOC-1: The support of governments is key for risky exploration, and they should set stable fiscal regimes that are able to promote enough reward.

References

APF Energy, Coalbed Methane Development in the Western Canadian Sedimentary Basin: A significant emerging resource for North America, Rocky Mountain Natural Gas, 2004.

ARI, Technically recoverable shale oil and shale gas resources: An assessment of 137 shale formations in 41 countries outside the United States, 2013.

Bowden J., European Natural Gas at a Crossroads, Committee Session 8.3, WGC 2012.

Bustin M., Overview on Unconventional Gas, CBM Solutions, presentation to Danagas, 20 June 2009.

Department of Energy and Climate Change, shale gas background note, (GFRAC TECHNOLOGIES)

Dieckel et al., Putting a Price on Energy: International Pricing Mechanisms for Oil and Gas, Energy Charter Secretariat, 2007.

Energy Delta Institute website (http://www.energydelta.org/mainmenu/energy-knowledge/country-gas-profiles/country-gas-profile-australia)

EIA, Emerging East Africa Energy Report, 2013

EIA, Energy Outlook 2014.

Farrel S. et al., Conventional discoveries outside North America down at mid-2014, IHS ENERGY Strategic Horizons, 4 August 2014.

Federal Institute for Geosciences and Natural Resources (BGR): Reserves, Resources and Availability of Energy Resources 2010.

Fichter L. S., Barrovian Metamorphic Rock Changes, James Madison University, http://csmres.jmu.edu/geollab/fichter/MetaRx/Barmetachanges.html, 2000.

Gautier D. L. et al., Assessment of undiscovered oil and gas in the Arctic, Science, v. 324, n. 5931, pp. 1175-1179, 2009.

Green C., Shale gas background note, Department of Energy & Climate Change, UK (2013).

Gonfalini Mauro, SPE Italian Section:Formation Evaluation Challenges in Unconventional Tight Hydrocarbon Reservoirs. June 7th, 2005

Government of Western Australia. LNG in Western Australia. Factsheet. Department of State Development. Updated March, 2014 – DMPFEB11_1144. 2014.

Hall M., Shale vs tight, http://www.agilegeoscience.com/journal/2011/2/23/shale-vs-tight.html, 2011.

IHS, Upstream Services, International Oil Letters

IMF, Regional Economic Outlook Update, Middle East and Central Asia Department, May 2014.

INPEX. The world-class Ichthys Project. Available at:

<http://www.inpex.com.au/projects/ichthys-project.aspx>.

Kang Yi-li; Luo Ping-ya. Current status and prospect of key techniques for exploration and production of tight sandstone gas reservoirs in China. Petroleum Exploration and Development, [S.l.], v. 34, n. 2, p. 239-244, 2007.

Kawata, Y.; Fujita K. Some predictions of possible unconventional hydrocarbons availability until 2100. In: SPE ASIA PACIFIC OIL AND GAS CONFERENCE AND EXHIBITION, 2001, Jakarta, Indonesia. Proceedings… Jakarta: SPE, 2001. SPE 68755.

Kramer, Andrew E. Exxon Reaches Arctic Oil Deal With Russians", The New York Times Company.

Komlev S., Gas Pricing in the Evolving European Market, Flame 2013.

Law B. E. and Curtis J. B., Basin-Centered Gas Systems, AAPG Bulletin, 86 (11), November 2002.

Lorenson T. D., Kvenvolden K. A., A global inventory of natural gas hydrate occurrence, USGS, 2001.

Mahdi, Wael. Saudi Aramco Ventures Continue Gas Exploration in Saudi Desert, Bloomberg news, 2011-06-06. Available at: <http://www.bloomberg.com>. 2011

Major, Jason. ENERGY: Researchers unveil plans to rescue 'stranded' gas fields. CSIRO, Solve Magazine, June, 2008.

Monteiro R. G., Subsidies to Petrobras' Strategic Plan 2020, Rio de Janeiro, 2013.

Nuccio V. F. et al., Basin-Centered Gas Systems of the U.S., Project DE-AT26-98FT40031, USGS and U.S. Department of Energy, NETL, 2000.

OIL and Gas Eurasia. SOCAR Raises Shah Deniz Gas Reserve Estimate to 1.2 Trln BCM. Oil and Gas Eurasia, September 2007.

Petrobjects, Petroleum Reserves Estimation Method, http://large.stanford.edu/courses/2013/ph240/zaydullin2/docs/ (2003).

Robertson J., World's Oil and Gas Endowment, USGS, 2012.

Saudi Aramco. Saudi Aramco Annual review, 2013

SPE et al., Petroleum Resources Management System, http://www.spe.org, 2007.

STRATFOR.COM's Global Intelligence Update. The tip of the iceberg: energy from the Arctic.

Stern J., Interview to the World Energy Council, 2013.

Stoppard M., Presentation to the IGU Council, Beijing, 2013.

Thomas, Charles P.; North, Walter B.; Doughty, Tom C.; Hite, David M. Alaska North Slope Oil and Gas: A promising Future or an Area in Decline? Addendum Report, DOE / NETL 2009 / 1385. National Energy Technology Laboratory. 2009

Thomas, Mark. Unlocking the Arctic: E&P industry warms to the challenge. ROGTEC Magazine, [S.l.], Sept. 5, 2011.

TOTAL S.A. Azerbaijan: Total makes a major gas discovery in the Caspian Sea. Total news, September 2011.

USGeological Survey: Gas Hydrates Primer : The U.S. Geological Survey Gas Hydrates Project

Watkins, Eric. GCA: Turkmenistan's Iolotan gas field is world's second-largest. Oil and Gas Journal, October 2011.

Wood Mackenzie, Upstream Insight Letters

World Bank, Natural Gas Rents, http://data.worldbank.org/indicator/NY.GDP.NGAS.RT.ZS, 2012.

Zhdannikov, Dmitry; Mosolova, Tanya. Russia's Gazprom ups Shtokman reserves to 3.8 tcm. Reuters. 2007.

Appendices

A List of Tables

B List of Figures

C Glossary and Acronyms

AAPG	American Association of Petroleum Geologists
ARI	Advanced Resources International, Inc.
Conventional reservoirs	those that can produce economic volumes of oil and gas without massive stimulation treatments, special recovery processes or leading-edge technology.
EIA	Energy Information Administration
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
WPC	World Petroleum Council

WOC 1 Triennial Report

2012-2015

STUDY GROUP 1.3

GAS RENT AND MINERAL PROPERTY RIGHTS

Study Group Leader

Marcos de Freitas Sugaya (Petrobras, Brazil)

Study Group Members

Decio Barbosa	IBP	Brazil
Luiz Cezar Quintans	G. Ivo Advogados	Brazil
Wang Guangjun	Petrochina	China
Liliane Wietzerbin	GDF Suez	France
Vincent Trocme	GDF Suez	France
Masoud Hassani	NIGC	Iran
Ikhyun Park	Kogas	Korea
Kyungsick Park	Kogas	Korea
Taehyeong Lee	Kogas	Korea
Zainal Abidin Zainudin	Petronas	Malaysia
Pawel Jagosiak	PGNiG	Poland
Alexey Semenov	Gazprom	Russian Federation
Oleg Borodionkov	Gazprom	Russian Federation
Guadalupe Vargas Giraldo	Repsol	Spain

Paris

June 2015

Table of Contents

3 GAS RENT AND MINERAL PROPERTY RIGHTS

Executive Summary

The literature is rich in the description of the regimes adopted around the globe to maximise the intake of governments from upstream oil and gas activities.

Much of the art involved in their design is related to the creation of a healthy business atmosphere where a win-win situation can be developed for all parts involved.

A large arsenal of fiscal instruments is readily available for that purpose, including signature bonuses, royalties and taxes on profits of varied nature. The obligation of acquiring goods and services in the local market is often used as well, in a tentative to further enhance the benefits of the activity.

The use of these instruments as a means to produce rent has been analysed in a number of different countries. Some of them can represent a severe burden to investors, which will always prefer progressive rates and the taxation of profits in lieu of revenues to enhance the recovery of costs at the early stages of their operations and even before that.

The solutions adopted by a number of countries were compared, aiming at the identification of regulatory tendencies, the assessment of business models, critical analyses of fiscal instruments and the development of upstream policies for gas rent.

The use of different contractual models has also been explored by the reports, who found the use of buy-back, transfer of rights and service contracts to be declining.

Concession and production sharing regimes increased their predominance. In the first, the investor sells the production for a price, deducts costs, pays taxes and keeps what is left. In the second, however, the operator receives part of the oil produced as a compensation for his costs, and another part of the production is passed on to him as a payment for his services, after taxes.

The use of production sharing seems to be increasing globally, but the results obtained so far seem to be questionable. A survey performed in 2013 among IGU members revealed the industry to be very conservative and undisposed to accept changes and new experiences in this area.

The exploration, development and production of gas reserves deserves a differentiated treatment from governments, which must ensure a proper balance of risks and rewards to promote the development of gas projects. Conditions may vary dramatically from associated to non-associated gas, or if an NOC is included or not in the business model.

As a result of the current analysis, the following best practices have been proposed to help the industry, policy makers and regulators in securing a reliable and affordable supply of natural gas to the consumers:

a) Reduce the relative importance of signature bonuses and area retention fees in the bidding processes;
b) Increase the relative importance of exploratory programmes, domestic content and other instruments that can harness economic and social development;
c) Promote a good assessment of the actual capability of local suppliers for equipment and services beforehand, and consider realistic mechanisms to account for the individual items that compose the requirements of domestic content, allowing companies to demonstrate higher than expected costs;
d) Replace flat royalty rates and other instruments based on production or income revenue by progressive mechanisms based on profits, or consider the use of progressive royalty rates;
e) Allow the depreciation of assets before production starts, and consider the use of generous uplift allowances that will not cause gold platting, especially for unconventional gas and production in frontier locations;
f) For marginal fields, consider a reduction of royalty rates and other mechanisms that will allow efficient operators to maintain production, employment and tax collection;
g) Whenever possible, consider ring fencing as a means to create equal opportunities and protect the government share;
h) For the production of unconventional gas, consider the concession of fiscal incentives to compensate for the higher costs.

3.1 Natural gas rent

In its Internet website, the World Bank defines gas rent as “the difference between the value of natural gas production at world prices and total costs of production” (http://data.worldbank.org/indicator/NY.GDP.NGAS.RT.ZS).

Based on the methods described in *The Changing Wealth of Nations* (2011), a report title that clearly refers to the *magum opus* of Scottish economist and philosopher Adam Smith, the Bank has obtained the results indicated in Figure 3.1.

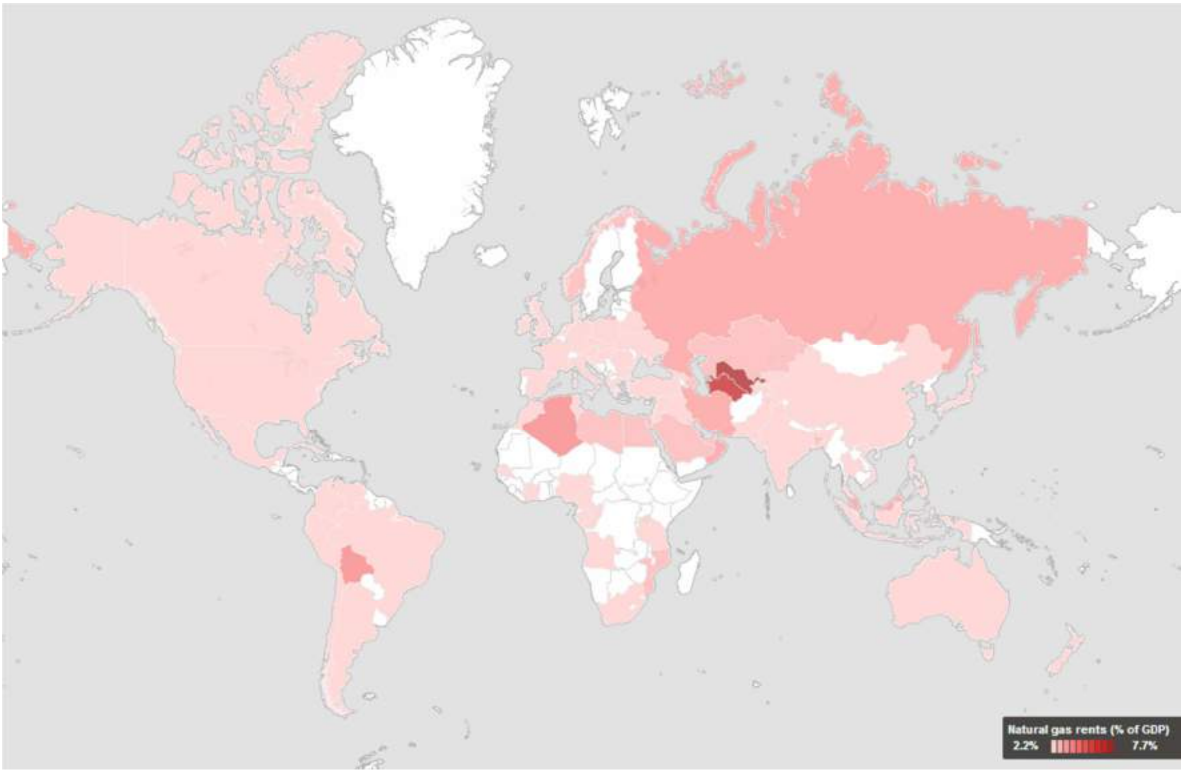


Figure 3.1 Gas rent map (World Bank, 2011).

In this map, it is interesting to note that a significant number of the highest gas rents occur in countries that are relative small in extension, and that in many cases natural gas plays a very important role in the country GDP, as indicated in Table 3.1.

Table 3.1 Largest gas rents in the world, % of GDP (World Bank, 2011).

Country name	2008	2009	2010	2011
Trinidad and Tobago	47.6	28.9	25.5	24.5
Turkmenistan	n.a.	23.0	22.3	22.6
Uzbekistan	73.6	22.8	16.6	15.1
Qatar	24.2	14.6	14.0	14.2
Brunei Darussalam	31.8	18.0	14.3	12.5

The gas rents of these countries were severely hit by the financial crisis of 2008, as a consequence of the collapse in the commodity prices, and they have not recovered ever since.

Nevertheless, the three most important conclusions pointed out by the Bank are as follows:

a) Natural resources account for over 20% of the wealth of developing nations;

b) The wealth of all countries is dominated by an intangible wealth, i.e., human and institutional capital, which rises as a share in the total as countries climb up in the development ladder;

c) In order to formulate new strategies and policies to promote development, it is necessary to improve the indicators that are commonly used to gauge progress.

The last conclusion is related to the fact that GDP broadly measures the value of the economic production in a country, but it is limited in many senses as an indicator of progress. As an example, a given country may quickly deplete natural resources to outgrow its GDP, but this result will not be unsustainable in the long term.

The first two findings, on the other hand, suggest that producing countries could climb up higher and faster in the development ladder by reinvesting their mineral rent in education, infrastructure and sustainable business.

Qatar constitutes an excellent example of that, as a number of such initiatives have already been implemented there. One particularly interesting instrument for that purpose is the Qatar Foundation for Education, Science and Community Development, which is helping the country on its journey “from a carbon economy to a knowledge economy”.

With the support of this organization, world leading universities such as Carnegie Mellon, Georgetown, Northwestern, UCL, and Texas A&M have opened branch campuses in Education City, a complex located in the outskirts of Doha that is envisioned to become a hub for the generation of new knowledge (Figure 3.2).

Figure 3.2 When completed, Education City will host 14 km^2 of educational, research, science and community facilities (pictures from http://www.romatreeproject.com and Google Earth).

The use of natural gas to promote economic and social development is indeed a very important topic, but this is already under the scope of activities of Programme Committee C (Gas Markets) in the current IGU triennium.

This report investigates instead the mechanisms and instruments that can assist governments in the production of rent from the exploration and production of gas. Their characteristics and limitations are explored, aiming at the development of models that are capable to promote a win-win situation for governments and investors.

Finally, in view of case studies taken from key producing countries, fiscal incentives for the production of unconventional gas are investigated, and some best practices are highlighted.

3.2 Fiscal instruments

Important characteristics of the most important fiscal instruments available for upstream rent are highlighted in this section. They have been broadly classified as progressive or regressive, according to the behaviour of their rate.

3.2.1 Signature bonuses

These are payments made up front for the right to develop an exploratory block. They are estimated from the hydrocarbon recovery potential, and can be called regressive because in practise their rate increases when production decreases.

3.2.2 Area retention

In addition to the signature bonus, investors are often required to pay an annual fee for the occupation or retention of the areas in which they are exploiting oil or gas. These are set up front as well, and can also be considered to be regressive.

3.2.3 Exploratory programme

Bidding processes may require competitors to offer exploratory programmes. In the 11th Brazilian bid round, for example, companies were supposed to consider the values indicated in Table 3.2, where an exploratory well was roughly quoted at US$ 50 million, US$ 30 million and US$ 2 million, respectively, if located in deep waters, shallow waters or onshore.

Table 3.2 Value of exploratory items in the 11th Brazilian bid round (1 UT was quoted at approximately US$ 0.5 million).

Location	Offered Basins/Sectors	Block Area (size)²	Exploratory Well	Seismic		Seismic Reprocessing		Potential Methods		Gama-spectrometry	Electromagnetic	Geochemistry	Minimum Stratigraphic Objective	UT amount for calculation of the Financial Guarantee of the First Period (R$/UT)
		(km²)	(UT/well)	2D (UT/km)	3D (UT/km²)	2D (UT/km)	3D (UT/km²)	GRAV (UT/km)	MAG (UT/km)	(UT/km)	(UT/receptor)	(UT/Sample)		
Deep Water	Barreirinhas – **SBAR-AP1 and SBAR-AP2**	760	1	0.085	0.349	0.006	0.018	-	-	-	0.326	0.160	Fm. Travosas (Cenomanian)	107
	Ceará – **SCE-AP3**	760	1	0.085	0.349	0.006	0.018	-	-	-	0.326	0.160	Fm. Paracuru (Albian)	107
Shallow Water	Barreirinhas – **SBAR-AR2**	180	1	0.155	0.633	0.011	0.033	-	-	-	0.592	0.291	Fm. Bom Gosto (Neoalbian)	59
	Foz do Amazonas – **SFZA-AR1**	190	1	0.155	0.633	0.011	0.033	-	-	-	0.592	0.291	Fm.Caciporé (Neocomian)	59
Shore Areas	Espírito Santo – **SES-T6**	30	1	9.849	28.436	0.284	0.707	0.128	0.128	0.128	5.760	0.238	Mb. Mucuri – Fm. Mariricu (Aptian)	3,8
	Potiguar – **SPOT-T3 and SPOT-T5**	30	1	9.849	28.436	0.284	0.707	0.128	0.128	0.128	5.760	0.238	Fm.Pendência (Neocomian)	3,8

3.2.4 Domestic content

Investors may be required to purchase equipment and services internally to promote the development of local businesses, but attention is required as excessive values can cause just the opposite effect.

Government authorities must carefully appraise the capabilities of local providers beforehand to minimise the controversy that often surrounds this issue. In the 11th Brazilian bid round, for example, the values indicated in Table 3.3 were considered, and winners were selected according to the formula

$$
\begin{aligned}
score = 40\frac{signature\ bonus\ offered}{highest\ signature\ bonus\ offered} \\
+ 5\frac{local\ content\ offered\ for\ the\ exploratory\ phase}{highest\ local\ content\ offered\ the\ exploratory\ phase} \\
+ 15\frac{local\ content\ offered\ for\ the\ development\ phase}{highest\ local\ content\ offered\ for\ the\ development\ phase} \\
+ 40\frac{exploratory\ programme\ offered}{highest\ exploratory\ programme\ offered}
\end{aligned}
$$

Table 3.3 Domestic content limitations for the 11th Brazilian bid round.

Block location	Exploratory phase		Development phase	
	Minimum (%)	Maximum (%)	Minimum (%)	Maximum (%)
Water > 400 m	37	55	55	65
Water > 100 m	37	55	55	65
Water ≤100 m	51	60	63	70
Onshore	70	80	77	85

3.2.5 Royalties

Royalties are perhaps the most traditional fiscal instrument in the oil and gas industry. They can be defined as payments made by a licensee to a licensor for the right of producing oil and gas.

Typically set as a percentage of the value of the wellhead production, royalties are very attractive to governments because they can generate rent as soon as production starts, but at the same time they exert significant pressure on the cash flow of producers, particularly during the early stages of their operations, when they are eager to pay debts and recover costs (Barbosa, 2011).

Because of this important characteristic, royalties are called a regressive instrument, and their use has been discontinued in a number of countries, such as Norway and the United Kingdom, where progressive instruments focused on the taxation of profits are now preferred in lieu of instruments based on production, income revenues or their equivalents.

Progressive royalty rates

In some countries a progressive design of royalty rates has been adopted as a tentative to better share risks and profits between governments and private investors.

In the frontier lands of Canada, for example, where costs and risks are higher, royalty rates are set incrementally from 1% to 5% of gross revenues.

In the USA a deep water royalty relief (DWRR) is applicable until a certain royalty suspension volume (RSV) is reached. For water depths in excess of 1.600 m the RSV is 12 million barrels, and for depths in excess of 2.000 m a maximum of 16 million barrels can be produced without royalties.

Royalties for marginal fields

Barbosa (2011) has criticized the use of royalties because they can induce a premature abandonment of the operations, as explained next.

Throughout the life of a typical reservoir, marginal costs increase as production declines, as indicated in Figure 3.3. When market values are topped, the facilities must be decommissioned.

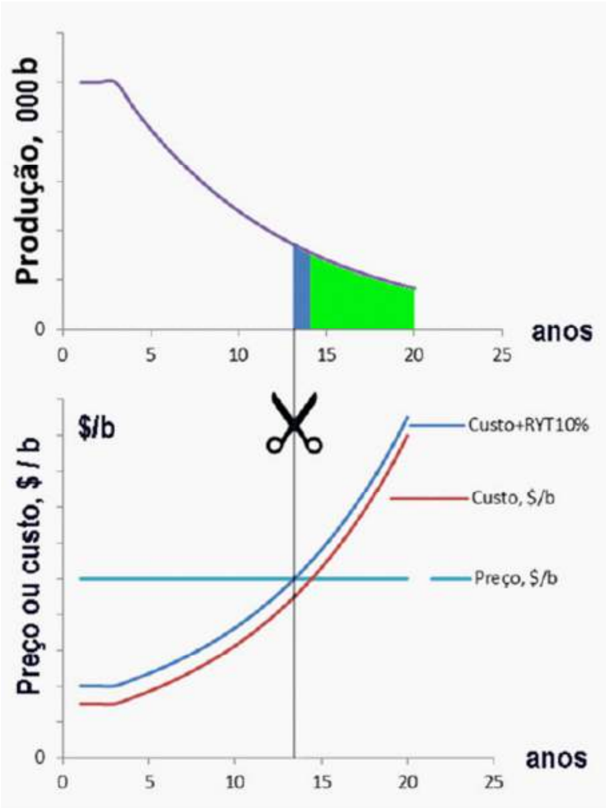


Figure 3.3. Royalties may induce a premature abandonment of the reservoir (Barbosa, 2011).

As indicated in this figure, royalties increase the production costs, causing the reservoir to be abandoned a little bit earlier than possible. To avoid this effect, they must be relieved or completely waived during the final stages of production.

Alternatively, the reservoir can be reoffered to the market in a new bidding round. Small investors are often able to extract value from marginal fields.

3.2.6 Excises

Excises can be defined as inland taxes on the production of specific goods or services. They are sometimes levied on the production of oil and gas, but the use of progressive rates is also possible, as in the case of royalties.

In Australia, for example, the first 30 million barrels produced are exempted from the Commonwealth excise, and varied excise rates are applied according to annual production level.

3.2.7 Inland revenue instruments

During the first years of a production project, companies are severely hit by a number of capital and operating expenditures. Production must be initiated as soon as possible to recover costs, and a number of fiscal instruments can assist them in that purpose, as described next.

Depreciation uplift

Cost depreciation, depletion and amortization (DD&A) can substantially accelerate the recovery of costs at the early stages of production, especially if an uplift factor is applied.

In countries like Australia, the United Kingdom and Norway, deduction is possible as soon as capital expenditure starts, but in others like Brazil a more regressive scheme has been preferred, as investors must wait until production starts to depreciate their investments.

Ring fencing of deductions

Ring fencing limits the compensation of losses to a certain geographic area, or to a certain business segment within a company.

It is commonly found in production sharing contracts, where the constitution of specific purpose companies for each exploratory area is commonly found.

In a certain manner, ring fencing discourages investors to perform new exploratory activities, as the corresponding costs cannot be deducted from the revenues produced by the facilities already in operation.

On the other hand, however, it enhances competitiveness by establishing more equalitarian conditions between new and existing players.

Ring fencing is also important to protect the government take, as it limits the compensation of losses by companies, thereby preventing the transference of risks from companies to governments. Barbosa (2011) appropriately depicted this, calling attention to the fact that even when the exploratory activity is successful, a delay takes place in the perception of revenues by governments when there is no ring fencing.

Last but not least, the absence of ring fencing could cause investors to gold plat their portfolio, as described further ahead.

Compensation of fiscal losses

The compensation of fiscal losses is usually limited, but in some countries losses can be carried forward indefinitely (e.g. Norway).

In the UK, exploratory and development costs can be compensated in future balances for a maximum period of six years at a 6% interest rate.

In Brazil these losses can be carried forward indefinitely, but the compensation cannot exceed 30% of the earnings before income tax, depreciation and amortization (EBITDA).

Abandonment costs

In general, these are deductible only when incurred, but in the UK they can be recovered from previous excises (Barbosa, 2011).

Research and development incentives

A deduction of expenditures may be offered to encourage R&D activities.

Gold plating

In oil and gas taxation, this name refers to the possibility of making uneconomic or unnecessary investments, because of an unfortunate combination of uplifts and too highly progressive taxation mechanisms (Kemp, 1996).

Barbosa (2011) gives an example of a 90%-10% sharing regime in which a 50% uplift is applied to drilling investments of US$ 100 million. This creates a cost recovery of US$ 150 million, and a reduction of US$ 15 million in petroleum profits for the company. If the total tax rate is at 50%, a reduction of R$ 7.5 million in taxes is obtained, and the overall result appoints to net savings of US$ 42.5 million, which makes advantageous to continue to drill even if the new wells will certainly be dry (-100 + 150 -15 + 7.5).

A similar rationale is often argued to possibly affect the production of shale gas outside the USA. This point is analysed further ahead.

3.3 Contractual models

Concession, service and production sharing contracts (PSC) are the most usual contractual models in place. Figure 3.4 next provides a visualization of their usage just before Mexico and Iran decided to initiate a discussion aiming at a revision of their models.

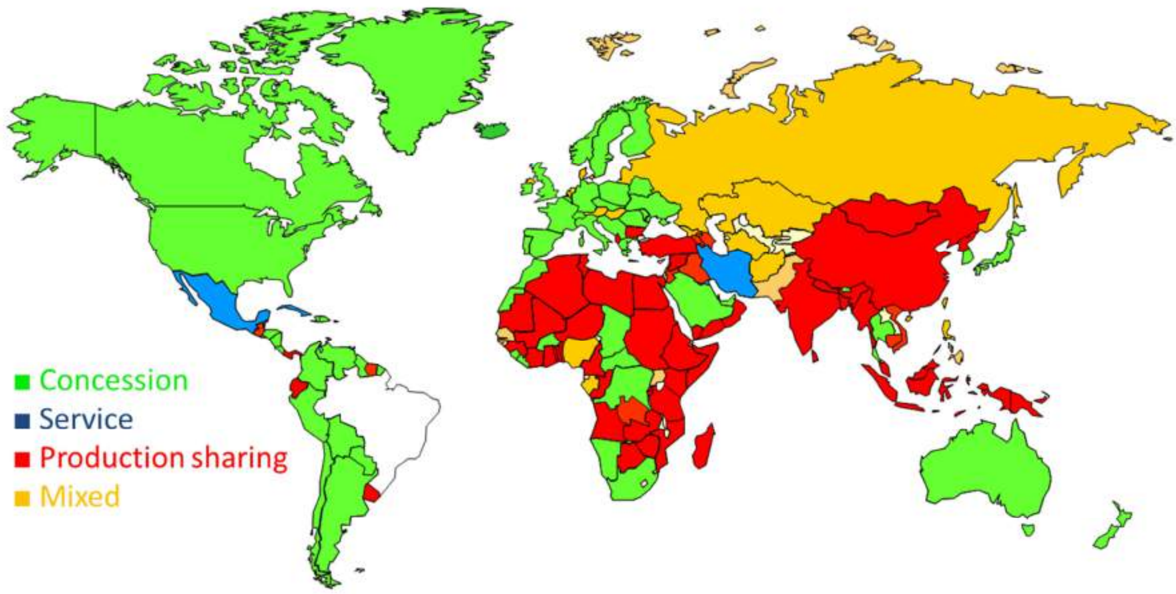


Figure 3.4 World use of concession, production sharing and service contracts (Barbosa, 2013).

In a few countries, such as the Russian Federation and Kazakhstan, concession and production sharing contracts co-exist. Recently Brazil joined this group, as its first PSC bid round took place in 2013.

Sharing contracts are a tendency for a number of important authors (Johnston, 2013), but many disagree on that. In theory, the same gas rent can be produced from any of these models, but the complexity of PSC is higher to manage; production costs must be reliably audited so that the oil or gas profit can be established with confidence.

No correspondence has been looked for between the gas rent and the contractual model adopted by countries, but upstream investments seem to be considerably higher where concession models are in place. This theme is worthy of proper investigation in the future.

3.4 Case studies

3.4.1 Mozambique

A *Natural Gas Master Plan for Mozambique* was recently developed by ICF International upon request of the Petroleum Governance Initiative (PGI) and the Public-Private Infrastructure Advisory Facility (PPPIAF).

The former is a collaboration between the Government of Norway and the World Bank that aims to support developing countries in developing appropriate frameworks for petroleum governance, including the management of resources, environmental and social issues, while the latter is a technical assistance promoted by the World Bank to help developing countries to improve the quality of their infrastructure.

The plan for Mozambique contains a number of policy and investment recommendations that could promote social and economic development if implemented in a fully coordinated manner.

Mozambique has very limited infrastructure and its workforce is still unskilled, but the country is on the verge of becoming a major player in the world energy market, due to the significant discoveries of natural gas and coal that have been recently announced (Figure 3.5).

Figure 3.5. The Rovuma Basin can hold 150 TCF of natural gas (El-Badrawy *et al.*, 2012).

These discoveries represent an excellent opportunity for social and economic development, but two basic theses have been raised upon what the country should do about them.

For some, LNG exportation projects would provide the country with important revenues by means of royalties and profit shares, which could be freely used internally for development.

For others, however, the use of these revenues should be performed in kind, in order to broaden the benefits attainable. That would promote local human capital, infrastructure, manufacturing and general businesses to increase employment and development to a higher extent.

These two paths are often assumed to compete, not only in Mozambique, but in other parts of the world as well. It seems more reasonable however to assume that they should be combined instead of opposed, as they are much more complementary than mutually exclusive.

As an example, Anadarko and ENI, who signed concession contracts in 2006 with the government, have recently announced recoverable gas discoveries of 33-38 TCF, and are now looking for liquefaction opportunities as the internal market is relatively small (the total population is 24 million).

Another good example is the expansion of the Temane-Secunda pipeline (Figure 3.6). In 2010, production in the Inhambane province reached 8.7 million m^3/d approximately, of which 94% were exported to South Africa.

Figure 3.6. The pipeline from Temane and Pande to Secunda will be expanded.

Under the current Exploration and Production Concession Contract model (EPCC), royalties are levied only after production starts. The rate is about 2~4% for natural gas and 3~7% for crude oil.

During the exploratory period, contractors are obliged to bear all costs incurred, but they can recover it during the development and production period (Figure 3.7).

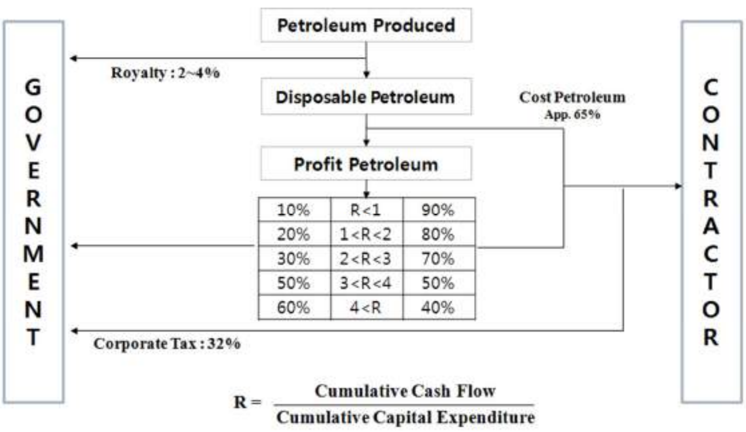


Figure 3.7. The rate of profit share is variable in Mozambique.

3.4.2 Tanzania

A National Natural Gas Policy was published in 2013, providing guidelines for the development of the natural gas industry in the country (Figure 3.8).

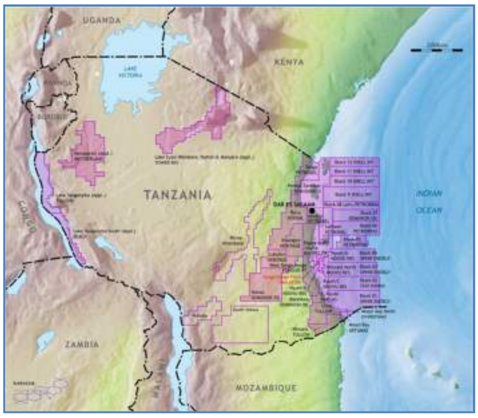


Figure 3.8. Exploration blocks in Tanzania (The Sharehub, 2011)

This document reflects a long term goal for local content, but appears to be limited to the mid and downstream segments. Provisions for the upstream segment could come in a new gas regulation, which is planned to formulate a regulatory framework for the entire industry.

The current policy clearly establishes that natural gas can be exported only after the domestic market has been satisfied, and all LNG facilities must be located onshore. Different fiscal regimes exist for deep offshore gas and oil (Figure 3.9 and Figure 3.10).

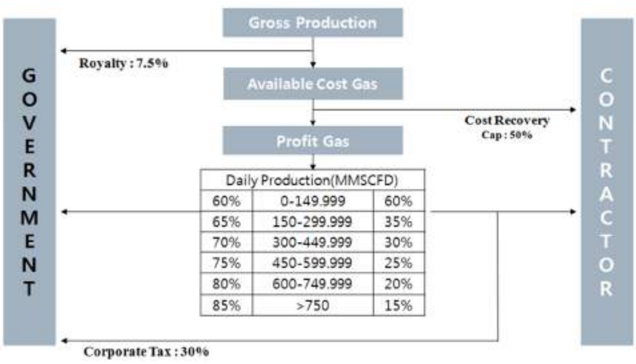


Figure 3.9. Fiscal regime for deep offshore gas.

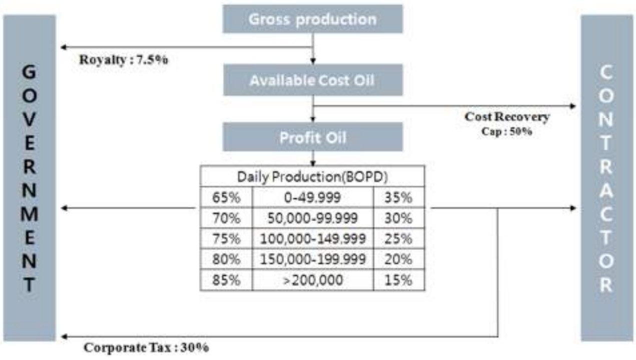


Figure 3.10. Fiscal regime for deep offshore oil.

According to the Model Production Sharing Agreement of 2013 (MPSA 2013), a significant increase in government profit share is expected as compared to the one previously in place for PSAs.

The Tanzania Petroleum Development Corporation (TPDC) is entitled to take part in any development area with a minimum share of 25%, subject to payment of all contractual expenses.

An additional profits tax (APT) can be applied when contractors earn specific rates of return (ROR) on net cash flow from the development area, in accordance with the provisions of the MPSA 2013. ATP varies from 25% at the first accumulated net cash position (FANCP) to 35% at the second accumulated net cash position (SANCP). No APT is due if the FANCP or SANCP is negative.

3.4.3 Russia

The fiscal regime generally applicable to the petroleum industry in Russia consists of a combination of mineral extraction tax (MET), corporate profits tax and export duty.

Mineral extraction tax (MET)

For oil, in 1 January 2015 the fixed rate approach for the MET was replaced by the formula

$$\textbf{MET (oil)} = \textbf{BR*Cp} - \textbf{Cdf}$$

where:

BR – a base rate of RUB 766 per tonne in 2015, RUB 857 per tonne in 2016 and RUB 919 per tonne in 2017;

Cp - a coefficient that reflects the dynamics of world oil prices;

Cdf – a coefficient that reflects a number of specific factors, including the level of depletion of reserves, the degree of difficulty for the extraction of oil, the initially extractable oil reserves and the geographical location.

From 1 July 2014, the fixed MET rate approach for both for natural gas and gas condensate was replaced by the formula

MET (gas) = BR* Usf* Cdf +Tg

where:

BR – a base rate of RUB 35 per 1,000 cubic meters;

Usf - a base value of a unit of standard fuel, which takes into account the price of the gas supplied to the domestic market and beyond the custom boundaries of the union, the proportion of the extracted gas to the total amount of gas and condensate, and the price of the gas condensate (linked to the price of oil).

Cdf - a coefficient that reflects the degree of difficulty for the extraction of the gas, equal to the lowest of the following coefficients, in the range of 0.1 to 1:

- the level of depletion of the gas reserves of a particular subsurface site containing a hydrocarbon reservoir;
- the geographical location of a subsurface site containing a hydrocarbon reservoir;
- the depth of the occurrence of a hydrocarbon reservoir;
- whether or not a subsurface site containing a hydrocarbon reservoir serves a regional gas supply system;
- specific factors relevant to the development of a particular subsurface deposit;

Tg – an adjustment linked to the transportation costs of the gas, taking into account:

- the difference between the actual average tariff for the transportation of natural gas and the estimated average rate of gas in the relevant year;
- the average transportation distance for natural gas on pipelines in the year preceding the year of the tax period by non-Gazprom-affiliated companies;
- a coefficient characterizing the ratio of the extracted gas by Gazprom and its affiliated companies to the amount of gas extracted by other taxpayers in the year preceding the year of the tax period;

Finally, for gas condensate the following formula is applicable:

MET (condensate) = BR * Usf * Cdf * Csp

where:

BR – a base rate of RUB 42 per tonne for gas condensate;

Usf - a base unit of standard fuel, considering the price of the gas supplied to the domestic market and beyond the custom boundaries of the union, the proportion of the extracted gas relatively to the total amount of gas and condensate and the price of the gas condensate (linked to the price of oil).

Cdf - a coefficient reflecting the degree of difficulty for the extraction of the gas condensate, equal to the lowest of the values of the following coefficients, in the range of 0.1 to 1:

- the level of depletion of gas reserves of a particular subsurface site containing a hydrocarbon reservoir;
- the geographical location of a subsurface site containing a hydrocarbon reservoir;
- the depth of the occurrence of a hydrocarbon reservoir;
- whether or not a subsurface site containing a hydrocarbon reservoir serves a regional gas supply system;
- specific factors relevant to the development of particular reservoirs of a subsurface deposit.

Csp - a special coefficient (4.4 for 2015, 5.5 for 2016 and 6.5 from 01.01.2017).

Corporate profit tax

Russian tax-resident companies and foreign companies operating in Russia through permanent establishments are subjected to a taxation of their profits. Deduction of economically justified expenses is possible whenever documented, including depreciation, exploratory and development costs.

The basic rate is 20%, but it can be reduced for particular categories of taxpayers up to a minimum of 15.5%.

Export duty

An **export duty** for oil is determined by the Government based on the price of the Urals blend at the Mediterranean and Rotterdam markets. For natural gas the export duty is 30%, and for LNG it is 0%.

New legislation for the continental shelf

Long periods with limited or no access, strong winds and waves have always been a challenge for the Arctic gas, but the most important hurdle comes now from the shale developments in North America.

A new tax policy has been designed to attract US$ 500 billion to the offshore Arctic over the next 30 years. The proposed regime sets different terms for each location, as conditions may change widely from zone to zone (Table 3.4).

Table 3.4 The fiscal system for the Russian offshore.

	Category 1	Category 2	Category 3	Category 4
Offshore area	Azov & Baltic Sea	White and Pechora Seas, Southern Okhotsk Sea and Shallow Black Sea	Deep Black Sea, Northern Okhotsk Sea, Southern Barents Sea	Northern Barents Sea, Kara Sea, Bering East-Siberian Sea, Chuckchi and Laptev Sea
Mineral Extraction Tax (MET) holiday period (years)	5 (no later than 2022)	7 (no later than 2032)	10 (no later than 2037)	15 (no later than 2042)

MET rate (revenue-based)	30%	15%	10%	5%
Export duty	Exempted until 31.03.2032		Exempted until 31.03.2042	
Corporate Tax	20%			
VAT	General order			
Import Duty	General order			
Property Tax	Exempted			
Losses carry forward	Without limitations			
Depreciation of fixed assets	Accelerated			

3.4.4 Angola

Angola moved from a partnership model established in the 1960s and 1970s (e.g. Block 0 and FS/FST) to a production sharing regime (PSA) in which the presence of the national company Sonangol is mandatory. Risk service contracts (RSC) are also possible, but rarer.

3.4.5 India

Shale gas has been considered as a strategic imperative for India, since a significant demand-supply gap occurs in the country and large resources would be available there, as indicated in Figure 3.11 (Gupta *et al.*, 2010).

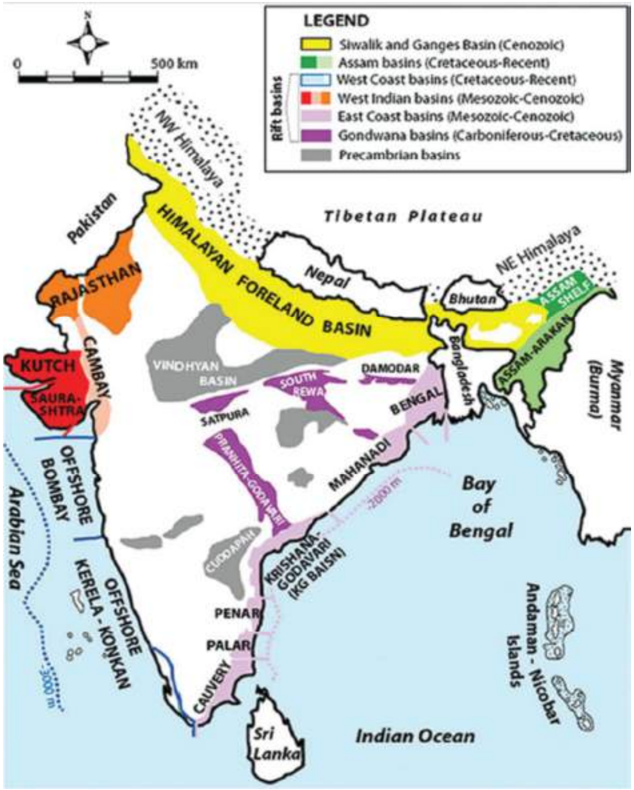


Figure 3.11 Sedimentary basins of India (Gupta *et al.*, 2010).

The first shale gas auction was scheduled for December 2013. The Petroleum Federation had suggested cost recovery to be allowed with a cap of around 40% to attract investment, as the production of unconventional gas is cost intensive and risky, but the draft policy did not seem to allow cost-recovery, to avoid the possibility of gold plating. Gail took its first stake in a U.S. shale in 2011, snapping up a 20% share in Carrizo's Eagle Ford assets for US$ 95 million (Robertson, 2011).

3.4.6 China

Chinese non-conventional gas developments have always been deemed as insufficient to service the expected growth in the internal demand, but production ramp-up is moving slower than originally expected.

The geology is certainly more complex and unknown than in the USA, but the most important resources are located far from the market, and some regulatory issues remain opened. As a consequence, only a small number of wells have started up production.

Only two auctions of mineral rights were organised by the Ministry of Land and Resources, in which four shale gas blocks were offered in 2011, and 19 more in 2012, covering an area of approximately 20,000 km^2 (11 blocks were larger than 1,000 km^2).

In the Chinese bidding rounds the partner must hold at least 51% of the joint venture shares, and the winner must be incorporated locally as a specific purpose company. Bidders must have a registered capital of approximately US$ 50 million.

An exploration period of three years is established, followed by a 30 year production under a new agreement. Taxation includes 5% royalties, 5%-10% resource taxes on product sales and 1% mineral resources compensation fee.

For shale gas a subsidy of US$ 0.06 per cubic meter applies, which is about US$ 1.44 per million Btu.

3.4.7 Norway

In 2013 the Norwegian Government surprised the world with a reduction in the capital uplift allowed in their petroleum tax system, from 30% to 22%. In addition to that, corporate tax was reduced from 28% to 27%, and the special petroleum tax was raised from 50% to 51%.

These new rules became effective in January 2014, and were motivated by an apparent overheating in the oil and gas sector, where cost overruns and delays have been common (WoodMackenzie, 2014). Tougher cost controls must be implemented by companies now, and new developments are expected to be affected as a consequence, especially where the production is not large.

3.4.8 United Kingdom

The fiscal system that is generally applied to the production of oil and gas in the United Kingdom comprises three taxes:

a) Ring fence corporation tax (RFCT)

Calculated in the same manner as the regular corporation tax, the RFCT is charged at 30% and cannot be compensated with losses suffered in other activities. All capital expenditures are eligible for a 100% allowance in the first year.

b) Supplementary charge (SC)

Set at a 32% rate, the SC is an additional charge on ring fence profits, excluding financial costs.

c) Petroleum revenue tax (PRT)

Charged on profits from fields whose consents were given before 16 March 1993, the PRT is charged at a 50% rate and is deductible as an expense in computing profits chargeable to RFCT and SC, i.e., when applicable it is equivalent to a 19% rate on ring fenced profits, raising the total tax rate from 62% to 81%.

A ring fence expenditure supplement (RFES) allows companies to uplift their ring fence losses and pre-trading expenditures by 10% to maintain their time value, for as much as six accounting periods, until they can be offset against future profits. This is very helpful at the start of a project, when companies do not have sufficient taxable income.

A new fiscal regime for shale gas

The production of unconventional gas requires long term certainty on taxes and incentives to encourage exploration, as its economics are poorer, especially because of the decay rates, which are typically large (Javid, 2013).

In recognition of the longer payback period required, a new package was proposed in the UK extending the RFES from six to ten accounting periods. In addition to that, because unconventional reservoirs are located in large areas, with boundaries relatively undefined, a "pad allowance" was introduced, as the previous field allowance depended on the existence of a clearly delineated ring fence.

It basically exempts the initial production from the SC, causing the total tax rate to be reduced from 62% to 30%, as indicated in Table 3.5.

Table 3.5. New fiscal regime will reduce the total tax rate for unconventionals in the UK.

	Tax	Development consent previous to 16 March 1993	Development consent from 16 March 1993
Conventionals	RFCT SC PRT (100%-RFCT-SC)*50%	30% 32% 19%	30% 32% -
	Total	**81%**	**62%**
Unconventionals	RFCT SC PRT (100%-RFCT-SC)*50%	30% 0% 35%	30% 0% -
	Total	**65%**	**30%**

The idea resembles the royalty relief in the USA as the amount exempted is supposed to be proportional to the capital expenditure in the pad. It is limited to expenditures classified as first year allowances, such as industrial equipment and production facilities, and companies would start to hold them as soon as they incur capital expenditure on the pad.

Previous to that, operators had already voluntarily committed to providing local communities with one per cent of their revenues, or a minimum of £ 100,000 per site, whenever hydraulic stimulation was practiced.

More recently the Environment Agency announced plans to simplify and accelerate the permitting process for shale gas developments, as the potential in the UK is very large.

3.4.9 Poland

Poland has recently announced a new bill to encourage investments in shale gas, but some postponing has already taken place as well. In the meantime, the country has announced that it will not collect taxes on the production of shale gas by 2020, in an attempt to revive the enthusiasm that initially surrounded the country potential (Reuters, 22 May 2013).

Bidding processes take into account the scope and technology proposed (60%), the technical and financial capabilities of the bidder (30%) and the fee proposed for the granting of usufruct to explore and exploit (10%). In addition to that, the winner has to pay a fee to establish a concession, which is negotiated.

3.4.10 USA

One of the most interesting aspects of the unconventional oil and gas revolution that took place in the USA is the fact that it was not performed by the traditional international oil corporations (IOC), but by the independent producers of oil and gas, as described in the second section of this report.

Some of them became large corporations, and the Administration is now reconsidering the tax provisions and deductions that were made available to them, causing a strong reaction from organisations such as the Independent Petroleum Association of America (IPAA).

Tax deduction of intangible drilling costs (IDC)

For independent producers, items that offer no salvage value such as labour costs, drilling fluids and completion chemicals can be fully deducted in the year they are incurred, rather than being capitalized over several years. Integrated oil and gas companies, on the other hand, may deduct only 70% of the IDCs at the time they are incurred, amortizing the remaining 30% over a period of 60 months (Brock *et al.*, 2007).

IDCs represent nearly 75% of the total cost of a well for unconventional gas (Duman, 2012). To illustrate their importance, Wood MacKenzie has estimated that a reduction of 3.8 million equivalent barrels per day would take place in ten years if the tax treatment of IDCs was ended, while the Joint Committee on Taxation (JCT) has estimated the cost of retaining IDCs for five years at US$ 6.2 billion (Inhofe *et al.*, 2013).

Tax deduction of tangible drilling costs (TDC)

This deduction is taken from drilling and completion equipment, which can be depreciated over a seven year period by the Modified Accelerated Cost Recovery System (MACRS) indicated in Table 3.6.

Table 3.6 MACRS Depreciation rates.

Year	Rate
1	14.29%
2	24.49%
3	17.49%
4	12.49%
5	8.93%
6	8.92%
7	8.93%
8	4.46%
Total	100.00%

Depletion allowance

All costs related to the lease are deductible through a cost depletion technique in which the units of production during a certain year are divided by the total proved reserves at the beginning of that year in order to produce a cost factor, which is then multiplied by the net leasehold costs of the property to arrive at a cost depletion amount (Brock *et al.*, 2007).

On top of that, independent producers and royalty owners can also compute a percentage or statutory depletion, currently set at 15%. This is limited to the first 1,000 bpd of oil or 6,000 mcf/d of natural gas produced, and it is also capped at the net income of the property and to 65% of the taxpayer net income (Duman, 2012).

This benefit is particularly important to small producers, as the recovery of costs provided is key to maintaining marginal wells running. Collectively, nearly 19% of the oil and 12% of the natural gas in the USA comes from wells that produce less than 15 bpd and 90,000 cfd, respectively (http://energytaxfacts.com/issues/percentage-depletion).

The JCT has recently estimated the cost of retaining percentage depletion for five years at US$ 5.7 billion, and many believe that the drilling activity in the USA could decrease by 30% if current tax treatment of IDCs, percentage depletion and passive loss exception were ended (Inhofe *et al.*, 2013).

State tax benefits

State income taxes for corporations can vary significantly from state to state. In California and Pennsylvania, for example, flat rates at 8.84% and 9.99% currently apply, while in Alaska and Iowa a progressive scheme is used. In Ohio and Texas, on the other hand, a gross receipts tax is preferred in lieu of the corporate income tax, while in Delaware and Virginia both of these are due (http://taxfoundation.org/article/state-corporate-income-tax-rates-2000-2013).

In the USA and Canada various states or provinces have differentiated fiscal terms to provide incentives for gas versus oil, horizontal wells, marginal wells, deep wells and unconventional resources. And government take can include revenues earned by native American tribal groups and university lands. As a consequence, Kepes *et al.* (2011) distinguished 188 fiscal systems in 35 jurisdictions.

Those concerned with the development of state policies for the production of unconventional oil and gas will find interesting analyses published by IHS CERA (2012) and Headwater Economics (2013). In Oklahoma, for example, a four year horizontal drilling incentive was introduced, and additional benefits subsist for deep wells, formerly inactive wells, production enhancement wells, three dimensional seismic wells, new discovery wells and wells at economic risk (Figure 3.12).

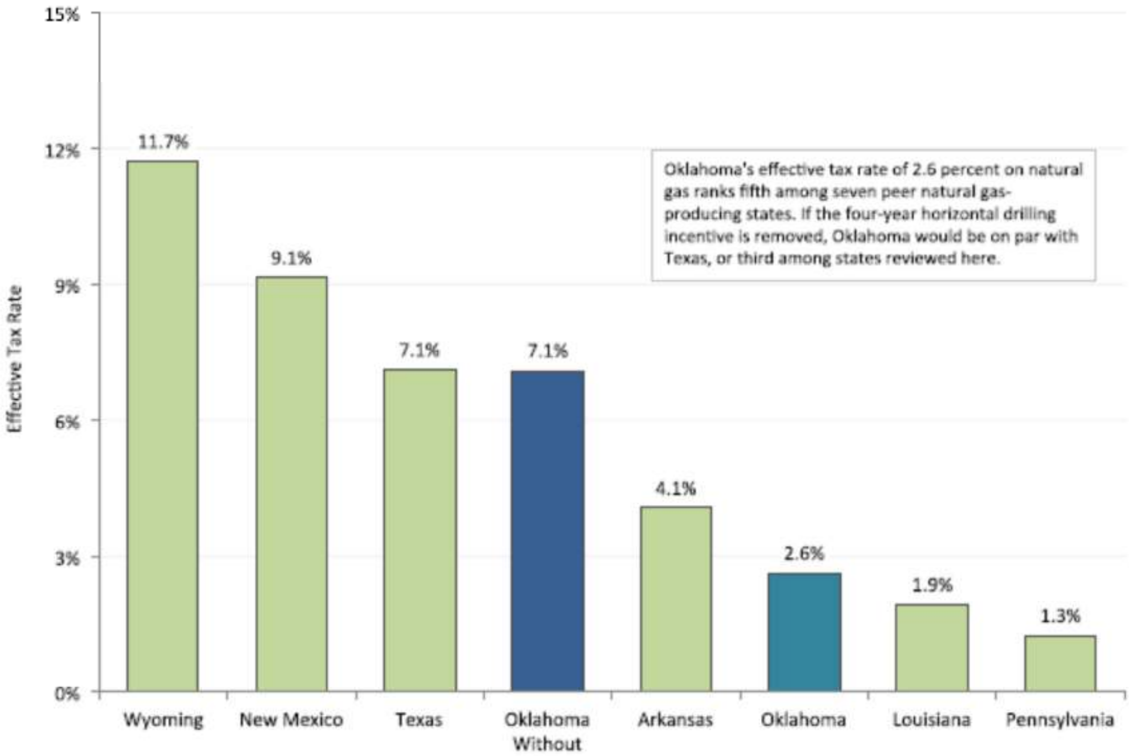


Figure 3.12 Effective tax rate on a typical unconventional gas well after 10 years of production (Headwater Economics, 2013).

The Severance Tax Refund Center has described the benefits available in Oklahoma as follows (text reproduced from http://severancetaxrefund.com/severance-tax-by-state/oklahoma-gross-production-tax-refunds, with permission from the owner):

* **Deep wells** - Brought into law in 1994 by Senate bill 841 and amended in 1995 by Senate bill 495. Oklahoma allows for a refund of six percent of the total seven percent gross production tax for production from wells deeper than 15,000 feet if spudded between July 1, 1995 and June 30, 1997. The law was later amended to included wells 12,500 feet and deeper if spud between July 1, 1997 and June 30, 2002. Most recently the law was amended again in 2002 to include wells spud between July 1, 2002 and June 30, 2015 and is deeper than 12,500 feet the well is will qualify for a gross production tax refund for 28 to 60 months depending on the depth of the well.
* **Formerly inactive wells** – Severance tax refunds for inactive wells was brought into law with 1994 by Senate bill 841. The law provides for refund of 6% out of the total 7% gross production tax for production from wells that have not produced oil, gas, or oil and gas for a period of not less than the 2 years prior to July 1, 1997. The law was later amended to allow for severance tax refunds for wells that had not produced for one year and are brought back to production after June 30, 1997. The exemption period for these refunds is 28 months.
* **Production enhancement wells** – Wells worked over to increase either/or oil and gas production on eligible for a 6% refund on the gross production tax on the incremental production. A simple example would be if the well produced 1,000 mcf per month before the workover and then after workover the well produced $1800 mcf per month then the operator could receive a gross production tax refund based on 800 mcf for 28 months. Production enhancement refunds was also part of Senate bill 841. Workover performed between July 1, 1994 to June 30, 2012 qualify.
* **New discovery wells** – Senate bill 495 approved for gross production tax refunds wells that were drilled as a new discovery. The law defines new discovery as an oil/gas well drilled at least one mile from the nearest oil well producing from the same formation; or drilling to a deeper formation that is more than one mile from an oil well producing from the same deeper formation. The refund is 6% of the total 7% of the gross production tax paid. The refund period is limited to the amount of time the exemption or credit equals the total cost of drilling and completing the well, but not longer than 28 months.
* **Horizontally drilled wells** – First production must have begun July 1, 1995 or after and before July 1, 2015. The refund is 6% out of the total 70% gross production tax from an oil and gas well. For wells which started producing prior to July 1, 2002 the refund period runs from project beginning date until project payback is achieved but not to exceed a period of 24 months. Wells which started producing after July 1, 2015 but prior to July 1, 2012 the term runs from beginning date until project payback is achieved but not to exceed 48 months starting with the month of initial production.
* **Three dimensional seismic wells** – Senate bill 1048 passed in 2000 which authorizes a severance tax refund for 18 months if the 3-D seismic shoot was shot before July 1, 2000, however, if the 3=D seismic shoot was after July 1, 2000 then the refund period is 28 months beginning with the month of initial production.
* **Economically at-risk wells** – Oil wells that lost money on a working interest basis in 1997 and/or 1998 qualify for a refund 6% of the 7% gross production tax paid. A gas

well with 15-to-1 gas to oil ratio will also qualify for a refund during 1997 and/or 1998 if it lost money. Additionally, any oil and gas well that lost money on a working interest level from 2005-2012 can receive a gross production tax refund equal to 6% of the 7% of the gross production tax paid.

Federal income tax

The state tax amount can be used as an allowable deduction for the federal income tax, which is calculated from the values indicated in Table 3.7 with the formula

$$tax = base\ tax + tax\ rate\left(federal\ taxable\ income - lower\ value\ of\ income\ bracket\right)$$

Table 3.7 Federal income tax rate schedule (Duman, 2012).

Tax Rate Schedule			
Lower bracket	Upper bracket	Base tax	Tax rate
0	50,000	0	15%
50,000	75,000	7,500	25%
75,000	100,000	13,750	34%
100,000	335,000	22,250	39%
335,000	10,000,000	113,900	34%
10,000,000	15,000,000	3,400,000	35%
15,000,000	18,333,333	5,150,000	38%
18,333,333			35% on all income

The Natural Gas Policy Act of 1978 and the Income Tax Credit of 1980

It is worthy to mention that other provisions were available in the USA in a more distant past, which were equally important to the industry, when it was still in its first steps towards the development of unconventional resources.

The first of them was the Natural Gas Policy Act (NGPA) of 1978, which came to attack a shortage that was ultimately caused by the existence of price controls in the interstate commerce. At that time, the Federal Energy Regulation Commission (FERC) was given the responsibility for harmonizing the regulation of wellhead gas sales in both intrastate and interstate markets. While doing so, FERC granted unconventional gas with the highest ceiling prices of all regulated categories.

The NGPA of 1978 also set the ground for a phased deregulation of prices, which was completed only by the Natural Gas Wellhead Decontrol Act in 1989. Much before that, however, a tax credit for unconventional fuels came into effect in 1980, following a deep concern in the country with imported energy. This benefit became known as Section 29 Tax Credit, in reference to the part of the Internal Revenue Code (IRC) that corresponds today to Section 45K. It established an income tax credit of US$ 3 per barrel, equivalent to about US$ 0,50/MBtu (Matlock and Nemirow, 2004).

Non-fiscal lessons from the unconventional gas revolution

In spite of the considerable efforts developed by regulators and policy makers located elsewhere, the unconventional gas revolution remains restricted to North America, where the shale gas industry has accounted for over 600,000 jobs, and paid annually almost US$ 20 billion in taxes just in the USA.

A large number of different essays have already been published on how to make the U.S. “shale gale” international. One of the first of them was published in 2012 by the International Energy Agency, who suggested principles to be followed by policymakers, regulators and operators to address environmental and social impacts. These were called “golden rules for a golden age of gas”.

Such principles would raise social acceptance, paving the way for a widespread development of unconventional resources, and would raise production costs by only 7% when applied to typical horizontal wells drilled into deep shale plays such as the Haynesville and Eagle Ford.

> Full transparency, measuring and monitoring of environmental impacts and engagement with local communities are critical to addressing public concerns. Careful choice of drilling sites can reduce the above-ground impacts and most effectively target the productive areas, while minimising any risk of earthquakes or of fluids passing between geological strata. Leaks from wells into aquifers can be prevented by high standards of well design, construction and integrity testing. Rigorous assessment and monitoring of water requirements (for shale and tight gas), of the quality of produced water (for coalbed methane) and of waste water for all types of unconventional gas can ensure informed and stringent decisions about water handling and disposal. Production related emissions of local pollutants and greenhouse-gas emissions can be reduced by investments to eliminate venting and flaring during the well-completion phase (IEA, Golden Rules for a Golden Age of Gas, 2012).

While a typical conventional vertical well would cost only US$ 3 million in the USA, the production of unconventional gas would raise this to about US$ 8 million, considering a depth of 3 km and 20 stages of fracturing alongside a horizontal section of approximately 1200 m, taking one month to drill and another one to complete (Figure 3.13).

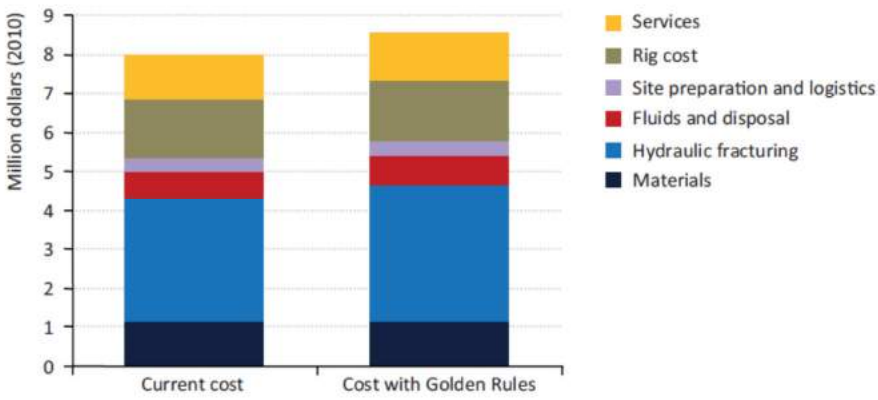


Figure 3.13 Cost increase caused by best practices suggested by the IEA (IEA, 2012).

These costs are very low, and could hardly be reproduced in other parts of the world. They are supposed to be the consequence of a number of factors, not only the large availability of suppliers of equipment and services in the USA and Canada.

Previous infrastructure

The literature often mentions technology, geological conditions, individual ownership of mineral rights, stable regulations, capital availability and abundance of risk hedging tools as some of the key drivers behind the changes that took place in the USA.

For Trifon (2012), however, the most important single factor that explains the unconventional gas revolution is the extensive, all interconnected natural gas pipeline system that exists in the USA.

He called it a “dirty little secret”, as not many people seem to remain aware of the fact that the American grid was established under a completely regulated environment, with costs integrally imposed to the final consumers.

This certainly helps to explain the growth experienced by the unconventional industry in the past, but not the persistence of the phenomenon.

Independent producers

In the previous sections a point was made in the sense that some of the most important fiscal benefits for the production of oil and gas in the USA did not especifically target the production of unconventionals, but independent companies that were willing to drill deeper, horizontally or under difficult circumstances.

It comes not as a surprise, consequently, that these companies dominate today the supply of natural gas in the USA, leaving less than 20% of the total to IOCs and energy integrated companies (Figure 3.14).

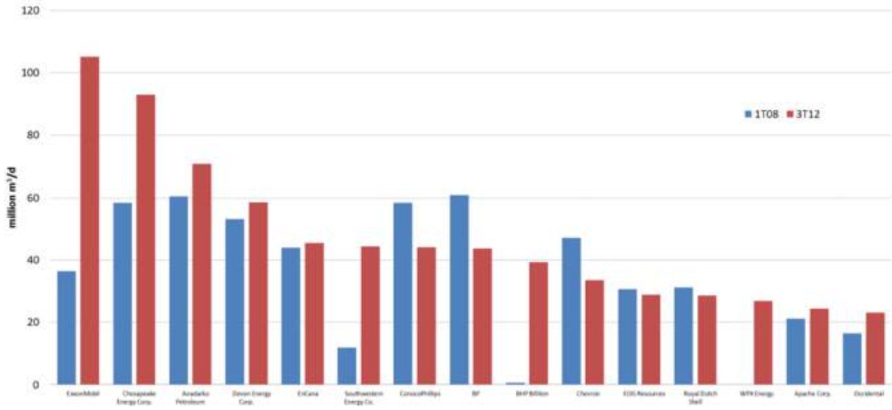


Figure 3.14. Independent producers still dominate the supply of natural gas in the USA (Kortchmar, 2013).

The purchase of XTO Energy in 2009 converted ExxonMobil into the single largest producer in the USA, but five out of the six largest producers in the USA continue to be independent companies. Their efficiency and response to changes in the market are very high, as indicated in Figure 3.15.

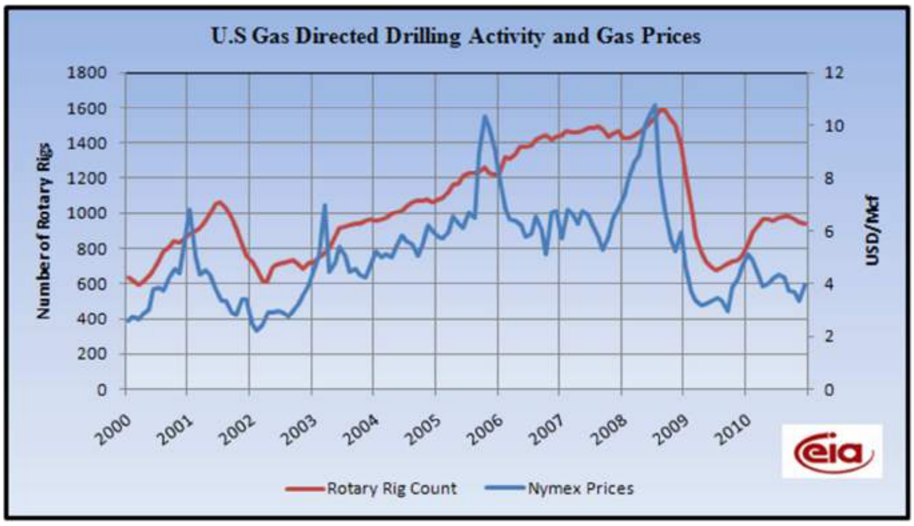


Figure 3.15. Drilling activity is closely connected to market prices (EIA, 2012).

More on the role of the independent producers is analysed in the second part of this report (Study Group 1.2).

Research and development

The U.S. federal government has supported a number of research projects that were key to the industry, such as the technology to air drill multi-fracture horizontal wells, and some important advances in micro-seismic imaging, funded by means of a surcharge on gas.

Equally important was the Eastern Gas Shale Project, in which new drilling, stimulation and recovery technologies were developed and implemented from 1976 to 1992, while determining the most important characteristics of shales located in the Appalachian, Illinois and Michigan basins.

These activities were all performed by a number of governmental organisations such as the Gas Research Institute, Sandia National Laboratories and the Department of Energy, in conjunction with private investors (Jenkins *et al*., 2011).

Associated gas and liquid

As can be seen in Figure 3.16 next, gas rig counts have largely declined over the last few years, especially in the older shale plays (Figure 3.17), but the overall production of gas continues to increase, as indicated in Figure 3.18.

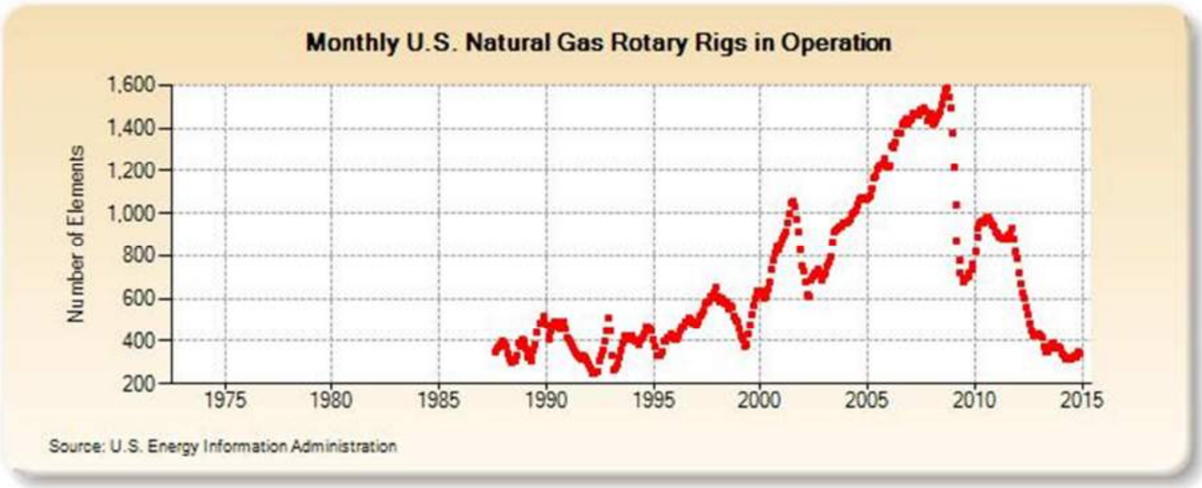


Figure 3.16 Rig count indicates a significant decline in gas drilling (EIA, 2015).

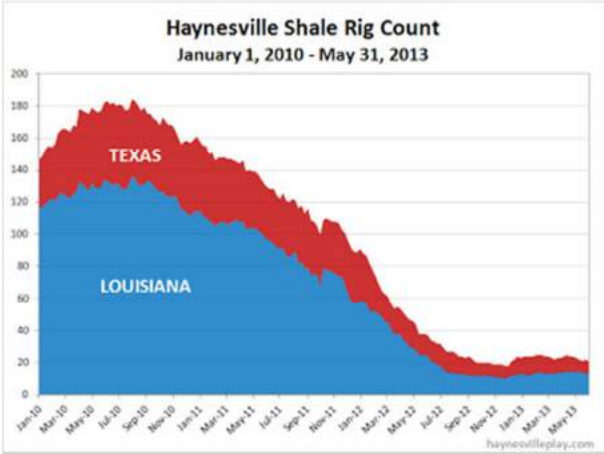


Figure 3.17 Rig count in the Haynesville play.

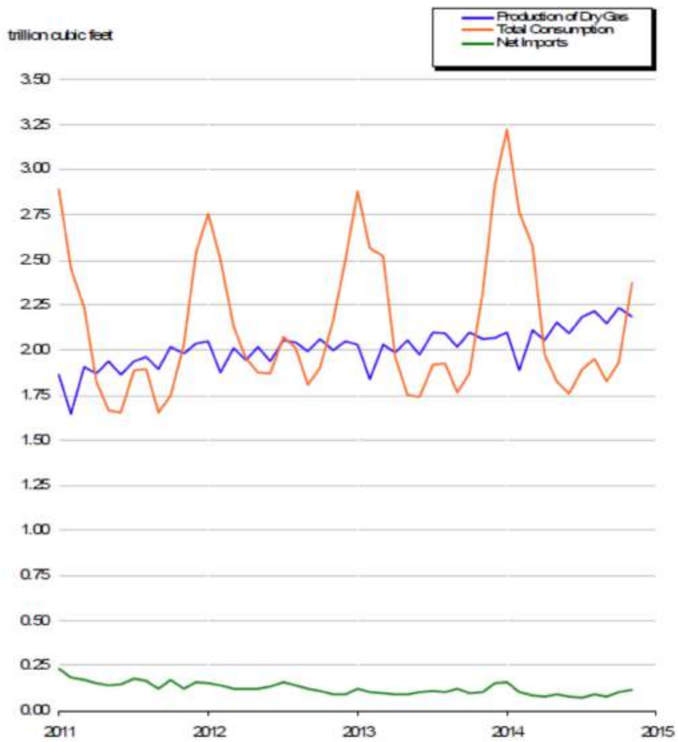


Figure 3.18 The internal production of gas in the USA continues to increase (EIA, 2015).

Associated gas from oil drilling is often mentioned in the literature as an important reason for the current gas glut in the USA, as the internal production of oil has increased significantly (Figure 3.19).

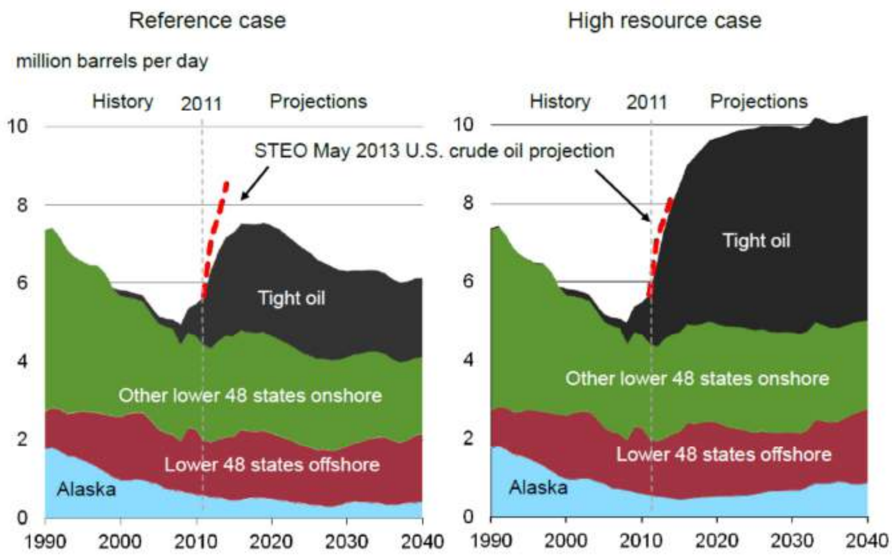


Figure 3.19 U.S. domestic crude oil production in two scenarios (Sieminski, 2013).

Unfortunately, fresh statistics on that are not readily available. Information on the website of the Energy Information Administration (EIA) stops in December 2011 (Figure 3.20). At that time, the monthly average production was at about 500 Bcf, or 16 Bcf/d, while the total demand was approximately 70 Bcf/d.

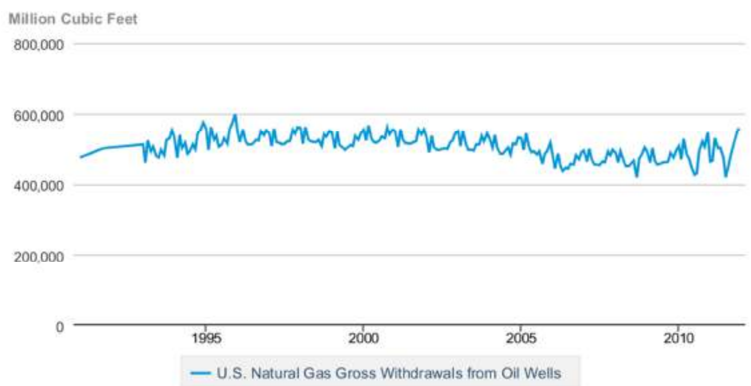


Figure 3.20 Statistics on the monthly production of associated gas in the U.S. stop in December 2011 (EIA, 2012).

Drilling carries and foreign investment

Some of the open literature often mentions that gas producers must continue to perforate new wells to receive drilling carries and hold the land. This is perhaps one of the most unorthodox reasons to explain the persistence of the U.S. gas glut, but some attention must be given to this point (Butler, 2012).

The term "drilling carry" refers to an accounting arrangement whereby one company acquires a working interest in another one by means of funding its drilling activity. As an example, CNOOC purchased interests in Chesapeake's leaseholds in Eagle Ford, in October 2010, for about US$ 1 billion, by means of drilling carries (Sreekumar, 2013).

Chinese companies alone have already invested about US$ 5.5 billion in U.S. tight oil and shale gas through joint-venture deals, according to data compiled by the EIA (Larson, 2013). Roughly, 20% of the US$ 133.7 billion invested in U.S. tight oil and shale gas from 2008 to 2012 came from abroad (Figure 3.21) and that would be enough to fund 3,300 unconventional wells in the USA.

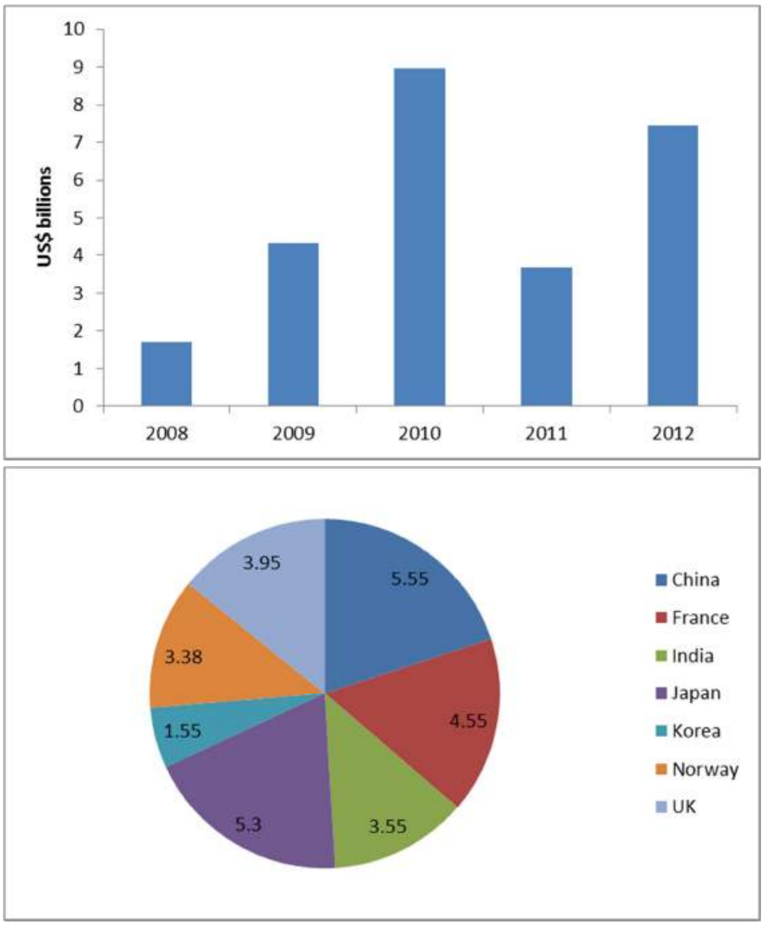


Figure 3.21 Foreign investment in U.S. tight oil and shale gas (data from Fawzi, 2013).

As can be seen, a significant part of the shale gas revolution was funded by foreign investment. These sponsors were not only interested in having access to a cheap and abundant supply of gas, which could eventually be exported from the USA, pending on a change of current regulations, but many of them were also interested in gaining access to the technology, and in developing partnerships that could help with the exploitation of the domestic resources available in their countries.

3.5 A fiscal system for unconventional gas

The significant differences that subsist between natural gas and oil businesses result in very different perspectives for investors, as upstream gas projects are typically much less robust than oil, for a number of reasons (Kellas, 2010).

The most important is perhaps the lower price that gas perceives. In addition to expensive LNG liquefaction, transport and regasification costs, or higher pipeline costs (larger diameters and more complex equipment are required for gas), it is not unusual to find regulated, subsidised prices in the domestic market of producing countries, which have to be compensated with higher government takes in exportation operations. Discounts as large as two thirds of the oil equivalent price can be found, which adds to the pressure and risks normally inflicted to oil investors (Kellas, 2010).

In addition to that, oil projects allow for a much faster recovery of costs, as their spot markets are much more developed than their gas counterparts. Typically, conventional gas production projects require long term contracts with a steady supply, while oil production can be easily accelerated at the early stages of production. This has a significant impact on the present value of the production, as indicated in Figure 3.22. Even if prices and costs were identical, the gas production would be a third less valuable than its oil equivalent.

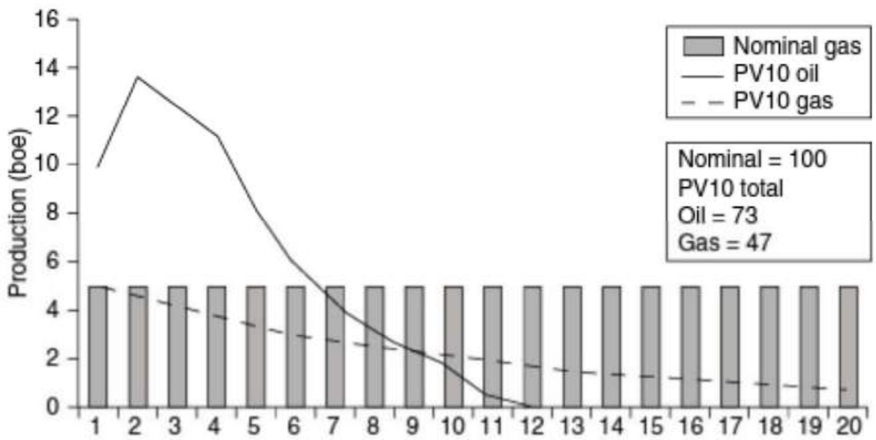


Figure 3.22. Gas upstream projects require long term supply contracts (Wood Mackenzie *apud* Kellas, 2010).

This characteristic is severely aggravated in case of unconventional gas, because of the production decay rates, which are extremely high. These facts must be considered in any master plan designed to maximize the gas rent of a given country. From the point of view of an investor, uplifted depreciations and a progressive system of profit taxations (in lieu of production royalties, for example) would be helpful.

3.6 Conclusions

Government take in the USA is the lowest among all countries investigated in this report. In spite of that, a number of fiscal benefits have been implemented there to further reduce taxes and encourage the production of oil and gas, which is a good example to be followed.

In addition to that, important differences between the production of oil and gas justify the adoption of distinctive sets of fiscal instruments for them, with a more intensive use of progressive instruments required for the production of natural gas.

Preferably these instruments should be based on profits in lieu of production rates, income revenues or their equivalents. Ideally, they should be designed to alleviate the cash flow during the first years of production, when investors are eager to recover theirs costs and pay their debts, in order to reduce their financial exposure.

The previous sections of this report have demonstrated that it vital to get the overall fiscal and regulatory framework right. In summary, the following could be recommended as good practices to fairly share risks and profits between governments and companies:

a) Reduce the relative importance of signature bonuses and area retention fees in the bidding processes;
b) Increase the relative importance of exploratory programmes and other instruments of economic and social development;
c) Consider realistic mechanisms to account for the individual items that compose the exploratory programme, and allow companies to demonstrate higher than expected costs in order to receive higher exemptions;
d) Replace royalties and other instruments based on production rates or income revenues by progressive instruments based on profits, or use progressive royalty rates to exempt or reduce the relative incidence of royalties at the initial stages of production;
e) For marginal fields, consider mechanisms that allow efficient investors to maintain production, employment and tax collection (e.g. reduction of royalties);
f) Carefully select the relative importance of domestic content in the bidding processes, taking into account the actual capabilities of the local suppliers of equipment and services;
g) Allow the depreciation of assets before production starts, and consider the use of generous uplift allowances;
h) Although unattractive at a first view for investors, ring fencing is important to create equal opportunities and protect the government share;
i) Allow the recovery of abandonment costs in previous excises to increase the guarantees surrounding a proper decommissioning of production facilities;
j) Avoid too highly progressive taxation schemes that can cause gold plating of investment portfolios.

References

Barbosa D., Royalties: Use com Moderação, *Monitor IBP*, pp.2-3., January 2011.

Bloomberg Businessweek, Foreign Investors Help Fuel U.S. Shale Boom, April 22nd, 2013.

Brock H.R. *et al.*, Petroleum Accounting, 6th Edition, Professional Development Institute, Denton (TX), 2007.

Buttler J. J., Natural Gas Depressed by Associated Gas Production, http://seekingalpha.com/article/541421-natural-gas-depressed-by-associated-gas-production, April 2012.

Dieckel *et al.*, *Putting a Price on Energy: International Pricing Mechanisms for Oil and Gas*, Energy Charter Secretariat, 2007.

Duman R. J., *Economic Viability of Shale Gas Production in the Marcellus Shale; Indicated by Production Rates, Costs and Current Natural Gas Prices*, M.Sc. Thesis, Michigan Technological University, 2012.

El-Badrawy K. *et al.*, The Rovuma Basin: Transforming East Africa into a Global Energy Player, Oil and Gas Investor, E-91, Nov. 2012.

Fawzi A., Shale Gas and Tight Oil Development in the U.S., Poland and the Rest of World: Status and Outlook (2013).

Gupta N. *et al.*, Shale Gas: A Strategic Imperative for India, Deloitte, 2010.

Headwater Economics and Oklahoma Policy Institute, *Unconventional Oil and Natural Gas Production Tax Rates: How Does Oklahoma Compare to Peers?*, 2013.

IHS CERA, The Economic and Employment Contributions of Unconventional Gas Development in State Economies, 2012.

Inhofe J. M. et al., Oil and Gas Tax Provisions, *Letter of July 26 to the U.S. Senate Committee on Finance*, 2013.

Javid S., Harnessing the potential of the UK's natural resources: a fiscal regime for shale gas, HM Treasury, July 2013.

Jenkins J. *et al.*, New investigation finds decades of government funding behind shale revolution (The Breakthrough, 2011).

Kellas G., Natural gas: Experience and issues, *The Taxation of Petroleum and Minerals: Principles, Problems and Practice*, Daniel P., Keen M. and McPherson C. (ed.), Routledge, 2010.

Kemp A. G., Jones P. D. A., Progressive Petroleum Taxes and the 'gold Plating' Problem, University of Aberdeen, Department of Economics, 1996.

Kepes J. *et al.*, Gas prices, others factors indicate changes in North American/shale play fiscal systems, Oil & Gas Journal, 4 October 2011.

Kortchmar B., Petrobras Internal Report, 2013.

Matlock J.M., Nemirow L.E., Section 29 Credits – Appellate Practice: Telling the Right Story, Journal of Taxation, November 2004.

National Agency of Petroleum, Natural Gas and Biofuels (ANP), *Tender Protocol for Granting Concession Contracts for Exploration and Production of Oil and Natural Gas*, Brazil, March 2013.

Pereira A., Contratos de Partilha de Produção: Histórico e Modelos Internacionais, *Comissão de E&P*, IBP (2010).

Robertson H., First US Shale Stake for Gail India, Petroleum Economist, 29 September 2011.

Sieminski A., Outlook for shale gas and tight oil development in the U.S., Deloitte Energy Conference, 2013.

Sreekumar A., 2 Surprising Takeways from the Chesapeake-Sinopec Deal, www.dailyfinance.com, March 20th 2013.

Trifon J., North American Natural Gas: How did we get here and what's ahead?, World Gas Conference, CS 8.2, presentation 242, Kuala Lumpur, 2012.

Wood Mackenzie, The Future of Exploration Survey, 2012.

World Bank, *Natural Gas Rents*, http://data.worldbank.org/indicator/NY.GDP.NGAS.RT.ZS, 2012.

Appendices

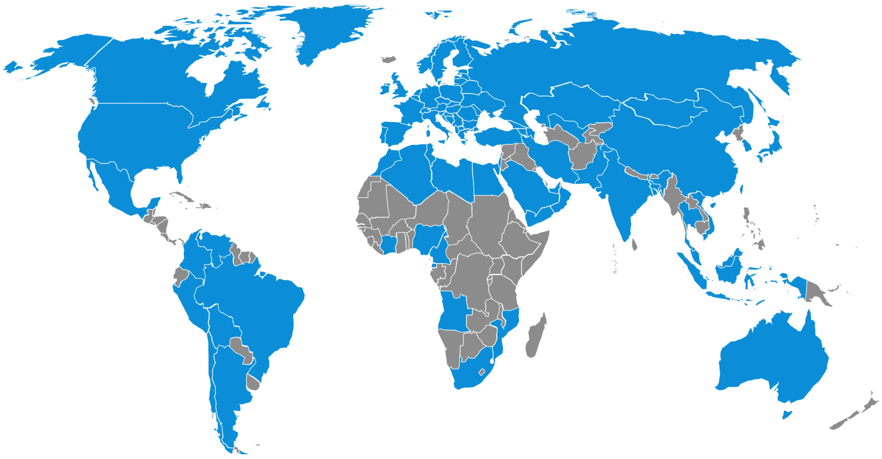
A List of Tables

B List of Figures

C Glossary and Acronyms

Excise	An inland tax on the sale or production of specific goods or activities
IOC	International Oil Company
JCT	Joint Committee on Taxation, U.S. Congress
NOC	National Oil Company
Reserves	Quantities anticipated as commercially recoverable and producible through the development of known accumulations. They can be proved (P1), probable (P2) or possible (P3).
Resources	Quantities deemed as technically recoverable from known or undiscovered accumulations. They can be contingent or prospective, respectively, if the accumulation is known or undiscovered.
Salvage value	The estimated market value of an asset at the end of its life.
Shale	A sedimentary rock formed by parallel layers of clay
Shale gas	Gas produced from shale formations
Shale oil	Oil produced from shale formations (requires cracking temperatures)
Schist	A metamorphic rock
Tax	An involuntary fee levied on corporations or individuals that is enforced by a level of government in order to finance government activities.
Tight gas	Gas produced from low permeability sandstones
Tight oil	Oil produced from low permeability sandstones

NOTES



The International Gas Union (IGU) was founded in 1931 and is a worldwide non-profit organisation promoting the political, technical and economic progress of the gas industry with the mission to advocate for gas as an integral part of a sustainable global energy system. The IGU has more than 142 members worldwide and represents more than 97% of the world's gas market. The members are national associations and corporations of the gas industry. The working organisation of IGU covers the complete value chain of the gas industry from upstream to downstream. For more information please visit **www.igu.org**

Address: Office of the Secretary General
c/o Statoil ASA, P.O. Box 1330, Fornebu, Norway

Telephone: +47 51 99 00 00
Email: secrigu@statoil.com
Website: www.igu.org