International Energy Agency

Natural Gas Liquids

Supply Outlook 2008-2015

Oil Industry and Markets Division

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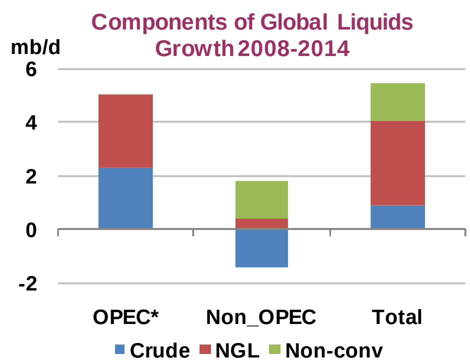
Summary

Global Natural Gas Liquids (NGL) production is forecast to grow by net 3.3 mb/d from 2008 to 2015, with 2.9 mb/d of the growth coming from OPEC and 0.4 mb/d from non-OPEC countries. Global incremental NGL production therefore represents a substantial contribution to total global liquids growth. According to the last medium term market update in December 2009, net additions of 3.1 mb/d of NGLs make up 60% of total liquids growth from 2008 to 2014, as illustrated in the graph, where OPEC crude capacity grows by 2.3 mb/d, non-conventional non-OPEC liquids grow by 1.4 mb/d and non-OPEC conventional crude decline by 1.4 mb/d. Most of the NGL growth stems from OPEC countries, notably Qatar, Iran, Saudi Arabia the UAE and Nigeria. Outside of OPEC, Russia and Kazakhstan will also see strong growth.

The level of expected growth in NGL supply has important implications for the global oil refining sector, since NGLs from gas processing plants will potentially displace refinery-sourced LPG or naphtha, while rising condensate supply will impact upon the quality of the refinery crude feedstock slate. Condensates can be spiked into a crude oil stream, effectively lightening and sweetening crude supply and they also have an important application in acting as a diluent for heavy, viscous bitumen and heavy oil export streams. More work is necessary to assess the impact on condensate demand and crude trade of that particular application. The development of dedicated condensate splitting capacity to distil petroleum products directly from condensate outside of the conventional refining sector is another trend which bears further analysis.



*OPEC crude is capacity additions

An important finding of this review has been that NGL output over the forecast period increases at a rate of 4.0%, while the marketed natural gas production increases by only 1.2%. As a consequence the liquids ratio (measured as NGLs in kb/d over dry gas in kboe/d) over the forecast period rises from 19.2% in 2008 to 23.3% in 2012, remaining at that level until 2015. How come that the natural gas apparently becomes more liquids-prone over 2008-2012? The report identifies four trends that will have a significant impact on liquids from gas globally. The first three trends drive increasing NGL supply, while the last has a negative impact on production levels. All four are examined in detail for main regions and countries:

1. The increasing scale of natural gas developments;
2. Increased utilisation of associated gas;
3. Wetter non-associated gas gradually replacing traditional dry, non-associated gas in some countries, among other reasons due to development of deeper reservoirs with high pressure and temperature;
4. The increasing replacement of wet associated gas by dry non-associated gas in some other countries.

The trend of increased utilisation of natural gas is to a large extent a result of measures to cut flaring of associated gas. The World Bank estimates that 140 bcm of natural gas was flared world-wide in 2008. Assuming that this natural gas had the average liquids ratio of 19.2%, this would imply that almost 0.5 mb/d of NGLs are being flared together with that gas. Since it is associated gas that is being flared, the volume is probably higher. Measures to reduce flaring of associated gas are behind a substantial part of the increased NGL production in Russia, Nigeria and Angola. NGLs are often developed as a part of a large scale gas development aimed at exports, but liquids from smaller-scale developments aimed at flaring reduction also hold the potential to substantially boost local consumption of LPG. In emerging economies, domestic sector use of LPG represents a logical early step away from reliance on traditional biomass fuels and enjoys the initial benefit of acting as a bridge before more costly natural gas distribution infrastructure is developed.

Large gas condensate deposits have been targeted for development by IOCs over recent years, and liquids in gas reservoirs have been developed relatively earlier than drier gas deposits as a way of maximising early project returns. The development of drier gas is a trend that will likely grow in importance in the longer term, although with less revenue from associated liquids, this will require the pricing of natural gas to better reflect marginal production costs.

Despite a substantial reworking of individual country data and projections, the aggregate result is a relatively minor 216 kb/d *downward* revision of the previous average MTOMR global gas liquids production estimates for the period 2008-2014 (all these comparisons are in relation to the MTOMR published in June 2009). Downward adjustments to OPEC forecast output averaged -339 kb/d, thus more than offsetting an upward adjustment of +123 kb/d to non-OPEC. In part, these revisions stemmed from a reassessed historical baseline production level. But in many cases, this reappraisal also resulted in a different trend for expected future production. Noteworthy changes to individual countries include Russia, where a higher baseline and more optimistic outlook have resulted in a substantially higher forecast production. Conversely, the outlook for the US, Canada and several key OPEC countries including Saudi Arabia, Kuwait, Algeria and Nigeria, were revised down.

This review reveals inconsistencies in reported data, which make an assessment of global liquids supply difficult, and presents specific recommendations for better definitions and reporting standards for NGLs, among others for data gathering and reporting for gas plant NGLs and field condensate separately and to establish GTL as a separate category.

The recent rapid development of non-conventional gas deposits in North America and elsewhere has fundamentally changed perceptions for global gas supply over the next decade. Although such unconventional sources of gas supply tend to be drier than their conventional counterparts, liquids content varies widely, so longer term NGL supply projections need to capture in better detail the likely associated liquids potential should large scale development of non-conventional gas deposits continue apace. While NGL and condensate development has implications that are most apparent for the midstream and downstream oil markets, it could also help postpone what is seen by some analysts as an inevitable global oil supply crunch in the medium term. Our own medium term market analysis already highlights that several future scenarios are possible, depending upon economic growth and oil use efficiency assumptions. NGLs, together with non-conventional oil supplies, and potentially rejuvenated OPEC crude capacity growth from countries such as Iraq, could also help change broader perceptions on the oil supply side in the coming decade.

Content and scope of report

NGLs make up a substantial component of global oil supply, yet are often under-reported or misrepresented in global oil balances. With the generous support of a voluntary contribution from Norway's Ministry of Petroleum and Energy, the Oil Industry and Markets Division (OIMD) has been able to review its existing data sources and methodology and to take a more systematic look at prospects for global NGL supply in the context of evolving natural gas production and liquids extraction capability. This report aims to:

- Give an in-depth review of condensate and other NGL data and forecasts by the OIMD;
- Clarify the terms and definitions for NGLs used by the IEA's Oil Market Report (OMR) and Medium-Term Oil Market Report (MTOMR) and IEA statistics and publications in general;

- Highlight issues concerning data quality on NGL production and use;
- Improve the NGL supply reporting and forecasts in the OMR and MTOMR, providing a 2008-2015 supply forecast and analysis of implications for the market.

To this end, after setting out definitions and methodology, this report reviews the NGL data currently included in the OMR/MTOMR. This report aims to raise awareness of existing inconsistencies in reporting of crude, condensate and other NGLs and, by suggesting common definitions, to encourage more consistent reporting practices.

To provide an updated supply forecast, this report took account of existing data and information sources, including official data submitted to the IEA by member countries, but also an updated IEA gas production forecast aligned to that contained in the World Energy Outlook 2009, and other market intelligence. The report also undertook an analysis of the midstream, attempting to gauge NGL capacities by examining gas processing facility capacity.

Future work

It will be important to sustain the analytical capability within OIMD which allowed production of this report. While the majority of the work on this study was undertaken by a secondee from Statoil, it will be important to ensure that the in-depth monitoring of gas supplies and gas liquids extraction capability is continued. The VC which enabled this report's production facilitated subscription to several new market intelligence sources, and resources will need to be dedicated to ensuring that OIMD can continue to access these sources.

The disparate nature of sources of future gas supply growth, with variable gas liquids content suggests that more detailed work on sources and characteristics of future gas supplies is required. Greater disaggregation between associated and non-associated gas supplies, and distinction between conventional and non-conventional gas, plus segregated reporting of non-conventional gas production by type would all help add granularity to NGL supply forecasts in future.

Consideration needs to be given to the segregated reporting of gas plant NGLs and gas condensate in IEA and JODI data. Similarly, national statistics should more clearly define and separate, where possible, the volumes of gas condensate that are included in reported crude oil supply. Inevitably, it will remain difficult to accurately capture volumes of spiked condensate, where these volumes are blended with crude oil. However, when gas condensate is processed or sold separately, it should wherever possible also be reported separately.

Greater study of the implications of higher condensate volumes within the global refinery feedstock slate for oil products supply should be undertaken. This needs to be tied in with deeper analysis of changing regional/global feedstock slates in general, and the currently prevalent analytical perception that medium gravity/sulphur feedstocks are being supplanted by lighter/sweeter grades at one end, and by heavier/sourer grades at the other.

Changing gas liquids plant availability will also have major implications for global/regional oil products markets, notably for naphtha and refinery-sourced LPG, and for the petrochemical sector in particular. Integrating more fully OIMD's oil product demand analysis, with its refinery supply analysis to capture changes within the petrochemical sector would be a valuable addition to market understanding.

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1 Definitions

1.1 Component parts of OMR NGL data

Natural gas liquids (NGLs) are light hydrocarbons that are dissolved in associated or non-associated natural gas in a hydrocarbon reservoir, and are produced within a gas stream. They comprise ethane, propane, butane and isobutene (collectively LPG), pentane-plus and gas condensate, i.e. molecules with 2-8 carbon atoms (C_2H_6- C_8H_{18}). Above the ground the rich gas stream is unstable, as heavier components will *condense*, while lighter components normally remain gaseous, and will have to be separated from the dry gas in a gas processing plant (GPP). Hence, there are two categories of NGLs - condensate and other NGLs. As condensate has many characteristics that make it different from other NGLs, it is useful to distinguish between the two.

Many companies and oil producers report NGLs together with other kinds of "other oil", that may include Gas-to-Liquids (GTL), mined synthetic crudes or biofuels. This review is restricted to condensate and other NGLs, and excludes all kinds of other oil. When we say that NGLs will come from a GTL project, we refer to the volumes of NGLs that are extracted from a rich gas stream to prepare a dry gas stream that will subsequently be processed to produce GTL, comparable to the NGLs that come out of an LNG project, which are the NGLs that are extracted from the rich gas to prepare the dry gas that is subsequently liquefied.

Field (or lease) condensate is a stable liquid consisting of hydrocarbons of C_5+ which is separated from the rich gas stream at the field processing centre. It shares many of the characteristics of a light crude oil with API gravity above 50° and can be transported like crude oil. NGLs other than field condensate are the components that are split out from the rich gas stream in a gas processing plant (GPP), and can be fractionated into gas plant ethane, propane, butane, isobutane, pentane and naphtha (or pentanes plus), as well as gas plant condensate. Because these components are extracted at a GPP we may refer to them as gas plant liquids. Condensate and other natural gas liquids differ in the way they are extracted, reported, transported, stored and marketed. Note that condensate may be extracted at the field or at a gas processing plant. This will often influence how it is reported. We often talk about condensate and other NGLs. In that case both field condensate and gas plant condensate is included in the condensate concept, while other gas plant liquids are included with the term "other NGLs". Note that ethane is not always extracted from the gas stream, but will often partly be left in the dry gas, as might also minor elements of LPG. In that case ethane and other heavier components are counted together with dry gas and not together with NGLs, i.e. only separated liquids are included in our NGL concept.

For OPEC countries the OMR reports all condensate and other NGLs separately from crude oil, partly stemming from the practice of OPEC producers to set production targets for crude oil, excluding condensate and other NGLs.

For non-OPEC countries OMR NGL estimates generally include only gas plant NGLs. For some countries field condensates are included as well, according to the way the condensate and other NGLs are reported by official sources. Often condensate production volumes are reported together with other crude oil volumes if the condensate in question is field condensate that is blended (spiked) into crude oil and transported as a blend, however some countries report condensates separately even though it is transported together with crude oil. The table below shows to which extent we report condensate in our NGL figures for non-OPEC countries. For many countries we are not certain whether the reported condensate is only gas plant condensate, or if it includes some field condensate as well. All the condensate volumes for non-OPEC that we have identified, but that we do not include within our OMR figure, are field condensate.

It is important to be aware of this inconsistency when comparing reported NGL production and the ratios of NGL to gas production (the so-called liquids ratio) among countries. For example the NGL forecast for Saudi Arabia in 2015 is 1.8 mb/d, while the forecast for the USA is 1.7 mb/d. However, the NGL figure for the USA does not include field condensate, which is included in crude oil volumes, while for Saudi Arabia the reported level aims to include an estimate of all condensate within the NGL figure.

2008 NGL production by category and reporting practice

(thousand barrels per day)

		Condensate	Other NGLs	Total OMR NGL figure	% of OMR figure that is condensate	Estimate of condensate included in OMR crude oil	Total NGL including estimate of condensate reported with crude oil	% of total NGL estimate that is condensate
Non-OPEC								
OECD	Netherlands		9	9	0%		**9**	0%
	Norway	251	275	527	48%		**527**	48%
	United Kingdom	37	179	215	17%		**215**	17%
	Canada	30	669	699	4%		**699**	4%
	Mexico		365	365	0%	54	**419**	13%
	United States		1,781	1,781	0%	470	**2,251**	21%
	Australia		74	74	0%	140	**214**	65%
Africa	Egypt	135	70	206	66%		**206**	66%
	Equatorial Guinea	48	17	65	73%		**65**	73%
	Tunisia		2	2	0%	6	**8**	76%
Asia	China			-		100	**100**	100%
	India		113	113	0%	45	**158**	29%
	Indonesia	115	31	146	79%		**146**	79%
	Malaysia		65	65	0%	100	**165**	61%
	Thailand	85	85	170	50%		**170**	50%
Latin America	Argentina		125	125	0%		**125**	0%
	Bolivia		7	7	0%		**7**	0%
	Brazil		86	86	0%		**86**	0%
	Peru	-	43	43	0%		**43**	0%
	Trinidad & Tobago		38	38	0%		**38**	0%
Middle East	Bahrain		10	10	0%		**10**	0%
	Oman	80	3	83	96%		**83**	96%
	Syria		35	35	0%		**35**	0%
	Yemen		18	18	0%		**18**	0%
FSU	Azerbaijan	41	1	42	98%		**42**	98%
	Kazakhstan	271	34	305	89%		**305**	89%
	Russia	356	180	536	66%		**536**	66%
	Turkmenistan	2	5	7	30%		**7**	30%
	Uzbekistan	53	7	59	89%		**59**	89%
Countries not included in the study			247	247		**-**	**247**	
Total non-OPEC		**1,502**	**4,575**	**6,077**	**25%**	**915**	**6,992**	**35%**

World Supply of Condensate and other NGLs 2008-2015

(thousand barrels per day)

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015	Compounded annual growth
Non-OPEC										
OECD North America	2,846	2,911	2,802	2,762	2,744	2,726	2,708	2,691	(154)	-1%
OECD Europe	767	737	735	728	733	720	705	692	(76)	-1%
OECD Pacific	91	95	100	104	108	111	116	120	29	4%
Total OECD	3,704	3,743	3,637	3,594	3,584	3,557	3,529	3,503	(201)	-1%
FSU	975	1,049	1,084	1,180	1,289	1,316	1,344	1,380	406	5%
Non-OECD Europe	15	15	14	14	13	12	10	9	(6)	-6%
Asia	647	660	692	714	759	793	797	792	145	3%
Africa	282	283	280	280	283	285	288	291	9	0%
Middle East	146	160	175	178	178	179	181	183	36	3%
Latin America	308	326	328	335	343	351	360	369	61	3%
Total non-OECD	2,373	2,492	2,573	2,701	2,866	2,937	2,981	3,023	650	4%
Total non-OPEC	**6,077**	**6,236**	**6,210**	**6,295**	**6,449**	**6,494**	**6,510**	**6,526**	**449**	**1%**
OPEC										
Middle East OPEC	3,202	3,305	3,964	4,716	4,997	5,231	5,402	5,534	2,332	8%
Other OPEC	1,126	1,277	1,428	1,487	1,558	1,594	1,658	1,671	545	6%
Total OPEC	**4,328**	**4,582**	**5,392**	**6,203**	**6,555**	**6,825**	**7,060**	**7,205**	**2,876**	**8%**
Total World Condensate and other NGLs	**10,405**	**10,818**	**11,602**	**12,498**	**13,005**	**13,320**	**13,570**	**13,731**	**3,326**	**4%**

World Supply of Condensate and other NGLs revisions compared to MTOMR June 2009

(thousand barrels per day)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Non-OPEC	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
OECD North America	-	-	1	27	24	54	(76)	(158)	(218)	(283)	(349)
OECD Europe	(6)	(8)	(14)	(2)	(11)	(3)	19	41	68	82	92
OECD Pacific	-	-	0	-	-	2	(4)	(15)	(16)	(17)	(17)
Total OECD	(6)	(8)	(12)	25	13	53	(62)	(132)	(166)	(218)	(275)
FSU	84	82	79	83	102	199	201	183	281	310	339
Non-OECD Europe	-	-	-	-	-	-	-	1	1	1	1
Asia	(16)	(9)	(24)	(28)	(28)	(37)	(27)	(12)	(27)	1	10
Africa	18	40	31	36	34	27	16	11	8	5	1
Middle East	(0)	(5)	(7)	(6)	(1)	8	18	20	20	18	16
Latin America	30	30	21	12	13	9	(7)	(19)	(20)	(17)	(12)
Total non-OECD	115	137	100	96	121	206	201	184	263	318	355
Total non-OPEC	**109**	**130**	**88**	**121**	**134**	**259**	**139**	**52**	**98**	**100**	**80**
OPEC	-	-	-	-	-	-	-	-	-	-	-
Middle East OPEC	(13)	15	40	33	46	(228)	(353)	(185)	(174)	(95)	(114)
Other OPEC	(210)	(244)	(291)	(323)	(338)	(321)	(237)	(143)	(84)	(87)	(61)
Total OPEC	**(223)**	**(230)**	**(251)**	**(290)**	**(292)**	**(550)**	**(590)**	**(329)**	**(258)**	**(183)**	**(175)**
Condensate and other NGLs	**(114)**	**(100)**	**(163)**	**(169)**	**(158)**	**(291)**	**(451)**	**(276)**	**(161)**	**(83)**	**(95)**

1.2 Natural Gas Liquids and the Gas Value Chain

The term Natural Gas Liquids (NGLs) is confusing, and the many different definitions used are reflected in the wide variance in the way NGL figures are reported across sources. For the sake of precision, it is necessary to take one step back and reflect over the value chain of NGL from the well to the market. How are NGLs produced, where do they go and how do they end up as petroleum products? Within the country by country analysis section of this report, real life NGL value chains across the globe are described.

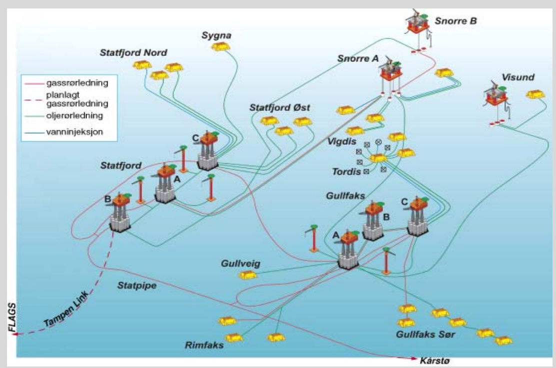
All words in bold in this section are defined in section 6 – Glossary.

Considering an oil well with associated natural gas production, or a non-associated natural gas well located at a field, in an onshore or offshore basin in a producing country, the hydrocarbons that flow from the well are an unstable mix of various hydrocarbon molecules, some of which would vaporise and create pollution, a security hazard and a loss of potential income if simply vented into the atmosphere. Often well streams also contain water or other non-hydrocarbon elements that in some instances need to be removed before the well stream can be transported away from the field. Streams from several wells will be led into separators at the field, or well streams will be gathered from many fields and transported into a central processing facility.

A field processing centre can vary in sophistication, and the need for processing will depend on the composition of the hydrocarbon stream. Mostly, the processing facility will split the well stream into water, stable liquids and rich gas, and connect with further transportation solutions. A rich gas stream is a stream of hydrocarbon molecules, each with one to eight carbon atoms that exist in a gaseous state at underground pressures, but where some of the hydrocarbons might condense, i.e. become liquid at atmospheric pressure, hence the term condensate.

Gas gathering from well stream to processing plant – an illustrative example

In the case of the Statfjord Satellites on the Norwegian Continental Shelf, the well streams from the three satellite fields Statfjord Nord, Statfjord Øst and Sygna, all of them developed via subsea templates, are fed to the inlet separator of the Statfjord C platform together with output from the Statfjord field itself.



Source: Norwegian Petroleum Directorate

At the field processing facility at the platform oil, gas and water are separated. Water is cleansed and pumped back into the sea, oil is stored at the platform and loaded onto shuttle tankers, while the rich gas is gathered together with rich gas streams of many North Sea fields and fed via the trunk line Statpipe to the natural gas processing plant onshore at Kårstø or through FLAGS to St Fergus. Here the rich gas is split into dry sales gas that is sold on the European gas market, while the NGLs are fractionated into ethane, LPG and condensate and sold on the global market.

The liquids may be transported relatively easily, directly from the field, on shuttle tankers, in oil pipelines, on rail car or by other economic routes. The liquids from the well are said to be 'stable' because the components in the liquid are practically all liquid under atmospheric pressure and prevailing surface temperatures. In molecular terms this means hydrocarbons of the type pentanes and higher (C_5+). Pentanes are molecules with five carbon atoms surrounded by hydrogen atoms. The more carbon atoms a hydrocarbon molecule has, the heavier it is. The "heaviness" or density of a liquid or the gravity of the liquids is measured by API gravity. As API gravity is inversely proportional to the specific gravity (SG), the higher the API gravity number, the lighter the liquid. Basically API gravity is a measure of how heavy a given volume of this liquid is compared to the same volume of water, and is calculated by the formula *API gravity = (141.5/SG) - 131.5*. A condensate with an API gravity of 50° has a specific gravity of 0.78, i.e. a litre of condensate will weigh not more than 0.78 kilogram.

A liquid with an API gravity of 50° API or higher, can be characterised as a **condensate**. Condensate recovered at field level does not differ much from other crude oil seen from a processing and transportation perspective, and is referred to as **field condensate**. Field condensate is the same as **lease (or licence) condensate**. A company or country will often report the volumes of field condensate together with other crude oil. The condensate will often be blended into other crude oil, frequently enhancing the quality of the blend for refiners. In such cases the condensate is known as **spiked condensate**. Alternatively, the field condensate might be transported as **segregated condensate** and sold to purpose built **condensate splitters**, **petrochemical facilities,** or used for **dilution of bitumen**, a technology that facilitates the pipeline transportation of otherwise highly viscous oils.

Unlike crude oil and field condensate, a rich, or 'wet', gas stream will always require transportation in pipelines, and therefore more investment in infrastructure. If no such infrastructure exists, associated gas streams are sometimes re-injected to the reservoir, flared or vented. Where it exists, pipeline infrastructure will lead to a **gas processing plant** where the stream will be split into **dry gas** and **natural gas liquids**. From an NGL perspective, this process is referred to as **NGL extraction**. Ideally it would be best to report the volume of NGLs produced at the very point of extraction, as this is the point in the value chain where the NGLs exist as a discrete entity. At this point of the value chain the NGLs are comparable to crude oil or condensate; a raw material ready for processing into petroleum products. While the processing into petroleum products of condensate is referred to as condensate splitting, and for crude oil is referred to as refining, for the NGLs the processing into petroleum products is referred to as **fractionation**.

The natural gas that is now stripped of NGLs is referred to as **dry gas** and consists mainly of **methane (CH_4).** Some non-associated gas is already dry when it comes out of the well, as the stream contains little more than methane. The dry gas might need further processing or purification in order to meet the **sales gas specification** in a market. The sales gas has to be transported further to markets in pipelines or be liquefied by cooling to **liquefied natural gas (LNG)** to enable transportation on LNG tanker vessels. Natural gas might also be transported as **Compressed Natural Gas (CNG)**. Dry gas might also be transported directly from the natural gas processing plant to a methanol factory, a petrochemical facility or a nearby gas power plant. This means that the dry gas often requires further investments in infrastructure in order to be monetised. Depending on the volumes produced and the proximity to markets the marketing of dry gas might or might not be deemed economically viable. Therefore the dry gas is sometimes at this point re-injected into the reservoir or to another oil reservoir to support the reservoir pressure to increase the recovery rate for oil. In some instances the gas is also flared.

NGLs are normally extracted from a rich gas primarily to obtain a dry gas that meets **sales gas** criteria, but also for the purpose of monetising the valuable heavier components in a rich gas stream. An **NGL fractionation** plant may be integrated with an NGL extraction plant. The NGL may be extracted at various field centres and gathered via long NGL pipelines to centrally located NGL fractionation plants. Often such fractionation plants will be located close to LPG export terminals or petrochemical facilities. In fact petrochemical complexes and NGL fractionation facilities or condensate splitters are frequently combined. The products of NGL fractionation are typically **LPG**, **ethane (C_2H_6)**, **gas plant naphtha**, **pentane (C_5H_{12})** and **gas plant condensate**. LPG is a common term for **propane (C_3H_8), butane (C_4H_{10}), isobutane** or any mix of those. The gas plant condensate is again a "raw product" that is sold for the same applications as field condensate. Alternatively, gas plant condensate may be directly fractionated into naphtha, gasoline and other petroleum products at the fractionation plant, so that no condensate as such is sold from the plant.

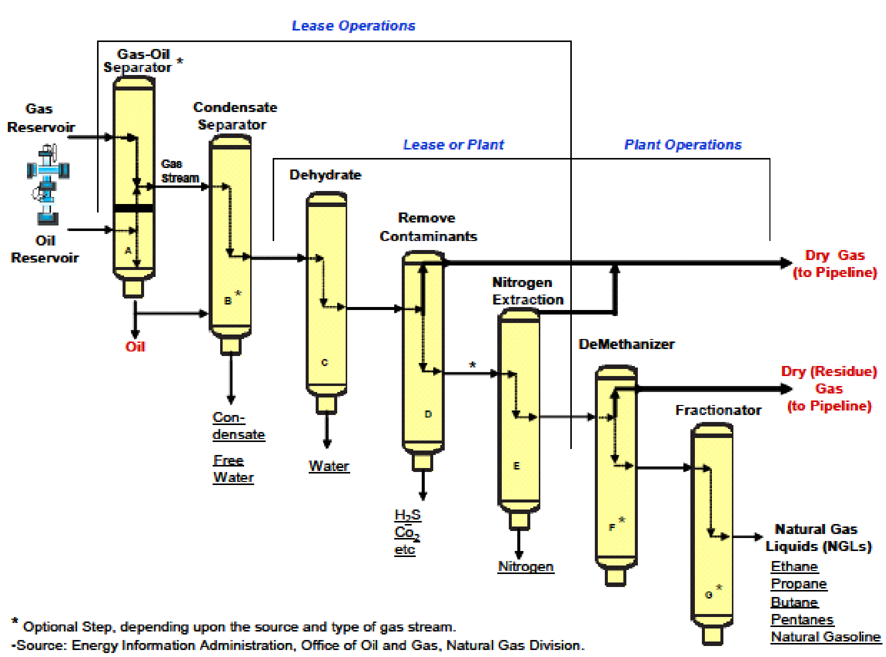
1.3 Is condensate a Natural Gas Liquid?

The inclusion of condensate alongside other gas liquids rests on three key analytical principles. Firstly field condensates are liquids that typically come with a natural gas stream, even though some gas condensate fields produce little associated natural gas. Secondly, field condensate has the same chemical composition and is put to the same use as gas plant condensate, so any division between these sources would be an artificial one dependent merely on the field separation facilities as opposed to liquid quality. Thirdly, from an analytical standpoint it is important to distinguish between condensates and crude oils produced by OPEC member countries. Calculation of OPEC crude production quotas by the OPEC secretariat and member states has historically tended to exclude gas condensate. Wherever possible, IEA data therefore attempt to separate condensate production by OPEC countries from crude production, reporting the condensate together with other NGLs. Within IEA oil market balances, crude production capacity, along with condensate and other NGL production are forecast. Yearly, quarterly or monthly levels of crude production by individual members are not, but rather are represented in aggregate terms by the implied 'call on OPEC crude and stock change'. For non-OPEC countries on the other hand, field condensate is often reported along with crude production, and often blended in with crude at or near source. The Oil Market Report (OMR) reports field condensate along with NGLs for those countries that split it out in a transparent and consistent way. Inevitably however, it is not always possible to segregate condensate production from reported crude volumes, leading to a degree of inconsistency within IEA and other sources of market data in the way that crude and NGL are categorised and reported. One aim of this report is to raise awareness of the inconsistencies in the reporting of crude, condensate and other NGLs and, by suggesting common definitions, to encourage more consistent reporting practices, involving ideally gas plant and field condensate reported separately and also information on the degree to which condensate is spiked or segregated.

1.4 NGLs and gas processing

Before natural gas can be used it is processed to remove impurities, to extract valuable components like propane, butane and ethane, and to ensure the production of consistent quality dry gas. The processing of natural gas works on the same principle as the refining of oil, where the different boiling points of the gas components facilitate their separation.

Natural Gas Processing: The Crucial Link between Natural Gas Production and Its Transportation to Market



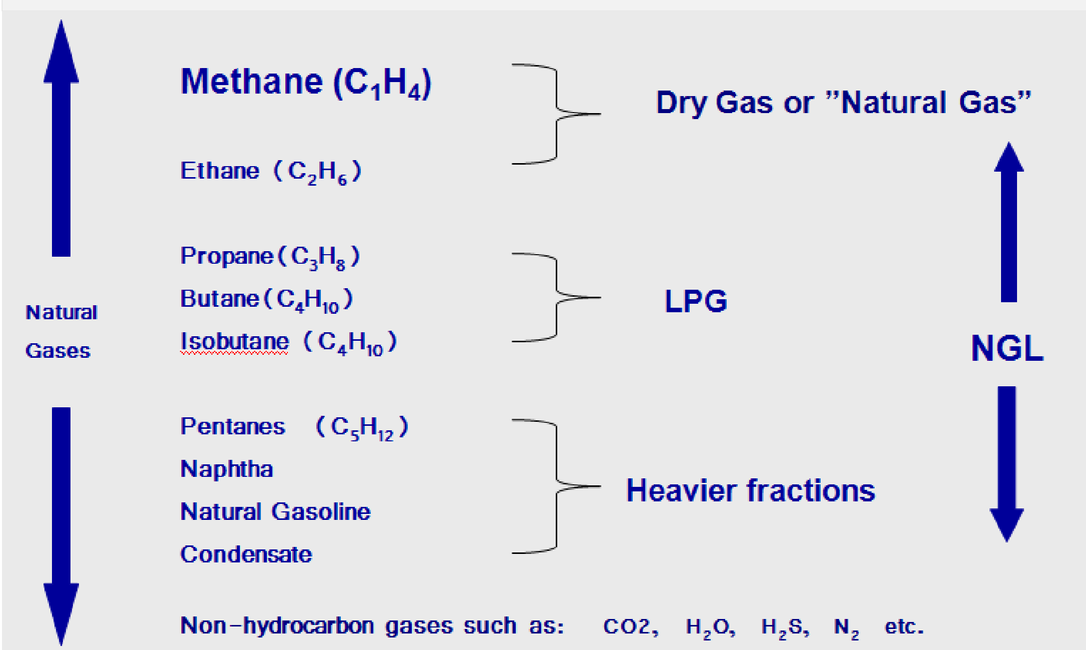
The illustration above is sourced from "Natural Gas Processing: The Crucial Link between Natural Gas Production and Its Transportation to Market", published by EIA in 2006. The illustration distinguishes between lease, or field, operations and plant operations, and highlights the fact that gas processing starts at the wellhead, and that different steps in the process from wellhead to petroleum products can take place at field level or at a gas plant given the characteristics of the gas and the equipment.

In step one the well stream from a gas or an oil reservoir enters an inlet separator where oil is separated and then transported to a refinery, while the gas continues to a separation process where the condensate is split out. The rich gas stream may now be transported to a gas plant for dehydration, removal of contaminants, and nitrogen extraction or those steps may be undertaken at the field. Contaminants that are removed are typically CO_2 and hydrogen sulphide (H_2S), but also metals, sand and other solids that could be detrimental to the pipelines or other equipment. In the demethaniser the methane, or dry gas, is split out and can move on to an export pipeline or to field-reinjection. The dry gas has to be compliant with the sales gas specification (spec) in the market. The spec will regulate the calorific content, acidity, dew point and other characteristics of the gas. The NGLs go to a fractionator where NGLs are split into ethane, propane, butane, isobutane, pentane, natural gasoline and gas plant condensate. The fractionator might be a separate plant or integrated with the gas plant. The NGLs are not the only by-products of gas processing. CO_2, sulphur and helium may also be extracted from the rich gas stream and disposed or marketed.

The separation and fractionation processes depend on the fact that various hydrocarbon components have different temperatures at which they vaporise, and the boiling point also depends on the pressure in the container. For example, propane and butane can be drawn off as liquid when natural gas is cooled to -42°C. To obtain ethane, the natural gas has to be further cooled to -89°C, the temperature at which ethane turns into liquid. By controlling the pressure and temperature in the container different fractions will separate and be removed.

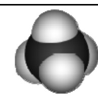
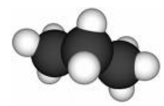
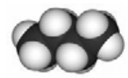
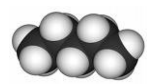
The illustration below summarised the definitions of dry gas, NGLs and other natural gases.

Definition of dry gas, NGL, LPG and non- hydrocarbon gases



The table below summarises the chemical connotations, molecular structure and boiling points at atmospheric pressure of the natural hydrocarbon gases from methane to pentane.

Natural hydrocarbon gases from methane to pentane

Name	Chemical denotation	Illustration	Boiling point
Methane	**C_1H_4**		-161.6°C
Ethane	**C_2H_6**		-88.6°C
Propane	**C_3H_8**		-42.1°C
Butane	**C_4H_{10}**		-0.5°C
Isobutane	**C_4H_{10}**		-11.7°C
Pentane	**C_5H_{12}**		36.1°C

1.5 Characteristics of, and markets for, NGLs

NGLs can be sold together with methane to, for example, power plants, or they may be destined for petrochemical or fertiliser production together with methane or they may be split out and commercialised as LPG or other products. LPG is a common term for propane, butane and isobutane or any mix of those components.

The products from gas processing plants are for most practical purposes identical to the light ends that come out of oil refining. IEA statistics estimates that 56% of global LPG and ethane production came from gas processing plants in 2007, while refineries accounted for the remaining 44%. The share of naphtha from gas processing plants was 4%. If we talk about gas plant liquids and refinery LPG and ethane alike we may refer to all of it as "**gas liquids**", as opposed to the term "natural gas liquids" that include only the liquids that we derive from natural gas.

NGLs require specialised transportation and handling up to the point of consumption. They are transported refrigerated or under pressure. LPG is highly combustible and has other characteristics that make it hazardous to handle. LPG will spread readily at ground level, and may infiltrate, for example, sewage or water systems in urban areas, generating a risk of wide-scale explosion. There have been several serious accidents in the history of LPG that have caused many fatalities and material damage. Components of LPG such as butanes and isobutanes may also be used as a blendstock for gasoline to improve fuel combustion performance. However, its use in this way is restricted during summer months and in high temperature areas because of the adverse impacts of evaporative emissions. For the reasons of evaporation and combustion risk, the transport and handling system for all LPG components has to be carefully designed and maintained. NGLs also need specialised storage facilities that comply with the safety imperatives of this fuel. However, once LPG is loaded into pressurised bottles or canisters it can be readily transported and used with little further need for infrastructure. LPG bottling plants are very simple facilities that require little investment.

LPG is a clean and efficient fuel, with a relatively low carbon footprint compared to oil in general because the molecules have relatively many hydrogen atoms to each carbon atom, ensuring a more complete combustion of which the "waste" is partly water. LPG also contains few or no contaminants so that emissions of SO_2 and NO_x gases are absent or negligible. LPG can compete with natural gas as a heating and cooking fuel, but with the advantage of requiring much less expensive infrastructure to distribute it to the residential or commercial market. There is massive growth potential in areas where biomass is currently used, notably in Africa. The middle distillate cut kerosene (or 'paraffin') is also a substitute for biomass in this way. As economies develop further, as for example China, India and Egypt, a switch to natural gas frequently takes place, at least in urban areas, while LPG (or kerosene) may still play a role in rural areas. In developed countries LPG is frequently used for camping and for heating in secondary or temporary holiday homes.

About half of global LPG demand comes from residential and commercial markets for heating and cooking in homes and businesses. LPG and natural gas are substitutes for each other in the residential and commercial sector, largely on a sequential basis. Typically as the energy economy evolves, infrastructure investments lead to the replacement of LPG (or kerosene) with natural gas. We therefore often see a pattern of a developing country first replacing biomass with LPG or petroleum fuel, and then replacing LPG with natural gas. Therefore, in the short and medium term, baseload demand from the residential-commercial sector is relatively insensitive to price.

The balance of the LPG market is highly sensitive to changes in LPG pricing due to high degree of fuel substitution. As feedstock to the petrochemical sector naphtha, LPG and natural gas are substitutes for each other in the manufacture of **olefins** and fertilisers. In the transport sector gasoline and LPG are potentially substitutes, although a vehicle would have to be fitted with an engine that can handle LPG instead of gasoline, and an LPG distribution network would have to be developed before widespread substitution could take place. On an economic basis therefore, transport fuel switching is at a much less developed stage than in the petrochemical sector.

On a long-term basis, global storage for LPG is quite limited. Apart from the USA, and especially the Mt Belvieu storage facility in the Gulf of Mexico, few locations around the world have a large amount of excess primary LPG storage capacity. Because LPG is a by-product, it is difficult to regulate global LPG production in response to oversupply. Consequently, when regional market supplies exceed baseload demand, LPG prices usually begin to fall relative to other petroleum products. The LPG market is typically cleared by price-sensitive olefins producers who can substitute LPG for other feedstock. These petrochemical companies switch opportunistically as prices come under downward pressure during periods of oversupply for the premium LPG markets.

1.6 Evaluating midstream investments

A consequence of the volatility of NGL prices is that the profitability of the NGL business, in particular natural gas processing, is also very volatile and difficult to predict. Therefore planned gas processing projects can often take considerable time to move from the drawing board to completion and start-up. Condensate is generally easier to monetise, and plans to install condensate production capacity can therefore arguably be realised on a more predictable timeline than other NGL extraction and fractionation plans. Midstream investments are also very difficult to evaluate from a financial point of view. The costs of developing segregated storage and shipment infrastructure have to be balanced against the value of monetising differentiated products at a time when multiple projects are competing for funds in an integrated oil company. Below is a list of factors that may drive decisions to invest in different configurations of midstream infrastructure:

1) *Large scale gas developments, either for major LNG or pipeline export projects or wide scale "country-wide gasification" projects.*

   Gas from one large field or multiple gas fields are needed to fill an LNG plant over its lifetime. Sales gas needs to meet certain quality specifications, and the existence of feed gas of various qualities will necessitate the construction of gas processing plants and a plan for the handling of NGLs. As harbour facilities are required to export the LNG, facilities for handling of **Very Large Gas Carriers (VLGC)** tankers may be built without adding too much cost.

2) *Companies specialising in midstream investments that all upstream operators benefit from.*

   In the USA specialised midstream companies dominate gas processing. Therefore natural gas can be processed in an efficient way even though the number of field operators is very high. Specialised midstream companies in Alberta, Canada have also developed systems to collect associated gas from multiple oil sand/ bitumen production sites, illustrating how this market structure can foster innovation and competitiveness.

3) *A gas processing centre that works as a hub for an entire producing country or region,*

   Some countries like Saudi Arabia and Algeria have country wide systems for gathering associated and non-associated gas, with pipelines connecting the infrastructure in the whole country from well to export terminals or points of domestic consumption. The country-wide system in Saudi Arabia is referred to as the Master Gas System.

   In countries with multiple unrelated producing, consuming or exporting regions, regional gas master systems may exist. In Australia, many gas producers in the Gippsland basin in the South East utilise the same gas plants, all gas producers in the onshore Cooper basin in the mid-East utilise another plant, while the Karratha gas plant process gas from various gas fields on the North West Shelf.

4) *An integrated system that is regulated like a natural monopoly*

   The Norwegian Continental Shelf benefits from an integrated transport and processing system where large trunk pipelines feed gas from multiple fields to central complexes for processing, and then to export pipelines or centrally located gas processing plants onshore. Ready third party access to processing and shipment infrastructure is a crucial component of this system, and a company jointly owned by the oil companies (Gassled) owns the infrastructure and coordinates investments, and prices are set by regulated tariffs.

2 Methodology

2.1 *Baseline revision*

Before setting out expected NGL production levels for the future, this review has involved a comprehensive review of existing and new sources of historical NGL supply data. NGL supply estimates contained in the IEA's Oil Market Report (OMR), Medium Term Oil Market Report (MTOMR) and Monthly Oil Data Service (MODS) have traditionally comprised a combination of monthly submissions from member countries (Monthly Oil Statistics (MOS)) for the month M-2, annual non-OECD data submissions with a 1.5 year time lag and monthly JODI data, typically with a time lag of at least M-1. These officially reported and fairly aggregated data have traditionally been augmented by data and information from other national, company-specific and market intelligence sources.

However, significant variance exists for reported NGL data between publicly available sources, frequently for the same country. Differences in definition (inclusion or exclusion of ethane, condensate etc) account for much of this variance. Variable conversion factors in instances where original data have had to be converted from mass or energy content into volume is also a factor. The reporting of components of NGL production alongside or as a part of natural gas, or refining sector data has also proved problematic. The general rule is that gas plant liquids are included with the NGL figures reported to the IEA by member countries, while the field condensate is reported along with the crude. However, there are exceptions to this rule, notably for Norway for which also spiked field condensate is included in the total NGL figure quoted by the OMR. The support provided for this project by the Norwegian government has also allowed OIMD to subscribe to a variety of new market intelligence sources which will allow more detailed cross-checking of monthly and annual supply estimates in future.

In aggregate, our attempt to verify and harmonise prevailing OMR/MTOMR/MOS NGL production estimates with third-party sources has resulted in revisions for 2007 and 2008 amounting to:

- Downward revisions of 169 and 158 kb/d globally;
- Downward revisions of 290 and 292 kb/d for OPEC countries and;
- Upward revision of 121 and 134 kb/d for non-OPEC countries.

Of the non-OPEC revision of 134 kb/d for 2008, 121 kb/d accrue to non-OECD countries and 13 kb/d to OECD countries, highlighting that data availability, timeliness and quality remains an issue when estimating non-OECD energy supply/demand.

2.2 *A midstream approach*

In order to verify aggregate production data and to assess the outlook for a given country or region, it has been useful to deploy also a **midstream** approach. The midstream is the infrastructure that lies between the field production (upstream) and the refining (downstream) ends of the oil and gas value chain. Typically, this refers to pipelines, but also the whole entire range of oil-gas-separators and gas processing plants. NGL fractionation, whereby NGLs are split into LPG and other products, is strictly speaking comparable to refining operations, but the NGL extraction and fractionation often takes part at the same complexes, and hence the whole gas processing plant may be considered as belonging to the midstream part of the value chain. A midstream approach involves trying to map the current NGL production and outlook by getting an overview of the infrastructure that a country has built and operates for gas gathering, transportation and processing. A field that produces associated gas has to be connected to a transportation system and a gas processing facility in order for the gas liquids to be utilised. Output of NGLs from countries such as Brazil, Angola and Russia has arguably been restrained by lacking investments in midstream infrastructure, while other countries have built midstream infrastructure to optimise value creation from all hydrocarbons. This approach was also useful to do a sense check of the existing OMR NGL data, and it was always useful in order to assess the outlook for a producing country or region. This 'bottom-up' approach based on gas gathering and gas processing infrastructure allows more aggregated production estimates to be checked. Information on midstream infrastructure is often available from government petroleum agencies and the trade publication Oil and Gas Journal (OGJ), publishes a global catalogue of gas processing plants, which was useful as a starting point for countries for which little information was available from official sources. For Russia we found good information on gas processing infrastructure on company websites. One of the main advantages of the midstream approach was that it in many cases allowed double counting of NGL production to be identified. As NGLs are often processed in multiple plants, stacking of various NGL projects that claim to give increased volumes of NGLs can often result in double counting. By trying to map producing fields, hubs, field processing facilities, pipelines and gas processing plants with NGL extraction and NGL fractionation, an overview of the NGL value chain in a region or a country was obtainable that would facilitate keeping track of volumes and the avoidance of double counting.

As a part of this approach export infrastructure and domestic consumption of products derived from gas fractionation plants was also mapped. That would often include assessing refinery production and the overall import and export balance of the same products in order to gain an appreciation of the viability of a country's midstream infrastructure plans. "NGL-awareness" was also identified as a factor in assessing supplies. The NGL awareness factor varies from country to country, and influences the extent to which a country would report the NGLs as an integrated part of the petroleum projects that they are undertaking. The OPEC countries and the USA are examples of countries with a high NGL awareness, while Russia, India, China and Brazil seem to be countries with a relatively low NGL awareness. NGL awareness can influence the extent to which countries flare or re-inject NGLs with associated gas, optimise NGL extraction in their value chains, leave NGLs within the sales gas stream or spike condensate into crude oil.

2.3 Alignment with natural gas forecasts

Estimates of future NGL supplies hinge critically on expected production of natural gas, split between associated and non-associated gas and between conventional and non-conventional sources. An indispensible input to this NGL forecast were therefore the natural gas production forecasts by country for 2008 and 2015 from IEA's World Energy Outlook 2009 (referred to in this text as WEO2009). It is important to note that the natural gas forecasts from WEO2009 were made for the purpose of a more aggregated and longer term outlook. The data are therefore not always a good guidance for a year by year and country by country outlook within the forecast period of this report.

Project stacking risks generating an overly-optimistic outlook on both oil and gas production, as it risks overlooking the decline in the underlying production base, which is hard to assess, and the impact of many factors like the investment climate, individual project costs, and the impact of natural gas demand. Generally, these NGL projections align closely with the WEO gas output projections. However, in the cases where a country has many well documented projects that will yield NGL in the medium term, and there were strong reasons to believe in the realisation of those projects, the approach of stacking projects has sometimes taken precedence over simple proportional alignment with the WEO natural gas forecast. One reason why NGL production can grow more rapidly than implied simply by natural gas production is for example in cases where high volumes of natural gas are re-injected. The WEO natural gas production forecast is for marketed dry gas production rather than gross gas production. NGL production may grow at a pace faster than suggested by natural gas production when technologies for NGL extraction are improved, for example when ageing NGL recovery facilities are replaced with new equipment, or if the underlying liquids content in the newer supplies of gas is higher than in older, baseload production, for example when gas condensate fields are developed. For the world as a whole the WEO forecasts natural gas production to grow at a compounded annual growth rate of 1.2% per year from 2008 to 2015, while NGL production is forecast to grow by a compounded average rate of 4.0% per year. Regional natural gas production from WEO 2009 is summarised in the table below.

Natural gas forecast from World Energy Outlook 2009 (bcm/y)

OPEC	Region	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
NON-OPEC	Africa	73	75	76	77	78	79	80	81	8	1.6 %
	Asia	365	351	366	378	390	402	422	434	69	2.5 %
	Latin America	124	116	109	119	123	127	131	135	12	1.3 %
	Middle East	44	46	55	55	59	60	60	60	16	4.5 %
	OECD Europe	309	301	298	294	290	286	283	279	-30	-1.4 %
	OECD North America	810	810	794	793	792	792	792	791	-19	-0.3 %
	OECD Pacific	53	59	62	64	67	70	72	75	22	5.0 %
	FSU and non-OECD Europe	873	808	810	827	844	861	878	903	30	0.5 %
NON-OPEC Total		**2,651**	**2,568**	**2,569**	**2,607**	**2,644**	**2,677**	**2,717**	**2,759**	**108**	**0.6 %**
OPEC	Africa	135	141	136	143	156	163	171	179	44	4.1 %
	Latin America	24	23	23	24	25	25	26	27	3	1.7 %
	Middle East	335	320	365	405	421	432	445	461	126	4.7 %
OPEC Total		**494**	**484**	**525**	**573**	**601**	**621**	**642**	**667**	**173**	**4.4 %**
Grand Total		**3,145**	**3,051**	**3,093**	**3,179**	**3,245**	**3,298**	**3,360**	**3,427**	**281**	**1.2 %**

2.4 Assessment of trends in liquid content of gas

Every natural gas stream has its own specific physical and chemical characteristics, not unlike crude oil. While for crude oils, published assays show potential buyers the API gravity, sulphur content and other characteristics of the crude oil, for natural gas the world is less transparent. Very often the information about the composition of rich gas is hard to obtain. This study has made use of published natural gas quality information in the limited number of instances where this has been available.

Otherwise an idea of the liquids content of the gas can be obtained by looking at data for dry gas and aggregate NGL production from a country, a plant or a project. Often the liquids content of natural gas can vary by field and area within a country. For example, associated gas is often more liquids-prone than the non-associated gas, gas from unconventional sources might have specific characteristics and so on. The development of large gas condensate fields in a country can increase the implied liquids to gas ratio for a country substantially. The liquids content of gas does not necessarily align when comparing the national level reserves and production from individual fields. Importantly, the liquids, which are mostly prices higher than natural gas, are frequently produced early in the lifetime of a gas field, both in order to maximise Net Present Value (NPV) as the dominant investment decision criterion, and because the liquids can often become trapped in the reservoir once the overall reservoir pressure starts to fall as a result of early-stage production. In order to have a measure for the liquids content in gas to facilitate comparisons between various sources of gas, the concept of the liquids ratio was developed. Normally the liquids ratio is stated in a weight unit of liquids divided by a volumetric unit of natural gas, for example grams per thousand cubic feet (mcf). In this report, reflecting the predominant use of barrels per day (b/d) in oil market analysis, the liquids ratio was calculated by dividing NGL supply in thousand barrels per day (kb/d) with the dry gas from the same source in thousand barrels of oil equivalents per day (kboe/d). Oil equivalents of natural gas is calculated with the conversion factor of 6.29 so that 1 bcm/y of gas is 1*6.29*1000/365= 17.2 kboe/d, assuming a heating value of the gas of 40 MJ/cubic meter.

For each country the extent to which the composition of the gas production is changing over the forecast period has been assessed in terms of associated and non-associated gas, gas production from new areas or new types of reservoirs, non-conventional gas reserves etc. The degree to which the relative composition of gas supply changes has also been used to assess fluctuation in the liquids ratio of the country. More often than not, judgement has been based on incomplete information to this respect. If specific information has been lacking it was assumed that the liquids ratio would remain constant. Wherever possible however, a liquids ratio for each kind of gas has been utilised alongside an estimate for the evolution of the composition of total gas production over the forecast period.

In the WEO2009 forecast, associated gas as a share of total conventional gas production remains stable at 27% over the forecast period to 2015, in spite of the fact that the share of associated gas in all regions falls slightly. The reason for this mathematical conundrum is that the share of the Middle East in global natural gas production is increasing, and the share of associated gas in the Middle East is much higher than elsewhere, albeit falling from 49% to 45% over the forecast period.

2.5 Selection of countries to be included in the study

OMR data comprise NGL production profiles from 59 countries. This NGL review includes in-depth assessments of the NGL baseline and outlook from 42 of those countries. The NGL production from the countries which are included in the review makes up 97.6% of the total NGL in 2008 and 98.3% of the NGL production in 2015. The selection of countries to be included in the study is done on the basis of the size of current NGL production, outlook for future production and/or possible interesting development trends. All 12 OPEC members are included. The OECD countries that are included are the USA, Canada, Mexico, Norway, UK, Denmark, Netherlands and Australia. Non-OPEC Latin American countries that are included are Argentina, Trinidad & Tobago, Bolivia, Brazil and Peru. Former Soviet Union (FSU) countries that are included are Russia, Kazakhstan, Azerbaijan, Turkmenistan and Uzbekistan. Asian countries that are included are Indonesia, Malaysia, Thailand, India and China. Non-OPEC Middle East countries that are included are Oman, Syria, Bahrain and Yemen. Non-OPEC African countries that are included are Egypt, Tunisia and Equatorial Guinea.

3 Trends in NGL production that impact NGL supply

An important finding of this review has been that NGL output over the forecast period increases at a rate of 4.0%, while the marketed natural gas production increases by only 1.2%. As a consequence the liquids ratio over the forecast period rises from 19.2% in 2008 to 23.3% in 2012, remaining at that level until 2015. How come that the natural gas apparently becomes more liquids-prone over 2008-2012? By studying the natural gas and NGL outlook country by country, four global trends in natural gas production can be identified that impact NGL supply. The importance of each trend varies by country or region, while multiple trends blur the picture in some regions. Trends 1-3 have a positive impact on the supply outlook for NGLs and the liquids ratio, while trend 4 has a negative impact.

1. *Large scale natural gas developments characterised by*
    - Participation by International Oil Companies (IOC) that tend to have a high NGL awareness compared to prevailing host country awareness.
    - The development of large gas condensate fields. The IOCs often see a larger potential in such fields than in stand-alone gas projects.
    - The development of LNG projects for which it is important to strip liquids out of the gas to make the sales gas match the spec of the target market and to optimise the value of the project by monetising valuable associated liquids. Integrated LNG and NGL infrastructure reduce the costs in the NGL value chain. 2009 saw eight new LNG trains/ capacity expansions come on stream with a total capacity of 66 bcm/y. In 2010 and 2011, a further five new LNG projects, will enter service, most of these with significant associated NGL production, as shown in the table below.
2. *Increased utilisation of associated gas*
    - Higher awareness of the value of associated gas, both as marketed gas and for re-injection to support oil production.
    - Initiatives to reduce flaring of associated gas.
    - Better infrastructure to gather and process associated gas.
3. *Higher liquids content in traditional dry non-associated gas*
    - When traditional shallow gas reservoirs are depleted, oil companies drill deeper down and find structures with higher pressure, generally containing more condensate and other NGLs.
    - Technology improvement, higher energy prices and experience make oil companies less reluctant to develop complex reservoirs.
    - The NGL awareness is higher, and therefore the value of gas condensate fields is rated higher.
4. *Wet associated gas is being replaced by dry non-associated gas*
    - As oil production declines in many countries compared to gas production, traditional associated gas with a high liquids content declines too.
    - Countries must replace associated gas with non-associated gas to meet domestic needs. This non-associated gas tends to be drier.
    - Growth in non-conventional gas production may result in lower liquids ratios.

Examples of trend 1 are the Shah Deniz field in Azerbaijan and the Karachaganak field in Kazakhstan, as well as most LNG projects. Examples of trend 2 are the cutback of flaring and increased processing of associated gas in Russia, and the gathering of associated gas to create an LNG project in Angola. In Nigeria the NGL II East Field project of NNPC and ExxonMobil is an example of a project where NGL recovery from associated gas, even when the dry gas is re-injected to support oil production, has given a substantial contribution to Nigerian NGL production. Examples of trend 3 are Russia (dry Cenomanian gas is being replaced by wetter gas), the USA (deepwater Gulf of Mexico, Rocky Mountains natural gas) and Norway and the UK (high pressure/ high temperature complex fields are now being developed, which tend to yield more condensate and other NGLs). Examples of trend 4 are Mexico (the gas in the Northern region is non-associated and drier than the traditional baseload associated gas), India (the large Krishna Godavari basin has created a new gas era, but the incremental output of NGLs is low). Saudi Arabia has tried to make IOCs participate in exploration drilling for dry gas for domestic consumption, but often the IOCs are only interested in natural gas for exports or when it comes with large condensate or other NGL volumes.

The table below lists all LNG projects that were launched or that will be launched in the period 2008 to 2010 and, where available, an estimate of their associated liquids. For 2012 and onwards the only LNG project that we assume will come into operations are Pluto LNG train 2 and Gorgon LNG in Australia which are expected to add very limited volumes of NGLs.

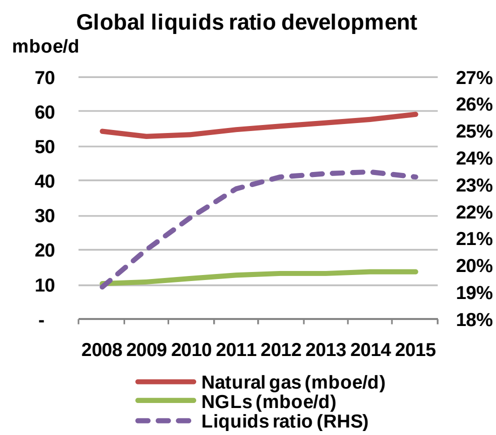
NGL from LNG projects 2008 - 2011

Country	Project	Location	Start	Capacity bcm/y	Condensate (kb/d)	Other NGLs (kb/d)	liquids ratio	comments
Australia	North West Shelf Train 5	Burrup Peninsula	2008	6.0	42		41%	
Nigeria	NLNG Train 6	Bonny Island	2008	5.6		20	21%	
Total additions in 2008				**11.6**	**42**	**20**	**31%**	
Indonesia	Tangguh LNG	Bintuni Bay, Papua	2009	10.3	5		3%	
Malaysia	MLNG debottlenecking	Bintulu Bay	2009	1.8			0%	
Russia	Sakhalin II	Prigorodnoye	2009	13.1	100		44%	Spiked condensate
Qatar	Qatargas II (Train 4)	Ras Laffan	2009	10.6	70		38%	
Qatar	Qatargas II (Train 5)	Ras Laffan	2009	10.6	70	14	46%	
Qatar	RasGas III (Train 6)	Ras Laffan	2009	10.6	50	45	52%	
Yemen	Yemen LNG (Train 1)	Bal Haf	2009	4.6	8		10%	
Yemen	Yemen LNG (Train 2)	Bal Haf	2009	4.6	8		10%	
Total additions in 2009				**66.3**	**311**	**59**	**32%**	
Peru	Peru LNG	Pampa Melchorita	2010	6.0		80	78%	
Qatar	Qatargas III (Train 6)	Ras Laffan	2010	10.6	70	7	42%	
Qatar	RasGas III (Train 7)	Ras Laffan	2010	10.6	50		27%	
Total additions in 2010				**27.2**	**120**	**87**	**44%**	
Australia	Pluto	Burrup Peninsula	2011	6.5	8		7%	
Qatar	Qatargas IV (Train 7)	Ras Laffan	2011	10.6	70		38%	
Total additions in 2011				**17.1**	**78**	**-**	**26%**	

The World Bank's Global Gas Flaring Reduction Initiative has estimated that a total of 140 bcm of natural gas was flared in the world in 2008, down from 162 bcm in 2005. The top 20 flaring countries accounted for 119 bcm of the total flaring, of which Russia flared 40 bcm, Nigeria 15 bcm, Iran 10 bcm and Iraq flared 7 bcm. It is difficult to say how much flaring of NGLs these numbers entail, since NGL might be recovered before the dry gas is flared. The World Bank estimates are based on satellite photos and analysis of the light intensity of the flame, but the composition of the material being flared is not a part of the study so far. This means that the content of NGLs might be an error source in the flaring estimates, as the liquids-prone gas would burn with a stronger light intensity than dry gas. If the share of NGLs in flared gas was equal to the world average of 19% liquids in the gas, the NGLs burned along with the gas would be 460 kb/d. In our NGL forecast for Russia we assume that a reduction of flaring by 25 bcm by 2015 will yield an increased NGL production of 126 kb/d, given an assumed constant liquids ratio of associated gas of 30%.

4 Global NGL supply outlook

As shown in the summary table below, the global supply of condensate and other NGLs is forecast to grow by 3.3 mb/d from 2008 to 2015, a compounded annual growth rate of 4.0%, compared to growth of 3.6% annually during 2000-2008. OPEC accounts for 2.9 mb/d of the increase. We estimate that the share of gas plant liquids to total NGLs included in our figures falls from 68% to 63% over the forecast period, with the remainder being field condensate. The highest growth in absolute terms is observed in 2009 and 2010. The trends of large natural gas development projects, better utilisation of associated gas and the development of more gas condensate fields amid a trend of developing deeper reservoirs contribute to the growth. Notably in 2009 the many LNG projects launched contribute to increases in NGL production in both years, as facilities gradually build up to full production. The trend towards greater reliance on drier, non-associated gas is important in several countries, but the effect globally is overshadowed by greater liquids recovery overall. As natural gas production increases by an average of 1.2% annually from 2008 to 2015, the global liquids ratio increases from 19.2% in 2008 to 23.3% in 2012 and remains at that level through to 2015.



Global liquids ratio developent

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Natural gas bcm	3,145	3,051	3,093	3,179	3,245	3,298	3,360	3,427	281	1.2 %
Natural gas (mboe/d)	54	53	53	55	56	57	58	59	5	1.2 %
NGLs (mboe/d)	10	11	12	12	13	13	14	14	3	4.0 %
Liquids ratio (RHS)	19.2%	20.6%	21.8%	22.8%	23.3%	23.4%	23.4%	23.3%		

As compared to the NGL estimates in the MTOMR June 2009, the global NGL figure is adjusted downward by 158 kb/d for the base year 2008, while the outlook is revised down by an average of 295 kb/d for the years 2009-2012. For 2013 and 2014 the forecast is revised down by 83 kb/d and 95 kb/d respectively. The revisions are due to delays in project development, the adoption of new reported baseline data and to better data and forecast quality as an outcome of this review.

Non-OPEC countries' NGL production is revised up by 259 and 139 kb/d for 2009 and 2010 respectively, with revisions for the years 2011-2014 averaging 82 kb/d. The main upward revision has taken place for Russia, which posts an upward revision of 154 kb/d in 2009, increasing to 223 kb/d in 2014. In par this derives from a reclassification of erstwhile crude oil volumes to condensate, but also due to underlying condensate growth. The aggregate NGL forecast for the OECD countries is revised down by 62 kb/d in 2010, with downward revisions reaching 275 kb/d in 2014, and the most important downward adjustments being those for the USA and Canada.

The aggregate NGL forecast for OPEC is revised down by 292 kb/d in 2008 and by 550 kb/d and 590 kb/d in 2009 and 2010 respectively, with the revision for 2014 narrowing to 175 kb/d. The downward revision for Algeria is partially a reclassification between condensate and crude oil and also a lower baseline for other NGLs. The downward revisions for Nigeria and Libya are due to the recognition that the utilisation of their installed capacity in recent years has been lower than previously assumed. The Saudi Arabia NGL forecast is revised down by 141 kb/d in 2009, by an average of 290 kb/d for the years 2010-2012 and by 221 kb/d and 214 kb/d for 2013 and 2014 respectively, mainly due to delays in the attainment of capacity output at several Saudi Arabian projects, notably the Khursaniyah project.

World Supply of Condensate and other NGLs 2008-2015

(thousand barrels per day)

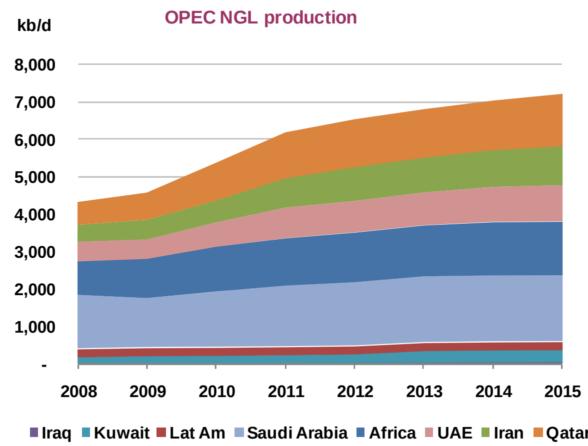
	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015	Compounded annual growth
Non-OPEC										
USA	1,781	1,886	1,790	1,763	1,757	1,752	1,746	1,741	(40)	-0.3%
Canada	699	655	636	622	610	597	585	573	(126)	-2.8%
Mexico	365	370	377	377	377	377	377	377	12	0.5%
OECD North America	**2,846**	**2,911**	**2,802**	**2,762**	**2,744**	**2,726**	**2,708**	**2,691**	**(154)**	**-0.8%**
Norway	527	533	536	529	532	531	528	526	(1)	0.0%
UK	215	179	174	176	180	170	160	150	(65)	-5.0%
Other OECD Europe	25	25	25	23	21	19	17	16	(9)	-6.5%
OECD Europe	**767**	**737**	**735**	**728**	**733**	**720**	**705**	**692**	**(76)**	**-1.5%**
Australia	74	79	83	87	91	95	99	104	30	5.0%
Other OECD Pacific	17	16	18	17	17	17	16	16	(1)	-1.0%
OECD Pacific	**91**	**95**	**100**	**104**	**108**	**111**	**116**	**120**	**29**	**4.0%**
Total OECD	**3,704**	**3,743**	**3,637**	**3,594**	**3,584**	**3,557**	**3,529**	**3,503**	**(201)**	**-0.8%**
Russia	536	589	627	662	698	735	772	817	281	6.2%
Kazakhstan	305	322	315	372	443	431	420	410	106	4.3%
Azerbaijan	42	44	42	46	46	46	46	46	5	1.6%
Uzbekistan	59	62	62	63	63	64	64	64	5	1.2%
Other FSU	33	33	37	37	39	41	41	42	9	3.5%
FSU	**975**	**1,049**	**1,084**	**1,180**	**1,289**	**1,316**	**1,344**	**1,380**	**406**	**5.1%**
Non-OECD Europe	15	15	14	14	13	12	10	9	(6)	-6.5%
Asia	647	660	692	714	759	793	797	792	145	2.9%
Africa	282	283	280	280	283	285	288	291	9	0.4%
Middle East	146	160	175	178	178	179	181	183	36	3.2%
Latin America	308	326	328	335	343	351	360	369	61	2.6%
Total non-OECD	**2,373**	**2,492**	**2,573**	**2,701**	**2,866**	**2,937**	**2,981**	**3,023**	**650**	**3.5%**
Total non-OPEC	**6,077**	**6,236**	**6,210**	**6,295**	**6,449**	**6,494**	**6,510**	**6,526**	**449**	**1.0%**
OPEC										
Iran	441	521	585	785	904	932	985	1,048	607	13.2%
Iraq	34	42	56	59	64	68	73	79	45	13.0%
Kuwait	161	190	195	205	223	308	320	320	159	10.3%
Qatar	610	721	1,010	1,228	1,280	1,296	1,326	1,400	790	12.6%
Saudi Arabia	1,428	1,311	1,475	1,625	1,690	1,759	1,768	1,765	337	3.1%
UAE	528	519	643	813	837	868	930	922	394	8.3%
Middle East OPEC	**3,202**	**3,305**	**3,964**	**4,716**	**4,997**	**5,231**	**5,402**	**5,534**	**2,332**	**8.1%**
Algeria	588	628	668	705	728	745	762	780	192	4.1%
Libya	117	115	111	111	111	122	168	172	55	5.7%
Nigeria	160	273	387	408	419	420	421	410	250	14.4%
Angola	50	50	50	50	86	92	92	92	42	9.1%
Venezuela	210	210	211	212	213	214	215	216	6	0.4%
Ecuador	2	2	2	1	1	1	-	-	(2)	-100.0%
Other OPEC	**1,126**	**1,277**	**1,428**	**1,487**	**1,558**	**1,594**	**1,658**	**1,671**	**545**	**5.8%**
Total OPEC	**4,328**	**4,582**	**5,392**	**6,203**	**6,555**	**6,825**	**7,060**	**7,205**	**2,876**	**7.6%**
Total world NGL & condensate	**10,405**	**10,818**	**11,602**	**12,498**	**13,005**	**13,320**	**13,570**	**13,731**	**3,326**	**4.0%**

World Supply of Condensate and other NGLs revisions compared to MTOMR June 2009

(thousand barrels per day)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Non-OPEC											
USA	-	-	3	7	-	70	(50)	(108)	(145)	(188)	(231)
Canada	-	-	-	20	24	(17)	(31)	(53)	(74)	(95)	(116)
Mexico	-	-	(2)	-	-	1	5	3	2	(0)	(2)
OECD North America	**-**	**-**	**1**	**27**	**24**	**54**	**(76)**	**(158)**	**(218)**	**(283)**	**(349)**
Norway	-	-	-	-	-	44	55	55	73	87	97
UK	-	-	2	(1)	(6)	(31)	(21)	(9)	-	-	-
Other OECD Europe	(6)	(8)	(15)	(1)	(4)	(16)	(15)	(5)	(5)	(5)	(5)
OECD Europe	**(6)**	**(8)**	**(14)**	**(2)**	**(11)**	**(3)**	**19**	**41**	**68**	**82**	**92**
Australia	-	-	-	-	-	5	(2)	(13)	(14)	(15)	(16)
Other OECD Pacific	-	-	0	-	-	(3)	(2)	(1)	(1)	(1)	(2)
OECD Pacific	**-**	**-**	**0**	**-**	**-**	**2**	**(4)**	**(15)**	**(16)**	**(17)**	**(17)**
Total OECD	**(6)**	**(8)**	**(12)**	**25**	**13**	**53**	**(62)**	**(132)**	**(166)**	**(218)**	**(275)**
Russia	65	61	58	58	65	154	214	150	173	198	223
Kazakhstan	29	29	29	34	34	48	(16)	24	95	97	100
Azerbaijan	(5)	(5)	(5)	(6)	0	(3)	(5)	(1)	(1)	(2)	(4)
Uzbekistan	2	2	2	2	9	8	13	15	18	21	23
Other FSU	(8)	(5)	(5)	(5)	(7)	(8)	(4)	(6)	(5)	(4)	(4)
FSU	**84**	**82**	**79**	**83**	**102**	**199**	**201**	**183**	**281**	**310**	**339**
Non-OECD Europe	-	-	-	-	-	-	-	1	1	1	1
Asia	(16)	(9)	(24)	(28)	(28)	(37)	(27)	(12)	(27)	1	10
Africa	18	40	31	36	34	27	16	11	8	5	1
Middle East	(0)	(5)	(7)	(6)	(1)	8	18	20	20	18	16
Latin America	30	30	21	12	13	9	(7)	(19)	(20)	(17)	(12)
Total non-OECD	115	137	100	96	121	206	201	184	263	318	355
Total non-OPEC	**109**	**130**	**88**	**121**	**134**	**259**	**139**	**52**	**98**	**100**	**80**
OPEC											
Iran	(33)	(84)	(65)	(37)	(20)	(114)	(139)	47	156	70	(28)
Iraq	-	-	-	-	5	10	26	29	34	38	43
Kuwait	-	-	-	-	5	-	-	(19)	(104)	(32)	(20)
Qatar	20	83	76	69	55	48	74	86	51	37	21
Saudi Arabia	-	-	30	-	1	(141)	(261)	(316)	(292)	(221)	(214)
UAE	-	16	-	-	-	(32)	(52)	(13)	(20)	13	83
Middle East OPEC	**(13)**	**15**	**40**	**33**	**46**	**(228)**	**(353)**	**(185)**	**(174)**	**(95)**	**(114)**
Algeria	(137)	(157)	(217)	(243)	(252)	(199)	(145)	(84)	(78)	(97)	(86)
Libya	(1)	(7)	(19)	(28)	(26)	(26)	(28)	(25)	(22)	(19)	(16)
Nigeria	(71)	(80)	(55)	(52)	(59)	(96)	(66)	(36)	(32)	(35)	(24)
Angola	-	-	-	-	-	-	-	-	46	60	60
Venezuela	-	-	-	-	-	-	1	2	3	4	5
Ecuador	-	-	-	-	-	-	-	-	-	-	-
Other OPEC	**(210)**	**(244)**	**(291)**	**(323)**	**(338)**	**(321)**	**(237)**	**(143)**	**(84)**	**(87)**	**(61)**
Total OPEC	**(223)**	**(230)**	**(251)**	**(290)**	**(292)**	**(550)**	**(590)**	**(329)**	**(258)**	**(183)**	**(175)**
Total world NGL & condensate	**(114)**	**(100)**	**(163)**	**(169)**	**(158)**	**(291)**	**(451)**	**(276)**	**(161)**	**(83)**	**(95)**

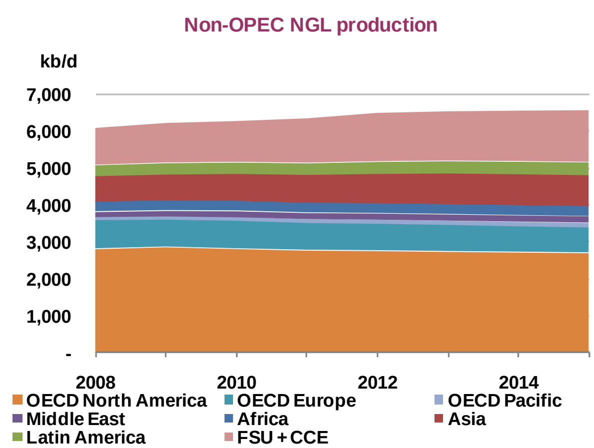
4.1 OPEC



The NGL production in OPEC countries posts a net growth of 2.9 mb/d from 2008-2015, a compounded annual growth rate of 7.6%. This compares with growth in the period 2000-2008 of 5.6% annually. The Middle East OPEC countries contribute 2.3 mb/d to the forecast, while Africa countries provide 0.5 mb/d. Qatar alone accounts for 0.8 mb/d of the total increase, while Iran generates a 0.6 mb/d. The United Arab Emirates add 0.4 mb/d, Saudi Arabia and Nigeria add 0.3 mb/d each, while Kuwait and Algeria add 0.2 mb/d each. All in all the OPEC NGL output it set to rise from 4.3 kb/d 2008 to 7.2 kb/d in 2015.

The OPEC countries have specific reasons to optimise NGL production, as such production is excluded from the organisation's self imposed production limits. Most of the countries therefore have a high NGL awareness and an elaborate infrastructure for NGL recovery. A large number of committed LNG projects and the need to rapidly expand local natural gas supply for power generation, desalination of seawater, industrial diversification and oilfield re-injection all combine to encourage the rapid expansion of OPEC natural gas production. Investments are taking place to optimise NGL production further, and large gas condensate fields are being developed. In West Africa the trend of better utilisation of associated gas is important for the NGL production growth. On the other hand, the development of drier natural gas deposits is being hampered by an unfavourable domestic pricing regime.

4.2 Non OPEC



In non-OPEC countries NGL production rises by 0.4 mb/d over the forecast period, a compounded annual growth rate of 1.0%, compared to a growth rate during 2000-2008 of 2.4%. Growth in the FSU of 0.4 mb/d and in Asia, Middle East and Latin America combined of 0.2 mb/d is partly offset by a decrease in North America of 0.2 mb/d. The NGL output is forecast to increase from 6.1 mb/d in 2008 to 6.5 mb/d in 2015.

The NGL production figure for non-OPEC includes only those condensate volumes reported distinct from crude oil, as is the practice in OMR. Applying the same NGL definition as we do for OPEC countries would yield an NGL figure higher by an estimated 0.9 kb/d in 2008, see table on page 9. A forecast is not made for these volumes.

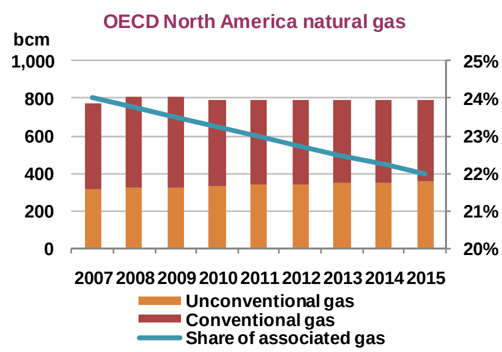
In Russia the trends of better utilisation of presently flared associated gas, and of non-associated gas becoming wetter due to the development of deeper reservoirs, have a significant impact. In Kazakhstan the growth of 106 kb/d is attributable to the further development of the Karachaganak field. Meanwhile in the Asia Pacific NGL production grows due to rising gas output, Indonesia, Vietnam and Thailand being the most important contributors in that region, albeit the liquids ratio in many instances falls due to a rising contribution from drier non-associated gas. In North America NGL production is expected to fall by a compounded annual rate of 0.8% due to a general decline in natural gas production and, on average, the exploitation of slightly drier gas deposits.

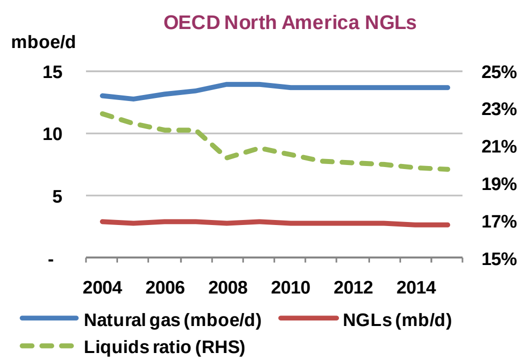
5 Regional and country by country outlook and analysis

5.1 North America

The region holds 9.5 tcm of proven natural gas reserves, an increase of almost 30% compared to the 2004 level as a consequence of higher exploitation of non-conventional gas resources. However, North America sees natural gas production falling slightly over the forecast period, sliding from 810 bcm in 2009 to 794 bcm in 2010 and staying stable around 791 bcm in 2015. US natural gas production accounts for the bulk of the fall in absolute terms. Canadian natural gas production is set to decline by an average of 1% annually, while Mexican natural gas production rises by an average of 1% per year. The share of associated gas to total conventional gas falls from 24% to 22%. Non-conventional gas production is projected rising from 322 bcm in 2008 to 357 bcm in 2015, including tight gas (which is not counted as unconventional gas by the US EIA). Coal bed methane accounted for 56 bcm of total US natural gas production in 2008, while shale gas accounted for 62 bcm, up from 32 bcm in 2007.

Total NGL production in North America is expected to fall by a compounded annual rate of 0.8% from 2,846 kb/d in 2008 to 2,691 kb/d in 2015. The liquids to gas ratio is forecast to fall from 20.4% in 2008 to 19.7% in 2015.





The liquids ratio for the USA and Canada has remained very resilient to the growing share of both non-associated gas and unconventional gas lately. However, the trend that has been observed since the 1990s of a slightly falling liquids ratio is expected to become re-established. The liquids ratio has remained remarkably stable since 1979, even during the post-1990 growth period for non-conventional gas. By studying areas with a high share of shale gas production, like Texas district 5, 7B and 9, we see that the recent growth in shale gas production has been accompanied by a strong, although relatively weaker, growth in NGL production. The liquids ratio for Texas as a whole fell by 7 percentage points from 30% in 1997 to 23% in 2008, and by 1.8 percentage points from 2007 to 2008 when the annual growth in shale gas production was the highest. Coal bed methane holds little or no liquids, and New Mexico, which has a high share of coal bed methane, has seen the liquids ratio falling from 28% in 1998 to 25% in 2008. In Canada one sees the same trends as in the USA, with increasing impact of non-conventional gas sources. Another trend that is observed in Canada is better utilisation of associated gas from oil sands. These NGLs from oil sands are still predominantly consumed in the bitumen production process, but by extracting liquids and marketing them the process can replace NGLs with dry gas, which is both cheaper and more environmentally friendly.

However, as natural gas prices in the USA have lost ground relative to oil and NGL prices over the last year, this fact has a positive impact on the liquids ratio. As the price difference grows, it becomes attractive for developers to look for the most liquids-prone pockets of the reservoirs within their license. The shale and tight gas plays with the highest liquids ratios become the most attractive ones to develop first.

In Mexico dry non-associated gas production in the north is gaining ground as compared to highly liquids-prone associated natural gas in the south. Although oil production is declining, natural gas production is rising and so NGL production is forecast to grow, albeit at a lower rate than total natural gas production.

5.1.1 USA

Relevant natural gas trends

After rising from 583 bcm in 2008 to almost 600 bcm in 2009, US natural gas production is forecast to fall to a low point of 565 bcm in 2011, before rising again to 570 bcm in 2015. A lower pace of investment during the recession and in the aftermath of sharply weaker gas prices in 2009 is behind the expectations of decline in natural gas production of 0.3% annually over the forecast period. While the count of natural gas rotary rigs as published by the US Energy Information Administration (EIA) peaked at almost 1600 in September 2008, it fell following the recession and hit a low of 675 in July 2009. Since then the rig count has gradually been picking up, approaching 800 in early 2010, still at its lowest level since 2003. In comparison the number of oil rigs was then back at pre-recession levels.

From 2007 to 2008 natural gas reserves in the USA increased from 6.0 tcm to 6.7 tcm, and further to 7.5 tcm in 2009. The reason for the increase in natural gas reserves recently is the rapid improvement in technologies to produce natural gas from unconventional sources, which according to WEO data accounted for 45% of natural gas production in 2008. However, the US reserves to production ratio is still low at 13, compared to 75 in Russia which had an almost identical 2009 natural gas production. The most important unconventional gas reserves in the US are tight gas, which accounted for 55% of unconventional gas production in 2008, then shale gas, which accounted for 23%, and coal bed methane which stood for the remaining 21%. Unlike the IEA, the EIA does not define tight gas as unconventional gas, only coal bed methane and shale gas. The expansion of both coal bed methane and tight gas has been going on since the 1990s, while the growth in production from shale gas reserves has expanded massively since 2007.

The resilient liquids ratio of US natural gas

The surprising observation from the USA is that the liquids ratio has remained range-bound between 17% and 21% since 1979, in spite of large changes in the composition of natural gas production and the influence of other non-geological factors discussed below. Thanks to the abundance of data and analysis from US government sources, it is possible to study the liquids ratio for the country as a whole and by region, and trying to assess the impact of various factors.

Associated versus non-associated gas

The share of associated versus non-associated gas rose in the period from 1979 to 1990, and has fallen slightly over the years from 2000. This is not assumed to have had any impact on the liquids ratio, as the liquids ratio in the US was stable or slightly increasing over the years up to 1990.

Tight gas in deepwater Gulf of Mexico and Rocky Mountains gas is generally wetter

Over recent years natural gas production has increased from deepwater gas fields in the Gulf of Mexico and from the Rocky Mountains. The liquids content from this gas is on average higher than gas from the rest of the USA. Liquids content of deepwater Gulf of Mexico gas is almost twice or three times as high as the natural gas from shallow water and onshore gas production in Texas respectively. This has had a positive effect on the liquids ratio of the USA. The Granite wash tight sand play in Texas is also characterised as liquids rich.

Shale gas could seem drier, but the wettest parts are developed first

71% of US shale gas production in 2008 took place in Texas. The Barnett Shale, Eagle Ford Shale and parts of the Haynesville Shale are all located in Texas. The Barnett Shale generated 23% of total Texas natural gas production in 2008. In the first six months of 2009 it produced 23 bcm of natural gas. "The shale gas districts" of Texas, district 5, 7B and 9 posted a joint 56% growth in natural gas production in 2008, while the NGL production from the same districts grew by 38%. Texas produced 32% of the natural gas in the USA in 2008, a total of 193 bcm, up 34% since 2004. Natural gas production in Texas grew by 12% from 2007 levels, while NGL production increased by 4%, resulting in the liquids ratio dropping by 1.8 percentage points.

However, one cannot conclude on this basis that shale gas is drier than other gas. The rapid growth itself might explain the falling liquids ratio in Texas. Midstream investments have struggled to keep pace with the natural gas production growth. The midstream company Enterprise is investing heavily in Texas in order to process and extract NGLs from the new natural gas production and suggest that all current capacity in Texas is fully used. Both the Barnett shale and the Eagle Ford shale are characterised as rich in NGLs.

Coal bed methane is dry, but coexists with wetter gas in the Rocky Mountains

The production of coal bed methane has evolved since the 1990s, and grew by 12% from 2007 to 2008. Coal bed methane, as the name indicates, consists of mainly methane, mixed with CO_2. In 2008 29% of coal bed methane production took place in Wyoming. 25% took place in Colorado and 23% took place in New Mexico. Total natural gas production in Wyoming and New Mexico in 2008 was 105 bcm, up 7% from 2007. The NGL production in the same states grew by 11% during 2008. The overall liquids ratio for Wyoming natural gas was 15% in 2008, while the ratio for New Mexico was 25%. Coal bed methane was 31% of the natural gas produced in New Mexico in 2008 and 25% of the natural gas produced in Wyoming. While coal bed methane is dry, it coexists in basins that hold strata of a different geological composition with high liquids content. As an example the San Juan and the Greater Green River basins in the Rocky Mountains are known as coal bed methane strongholds, but the overall reserves in these basins show liquids ratios of more than 30%.

Non-geological factors

The following three non-geological factors have affected the NGL potential in the USA over the recent years:

1) In the early 2000s the natural gas pricing scheme in the USA changed from a volume basis (per thousand cubic feet) to a heat-content basis (per million Btu). This created an incentive for producers to increase the Btu content of the natural gas delivered into the pipeline grid while decreasing the amount of natural gas liquids extracted from the natural gas stream. Due to strict gas specifications in the natural gas grid the natural gas delivered in the US gas grid must nevertheless be at 1050 btu/mcf +/- 50 btu, limiting the scope for such optimisation by retaining liquids in the gas stream.

2) The price difference between NGL products and natural gas will influence how much NGL producers will choose to leave in the sales gas, limited however by the strict sales gas specifications in place. Over 2009 the natural gas price has plummeted, while the oil price recovered more rapidly after the crash in late 2008. However, LPG prices did not recover as rapidly or as strongly crude oil prices, reflecting the competitive pressures from both gas and other oil products. However, the price spread in 2009 favoured optimisation of NGL extraction.

3) While US natural gas producers previously were owners of gas processing plants, specialised midstream companies have now taken over, creating a more competitive environment in the

midstream sector. This together with substantial geographical relocation of US gas production has led to idling of many old gas processing plants and the construction of many new and larger units. From 1995 to 2004 the number of gas processing plants in the USA fell from 727 to 530. The number is still extremely high compared with other countries with the exception of Canada, which is in the same league. Duke Energy Field Services, Enterprise Products Operating LP, Williams, Dynergy and Koch are examples of important midstream operators in the USA.

USA production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	583	596	569	565	566	567	568	570	-13	-0.3 %
Gas production (kboe/d)	10,042	10,272	9,806	9,741	9,758	9,777	9,795	9,815	-227	-0.3 %
NGL (kb/d)	1,781	1,886	1,790	1,763	1,757	1,752	1,746	1,741	-40	-0.3 %
NGL to gas ratio	17.7%	18.4%	18.3%	18.1%	18.0%	17.9%	17.8%	17.7%		

Current NGL production

The EIA is an excellent source of NGL data from the US. The EIA includes only gas plant liquids in its NGL definition. Since this is the NGLs extracted and not the products of NGL fractionation, it is a raw NGL mix which is not split into products. Total NGL production so defined in 2008 stood at 1781 kb/d. The figures do not include lease (or field) condensate production that was about 470 kb/d in 2008, down from 496 kb/d in 2007. Lease condensate is included within OMR crude oil figures for the USA. This inclusion of only natural gas plant liquids in the NGL definition and a separate specification of field condensate volumes among US official data are arguably the clearest treatment of NGL reporting and one that IEA member countries and other reporting services would do well to emulate.

The USA is the world’s NGL superpower. This was the country where gas cylinder containers were invented, enabling the commercialisation of LPG, and the country which first saw the processing of natural gas to produce gas plant LPG and other products. The USA has traditionally been by far the largest producer of NGLs and consumer of LPG and naphtha, although looking ahead this pre-eminent position might whither.

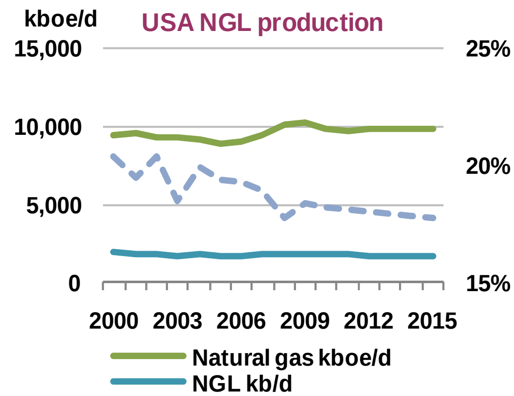
The USA has a very dry sales gas spec and a dynamic and competitive investment environment for the midstream sector. During the recent recession, the midstream industry has consolidated even more, continuing the structural change from the turn of the millennium. With more liquids production from shale gas, and the location of natural gas production changing, the midstream companies are racing to keep up with the speed of investment in upstream natural gas.

Enterprise is the biggest midstream player in Texas, and holds 500 kb/d of fractionation capacity at eight NGL fractionators along the US Gulf coast, all of which are reportedly running near capacity due to new shale gas production. Two new NGL pipelines, the 110 kb/d Overland Pass and the 160 kb/d Arbuckle pipeline are increasing the supplies to the Gulf coast. Enterprise built a new 75 kb/d fractionator in Hobbs in Gaines County, Texas in 2007. In 2008 Enterprise also built a new 70 kb/d fractionator called the Meeker expansion in the Rio Blanco county in Colorado. Enterprise plans to build a new 75 kb/d fractionator near Mt Belvieu that will take the NGL fractionation capacity in the area up to 600 kb/d by 2011.

There has been some evidence of a supply glut of LPG in the USA recently, as supplies grew in 2008 and the petrochemical industry was hit by the recession. The bulk of US LPG, ethane and naphtha demand is in the petrochemical sector, and butane is also used as a gasoline blending component in the winter. In the summer of 2009 the USA reportedly exported propane for the first time, while it was previously an importer of LPG all year around, holding by far the highest LPG storage capacity in the world in the 15 mt (174 mb) Mt Belvieu salt caverns. However a stronger market has been evident in Latin America during

2009, as both Mexican and Argentinean export volumes have fallen, supporting prices somewhat. The demand for ethane and propane is increasing as previous heavy crackers are converted to be able to use lighter ethane and propane feedstock streams.

The outlook for NGL production



US NGL production is forecast to decline from the 2009 level of 1885 kb/d to 1741 kb/d in 2015, which is not far from the 2008 production figure. The NGL outlook for the USA has been revised down from that contained in the June 2009 MTOMR. Both the WEO2009 and EIA projections now envisage declining gas production in contrast to the more optimistic gas picture in our earlier projections. The liquids ratio is assumed to continue its slight downward trend, due to a higher share of shale gas and coal bed methane. The main uncertainly to the forecast however is the outlook for US natural gas production, the impact of unconventional gas on the liquids ratio going forward and the spread between NGL and natural gas prices.

5.1.2 Canada

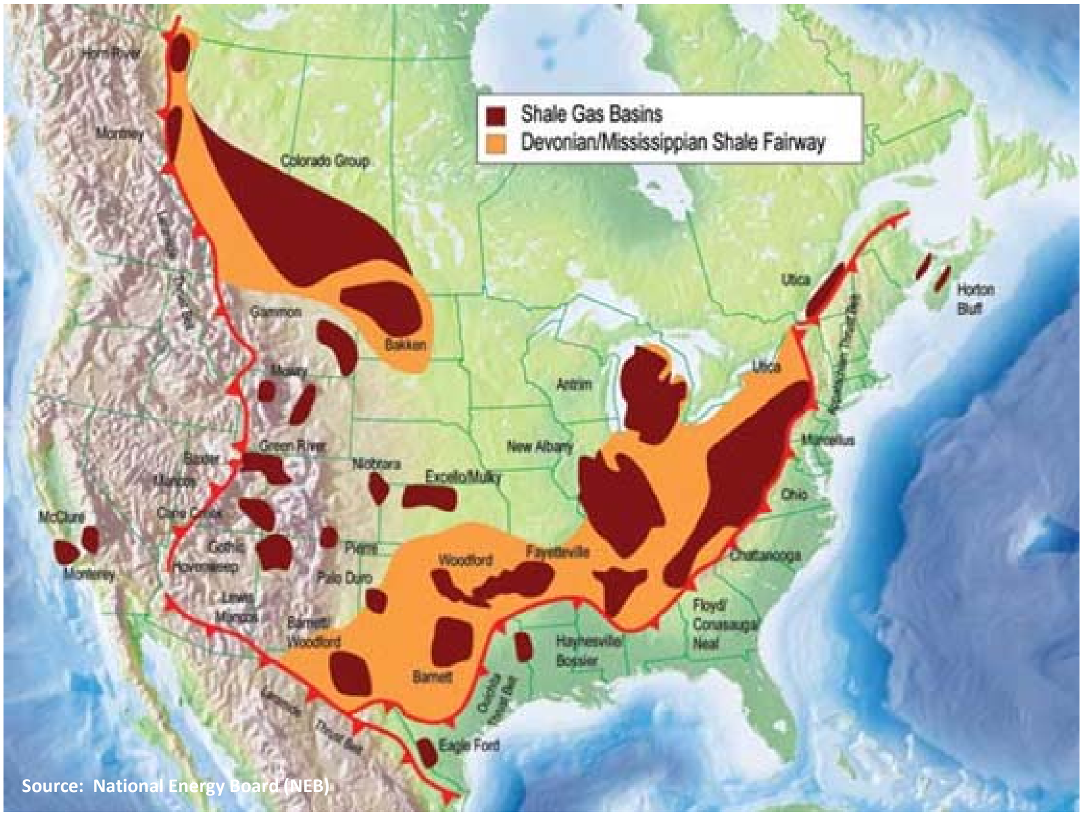
Relevant natural gas trends

Natural gas production in Canada is expected to decline by 1% annually over the forecast period from 175 bcm in 2008 to 166 bcm in 2015, while the contribution from unconventional gas resources is set to increase slightly from 58 bcm to 60 bcm. The West Canadian sedimentary basin covers Alberta and parts of Saskatchewan and British Columbia. These three provinces house 97% of the marketed gas production of Canada.

Canada, like the USA, shows a massive decline in traditional natural gas production being replaced by unconventional gas production, mainly shale gas and coal bed methane. Canada is a country which combines the trend of less liquids-prone new sources of gas, with at the same time better utilisation of associated gas. The associated gas from oil sands production has previously not been well exploited but technology and investments to market NGLs from oil sands are now on the way. The map below shows how the shale gas basins of North America straddle Canada and the USA. The high growth in shale gas production in the USA has prompted optimism with regard to the potential development of similar resources in Canada. Today, efforts are ongoing to assess shale gas prospects in northeast British Columbia (Horn River Basin and the Montney Formation), southern Alberta and Saskatchewan (Colorado shale), Quebec (Utica shale), and Atlantic Canada (Windsor Group shales). However, due to the current North American gas glut and low gas prices, high growth in Canadian shale gas production is not expected over the forecast period. The natural gas production in Canada for 2009 shows a lull compared to 2008 figures and the 2010 forecast either side, as Canadian gas exports to the USA have been hit by lower US import needs.

Canada production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	175	187	174	172	171	169	168	166	-9	-0.7 %
Gas production (kboe/d)	3,017	3,229	2,994	2,968	2,943	2,918	2,893	2,868	-149	-0.7 %
NGL (kbd)	699	655	636	622	610	597	585	573	-126	-2.8 %
NGL to gas ratio	23.2%	20.3%	21.2%	21.0%	20.7%	20.5%	20.2%	20.0%		



Source: National Energy Board (NEB)

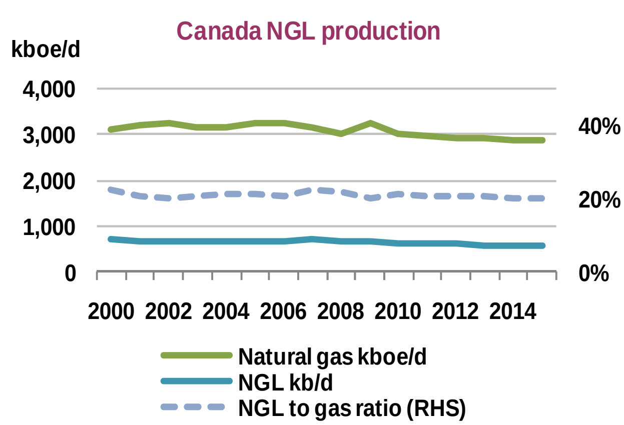
Current NGL production

The Canadian government report an NGL figure for 2008 of 699 kb/d that includes gas plant ethane, propane, butane, pentane and gas plant condensate, a definition of NGLs that is consistent with our preferred NGL definition for non-OPEC countries.

Like the USA, Canada has an elaborate infrastructure to gather and process natural gas, with a high quantity of gas processing plants. 79% of the marketed production of natural gas in Canada comes from Alberta, and 91% of the NGL production. The current production from shale gas and coal bed methane deposits also takes place in this province. As natural gas and NGL production data are only disaggregated on a province level it is hard to assess the impact that unconventional gas has had on the liquids ratio in Canada, but it is assumed that the impact is comparable to that observed in the USA. The liquids ratio of Canada was 23% in 2008, fairly stable from 2000.

The outlook for NGL production

Canadian NGL production is forecast at 573 kb/d in 2015, implying a decline by an average of 3% annually from 2008 to 2015. Two factors in Canada might have a negative impact on the liquids ratio. That is the higher share of non-conventional gas, notably the effect of coal bed methane, and secondly lower rates of associated gas production from oil sands as compared to other oil production. Despite this, the associated gas from oil sands has previously



not been well exploited but technology and investments to market NGLs from oil sands are now on the way.

The National Energy Board of Canada expects the NGL production to fall by 185 kb/d from 2007 to 2020. This would imply an annual reduction in NGL production conforming to our projection.

5.1.3 Mexico

Relevant natural gas trends

From 2008 to 2015 the WEO forecasts that Mexican gas production will remain flat at 55 bcm from 2009 to 2015, following a growth from 52 bcm to 56 bcm from 2008 to 2009. The share of associated gas is expected to decline as compared to non-associated gas, partly because oil production is forecast to decline by 5% annually over the forecast period.

Mexico is an example of a country where non-associated gas is markedly drier than associated gas. Over the last ten years the share of non-associated gas has increased, and this has caused the liquids content to decline from 71% in 1998 and 1999 to 41% in 2008. However, over the years 2004-2007 the production of associated gas increased in spite of the fact that the oil production decreased, but at a much lower rate than non-associated gas. Associated gas production in Mexico increased by an average of 5% per year during 2004-2007, in a period where oil production fell by an average of 3% per year. This is assumed to be partly due to better utilisation of associated gas. PEMEX launched plans to improve its utilisation rate for associated gas during these years, including curbing of flaring. However, flaring figures from the World Bank show an increase from 0.9 bcm in 2005 to 2.6 bcm in 2008 and it is indicated that flaring in 2009 is much higher than that, especially from the Cantarell field. The reason is that Pemex has injected nitrogen into the reservoir for many years to maintain pressure, and the produced gas now contains more nitrogen than can be separated by currently installed processing facilities. The non-associated natural gas production of Mexico increased by an average of 19% during the same period.

Mexican natural gas production increased by an average of 4% annually from 2000 to 2008, and by 9% annually from 2004 to 2007. From 2004 to 2008 the share of non-associated gas rose from 34% to 43%, corresponding to 24 bcm of marketed production in 2008. Nearly all the non-associated gas production in Mexico is in the North, notably from the Burgos basin and nearby fields, and is being processed at the Burgos gas plant. Other non-associated gas is produced in Macuspana, Veracruz, Misantla and Tampico further south in the Northern region and are being processed at the Arenque and Poza Rica plants near Veracruz. The Burgos basin had a production at start-up in 1999 of 10 bcm, and this production increased to 15 bcm in 2009. The ratio derived from dividing the estimated liquids production from the Burgos plants as well as the Veracruz plants by total Northern gas production is a 7% liquids ratio, while for the rest of the country this is estimated at 70%, generally the sort of ratio that Mexican gas had in 1998, before the Burgos basin came into production.

Mexico production outlook for natural gas and NGLs

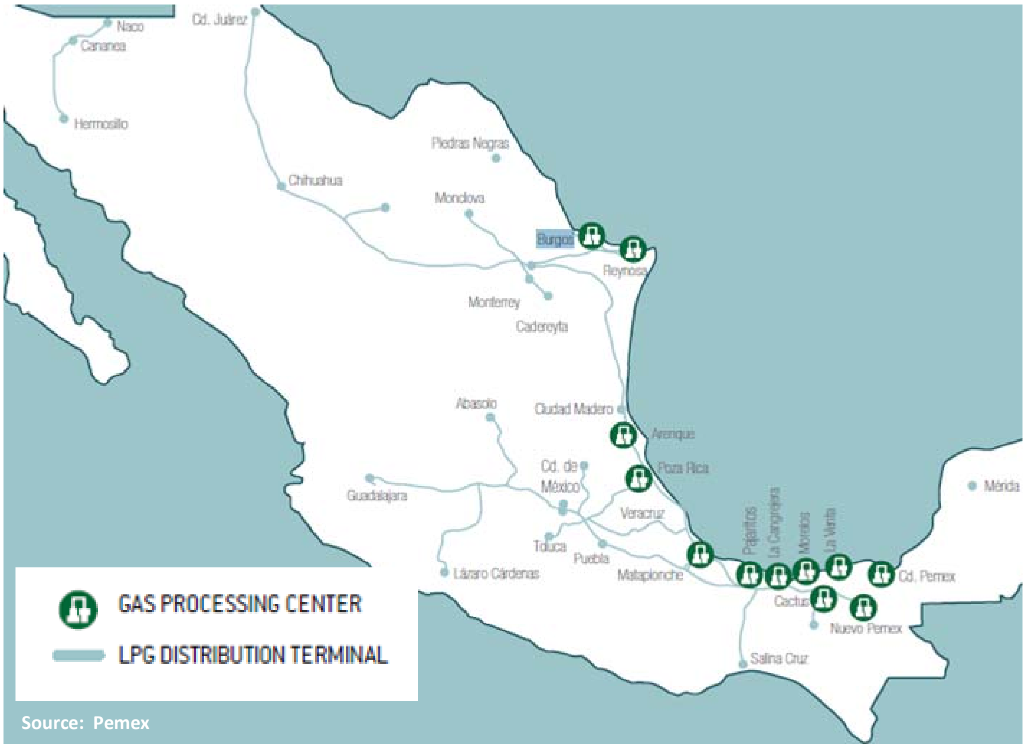
	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	52	56	56	55	55	55	55	55	3	0.9 %
Gas production (kboe/d)	899	957	958	956	956	955	955	955	56	0.9 %
NGL (kbd)	365	370	377	377	377	377	377	377	12	0.5 %
NGL to gas ratio	40.6%	38.7%	39.4%	39.5%	39.5%	39.5%	39.5%	39.5%		

Current NGL production

The OMR baseline data for Mexico are based on Pemex NGL reporting. The total figure of 365 kb/d for

2008 includes the gas plant LPG, ethane, gasoline and others. Not included in the figure is 54 kb/d of field condensate, as these volumes are reported together with crude oil production.

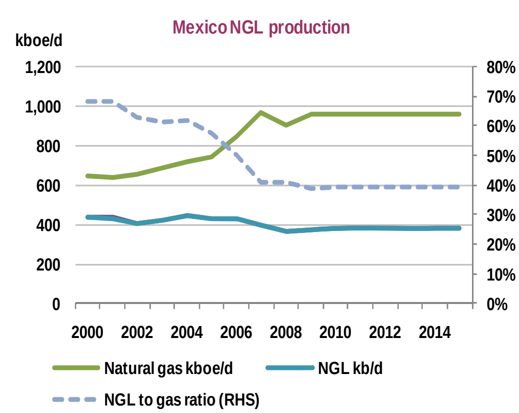
According to the Oil and Gas Journal (OGJ), Mexico has eight gas processing plants, of which the Cactus plant and the Nuevo Pemex plants in the south east are by far the most important in terms of NGL production. 80% of the NGLs produced in Mexico come from those two plants, according to OGJ.



The outlook for NGL production

The NGL production of Mexico is forecast to remain flat at 377 kb/d over the forecast period 2015, at the same level as at the end of 2009. Looking at proven reserves for Mexico, the share of NGLs as compared to natural gas is 47%, higher than the current share of production. If we look at the Northern region, where most of the non-associated gas is located, the NGL to natural gas reserve ratio is 36%. The current rate of 40% liquids recovery could therefore be sustained going forward. This implies the following assumptions: Associated gas production falls by 2% annually. The liquids ratio of associated gas is assumed constant at 65%. The liquids ratio of non-associated gas increases from 5% in 2008 to 13% in 2015. These assumptions gave an NGL profile in line with existing OMR/MTOMR estimates, and the production forecast was not revised for this country.

Going forward, the associated gas production is assumed to decline less than oil production, while the non-associated gas increases to make up the balance of the total Mexico natural gas production forecast from the WEO. The liquids content in associated gas is assumed to remain constant, while the liquids content of non-associated gas rises to account for the fact that other sources of non-associated gas are unlikely to be as dry as the Burgos basin gas.

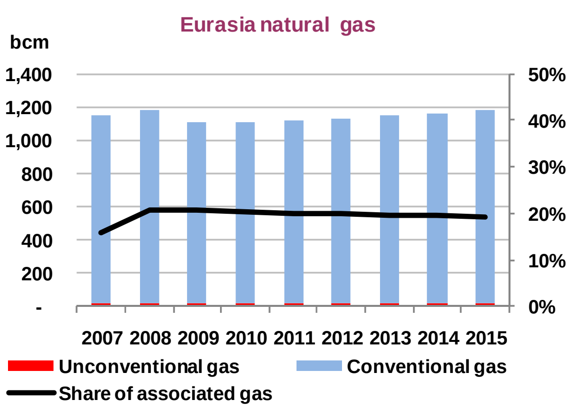


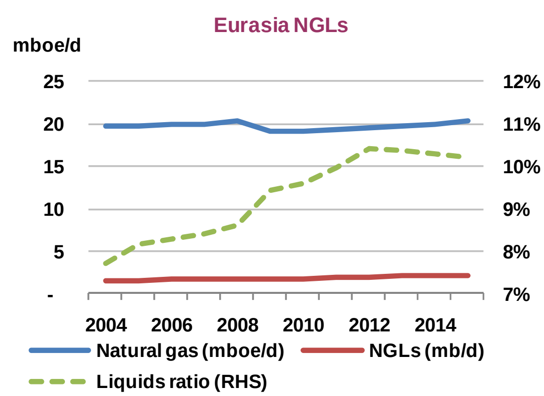
5.2 Eurasia

The geographical aggregation of Eurasia is selected due to a lack of a more disaggregated data break-down between associated/ non-associated gas production and unconventional gas production on a lower level than Eurasia in the WEO2009 natural gas forecast. The region holds 60.3 tcm of proven reserves, 33% of the world total. 90% of the reserves are held in the Former Soviet Union, with Russian reserves alone accounting for 44.9 tcm. Turkmenistan and Norway both have 3 tcm of proved reserves, although the total resource potential of Turkmenistan is probably much higher. The reserves estimate has been stable since 2000. From a supply point of view Eurasia consists broadly of the two regions - the North Sea and Russia/Caspian. Natural gas supply from the region is forecast to return to 2008 annual levels of 1.2 tcm over the forecast period after a fall to 1.1 tcm in 2009. The unconventional gas in this region consists of Russian tight gas, and is forecast to remain minor, rising from 22 to 24 bcm, while the share of associated gas falls slightly from 21% to 19% of total conventional gas production.

NGL production increases by 324 kb/d from 1.8 to 2.1 mb/d, with growth in Russia and Kazakhstan of 281 kb/d and 106 kb/d respectively offset mainly by a decline in OECD Europe of 76 kb/d over the forecast period. UK NGL output declines by 65 kb/d over the forecast period, while Norwegian production remains stable.

The main gas trend observed in this region is for an increasing share of gas condensate fields in Norway and the UK, making NGL production decline more gradually than crude oil. In Norway natural gas production rises over the forecast period, while it falls in the UK, explaining the different outlook of the two countries. The increasing liquids ratio for both is related to the development of deeper reservoirs with higher pressure and temperature, often containing more condensate and other NGLs.





For Russia, the main trend is better utilisation of associated gas and lower levels of flaring. Even although natural gas production in Russia is expected to remain flat over the forecast period, a better utilisation of associated gas means more NGLs and a much higher produced liquids ratio in associated gas for this country over the outlook period. Non-associated Russian gas has traditionally been very dry, coming from shallow reservoirs, but these sources are being complemented by more liquids-prone production from deeper reservoirs, supporting the liquids ratio. In Kazakhstan the growth comes mainly from the next development phase of the Karachaganak field, assumed to yield 94 kb/d of condensate by 2012.

5.2.1 Norway

Relevant natural gas trends

Natural gas production in Norway is increasing, with 2% annual growth expected from 103 bcm in 2008 to 120 bcm in 2015. The liquids ratio of Norway has been declining from a 2001 level of 31% to a current level of 20% excluding field condensate, although including condensate the liquids ratio has been rather stable at around 30%.

The two most important new gas fields in Norway are Gjøa (2010) and Skarv (2011), but also Tyrihans (2009), Vega and Vega Sør (2010), Morvin (2010) and Volund (2009) will also contribute incremental gas and NGL production in the years to come. The NGL to gas ratio of recoverable reserves for these fields together is 26%, and 29% if condensate is included. Other finds/possible future developments also have comparable liquids ratios.

Norway production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	103	104	107	110	113	116	118	120	17	2.2 %
Gas production (kboe/d)	1,775	1,789	1,845	1,897	1,946	1,991	2,032	2,070	295	2.2 %
NGL (kb/d)	527	533	536	529	532	531	528	526	-1	0.0 %
NGL to gas ratio	29.7%	29.8%	29.1%	27.9%	27.3%	26.7%	26.0%	25.4%		

Current NGL production

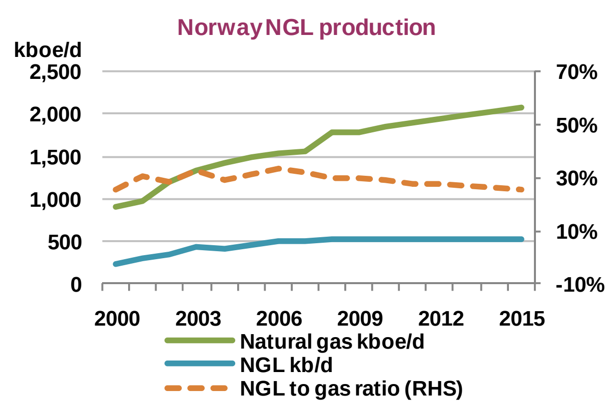
The NGL production for Norway is forecast to remain flat over the forecast period at around 530 kb/d. The source for Norwegian NGL data is the Norwegian Petroleum Directorate (NPD), which publishes monthly production data for condensate and other NGLs per field. The condensate from Kristin, Mikkel and Åsgard is blended with oil and marketed as the Halten blend. These condensate volumes were earlier reported with the Norwegian total condensate figures, and are still included among these in the condensate figures for Norway reported in the OMR, for the sake of series continuity. The oil production from these three fields, about 110 kb/d, accounts for the difference between the NPD and OMR NGL figures.

In Norway NGLs are mainly extracted and fractionated at the gas plant Kårstø at the southwestern coast of Norway, which, with a capacity to produce more than 170 kb/d of LPG and ethane and 90 kb/d of condensate, mainly for export, is one of the world's largest LPG export terminals. Most of the fields in the North Sea that produce rich gas deliver to Kårstø; the Gullfaks fields, Heidrun, Jotun, Mikkel, Norne, Sigyn, Sleipner fields, Statfjord fields, Urd, Volve and Åsgard. The second most important gas processing facility in Norway is the Kollsnes/Mongstad/Vestprosess complex which process both dry and rich gas from the fields Fram, Kvitebjørn, Kristin, Troll, Tyrihans and Visund. The LPG volumes from this plant are handled and sold together with refinery LPG from the Mongstad refinery. The Nyhamna gas plant extracts and exports condensate from the Ormen Lange field, while both condensate and LPG are sold from the Snøhvit LNG plant in the Barents Sea. Some Norwegian rich gas is also processed at Teeside in the UK, as the natural gas from the fields Eldfisk, Ekofisk, Tor, Valhall, Brae and Skirne is piped there, while rich gas from the fields Heimdal and the Statfjord Latelife are shipped to St Fergus in the UK by the FLAGS pipeline. As a marketer of the substantial LPG volumes exported from these facilities, including their own, state Petoro's and third party volumes, Statoil claims to trade 15% of the global waterborne LPG market.

The outlook for NGL production

Oil production in Norway is in decline, with an assumed average decline of 5% per year over the forecast period. A decline in associated gas production in Norway has a negative impact on the liquids ratio. The development of deeper and more complex reservoirs that often contain condensates however will help counteract this trend. The Norwegian natural gas giant Troll field produces dry gas.

None of the NGL facilities listed above plan expansions, possibly with the exception of a Snøhvit LNG train 2 (not included in the forecast) reflecting the maturity of this producing region. The Kårstø plant is currently under an upgrading programme named KEP 2010, although the upgrade is aimed at securing regularity and safety, rather than capacity expansion.



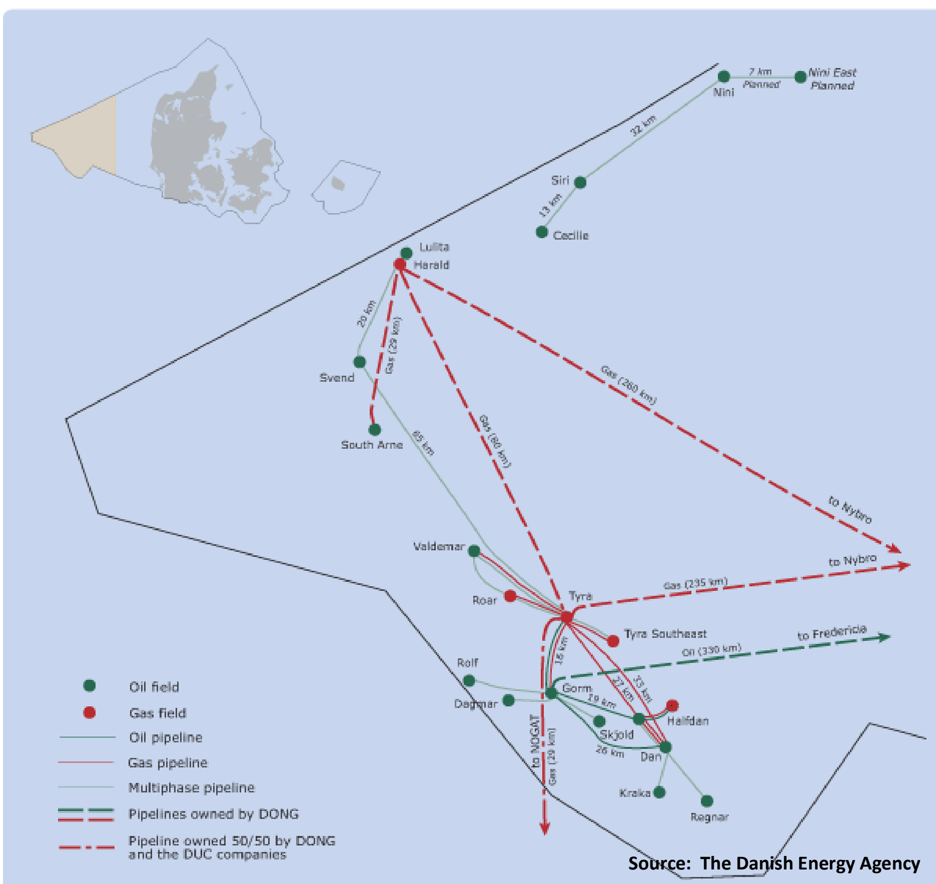
The NPD expects the NGL production to remain fairly constant over "the next five years" (statement from 2009). The NPD also recently published an outlook with forecasts running forward to 2013. In this projection, NGL production from Norway has been kept in line with the level suggested by NPD. After 2013, NGL supply has been held flat, but all in all, the Norwegian 2014 NGL forecast has been revised up by 97 kb/d compared with the 2009 MTOMR projection.

5.2.2 Denmark

Danish natural gas production is forecast to fall by an average of 8% annually from 10 bcm in 2008 to 6 bcm in 2015. Denmark does not report NGL or condensate production, but is believed to extract condensate from the well streams at the Tyra Øst processing facility/field centre, and at the Nybro gas treatment plant. The condensate volumes are likely reported along with crude oil.

The natural gas production infrastructure on the Danish continental shelf is focused around the Tyra field complex which receives gas from all gas producing fields off Denmark. Tyra Vest receives parts of the natural gas production from the Halfdan and Valdemar fields. Tyra Øst receives gas from the Valdemar satellites, Roar, Svend, Tyra Sydøst and Harald/Lulita, as well as the natural gas from Gorm, Dan and parts of Halfdan. At Tyra Øst there is a processing facility that includes a facility for preparation of oil, condensate, gas and water. The water is returned to the sea after cleansing at the platform.

Oil and condensate production from the Tyra field and satellites are led to shore via Gorm. Most of the natural gas production is fed from Tyra Øst to the Nybro Gas Treatment plant and the rest is exported from Tyra Vest to the NOGAT pipeline to the Netherlands.



Source: The Danish Energy Agency

5.2.3 UK

Relevant natural gas trends

UK oil production has fallen by 7% annually from 2000 to 2008, while the natural gas production has fallen by 6% annually in the same period. Both are expected to continue falling by 7% annually over the forecast period. However, NGLs have been more resilient and have fallen only by 2% annually from 2000 to 2008. In fact, many new fields that came on stream in 2008 were gas condensate fields, and more new gas condensate fields are expected to come on stream in the years to come. Among 50-60 fields that are expected to come on stream from 2009 and onwards, ten are gas condensate fields and nine are gas/oil fields that probably hold some NGLs as well, reflecting the trend of more condensate in the deep and complex reservoirs that are now being developed.

Current NGL production

The current NGL profile for the UK included in OMR comprises NGL and gas plant condensate as published by the Department of Energy and Climate Change. The 2008 production figure was 215 kb/d, falling from a peak of 271 kb/d in 2002.

In the UK, there are approximately 470 offshore oil and gas installations. These are mainly located in the Northern, Central and Southern North Sea, as well as in the waters west of Shetland and in the Irish Sea. The natural gas is piped to onshore gas processing facilities via broadly speaking four trunk line systems that also bring in gas from some of the Norwegian North Sea fields. In fact the British and the Norwegian continental shelves are highly integrated with some fields straddling both countries, like the Murchison field and the Statfjord field, which has caused some reservoir determination issues in the past.

The most important NGL producing system in the UK is the Shell Expro Gas and Associated Liquids Process System (SEGAL) which comprises the Far North Liquids and Associated Gas system (FLAGS) and Fulmar pipelines that bring in natural gas from the Brent fields. The natural gas is landed at the St. Fergus gas processing facility and the NGLs extracted there are sent south to the Mossmorran NGL plant for fractionation. The LPG and other gas plant products are then exported from the Braefoot Bay terminal, which may handle about 170 kb/d of NGLs and is the most important North Sea LPG export terminal next to Kårstø. The Forties pipeline system transports oil and gas liquids to the Kinneil gas-processing and stabilisation plant at Grangemouth which has an output capacity of about 40 kb/d. Production from around 25 fields in the central North Sea is connected by this trunk line, either through the Forties C platform or the new Unity platform. The third system brings rich gas to Teeside through the Central Area Transmission system (CATS) as well as through Norpipe. The fields brought in here are the Everest, Lomond, J-Block, Armada Area, Andrew, Banff, ETAP and Erskine fields, as well as some Norwegian North Sea fields. The volumes brought in via Norpipe are from Fulmar, Auk , Clyde and Gannet. About 10 kb/d of NGLs may be extracted at Teeside.

UK production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	73	71	66	61	56	52	48	44	-29	-7.0 %
Gas production (kboe/d)	1,265	1,222	1,135	1,052	973	897	826	759	-505	-7.0 %
NGL (kb/d)	215	179	174	176	180	170	160	150	-65	-5.0 %
NGL to gas ratio	17.0%	14.6%	15.3%	16.7%	18.5%	18.9%	19.4%	19.8%		

The outlook for NGL production

For the UK we have retained the existing OMR/MTOMR NGL forecast, which implies a lower decline for NGLs than for oil and gas. This reflects the trend of more gas condensate fields being developed in the mature phase of this region. Total production averages 215 kb/d in 2008, falling to 150 kb/d in 2015.

5.2.4 Netherlands

According to the WEO2009 forecast, natural gas production from the Netherlands is set to decrease by an average of 2% annually from 85 bcm in 2008 to 71 bcm in 2015. Only one third of Netherlands natural gas production now comes from the hitherto dominant Groningen field. The "small field strategy'' has been successful, whereby the decline in the large Groningen field is replaced by an "endless stream" of small onshore and offshore gas developments. Between 2008 and 2010 the Netherlands will put nine new fields on stream, and seven more fields are due to come on stream by 2014.

TNO, Geological Survey of the Netherlands, publish field by field production data on the webpage www.nlog.nl. The Netherlands has very small NGL production compared to its gas production. Over the forecast period the NGL production from the Netherlands is forecast to fall from 9 kb/d in 2009 to 6 kb/d in 2015. The NGL production consists only of condensate, and no central gas processing plant exists for the Netherlands. The tiny condensate production from the Netherlands is collected from the rich gas streams of almost 270 individual fields, at the beaching points for offshore fields or at field level for onshore fields, and transported to refineries by trucks or train. At the Rijn offshore oil field (P-15) the condensate from associated gas is separated and brought by oil pipeline to the Rotterdam area, while dry gas is transported in a gas pipeline. Sometimes nitrogen is also blended with the gas to adjust the heating value of the gas to the spec set for the gas distribution network (GTS). Our forecast implies a continuation in the trend we have seen since 2000 of a falling liquids to gas ratio.

Netherlands production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	85	77	76	75	75	74	72	71	-13	-2.4 %
Gas production (kboe/d)	1,460	1,331	1,316	1,300	1,284	1,267	1,249	1,231	-229	-2.4 %
NGL (kb/d)	9	9	9	9	8	7	6	6	-3	-6.6 %
NGL to gas ratio	0.6%	0.7%	0.7%	0.7%	0.6%	0.6%	0.5%	0.5%		

5.3 Russia and the Caspian region

Natural Gas Liquids in the Former Soviet Union

NGLs were often a forgotten component of natural gas production in the Soviet Union. The main reason for this is the substantial volumes of very dry gas (from Cenomanian-age reservoirs in West Siberia) as well as indifference to the potential of the associated gas liquids. The absence of equipment, dedicated pipelines and markets in the natural gas sector means that the Russian gas industry remains largely focused on pipeline gas. After the fall of the Soviet Union, the region's NGL business deteriorated, and output of LPG almost halved between 1990 and 1994. A Soviet initiative to use LPG as autogas was idled during these years.

Logistical issues and high transportation costs have limited market access and been an obstacle to Russian NGL output growth. Some special-purpose pipelines exist for transportation of NGLs from gas processing plants to petrochemical plants etc, but otherwise rail transportation is the dominant logistical solution for LPG in Russia, supplemented by road transportation on trucks and waterborne tanker vessels. In the 1960s Russia started shipments of LPG from the Baltic Sea to Europe, and even over the Atlantic to Cuba. For some time an NGL pipeline across the Urals provided a partial solution to the problem of NGL transportation in Russia. The pipeline transported so called ShFLU ("broad fraction", a kind of raw NGL mix) from the East to petrochemical plants in the West. However, the pipeline suffered a devastating explosion in June 1989 near Ufa, with over 100 fatalities, lit by the spark from a passing Trans-Siberian train, and has never again operated beyond Tobolsk.

However, several factors could make NGLs from the Former Soviet Union more important in the future

- The nature of Russian gas supply, as deeper, more NGL-rich gas production horizons are complementing the more mature Cenomanian reservoirs that are in decline.
- Environmental legislation that requires flaring of associated gas to decrease drastically. The target is 95% utilisation of associated gas by 2011.
- The participation of International Oil Companies that plan condensate and NGL extraction as an integrated part of the natural gas value chain, so far most notably in Azerbaijan and Kazakhstan.

5.3.1 Russia

Relevant natural gas trends

Russia marketed a total of 657 bcm of natural gas in 2008, making it the world's largest producer. Russian gas production fell sharply in 2009, as a consequence of recession-hit gas demand, but is expected to rebound again over the forecast period and reach 655 bcm in 2015.

In Russia, the bulk of natural gas production is non-associated, very light and clean gas that requires almost no gas processing at all, but may be fed directly into pipelines. However, as traditional reservoirs are being depleted, development of deeper reservoirs yields more liquids-prone natural gas that requires processing but at the same time may add valuable by-products. The quote below from the 2008 Annual report of Novatek illustrates this development.

"Currently, Russia has fewer known deposits of easily developed "dry" Cenomanian gas which is almost 100% pure methane and does not require additional processing. In recent years, there has been an increase in the discovery and development of deeper deposits of so called "wet" gas from Valanginian and Achimov horizons which also yields valuable gas condensate but requires additional processing. Our new plant removes current and future processing capacity constraints enabling us to optimize the development of our fields."

According to reporting from the Ministry of Oil and Energy in Russia, the production of associated gas in Russia was 55 bcm in 2009. The World Bank estimated that 40 bcm of Russian gas was flared in 2008, down from 50 bcm in 2007. An upcoming ban on flaring of associated gas as well as a change in the monopoly position of Gazprom and Sibur on gas processing and transportation is already about to change the scene for associated gas production in Russia. In February 2008 the government liberalised prices for associated gas and established a 95% utilisation target by 2011, accompanied by tougher penalties for flaring.

Russia production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	657	590	596	607	618	628	637	655	-2	0.0 %
Gas production (kboe/d)	11,322	10,167	10,264	10,461	10,645	10,820	10,986	11,288	-34	0.0 %
NGL (kbd)	536	589	627	662	698	735	772	817	281	6.2 %
NGL to gas ratio	4.7%	5.8%	6.1%	6.3%	6.6%	6.8%	7.0%	7.2%		

Current NGL production

NGLs in Russia are often referred to as *Shirokaya Fraktsiya Legkikh Uglevodorodov* (ShFLU). This is a wide-fraction, light hydrocarbon mixture, the basic constituent of LPG, fractionated at petrochemical plants or refineries. ShFLU has a yield of up to 70% LPG. LPG in Russia is referred to as *Szhizhennyye Uglevodorodnyye Gazy* (SUG).

ShFLU must be sold to customers that have the equipment to break it down into its components, often petrochemical plants. Those may then produce LPG from ShFLU. For this reason 34% of Russia's LPG production comes from four petrochemical plants. Russia also exports ShFLU as a quasi-raw material for further processing in Europe, especially to Poland.

The Russian Ministry of Oil and Energy does not report NGLs per se, but they do report LPG and condensate production per company. In this study we have applied the reports of LPG and condensate production per company as a starting point to arrive at a proxy for Russian NGL production. Based on the reported figures at August 2009 the LPG production of Russian gas processing plants was 230 kb/d, while the condensate production was 361 kb/d, a total of 591 kb/d. For condensate, the two big producers are Gazprom and Novatek at about 240 kb/d and 70 kb/d respectively in 2009. For LPG the number of significant producing companies is higher, the biggest of which are Gazprom, Sibur (the natural gas processing arm of Gazprom) and Lukoil. The overview below shows major gas plants and their estimated capacity to process gas and extract various NGLs. The overview is based on various web sites etc, and is assumed to be incomplete. For Gazprom the figures in the table are the reported production per August 2009.

NGL from Russian gas processing plants

Companies	Facility	Gas processing capacity (bcm/y)	Product	2009 production capacity (kb/d)
Lukoil	Korobkovsky GPP	0.5	LPG	3.2
			ShFLU	2.2
	Lokosovsky GPP	2.3	LPG	16.4
			ShFLU	11.2
	Sibur-Neftehim - Perm GPP	0.5	LPG	3.6
			ShFLU	2.5
	Usinsk GPP	0.5	LPG	3.8
			ShFLU	2.6
Lukoil Total		**3.8**		**45.4**
Sibur	Belozerny GPP, train 1,2	4.3	LPG	19.0
	Nizhnevartovsk, train 1-4	8.6	LPG	19.0
	Yuzhno Balyksky GPP	1.5	LPG	15.0
	Yuzhno Balyksky- expansion	1.5	LPG	15.0
	Gubinsky GPP	2.1	LPG	11.0
	Vyngapurovsky gas plant	2.1	LPG	11.0
	Nyagangazpererabotka	unknown	LPG	7.0
Sibur Total		**20.1**		**97.0**
Novatek	Purovskiy Condensate stabilization plant	3	Condensate	35.0
			LPG	20.0
Novatek Total		**3**		**55.0**
Rosneft	Otradensky	1	Ethane	2.0
			ShFLU	3.9
	Neftegorsky	1	Ethane	2.0
			ShFLU	3.9
Rosneft Total		**2**		**11.9**
Gazprom	Various Gazprom	52.5	Condensate	237.0
			LPG	68.0
Gazprom Total		**52.5**		**305.0**
Tatneft	Tatneft Gazpererabotka (incl Minnibaevo GPP)	0.4	Ethane	4.0
			LPG	11.0
Tatneft Total		**0.4**		**15.0**
Surgutneftegaz	Surgutneftegas	7.2	LPG	7.0
Surgutneftegaz Total		**7.2**		**7.0**
Grand Total		**89.0**		**536.3**

Source: Web pages and annual reports of the companies

The total estimated feed handling capacity for all these gas processing plants is 89 bcm. The Russian Ministry of Oil and Energy reported marketed Russian associated gas of 55 bcm in late 2009. Some of the gas processing plants, notably Novatek's plant treat liquids-rich non-associated gas and not associated gas.

The outlook for NGL production

The revamped forecast for NGL production for Russia is the most elaborate of those conducted during this study. The forecast sets the NGL output to increase from a 2008 level of 536 kb/d to a 2015 level of 817 kb/d, a compounded annual growth from 2008 to 2015 of 6.2%. This compares with MTOMR June 2009 estimates of 470 and 561 kb/d respectively.

The parameters of the forecast are

- Gas production forecast from WEO2009,
- Current flaring of associated gas and the assumed reduction in flaring, increasing the component of associated gas in the total natural gas production, and
- Liquids content in each category, and especially the evolution of liquids content in non-associated gas.

The split of NGLs between condensate and other NGLs is assumed to be constant as of total liquids from natural gas production over time. The table below shows the assumed liquids ratios in associated versus non-associated gas.

Assumed liquids content and volumes of Russian associated vs non-associated gas

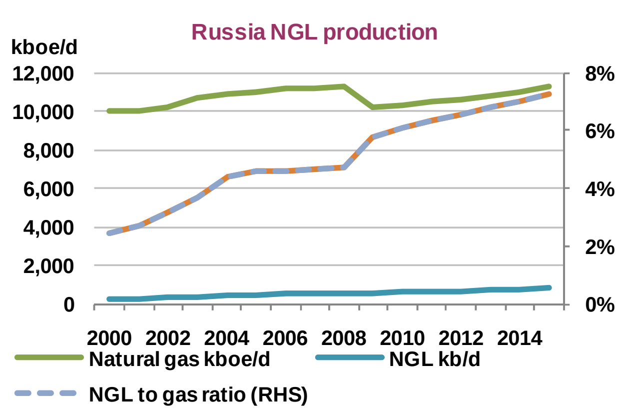
	2008	2009	2010	2011	2012	2013	2014	2015
Associated gas (bcm)	51.0	55.0	58.0	61.2	64.6	68.1	71.9	75.8
Liquids content	29.5%	29.5%	29.5%	29.5%	29.5%	29.5%	29.5%	29.5%
Non associated gas (bcm)	606.0	535.0	537.6	545.8	553.1	559.7	565.6	579.2
Liquids content	3.3%	3.4%	3.6%	3.7%	3.9%	4.0%	4.2%	4.3%

Associated gas

Recent estimates for associated gas production from Russia indicate 55 bcm, a level that is assumed to grow annually with the assumed reduction in flaring. According to officially reported data associated gas production in Russia has increased by 7% in 2009 when overall Russian gas production has fallen by 10%. However, this makes sense not only due to the reduction in flaring, but also due to the increase in Russian oil production over 2009. That is an important reason why we see Russian NGL production increasing in a year where gas production is going down considerably.

Flaring

For estimates of how much associated gas that Russia currently flares, the World Bank has published data showing 40 bcm in 2008. Official data from Russia is quoted to state that only 15 bcm of associated gas is flared in Russia. Industry sources envisage flaring of associated gas may be reduced by 25-30 bcm over the coming years. According to the World Bank Russia reduced flaring by 10 bcm from 2007 to 2008. This report assumes flaring to be reduced by another 21 bcm from 2009 to 2015 increasing associated gas production of Russia to 76 bcm. As mentioned earlier in the report, the World Bank flaring estimate is uncertain, not at least due to the shortcoming of their methods to identify the composition of the gas that is being flared, hence a high content of liquids in the gas flared could possibly inflate the estimate of the volume of natural gas being flared.



Liquids content in each category

For the liquids content of non-associated gas Gazprom production of LPG and condensate divided by the total non-associated gas production of Russia has been used, expressed in barrels of oil equivalent. For the liquids content of associated gas non-Gazprom gas plant production of LPG and condensate divided by the total non-associated gas production of Russia has been employed expressed in barrels of oil equivalent. The liquids content in non-associated gas is assumed to increase by 0.15 percentage point per year over the forecast period, while the liquids content of associated gas in Russia is expected to remain constant.

Limitations on growth

The primary limitation on NGL expansion in Russia has always been unattractive domestic pricing, difficult exports, a lack of third party access to pipelines and limited investments in midstream infrastructure.

However, it appears the needed policy changes are already happening, with many gas processing plant projects being announced and a policy change under way or already implemented as to third-party access to pipelines. Notably, the expansion of the Purovsky gas processing plant of Novatek is expected to double Novatek's capacity to extract NGLs from its gas over the forecast period.

5.3.2 Kazakhstan

Kazakhstani natural gas production is forecast to grow by 7.6% annually over the forecast period, from 26 bcm in 2008 to 43 bcm in 2015. Kazakhstan re-injects most of its associated gas to support oil production, while the Karachaganak field is the most important producer of natural gas. Over the recent years sales gas has been less than 50% of total reported output, as most of the balance has been re-injected to support oil production. With the exception of this field, most of the natural gas reserves of Kazakhstan are sour, with as much as 15% non hydrocarbon content, notably in the Tengiz and Kashagan fields.

Of the 305 kb/d of NGLs produced in Kazakhstan in 2008, most of the condensate is from the Karachaganak field. Natural gas from the Karachaganak field is processed at the Orenburg gas processing plant in Russia. For the Karachaganak condensate field there is a specific expected plateau and decline profile that is implemented in our condensate forecast. The next development phase of Karachaganak is assumed to enter into production in 2011 and boost Kazakhstani condensate production from 270 kb/d to 397 kb/d by 2012.

Kazakhstan has also four gas processing plants producing LPG, the biggest of which is the Tengizchevroil plant, which has contributed substantially to Kazakh gas plant liquids production and exports over the last years. Tengiz term sales into Poland compete with Russian LPG trade there, and Kazakhstan also exports LPG to Georgia, Hungary, Poland, Romania, Slovakia, Turkey, Finland, Kyrgyzstan, China and Iran.

Kazakhstan production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	26	34	31	33	35	38	40	43	17	7.6 %
Gas production (kboe/d)	446	591	527	565	605	648	694	743	297	7.6 %
NGL (kbd)	305	322	315	372	443	431	420	410	106	4.3 %
NGL to gas ratio	68.3%	54.4%	59.6%	65.9%	73.3%	66.6%	60.6%	55.3%		

We assume gas plant liquids production to grow at the same rate as the Kazakhstan gas production, namely 8% per year, from 34 kb/d in 2008 to 57 kb/d in 2015. The Kashagan field, one of the largest field ever discovered outside of the Middle East, is assumed to come on stream within the forecast period, and the crude production from this field is included in our crude oil production from the end of 2013. However, possible NGL profiles are not known and not included in this forecast, representing one potential source of upside risk for our NGL forecast.

5.3.3 Azerbaijan

Relevant natural gas trends

The gas production of Azerbaijan fell from 8 bcm in 1991 to 5 bcm in 2004, and then rose year by year to 16 bcm in 2008 and is expected to climb further to 20 bcm by 2015. The Shah Deniz phase 1 project was inaugurated in 2006, and reached its peak production level of 8.6 bcm in 2009, along with 43 kb/d of condensate. Azerbaijan's major natural gas production increases in the future are expected to come from the further development of the Shah Deniz field. Industry analysts estimate that Shah Deniz is one of the world's largest natural gas field discoveries of the last 20 years. The State Oil Company of the republic of Azerbaijan (SOCAR) has the right to most associated gas in Azerbaijan. The associated gas from the Azeri-Chirag-Guneshli (ACG) field has until now mainly been re-injected to support reservoir pressure. Important gas producing fields in Azerbaijan that are on decline are the Bakhar fields and the Gunashli shallow water fields.

Azerbaijan is a country that traditionally had dry gas and low awareness of NGLs, but that has now developed a gas condensate field in consortia with international oil companies.

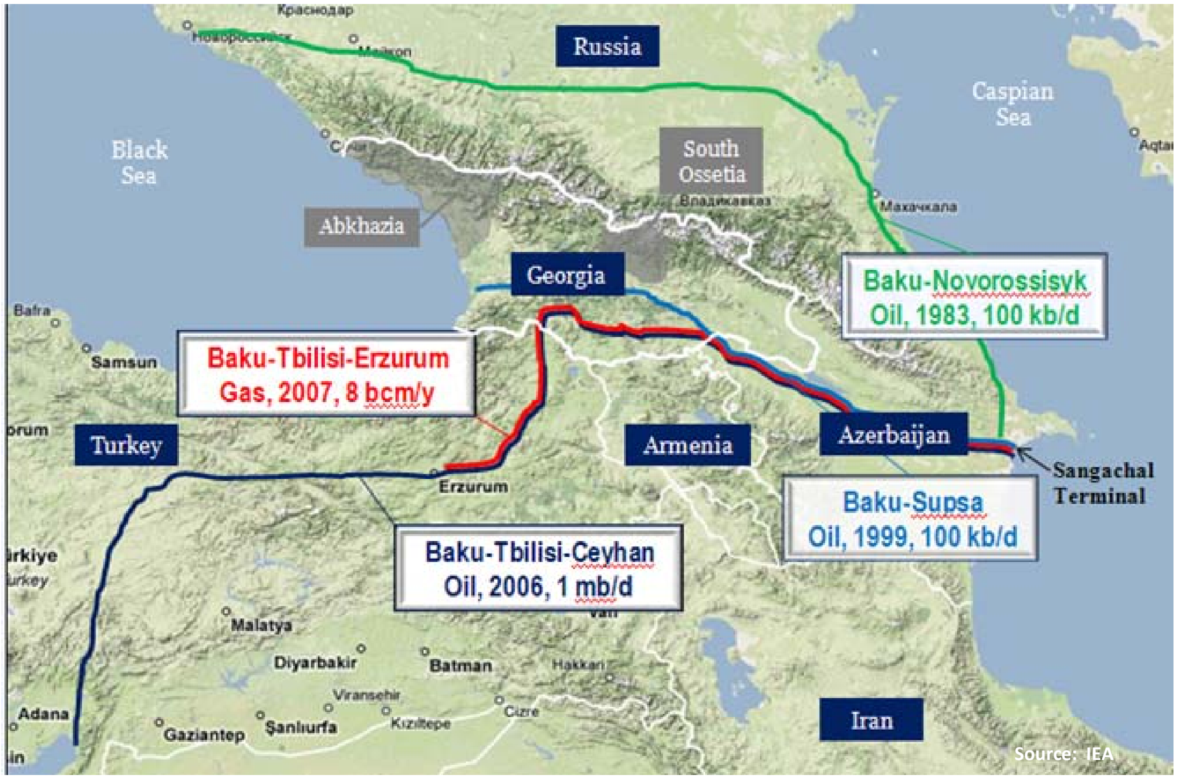
Azerbaijan production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	16	17	15	16	17	18	19	20	4	2.9 %
Gas production (kboe/d)	282	290	255	271	288	306	325	345	63	2.9 %
NGL (kbd)	42	44	42	46	46	46	46	46	5	1.6 %
NGL to gas ratio	14.7%	15.1%	16.5%	17.0%	16.0%	15.1%	14.3%	13.4%		

Current NGL production

SOCAR gas production in addition to some ACG gas production is processed by a gas processing plant operated by SOCAR. It was built in 1961 and has currently a capacity of 6.5 bcm of feed gas. Unconfirmed reports suggest production of only 1 kb/d of LPG annually from this plant, slightly increasing year on year over the last three years. Earlier OMR estimates had an NGL profile of 6 kb/d per year for Azerbaijan, but likely included refinery LPG from the refinery Azernefyanajag. The liquids ratio from traditional Azeri gas production appears to have been close to zero. However, with no official reporting on gas plant liquids this remains uncertain. Shah Deniz phase 1 yields 43 kb/d of condensate from 8.6 bcm of natural gas, a liquid to gas ratio of 30%.

Oil and gas volumes from the ACG field and Shah Deniz projects are brought to the Sangachal Terminal located on the coast of the Caspian Sea 45 kilometres south of Baku. The terminal receives oil from the ACG field and natural gas from the Shah Deniz gas field. From the Sangachal Terminal four oil and gas pipelines carry crude oil (including condensate) and natural gas to the Black Sea, Turkey and the Mediterranean Sea. The oil is exported via the Baku-Tbilisi-Ceyhan pipeline to Turkey's Mediterranean coast and via the Baku-Supsa Pipeline and the Baku-Novorossiysk Pipeline to the Black Sea coast.



The outlook for NGL production

For Shah Deniz phase 1 the existing OMR supply profile has been retained. For LPG growth of 5% per year has been assumed. This should reflect the general trend in FSU countries of better awareness of the value of LPG, as well as the natural gas production growth itself. We do not assume Shah Deniz phase 2 production until 2016, outside the limits of this forecast.

5.3.4 Turkmenistan

Relevant natural gas trends

Turkmenistan produced about 71 bcm of gas in 2008 and is forecast to raise its production to 86 bcm by 2015. The country has a huge potential due to the large resource base, with the highest proven reserves in the Caspian region at 3 tcm. The resources are probably much higher than the reserves, potentially placing the country at number four in the world after Russia, Iran and Qatar. The South Yolotan and Osman fields, which are yet to be developed, are thought to hold 4-14 tcm of natural gas alone, possibly making it the world's fifth largest gas deposit.

The largest gas producing field in Turkmenistan is the Daulatabad field in the southeast, which ranks as the world's thirteenth largest gas field. After the disintegration of the Soviet Union, Turkmen gas production was curbed by export constraints and price disputes, and in April 2009 Turkmen exports to Russia were further hit by an explosion in the Central Asia Center (CAC) pipeline and then an extended dispute over the terms for restarting gas sales operations. In December 2009 the country inaugurated the 30-40 bcm/y capacity Trans Asian Gas Pipeline (TAGP) to China. In January 2010 it opened its second gas export pipeline to Iran, named Daulatabad-Sarahs-Hangeran, increasing its natural gas export capacity to Iran from 8 to 14 bcm. With recently resumed natural gas exports to Russia, Turkmenistan is in the privileged situation of having viable export routes to North, South and East. The Nabucco pipeline would represent an opportunity for Turkmenistan to export natural gas to Europe, but for this option to materialise many issues remains to be solved, including how to transport gas across or around the Caspian Sea. Turkmenistan has many large fields that still remain to be developed, notably the South Yolotan–Osman field, which is a dry gas field, and the South Gutlyayak field, which is a gas condensate field. Contracts to develop the South Yolotan fields were recently awarded to Korean and UAE-based firms. Turkmenistan has restrictive policies for IOC involvement in onshore developments, but has currently several operational PSA agreements with IOC to develop offshore fields. It also has an agreement with CNPC to develop gas production in the East of Turkmenistan to fill the new pipeline to China.

Oil production in Turkmenistan is mainly located offshore in the Caspian Sea. The Serdar Kapaz field located on the division line between Turkmenistan and Azerbaijan is believed to have a high potential, though the political issues need to be resolved. However, information on associated gas and natural gas liquids from oil fields in Turkmenistan is very limited.

Turkmenistan production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	71	71*	72	74	77	80	83	86	15	2.8 %
Gas production (kboe/d)	1,221	1,227	1,232	1,279	1,327	1,377	1,428	1,482	261	2.8 %
NGL (kbd)	7	7	10	10	12	14	15	16	9	12.7 %
NGL to gas ratio	0.6%	0.6%	0.8%	0.7%	0.9%	1.0%	1.0%	1.1%		

*Estimate from mid-2009. The actual 2009 natural gas production was much lower than 71 bcm due to the dispute with Russia.

Current NGL production

In spite of being a large natural gas producer, Turkmenistan produces only small volumes of gas plant NGLs, placing its liquids-to-gas ratio at the lowest of the countries covered in the study. The gas plant LPG and condensate in Turkmenistan come from six processing units; four of them located at the Naipsky plant that process gas from the Naip, Gazlydepe and Balgul fields, and the fifth and sixth at the Bagadzha and Yashlar plants, that process gas from the Bagadzha field and the Yashlar fields respectively. All of these fields are onshore non-associated gas fields, and all of these plants have only small output of NGLs. The former NGL profile for Turkmenistan seemed to include all LPG production in Turkmenistan, of which most of it is refinery LPG, and the NGL profile for Turkmenistan has been revised down accordingly. The Turkmen state company Turkmengas is said to produce condensate in the East of the country, but these volumes are assumed to be included with our crude oil figures.

The outlook for NGL production

A new gas processing plant is planned by Petronas at the Kiyanly field. This plant would process rich gas from the Kiyanly, Diyarbekir and Magtymuly fields situated offshore in the Caspian Sea. The NGL production in Turkmenistan is assumed to increase by 13% annually, to account for the expected increase as a consequence of higher liquids content in some of the new gas fields to be developed.

The outlook for gas condensate fields in Turkmenistan might change the scene for condensate and NGL production in Turkmenistan in the future. Notably the South Gutlyayak field is said to contain a very rich gas. However, field details remain sketchy, suggesting longer term condensate development, outside the scope of this forecast.

5.3.5 Uzbekistan

Uzbekistan is expected to see almost flat natural gas production over the forecast period, from 67 bcm, via a decline to 66 bcm in 2009 up to 68 bcm by 2015. The country has many fields producing associated gas and non-associated gas, as well as gas condensate fields. The natural gas to liquids ratio is assumed to remain constant at 5%.

Condensate production in Uzbekistan fell from 71 kb/d in 2000 to 44 kb/d in 2007, and rose again to 55 kb/d in 2009, indicating that some new production might have come on stream. Uzbekistan has three gas processing plants with a joint production of 7 kb/d in 2008; Mubarek GPP, the Shurtan gas chemical complex, which are both new, and the Shurtanneftegas gas plant which is older. Market reports suggest that the gas plant LPG production of Uzbekistan was set to increase to 19 kb/d with the new capacity that has just been commissioned, but this includes refinery LPG. Sasol also plans to build a GTL plant in Uzbekistan, and the liquids stripping of gas to be fed into the GTL plant might add volumes of gas plant liquids.

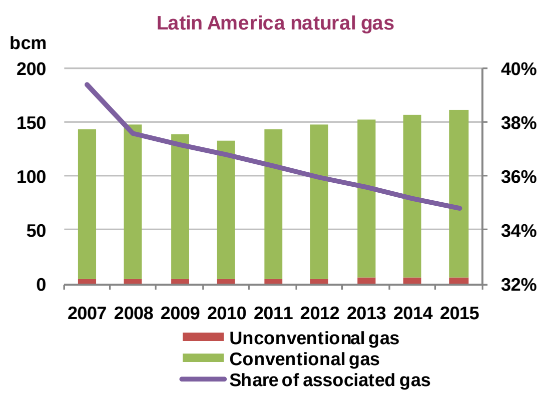
It is assumed that both condensate and other NGL production will grow at the rate of the natural gas production, although, the forecast remains uncertain in the absence of reliable condensate data. However, investments are taking place in gas processing and Uzbekistan has good export options for LPG, notably to Afghanistan and other central Asian republics. Total NGL production in Uzbekistan is set to increase from 59 kb/d in 2008 to 64 kb/d in 2015.

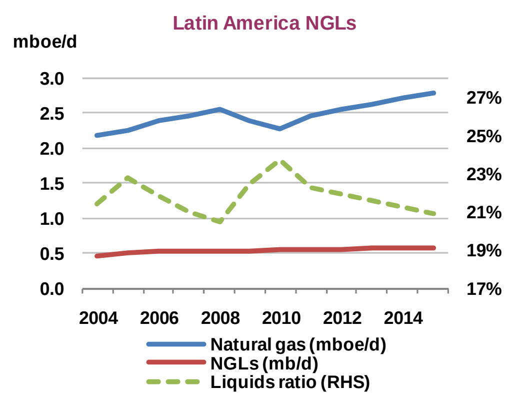
Uzbekistan production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	67	65	66	66	67	67	68	68	1	0.1 %
Gas production (kboe/d)	1,161	1,127	1,135	1,142	1,150	1,157	1,165	1,172	12	0.1 %
NGL (kb/d)	59	62	62	63	63	64	64	64	5	1.2 %
NGL to gas ratio	5.1%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%		

5.4 *Latin America*

Latin America holds 7.5 tcm of proven natural gas reserves, and the reserves have been falling since 2006. Venezuela has by far the highest natural gas reserves of this region, with 65% of the total, and its reserves have been increasing over the recent years. Regional production of natural gas is projected to rise by an average of 1.4% annually from 148 bcm in 2008 to 162 bcm in 2015. Venezuela has the highest potential to increase natural gas production, but in the present investment environment is only forecast to grow by 2.8 bcm over the forecast period. The highest levels of growth come from Bolivia at +6.4 bcm, Peru at +5.1 bcm and Brazil at +3.8 bcm, while other countries have falling or stable production.





The project realisation potential of both Venezuela and Bolivia represent the highest uncertainty in the Latin American forecast, as both countries might obtain higher growth if investment conditions were more favourable. Venezuela has three proposed LNG trains with a total capacity of 20 bcm, but none of them are expected to come on stream within the forecast period. The share of associated gas in Latin America is expected to fall from 38% to 35% over the forecast period, while the element of unconventional gas is predicted to remain stable at 5 bcm of tight gas.

NGL production in Latin America is forecast to grow with an average of 1.7% annually from 520 kb/d in 2008 to 585 kb/d in 2015. It is difficult to point to a specific trend in gas production that influences the NGL outlook for Latin America, mainly due to the lack of data and information. The most important contribution to NGL production in Latin America, an increase of 37 kb/d realised from 2008 towards the end of 2009 is the Camisea project, which now has a total NGL production of 80 kb/d, with the natural gas destined for the Peru LNG project that is due to come on stream in 2010. Our NGL forecast further assumes Brazilian NGLs to grow almost at the rate of natural gas production and to add 19 kb/d of NGLs over the forecast period. However, we do not have specific information about the NGL contribution from the new Brazilian gas developments, that we assume to come partly from associated and partly from non-associated sources. For Venezuela we have little information on the current state of the NGL production capacity, and the difficult investment climate continues to dampen growth prospects. Argentina, which is traditionally the most important exporter of LPG in the region, faces falling NGL production with declining natural gas production and little reserve replacement.

5.4.1 Argentina

Natural gas production in Argentina is forecast to fall over the period from 2008 to 2011, and then to rise from 2011 to 2015 by an average of 3.3% annually. During 2008 Argentina has strived to sustain LPG exports, because of a shortage of natural gas, and it has had to leave more heavy components in the natural gas to be able to meet domestic needs. In 2008 Argentina became an importer of LNG, something that will ease this situation. Argentina also imports gas from Bolivia, albeit the volumes have been very low. There is a natural gas pipeline built to export Argentinean gas to Brazil, but the pipeline is currently idled.

Argentina is the largest LPG exporter in Latin America, and exports LPG mostly to Chile and Brazil. Argentina has several gas processing plants of which the most important one is the fractionation plant at Bahia Blanca on the east coast. The plant receives NGLs extracted at various plants in Neuquen producing area in the middle of the country, including the much trumpeted Proyecto Mega, and prepares LPG for export as well as for distribution domestically. The offshore fields Carina and Aries are located on the Eastern side of the Southern tip of the country. Argentinean refinery LPG production has fallen somewhat from 35 to 30 kb/d over the last 10 years, along with oil production.

Argentina production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	45	41	36	37	39	40	41	43	-2	-0.7 %
Gas production (kboe/d)	772	708	626	646	667	689	712	735	-37	-0.7 %
NGL (kb/d)	125	115	101	105	108	112	115	119	-6	-0.7 %
NGL to gas ratio	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%		

Data availability is not good for Argentina, but a comparison of external sources suggest a 2008 condensate production of 30-40 kb/d and other NGLs of around 70-90 kb/d. The current OMR figure of 125 kb/d for 2008 therefore seems reasonable, and no revision was suggested. The liquids ratio of Argentina of 16% matches well with stated liquids ratios for the most important offshore gas fields in Argentina, Aries and Carina. Carina has a liquids ratio of 16%, and Aries is said to have "an even higher liquids ratio", according to the operator Wintershall. The distribution between condensate and LPG is 50/50 on the Carina field and not stated for Aries. Going forward our forecast suggests that the NGL production will follow gas production, implying an NGL forecast of 119 kb/d by 2015.

5.4.2 Venezuela

Relevant natural gas trends

Venezuela has 4.9 tcm of proven natural gas reserves, the second largest in the Western Hemisphere behind the United States. An estimated 90% of Venezuela's natural gas reserves are associated with oil. Most of the non-associated gas reserves are found in the offshore Northern basin. The petroleum industry consumes over 70% of Venezuela's natural gas production, with the largest share of that consumption in the form of re-injection to aid crude oil extraction. The marketed production of natural gas in Venezuela is estimated to have fallen over recent years from 28 bcm in 2000 to 23 bcm in 2008, as associated gas has fallen as a result of falling oil production, but is forecast to rise to 26 bcm again over the forecast period. Venezuela is a country with a high potential for increased gas production, with several big projects, including LNG projects, being planned. Most of Venezuela's non-associated gas is located offshore, and the most concrete plans to develop those resources are the Delta Caribe and Mariscal Sucre/Cigma projects that include LNG exports. However, given the many investment and operational problems confronting potential project sponsors in Venezuela, we do not assume these plans materialise over the forecast period, as is also implied by the WEO2009 natural gas forecast.

Venezuela production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	23	22	23	23	24	25	25	26	3	1.6 %
Gas production (kboe/d)	403	381	392	403	415	426	439	451	48	1.6 %
NGL (kb/d)	210	210	211	212	213	214	215	216	6	0.4 %
NGL to gas ratio	52.1%	55.1%	53.8%	52.6%	51.4%	50.2%	49.1%	48.0%		

Current NGL production and outlook

The gas hub of Eastern Venezuela is Anaco where liquids are extracted at the San Joaquin, Santa Barbara and Jusepin plants. The José gas processing plant in the state of Anzoategui, linked to Anaco by pipeline, is the only NGL fractionation plant in Eastern Venezuela. In Western Venezuela, in the Lake Maracaibo producing area, there is NGL extraction capacity at the Tia Juana, Lama and Lamarliquido processing centres and fractionation plants at Bajo Grande, Ule and El Tablazo. LPG and condensate are exported from the ports La Salina at Maracaibo in Western Venezuela and from José in Eastern Venezuela. Recent export data indicate that both NGL producing regions are operational and export both condensate and LPG. The total NGL fractionation capacity in 2006 is believed to have been 230 kb/d, based on various sources, possibly with field condensate on the top of that.

There are few verifiable sources available for current Venezuelan NGL production. Venezuela's Ministry of Oil and Mines (PODE) published detailed data earlier, but the time series stops in 2006. PDVSA filed reports on form 20-F with the SEC until 2005, and the latest 20-F, with production figures up until 2004, is considered as the last reliable source for NGL production data from Venezuela. According to that report Venezuela produced 25 kb/d of condensate and 166 kb/d of other NGLs in 2004, somewhat lower than the pre-strike production in 2002 of almost 220 kb/d of condensate and other NGLs. The current OMR NGL figure of 210 kb/d is based on a slight improvement of NGL production from the immediate post-strike situation.

According to the PODE report from 2006, 2004 production of NGLs was 286 kb/d, of which 124 kb/d was condensate and 162 kb/d was NGLs. The difference here could be the categorisation of condensate. The US EIA's estimate of natural gas plant liquids from Venezuela is currently at 216 kb/d. In their last country analysis brief of Venezuela the EIA suggests that Venezuela produced 300 kb/d of condensate and other NGLs in 2006. This is in line with the PODE 2006 figure for condensate and other NGLs.

Our conservative view on the NGL production from Venezuela is due to the many operational problems evident after the oil strike in 2002/2003 since when the industry lost many technical and managerial staff and saw a sharp dilution in foreign oil company involvement. Our outlook is based on a proportional growth along with the WEO2009 gas production forecast, resulting in a forecast of 216 kb/d in 2015.

5.4.3 Trinidad & Tobago

Marketed natural gas production in Trinidad & Tobago was 35 bcm in 2008, and is forecast to decline to 29 bcm in 2010, before increasing again to 34 bcm in 2015. Trinidad & Tobago is an established LNG exporter with an LNG capacity of 20.5 bcm from four trains at the Atlantic LNG plant built between 1999 and 2005.

The government of Trinidad & Tobago publish monthly NGL production figures, split in propane, butane and natural gasoline, totalling 38 kb/d in 2008, rising to 44 kb/d on average in 2009, but reaching 48 kb/d in the two last months of the year. LPG make up two thirds of the reported volumes. On the webpage of Atlantic LNG they stated the NGL production capacity per LNG train, which gave a total of 30 kb/d. The NGL facility at Atlantic LNG is assumed to be the only NGL plant in Trinidad & Tobago, but the capacity has obviously been expanded over the later years. It is unclear whether Trinidad & Tobago produces any condensate in addition to the gas plant liquids reported by the government. According to the government source about all the NGL production from Trinidad & Tobago is exported. External sources suggest that LPG exports from Trinidad & Tobago is approximately 20 kb/d, and highly variable over the year by the pattern of domestic consumption.

We assume that the natural gas volumes processed at the Atlantic LNG plant will be constant in volume and liquids content, and the NGL figure therefore is set flat over the forecast period at the higher level seen reported in the last months of 2009.

Trinidad and Tobago production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	35	34	29	30	31	32	33	34	-1	-0.3 %
Gas production (kboe/d)	598	593	505	520	536	552	569	586	-12	-0.3 %
NGL (kbd)	38	44	48	48	48	48	48	48	10	3.3 %
NGL to gas ratio	6.4%	7.3%	9.5%	9.2%	9.0%	8.7%	8.4%	8.2%		

5.4.4 Bolivia

Natural gas production in Bolivia is set to increase by 6% annually from a 2008 starting point of 14 bcm, to 20 bcm in 2015. Bolivian natural gas production jumped from 2003 to 2005 as Bolivia started to export gas to Brazil. The country also has installed a pipeline to export gas to Argentina, and the WEO2009 forecast assume a low utilisation of that export route.

Bolivia production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	14	14	15	16	17	18	19	20	6	5.6 %
Gas production (kboe/d)	241	241	265	280	298	317	334	352	111	5.6 %
NGL (kbd)	7	7	8	8	9	9	10	10	3	5.6 %
NGL to gas ratio	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%		

Bolivia regularly reports NGL figures, both gas plant LPG and condensate volumes. The volumes in 2008 were 1 kb/d of LPG and 6 kb/d of condensate. Natural gas from Bolivia reportedly has a high content of liquids, but the production of LPG has been impeded by slow investment in infrastructure. Some of the undeveloped discoveries of Bolivia are gas condensate fields, like the Margarita and Itau fields operated by BG. The current liquids to gas ratio is very low at 3%, so there could be substantial scope to expand output. It has been suggested that Bolivian gas plant liquids production could easily increase from 7 kb/d to 15 kb/d based on current infrastructure. Bolivia has possibly as many as 7 gas processing plants with a capacity to extract 22 kb/d of NGLs, among others a 5-train Repsol operated plant in Santa Cruz. The biggest plant in terms of NGL output is probably the BG operated plant in Vertiente. Bolivia's government has recently revived to expand operational NGL extraction and separation capacity in Rio Grande in the eastern region of Santa Cruz and Chaco in southeastern Tarija (see map).

There have been many violent civil protests in Bolivia against natural gas exports, and the unstable political climate underlies the conservative outlook for natural gas and NGL production, as compared to the potential. We assume a growth in line with the natural gas production growth, which will take the 2015 NGL production up to 10 kb/d, although clearly volumes could ultimately rise higher should natural gas potential be more fully realised.

5.4.5 Brazil

Relevant natural gas trends

Brazil is a modest natural gas producer with a 2008 marketed production of 13 bcm, but has a large potential both in terms of resources and for better utilisation of current non-marketed gas production. A lack of distribution infrastructure outside of the large coastal cities in the South East is an impediment to growth. The gross domestic output, which includes re-injection and flaring, is estimated at 59 bcm. According to the National Petroleum Agency (ANP), Brazil had gas processing plants in eight states with a joint capacity to process about 30 bcm of natural gas. The natural gas production is divided between the South East, the Amazon and the North East. The strongest growth region is the South East with the important Campus, Santos and Espirito Santo offshore basins. The natural gas in the Amazon and in the North East is mostly non-associated, while more than half of the natural gas is associated in the South East. Some natural gas is re-injected after liquids extraction, notably in Amazon state, where no infrastructure is currently in place to monetise natural gas. From 1998 to 2008 Brazil's marketed domestic gas production almost doubled from 7 bcm to 13 bcm. The marketed production is set to grow steadily by an annual rate of 4%, reaching 17 bcm in 2015.

From 1998 to 2008 Brazilian natural gas imports increased from zero to 12 bcm. Brazil imports natural gas from Bolivia as well as LNG, while an import pipeline from Argentina is currently idled. Brazil became an LNG importer in 2009, and imports small volumes of LNG to feed thermoelectric power plants in the South East.

Brazil production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	13	14	14	15	15	16	16	17	4	3.8 %
Gas production (kboe/d)	219	241	248	255	262	269	277	284	66	3.8 %
NGL (kb/d)	86	79	82	86	91	95	100	105	19	2.8 %
NGL to gas ratio	39.5%	32.6%	33.1%	33.9%	34.6%	35.4%	36.1%	36.9%		

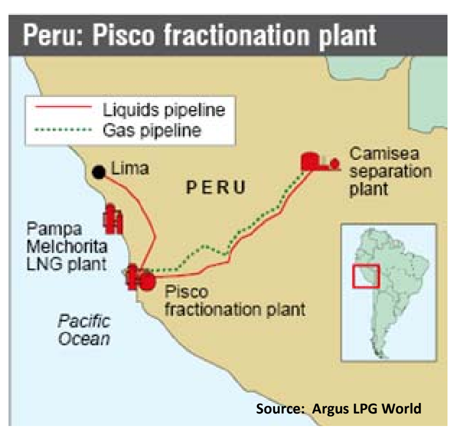
Current NGL production and outlook

The ANP is a primary source for NGL data for Brazil, and reports gas plant liquids, but not field condensates. The Brazilian NGL output equalled 86 kb/d in 2008, and the reported volumes are split into ethane, LPG and pentane. Production is also reported per gas processing plant. Brazil has nine gas processing complexes with liquids extraction, of which the Cabuinas complex in Rio de Janerio and the Urucu complex in the Amazon are the most important. At the Urucu complex the NGLs are extracted and transported via pipeline to the state capital Manaous, where LPG forms an important part of the fuel mix. Brazil lacks a gas gathering system offshore, especially for many mature fields in the South East. These fields are only connected to shore by oil shuttle tankers, while the natural gas is flared or re-injected without NGL extraction. Much of the associated gas is produced from deposits located below deep waters far from land. There is also often a high CO_2 content, and various technical challenges that must be overcome in order for the gas to be utilised. However, several gas processing plants are under construction in the South East to monetise dry gas and extract NGLs from new developments in the same basins.

The biggest uncertainty underlying our NGL forecast for Brazil is the speed of growth in marketed natural gas production, and how the new composition of natural gas sources will influence the ratio of NGL to natural gas. Our growth estimate assumes a constant liquids ratio to marketed gas going forward, with output reaching 105 kb/d by 2015.

5.4.6 Peru

Peru's project of the decade - the Camisea natural gas gathering and processing programme – was completed in 2009, and is likely to be the single most important contributor to Latin American NGL production growth over this forecast period. Peru's LNG plant will come on stream in 2010 and the marketed natural gas production of Peru will then reach 10 bcm from a 2008 level of 5 bcm. Peru LNG is one of the few LNG export projects in the world outside of Qatar due to come on stream in 2010, and the first in Pacific South America. The natural gas is transported westwards from the Camisea fields in the country's southeast rainforest through a 408 km pipeline to the terminal located 170 km south of Lima.



Source: Argus LPG World

Peru production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	5	3	3	10	10	10	10	10	5	10.2 %
Gas production (kboe/d)	90	53	58	164	168	171	174	178	88	10.2 %
NGL (kb/d)	43	74	80	80	80	80	80	80	37	9.3 %
NGL to gas ratio	47.7%	138.9%	138.3%	48.8%	47.7%	46.8%	45.9%	45.1%		

For Peru there is official data for liquids production per block, and the NGL production correspond to the liquids output from the Camisea field, which comprises block 88, 56 and 31-C in the reported figures. The NGL volumes are fractionated at the Pisco plant, and currently amount to 80 kb/d, which is marginally below the nameplate capacity of the plant. No further phases of the Camisea project or other big projects in Peru are assumed over the forecast period.

5.4.7 Ecuador

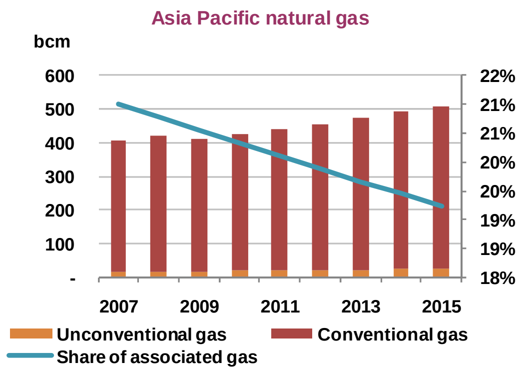
Ecuador's gas production is forecast to remain under 1 bcm by the end of the forecast period. Ecuador processes some of its associated gas at the Shushufindi plant in the Amazonas, while most of it is flared. Ecuador produces non-associated gas from the Amistad field in the Guaya bay, which is processed at a gas processing plant there. Our current NGL production estimate of 2 kb/d is set to decline towards 1 kb/d by 2011 and diminish by 2015. No revision is suggested to the Ecuador NGL profile, however their associated gas probably represents a potential that could probably be utilised better for NGL production and be a source of diversifying revenue to this OPEC country.

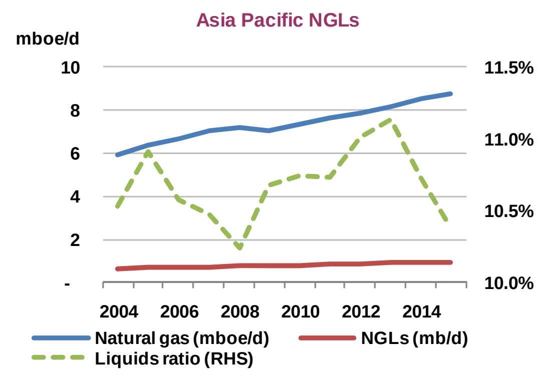
5.5 Asia-Pacific

The Asia-Pacific region holds 15 tcm of proven natural gas reserves, and this number has increased over the last years. China, but also Indonesia, Australia and India have upgraded their reserves recently. Asia-Pacific sees its natural gas production rise by an average of 2.8% annually over the forecast period, from 419 bcm in 2008 to 510 bcm in 2015. Natural gas production in India, China and Australia is forecast to grow by 31 bcm, 28 bcm and 21 bcm respectively, offset by weaker profiles in other countries. The share of associated gas to total conventional gas falls from 21% to 19%, while non-conventional gas rises from 15 bcm in 2008 to 27 bcm in 2015, where shale gas and coal bed methane in Australia, China and India stand for most of this growth.

Total NGL production in Asia Pacific is forecast to increase by an average of 3.1% annually from 2008 to 2015, from 738 kb/d to 912 kb/d, resulting in an increase of the liquids ratio for Asia-Pacific from 7.8% to 8.3% over the forecast period. Two of the large growth contributors are Indonesian and Vietnamese field condensate production, increasing by 66 kb/d and 59 kb/d respectively. Condensate is reported with NGL figures for Indonesia, Thailand and Vietnam, but not for China, India and Australia, where only gas plant liquids are included in the OMR figure. Condensate is included with the crude oil figure when not included with the NGL figure. If Indonesian and Vietnamese condensate were excluded from our forecast, the liquids ratio for Asia-Pacific would decline from 7.8% to 7.2% over the forecast period.

Another source of growth is Thai NGL production. Thailand is building new gas processing plants for its petrochemical expansions, and hence improving the liquids ratio and the utilisation of NGLs. India contribute 31 kb/d to the growth, while Australia contribute 21 kb/d to the growth, both with decreasing liquids ratios.





The countries that have the highest gas production growth over the forecast period, however tend to incorporate little in the way of associated liquids. The D6 development in the Krishna Godavari basin in India is rather dry, and the liquids ratio in India falls from 23% to 13% over the forecast period. China does not report any NGL production and as far as we know does not have any quantifiable production of gas plant liquids. However, China does according to several sources have rising condensate production, notably from the Tarim basin, although these volumes are not reported separately and are included in our crude figures. Our liquids ratio for China hence remains at zero throughout our forecast period. Australia produced 70 kb/d of gas plant liquids in 2008, in addition to about 130 kb/d of condensate that is reported along with crude. Over the forecast period NGL output from Australia is assumed to lag growth in natural gas production. Australia has several very liquids-prone LNG projects planned, notably Ichtys LNG and Prelude LNG, and should these materialise within the forecast period this would fundamentally raise our outlook for NGLs from Australia. However we assume these projects to come on stream after 2015. Likewise, we do not assume the PNG LNG plant to come on stream within our forecast period.

5.5.1 Indonesia

Indonesia is a mature oil and gas producing country, which struggles to maintain its gas production, and is set for an average annual decline of 1% from 77 bcm in 2008 to 71 bcm in 2015. Indonesia has a legacy NGL plant at Arun, a large LNG complex at Bontang and a newly opened LNG plant at Tangguh. We do not assume any new LNG trains enter service during the forecast period, in spite of some proposed projects.

For Indonesia our NGL figure includes both condensate and other NGLs, as reported monthly by the Indonesian regulatory body BP Migas. The condensate baseload consists of declining Arun condensate and some Bontang condensate from the Bekapai and Handil fields, which reportedly had a total production of 75 kb/d in 2008. The Tangguh LNG plant just started up and added a small volume of condensate. We forecast a growth in condensate production from 115 kb/d in 2008 to 180 kb/d in 2015 with new condensate volumes coming on from the Aster field, the Gendalo Gehem field and the Kirisi-Hiu field.

Indonesia production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	77	66	69	70	70	71	71	71	-6	-1.1 %
Gas production (kboe/d)	1,324	1,139	1,196	1,210	1,213	1,216	1,219	1,222	-102	-1.1 %
NGL (kb/d)	146	154	183	194	217	217	217	217	72	5.9 %
NGL to gas ratio	11.0%	13.5%	15.3%	16.0%	17.9%	17.9%	17.8%	17.8%		

BP Migas reports LPG production by gas plant, and this figure totalled 31 kb/d in 2008. The numbers of gas plants in 2008 was 12, where 82% of total production came from the Jabung and Belanak plants. Indonesian LPG production was 60 kb/d early in the decade, but fell to 13 kb/d in 2006 due to an outage of the Bontang plant. Going forward the gas plant liquids production is forecast to increase by an average of 3% annually, as new investments are undertaken in NGL extraction capacity, and is set to reach 37 kb/d by 2015. LPG demand in Indonesia recently doubled as the authorities used subsidy mechanisms to divert demand from kerosene to LPG, and this is a driver for investments in NGL extraction capacity.

5.5.2 Malaysia

Gas production in Malaysia is expected to grow by 1% annually from 62 bcm in 2008 to 64 bcm in 2015. There does not appear to be a good official source for NGL data in Malaysia. The OMR NGL figure excludes condensate, which is included in the crude production numbers. According to external sources Malaysian non-refinery LPG production jumped in 2006 from 40 kb/d to 65 kb/d due to the opening of a new gas processing plant. The plant in question is probably the GPP1 that was rejuvenated in 2006 and added capacity, though it is hard to obtain information regarding the quantity. The new train on the LNG facility in Malaysia MLNG 3 (Tiga) that became operational in 2003 and added about 60-70 kb/d of condensate and 10.5 kb/d of LPG might also have ramped up production during this year. Based on this information our 2008 NGL baseline has been revised from 47 kb/d to 65 kb/d.

Malaysia production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	62	61	61	62	62	63	64	64	3	0.6 %
Gas production (kboe/d)	1,060	1,044	1,054	1,065	1,075	1,085	1,096	1,107	46	0.6 %
NGL (kb/d)	65	65	66	66	67	68	68	69	4	0.8 %
NGL to gas ratio	6.1%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%		

Malaysia also produces condensate, including 80-90 kb/d from fields that produce feedgas for the MLNG plant, called Bintulu condensate. External sources vary a great deal on the outlook for Malaysian condensate production. The Bintulu condensate is assumed to decline towards the end of the forecast period, while new sources of condensate include the Gumusut and Malikai fields. The Malaysian condensate is reported along with crude in the OMR. We assume gas plant NGL production to grow in line with natural gas production, and reach 69 kb/d by 2015.

5.5.3 Thailand

Thailand's gas production appears to be flat at 28 bcm from 2008 to 2015, but this hides a fall from 2008 to 2009 and growth thereafter. Thailand has produced natural gas from the Gulf of Thailand since 1981, and natural gas is extensively used domestically for power generation, transportation fuel and industrial appliances. Thailand has seen a steady stream of new offshore gas developments and does also have a potential in the overlapping area with Cambodia, where one project entered into production in 2008.

Thailand production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	28	24	26	26	27	27	27	28	-1	-0.4 %
Gas production (kboe/d)	488	419	442	449	459	466	470	474	-14	-0.4 %
NGL (kbd)	170	170	169	184	194	204	214	214	44	3.4 %
NGL to gas ratio	34.7%	40.5%	38.2%	41.0%	42.3%	43.7%	45.5%	45.1%		

The Energy Policy and Planning Office (EPPO) of Thailand reports monthly condensate and LPG production data. The agency posted 2008 production at 170 kb/d with 84 kb/d of condensate and 86 kb/d of gas plant LPG. Thailand is undertaking an active industrial development in the Rayong industrial area at the north of the Thailand bay, where the GSP6 Rayong, the GSP7 Ma Ta Phut, the ESP Rayong ethane gas processing units are planned, and where the country also envisages to double its petrochemical industry. Another new gas plant project is the TTM GSP2 Songkhla plant, situated at the southwest of the Thailand bay. Early in 2010 the news were launched that the Ma Ta Phut NGL plant of Thailand, along with several other industrial projects in the area, which were ready to resume operations, had been halted due to failure to comply with environmental requirements. The start-up of the new NGL/ petrochemical complex of Thailand was therefore delayed by 1.5 years, and gas plant LPG production is now assumed to build up from 2011 and onwards and reach the targeted 130 kb/d level by 2014.

The condensate production is assumed to remain stable over the forecast period. Current condensate production from among others the Pailin, Erawan and Bongkot fields, as well as new production from the Arthit field that started operations in 2008, are expected to sustain production levels throughout the forecast period, and decline is going to be replaced by new developments. For Thailand planned NGL expansions outpace the growth in production of natural gas, as exploitation of liquids increases, driven by the growth ambition for petrochemical production in Thailand. Thailand also imports condensate and LPG to fill its domestic needs.

5.5.4 India

Relevant natural gas trends

India is entering a new gas era and compounded annual natural gas production growth is set to 11% from 29 bcm in 2008 to 60 bcm in 2015. The production from the Krishna Godavari basin on the mid-east coast of India will possibly reach 30 bcm by 2011, with the 2008 development of D6 by Reliance being the first project to be launched. While the liquids ratio of Indian gas has been around 25-20%, the new gas is deemed to be drier and results in only small increments to the NGL production.

India production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	29	38	41	44	48	52	56	60	31	11.0 %
Gas production (kboe/d)	498	655	707	763	823	889	959	1,036	537	11.0 %
NGL (kb/d)	113	118	120	122	124	126	129	131	19	2.2 %
NGL to gas ratio	22.6%	18.0%	16.9%	16.0%	15.0%	14.2%	13.4%	12.7%		

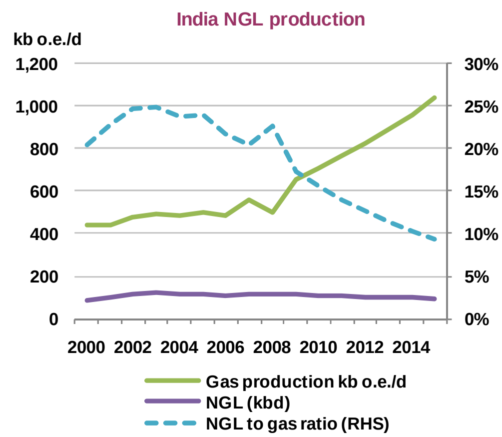
Current NGL production

For India there does not appear to be any official source for NGL data, but an important external source is the publication "Indian Oil & Gas", where gas plant liquids production data are reported as "products from fractionators. In 2008 production was 113 kb/d rising to 118 kb/d in 2009, as natural gas production increased by 9 bcm. Condensate from the Bombay offshore basin is reported in the magnitude of

39 kb/d in 2005 increasing evenly to 47 kb/d in 2009, but these volumes are included within the OMR crude figures for India.

No new gas processing plants seem to have been built or planned as a consequence of the D6 offshore development. The D6 gas is processed at six GAIL operated gas processing plants that already process gas from the Panna Mukti Tapti gas offshore field, which reportedly is set to increase its production as well.

India is a mature LPG consumer with demand about 400 kb/d annually, with 80% of demand met by domestic refinery LPG production. GAIL operates an LPG pipeline, opened in 2000, that transports LPG 1267 km from Jamnagar to Loni, near Delhi. Refinery production of LPG is growing in India because of the recently expanded Jamnagar refinery, but demand growth is slowing. Now as the country enters a new gas era, greater natural gas distribution reportedly hampers the growth of LPG consumption, the same trend as we see in China.



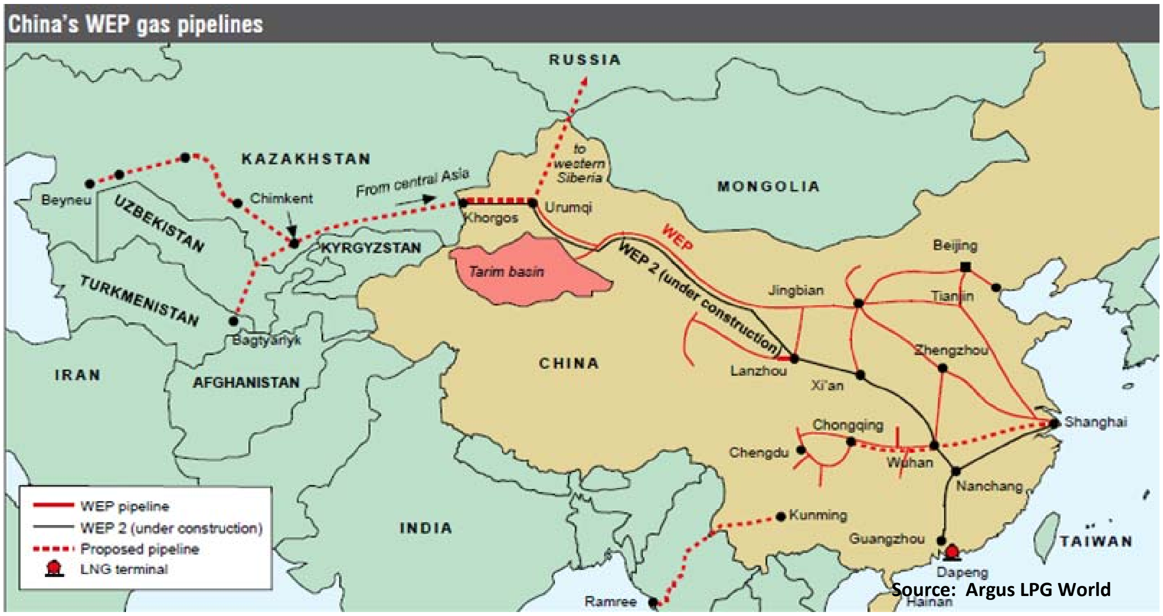
The outlook for NGL production

While further D6 Krishna Godavari developments are expected, the natural gas is believed to be dry. While gas production in India rose by 31% from 2008 to 2009, NGL production increased by only 5%. The same proportional increments in NGL production from rising Indian gas production is assumed, implying a fall in the liquids ratio from 23% in 2008 to 13% in 2015. NGL production is forecast at 131 kb/d for 2015.

5.5.5 China

China's gas production is set to grow by an average of 5% annually from 76 bcm in 2008 to 104 bcm in 2015. No data on NGL or condensate from China is available from official sources, and neither the OMR data nor most comparable sources include any segregated NGL or condensate volumes from China. Natural gas in China is believed to be mostly from coal formed deposits that contain little liquids, but often contain hydrogen sulphide (H_2S). However, the natural gas from the continental Tarim Basin and Permian gas of Ordos Basin should be relatively wet, while the driest gas is thought to be the marine natural gas of Sichuan Basin and biogenic gas of Sanhu region of Qaidam Basin. The Tarim basin is in a production step-up period with the West-East natural gas pipeline just coming on stream, and is believed to currently supply at least 100 kb/d of condensate, stepping up to 150 kb/d over the forecast period. CNPC reportedly has proved 13 high pressure gas condensate fields in the Tarim basin.

China has a high consumption of LPG, but all of it is supplied by its refineries as well as traditionally some imports. However, natural gas is replacing LPG in the residential sector, which has caused LPG demand to stagnate, while the petrochemical sector has been mostly reliant on naphtha. As naphtha is often the main product yielded by condensate, the condensate deposits should be most welcome for China going forward. Although condensate volumes may rise going forward, a lack of specific data prevents the separation of this production from crude production.



5.5.6 Australia

Relevant natural gas trends

Australia holds 2.6 tcm of natural gas reserves, second only to China in the Asia-Pacific region. Its natural gas production of 45 bcm in 2008 ranks it fourth regionally below Indonesia, China and Malaysia. The natural gas production growth from 33 bcm in 2000 to 45 bcm in 2008 is slightly lower than its projected growth of 5.6% per year from 2008 to 2015, expected to take its natural gas production to 66 bcm. Australia currently operates two LNG complexes, the 4.5 bcm Darwin LNG which is fed by natural gas from the Bayu Undan field in the shared zone between East Timor and Australia, and the 22 bcm North West Shelf LNG, of which the fifth train came into production in 2008. Natural gas production in central and southwest Australia feeds domestic natural gas consumption, whereas production on the North West Shelf tends to be aligned towards LNG exports.

Australia has a list of LNG projects pending over the forecast period. Assuming all possible projects start up on schedule Australian natural gas production could theoretically rise from 45 bcm in 2008 to 100 bcm by 2015. However, the WEO2009 gas forecast entails an increase of only 21 bcm over the forecast period. This would imply continued ramp up at the NWS LNG plant, two 6.5 bcm phases of the Pluto LNG development, the first of which is due to come on stream in 2011, and the Gorgon development, that will add 20.5 bcm of capacity, coming on stream towards the end of the forecast period.

Australia production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	45	50	53	55	58	60	63	66	21	5.6 %
Gas production (kboe/d)	779	866	907	949	993	1,040	1,088	1,139	360	5.6 %
NGL (kb/d)	74	79	83	87	91	95	99	104	30	5.0 %
NGL to gas ratio	9.5%	9.1%	9.1%	9.1%	9.1%	9.1%	9.1%	9.1%		

Current NGL production

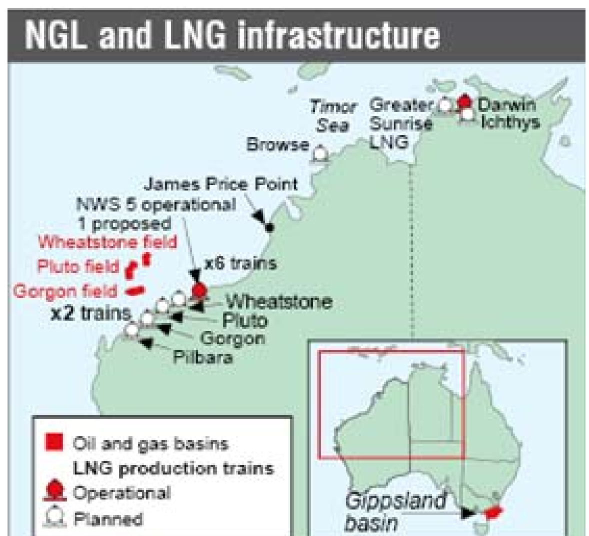
While natural gas production has been growing by 4% annually from 2000 to 2008, the production of gas plant NGLs has been variable between 73-89 kb/d, and is currently at the same level as in 2000, below 80 kb/d. This has caused the liquids ratio of Australia to fall from 14% to 9% over this period.

The Australian Bureau of Agricultural and Resource Economics (ABARE) publishes disaggregated data on condensate and gas plant liquids production. The condensate production of about 140 kb/d is included with our crude figures for Australia, while a 2008 figure of 74 kb/d of NGLs included gas plant LPG and ethane. Gas plant LPG and ethane in Australia comes mainly from the North West Shelf LNG gas processing plant at Karratha, the Gippsland gas processing plant and several smaller new gas processing plants near Victoria in the South East and the Moomba gas processing plant in the Cooper basin. Condensate comes mainly from the North West Shelf, with about 10 kb/d from the Gippsland basin. The around 100 kb/d of condensate from the Bayu Undan field that is attributed to East Timor in OMR estimates.

The outlook for NGL production

The amount of liquids in an LNG project is important for its economic viability, and many of the proposed LNG projects in Australia have high liquids ratios. The Ichtys project stands out with a liquids ratio of 80%, and Prelude LNG with 51% (including the condensate). However, the Pluto and the Gorgon projects, which are the next LNG projects scheduled, appear to have less liquid content. Australia has also proposed some coal bed methane-based LNG projects, but those projects are not assumed to materialise over the forecast period.

As NWS LNG added a new train in 2008, total liquids production from the complex remained constant, as decline in LPG production was offset by rising condensate production, so that the liquids ratio for this project went down. Australia's second most important LPG producing area, the Gippsland basin, has also posted declining NGL production figures. But the Kipper project will add gas volumes to the Gippsland gas processing plant, and is expected by 2011. Three newer gas processing plants have recently been build near the Gippsland gas processing plant, the Bassgas, Minerva and Otway gas processing plants, to support several gas developments in the area, although these projects are only expected to smooth the decline of the basin. The third most important NGL producing basin of Australia, the central-east onshore Cooper basin, is also in decline.



Source: Argus LPG World

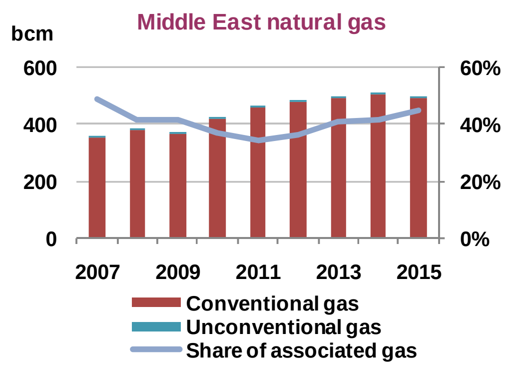
Recently, ABARE stated that Australian LPG production will increase by 35% by 2013-14. However, after having scrutinised the upcoming Australian gas developments to the degree possible, we take a more cautious outlook. For example the Browse and the Ichtys LNG projects might add 50 kb/d of gas plant LPG production each, but we assume these projects to come later than 2015.

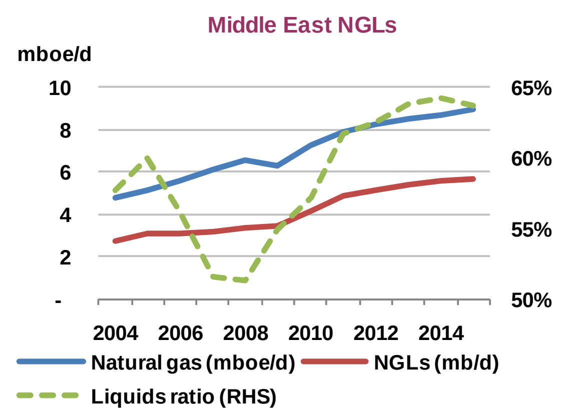
Our forecast assumes that the liquids ratio remains constant at its current level of 24%, implicitly a downward revision of the prevailing OMR/MTOMR projections. But with higher gas potential on one hand, and a trend towards drier gas on the other, uncertainty permeates this outlook.

5.6 Middle East

The Middle East holds 75 tcm of proven natural gas reserves, 41% of the world total. Reserves are highly concentrated in Iran, Qatar and Saudi Arabia, which account for 82% of total natural gas reserves in the region, which have also been increasing over recent years. The Middle East sees the production of natural gas increase most rapidly over the forecast period, at a compound annual growth rate of 4.6% per year. Production is forecast to rise from 379 bcm in 2008 to 521 bcm in 2015, where Qatar has the highest growth in absolute terms over the forecast period, with +86 bcm, while Iran and Saudi Arabia grow by 14 bcm and 15 bcm, respectively. That said, the forecasts for many countries in this region are highly uncertain, especially for Iran, which has a very big potential but struggles with project execution.

This region also sees the sharpest rise in the share of non-associated gas as compared to associated gas, next to Africa. Middle East countries have traditionally produced associated gas as a by-product of oil, but have now a growing need for natural gas for domestic consumption and in the case of Qatar, Abu Dhabi, Oman and Yemen, and possibly Iran, LNG export plans, and this has led to a growth in non-associated gas production. The Middle East countries are dependent on export revenues from oil, and therefore prioritise the use of natural gas domestically. They use natural gas for the domestic sector, power generation and desalination of water. Some countries also re-inject large volumes of natural gas into oil reservoirs to support oil production, notably Iran. Many Middle East countries have had difficulties involving IOCs in gas developments for domestic consumption, due to an uncompetitive price environment, and sometimes difficult gas reservoir conditions. Due to a lower than envisaged speed of gas developments, some Middle East countries are now facing the outlook of having to import LNG, a prospect that will probably trigger more rapid development of domestic gas resources.





For the Middle East countries that are OPEC members, as for other OPEC members, natural gas, condensate and other NGLs accrue an additional advantage, in that such production is exempt from the cartel's self imposed production quotas. Therefore the export of LNG and NGLs may represent a steadier source of income for the countries. This is one reason why many OPEC countries were among the first countries outside of the USA to build advanced systems to extract and monetise NGLs from associated gas production. Saudi Arabia has for a long time been the world's largest exporter of LPG, but recent expansions in the local petrochemical sector have reduced the scope for LPG exports.

Iran and Qatar also enjoy benefits of scale, as much of their natural gas reserves are situated in one huge field, the South Pars/ North Field that straddles the Iran/ Qatari border in the Middle East Gulf. This enables development in which large quantities of NGLs and natural gas can be developed simultaneously and hence allow advantages of scale in midstream investments.

NGL production in this region increases more than natural gas production, at a compounded annual rate of 7.9% over the forecast period. Notably there is a jump in NGL production from 2009 to 2010 of +0.7 mb/d and from 2010 to 2011 of +0.8 mb/d. NGL output in Qatar is expected to rise by 0.5 mb/d, and in Iran, United Arab Emirates and Saudi Arabia by 0.3 mb/d each over these two years. At the same time, the liquids ratio for Iran increases from 29% to 40% , from 130% to 139% for Saudi Arabia and from 64% to 91% for the UAE, while the liquids ratio for Qatar rises more moderately from 45% to 49%. The upward surge in the liquids ratio is not so much reflected in the resource potential for these countries as in the need to develop the NGLs early to improve project economics and realise attractive liquids sales that are not subject to OPEC quotas. A high NGL content in natural gas is often also a condition for IOC participation as long as domestic natural gas prices are so low. In summary, the main trends in gas production in the Middle East relevant for NGL production are large scale natural gas developments with IOC participation and the development of more gas condensate fields.

5.6.1 Saudi Arabia

Relevant natural gas trends

Natural gas production from Saudi Arabia is set to increase by an average of 2.7% annually over the forecast period, from 70 bcm in 2008 to 85 bcm in 2015. This forecast is in line with a recent growth outlook statement from the Saudi Aramco CEO, but looks modest in comparison with the potential rise in domestic gas needs.

Saudi Arabia holds 7.6 tcm of proven gas reserves, comparable to the size of US natural gas reserves, but dwarfed by the region's two gas reserve giants Qatar and Iran. Associated gas accounts for 60% of the total reserves. More than half of the annual natural gas production in Saudi Arabia so far has been associated gas. Marketed production equalled around 70 bcm in 2008. According to the 2008 annual report of Saudi Aramco, the kingdom has a natural gas processing capacity of 96 bcm, which they plan to step up to 129 bcm over an undefined period.

Current non-associated natural gas production in Saudi Arabia comes from the Khuff field beneath the Ghawar and the Abqaiq oil fields, while the associated gas comes mainly from the Ghawar field, but also from the Safaniya, Zuluf and Abqaiq fields. For many years, Saudi Arabia has struggled to meet its domestic needs for gas in the petrochemical sector, desalination of water, power generation and some re-injection. Production cuts due to OPEC quota commitments have also curbed the production of associated gas. The biggest projects to expand non-associated gas production are the Karan field, which will add 19 bcm from 2011/12, and the Arabiyah and Hasbah fields/ Wasit facility that could yield 26 bcm of natural gas beyond the forecast period. Due to gas shortage, the government halted gas-fired power plant construction in 2006, shifting to oil. Recent months have also seen rising volumes of crude used for power generation, as international markets have remained weak. The government has also encouraged development of new gas fields, especially in Saudi Arabia's "Empty Quarter", but poor sales terms for gas discourage the participation of IOCs, which are more interested in finding condensate. Saudi Arabia is also considering LNG imports.

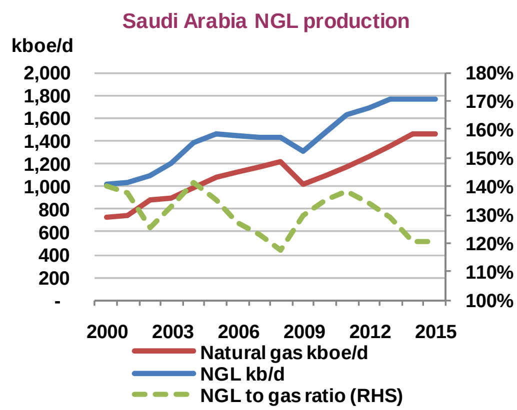
Saudi Arabia production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	70	59	63	68	73	79	85	85	15	2.7 %
Gas production (kboe/d)	1,212	1,011	1,089	1,173	1,263	1,360	1,465	1,465	253	2.7 %
NGL (kbd)	1,427	1,311	1,475	1,625	1,690	1,759	1,768	1,765	338	3.1 %
NGL to gas ratio	117.8%	129.6%	135.5%	138.6%	133.8%	129.3%	120.7%	120.5%		

Current NGL production

The Saudi Aramco annual report forms the basis for OMR historical NGL production figures for the kingdom. The production data are disaggregated in condensate, gas plant LPG and ethane. The latest data are from 2008, meaning that our 2009 figure is an estimate. Saudi Arabia bore the brunt of the OPEC production cuts as a response to the economic recession, and this is likely to have curbed NGL output in 2009.

Saudi Arabia's Master Gas System collects both associated and non-associated gas from fields throughout the country. The Master Gas System consists of numerous gas-oil separation plants (GOSPs) at fields, gas-processing plants and an extensive NGL pipeline network. In fact Saudi Arabia has been a pioneering state within the NGL business, and its Yanbu gas processing plant was one of the world's first sources of gas plant NGLs. The Master gas system is said to have a gathering capacity of 114 bcm of gas. The plants classified during this study as NGL extraction plants are estimated to have a capacity of 134 bcm of natural gas. Those are the older Berri, Shedgum, Utmaniyah and Abqaiq plants, and the Haradh, Hawiyah and Khursaniyah plants that have recently added capacity. The plants that are classified during this study as NGL fractionation plants, are estimated to have a capacity of 2.5 mb of NGLs. Those plants are the Ju'aymah plant and the Yanbu plant that are both being expanded. The Ju'aymah plant is located by the Arab Gulf, while Yanbu located by the Red Sea. An NGL pipeline connects the two NGL centres.



Saudi Arabia is the world's biggest exporter of LPG, followed by Algeria and Norway. Saudi state marketer Petromin sells LPG in all markets and has traditionally been an important provider of benchmark LPG prices both East and West. Exports of refinery LPG from Saudi Arabia started from Ras Tanura in 1961. Until the 1970s the LPG exports from Saudi Arabia went entirely to Japan. After the oil crisis in 1973 Saudi Arabia launched its master gas system to recover liquids from gas previously flared. Since half of Saudi Arabia's LPG production comes from associated gas, the production has decreased recently, due to its lower OPEC quota. Going forward Saudi Arabian LPG exports are expected to decline due to the sharp build-up in the petrochemical industry within Saudi Arabia that will create more domestic gas liquids demand.

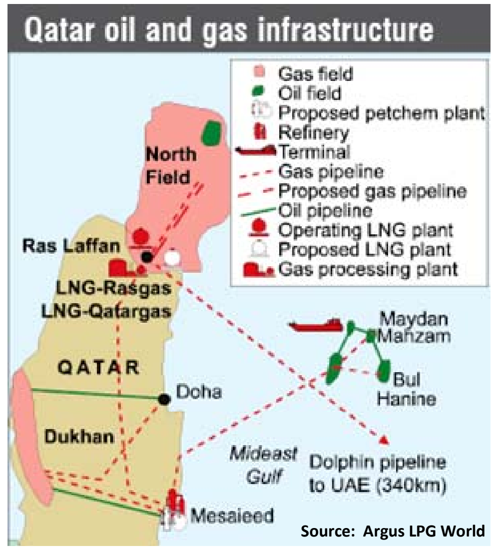
NGL production outlook

While baseload associated gas volumes are forecast to decline, growth is expected to come from the Haradh 3, Manifa, Khurais and Khursaniyah projects. NGL volumes are forecast to increase by 338 kb/d during 2008-2015, with the bulk of the growth from NGLs as opposed to condensates, which remain more stable. More than two-thirds of Saudi Arabia's growth in NGLs will come from the Hawiyah NGL project that is forecast to add 310 kb/d by 2013, while the Khursaniyah project is assumed to add 210 kb/d by 2013, both slowly ramping up from their production start-up in 2009/2010. The Manifa project is forecast to come on stream by the end of 2013 and ramp up towards 65 kb/d of condensate by 2015. The Khursaniyah NGL plant will process rich gas from both the Karan non-associated gas field and the Manifa field, as well as gas and condensate from the Arabiyah and Hasbah fields. All in all we forecast Saudi NGL production to reach 1765 kb/d by 2015, from 1427 kb/d in 2008.

5.6.2 Qatar

Relevant natural gas trends

The Qatari hydrocarbon sector is dominated by natural gas. Qatar has the world's third biggest gas reserves and is ramping up its production rapidly. From a 2008 production of 79 bcm, natural gas production is expected to increase by an average rate of 11% annually, reaching 165 bcm in 2015. The North Field, the worlds biggest gas field, shared with Iran (where it is called South Pars), contains 99% of the country's gas reserves. The associated gas reserves of Qatar are contained in the Dukhan field and in the Maydan, Mahzam and Bul Hanine offshore oil fields.



Source: Argus LPG World

Qatar exported 40 bcm of natural gas as LNG in 2008, and its LNG export is set to reach 102 bcm by 2012. The major growth vehicles have been the RasGas and Qatargas LNG projects, aimed at long-distance exports. Qatar also exports natural gas to UAE through the Dolphin pipeline, and has launched one GTL project. The prospects for Qatari gas production and exports beyond 2012 remain very uncertain because of a moratorium on new export projects imposed in 2005 to allow time to study the effect of the existing project load on North Field reservoirs. The moratorium was recently prolonged until 2014.

Qatar production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	79	93	129	154	159	158	159	165	86	11.1 %
Gas production (kboe/d)	1,367	1,603	2,218	2,661	2,732	2,723	2,743	2,851	1,485	11.1 %
NGL (kbd)	610	721	1,010	1,228	1,280	1,296	1,326	1,400	790	12.6 %
NGL to gas ratio	44.7%	45.0%	45.5%	46.1%	46.9%	47.6%	48.4%	49.1%		

Current NGL production and outlook

The OMR assessment of 610 kb/d production in 2008 for both condensate and other NGLs is in line with comparable sources. The annual report of Qatar Petroleum mentions produced volumes in 2008 for several projects, but does not give a complete set of figures, and we are not aware of a comprehensive source of monthly production data for NGLs.

Qatar's first gas processing trains were located in Umm Said in the South East of Qatar, referred to as the Mesaieed plant. The phases of the development of the plant are referred to as NGL 1 & 2 and NGL 4. The natural gas treated here comes from the large onshore Dukhan oil and gas field, situated 80 km west of Doha, from which the first oil was exported in 1949, as well as from the Maydan, Mahzam and Bul Hanine offshore oil fields. The first NGL plant was opened in 1974. According to OMR data NGL production from NGL 1 & 2 and NGL 4 was 200 kb/d in 2008, and declines somewhat over the forecast period.

The Dolphin gas project yields 100 kb/d of condensate, while Oryx GTL added 34 kb/d of NGL production from 2008. The Dukhan gas cap yields 20 kb/d of condensate while the natural gas recycling project is reported to yield 38 kb/d of condensate.

Qatar NGL production forecast (kb/d)

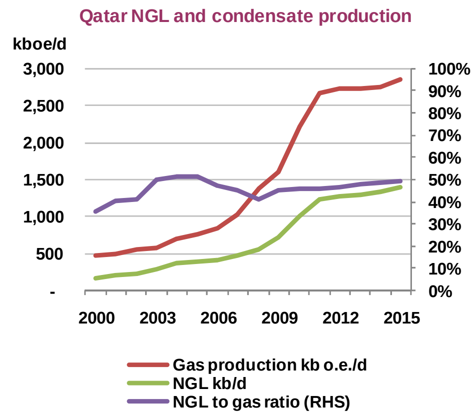
Product	Facility	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015
Condensate	Barzan	-	-	-	-	-	-	-	25	25
	Dolphin	47	83	100	100	100	100	100	100	53
	North Field Alpha	24	24	24	24	24	24	24	24	-
	Qatargas 1, T1-3	35	33	35	35	35	35	35	35	-
	Qatargas 2, T4	-	5	54	70	70	70	70	70	70
	Qatargas 2, T5	-	5	54	70	70	70	70	70	70
	Qatargas 3, T6	-	-	15	55	70	70	70	70	70
	Qatargas 4, T7	-	-	-	55	70	70	70	70	70
	RasGas 2, T3	33	33	33	33	33	33	33	33	-
	RasGas 2, T4	33	33	33	33	33	33	33	33	-
	RasGas 2, T5	24	30	30	30	30	30	30	30	6
	RasGas 3, T6	-	5	30	50	50	50	50	50	50
	RasGas 3, T7	-	-	30	50	50	50	50	50	50
	Al Khaleej Gas 1 (ga	31	31	31	31	31	31	31	31	-
	Al Khaleej Gas 2	-	10	40	40	40	40	40	40	40
	RasGas 1,T 1-2	30	30	30	30	30	30	30	30	-
	Dukhan gas cap	20	20	18	18	18	14	14	10	(10)
	Gas recycling	38	38	38	38	38	38	38	38	-
Condensate Total		**314**	**379**	**594**	**761**	**791**	**787**	**787**	**808**	**494**
Ethane	Al Khaleej Gas 2	-	10	40	40	40	40	40	40	40
Ethane Total		**-**	**10**	**40**	**40**	**40**	**40**	**40**	**40**	**40**
LPG	Dolphin	22	43	45	45	45	45	45	45	23
	North Field Alpha	30	29	27	26	24	23	22	21	(9)
	Oryx GTL expansion	-	-	-	-	15	35	51	65	65
	Pearl GTL	-	-	-	33	50	60	70	70	70
	Pearl II	-	-	-	-	-	-	13	60	60
	Qatargas 1, T1-3	5	5	5	5	5	5	5	5	-
	Qatargas 2, T5	-	4	8	14	14	14	14	14	14
	Qatargas 3, T6	-	2	4	7	7	7	7	7	7
	RasGas 2, T5	12	15	15	15	15	15	15	15	3
	RasGas 3, T6	-	3	26	45	45	45	45	45	45
	RasGas 3, T7	-	-	-	-	-	-	-	-	-
	NGL 1&2	90	84	81	77	73	70	66	63	(27)
	NGL 4	109	104	99	94	89	85	80	76	(33)
	Al Khaleej Gas 2	-	10	32	32	32	32	32	32	32
	Oryx GTL	27	34	34	34	34	34	34	34	7
LPG Total		**296**	**332**	**376**	**427**	**449**	**469**	**499**	**552**	**257**
Grand Total		**610**	**721**	**1,010**	**1,228**	**1,280**	**1,296**	**1,326**	**1,400**	**791**

The North Field Alpha project yielded 24 kb/d of condensate in 2008 and 30 kb/d of NGLs. The condensate production is expected to remain at that level over the forecast period, while the NGL production is expected to decline.

The Al-Khaleej Gas project yields 31 kb/d and is expected to remain at this level over the forecast period. The Al-Khaleej 2 project is expected to yield above 70 kb/d of LPG and ethane, ramping up from 2009 and onwards. The Qatargas Phase 1 delivered its first LNG cargo to Japan in 1997, and yielded 35 kb/d of condensate and 5 kb/d of NGLs. The Qatargas Phase 2, aimed at the British market, with two more trains came on in 2009, and is ramping up production to deliver 100 kb/d of condensate and 14 kb/d of NGL by 2011. Qatargas Phase 3 is expected from 2010 with plateau production of 70 kb/d of condensate and 7 kb/d of NGLs, while Qatargas Phase 4 is expected to enter into production a year later and yield 70 kb/d of condensate.

The Rasgas Phase 1 started up in 1999 and yields 30 kb/d of condensate. RasGas Phase 2 came into production in 2004-2007 and ramped up to its 30 kb/d plateau of condensate and 15 kb/d of NGLs over 2009. RasGas Phase 3 (train 6 and 7) come on during 2010 and add 100 kb/d of condensate and 45 kb/d of NGLs. All in all we forecast the NGL production of Qatar to reach 1400 kb/d by 2015, the highest NGL growth in the world.

Qatar has a high liquids ratio, and all its gas developments come with large quantities of associated NGLs. The liquids ratio of Qatar was 45% in 2008, and is expected to increase towards 49% over the forecast period. The liquids ratio of the North Field as a whole is probably much lower than the current liquids ratio indicates, but the country is developing the condensate and NGLs early to boost the profitability of the projects.



5.6.3 Iran

Relevant natural gas trends

Despite having the world's second largest reserves of natural gas, Iran's marketed gas production was only 121 bcm in 2008, somewhat less than its consumption of 122 bcm. Domestic demand for natural gas has increased sharply due to highly subsidised prices. Total gas subsidies totalled an estimated USD 16 billion in 2007. Iran's ability to meet its domestic needs for natural gas and to produce natural gas for exports and oilfield re-injection depends on political conditions and capability to execute projects. Impediments to faster gas production growth in Iran are the threat of sanctions from the world community as a reaction to Iran's nuclear programme and unattractive contract terms related to price subsidies. More than 60% of Iran's gas reserves are located in non-associated fields. In addition to South Pars, the main gas fields in production are North Pars, Tabnak and Kangan-Nar. Since 2004 Iran has added 45 bcm of natural gas production from the South Pars field. The bulk of the future growth is also expected to come from that field.

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Iran production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	121	104	106	114	118	122	125	135	14	1.6 %
Gas production (kboe/d)	2,081	1,799	1,827	1,962	2,031	2,097	2,156	2,320	239	1.6 %
NGL (kbd)	441	521	585	785	904	932	985	1,048	607	13.2 %
NGL to gas ratio	21.2%	29.0%	32.0%	40.0%	44.5%	44.4%	45.7%	45.2%		

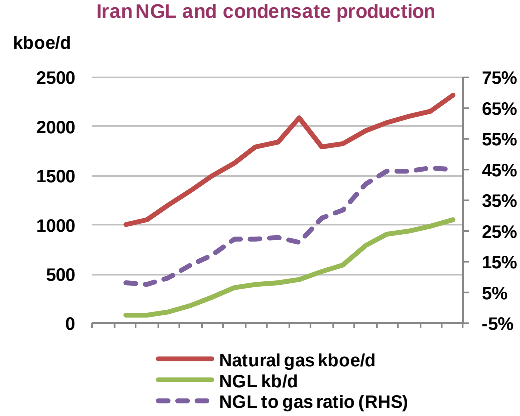
Iran's marketed gas production is projected to fall from 121 bcm in 2008 to 104 bcm in 2009, and then rise again to 135 bcm by 2015. The country's natural gas production target for 2015 is set at 146 bcm. Incremental gas is expected to come from South Pars phases 6-10 (45 bcm) and possibly South Pars phases 12, 15/16 and 17/18 (60 bcm), of which only phase 12 is included in our forecast. The Bid Boland expansion project, with 20 bcm of incremental volumes from the Aghar Jari, Marun and Ahwaz fields, is also included in the production target. Iran currently re-injects 30-40 bcm of natural gas, and the WEO2009 assumes this volume increases to 100 bcm by 2015. According to the Arab Oil and Gas Directory, Iran's gross gas production was 174 bcm in 2007, of which 64% was marketed (111 bcm), while 16.9% (29 bcm) was re-injected and 9.6% (17 bcm) was flared. This is higher than the World Bank estimate of flaring which was 10.3 bcm in 2008, 10.6 bcm in 2007, and 11.3 bcm in 2005.

Current NGL production

Iran does not publish official data for condensate and other NGL production, so estimates are based on secondary sources.

According to the Arab Oil and Gas Directory, Iran has capacity to process around 180 bcm of wet gas at 11 gas processing complexes. These plants extract NGLs that are later fractionated in other plants, like the NGL100-2300 plants of NIOSC that feed NGL products into the Bandar Imam petrochemical complex and the Bid Boland gas refinery. Iran also has three export facilities for LPG, the most important of which is at Bandar Abbas.

Iran NGL and condensate production



The outlook for NGL production

There are several ongoing expansion projects in gas processing plants that will increase the gathering and processing capacity of associated gas, the most important of which is the Bid Boland expansion and the Kharg Island gas gathering project.

Otherwise the various phases of the non-associated South Pars development will yield the bulk of the growth in NGL production from Iran. Phases 6-8 all entered into production in 2008-2009, and Phases 9-10 are expected in 2010, yielding a total of 200-240 kb/d of condensate and 130 kb/d of other NGLs. South Pars 12 is expected to come into production by the end of the forecast period and ultimately add 130 kb/d of condensate and 125 kb/d of NGLs. Later phases of the South Pars development are expected to come into production beyond 2015. See overview below for details of our forecasts. The political

risk and contract terms of Iran are important impediments to growth, and should these factors improve the growth prospects for the country would improve considerably both in the medium and the longer term.

Iran NGL production forecast (kb/d)

Product	Facility	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015
Condensate	SP phase 1	40	40	40	40	40	40	40	40	-
	SP phase 2/3	80	80	80	80	80	80	80	80	-
	SP phase 4/5	80	80	80	80	80	80	80	80	-
	SP phase 6/7 and 8	10	70	95	129	132	132	132	156	146
	SP phase 9/10	-	-	13	55	80	80	80	80	80
	SP phase 12 Petropars)	-	-	-	-	-	-	30	60	60
	Nar & Kangan	32	32	32	32	28	28	26	26	(6)
	Dalan & Aghar	9	9	9	9	9	9	9	9	-
	Other Iran condensate	27	25	25	25	25	25	25	25	(2)
	Bidboland expansion	-	-	-	10	20	20	20	20	20
	Kharg island gas gathering system	-	-	-	-	-	3	4	5	5
Condensate Total		**278**	**336**	**374**	**460**	**494**	**497**	**526**	**581**	**303**
Ethane	SP phase 4/5	49	48	48	48	48	48	48	48	(0)
	SP phase 9/10	-	-	8	32	46	46	46	46	46
	Bidboland expansion	-	-	-	35	70	70	70	70	70
Ethane Total		**49**	**48**	**56**	**115**	**165**	**165**	**165**	**165**	**116**
LPG	SP phase 4/5	32	32	32	32	32	32	32	32	(0)
	SP phase 6/7 and 8	3	25	38	50	50	50	50	50	47
	SP phase 9/10	-	-	6	23	34	34	34	34	34
	SP phase 12 Petropars)	-	-	-	-	-	-	3	6	6
	Bidboland expansion	-	-	-	25	50	50	50	50	50
	Kharg island gas gathering system	-	-	-	-	-	25	45	50	50
	NGL 100-1600)	80	80	80	80	80	80	80	80	-
LPG Total		**115**	**137**	**155**	**210**	**246**	**271**	**294**	**302**	**187**
Grand Total		**441**	**521**	**585**	**785**	**904**	**932**	**985**	**1,048**	**607**

5.6.4 Oman

Relevant natural gas trends

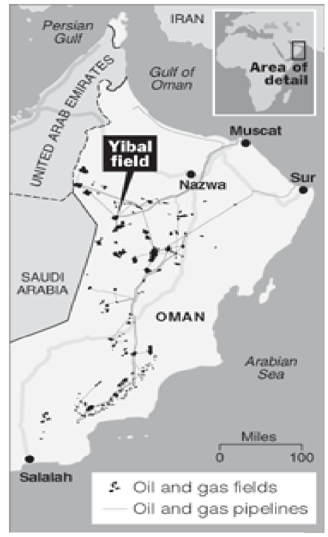
Omani gas production was 26 bcm in 2008 and is expected to increase marginally to 27 bcm over the forecast period. The first gas production in Oman was associated gas. The Yibal gas plant was opened in 1978, and this event marked the beginning of the natural gas industry in Oman. Gas was first found in the 1960s in the Yibal and Natih fields. Infrastructure to exploit associated gas that had earlier been flared was built at the Yibal field and the Saih Rawl fields.

Gas was later found in the Saih Nihyada, Saih Rawl and Barik fields. The natural gas output of Oman increased strongly from 2000-2005, as gas was developed for exports from the two train Oman LNG plant. The third train, referred to at Qalhat LNG, came on stream in 2006. The LNG plant is located at Qalhat in Sur, 340 kilometres from Muscat.

Oman production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	26	27	27	27	27	27	27	27	1	0.5 %
Gas production (kboe/d)	444	461	461	461	461	461	461	461	17	0.5 %
NGL (kbd)	83	88	103	106	109	112	117	120	37	5.4 %
NGL to gas ratio	18.7%	19.1%	22.4%	23.1%	23.7%	24.4%	25.3%	26.0%		

Source: EIA



Source: Argus LPG World

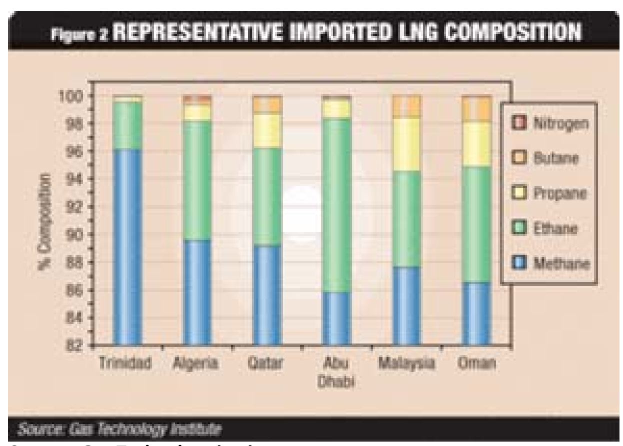
Until 2000 all gas in Oman had been associated with oil, but the fields developed to feed the LNG plant were all non-associated gas fields. The non-associated gas developed in Oman during these years appears to have been drier than the associated gas, as Oman's condensate production decreased in the years 2001-2007, while the natural gas production rose sharply. PDO operates the central reservoirs of Saih Nihayda, Saih Rawl and Barik, which lie deep beneath the three oilfields and account for most of Oman's non-associated gas reserves.

However, Oman seems to have as much condensate reserves compared to gas reserves, and some gas condensate fields produce more condensates than gas. The Kauther gas field and gas processing plant came on stream in 2007 and further boosted Omani condensate production.

Current NGL production

The Petroleum Directorate of Oman (PDO) provides Omani condensate data and this is reported in the OMR. The level of condensate production from Oman was 77 kb/d in 2008. All the condensate production of Oman is spiked into crude.

The Yibal gas plant which came in operation in 1978 prepared natural gas for distribution, and extracted propane and butane. The propane was used in the gas plant for cooling, while the butane was bottled and sold at the domestic market. The plant is still operational.



Source: Gas Technology institute

However, Oman does little to segregate LPG production, leaving much of C_2-C_4 in their sales gas. Their LNG has the highest calorific content in the world next to the LNG from Libya's dysfunctional plant. In addition to that, propane is consumed within the gas plants themselves. Our latest estimates represent a downgrading from previous ones, which were inflated by refining LPG volumes.

The gas processing plant related to Qalhat LNG, Saih Nihayda, has a capacity to extract 10 kb/d of condensate to 7.3 bcm of natural gas. An EPC contract was recently awarded to increase the capacity of the plant by 25%, however the liquids ratio of the gas that feeds Qalhat LNG is less than 10%.

The figure above shows a comparison of the composition of Omani LNG compared to some other LNGs. We see that LNGs that are aimed for the Japanese market are the ones with the highest NGL and hence calorific content.

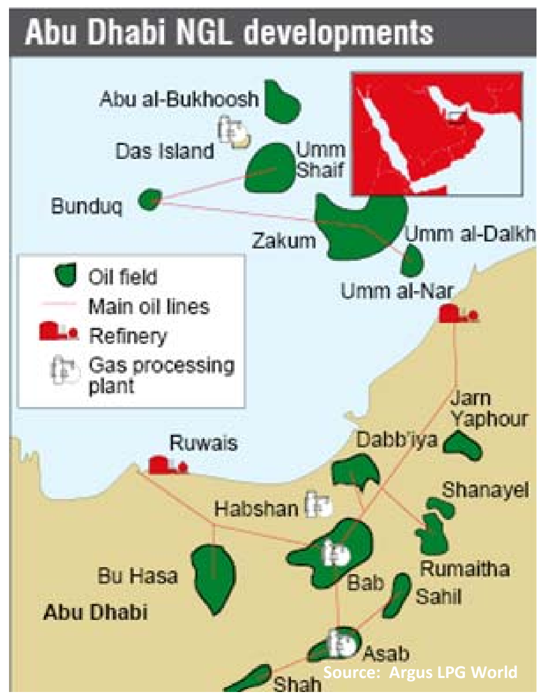
The outlook for NGL production

The Kauther field and gas processing plant, which came on stream in 2008, boosted Omani condensate production, which is now estimated at 100 kb/d, and possibly could reach a level of 120 kb/d over the forecast period. Oman needs the condensate to spike into its crude oil to meet the quality spec of Oman blend. As to its LPG production, there are few plans to monetise more LPG on a stand-alone basis. As for the LNG, they are bound by contract to keep the quality at the high calorific level that suits their Japanese customers that use the LNG for input into gas power plants that are adapted to highly calorific natural gas. A change of the LNG sales contract conditions would enhance the potential for gas plant liquids production from Oman.

5.6.5 United Arab Emirates (UAE)

Current natural gas and NGL production

Natural gas production in the United Arab Emirates was 51 bcm in 2008, and is expected to fall to 47 bcm in 2009 and then increase over the forecast period to 56 bcm by 2015. By contrast, NGL production is forecast to increase by 75% over the same period.



Abu Dhabi has an elaborate system to collect associated and non associated gas to produce sales gas and natural gas liquids ranging from ethane to condensate. It also produces sulphur as a by-product of sour gas processing. The natural gas processing and the extraction of NGLs takes place at the Habshan-Bab Gas Complex in the desert, which gathers NGLs from the Bu Hasa NGL Plant, the Asab NGL Plant and the Asab Gas Plant. The wet gas from the Bab field is produced from both the associated Thamama C reservoir and the non-associated Thamama B, D and F and Thamama 6 and 7. The NGLs from the Habshan complex are sent for fractionation at the Ruwais NGL plant while the condensate produced at the Habshan and Asab AGP plants is shipped by pipeline to the two oil refineries at Ruwais and Umm Al-Nar, operated by the Abu Dhabi Oil Refining Company (TAKREER). From the NGL fractionation plant the ethane is sent to the petrochemical plant Abu Dhabi Polymers Company Ltd. (Borouge), while the LPG is exported from the Ruwais jetty or used domestically. As Abu Dhabi has a shortage of gas, ethane and LPG are also sometimes used to substitute natural gas. Current production from the Habshan complex is about 220 kb/d of condensate and 210 kb/d of LPG, a total of 430 kb/d.

Offshore NGLs are processed in connection with the LNG plant at Das Island. NGL production from Das Island is estimated at 50 kb/d of LPG and 10 kb/d of naphtha/pentane. There is also condensate production in the emirates of Dubai and Sharjah, at a total estimated around 30 kb/d.

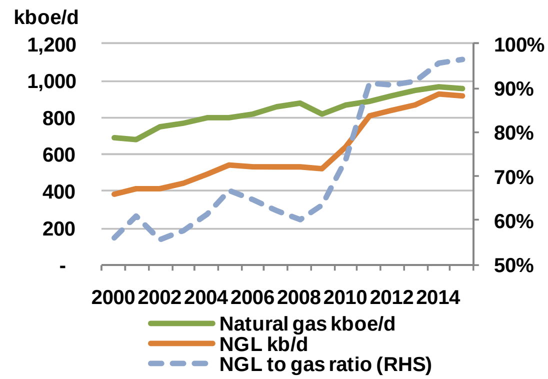
UAE production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	51	47	50	52	53	55	56	56	5	1.2 %
Gas production (kboe/d)	879	817	869	891	921	948	970	956	78	1.2 %
NGL (kbd)	528	519	643	813	837	868	930	922	394	8.3 %
NGL to gas ratio	60.1%	63.5%	73.9%	91.3%	90.9%	91.6%	95.8%	96.4%		

The outlook for NGL production

Three well documented new projects are coming on stream and are expected to raise the UAE's NGL production from 528 kb/d in 2008 to 922 kb/d in 2015, an increase that puts Abu Dhabi in the league of Iran, Qatar and Saudi Arabia in terms of production growth over the forecast period. The projects will take the liquids ratio of UAE up from 60% in 2008 to 96% in 2015. Since the UAE already has an elaborate system to extract NGL this suggests a development of more optimal NGL capture or wetter gas as well as more gas re-injection. The NGL capture is assumed to have a potential to improve, as the systems in place are often partly 40-30 years old.

UAE NGL and condensate production



The projects that will add NGL production over the forecast period are the capacity increase at Habshan (OGD 3) and Asab (AGD 2), followed by a capacity increase at the Ruwais NGL fractionation plant. Further, there is the IGD (Integrated Gas Development) project. The OGD 3 project is assumed to add 120 kb/d of condensate and 120 kb/d of NGL production from 2010 to 2012. The AGD 2 project is assumed to add 80 kb/d of NGLs over 2010 to 2011, while the IGD project is expected to add 30 kb/d of condensate and 110 kb/d of NGL production from 2013 to 2015. Much of this project is related to gas re-injection to support oil production. Existing production is expected to slowly decline over the forecast period.

5.6.6 Kuwait

Relevant natural gas trends

Kuwait's natural gas production of 12 bcm is expected to grow to 13 bcm over the forecast period. In 2007 Kuwait started non-associated gas production, but the non-associated gas is from gas condensate fields with high liquids content. Given its limited gas resources, Kuwait has sought to maximize associated gas recovery at its oilfields. All fields were tied in to a gas gathering and processing network by the mid-1980s and similar facilities were also installed in the Neutral Zone which is shared 50/50 with Saudi Arabia. Kuwait plans to improve the capture also in the Partitioned Zone, which still flares some gas (1.8 bcm in 2008, which was down from 2.5 bcm in 2006).

Kuwait started producing non-associated gas in mid-2008 as the Umm Niqa and Sabriyah fields came on stream and added 1.4 bcm of natural gas as well as 50 kb/d of condensate production, a very high liquids ratio. We assume Phase 2 of non-associated gas developments will come on stream in 2012, and take the total condensate production up to 165 kb/d by 2014. The non-associated gas is located in Northern Kuwait, and aside from the Umm Niqa and Sabriyah fields the relevant fields are Bahra, Northwest Raudhatain and Raudhatain. The Dorra project is related to a find from 1960 that straddles the borders between Kuwait, Iran and Saudi Arabia. We assume the Dorra project to come onstream after the forecast period and to have a lower condensate content than the Umm Niqa/Sabriyah field.

The first phase of the non-associated gas development caused large challenges to Kuwait Oil Company (KOC) due to the complexity of the reservoir. KOC has yet to signal that it wants IOC involvement in further stages for the field developments. So far, Kuwait has a shortage of gas, and the country became an LNG importer in 2009, with LNG imports of about 1 bcm, expected to increase in the years to come.

Kuwait production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	12	12	12	12	12	13	13	13	1	0.7 %
Gas production (kboe/d)	211	206	208	211	213	216	218	221	10	0.7 %
NGL (kbd)	161	190	195	205	223	308	320	320	159	10.3 %
NGL to gas ratio	76.6%	92.4%	93.7%	97.4%	104.5%	142.7%	146.8%	145.1%		

Current NGL production and outlook

Historical OMR Kuwaiti NGL figures are based upon the KNPC annual report, which details gas plant liquids with a break down for propane, butane and gas plant naphtha from the natural gas processing plants in Shuaiba and Mina Al-Ahmadi. Condensate production from Kuwait was estimated at 21 kb/d in 2008, while other NGLs were reported by the KNPC at 140 kb/d.

For the outlook NGL production grows in tandem with natural gas production, and is stable at 155 kb/d from 2011 and onwards. The ramp-up plan for Umm Niqa sets the growth for condensate, estimated to reach 165 kb/d by 2014.

5.6.7 Syria

Relevant natural gas trends

According to WEO2009 gas forecasts, gas production is expected to stay at today's level of 6 bcm, well below more optimistic prognoses suggesting Syria's gas production could reach 15 bcm shortly. Most of Syria's gas reserves are non-associated gas, but the current production is associated gas, of which some is re-injected after liquids extraction. The liquids ratio of Syria today is around 30-40%. The recently launched South Middle Area gas project is estimated to have a liquids ratio of 13%. The next gas project to be developed, the non-associated gas fields in the Palmyrides region including the Jihar field, seems to have a liquids ratio of only 9%, and be smaller than earlier projects. However, this region is supposed to have a higher potential and is where the future production growth could come from. Assuming associated gas is gradually being replaced by non-associated gas, we expect the liquids ratio of natural gas to go down. Syria recently started gas imports from Egypt via the Arab Gas Pipeline (AGP) to meet domestic needs for gas.

Syria production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	6	5	6	6	6	6	6	6	0	0.3 %
Gas production (kboe/d)	104	92	97	99	101	103	105	106	2	0.3 %
NGL (kbd)	35	35	35	35	33	32	30	29	-6	-2.9 %
NGL to gas ratio	33.6%	38.1%	36.0%	35.4%	32.9%	30.6%	28.7%	26.8%		

Current NGL production and outlook

Syria is a small producer of gas, but not an insignificant producer of NGLs, albeit reliable data is difficult to find. Gas production in Syria started in 1984, and four gas processing plants were built in 1985, 1988, 1991 and 2002. A fifth gas processing plant came on stream in late 2009. Existing data and outlook seem reasonable for Syria, and no revision has been suggested following this review.

The outlook suggests a decline based on a lower liquids ratio, as natural gas production is set to increase slightly. This should reflect the assumption that new gas is drier than current gas that is declining. The South Middle Area Gas Project which included the construction of a gas processing plant near Firoqlos to process gas from the Qom Qom, Al Feid North and Abu Rabah fields is reported to have a capacity to process 2.6 bcm of natural gas and yield 4 kb/d of condensate and 1.7 kb/d of LPG, a liquids ratio of only 13%. The gradual step-up in production from this facility is assumed to replace declining production from other facilities.

5.6.8 Bahrain

Relevant natural gas trends

Around 20% of Bahrain's 2007 natural gas production was associated gas from the declining Awali oil field. However production of non-associated dry gas from the Pre-Khuff formation below the Bahrain oil field is increasing, which impacts the liquids ratio, as this gas is considerably drier than the associated gas. Bahrain recently held a licensing round for their Pre-Khuff-gas, but the interest among IOCs was limited given the low liquids potential of the gas.

Bahrain production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	10	8	9	9	9	9	10	10	0	0.3 %
Gas production (kboe/d)	165	140	149	152	157	161	164	168	4	0.3 %
NGL (kbd)	10	10	9	9	8	8	7	7	-3	-4.5 %
NGL to gas ratio	5.9%	6.9%	6.1%	5.7%	5.2%	4.8%	4.5%	4.2%		

Current NGL production and outlook

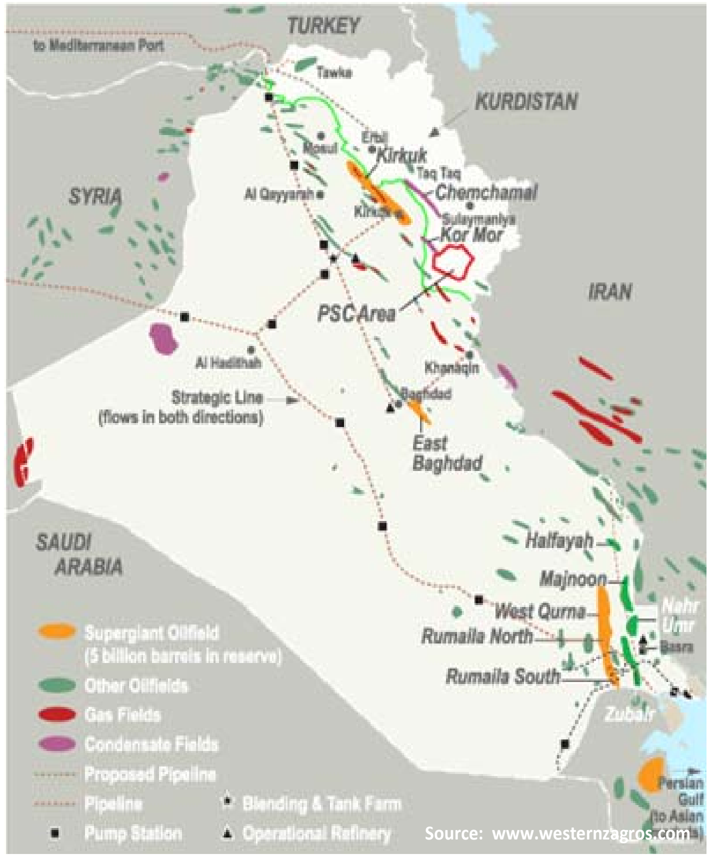
Bahrain has a small liquids production compared to its gas production, about 7%. NGLs are extracted at the Sirta gas plant.

As oil production falls and associated gas production is being replaced by dry Pre-Khuff gas the liquids ratio is set to decrease. Bahrain is an example of a country where it makes sense to let forecast NGL production follow the profile of oil production. A planned upgrading at the Sirta gas plant might have a positive effect on NGL production, although the effect is assumed to be marginal.

5.6.9 Iraq

Relevant natural gas trends

With its proven reserves of 3.2 tcm of natural gas and gas processing facilities with a total design capacity of 60 bcm, Iraq has a potential to increase its gas output substantially over the forecast period. The WEO forecasts a build-up from 1.4 bcm in 2008 to 8 bcm in 2015, still very low compared to the potential. Iraq had a gross production of natural gas of almost 14 bcm in 2008, of which 7 bcm was flared (World Bank) 1.4 bcm reached the market, while the balance was lost due to shrinkage, including venting.



Source: www.westernzagros.com

70% of the natural gas reserves are associated gas, (of which 83% is located in the Southern oil fields), 10% is gas cap gas and 20% is non-associated gas. The largest accumulations of associated gas are located in the Kirkuk, Jambur and Bai Hassan fields in the north and in the South Rumailia, North Rumailia and Al-Zubair fields in the south. The most important non-associated gas deposits are Anfal, Chemchemal, Khashim al-Ahmar, Jeria Pika and Mansouriyah in the North, the Sibba field South of Bashrah and the Akkas field in the Westen desert (close to the Syrian border).

Iraq is determined to increase its gas production both for domestic consumption, mainly for power generation and industry, and possibly for export through LNG. Iraq earlier exported natural gas to Kuwait through a pipeline. The Akkar field once developed could export Iraqi gas into Syria.

The only non-associated gas production marketed in 2008 reportedly came from the Anfal field, which entered into production in 1990, and supplies about half of all the natural gas consumed in Iraq. The natural gas was processed at the Jambur gas plant near Kirkuk. From there dry gas supplies power stations and petrochemical plants.

Iraq production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	1	4	5	5	6	6	7	8	6	27.5 %
Gas production (kboe/d)	24	72	80	89	98	108	120	132	108	27.5 %
NGL (kbd)	29	42	56	59	64	68	73	79	50	15.4 %
NGL to gas ratio	120.2%	58.4%	69.6%	67.2%	65.1%	63.1%	61.3%	59.7%		

Current NGL production

Official data for condensate and other NGL production for Iraq are patchy, and uncertainty prevails over historical and current production levels.

Iraq has five gas processing plants with a total design feedgas processing capacity of 60 bcm and NGL production capacity of more than 200 kb/d. The Khor al-Zubair gas plant near Basra is the most important one, while other gas plants are located at Northern Rumaila and in Kurdistan. Shell has won a contract to renovate the natural gas processing capacity in the Basra region in the south, but the potential is yet to be realised. An entity named South Gas Utilisation Venture is established with participation from Iraq's gas company and Mitsubishi in addition to Shell. Reportedly contractual terms of the gas and LPG sales have so far been hampering project development. Iraq became a condensate producer in 2008, as the Khor Mor in the Kurdish region came into production, operated by UAE-based Dana Gas in consortium with Crescent Petroleum. The field is currently estimated to yield a condensate production of 15 kb/d. Dana Gas also built an LPG facility at Khor Mor, but no estimates have been seen of the quantity of LPG that will be produced. They are currently looking at the development of the Chemchemal field. The NGL baseline and forecast of Iraq are therefore very uncertain.

The outlook for NGL production

Given the uncertain investment climate of the country, this is reflected in a fairly conservative gas supply forecast in WEO2009. Based on historical Iraqi gas processing levels, a liquids ratio of 44% seems reasonable. Since the natural gas production is forecast to reach 8 bcm (132 kboe/d) a gas plant NGL production of about 59 kb/d by 2015 has therefore been derived.

5.6.10 Yemen

Relevant natural gas trends

Yemen's proven natural gas reserves are extremely concentrated, with 84% located on Block 18, which provides the feed gas for the Yemen LNG liquefaction plant, and 7.3% on Block 5, which is operated by Hunt Oil. However, gas reserves discovered on other tracts (which are frequently associated with oil) are being exploited or could be in the near future. The Yemen LNG project is the most important investment ever made in Yemen. It consists in supplying gas from Block 18, located in the Marib region in central Yemen, through a 320 kilometres dedicated pipeline to the LNG plant located at the port of Balhaf on the southern coast of the country. The plant has recently started production from the first train, while the construction of the second train is being completed. Total production capacity is expected to reach 6.7 mt/y of LNG per year by the end of 2010.

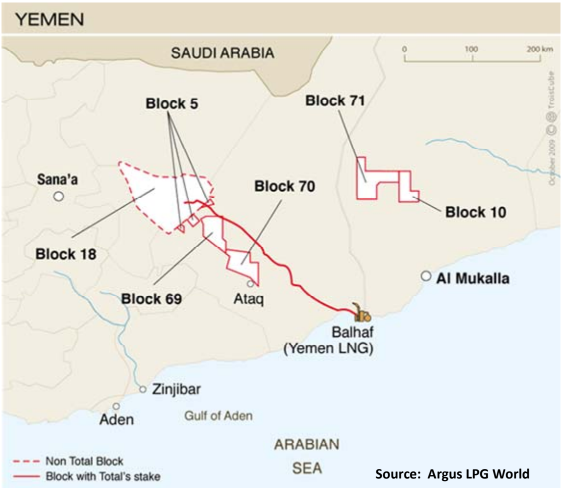
Yemen production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	-	3	10	10	10	10	11	11	11	#DIV/0!
Gas production (kboe/d)	-	50	176	177	179	181	182	184	184	#DIV/0!
NGL (kbd)	18	26	27	27	27	27	27	27	9	5.9 %
NGL to gas ratio	#DIV/0!	52.8%	15.6%	15.5%	15.3%	15.2%	15.0%	14.9%		

Current NGL production and outlook

In Yemen liquids are removed from gas at four gas processing plants. The associated gas is treated to remove condensate, and extract propane and butane. Until recently, the lean gas was re-injected into the reservoirs to boost oil recovery. The objective of Yemen LNG was to recover this lean gas, and liquefy and export it.

Yemen has for a long time been processing about 17 bcm of associated gas annually, notably from the Marib/Jawf field. Before the LNG plant came into production in October 2009, with a capacity of 9.2 bcm, all of this gas has been re-injected after extraction of NGLs.

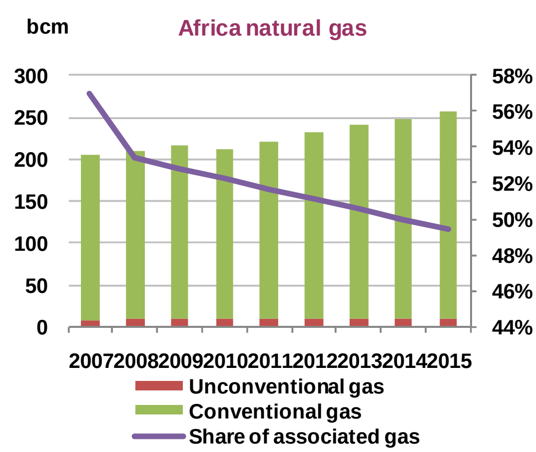


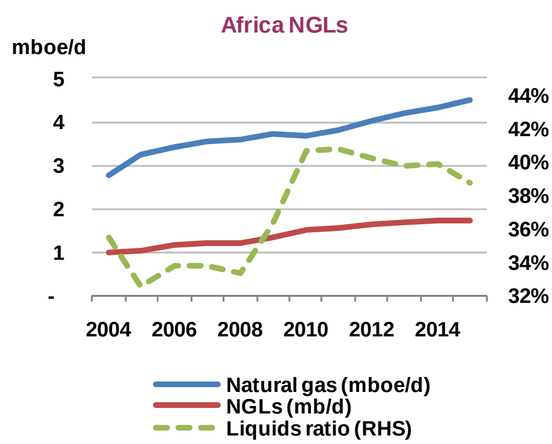
Source: Argus LPG World

In spite of a commercial gas production growth from zero to 9.2 bcm in 2009, there are doubts whether the NGL production of the country will pick up, as possibly no more gas than before will be processed. However, we assume that some increased condensate production will be forthcoming from Yemen, as the natural gas processing plant has been revamped to prepare for the quality requirements of the LNG plant, and our forecast assumes 8 kb/d of incremental condensate supply following the start-up of the LNG plant in 2010.

5.7 Africa

Africa holds natural gas reserves of 14.7 tcm, and its proven reserves have been growing steadily. Africa's gas reserves are highly concentrated in Nigeria, Algeria, Egypt and Libya, and 93% of its current natural gas production comes from those four countries, with Algeria alone accounting for 40%. The natural gas production of Africa is forecast to grow from 208 bcm in 2008 to 262 bcm in 2015, a compounded annual growth rate of 3.3%. All the established gas producers increase their gas production at levels close to the regional average over the forecast period. Angola posts the highest growth in percentage terms as it is forecast to launch its LNG project by 2012, based on associated gas. The share of associated gas to total natural gas production from Africa fell sharply from 2007 to 2008, and is expected to continue its downward trend. The contribution from unconventional gas in Africa is mainly tight gas, and is expected to grow from 8 to 10 bcm over the forecast period.





Better utilisation of associated gas and more gas condensate fields being developed should see a sharp increase in Africa's liquids ratio. Both trends are apparent in Nigeria and Angola. Over recent years the liquids ratio from Egypt has been falling rapidly, as wet associated gas has been replaced by drier non-associated gas. Total NGL from Africa is forecast to grow by an average of 5.5% annually from 2008 to 2015. Average annual growth of 11.7% is forecast between 2008 and 2010. In absolute terms NGL volumes are forecast to grow by 549 kb/d over the forecast period, with 299 kb/d of this growth taking place between 2008-2010.

Nigeria accounts for 227 kb/d of the growth from 2008 to 2010 with 175 kb/d from the Apko condensate field, the Gbaran/Ubie project and an increase in NGL production due to additional volumes from the East Field NGL II project. Algeria, which is the world's second-largest LPG exporter, is also about to ramp up gas plant LPG production, expanding the capacity of their country-wide integrated gas gathering system to process additional rich gas volumes from several new projects in the Sahara desert. Since Algeria, Nigeria and Angola are all OPEC members, OMR convention records condensate volumes with NGL since condensate lies outside of OPEC production targets. Condensate is also included within Egyptian NGL volumes as reported by EGAS.

The key uncertainty of our NGL forecast for Africa is the operating environment in Nigeria going forward. With abundant natural resources, and much gas currently flared, the potential is high, and many projects are beyond engineering phase and could flourish if the investment climate improves. Lags in upstream investment as compared to midstream investment have caused underutilisation of the Bonny LNG plant and NGL extraction and fractionation capacity installed at both Bonny Island and other locations. For both Nigeria and Libya historical and current NGL figures are difficult to assess due to lacking transparency.

An issue worth mentioning for Africa in relation with NGLs is the remarkable underutilisation of LPG as a fuel in sub-Saharan Africa. As many people in Africa use biomass for cooking, the scope for improvement in quality of life is large if one could replace biomass with LPG in the residential sector. The problem for sub-Saharan Africa has been a lack of investment in, and maintenance of, infrastructure to distribute LPG and the integration of logistical networks.

5.7.1 Egypt

Relevant natural gas trends

Egypt holds natural gas reserves of 2.2 tcm, lying third behind Nigeria and Algeria on the African continent. Marketed natural gas production has grown from 22 bcm in 2000 to 58 bcm in 2008, and natural gas is the main focus of the petroleum industry in Egypt. While associated gas production is decreasing alongside a declining oil production, overall natural gas production in Egypt is expected to rise from 58 bcm in 2008 to 66 bcm in 2015, an annual growth rate of 2%, thanks to a steady flow of non-associated natural gas discoveries and developments.

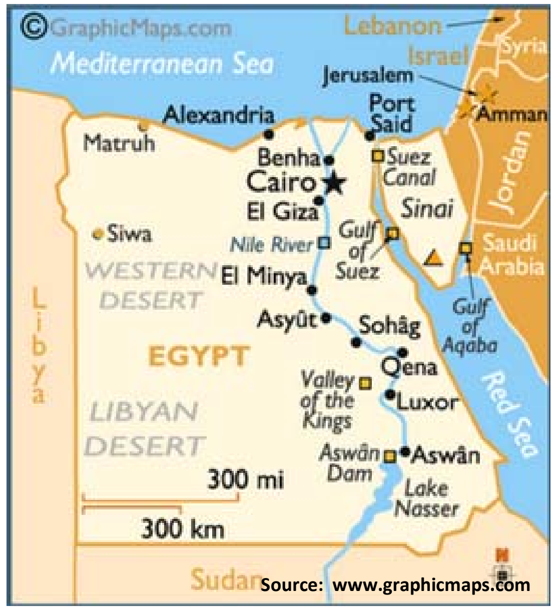
The Abu Madi, Badreddin and Abu Qir fields in the Nile Delta currently account for approximately one-half of Egypt's gas production, and are mature non-associated fields. The Trans Gulf and the Ras Shukeir gas gathering facilities assure utilisation of associated gas from oil fields in the Gulf of Suez, and the Zeit Bay and Abu Rodeis gas processing plants process associated gas in the Red Sea. Most current exploration and production takes place in the Nile Delta region and in the Western Desert. Offshore developments in the Mediterranean region include Port Fuad, South Temsah, Wakah, Rosetta, the Scarab/Saffron fields and the newly discovered Satis field found by BP and Eni in early 2008. In the Western Desert, the Obeiyed and Khalda fields are the most important natural gas areas.

Egypt began pipeline gas exports in 2003 with the Arab Gas Pipeline that connects Egypt to Jordan, and recently the pipeline was expanded to Syria. Egypt has three LNG trains on the Damietta and the Idku LNG complexes, and Egyptian LNG production capacity reached 14 bcm in 2006. In January 2008, the World Bank approved loans for the Natural Gas Connections Project, which serves to switch consumption of LPG to natural gas through investment in new connections and further expand natural gas use in densely populated low income areas.

Egypt production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	58	60	61	62	63	64	65	66	7	1.7 %
Gas production (kboe/d)	1,006	1,041	1,056	1,072	1,087	1,103	1,119	1,135	129	1.7 %
NGL (kbd)	206	213	216	219	222	225	229	232	26	1.7 %
NGL to gas ratio	20.4%	20.4%	20.4%	20.4%	20.4%	20.4%	20.4%	20.4%		

NGL production and outlook



Egyptian Gas company EGAS is a good source for NGL production data, with gas plant LPG, ethane and condensate figures published disaggregated. Egyptian NGL production has been increasing from 123 kb/d in 2000 to 206 kb/d in 2008, an annual growth rate of 7%, compared to a natural gas growth rate of 13% over the same period. About one third of the NGLs in Egypt still come from associated gas production in the Gulf of Suez and the Red Sea, which is declining with oil production. Associated gas in Egypt has a high liquids ratio, at about 60%, while non-associated natural gas in Egypt is generally drier. In 2000 the liquids ratio of Egypt was close to 35%, but has fallen and subsequently stabilised at 20% over the recent years. The natural gas developments that provide feedgas to the Idku and Damietta LNG plants, the Scarab/Saffron and the Simian, Sienna and Sapphire fields, contributed to the decline in the liquids ratio, while some developments in the Western desert have liquids ratios between 20-30%. Egypt is thereby a country which exemplifies the trend of wet associated gas being replaced by drier non-associated gas.

Egypt has 22 gas processing plants, and is currently investing in several new projects that will add capacity for NGL extraction and fractionation. Historically, all gas gathering and gas processing facilities were owned and operated by state Gasco, while many of the newer facilities are owned and operated by private companies, like the Western Desert gas complex that is owned by the Khalda Petroleum company and El Manzala and West Khilala in the Nile Delta that are operated by Centurion Energy and Melrose resources respectively.

About two thirds of Egypt's LPG production is gas plant LPG. Egypt still imports some LPG from Algeria to meet its domestic demand. Although the country's expanding natural gas network is slowly eroding LPG's dominance, retail sales of butane cylinders for cooking reportedly continue to grow.

The NGL production of Egypt is forecast to rise to 232 kb/d by 2015. This is based upon the liquids ratio stabilising at 20%, with associated gas being replaced by drier non-associated gas with a liquids ratio in the range from 5-30%.

5.7.2 Tunisia

Natural gas production in Tunisia is set to remain stable around 3 bcm from 2008 to 2015. Compared to its limited natural gas production, NGL production is rather high at 8 kb/d in 2008 rising to 30 kb/d in 2015.

Tunisia production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	3	2	3	3	3	3	3	3	1	3.3 %
Gas production (kboe/d)	48	33	53	54	56	57	59	60	12	3.3 %
NGL (kbd)	8	8	17	28	29	29	30	30	22	21.1 %
NGL to gas ratio	16.5%	23.7%	32.8%	51.5%	51.1%	50.8%	50.5%	50.3%		

The Miskar LPG plant has for a long time been the sole LPG plant in Tunisia. Total LPG production in Tunisia is 3.5 kb/d according to external sources, but this includes refinery LPG. No estimate is available for LPG production from the Miskar LPG plant, which is said to produce 6 kb/d of condensate, and there is a separate condensate pipeline that brings this to the export terminal of Skhira.

The Hasdrubal gas and condensate field started up in late 2009, and will add 13 kb/d of LPG and 15 kb/d of condensate from the Hannibal LPG plant. Half of the production capacity is included in 2010 and full production is assumed from 2011.

5.7.3 Libya

Relevant natural gas trends

Libya's oil and gas sectors have been stunted by the impact of decade-long UN and US sanctions. The much-hoped expansion of the energy sector following the lifting of sanctions in 2003-2004, however, has yet to materialise and the prospects for growth appear dimmer following the country's resurgent nationalism in 2009. However, while Libya's crude production has declined since the 1960s peak of around 3 mb/d, natural gas production has posted modest growth.

Libya initially focused on reviving its oil sector after the lifting of sanctions, but so far without much success. Development of the natural gas sector is also a priority in order to meet rising domestic gas demand, increase gas exports to Europe's growing market as well as free up crude oil currently used domestically for export. Libya also needs to cut back on flaring and better utilise associated gas for reinjection to support oil production. According to the World Bank, Libya flared 3.7 bcm of natural gas in 2008, slightly less than the estimated 4.3 bcm flared in 2005. Marketed gas production in 2008 was 17 bcm, and is expected in increase to 22 bcm over the forecast period. The West Libya Gas Pipeline (WLGP), also called Greenstream, which came on stream in 2005 considerably increased Libya's natural gas exports to Italy.

In 1971 Libya became the second country in the world (after Algeria in 1964) to export LNG. However, the output from the LNG plant located in Marsa el Brega, has remained low due to sanctions-related technical issues which have limited the plant's ability to separate out LPG, and the plant liquefied less than 1 bcm of natural gas in 2008. Extensions to the plant are planned to come on stream after 2010 and add 3 bcm of liquefaction capacity.

Libya production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	17	17	17	18	19	20	21	22	5	3.6 %
Gas production (kboe/d)	293	288	301	315	329	344	359	376	83	3.6 %
NGL (kbd)	117	115	111	111	111	122	168	172	55	5.7 %
NGL to gas ratio	39.9%	40.1%	36.8%	35.2%	33.7%	35.6%	46.7%	45.8%		

Current NGL production and outlook

Gas plant LPG from Libya has been available since the 1970s. Occidental's Libyan plant at Zueitina supplied Mediterranean outlets in the early 1970s, but Libyan LPG production has since been suffering from the UN sanctions. Libya has two NGL plants, the Zueitina plant with a capacity of 82 kb/d and the Marsa el Brega NGL plant with a capacity of 190 kb/d.

Progress in expanding and rehabilitating old facilities has been slow, but capacity should increase over the forecast period, with NGL production expected to increase from 117 kb/d in 2008 to 172 kb/d in 2015. Condensate production got a boost in 2006 as the Waha Oil Company's Bahr al-Salam and Waha fields reached full capacity. The project includes the Mellitah gas processing plant which extracts about 45 kb/d of condensate from the gas, and the dry gas is exported through Eni's Greenstream. The Waha Oil company is a wholly owned subsidiary of the Libyan National Oil Company which works in consortium with ConocoPhillips, Marathon and Amerada Hess. The consortium plans further oil and gas developments, of which the NC-98 field is expected to increase condensate production further to 97.5 kb/d by 2014. Shell is moving forward with plans to develop gas fields in the onshore Sirte basin, including upgrading of the Marsa el Brega LNG plant, while BP has committed to invest strongly in gas drilling, and plans an integrated LNG project if successful.

Other multinational and national oil companies have also secured acreage in Libya during the licensing rounds in 2005-2007. However, a continued political instability hampers the development. We have assumed increasing utilisation rate for the Marsa el-Brega NGL plant over the forecast period, with output reaching 82 kb/d over the forecast period, still considerably below the nameplate capacity.

5.7.4 Algeria

Relevant natural gas trends

Annual forecast growth in natural gas production in Algeria is 4% from 82 bcm in 2008 to 107 bcm in 2015. Algeria has scaled back its oil production target in the past two years, as it focuses on raising its natural gas exports.

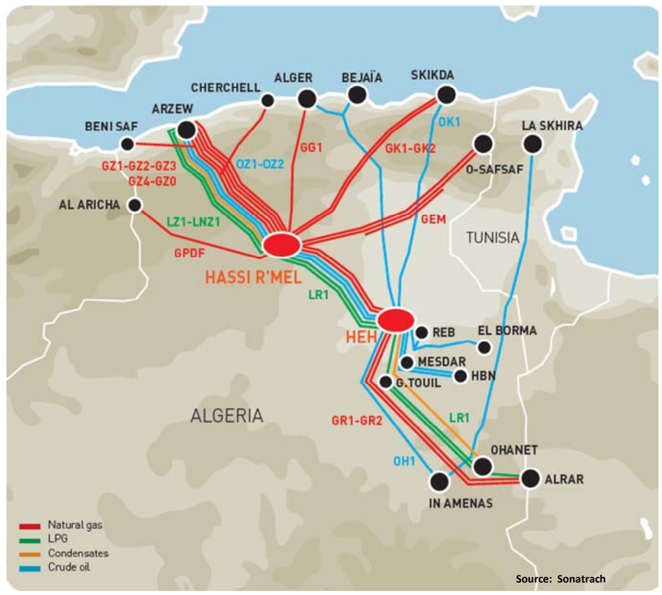
Algeria has 4.5 tcm of proven gas reserves. Its largest natural gas field, Hassi R'Mel, was discovered in 1956 and holds proven reserves of about 2.4 tcm. Hassi R'Mel accounts for about a quarter of Algeria's total dry natural gas production. The remainder of Algeria's natural gas reserves come from associated and non-associated fields in the south and southeast of the country. Algeria has a large range of new natural gas developments, including In Salah, In Amenas, Gassi Touil, Ohanet, Ahnet, MLE, Timimoun, Touat, Reggane, Rhoude Nouss and Tinrhert, some of which are developed, while final investment decisions are pending for others, as they are technically challenging and costly to develop. Algeria became the world's first exporter of LNG in 1964. Currently one third of Algeria's natural gas exports derive from their LNG plants in Arzew and Skikda, the latter of which has been out of operation since an explosion in 2004, but will soon be back on stream. Algeria currently has 39 bcm of cross-Mediterranean export capacity through the Transmed and Maghreb-Europe pipelines. Two new LNG trains are under construction, one at Arzew and one at Skikda, which will replace the three old liquefaction trains at this site. The new trains will add 12.5 bcm of natural gas export capacity by 2013. Algeria plans to increase its pipeline export capacity through expansions in Transmed and the Medgaz and Galsi pipelines.

Algeria production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	82	87	81	85	90	96	101	107	25	3.9 %
Gas production (kboe/d)	1,418	1,508	1,387	1,469	1,556	1,648	1,746	1,849	431	3.9 %
NGL (kbd)	588	628	668	705	728	745	762	780	192	4.1 %
NGL to gas ratio	41.4%	41.6%	48.1%	48.0%	46.8%	45.2%	43.7%	42.2%		

Current NGL production

We have aligned OMR production estimates more closely with Algerian Ministry of Petroleum reports of condensate and NGL production. The revision is partly a reclassification between crude and condensate, and partially a downward revision of NGL numbers. The Ministry figures are also in line with available external sources.



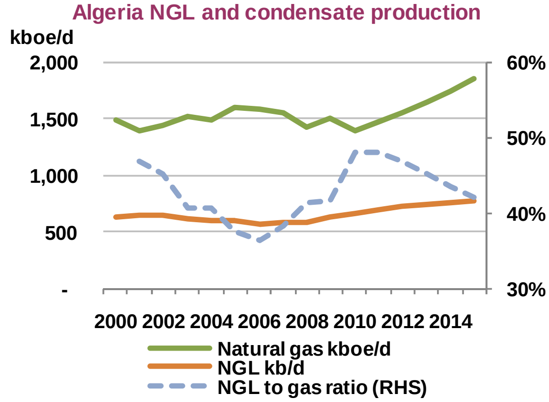
Sonatrach operates an oil, condensate and NGL pipeline network that links Hassi R'Mel and other fields to Arzew. Condensate and other NGLs are extracted at several field level processing plants, and NGLs are fractionated into LPG and ethane at a plant in Arzew. Algeria is the world's second largest exporter of LPG, and was also one of the first countries in the world to export large-cargo LPG.

Algeria is currently investing heavily to increase its capacity to extract, transport and fractionate NGLs and condensate. On 24 August 2009 the first stage of the 500 km pipeline that will raise capacity to transport NGL from the Hassi R'Mel plant to the Arzew export terminal from 9 mt/y to 15 mt/y was completed. The second phase was due be completed in January 2010. In July 2009 a 5 mt/y (135 kb/d) condensate splitter in Skikda began operations. It will produce 4 mt/y of naphtha, with jet fuel and gasoil being the other main products. Algerian naphtha has a high paraffin content and is considered desirable as petrochemical feedstock. The plant is supplied by a 650 km pipeline from the Haoud El Hamra oil fields, near Hassi Messaoud, to the coast. The nameplate transportation capacity will be 18 mt/y.

The outlook for NGL production

Algerian gas plant LPG and ethane production is forecast to reach 13 mt/y by 2012, which corresponds to 413 kb/d. The forecast is based on statements from official and industry sources as well as ongoing capacity expansions of LPG plants and pipelines. Growth in NGL production in 2013 and onwards is expected to be in line with the natural gas production growth. Some new streams of condensate will come from fields such as El Merk and the MLE development, both in the Berkine basin. However there is also ongoing decline in existing production, and there is no suggestion that overall condensate production will increase. However, no

Algeria NGL and condensate production



statements are given that overall condensate production is set to increase. The new condensate splitter described above is an investment to increase the possibility for Algeria to export their attractive high-paraffinic naphtha instead of condensate. Condensate production is therefore assumed to be stable at 315 kb/d over the forecast period. All in all, our liquids to gas ratio falls for Algeria after 2010. Various newer gas development projects for which the relative amounts of dry gas and NGL is described, like In Amenas, Ohanet and MLE, show a liquids ratio below the current level of 40%, with the possible exception of the Berkine basin projects, El Merk and block 405a/b. Around 9 bcm of natural gas from In Salah is said to be dry without any associated liquids. Nonetheless, Algerian liquids output rises by 200 kb/d during 2008-2015.

5.7.6 Nigeria

Relevant natural gas trends

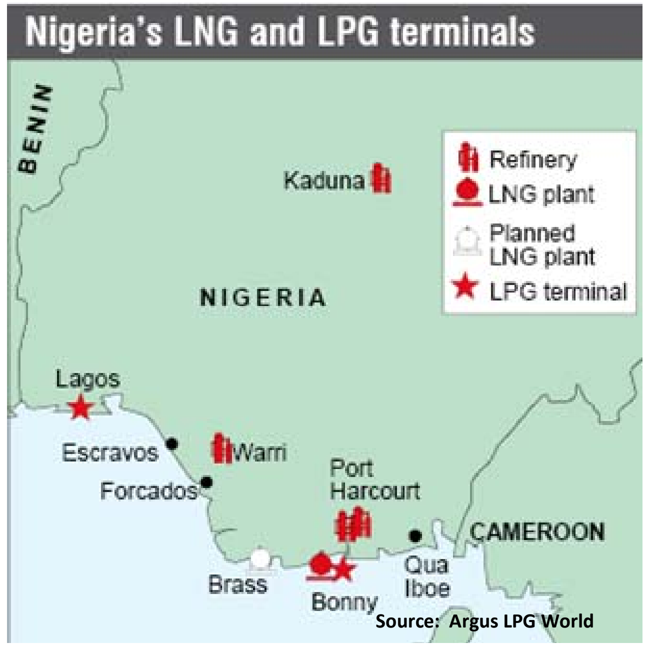
Nigeria holds 5.3 tcm of proven gas reserves, the highest in Africa. Nigeria has a lot of plans to increase natural gas production, which is currently at 35 bcm to which one must add 15 bcm of flaring and 5 bcm of gas re-injection to arrive as gross production. Of the marketed gas, 21 bcm was exported as LNG and 14 bcm was consumed domestically. Adding 5 bcm of exports through the West Africa Gas pipeline and 9 bcm of increased domestic consumption would yield 49 bcm by 2015. Eliminating flaring and extracting economic value from the associated gas is a major priority of the Nigerian government, and in 2008 it announced a Gas Master Plan, involving the construction of three gas gathering and processing plants and three pipeline systems to feed gas to power plants. The project could boost natural gas supply by 9 bcm by 2011. In addition one could assume that the LNG plant at Bonny Island would work closer to its nameplate capacity of 30 bcm and that more LNG projects would come on stream. However, the WEO2009 natural gas production forecast is much less optimistic. They forecast 2015 natural gas production of 44 bcm, an annual growth of 3.2%. It goes without saying that the natural gas forecast of Nigeria is highly uncertain and could easily reach much higher levels given a more favourable investment climate.

Nigeria production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	35	37	38	39	40	41	43	44	9	3.2 %
Gas production (kboe/d)	610	629	649	670	691	712	735	758	148	3.2 %
NGL (kbd)	160	273	387	408	419	420	421	410	250	14.4 %
NGL to gas ratio	26.2%	43.3%	59.6%	61.0%	60.7%	58.9%	57.3%	54.1%		

Current NGL production

It is hard to get an overview of the NGL extraction and fractionation capacity of Nigeria. The largest NGL fractionation plant, which also has the most important export terminal for LPG, is located at Bonny Island, in connection with the Bonny LNG plant. Four gas trunklines from the Niger Delta as well as offshore pipelines feed the LNG plant with gas, but upstream natural gas development in Nigeria has lagged the expansion of the LNG plant, which has been operating below capacity due to lack of gas and other operational difficulties. The stripping of NGLs from gas prior to its shipment to Bonny has also left the NGL extraction capacity at Bonny Island underutilised. The capacity at the NGL fractionation plant at Bonny Island was 2.25 mt/y before train 6 came in 2008, which corresponds to 72 kb/d. Assuming that the NGL handling capacity increased proportionally with the natural gas liquefaction capacity, the NGL capacity at Bonny Island should now be about 90 kb/d. Another nearby NGL plant is the 11 kb/d Cawtorne Channel plant, which deliver stripped gas to Nigeria LNG. The Obiafu-Obrikom gas plant is located further up in the Niger Delta, and processes gas from the production licenses OML 60-63. The gas is used for power generation, and the gas plant has the capacity to extract 10 kb/d of NGL marketed locally.



Source: Argus LPG World

Recently the offshore East Area field operated by Exxonmobil and NNPC has added 50 kb/d of NGL extraction capacity, and these NGL volumes are being fractionated at an NGL terminal off Bonny Island. The NGLs are extracted from ageing offshore fields outside the Niger Delta, and most of the natural gas is re-injected to support oil production. This is a classical project that shows how the trend of better utilisation of associated gas, even if it's for re-injection, impacts NGLs production. The World Bank estimates that Nigeria flared 14.9 bcm of natural gas in 2008, down from 21.3 bcm in 2005, but still the highest natural gas volume flared after Russia.

The Escravos plant is located further west in the country, closer to Lagos, and supplies natural gas for the domestic market and the West African Gas Pipeline, (see illustration from Chevron below). This plant is assumed to have the capacity to extract 9 kb/d of NGLs.

External sources suggest that the total LPG production of Nigeria was 53 kb/d 2006 and 76 kb/d in 2007. According to the Nigeria National Petroleum Company (NNPC) statistical report the total NGL production in 2008 was only 37 kb/d, but no assessment can be made as to the reliability and completeness of these figures. However, the Nigeria LNG (NLNG or Bonny LNG) complex was out of operation most of 2008, and the new train 6 has not yielded any additional LNG production from NLNG, since there is a lack of feed gas. As an outcome of this review the historical OMR NGL production profile was revised down.

Source: Chevron

The only condensate stream included in OMR figures in 2008 was the Oso condensate stream. Assessment of the volume here varies among other sources, but existing OMR estimates appear reasonable and have been retained.

The outlook for NGL production

For condensate, the Oso field is forecast to decline from its 2009 level of 66 kb/d. The Akpo field, which came on stream in 2009 will add 175 kb/d over 2009 and 2010, while the Gbaran/Ubie development is forecast to add 70 kb/d of condensate by 2012. It is not sure whether the oil from this project will actually be condensate or a light crude oil, but in our forecast we have assumed it to be condensate. All told, condensate increases from 69 kb/d in 2008 to 281 kb/d in 2015, an increase of 212 kb/d.

For the gas plant liquids forecast we assume a higher utilisation of the NGL capacity at the Bonny LNG plant. In addition to that 40 kb/d of NGL volumes from the East Field development is added, even though the extent to which this plant is integrated with the Bonny LNG plant remains uncertain. No GTL or new LNG plants are assumed to come on stream in Nigeria over the forecast period. However, with so many projects at or beyond engineering stage, an improvement in the investment climate of Nigeria could drastically change the scene for this resource-rich country.

5.7.7 Angola

For Angola there are very few available sources for NGL data. Angolan gas production is very modest at 2 bcm. There is one field that supplies NGLs, the Sanha-Bomboco field. The 2008 OMR figure for NGL is 30 kb/d while the condensate figure is 20 kb/d, in line with external sources. There is a consensus that Angola LNG will come on stream in 2012 and commercialise associated gas that is currently being flared at various fields. Development of the Angola LNG Project includes construction of an onshore liquefaction train with storage capacity for LNG, LPG and condensate. Additionally, a pipeline will be built to transport natural gas to Angola markets. The assumed condensate and other NGL output from Angola LNG is included in the forecast that takes Angola's total NGL output from 50 kb/d in 2008 to 92 kb/d from 2013 onwards.

Source: Chevron

Angola production outlook for natural gas and NGLs

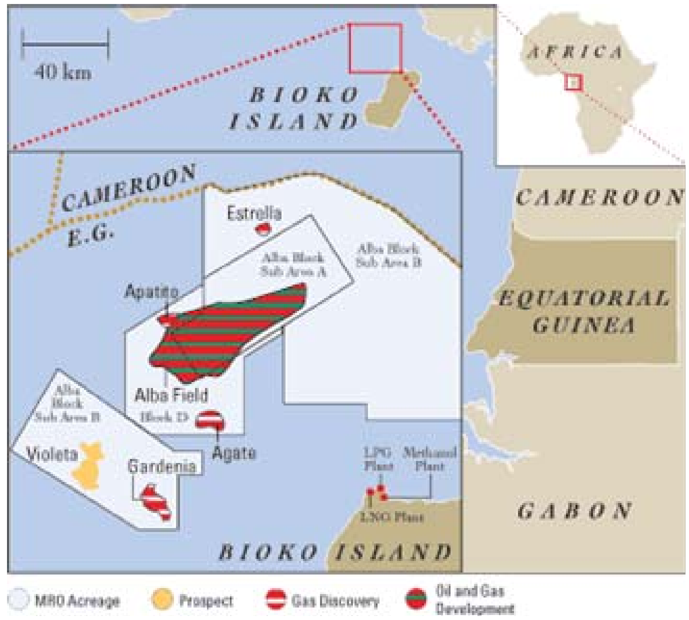
	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	1	1	1	1	6	6	6	6	6	38.0 %
Gas production (kboe/d)	11	11	12	13	105	106	106	107	96	38.0 %
NGL (kb/d)	50	50	50	50	86	92	92	92	42	9.1 %
NGL to gas ratio	446.4%	442.4%	409.2%	392.6%	81.4%	87.0%	86.7%	86.1%		

5.7.8 Equatorial Guinea

The Equatorial Guinea LNG plant started up in April 2007. The Alba field had come on stream earlier, with natural gas previously partly used for methanol production, partly re-injected. Now, the natural gas from the Alba field mainly supplies the LNG plant, but still produces methanol as well, while a declining amount of liquids is extracted.

According to the annual report of the Alba field operator Marathon, out of 65 kb/d of liquids produced in 2008, 17 kb/d was LPG and 48 kb/d condensate (41.3 at field, 6.3 at plant) and 17 kb/d of LPG, in accordance with the OMR figures.

The Alba field is in decline, but it is assumed that new gas will be supplied from other fields during 2011-2012 as mentioned by Marathon and illustrated in the picture below, stabilising NGL production. The potential Alba LNG train 2 is not assumed to come on stream within the forecast period. Bioko Island is situated near the Niger Delta, and might theoretically be supplied by natural gas from its more resource rich neighbour, but that solution is not deemed likely.



Source: Marathon

Equatorial Guinea production outlook for natural gas and NGLs

	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015 change	Compounded annual growth
Gas production (bcm)	5	5	5	5	5	5	5	5	0	0.0 %
Gas production (kboe/d)	86	86	86	86	86	86	86	86	0	0.0 %
NGL (kb/d)	65	59	52	46	46	46	46	46	-19	-4.8 %
NGL to gas ratio	75.4%	68.5%	60.3%	53.4%	53.4%	53.4%	53.4%	53.4%		

6 Glossary

API gravity

API (American Petroleum Institute) gravity is inversely proportional to the specific gravity (SG) of a liquid. API gravity is a measure of how heavy a given volume of this liquid is compared to the same volume of water, and is calculated by the formula *API gravity = (141.5/SG) - 131.5*. A condensate with an API gravity of 50° has a specific gravity of 0.78, i.e. a litre of this condensate will weigh not more than 0.78 kilogram.

Associated gas

Associated gas is natural gas associated with oil accumulations, which may be either dissolved in the oil or may form a cap of free gas above the oil.

Biofuels

Biofuels are transportation fuels derived from biological sources including cereals, cellulosic materials, sugar, oil seed crops and organic waste. The OMR supply and demand balances include the biofuels ethanol and biodiesel.

Bitumen

Bitumens are exceptionally heavy hydrocarbons, either naturally occurring crude bitumen (crude bitumen produced from oil sands), or deriving from the residue refining process. Bitumen is highly viscous or solid and must be eiter upgraded to synthetic crude oil or diluted with for example condensate to allow pipeline transportation and refining.

Butane (C_4H_{10})

A normally gaseous straight-chain hydrocarbon extracted from natural gas or refinery gas streams. The boiling point under atmospheric pressure is 0.5°C.

CNG (Compressed natural gas)

Natural gas that is compressed to a pressure of 200 – 250 bar and stored in tanks, in most cases to be used in vehicles running on natural gas.

Coalbed methane (CBM) or Coal seam methane

A type of unconventional natural gas, formed in the coalification process and found on the internal surfaces of the coal. Tor extract the gas water must be removed from the coalbed to reduce partial pressure. The large quantities of water, sometimes saline, produced from CBM wells pose an environmental risk if not disposed properly.

Condensate

The liquids dissolved in natural gas in the reservoir that condense to a stable liquid in atmospheric pressure. Consists of molecules typically from C_5 to C_8, and might also be characterised as a light crude oil with API gravity above 50° and a low sulphur content.

Condensate splitter

Condensate splitters are simple distillation towers with cut-points adjusted to handling a high proportion of light product and tower overheads sufficient to handle that volume flow.

Dilution of bitumen

Dilution of bitumen is when naphtha or condensate or another light hydrocarbon is added to non-upgraded bitumen to make a fluid that can be transported by pipeline. The blend is called dilbit. The diluent typically make up 17-32% of the dilbit.

Downstream

The oil industry term used to refer to all petroleum activities from the process of refining crude oil into petroleum products to the distribution, marketing, and shipping of these products (see Upstream).

Dry gas

Gas that does not contain heavier hydrocarbons or that has been treated to remove heavier hydrocarbons.

Ethane (C_2H_6)

A normally gaseous straight-chain hydrocarbon extracted from natural gas or refinery gas streams. The boiling point under atmospheric pressure is -88.6°C.

Field condensate

Condensate may be extracted from a gas stream at the field or at a gas processing plant. Condensate which is recovered as a liquid from natural gas in field separation facilities is referred to as field condensate. Field condensate is the same as lease condensate, which is the term used in the USA.

Flaring

Burning off unused natural gas, typically at an oil producing field where the associated gas cannot be economically utilised. Sometimes gas is flared as a safety measure to mitigate overpressure of other gas systems.

Fractionation

See *NGL fractionation*

Gas liquids

If we talk about gas plant liquids and refinery LPG and ethane alike we may refer to all of it as “gas liquids”, as opposed to the term “natural gas liquids” that include only the liquids that we derive from natural gas.

Gas plant condensate

Condensate may be extracted from a gas stream at the field or at a gas processing plant. Condensate that is extracted at a gas processing plant is referred to as gas plant condensate.

Gas plant naphtha

Naphtha may be produced both at a refinery and at a gas processing plant. Naphtha that is produced at a gas processing plant is referred to as gas plant naphtha.

Gas processing plant

A facility designed to recover natural gas liquids from a stream of natural gas which may or may not have passed through field separation facilities. These facilities also control the quality of the natural gas to be marketed.

Gas-to-Liquids (GTL)

Gas-to-Liquids technology involves the production of low-emission diesel and naphtha from natural gas reserves. Production of these fuels is included in both the supply and demand side of OMR balances.

Hub

Physical or virtual location where multiple natural gas pipelines interconnect or natural gas is assumed to be delivered between multiple parties.

Hydrocarbons

An organic compound containing only carbon and hydrogen. The term is often used commonly for natural gas, oil and coal.

Isobutane (C_4H_{10})

A normally gaseous branch-chain hydrocarbon. It is a colourless paraffinic gas that boils at a temperature of 11.7°C. It is extracted from natural gas or refinery gas streams.

Lease condensate

See field condensate.

LPG (Liquid Petroleum Gases)

LPG is a common term for propane (C_3H_8), butane and isobutene (C_4H_{10}) or a mix of those.

Methane (CH_4)

The lightest hydrocarbon molecule. The primary component of natural gas and particularly of dry natural gas.

Midstream

The midstream is the part of the oil and gas value chain that lies between the upstream and the downstream. Typically, this refers to infrastructure such as pipelines, but also the whole entire range of oil-gas-separators and gas processing plants. The NGL fractionation, whereby NGLs are split into LPG and other products, is strictly speaking a part of downstream operations, but the NGL extraction and fractionation often takes part at the same complex.

Naphtha

A petroleum distillation fraction most commonly used as feedstock destined for the petrochemical industry (e.g. ethylene manufacture). Naphtha comprises hydrocarbons in the 30°C and 210°C distillation range or part of this range.

Natural gas

Light paraffinic hydrocarbon mixture, mainly methane, small quantities of ethane and propane and in variable proportions nitrogen, carbon dioxide and hydrogen sulphide. Natural gas can be associated with crude oil or be found alone in non-associated natural gas wells.

Natural gas liquids (NGL)

Natural gas liquids (NGLs) are light hydrocarbons that are dissolved in associated or non-associated natural gas in a hydrocarbon reservoir, and are produced within a gas stream. They comprise ethane, propane, butane and isobutene (collectively LPG), pentane-plus and gas condensate, i.e. molecules with 2-8 carbon atoms (C_2H_6- C_8H_{18}). Above the ground the rich gas stream is unstable, as heavier components will *condense*, while lighter components normally remain gaseous, and will have to be separated from the dry gas in a gas processing plant (GPP). Hence, there are two categories of NGLs - condensate and other NGLs. As condensate has many characteristics that make it different from other NGLs, it is useful to distinguish between the two.

Natural gasoline

Natural gasoline is a natural gas liquid with a vapor pressure intermediate between natural gas condensate and liquefied petroleum gas and has a boiling point within the range of gasoline. The typical gravity of natural gasoline is around 80 API and the main components are typically hydrocarbons in the range C_5-C_6. Naphtha is sometimes referred to as natural gasoline.

NGL extraction

The process by which NGLs are separated from natural gas.

NGL fractionation

The process by which NGLs are separated into distinct products, or "fractions," such as propane, butane, and ethane.

Non-associated natural gas

Natural gas that is not in contact with crude oil in the reservoir. Natural gas that is produced from a well that does not produce other oil than NGLs.

Olefins

A class of unsaturated aliphatic hydrocarbons having one or more double bonds, produced by cracking naphtha or other petroleum fractions at high temperatures (e.g. propylene, ethylene).

Paraffinic hydrocarbons

Straight-chain hydrocarbon compounds with the general formula C_nH_{2n+2}.

Pentane (C_5H_{12})

A straight-chain hydrocarbon. It is a colourless paraffinic gas that boils at a temperature of 36.1°C. It is extracted from natural gas or refinery gas streams.

Pentanes plus

A mixture of hydrocarbons, mostly pentanes and heavier, extracted from natural gas. Includes isopentane, natural gasoline, and plant condensate.

Petrochemical facilities

Facilities where petrochemicals are produced.

Petrochemicals

Organic and inorganic compounds and mixtures that include but are not limited to organic chemicals, cyclic intermediates, plastics and resins, synthetic fibers, elastomers, organic dyes, organic pigments, detergents, surface active agents, carbon black, and ammonia.

Play

A set of known or supposed accumulations of hydrocarbons sharing similar geologic properties, such as source rock, migration path, trapping mechanism, and hydrocarbon type.

Propane (C_3H_8)

A normally gaseous straight-chain hydrocarbon extracted from natural gas or refinery gas streams. It is a colourless paraffinic gas that boils at a temperature of -42.1°C.

Re-injection

Re-injection is the act of putting produced gas back to the reservoir from which it came or to another reservoir. Gas is re-injected either to support pressure in the reservoir or because the gas can not be economically used elsewhere.

Sales gas

Dry gas marketed under controlled quality conditions.

Sales gas specification (spec)

The sales gas specification (spec) is the quality specifications with which the dry gas has to be compliant in order to be marketed. The "spec" will regulate the calorific content, acidity, dew point and other characteristics of the gas.

Segregated condensate

Condensate marketed as such.

Shale gas

Natural gas that is produced from reservoirs predominantly composed of shale (a fine-grained sedimentary rock), rather than from more conventional sandstone or limestone reservoirs.

Specific gravity

Specific Gravity is the relative weight per unit volume of water (or density) of any given substance. With water having an SG of 1.0, most oils lie in an SG range of 0.6-1.0. The lower the SG, the lighter the oil.

Sour gas

Natural gas that contains significant amount of hydrogen sulphide.

Spiked condensate

Condensate blended with crude oil and marketed as a crude oil blend. The condensate might be spiked as a viscosity cutter or in order for the blend to obtain a target API gravity.

Unconventional gas

Unconventional gas is gas that is more technologically difficult or more expensive to produce than conventional gas. Unconventional gas resources can be divided into coalbed methane, tight gas, shale gas and methane hydrates.

Upstream

Oil sector activity in the OMR is defined as exploration, appraisal, development and production activities pertaining to reserves of crude oil, natural gas liquids and condensates. Processing, transportation and marketing activities are excluded.

Very Large Gas Carriers (VLGC)

A Very Large Gas Carrier is an LPG vessel with capacity above 60,000 scm. An LPG vessel is used to transport ammonia and liquid gases (ethane, ethylene, propane, propylene, butane, butylenes, isobutene and isobutylene).The gases are transported under pressure and/or refrigerated.

Wet gas

A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentane. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, hydrogen sulfide, nitrogen and trace amounts of helium. Under reservoir conditions, natural gas and its associated liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with crude oil and are not distinguishable at the time as separate substances. Wet gas might also be referred to as rich gas or simply natural gas.

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Notes on use of estimates and statistics from other sources

All historical levels of natural gas production, oil production and NGL production are from the IEA Annual Oil Statistics (AOS), Monthly Oil Statistics (MOS) or Monthly Oil Data Service (MODS).

All oil production forecasts are based on Medium Term Oil Market (MTOMR) Update from December 2009.

All natural gas production forecasts including splits in associated and non associated gas, conventional and unconventional gas on country or region level are forecasts for marketed gas production made for the purpose of the IEA publication World Energy Outlook (WEO) 2009. The figures were neither initially prepared to be used on the disaggregated level in which they have been used in this study, nor to be used for such a short term outlook.

All reserves estimates quoted are from Cedigaz, which was also the main source for WEO2009. For reference reserves tables from BP and OGJ have been used.

All flaring levels quoted are from the World Bank, Global Gas Flaring Reduction Programme.