The Future of Natural Gas

Supplementary Paper SP 2.2

Background Material on Natural Gas Resource Assessments, with Major Resource Country Reviews.

(Ejaz)

This paper provides background material for the MIT Energy Initiative report entitled the Future of Natural Gas.

We start by discussing various definitions that are commonly used – and often abused – in the discussion of natural gas resources, and describe the geological context for various types of gas deposits. This is followed by an overview of global gas resources, and then a detailed review of the resource potential of the five largest natural gas resource countries in the world: the U.S.; Canada; Russia; Iran; and Qatar. A separate discussion of the methodologies used by various agencies for their assessment and estimations is contained in a companion Supplementary Paper SP 2.1.

Discussion of Resource Definitions

There is some confusion surrounding the terminology used to describe hydrocarbon resources, as a result of the fact that different agencies involved in resource assessment use somewhat different definitions and methodologies. We will describe the fundamental concepts, and clarify the definitions adopted within our study. The modified McKelvey diagram shown in Figure 1 provides a useful framework for describing the basic principles.

Gas Initially In Place (GIIP) – this describes the total volume of gas estimated to be contained in the subsurface before any production has occurred; this includes gas already discovered and produced, and estimates of gas yet to be discovered through future exploration activities. GIIP is represented in Figure 1 by the total area. Clearly, as also indicated on the diagram, there are various levels of uncertainty associated with these estimates. Estimates of gas yet-to-be-found in undeveloped basins (the right hand side of the diagram) are subject to very high levels of uncertainty; resources already produced (the top left of the diagram) are known with reasonable accuracy.

Technically Recoverable Resources - for various technical reasons, only a portion of the GIIP will ultimately be recoverable through production. This is shown as the Technically Recoverable area in the McKelvey diagram (Figure 1). Depending on the nature of the gas accumulation, the fraction of gas-in-place recovered can vary widely; for example in conventional reservoirs it could be as high as 90% of GIIP while in shale plays it may be as low as 10%. In practice, the "technically recoverable" boundary will shift over time, as new technology allows the development of gas accumulations that were previously thought to be unrecoverable. For example, the Fayetteville shale play was not assessed by the USGS when it assessed the Arkoma Basin in 1995, as it was not considered a recoverable resource at that time (US Geological Survey 1995). However the Fayetteville shale today is the seventh largest gas field in the US as ranked by proved reserves, and produced 275 BCF of gas in 2008 (Energy Information Administration 2009).

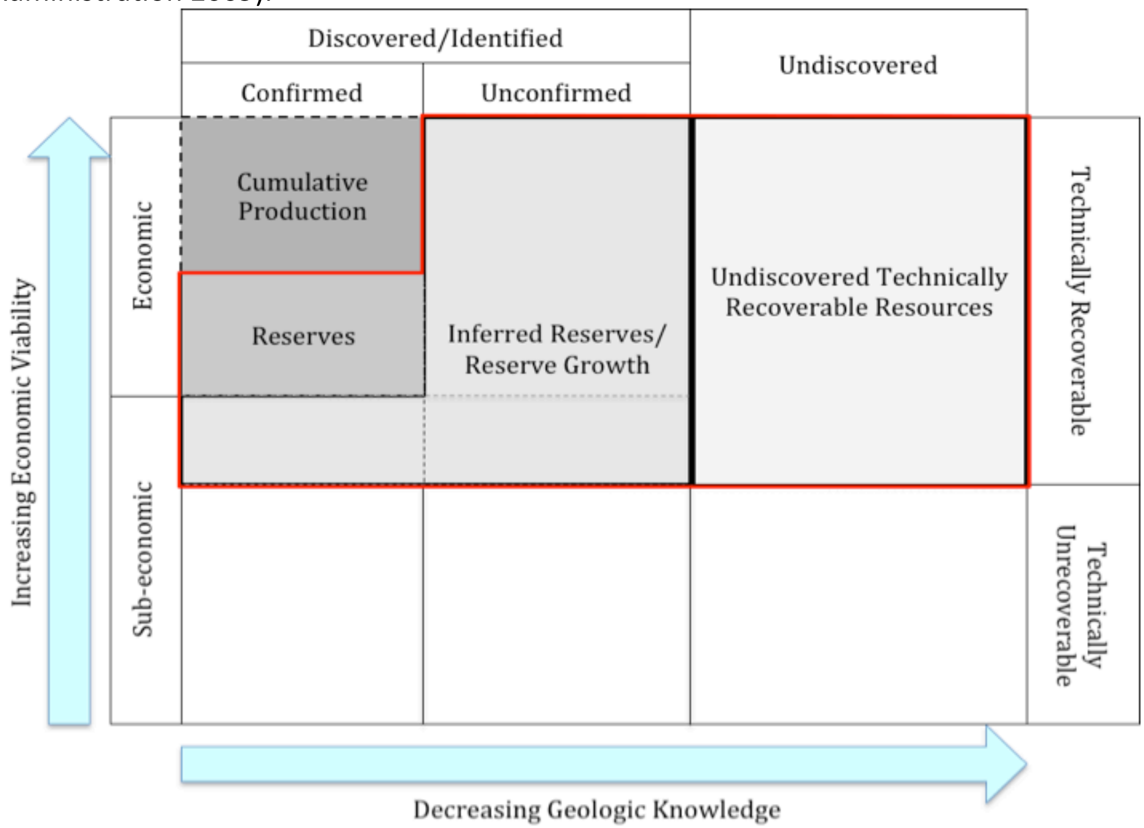

Figure 1: This is a modified McKelvey diagram (adapted from (US Geological Survey 1995)) to show the division of gas initially in place into various categories (not to scale). The resource categories contained in the red polygon are the remaining recoverable resource. Undiscovered technically recoverable resources and inferred reserves are estimated by various agencies, such as USGS and PGC. Reserve volume estimates are conducted by oil and gas companies, which in the US are reported to EIA. The various dividing lines move with time as resources are exploited, and economic and technological factors change.

Remaining Recoverable Resources (RRR) – this is the technically recoverable resource base minus the production to-date; the area outlined in red on the McKelvey diagram represents RRR. For the purposes of this study, we are primarily concerned with the Remaining Recoverable Resource – the resource that we expect to recover from this point in time forward – and when we refer to resource in the text, we are generally referring to the RRR, unless otherwise specified.

Economically Recoverable Resources - the McKelvey diagram further subdivides technically recoverable resources into economic and sub-economic categories. The economic decision to develop a particular gas accumulation is driven by a variety of considerations: in particular, the cost of development, the expected production rate and ultimate recovery, and the price received for the gas sold. The boundary between economic and sub-economic resources shifts as gas price varies, and as technology development drives down cost. We have attempted to capture this effect in the development of gas supply curves, which demonstrate the relationship between remaining recoverable resources and well-head gas price.

Reserves - the technically recoverable resource is divided into discovered and undiscovered. The discovered portion includes reserves. This is the volume of technically recoverable resource from a formation that an oil or gas company reports as being producible with current technology and in current economic conditions. Different volumes from a given formation may be producible with different levels of certainty. In the US, SEC requirements mandate that reserves be reported at the 90% confidence level; i.e. with a 90% probability, or with the most conservative scenario in a deterministic analysis that the given volumes will be produced over time. Reserves with such high probability of producibility are called 1P reserves (SPE-PRMS) or *proved reserves*. It is important to note that with the stringent definition of proved reserves mandated by the Securities and Exchange Commission (SEC), these reserves in the US represent only a relatively small fraction of the total Remaining Recoverable Resource base. In the rest of the world, reserves are often realized against less stringent criteria, such as a 50% confidence level, and sometimes with no reference to economic viability.

In the US, proved reserves are reported by the Energy Information Administration (EIA) (Energy Information Administration 2009). Data for world reserves is gathered from a variety of sources and is most conveniently available in the BP statistical review (BP 2009) or from EIA's international databases.

Reserve Growth – reserve growth is a catch-all category used in resource assessment to describe the additions to reserves over time. Reserves represent, in effect, an inventory of the resources on production or under development at any point in time. These reserves are continuously depleted through production, and continuously replenished by a variety of activities designed to increase recovery from existing reservoirs and to develop additional reservoirs within the field boundaries, such as, infill drilling and discoveries of new pools in existing fields.

Reserve-growth has been estimated by the United States Geological Survey (USGS) using oil and gas field data collected by EIA to create growth functions. These were used by the USGS to estimate reserve growth in the whole world as part of its 2000 World Assessment of Oil and Gas Resources (Attanasi and Root 1994). The Potential Gas Committee (PGC) also estimates reserve growth (the "Probable" resources) as part of its assessment in the US (Potential Gas Committee 2009).

Of the undiscovered gas in place, a portion will be recoverable with today's technology. This portion of the resource is called technically recoverable. These estimates do not include explicit economic assumptions. However the process of resource estimation is done in the context of identified prospects and the definition and delineation of prospects implicitly introduces economic assumptions.

The above definitions were formulated in a top-down fashion, an approach that is useful in conveying concepts to non-specialists in the field. For people involved in the oil and gas business, a bottom-up approach is more intuitive. An oil or gas company conducts exploratory drilling, which may or may not lead to a discovery. Once a discovery is made, data is collected to estimate the quantity of movable hydrocarbon in the discovered accumulation. Then as a next step, recovery projects are developed, and the results of these estimates under specified regulations and rules get recorded as proved reserves. As projects are developed, based on economic conditions, gas is produced from these reserves. Probable and possible reserves are then the quantity of gas that will move into the proved reserves category in the future due to infill drilling, technological improvements in recovery, and improved commercial feasibility (Etherington and Ritter 2007). There is less certainty associated with reserves growth than reserves. Geological assessments are conducted to estimate what may be discovered and added to reserves in future exploratory efforts. The amount of technical data available for these estimates is smaller than that for reserves and the range of uncertainty associated with them is greater.

Assessment of undiscovered technically recoverable resources and reserves growth in the US is carried out by several agencies. The primary government agency that carries out these assessments is the United States Geological Survey's (USGS) National Oil and Gas Assessment (NOGA) program. The USGS published its last US-wide assessment in 1995 with several updates for priority basins conducted since then. The USGS does not include reserves and reserves growth in the publication of its technically recoverable resources, though it has conducted reserve growth studies, most recently as part of the 2000 World Petroleum Assessment (T. R. Klett, D.L. Gautier, and T.S. Ahlbrandt 2000). EIA publishes resource numbers as part of its energy outlook (see, for example, (Energy Information Administration 2010a)), but they base them primarily on USGS assessments of undiscovered resources, and use their own reserve numbers.

The primary non-governmental volunteer agency that publishes bi-annual assessments of natural gas resources is the Potential Gas Committee (PGC). The PGC is an independently governed non-profit organization which works to provide insights into the future of natural gas supply in the United States. The committee has approximately 100 members who are experts in various aspects of the natural gas industry. This membership works to generate regular reports and assessments of the reserves of natural gas in the United States, reporting to the Secretary of Energy. The PGC is supported in this activity by the Potential Gas Agency at the Colorado School of Mines. Like the USGS, the PGC develops its resource estimates from fundamental analysis of geological and other pertinent data; however, the methodology and resource classification used by the PGC differs significantly from that used by the USGS. For example, the PGC includes reserve growth in its resource numbers but not proved reserves. The most recent resource estimate used in this study by the PGC is its 2008 report (Potential Gas Committee 2009).

An additional important source of data for North America is the National Petroleum Council (NPC). The NPC is a federally chartered and privately funded advisory committee, whose purpose is to represent the views of the oil and natural gas industries to the Secretary of Energy. It published a comprehensive report on natural gas in 2003 (National Petroleum Council 2003) in response to a request from Secretary of Energy. Private businesses conducting assessments include ICF International and ARI.

The National Energy Board (NEB), in conjunction with relevant province bodies, for example Alberta Energy and Utilities Board, and British Columbia Ministry of Energy, Mines and Petroleum Resources, conducts assessments of Canadian resources.

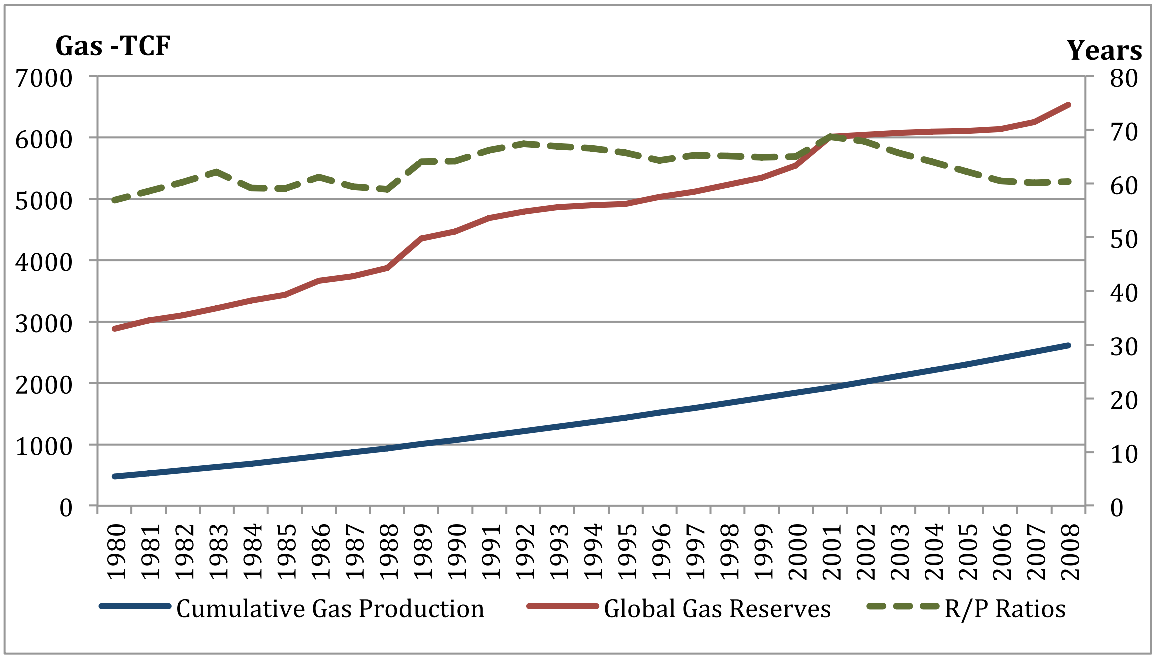

Figure 2: In this figure, it is shown that despite increasing cumulative production, remaining world gas reserves continue to grow due to new discoveries and upward revisions in reported reserves.

It is in the nature of the assessments of remaining recoverable resources that they change with time. This can happen for several reasons in the various resource categories. On the one hand, remaining resources are depleted by continuous production. On the other, undiscovered resource assessment volumes often increase because of better geologic information and from improvements in technology available for extraction. An example of this is the increase in undiscovered gas volumes in US and Canada due to unconventional resources. Reserves can increase due to new discoveries arising from exploratory efforts and due to improvements in technology and economic climate. This trend can be seen in the historical world reserve data shown in Figure 2.

Discussion of Related Geological Definitions for Natural Gas

The discussion in the previous section has presented gas resources through a lens of geologic, technological and economic uncertainty. There is a parallel discussion of these facets of gas resources based on the quality and quantity of GIIP.

Gas in a high quality reservoir is generally producible at a lower cost; consequently reserves are comprised of the highest quality fraction of a known reservoir. Exploration activities, also, preferentially find the largest and best quality reservoirs first. And development plans, due to better economics, produce the higher quality resource first. Thus the process of exploration for gas, and its discovery and production automatically links reservoir quality with the geologic, technological and economic uncertainty. Lower quality reservoirs require increased technology use for economic production without which their production would not be economically viable. Further, the quantity of GIIP is inversely proportional to the quality of the reservoir. These ideas are often conveyed as a resource pyramid shown in Figure 3.

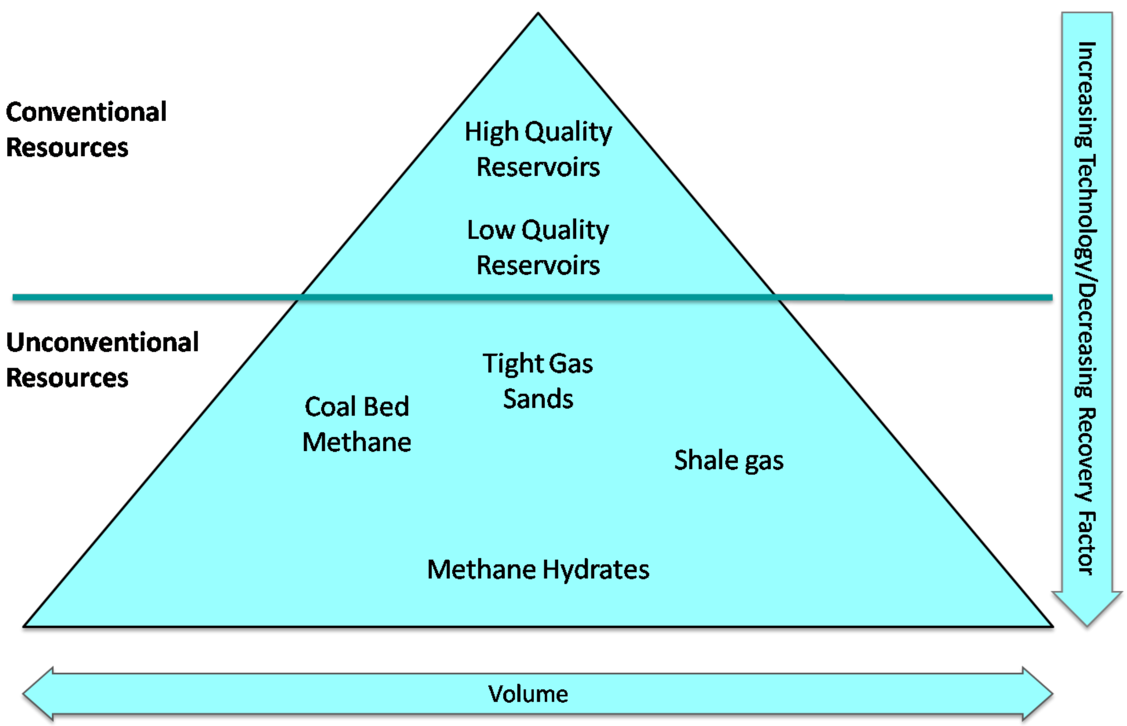

Figure 3: This figure schematically illustrates in-situ natural gas (GIIP) as a pyramid in volume and quality. Conventional reservoirs are at the top of the pyramid. They are of higher quality because they have high permeability and require less subsurface technology for development and production. The unconventional reservoirs lie below the conventional reservoirs in this pyramid. They are more abundant in terms of GIIP but are currently assessed as recoverable resources - and commercially developed - only in North America. They have lower permeability and require advanced subsurface technology for economic production. (Adapted from (Holditch 2006))

Remaining Recoverable Resources are divided into conventional and unconventional resources, the same way that GIIP is in Figure 3. *Conventional deposits*, from a geologic perspective, are finite, discrete deposits commonly delineated by down-dip water contacts. They are created by the upward migration of gas, over geologic time, from source rock where the gas is produced; gas which becomes trapped in conventional reservoirs by impermeable barriers. These impermeable barriers are in the form of structural or stratigraphic traps (see Figure 4 and Figure 5). All four conditions, i.e., the existence of source rock, migration pathway, reservoir, and trapping mechanism, must be met for the existence of conventional gas. As a consequence of these properties of conventional reservoirs, assessments of undiscovered conventional resources focus on estimating the number and size distributions of fields along with probabilities for existence of source rock, migration pathways, reservoirs and trapping mechanisms.

Note that this definition is geology-based and does not refer to the economics or type of technology required for its development and production. However, in most contexts, conventional resources do not require advanced subsurface technological methods, and in most of the world conventional resource is the most economic option.

Unconventional resources are typically difficult to delineate discretely into fields based on geology, even though they have regions with better productive qualities referred to as *sweet spots*. They also do not have a down-dip water contact (again, see Figure 4 and Figure 5). They have lower permeability (10^{-2} to 10^{-5} orders of magnitude less than a typical conventional reservoir) and typically require advanced technology, such as horizontal drilling and slick-water fraccing, making the wells more expensive. However, for some shale developments in the US, this higher cost is off-set by higher gas recovery per well, leading to a lower break-even price.

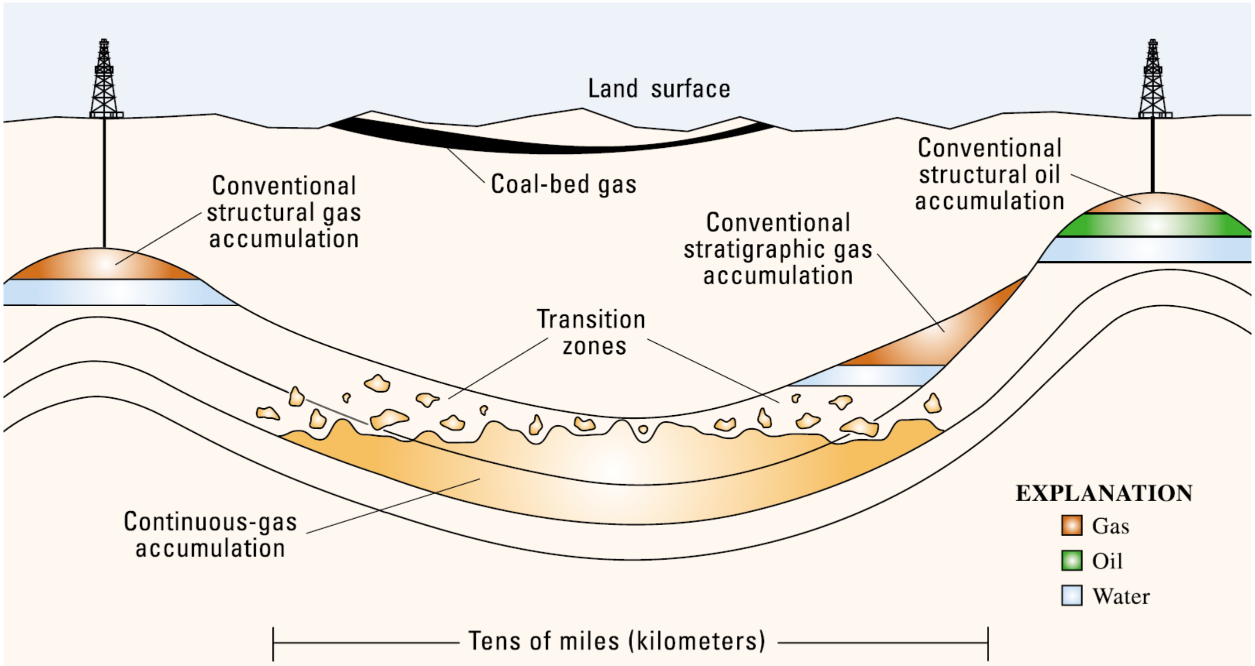

Figure 4: A schematic illustration of conventional and unconventional (continuous) gas accumulations is shown in this figure (reproduced from (C. J. Schenk and Pollastro 2002)).

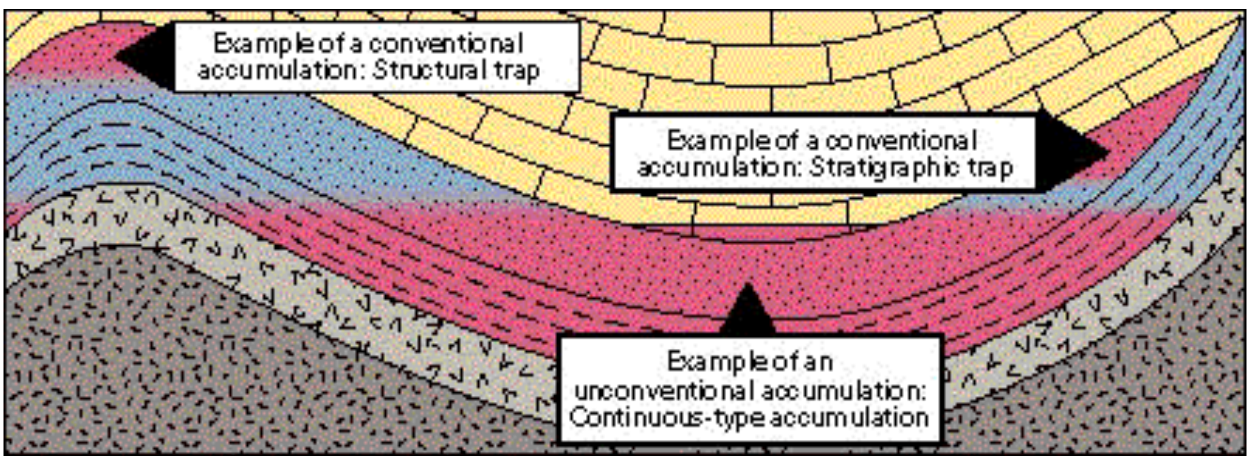

Figure 5: A schematic drawings showing the geologic setting of continuous-type gas and oil accumulations relative to discrete accumulations. In the bottom figure, gas accumulations are shown as red; water is shown as blue. Note that continuous-type accumulations across permeable rock layer boundaries. Scale of diagram is tens of miles across.(James Schmoker n.d.)

Natural gas resources generally occur in geologic *basins*. These basins are areas where thick sedimentary rocks are accumulated in topographic depressions due to tectonic processes during their geologic history. Gas can also migrate and accumulate outside of sedimentary basins in interbasinal regions. A basin, or interbasinal region, may be divided into several geologic *provinces*. A geologic province is comprised of large areas, which are unified based on geologic similarity of structure or stratigraphy. *Sub-provinces* are smaller areas within a province that share close similarity in both geologic structure and stratigraphy; and same or closely similar formations. Within a province, *trends* are belts in which petroleum production is especially favorable. These conditions include reasonably high porosity and permeability (especially for conventional gas), thickness of reservoir rocks, suitable traps, good source rocks and reasonable drilling depths. These trends may underlie different locations or may lie beneath another. A *play* in a trend or basin has stratigraphic limits and is confined to a formation or a group of closely related formations, on the basis of lithology, depositional environment, or structural and/or stratigraphic elements. Individual accumulations can be visualized to be part of a play or a trend. A *field* is defined as an area consisting of single or multiple pools or reservoirs of oil or gas, which belong to a common, individual geologic structure and (or) stratigraphic feature.

Methane gas occurs in conjunction with heavier hydrocarbons, called *natural gas liquids* (NGL), such as ethane, propane and butane; and a given reservoir lies along a spectrum of relative concentrations of these NGLs. A gas reservoir with higher concentrations of NGLs is called wet. When natural is found in an oil field (either dissolved in oil or as a cap on top), it is called *associated gas*. When found independently of oil, it is called *non-associated gas*.

Global Resource Numbers

Natural gas resources are concentrated in a few key countries, and regions; and are usually located away from existing and emerging demand centers, such as Europe, China and India.

Figure 6 is a map showing the concentration of gas resources. The regional breakdowns adopted here are somewhat arbitrary – for the purposes of this study, we have used regions which align with the Emissions Predictions and Policy Analysis (EPPA) model (Paltsev et al. 2005).

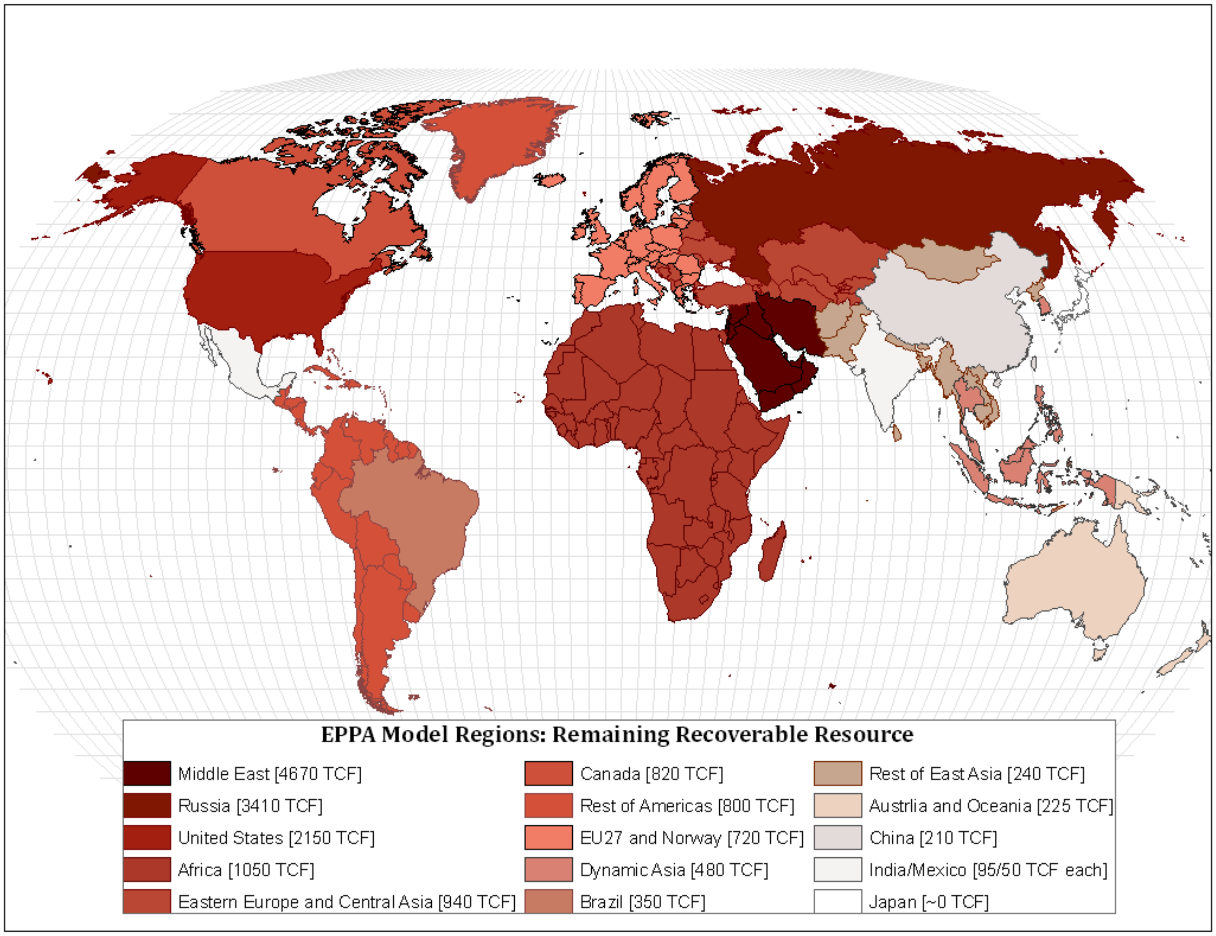

Figure 6: Global Gas Remaining Recoverable Resources by EPPA Regions are shown in this figure.

There are a total of 16 EPPA regions, one of which (Japan) has negligible gas resources. It can be seen in this figure that the top three countries/regions are the Middle East, Russia, and the US. In this map, unconventional resources are included only for North America (US and Canada), where it accounts for 45% of the resource base. While it is anticipated that there are significant unconventional resources in the rest of the world based on GIIP studies, outside of North America there are no comprehensive estimates of remaining recoverable unconventional gas resources, and very little prodcution[1].

Nearly 70% of the world's remaining recoverable resource is located in only three EPPA regions: Middle East (29%), Russia (21%), and North America (18%). As shown in Figure 7, there is a disparity in the ratio of reserves to recoverable resources. This has to do with the disparity in reserves reporting practices. North America has the smallest reserves both because of more stringent reporting requirements and the maturity of gas production.

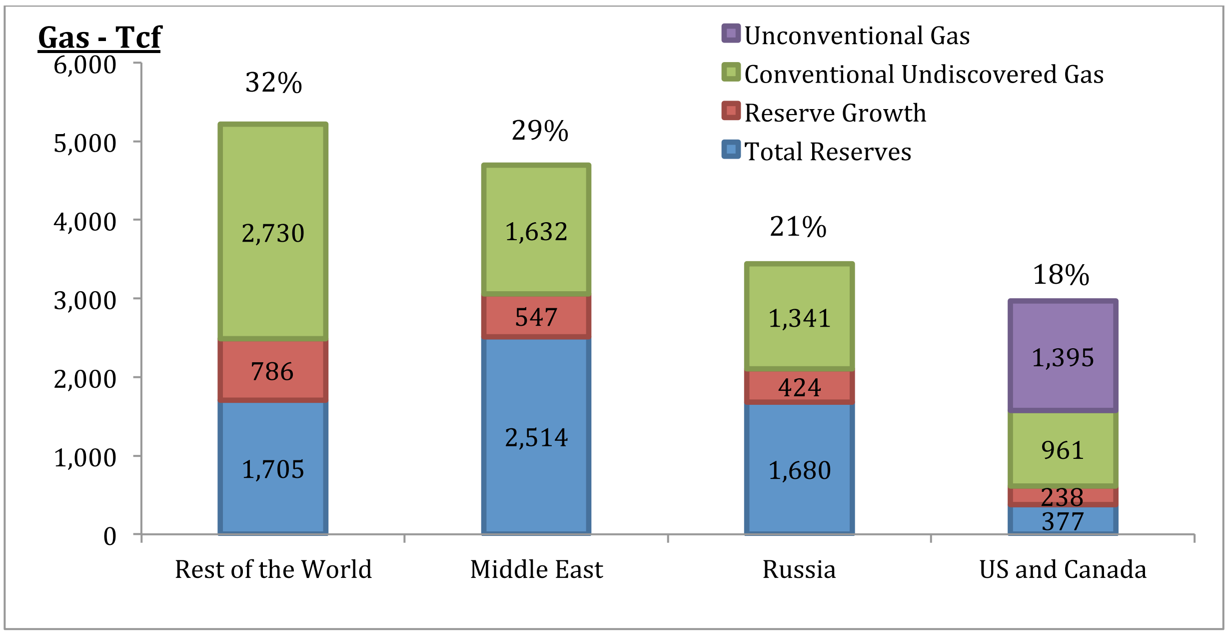

Figure 7: Nearly 70% of the world resources lie in three regions - Middle East, Russia, and North America (US and Canada). Reserves are a significant portion of the world's resources outside North America. While GIIP estimates exist for unconventional resources, there is no reliable estimate available for the recoverable portion of unconventional gas in the world.

Global Remaining Resources

This section tabulates the recoverable gas resource numbers for the world according to EPPA regions. Data for undiscovered conventional resources is from USGS World Petroleum Assessment (2000)[2] and the National Oil and Gas Assessment Program (for US); for proved reserves is from EIA and Oil and Gas Journal; and for reserve growth is based on USGS analysis but with several additional constraints imposed to restrict the growth when the reserves to production ratio is large compared the US.

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[1] Australian 2P CBM reserves are estimated at 3477 PJ (3.2 Tcf) and are located primarily in the Bowen Basin (79%) and Surat Basin (19%). 98% of these reserves are located in Queensland and the remainder in New South Wales.
(See: http://www.australianminesatlas.gov.au/education/fact_sheets/coal_bed_methane.jsp#history).

[2] The data from USGS included here does not use the recent conventional gas estimates for undiscovered resources in the circum-arctic (Gautier et al. 2009). There are two key reasons: First there are key offshore basins with high estimates for which country boundaries have not been agreed upon by relevant governments, such as US and Canada, and Russia and Norway; second these resources would have very high exploration and discovery cost and would contribute only to the far right of the cost curves.

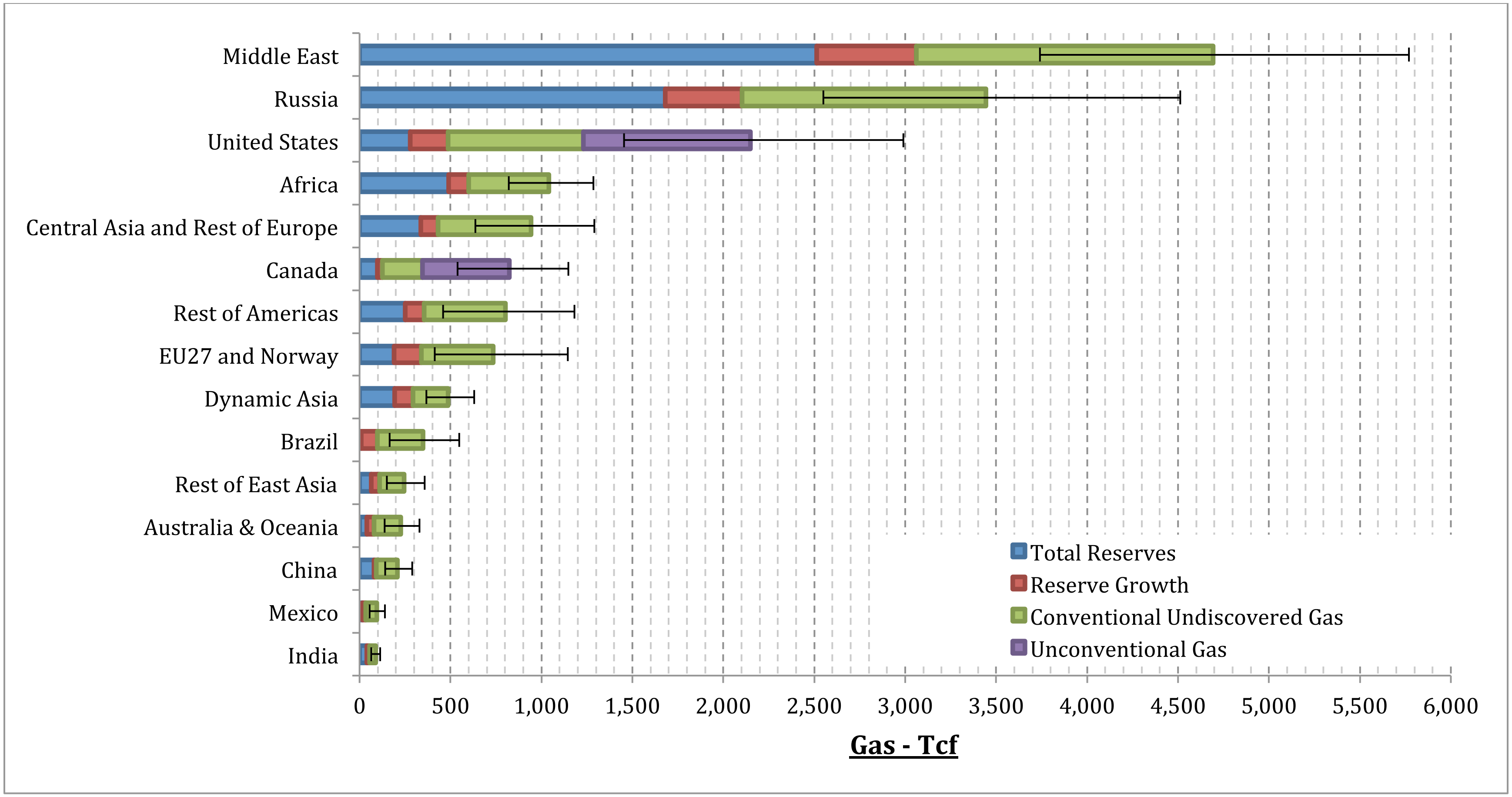

Figure 8: Total remaining recoverable gas by EPPA regions, including reserves, reserve growth, undiscovered conventional resources and unconventional resources. The error bars indicate the P10 and P90 values for the undiscovered and reserve growth portion of gas. The data for this figure are shown in the following table.

Table 1: The recoverable resources by EPPA regions are shown in this table. The world P10 and P90 numbers were found by statistical aggregation.

Region	EPPA Region	Reserves	Reserve Growth			Conventional Undiscovered			Total Undiscovered Resources[3]			**Remaining Recoverable Resource**		
			Mean	P90	P10	Mean	P90	P10	Mean	P90	P10	Mean	P90	P10
North America	United States	279[4]	209	161	270	742	410	1,174	1,661	1,015	2,442	2,149	1,455	2,990
	Canada	98	29	22	37	219	104	356	695	419	1,013	822	539	1,148
Latin America	Brazil	8	90	69	116	251	89	425	251	89	425	349	167	549
	Mexico	14	19	15	25	61	27	101	61	27	101	95	56	139
	Rest of Americas	250	106	81	137	447	128	795	447	128	795	803	459	1,181
Europe and FSU	EU27 and Norway	191	150	116	194	393	108	761	393	108	761	734	414	1,145
	Russia	1,680	424	326	547	1,341	543	2,287	1,341	543	2,287	3,445	2,550	4,513
	Central Asia and Rest of Europe	338	94	72	121	511	226	831	511	226	831	944	636	1,291
Middle East	Middle East	2,514	547	421	705	1,632	805	2,550	1,632	805	2,550	4,693	3,740	5,769
Asia and Pacific	China	80	13	10	16	117	50	193	117	50	193	209	140	290
	India	38	16	12	20	34	15	56	34	15	56	88	66	114
	Dynamic Asia	192	102	79	132	194	95	306	194	95	306	488	366	630
	Rest of E. Asia	66	44	34	56	134	52	236	134	52	236	244	151	358
	Australia & Oceania	39	40	31	51	149	68	239	149	68	239	228	138	329
Africa	Africa	489	112	86	145	439	246	653	439	246	653	1,040	821	1,286
World	**World**	6,275	1,994	1,536	2,573	6,665	3,729	10,104	8,060	4,770	11,934	16,329	12,581	20,781

3 The entries here include unconventional and conventional resources. Unconventional resources have only been included for United States and Canada.
4 The 279 Tcf of reserves is the sum of 245 Tcf of proved reserves and 34 Tcf of stranded reserves, primarily located in Alaska.

Figure 8 shows the gas resources ranked by EPPA regions and the bands of uncertainty associated with the undiscovered portion of the recoverable resource. US ranks third based on its conventional resources, and even the 920 Tcf of unconventional gas does not allow it to overtake Russia. The data underlying this figure can be seen in Table 1, which also shows that the world contains over 16,000 Tcf of gas, which at current consumption of 100 Tcf annually is equivalent to 140 years of supply. Using the P10 and P90 numbers for undiscovered gas instead of the mean, one gets 20,600 and 12,500 Tcf, which represent 200 and 120 years of supply respectively.

Global Unconventional Numbers

Reliable numbers for remaining recoverable resources are only available in North America for US and Canada. Recently the estimates for shale gas in US have increased dramatically from 35 Tcf (NPC 2003) to over 600 Tcf (PGC-2008). The numbers adopted for unconventional resources in US and Canada are shown below in Table 2; data for unconventional resources are from USGS, NPC and ICF

Table 2: This table contains the undiscovered recoverable unconventional gas resources adopted in this study for North America. The P10 and P90 numbers give the 10% and 90% probability estimates.

Gas – Tcf

	Technically Recoverable Unconventional Gas, (excluding Proved Reserves)		
	Mean	***P90***	***P10***
US			
-Tight	173	118	239
-Shale	631	418	871
-CBM	115	69	162
Total US	**919**	**605**	**1272**
Canada			
-Tight	-	-	-
-Shale	443	294	611
-CBM	33	20	46
Total Canada	**476**	**314**	**657**
North America	**1395**	**1042**	**1829**

In 1997, based on a comprehensive literature survey of studies of GIIP, H. H. Rogner (Rogner 1997) published resource numbers for the world based on International Institute for Applied Systems Analysis (IIASA) and the World Energy Council (WEC) regions, which are shown in Figure 9. The GIIP estimates are given in Table 3.

Note that these are estimates of GIIP, and the recoverable portion may be only 10%-35%. Assuming a recovery factor of 20% gives a global resource of over 6400 Tcf, which is over

Table 11: Shale volumetric properties for US and Canadian shale plays included in the shale resource volumes in this study are shown in this table (Source: ICF).

Play	*Assessed Gross Play Area*	*Basin Avg.ShaleThickness*	*Shale Volume*	*Unrisked Gas in Place*	*Risked Gas in Place*	*Assessment Well Spacing*	*Recovery Factor at this Spacing*	**Technical Recovery at this Spacing**
	sq. mi.	Ft	cu.miles	Tcf	Tcf	Acres		**Tcf**
Fort Worth Barnett	7,755	249	366	1,158	538	40	0.20	**107**
Appalachian Marcellus	35,725	140	947	1,635	966	80	0.30	**290**
Arkoma Fayetteville	9,144	188	326	309	216	40	0.40	**86**
Arkoma Woodford	11,628	83	183	719	169	40	0.37	**62**
West Texas Barnett	5,107	440	426	1,302	205	80	0.05	**10**
Louisiana Haynesville	7,189	219	298	753	433	80	0.24	**104**

Table 12: A selection of key geological and geophysical properties of shale plays are shown in this table. [Reproduced from Table 16 in (Vidas and Hugman 2008)]

Basin		**Ft. Worth**	**Arkoma**	**Arkoma**	**Michigan**	**Illinois**	**Permian**	**Appalachian**	**Appalachian**	**Louisiana**	**Warrior**
Shale Play		**Barnett (non-core)**	**Fayetteville**	**Woodford**	**Antrim**	**New Albany**	**Woodford**	**Marcellus**	**Huron**	**Haynesville**	**Floyd**
Well type		**Horizontal**	**Horizontal**	**Horizontal**	**Vertical**		**Vertical**	**Vertical**		**Horizontal**	**Vertical**
Geologic Age		Devonian	Devonian	Mississippian	Devonian	Devonian	Devonian	Devonian	Devonian	Jurassic	Mississippian
Vertical Depth	*Ft*	4,500 - 9,000	1,500 - 6,500	6,000 - 12,000	600 - 2,400	3000	8,000 - 12,000	5,000 - 8,500	3,500 - 5,500	10,000 - 13,000	6,500 - 9,000
Gross Thickness	*Ft*	200 - 800	50 - 400	100 - 300	150	100 - 300	400 - 800	50 - 200	150 - 200	200+	100 - 300
Pressure Gradient	*Psi/ft*	0.45 - 0.50	0.44			0.43				0.50 – 0.70	
Origin of gas		Thermogenic	Thermogenic	Thermogenic	Biogenic	Thermogenic	Thermogenic	Thermogenic	Thermogenic	Thermogenic	Thermogenic
Total Organic Content	*%*	3.5 – 5.0+	2.0 - 5.0+	3.0 - 10.0	0.3 - 20.0+	1.0 - 25.0	4.0 - 7.0	2.0 - 6.0	3.5	3.0 - 5.0	1.8 (0.5 - 10.0)
Vitrinite Reflectance	*%Ro*	1.0 – 2.2	1.5 - 4.0	1.1 - 3.0	0.4 - 0.6	< 0.7		1.0 - 2.5			0.92 - 1.6
Silica Content	*%*	40 – 60	40 - 60	60 - 80							
Gas Content	*Scf/ton*	300 - 500			40 - 100						
Gas-in-place/sq. mi	*Bcf/Sq. mi*	50 - 250	30 - 80	35 - 130	6.0 - 15.0		100 - 500			150 - 250	
Reserves per well	*Bcf*	1.5 – 3.0+	1.6+	3.0 - 5.0	0.2 - 0.6		3	0.8 (vert)	0.8 - 1.5	3.0 - 6.5	
General gas wetness		Wet		Wet		Wet		Wet			Dry
CO2	*%*				Up to 20%	0 - 5%					negl.
Methane	*%*							80 - 95			
Heating Content	*Btu/cf*	1,000 - 1,400						900 - 1,300			

30 years of gas supply at current production rates. Considerably more work is required to obtain reliable estimates of unconventional gas resources outside North America.

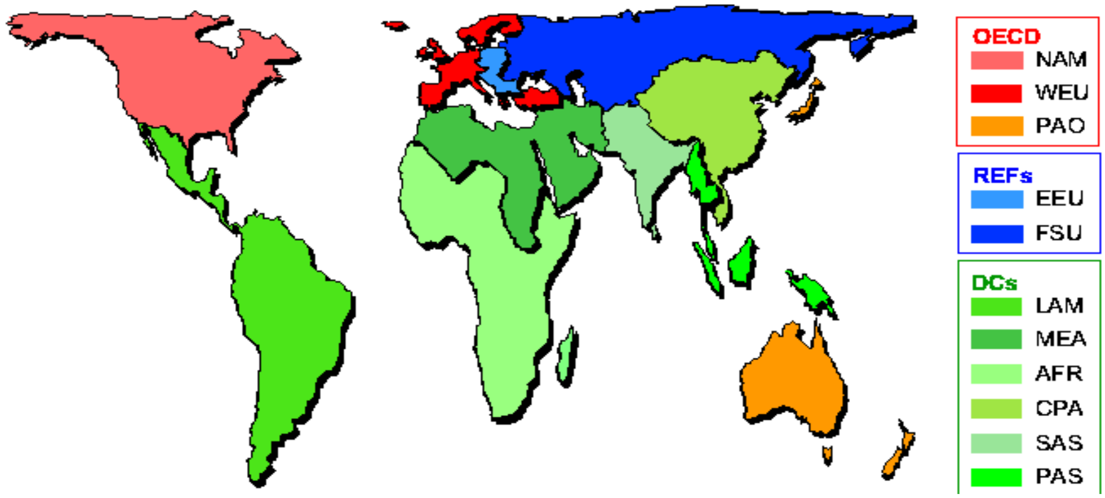

Figure 9: IIASA/WEC world regions used in Rogner's study of global unconventional GIIP are shown in this ma.

Table 3: Below is a tabulation of GIIP for global unconventional resources from Rogner's study (Rogner 1997). The recoverable resource, based on production data in the US, may lie in the 10% to 35% range of GIIP.

Gas – Trillion Cubic Feet

Region	**Region Code**	**Unconventional Gas Initially in Place**			
		Tight gas	***Shale gas***	***Coalbed Methane***	**Total**
North America	NAM	1371	3840	3017	8228
Former Soviet Union	FSU	901	627	3957	5485
Centrally planned Asia and China	CPA	353	3526	1215	5094
Pacific OECD	PAO	705	2312	470	3487
Latin America	LAM	1293	2116	39	3448
Middle East and North Africa	MEA	823	2547	0	3370
Sub-Saharan Africa	AFR	784	274	39	1097
Western Europe	WEU	353	509	157	1019
Other Pacific Asia	PAS	549	313	0	862
Central and Eastern Europe	EEU	78	39	118	235
South Asia	SAS	196	0	39	235
World		**7406**	**16103**	**9051**	**32560**

Assuming a 20% recovery factor for these GIIP numbers gives the recoverable unconventional resources in North America[5] shown above. Similarly, reconciling the tight, shale, and CBM estimates requires recovery factor assumptions of 25%, 30%, and 5-10%

[5] This is computed by estimating cumulative production and RRR (including reserves). The cumulative production is estimated to be 30 Tcf (CBM), 70 Tcf (tight) and 12 Tcf (shale), the assumed reserves are 20 Tcf (CBM), 80 Tcf (tight) and 35 Tcf (shale), while the UTRR is 205 Tcf (CBM), 325 Tcf (tight) and 1150 Tcf (shale).

respectively. This illustrates the difficulty in reliably using GIIP numbers to deduce recoverable resources. And given the large volume of GIIP, small changes in recovery factors can have a huge impact on RRR estimates.

Analyses of Key Countries

This section contains further details about the resources in US and Canada, especially with a focus on the basin and play level assessments of conventional and unconventional resources. This section also contains country profiles for Russia, Iran and Qatar, which accounted for 28% of 2008 global natural gas production; while their combined year-end reserves accounted for 57% of worldwide natural gas reserves. These numbers are shown in Table 4.

Table 4: 2008 and 2009 annual data for natural gas production, imports, exports, consumption, reserves and reserves to production (R/P) ratio for the World, United States, Canada, Russia, Iran, and Qatar[6] are shown in this table.

	Production		Imports[7]		Exports[8]		Consumption		Reserves		R/P ratio	
	Tcf		*Tcf*		*Tcf*		*Tcf*		*Tcf*		*Years*	
	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009
World	109.9	106.5	35.4	32.5	0.0	0.0	111.0	106.8	6212	6261	57	59
United States	20.3	21.0	4.0	3.8	1.0	1.1	23.2	22.8	238	245	12	12
Canada	6.0	5.6	0.6	0.7	3.7	3.3	3.4	3.1	58	58	10	10
Russia	23.4	20.6	2.0	1.2	8.6	6.3	16.8	15.5	1680	1680	72	82
Iran	4.1	4.6	0.3	0.2	0.1	0.2	4.2	4.6	948	992	231	214
Qatar	2.7	3.2	0.0	0.0	2.0	2.4	0.7	0.7	905	892	333	283

- Data not available at the time of table compilation

United States of America

Natural gas is a well-exploited resource in US compared to the rest of the world, with a well developed, transmission infrastructure and a large, liberalized market. The US has produced more gas than any other country in the world and is the world's largest gas consumer. The US is also the leader in innovation in gas production technology, allowing it to produce gas from unconventional sources. A detailed overview of the remaining recoverable resource is provided for the US in this section; discussion of gas production and the technical details of unconventional resource production are presented in later sections.

Table 5 summarizes the assessment of US resources by the National Petroleum Council (NPC), USGS (for onshore and state offshore waters), and Minerals and Management Services (MMS – for federal offshore waters), the PGC, and the EIA. The proved reserve numbers are by EIA, and differ according to the year of the assessment. The conventional resource numbers include both reserve growth and undiscovered technically recoverable resources. The PGC data represents the "Most Likely" value from their estimates; all the other estimates are mean values.

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[6] Note: Reserves numbers are from Oil and Gas Journal, as of Jan 1, 2009; the rest of the data is from EIA for 2008 and 2009.

[7] Imports and exports data for the World are the reported volumes in international trade.

[8] See [7]

Conventional resources are still the dominant portion of production, reserves and undiscovered resources. However unconventional resource estimates have grown significantly since their commercial extraction began.

Table 5: A comparison of various assessments of remaining recoverable natural gas resources in United States is shown in this table. The conventional gas numbers include reserve growth estimates.

Gas- Tcf

<table>
<tr><th></th><th>NPC</th><th>USGS/MMS</th><th colspan="2">PGC</th><th>EIA</th><th>ICF</th></tr>
<tr><th></th><th>2003</th><th>02-08/06</th><th>2006</th><th>2008</th><th>2009</th><th>2009</th></tr>
<tr><td>Lower 48</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>- Conventional[9]</td><td>691</td><td>927</td><td rowspan="3">966</td><td rowspan="2">870</td><td>939</td><td>693</td></tr>
<tr><td>- Tight</td><td>175</td><td>190</td><td rowspan="2">237</td><td>174</td></tr>
<tr><td>- Shale</td><td>35</td><td>85</td><td>615</td><td>631</td></tr>
<tr><td>- CBM</td><td>58</td><td>71</td><td>99</td><td>99</td><td>67</td><td>65</td></tr>
<tr><td>Total L48</td><td>959</td><td>1273</td><td>1065</td><td>1584</td><td>1243</td><td>1563</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Alaska</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>- Conventional</td><td>237</td><td>356</td><td rowspan="2">194</td><td rowspan="2">194</td><td rowspan="2">271</td><td>237</td></tr>
<tr><td>- Tight</td><td></td><td></td><td></td></tr>
<tr><td>- Shale</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>- CBM</td><td>57</td><td>18</td><td>57</td><td>57</td><td>18</td><td>57</td></tr>
<tr><td>Total Alaska</td><td>294</td><td>374</td><td>251</td><td>251</td><td>289</td><td>294</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Total US</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>-Conventional</td><td>928</td><td>1283</td><td rowspan="3">1160</td><td rowspan="2">1064</td><td>1210</td><td>930</td></tr>
<tr><td>- Tight</td><td>175</td><td rowspan="2">275</td><td rowspan="2">259</td><td>174</td></tr>
<tr><td>- Shale</td><td>35</td><td>615</td><td>631</td></tr>
<tr><td>- CBM</td><td>115</td><td>89</td><td></td><td></td><td>85</td><td>122</td></tr>
<tr><td>Total US</td><td>1253</td><td>1647</td><td>1316</td><td>1835</td><td>1554</td><td>1857</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Proved Reserves[10]</td><td>183</td><td>245</td><td>213</td><td>245</td><td>245</td><td>245</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Grand Total</td><td>1436</td><td>1894</td><td>1529</td><td>2082</td><td>1801</td><td>2102</td></tr>
</table>

Proved Reserves

Due to stringent reporting requirements for reserves and a lack of a market for Alaskan gas in the absence of a pipeline connection with the Lower-48 (L48), almost all the reported reserves are located in the L48, even though the Alaskan gas potential is significant. The shale and CBM reserves shown in Table 6 are roughly the same percentage of reserves as their annual production is of total annual gas production. Further, natural gas reserve

[9] Conventional resource numbers include reserve growth and UTRR.

[10] Proved reserve numbers are shown for the relevant year of the report by NPC and PGC.

volumes in the US are concentrated in a few fields, even though gas production is spread over a wide region of the country, and are increasingly comprised of unconventional resources. An illustration of this is that the top 10 fields contain 40% of total proved reserves for 2008; the top three are unconventional plays, namely the Barnett Shale (shale gas), the San Juan Basin Gas Area (CBM), and the Jonah Pinedale Field (tight sands).

Table 6: 2008 year-end proved reserves for the US are shown in this table. Tight gas reserves are not reported separately, but are included in the Non-associated gas reserve number (Energy Information Administration 2009). These are wet gas volumes.

Gas- Tcf

Resource Category	Lower 48	Alaska	US total	Percentage of total
Total Reserves	247.3	7.8	255.0	100%
Associated Reserves	22.4	6.6	29.0	11%
Non-associated reserves	224.9	1.1	226.0	89%
Shale Reserves	32.8	0.0	32.8	13%
Coalbed Methane Reserves	20.8	0.0	20.8	8%

Conventional Gas

Undiscovered technically recoverable conventional gas resources are primarily located in Alaska and Gulf of Mexico (GOM), with the L48 onshore resource being very mature, which can be seen from Table 7. This table provides a comparison of assessments of undiscovered technically recoverable conventional gas resources in selected basins by NPC, USGS/MMS and PGC. The PGC 2009 report does not separately show the tight gas assessments; hence for comparison the tight gas numbers for the chosen basins have also been shown. These basins are shown in Figure 10.

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The bulk of the conventional gas UTRR is located in Alaska and Gulf of Mexico (GOM) OCS. The resources in Alaska do not have access to a market due to the unavailability of a pipeline connecting it to the L48. Transporting Alaskan to markets present a significant economic challenge. The table above shows considerable variation between different agencies within individual basins indicating considerable uncertainty inherent in estimating undiscovered resources. According to the USGS/MMS estimates shown in Table 7 nearly 60% of the L48 onshore UTRR is situated in the Western Gulf province, but this is only 68 Tcf, less than 4 years of consumption for the US and less than 10% of the conventional UTRR. Also, more than half of the conventional UTRR is located in offshore OCS areas.

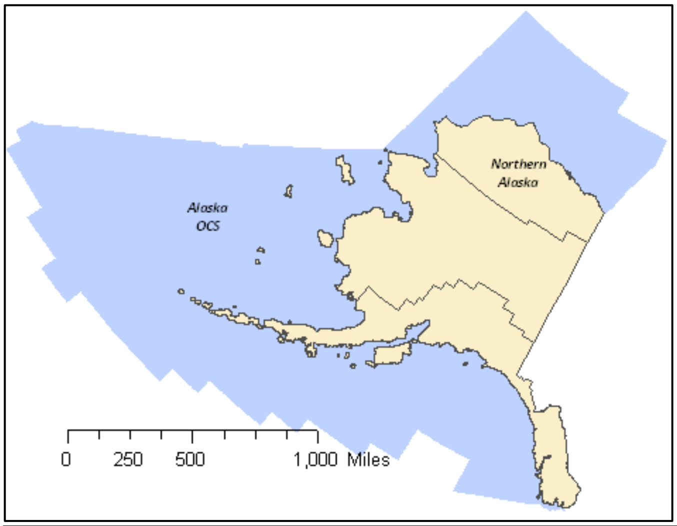


Figure 10: Selected US conventional gas basins are shown in this map. The panel on the left shows the Northern Alaskan province and the Outer Continental Shelf (OCS). The bottom panel shows the L48 basin boundaries, the main regions and the Atlantic, Pacific and Gulf of Mexico OCSs. The basins indicated contain the majority of the conventional undiscovered technically recoverable resource, with the Gulf Coast region containing 60% of the onshore L48 resource according to the USGS. The Southwestern Wyoming basin (also called the Green River Basin) primarily contains tight gas resources.
GIS Data Source: USGS National Oil and Gas Assessment (NOGA) and MMS

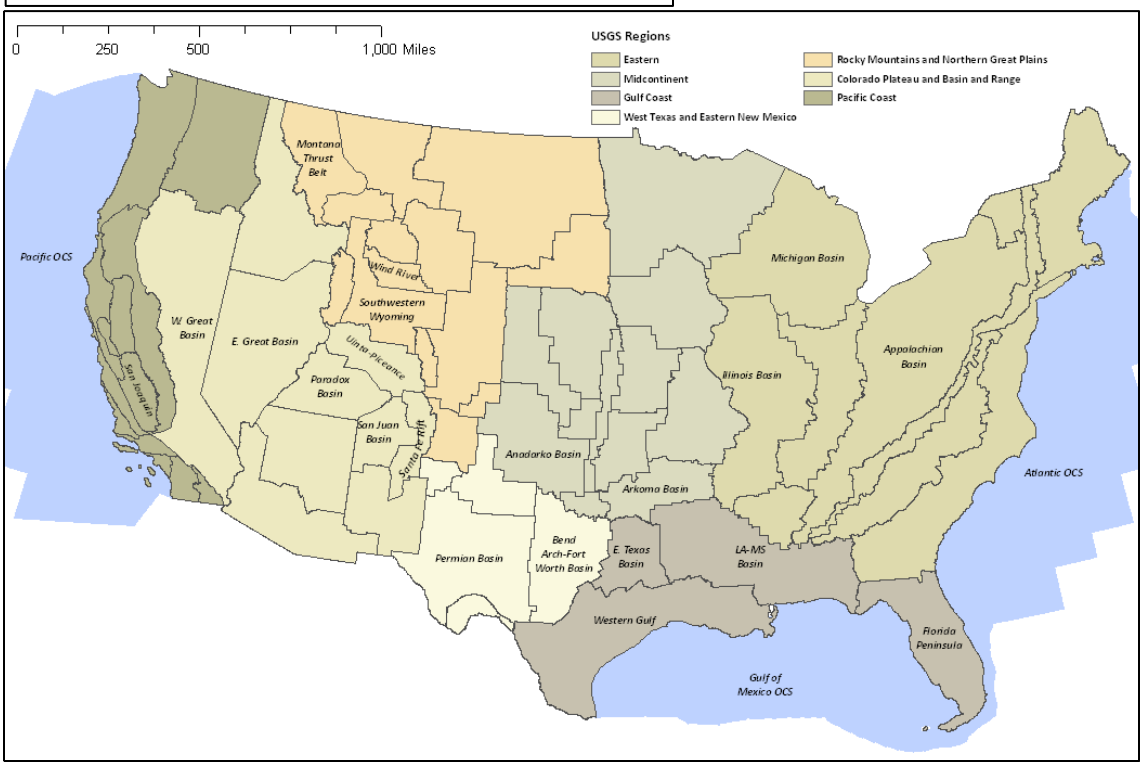
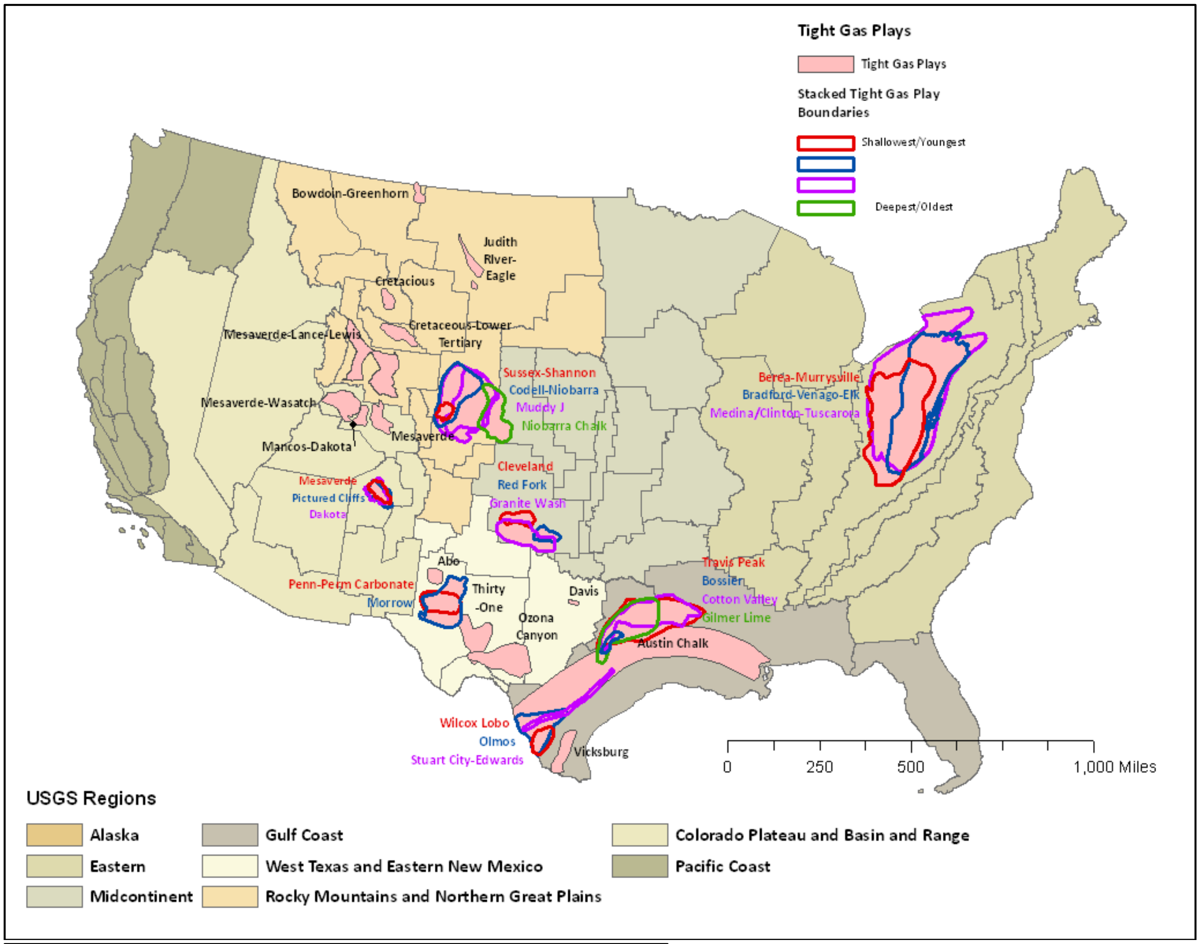


Table 7: This table contains a list of basins with significant undiscovered conventional gas resources for NPC, USGS/MMS, and PGC. As PGC does not separately provide data for conventional and tight gas, the USGS and NPC tight gas assessments have also been included. (See Table 8 for further details on tight gas.). PGC Probable resources are the equivalent to reserve growth while the sum of Possible and Speculative are that of UTRR.

Gas- Trillion cubic feet (Tcf)

US Region	Basin/Province	NPC 2003		USGS/MMS 2002-08/2006		PGC 2009	
		Conventional	Tight Gas	Conventional	Tight Gas	Probable	Possible and Speculative
Eastern Region	Appalachian Basin	6.2	34.8	4.3	45.4	11.6	17.5
	Michigan and Illinois Basin	7.8	-	4.4	-	0.3	0.3
	Other	1.5	-	1.9	-	0.4	15.2
	Total	15.5	34.8	10.6	45.4	12.3	33.0
Midcontinent Region	Anadarko Basin	21	-	14.2	-	21.4	29.2
	Arkoma Basin	3.8	-	2.5	-	1.3	3.4
	Other	2.1	-	2.9	-	0.5	1.8
	Total	26.9	-	19.6	-	23.2	34.4
Gulf Coast	E. Texas, LA-MS Salt Basin and Florida Peninsula	29.2	5.9	31.2	6.0	32.4	50.5
	Western Gulf Basin	47.9	2.6	68.1	-	38.6	69.2
	Total	77.1	8.5	99.2	6.0	71.0	119.7
W. Texas and E. New Mexico	Permian and Bend Arch-Fort Worth Basin	19.6	-	5.7	-	10.7	25.4
	Other	-	-	0.1	-	-	-
	Total	19.6	-	5.8	-	10.7	25.4
Rocky Mountains and Northern Great Plains	SW Wyoming Basin	4.7	65.8	2.4	80.5	10.9	15.5
	Wind River Basin	1.6	-	0.5	1.7	5.0	9.8
	Montana Thrust Belt	8.3	-	0.1	-	0.0	12.6
	Other	3.4		14.5	8.2	35.5	15.9
	Total	18	65.8	17.5	90.4	51.4	53.7
Colorado Plateau and Basin and Range	Uinta-Piceance Basin	2.1	22.8	0.2	18.8		49.7
	Paradox and Great Basin	2.7	-	4.3	-	0.6	4.1
	San Juan and Santa Fe Rift	0.7	21	0.5	26.1	5.6	7.0
	Other	-	-	0.4		12.6	6.0
	Total	5.5	21	5.4	44.9	18.7	66.8
Pacific Region	San Joaquin Basin	5.9	-	1.8	-	1.7	10.0
	Other	4.5	11.9	6.6	-	1.0	17.4
	Total	10.4	11.9	8.3		2.7	27.4
Pacific Offshore/OCS	Pacific Offshore	20.7	-	18.3	-	0.1	15.8
Gulf of Mexico/OCS	GOM Offshore	244.4	-	232.5	-	15.6	77.7
Atlantic Offshore/OCS	Atlantic Offshore	32.8	-	37.0	-	0.0	13.0
Lower 48	Total	486.4	175.2	454.2	189.9	205.7	466.8
Alaska	Northern Alaska	72.1	-	204.6	-	26.2	42.0
	Other	3.7	-	7.6	-	4.7	2.1
	Total Onshore	75.8	-	212.2	-	30.9	44.1
	Alaska Offshore/OCS	125.2	-	132.1	-	2.4	65.7
	Total	201	-	344.3	-	33.3	109.8
U.S.	Total	687.4	175.2	798.5	189.9	239.0	576.6

Tight Gas (Sands)



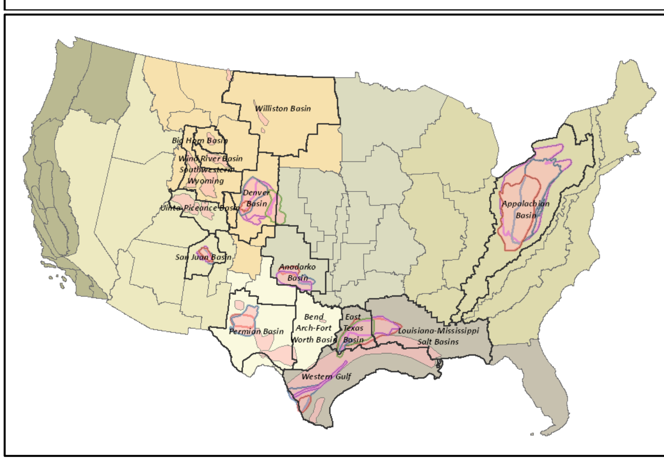


Figure 11: A map of the US tight gas plays is shown here in the top panel. These plays are concentrated in a few basins. These basins are shown in the map in the left hand panel. Some of these basins, such as the East Texas and Western Gulf Basins, have also been significant producers of conventional gas. Other basins, such as, Southwestern Wyoming, are dominated by unconventional resources.
GIS Data Source: USGS NOGA and EIA

Tight gas sands represent the largest share of unconventional gas production in the US. Current and prospective tight gas plays are shown in Figure 11, along with the relevant basins. An examination of Figure 12 and Table 8 shows that the bulk of the resource is located in a few basins, namely the Southwestern Wyoming basin, the Appalachian Basin, and the Uinta-Piceance Basin. The data for this figure is contained in Table 8.

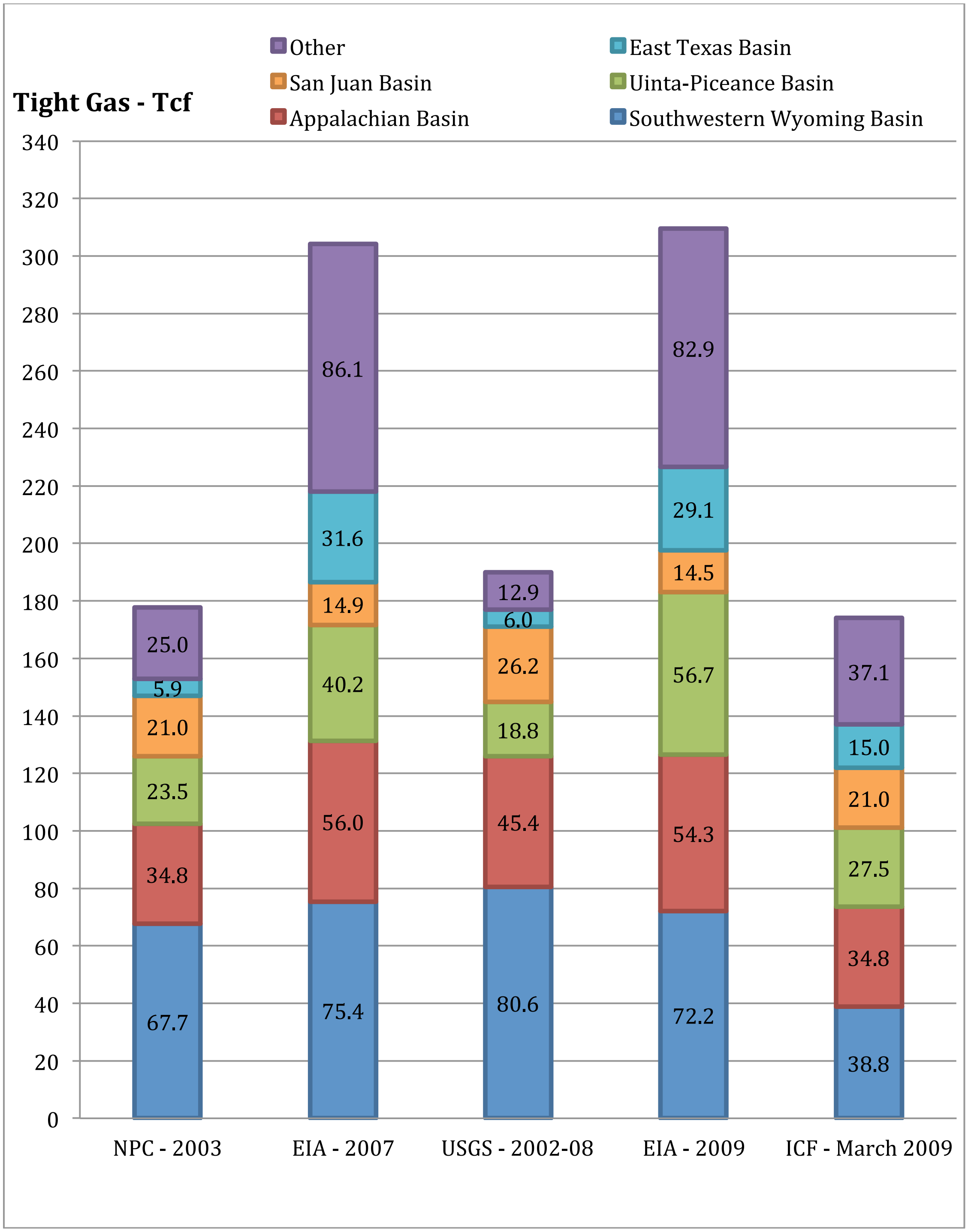


Figure 12: A comparison of tight gas resource assessments shows a disparity in the assessments of different agencies. However, the resource is concentrated in only a few basins.

Table 8: Tight gas mean estimates of undiscovered recoverable resources by basin; and by agency, and year. PGC reports its tight gas estimates with conventional gas.

Gas- Trillion cubic feet (Tcf)

US Region	Basin/Province	Plays	NPC *2003*	EIA *2007*	USGS *2002-08*	EIA *2009*	ICF *March, 09*
Eastern Region	Appalachian Basin		34.8	56.0	45.4	54.3	34.8
Midcontinent Region	Anadarko Basin		-	13.4	-	12.7	-
	Arkoma Basin		-	4.1	-	3.6	-
	Total		-	17.5	-	16.3	-
Gulf Coast	E. Texas and LA-MS Salt Basin		5.9	31.6	6.0	29.1	25.2
	Western Gulf Basin		2.6	14.6	-	13.3	4.6
	Total		8.5	46.2	6.0	42.4	29.8
W. Texas and E. New Mexico	Permian Basin		-	13.8	-	13.4	-
Rocky Mountains and Northern Great Plains	South Western Wyoming Basin [1]		65.8	75.4	80.5	72.2	38.8
	Wind River Basin		-	19.6	1.7	19.6	0
	N. Cent. Montana		5.8	4.8	6.1	4.7	5.8
	Williston Basin		1.8	-	0.1	-	1.8
	Denver Basin		2.0	9.2	2.0	9.1	2.0
	Total		77.3	109	90.4	105.6	48.4
Colorado Plateau and Basin and Range	Uinta-Piceance Basin	*Piceance Basin*	9.7	24.3	5.0	41.0	11.7
		Uinta Basin	13.8	15.9	13.8	15.6	15.8
		Total	23.5	40.2	18.8	56.6	27.5
	San Juan Basin		21.0	14.9	26.1	14.5	21.0
	Total		44.5	55.1	44.9	71.1	48.5
Pacific Region	Western Oregon Basin		11.9	6.4	2.1	6.5	11.9
Lower 48			175.2	304.2	189.9	309.5	174.3
Alaska			-	-	-	-	-
U.S.			175.2	304.2	189.9	309.5	174.3

Coalbed Methane

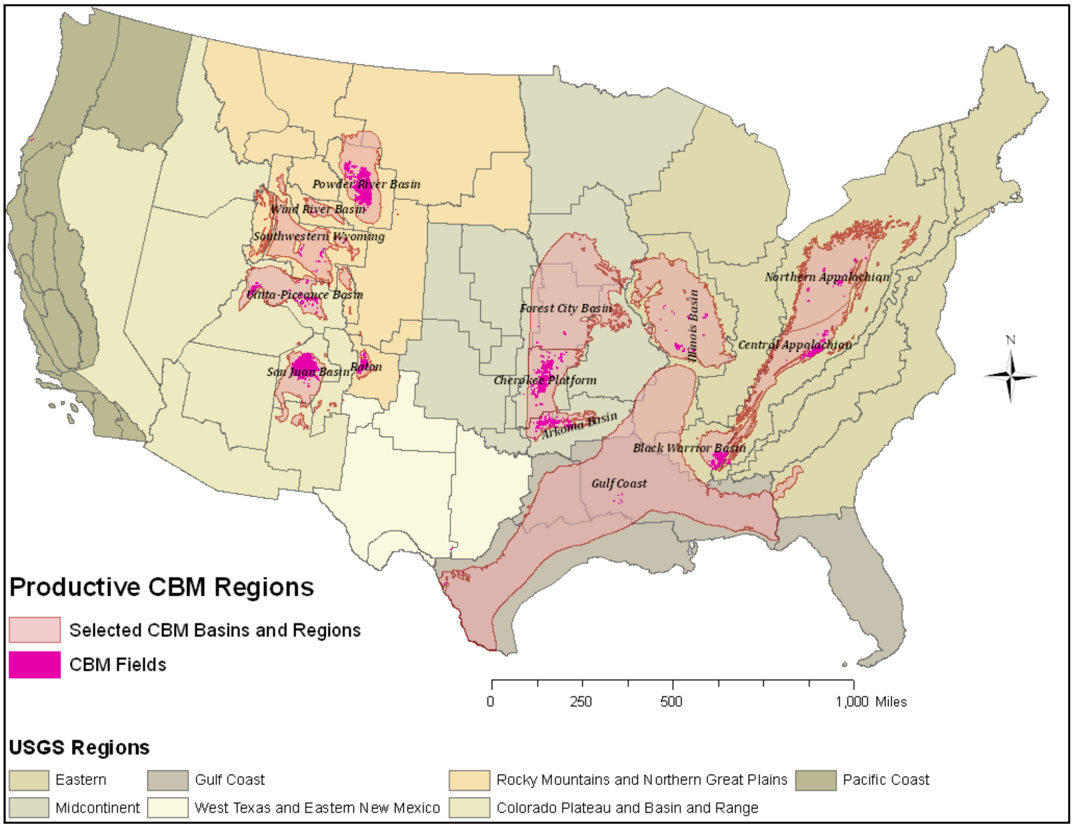


Figure 13: A map of US CBM basins and fields is shown in this figure.
***GIS Data Source:* USGS NOGA and EIA.**

Coalbed methane (CBM) has been an important component of the US resource base. Key areas for CBM plays and basins are shown on the map in Figure 13. A tabulation of US CBM resources by basins, significant plays and key agencies is shown in Table 9 and the data are illustrated in Figure 14. The figure and table show that CBM resource assessments in the US have stagnated, with a mean number of around 70 Tcf in the Lower-48 states. 50% to 90% of the resource is located in five key regions/basins: Powder River Basin, San Juan Fruitland (in San Juan Basin), Uinta-Piceance Basin, Appalachian Basin, and Black Warrior Basin. Alaska also contains significant CBM resources (18-57 Tcf), however, given the significant conventional resources and the lack of access to major markets via pipeline, the prospects of the development of these resources in the short to medium term is small.

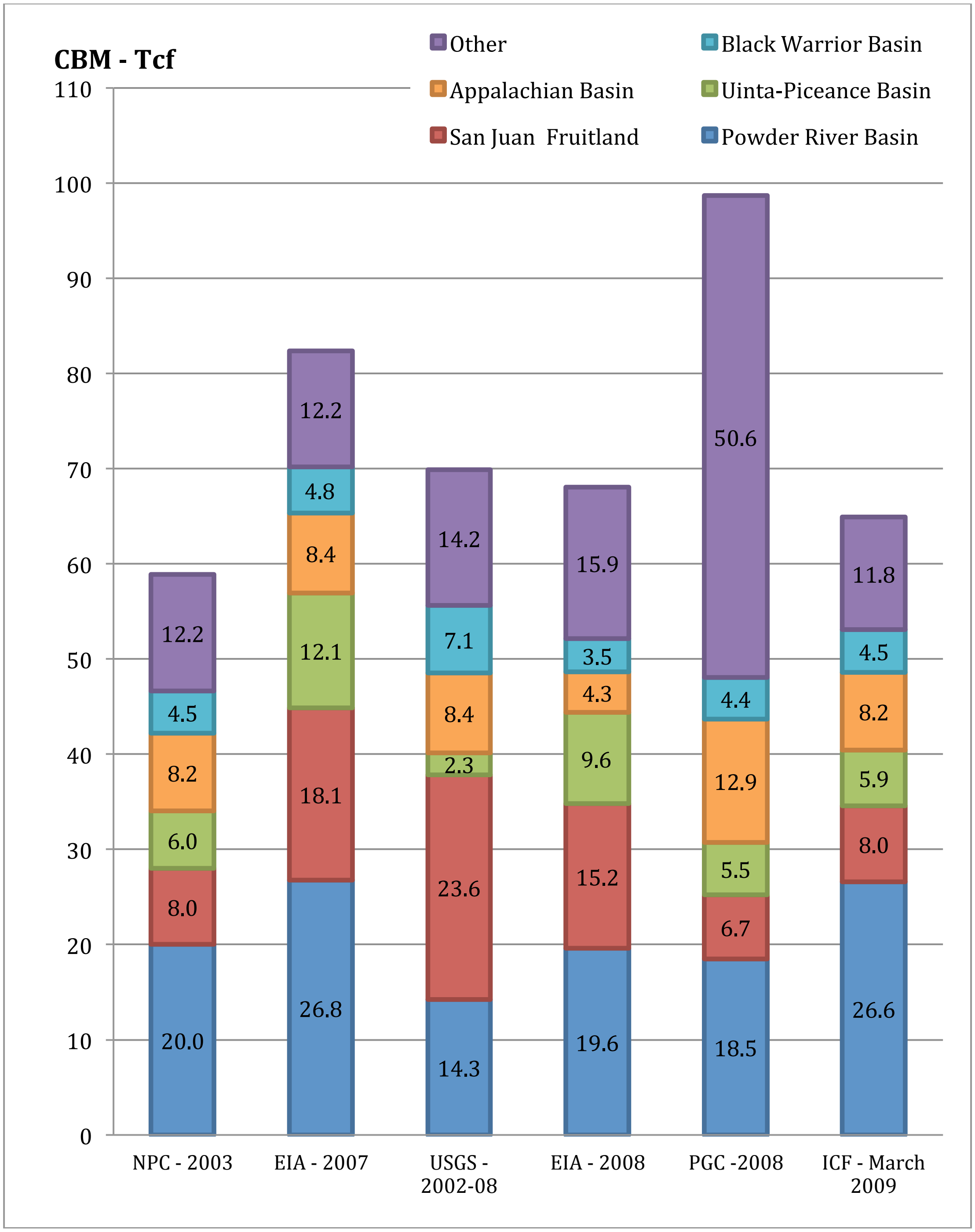


Figure 14: A comparison of CBM resource assessments in the US for Lower-48. The assessed volumes for Alaska, which are not included in this chart, also vary between agencies and can be as high as 57 Tcf (NPC, PGC, ICF).

Table 9: CBM mean estimates of undiscovered recoverable resources by basin; and by agency, and year are hsown in this table.

Gas- Trillion cubic feet (Tcf)

US Region	Basin/Province	Sub-Province	NPC 2003	EIA 2007	USGS 2002-08	PGC 2008	EIA 2009	ICF March, 09
Eastern Region	Appalachian Basin	*C. Appalachian*	3.5	3.6	3.6	10.6	2.8	3.5
		N. Appalachian	4.7	4.8	4.8	2.4	1.5	4.7
		Total	8.2	8.4	8.4	12.9	4.3	8.2
	Black Warrior Basin		4.5	4.8	7.1	4.4	3.5	4.5
	Illinois Basin		1.6	0.6	0.4	7.7	0.6	1.6
	Total		14.3	13.8	15.9	25.0	8.4	14.3
Midcontinent Region	Forest City Basin		0.4	2.4	0.5	6.1	1.9	0.4
	Cherokee Platform		1.9	-	1.9	2.8	-	1.9
	Arkoma Basin		2.6	3.2	2.6	1.8	4.1	2.6
	Total		4.9	5.6	5.0	10.7	5.9	4.9
Gulf Coast	E. Texas, W. Gulf, and LA-MS Salt Basin	*Gulf Coast Coal Region*	-	-	4.1	3.4	-	-
W. Texas and E. New Mexico	Bend Arch-Fort Worth Basin	*Southwestern Coal Region*	-	-	-	5.8	-	-
Rocky Mountains and Northern Great Plains	Raton Basin		2.0	4.0	1.6	4.3	5.5	1.9
	Wind River Basin		0.4	-	0.3	2.5	-	0.4
	South Western Wyoming Basin [1]		2.0	1.7	1.5	8.6	3.7	2.0
	Powder River Basin		20.0	26.8	14.3	18.5	19.6	26.6
	Others[11]		-	-	-	1.1	-	-
	Total		24.4	32.5	17.7	35.0	28.8	30.9
Colorado Plateau and Basin and Range	Uinta-Piceance Basin	*Piceance Basin*	3.8	7.9	0.4	5.5	6.3	3.7
		Uinta Basin	2.3	4.2	2.0	w/ Pic	3.3	2.2
		Total	6.1	12.1	2.4	5.5	9.6	5.9
	Paradox Basin		-	-	-	2.8	-	-
	San Juan Basin	*San Juan Fruitland*	8.0	18.1	23.6	6.7	15.2	8.0
		San Juan Menefee	0.7	0.2	0.7	-	0.2	0.4
		Total	8.7	18.4	24.2	6.7	15.4	8.4
	Total		14.8	30.5	26.6	15.0	25.0	14.3
Pacific Region	Western Oregon Basin		0.7	-	0.7	2.6	-	0.7
Lower 48			58.9	82.4	69.9	98.7	68.1	64.9
Alaska			57.0	-	18.1	57.0	-	57.0
U.S.			115.9	82.4	87.9	155.7	68.1	121.9

[11] Includes Denver Basin and Big Horn Basin

Shale Gas

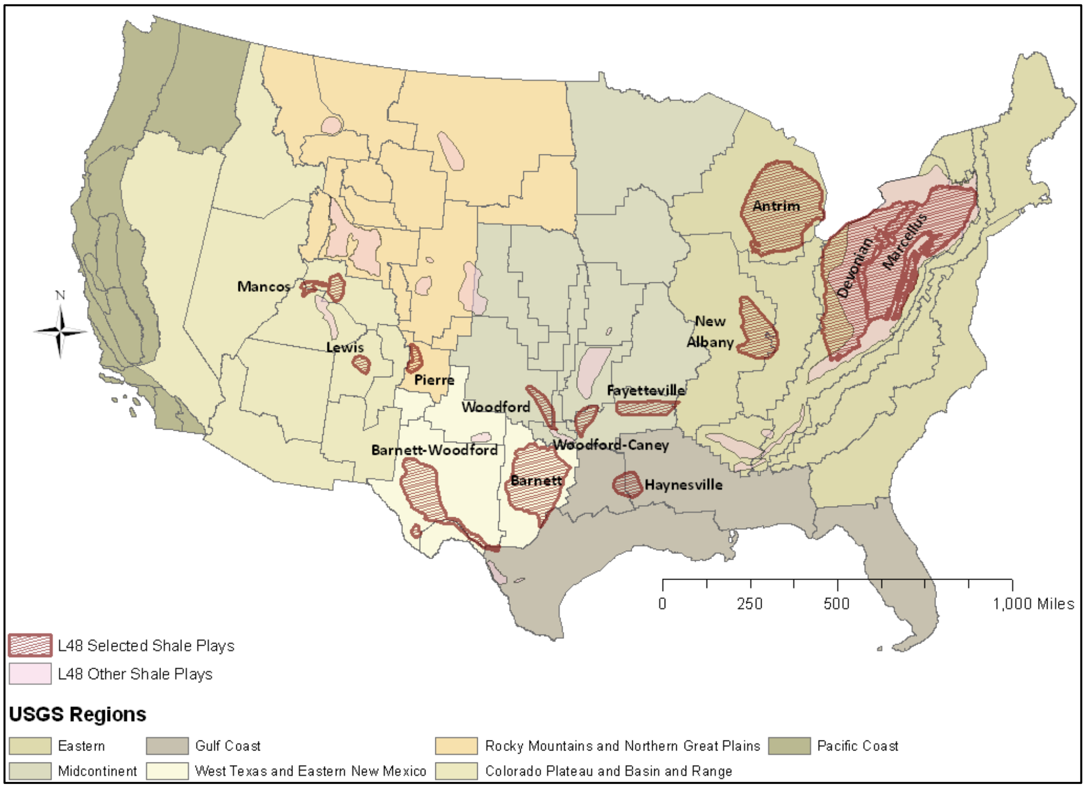


Figure 15: A map of selected US Shale gas plays, superimposed on USGS basins and regions is shown here.
GIS Data Source: USGS NOGA and EIA

Shale gas resource estimates have undergone rapid revisions in the past seven years. The volumes in the assessments have increased by a factor of 20 (NPC 2003 vs. PGC 2008). Selected US shale plays in the L48 are shown in Figure 15. However, as shown in Figure 16, the resource estimates have grown in only a few key plays. These are the Marcellus, the Barnet, the Haynesville, the Woodford and the Fayetteville shale plays. The increase in recoverable resource estimates have arisen from taking into consideration the increased production from technology advancements, for example vertical well drilling being replaced by horizontal wells. These assessments have the potential of increasing due to further technology advancements and decreased well spacing; RRR increases when well spacing is decreased from 80 acres per well to 40 or even less acres per well in the assessment. Play level assessments are shown in Table 10 and Figure 16. Volumetric properties for these leading shale plays in the US are shown in Table 11.

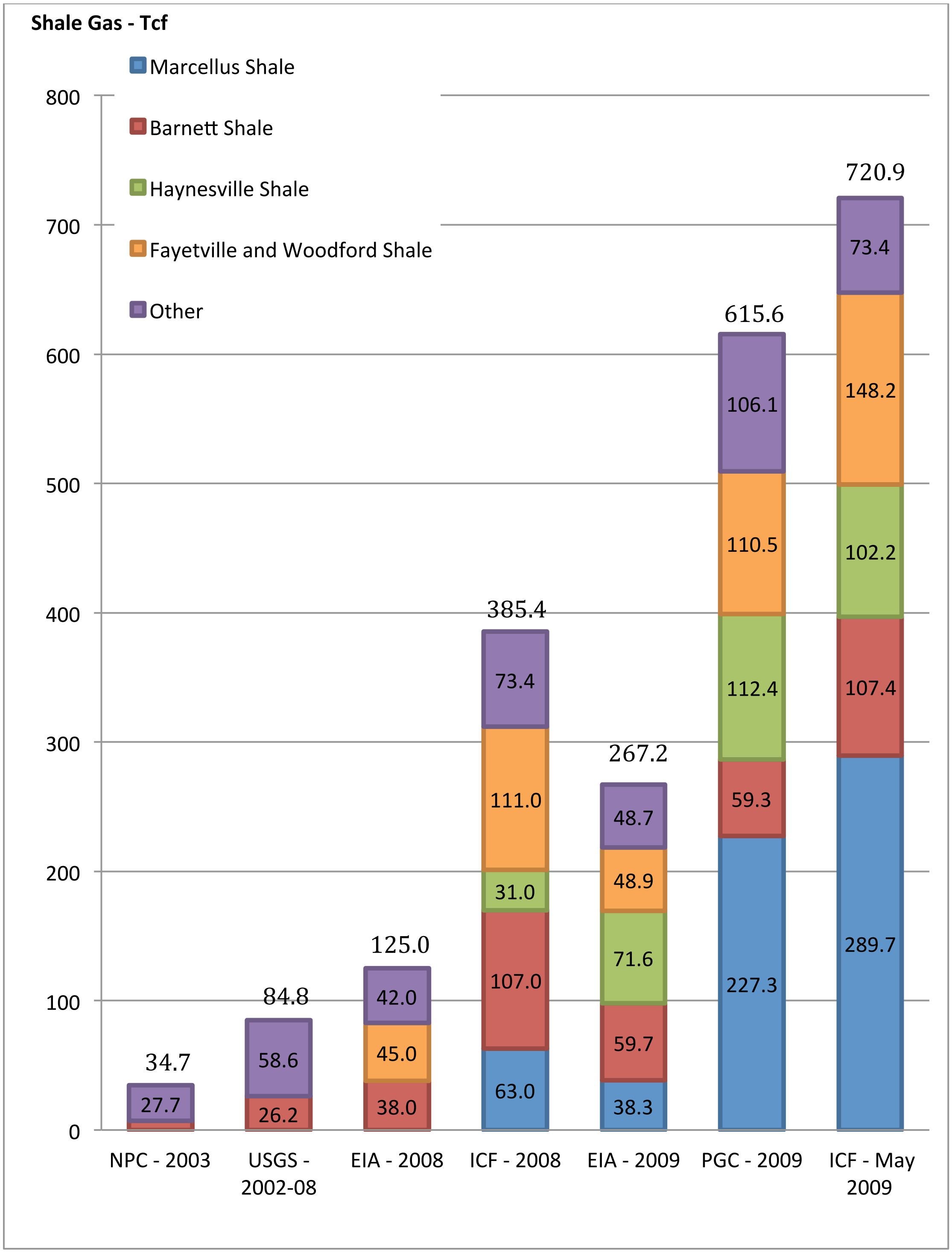


Figure 16: A comparison of shale resource assessments in the US. The estimated volumes of recoverable resource have increased dramatically, with the resource concentrated in a few key plays.

Table 10: Shale gas mean estimates of undiscovered recoverable resources by basin; and by agency, and year.

Gas- Trillion cubic feet (Tcf)

US Region	Basin/Province	Shale Plays	NPC 2003	USGS 2002-08	EIA 2008	ICF 2008	EIA 2009	PGC 2008	ICF Mar, 09
Eastern Region	Appalachian Basin	*Devonian – Low Pressure*	17.0	12.2	14.4	30.6	13.1	227.3	30.6
		Marcellus	-	-	-	63.0	38.3		289.7
		Huron	-	-	-	20.0	-		20.0
		Total	17.0	12.2	14.4	113.6	51.4	227.3	340.3
	Michigan Basin	*Antrim*	7.4	7.5	10.6	4.0	10.0	5.9	4.0
	Illinois Basin	*New Albany*	1.8	3.8	2.0	3.2	3.1	5.4	3.2
	Cincinnati Arch	*New Albany, Chattanooga*	1.3	-	0.8	2.3	1.1	-	2.3
	Total		27.5	23.5	27.8	123.1	65.6	238.6	349.8
Midcontinent Region	Arkoma Basin	*Fayetteville*	-	-	29.2	58.0	29.2	110.5	86.3
		Woodford	-	-	15.8	53.0	19.7		61.9
		Total	-	-	45.0	110.3	48.9	110.5	148.2
	Anadarko Basin	*Woodford-Caney*	-	-	-	-	7.1	2.1	-
	Total		-	-	45.0	111.0	56.0	112.6	148.2
Gulf Coast	E. Texas, and LA-MS Salt Basin	*Haynesville*	-	-	-	31.0	71.6	112.4	102.2
W. Texas and E. New Mexico	Bend Arch-Fort Worth Basin	*Barnett*	7.0	26.2	38.0	107.0	59.7	59.3	107.4
	Permian Basin	*Barnett and Woodford*	-	35.1	-	10.0	-	3.9	10.0
	Total		7.0	61.3	38.0	117.0	59.7	63.2	117.4
Rocky Mountains and Northern Great Plains	Raton Basin	*Pierre*	-	-	-	2.0	-	-	2.0
	Williston Basin	*Niobrara*	-	-	3.9	*	3.9	-	*
	Total		-	-	3.9	2.0	3.9	-	2.0
Colorado Plateau and Basin and Range	Uinta-Piceance Basin	*Mancos*	-	-	-	*	-	60.2	*
	Paradox Basin	*Gothic*	-	-	-	1.0	-	-	1.0
	San Juan Basin	*Lewis*	-	-	10.4	*	10.5	4.5	*
	Total		-	-	10.4	1.0	10.5	64.7	1.0
Pacific Region	San Joaquin Basin	*McClure*	0.3	-	-	0.3	-	-	0.3
Lower 48			34.7	84.8	125.0	385.4	267.2	615.9	720.9
Alaska			-	-	-	-	-	-	-
U.S.			34.7	84.8	125.0	385.4	267.2	615.9	720.9

* Assessed with tight gas

There are several geological and geophysical characteristics of shale plays that are important in determining the resource volume and its producibility. These include vitrinite reflectance, total organic content (TOC), pressure gradients within the rock, and the volume and thickness of the gas-bearing shale. As shale plays have very low porsosity and permeability, the recoverability of the gas resources crucially depends on the success of hydrolic fracturing. There also appears to be a correlation between this and the silica and clay content of the shale. Some of these properties are shown in Table 12.

Canada

Canada is the third largest producer of natural gas in the world after Russia and United States. It produced 5.7 Tcf in 2009, of which 58.6% was exported. Canada is also the largest exporter of natural gas to the US, with Canadian gas accounting for 16% of US consumption and 90% of all US imports in 2008. Canada and the US form a highly integrated regional market facilitated by a large pipeline network interconnecting the two countries. Gas production is following similar trends to that in the US, with conventional gas producing regions in decline, and increasing production of unconventional gas due to ready transfer of technology across the border.

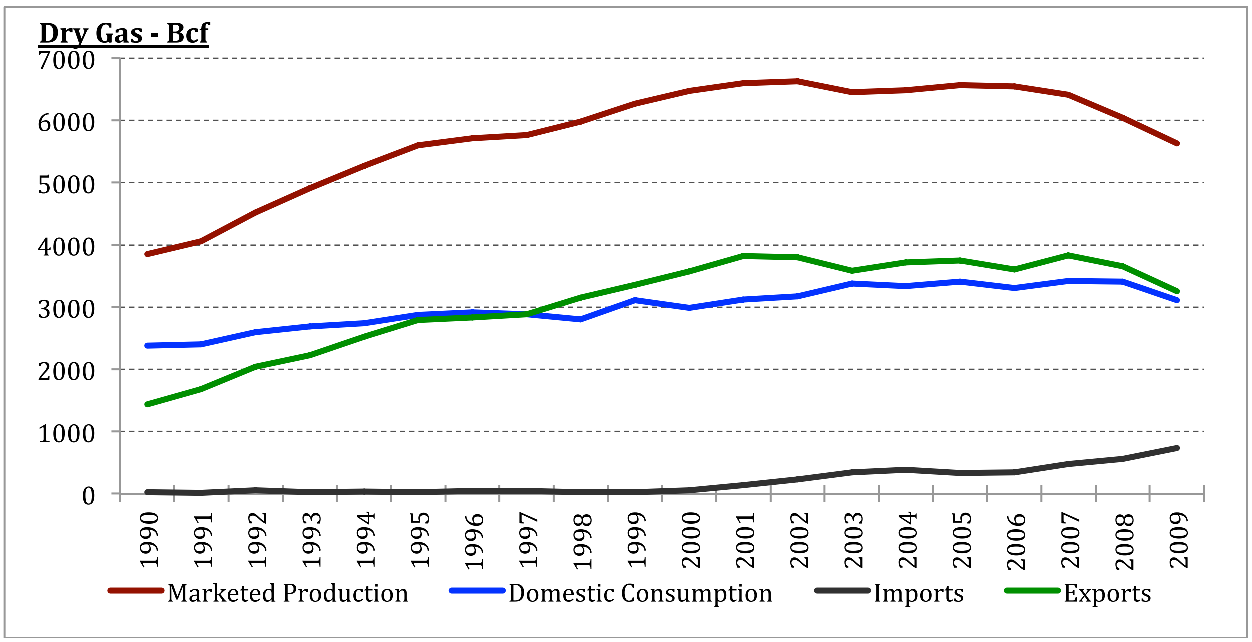


Figure 17: Canada is the third largest producer of Natural Gas in the world, after Russia and the US. Only 39.8% of the produced gas in 2008 was consumed domestically, the rest being exported via pipelines to the US and via LNG. (Source: EIA International Energy Statistics database)

Conventional Resources

The largest and most important hydrocarbon bearing basin is the Western Canada Sedimentary Basin (WCSB). The basin covers most of Alberta, nearly a third of Saskatchewan, and smaller portions of British Columbia, Yukon and the Northwest Territories and Manitoba. The 2000 USGS World Assessment (Ahlbrandt et al. 2005) divided WCSB into 3 basins: the Alberta Basin, the Williston Basin and the Rocky Mountain Deformed Belt, with undiscovered technically recoverable conventional resource of 11.9

Tcf, 0.5 Tcf and 3.2 Tcf respectively, resulting in a total estimate of 15.6 Tcf for WCSB. This is very low compared to estimates from NPC of 92.6 Tcf (National Petroleum Council 2003), from CGPC 0f 88 Tcf (Meneley 2005), and from National Energy Board of 96 Tcf[12]. Different assessments for Canada are tabulated in Table 13, and the gas bearing regions are shown in Figure 18.

Table 13: A comparison of undiscovered recoverable conventional gas resource assessments by CGPC, NPC, and NEB is shown in this table. There has been a dramatic increase in the estimated resource for East Canada Offshore, which includes Labrador, Newfoundland, and Nova Scotia.

	CGPC	NPC	NEB
	2001	*2003*	*2004*
Western Canada Sedimentary Basin	88	93	92
East Canada Offshore	13	68	77
East Canada Onshore	1.4	2	2
West Coast	0	11	17
Northern Canada	35	46	94
Total	138	219	282

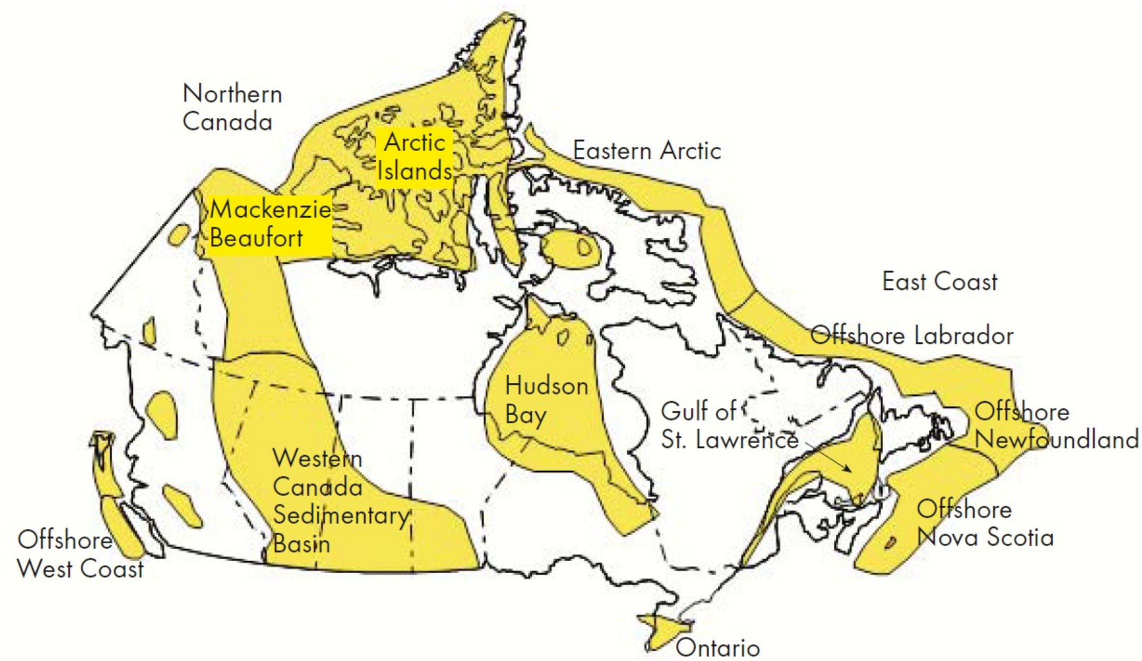


Figure 18: Canadian sedimentary basins. (Source: NEB - Canada's Conventional Natural Gas Resources - A Status Report. April, 2004)

Coalbed Methane

Coalbed methane resources in Canada lie in the Mannville (GIIP 350 Tcf), Ardley (GIIP 20 Tcf) and Horseshoe Canyon (GIIP 84 Tcf) formations in WCSB[13], with majority of the

[12] The CGPC and NEB estimates are for marketable gas, which is computed using some Arp-Robert like discovery process algorithm. It seems plausible that such a methodology gives a lower estimate than just the undiscovered technically recoverable resource.

[13] GIIP Source: Alberta ERCB/EUB and NEB as referenced in Gatens, 2008 (Gatens, Michael, 2008, "The Role of Unconventional Gas in North America," CERI 2008 Natural Gas)

development currently taking place in the dry Horseshoe Canyon and Belly River coal seams in south central Alberta[14] (See Figure 19). NPC estimated 33 Tcf of technically recoverable CBM resource.

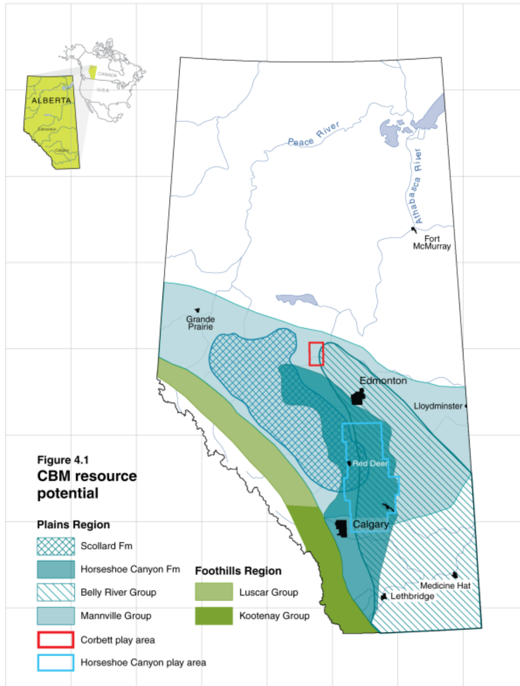


Figure 19: The CBM producing formations in Alberta, Canada are shown in this figure. These formations are Horseshoe Canyon, Belly River and Mannville.

Shale Gas

While studies for GIIP of shale gas exist, technically recoverable resource estimates are more difficult to find. Historically the majority of gas production from WCSB has occurred in Alberta. However, the two emerging shale plays in WCSB, namely Montney and Horn River, are located in British Columbia. They are shown in Table 15 and their volumetric properties are given in Table 16.

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[14] Source: Energy Resources Conservation Board (ERCB), Alberta http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_316_258_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/publications_catalogue/publications_available/serial_publications/st98.aspx

Table 14: Assessments by NPC and ICF of the technically recoverable volumes of Canadian shale gas are shown in this table.

Gas – Tcf

Region	Play Area	NPC *2003*	ICF *May 2009*
Eastern Canada	Quebec Area	-	7.0
Alberta, Saskatchwan and Manitoba	Cretaceous Shale - Vertical	3.1	9.4
	Triassic Doig - Vertical	2.8	8.4
	Triassic Montney - Vertical	3.7	11.2
	Devonian Shale - Vertical	7.5	22.6
	Triassic Montney -Horizontal (part)	0.0	26.7
	Total	17.2	78.3
British Columbia	Triassic Montney -Horizontal (part)	-	203.6
	Devonian Shale - Horizontal	-	154.2
	Total		357.8
Canada Total		17.2	443.1

- not assessed

Table 15: Volumetric properties of selected shale plays in Canada are shown in this table. (Source: ICF)

Play	*Assessed Gross Play Area*	*Basin Avg.Shale Thickness*	*Shale Volume*	*Unrisked Gas in Place*	*Risked Gas in Place*	*Assessment Well Spacing*	*Recovery Factor at this Spacing*	**Technical Recovery at this Spacing**
	sq. mi.	ft	cu. mi	Tcf	Tcf	acres		**Tcf**
BC Devonian Horn River Muskwa	5,175	400	392	1,007	771	80	0.20	**154**
WCSB Montney	38,346	878	6,376	4,651	1,536	80	0.15	**230**

Table 16: Selected geological and geophysical properties of shale plays in Canada are shown in this table. [Reproduced from Table 16 in (Vidas and Hugman 2008)]

Basin		**E. Canada**	**BC**	**BC**
Shale Play		**Utica**	**Muskwa**	**Montney**
Well type		**Horizontal**	**Horizontal**	**Horizontal**
Geologic Age		Ordovician	Devonian	Triassic
Vertical Depth	*Ft*	2,300 - 6,000	7,800 - 13,000	6,500 - 12,000
Gross Thickness	*Ft*	500	500	500
Pressure Gradient	*Psi/ft*	.45 - .60		
Origin of gas		Thermogenic	Thermogenic	Thermogenic
Total Organic Content	*%*	1.0 - 3.1	3.0	1.5 - 6.0
Vitrinite Reflectance	*%Ro*	1.3 - 3.0	2.8	0.8 - 2.5
Silica Content	*%*		65	
Gas-in-place/sq. mi	*Bcf/Sq. mi*	75 - 350	180 - 320	75 – 100
Reserves per well	*Bcf*	1,700	4,000+	2000+
CO2	*%*	none		
Methane	*%*	88 - 97		
Heating Content	*Btu/cf*	1,027 - 1,136		

Figure 20: Horn River Shale and Montney Shale in British Columbia and Alberta

Russia

Russia has the world's largest gas reserves and resources. It is also the world's largest producer (with the exception of 2009[15]), net exporter and second largest consumer of gas after US. Figure 21 shows the overall gas balance for Russia since 1992. Annual domestic consumption in 2008 was 16.8 Tcf or 71.8%[16] of total production. Russia exported 4.5 Tcf to Europe, 22% of Europe's gas consumption in 2008 (20.4 Tcf).

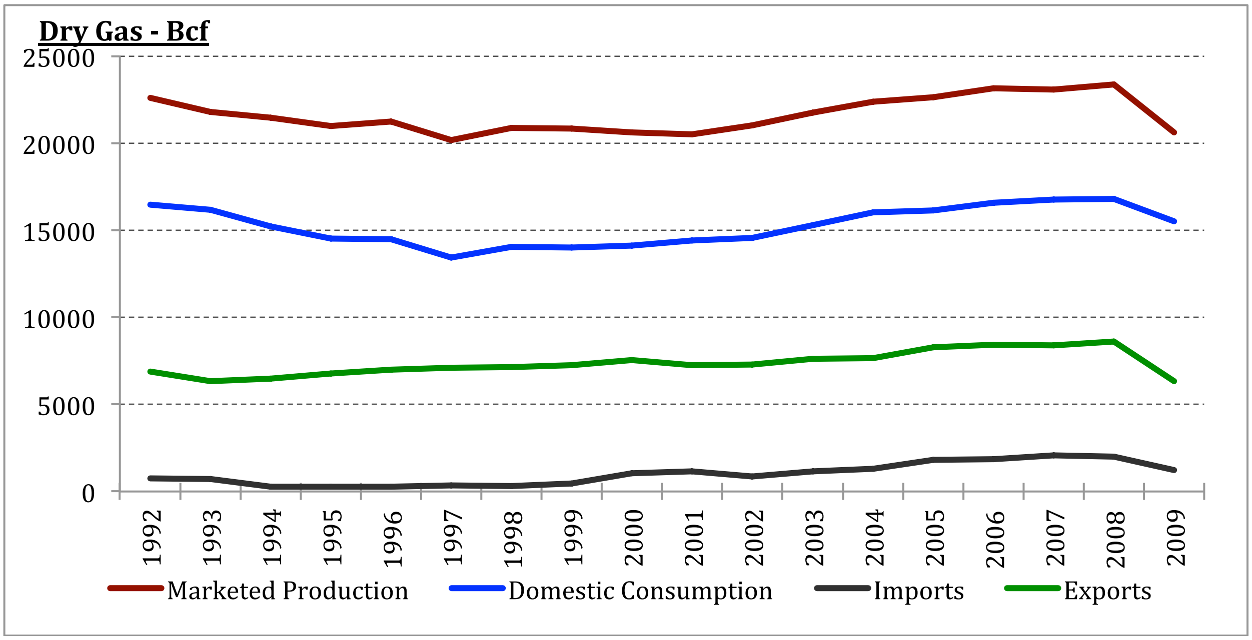

Figure 21: Dry natural gas production, consumption, imports and exports of natural gas for Russia (1992-2008). (Energy Information Administration 2010b)

At the same time, exports - which are mostly to Europe - have also been steadily increasing. The increase in these exports is approximately equal in volume to the imports from former Soviet Republics, primarily Turkmenistan, keeping net exports nearly flat.

Largest gas resource holder globally

Its 2009 year-end reserves of 1,680 Tcf account for nearly 27% of the world's reserves. At current rates of production, the reserves are equivalent to nearly 70 years of production and its RRR of 3400 Tcf to that of 170 years. As of 2008, state-owned Gazprom holds 1170 Tcf[17] or 70% of the reserves[18].

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[15] In 2009 Russian gas production fell dramatically by 4.7 Tcf, a decrease of 17% due to the economic recession. While US gas production continued to rise due to shale gas production, making US the top producer for the first time since records are available from EIA (1980).

[16] This percentage for domestic production consumed internally is calculated by subtracting imports from domestic consumption, and then dividing by total domestic production.

[17] Cubic meters have been converted to cubic feet by using a multiplicative factor of 35.3.

[18] All Gazprom data taken from (Gazprom 2010).

Industry structure: Gazprom is the dominant player

Gazprom dominates the Russian gas industry. The company is the direct descendent of the Soviet gas ministry, and it remains majority government-owned. Its special status comes with privileges (e.g. export monopoly, control of pipeline system, and preferential access to resources) but also with substantial obligations (e.g. domestic supply obligation at low, regulated prices). Its special status has made it the largest gas company in the world in terms of reserves ownership, gas production and market capitalization.

The structure of the Russian market is fundamentally different from the liberalized US markets. Gazprom has limited price risk, as domestic markets are regulated and export markets are almost entirely tied to long-term contracts with gas prices indexed against oil and petroleum products. However, given its responsibility for the overall system, it has significant volume risk, requiring it to act as swing supplier. As a result, Gazprom's gas production is effectively a function of demand (domestic and export), not just price and its pure supply potential. This is almost the exact opposite of a US producer who typically faces limited volume risk but with substantial price risk.

Gazprom has a significant degree of operational autonomy but in many areas is also required to operate as an instrument of the state. Its pivotal role in the industry combines regulatory and commercial functions while maintaining a tight control over the gas market, infrastructure, and information flows. It controls, owns and operates the vast Russian inter-regional pipeline infrastructure of 100,000 miles, the longest in the world. It owns all gas storage facilities in Russia and operates 25 underground storage sites. It has a monopoly on gas processing in Russia, making it the sole buyer of wet gas from oil companies and independent producers. It has sought an increased international role both upstream (e.g. South Pars field in Iran) and downstream (e.g. pipelines and marketing operations in Europe). It has expanded its energy sector footprint by acquiring Sibneft, Russia's fifth-largest oil producer, and building up controlling stakes in multiple power generating assets. It has also acquired a diverse array of holdings in such sectors as banking, insurance, agriculture, media, and construction. Finally, and very significantly, Gazprom has a complete monopoly on all gas exports.

Although Gazprom continues to dominate the domestic market, there are other players in the market that seek to expand their market share. One of these players is the company Novatek, which was founded in 2004 and is focused on production from the Yamal. Its 2008 production of nearly 2 Tcf[19] was equal to 5.6% of Gazprom's 2008 production of 19.4 Tcf.

Domestic market: balancing demand and supply, and price reform uncertainty

Russian consumption declined in the 1990s following the collapse of the Soviet Union and the restructuring of the Russian economy, but it still remained quite stable compared to other sectors of the economy. Following the 1998 financial crisis and devaluation, the economy grew strongly and with that domestic natural gas consumption. Matching demand, production of natural gas declined steadily from 1992 to 1997, and has been mostly

[19] From Novatek website http://www.novatek.ru/eng/our_business/production/ (accessed Nov 12, 2010)

increasing since 1998-2008 at an average annual rate of 1.37%. These trends can be seen in Figure 21.

As the operator of the national gas system (Unified Gas Supply System), Gazprom is ultimately responsible for ensuring that domestic demand and export commitments are met with adequate supply from its own supply, independent domestic producers and imports from Central Asia, primarily Turkmenistan.

Most of the demand centers are located far from the productive regions in the Western Siberian basins. To supply gas to local consumers and export markets, Russia has an extensive high-pressure inter-regional pipeline system, which is owned and operated by Gazprom. These aspects can be seen in Figure 22.

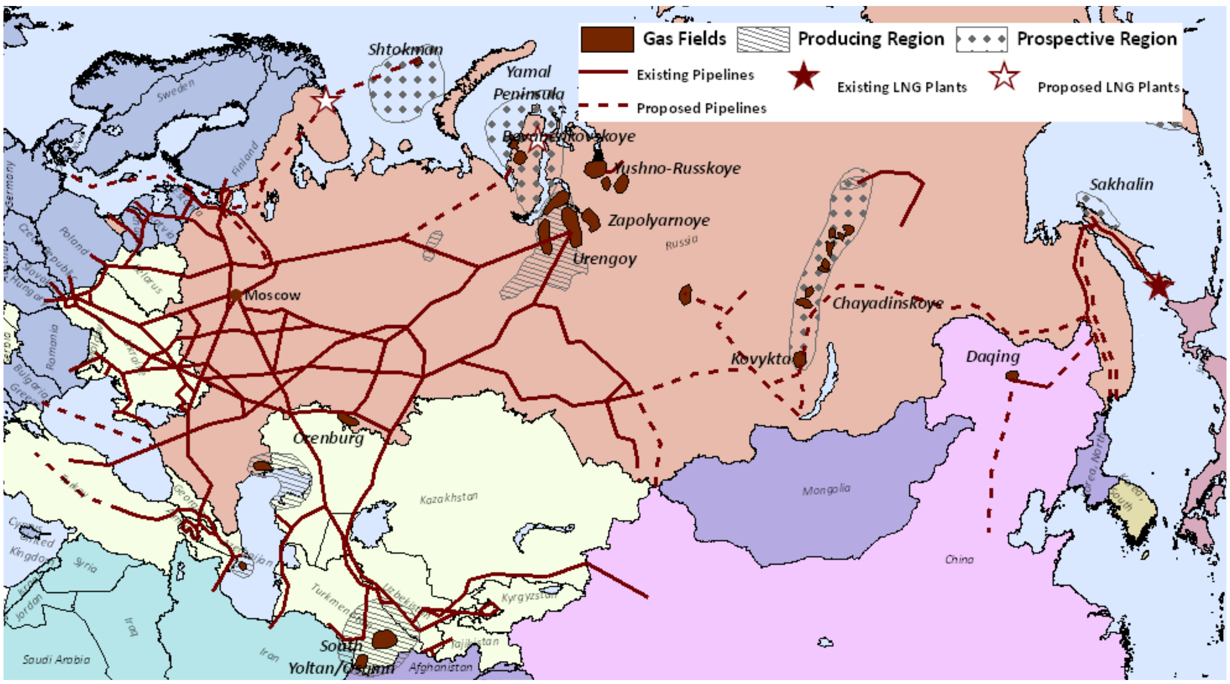

Figure 22: Major gas fields and supply infrastructure in Russia. (Source: IEA 2009 World Energy Outlook.)

Laws in Russia mandate third party access to transmission pipelines, but only if there is sufficient capacity available. Gazprom can also refuse access on technical grounds such as the quality of the gas. There is also lack of transparency in how Gazprom reaches decisions in determining capacity. These factors allow it to restrict access to independent producers who may wish to supply gas in the local market. In addition to the access issues, the domestic market itself is not very conducive to increased production from other producers due to low regulated prices.

The government and Gazprom negotiate a year ahead how much gas is to be supplied domestically by Gazprom at regulated, artificially low prices to domestic consumers – on an energy equivalent basis, natural gas is cheaper in Russia than coal, the only country in the world where this is true. The shortfall in supply is filled by imports from Turkmenistan, and possibly Kazakhastan in the future, to domestic markets in the south, and by independent producers and oil companies. Until recently it was difficult for non-Gazprom producers to gain access to profitable customers, and would lead them to either flare the gas or sell it at depressed prices to Gazprom. Consequently significant resources were left unexploited.

The domestic market is the biggest market for Gazprom, but not a profitable one, given low prices. The inefficiencies in usage and artificially low prices of gas in Russia present significant challenges for Gazprom and the Russian government. The government has started the implementation of price increases, though the trajectory is uncertain, not least because of the 2009 financial crisis.

Current supply: supergiant fields dominate production

In 2008, Gazprom produced 19.4 Tcf of gas, of which 52%[20] was sold to domestic markets. Domestic supply came from Gazprom (63.3%), domestic oil companies or independent gas producers (22.1%) and Central Asian imports[21] (14.6%). Domestic supply is dominated by production from super ginat fields. The top 3 fields, as ranked by 2008 production, accounted for 53% of total Russian gas production.

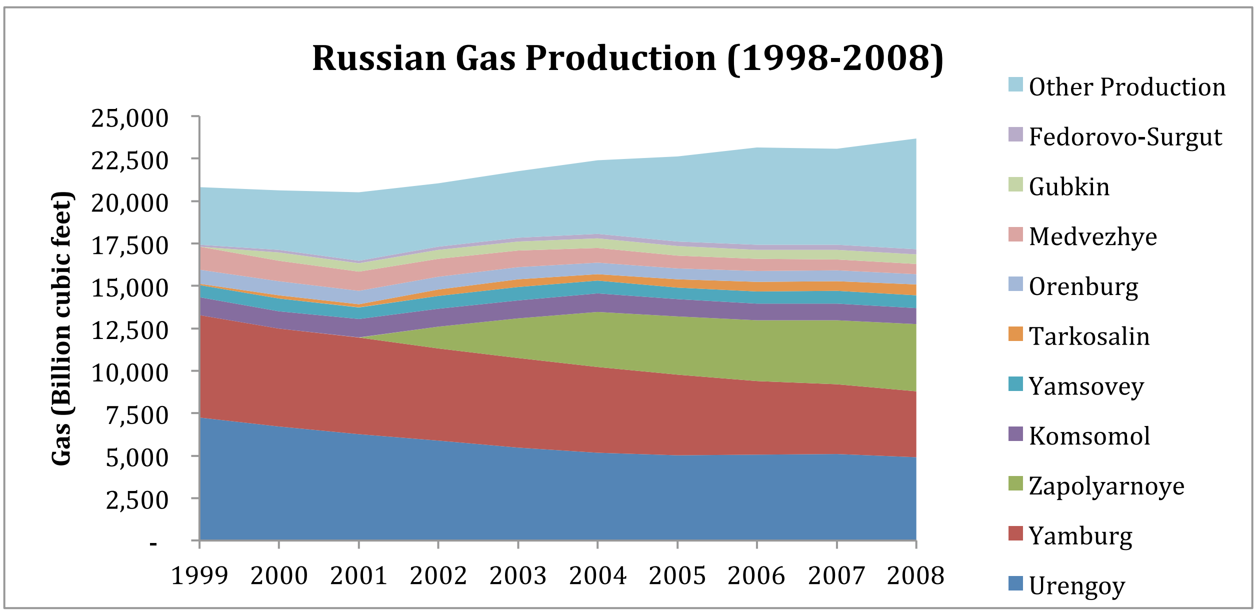

Figure 23: Russian gas production by major fields. The decline from the super giant fields of Yamburg and Urengoye is partially compensated by the new super giant field of Zapolyarnoye. (Data from HIS International, provided by EIA)

These fields are the super giant fields Urengoy, Yamburg, and Zapolyarnoye, which are all located in the Nadym-Pur Taz region in the West Siberian Basin. These three fields are the world's biggest conventional gas fields when rated by peak production, and are in the top-10 fields as rated by initial reserves.

[20] Russian total production and domestic consumption data is taken from (International Energy Agency 2010).

[21] Imports are from Turkmenistan, Uzbekistan and Kazakhastan.

The production from Urengoy and Yamburg is in decline with an average annual decline rate from 2001-2008 of about 4.5%. Zapolyarnoye is the last supergiant field to be developed by Gazprom, starting in 1999. After the initial ramp-up, Zapolyarnoye's production from 2005-2008 has been increasing annually at about 5%.

Table 17: The data for discovery/development date, peak annual production and estimated 2008 production for the leading three Russian gas fields by initial reserves are shown in this table.

Field	Discovered	Developed	Peak annual production		Initial Reserves (Tcf)	2008 Estimated Production (Bcf)
			Bcf	% reserves		
Urengoye	1966	1976	10,560	2.9%	360.3	4,902
Yamburg	1969	1983	6,251	2.9%	215.4	3,876
Zapolyarnoye	1965	1999	3,638	2.9%	105.9	3,967

Of the fields shown in Figure 23, Gazprom owns Urengoy, Yamburg, Zapolyarnoye, Medvezhye, and Yamsovey. Although Gazprom produces the bulk of gas in Russia and supplies 77% of the domestic market, its share in production has declined with the growth in production from independent gas producers while its production has remained more-or-less constant.

Export markets: key supplier to Europe; increasingly looking East

Russia exported 5.5 Tcf of gas via pipeline to European countries in 2008. The volumes of gas exports to OECD countries are shown in Figure 24. It can be seen from this figure that Germany, at 1280 Bcf imported the largest share (23%). The next largest importer is Italy (865 Bcf, 16%) with Turkey as a close third (830 Bcf, 15.3%). The main transit FSU countries, for export to Europe, are Ukraine, and Belarus, with almost 90% of European exports passing through Ukraine. Major Russian gas export pipelines to Europe are shown in Figure 25.

Although Figure 23 shows that Russian gas production is increasing, there are concerns about Russian gas supply and exports. The concern centers on two issues. The first issue is the ongoing disputes with transit countries; specifically Ukraine and to a lesser extent Belarus. The relationship with Ukraine has caused temporary halts in gas flows from 2006 and has undermined Russia's reputation as a reliable supplier to Europe. The second is, Russia's ability to meet future natural gas demand, both domestically and from Europe, has frequently been brought into question, because of perceived low investment rates and Gazprom's apparent focus on acquiring oil and electricity assets. However, such criticisms appear to be superficial. There are several important variables, such as the evolving and emerging production plans in the Yamal Peninsula where there appears to be concrete progress in bringing Bovanenko online in 2012, the reduction in demand following the global recession in 2008, the potential role for independent gas producers and oil companies, and import obligations from Central Asia, primarily Turkmenistan, that should also be taken into consideration when assessing the question (Stern 2009).

However, there is little doubt that Russia has a more than adequate resource base. Despite similar concerns being raised in the past, Gazprom, and Russia have been able to meet demand.

Nevertheless, much will ride on Gazprom's ability to bring the next generation of supergiant fields in Yamal onstream in a timely fashion, as well as the speed in recovery in demand following the 2009 global economic recession.

Figure 24: This figure shows the exports of Russia to OECD countries. (Note: 2008 exports to Austria have been set equal to 2007 exports).

Russia wants to meet gas demand in its eastern provinces and to reach markets in the Far East, including China. With this view, it plans to set up production in four new provinces, namely Sakhalin, Yakutsk, Irkutsk and Krasnoyarsk. Part of this plan is to expand the UGSS into the east. Sakhalin has been chosen as the initial region full-scale commercial development. As part of the commercial development of the Sakhalin II field, Gazprom brought an LNG plant online in February 2009.

Figure 25: The network of pipelines connecting Russia to Europe and Turkey are shown in this map.

Production plans

To maintain its own production, Gazprom has also been developing and bringing online smaller satellite fields in the Nadym-Pur-Taz region close to existing infrastructure. Ultimately, the decline from the giant fields cannot be compensated for by rising production from Zapolyarnoye and the smaller fields. Consequently, there is a need for developing fields in other regions, such as the Yamal peninsula and the Ob-Taz Bay located north of the Nadym-Pur-Taz region, and the offshore Barents and Kara Sea fields, shown in Figure 26.

There are important challenges in developing fields in the Yamal peninsula. The harsh Arctic climate makes the development of these fields challenging and expensive. The remote location also requires construction of additional pipelines to bring the gas to market. No one has more experience than Gazprom at operating in the difficult climate in Western Siberia but these are challenging projects by natural gas industry standards, both upstream and midstream.

Gazprom's development and production plans for Yamal Peninsula have evolved in recent years with the latest revisions in 2009 following the severe global financial crisis. Gazprom now expects the first Yamal field (Bovanenko) to start production in late 2012, and expects Bovanenko to reach peak production of 4.1-4.9 Tcf/yr after 2015.

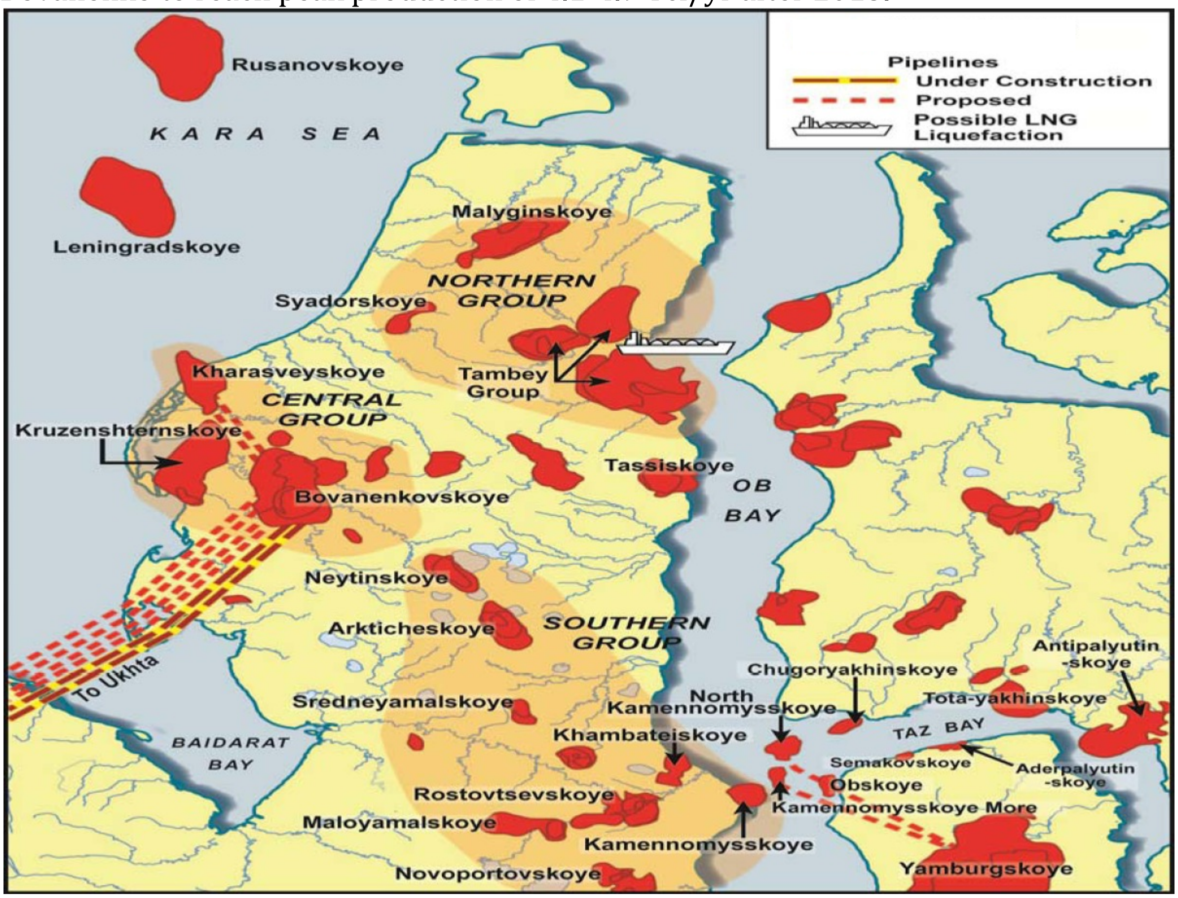

Figure 26: Yamal Peninsula, north of the Nadym-Pur Taz region - the focus of Gazprom's future supply strategy. (Source – Oxford Energy Institute, Jonathan Stern)

The offshore Shtokman field in the Barents Sea, discovered in 1988, but still undeveloped has initial reserves of 134 Tcf. IEA estimates the cost of production from the Barents Sea area in Russia, where Shtokman is located, to be $4.00-$4.50/mcf (2008 dollars). This is a very challenging field, located 350 miles from the main Russian coastline in inhospitable arctic conditions. The current field development plan has three phases, each of 850 Bcf/yr, with output split between export pipeline (to be connected to Nordstream) and LNG export of 30 Mt/yr.

Transportation plans

Gazprom's domestic infrastructure priority is to construct additional pipelines to link future production from Yamal Peninsula to the consuming regions in European Russia. Given the size of the existing network, Gazprom also has an extensive ongoing maintenance and upgrade program.

The other transportation priority is the construction of new export pipelines to Europe. These are Nord Stream and potentially South Stream, initially designed to reduce dependence on transit through Ukraine and also facilitate an increase in export volumes should Europe demand additional Russian gas, as Nord Stream bypasses transit countries and provides a separate link to the European markets. Financing for phase I of Nord Stream has been secured and first gas is projected to flow in 2011. Phase I will have annual capacity of 971 Bcf, set to double with phase II. Nord Stream will stretch nearly 750 miles across the Baltic Sea from Portovaya Bay (Vyborg) to the German coast at Greifswald. The South Stream pipeline aims to provide gas to South and Central Europe after crossing the Black Sea. Its undersea section will be nearly 560 miles long, with maximum depth in excess of 1.25 miles. The full offshore capacity will be 6 Bcfpd or 2.2 Tcf.

Gazprom has also developed a Priority Actions Program to debottleneck the Central Asia – Center (CAC) gas transmission system, which is over 30 years old. This will allow it to secure imports from Turkmenistan.

Since 1995, Gazprom has been expanding the existing pipeline infrastructure that connects Urengoy-Nadym-Pergerebnoye-Ukhta-Torzhok multiline system. This will allow it to increase supply to domestic consumers and to increase export volumes via the Yamal-Europe pipeline.

Iran

Iran has the second largest reserves in the world at 992 Tcf (O&GJ). It has an RRR base of nearly 1565 Tcf (UTRR: 397.3 Tcf; reserve growth: 177.5 Tcf[22]). However, its 2007 gas production of 3.8 Tcf was only 3.5% of global production. The figure below shows natural gas production, consumption and volumes of international trade. Iranian gas production has been rising steadily. At the same time, domestic consumption has also risen rapidly. Currently, it is the world's third largest consumer of gas after US and Russia.

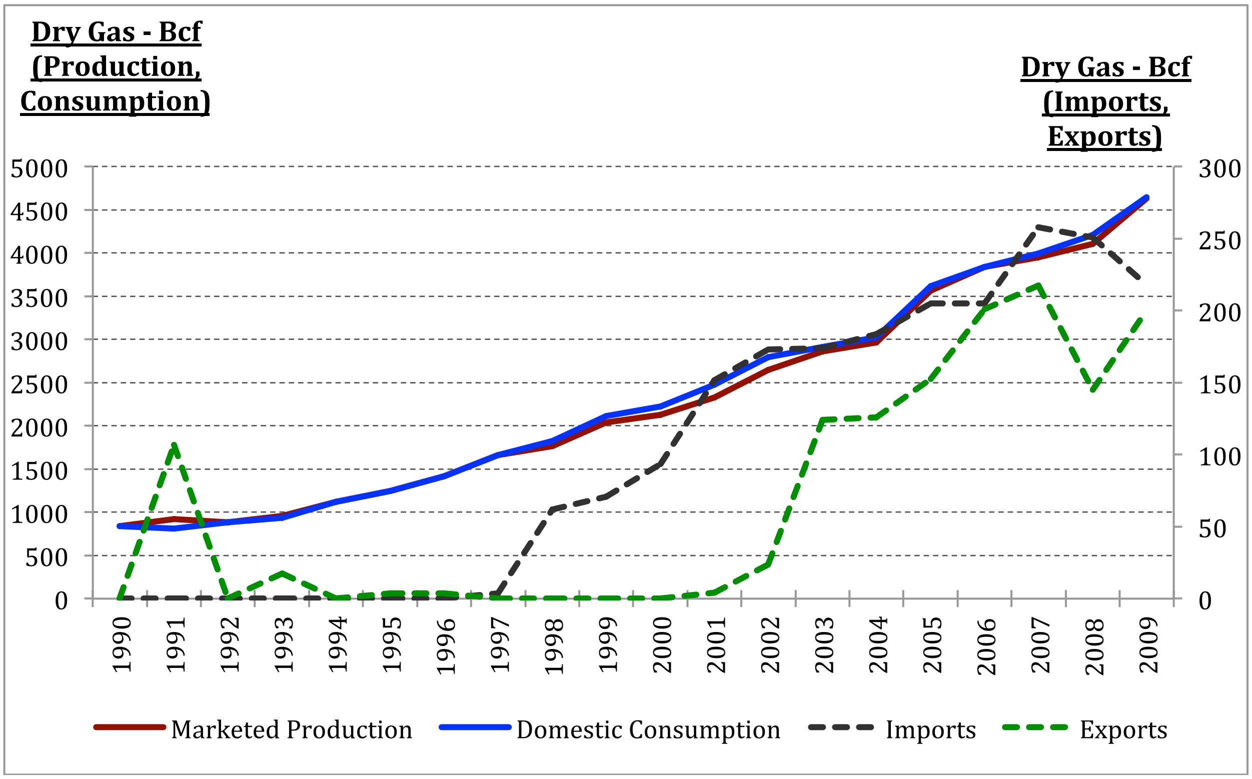

Figure 27: Iranian gas production and consumption have been rising steadily. Exports and imports account for a very small portion of total production. (Energy Information Administration 2010b)

Iran Imports small quantities of gas from Turkmenistan and exports smaller quantities of gas to Turkey, making it a net importer of gas. In 2008, Iran exported 205 Bcf to Turkey, and imported 230 Bcf from Turkmenistan. The imports from Turkmenistan, and in the future potentially from Azerbaijan, supply the domestic markets in Northern Iran, which is located far from the gas production regions in the south, and are not supplied yet with pipelines.

The state-owned National Iranian Oil Company is responsible for oil and gas exploratory efforts and production. Under the Iranian constitution, oil and gas upstream functions cannot be owned by non-state entities. The state however allows collaboration with

[22] The reserve growth estimate is based on USGS 2000 World assessment (T. R. Klett, D.L. Gautier, and T.S. Ahlbrandt 2000) with some constraints imposed by ICF. The UTRR estimate is also based on the same USGS study, with the field size distribution modified to a linear ratio model.

international partners to be set up as buy back contracts. This means that they can enter exploration and development contracts through Iranian affiliates, and receive a remuneration fee, usually in the form of entitlement to production from the developed field. Almost 60% of Iranian reserves lie in offshore, non-associated and partially developed fields. The majority of the offshore reserves are in the South Pars field, which contains 495 Tcf, nearly half of Iran's total reserve base. The South Pars field and the North Dome field in Qatar are a single gas/condensate field, of which over one-third lies in Iranian territory and the remainder in Qatari territory.

The South Pars field started production in 2004, and now accounts for nearly 60% of total Iranian production. The field has 28 phases in its development plan spanning 20 years, of which 10 have been completed. As a result, the field has annual production capacity of nearly 3.2 Tcf. Since 2000, capacity additions to the South Pars field have been greater than the North fields, 1590 Bcf/year compared to 1415 Bcf/year (IEA).

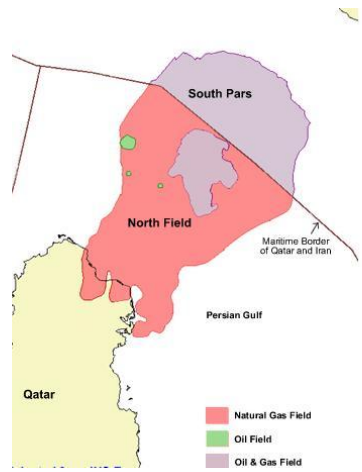

Figure 28: The South Pars/North Dome Field lies in the Qatar Arch geologic basin.

Table 18: This table shows discovery and development dates, the peak annual production and the initial reserves for the North Dome/ South Pars field. The North Dome is in Qatari territory, while the South Pars is in Iranian waters

Field	Discovered	Developed	Peak annual production		Initial Reserves (Tcf)
			Bcf	% reserves	
North Dome	1971	1988	2,650	0.3%	989.0
South Pars	1993	2002	1,731	0.4%	494.5

The South Pars field is not a completely developed field, and based on IEA analysis of peak production for super giant fields, it could have a peak production of 14.8 Tcf (3.0% of initial reserves). The development phases of 6-8 seek to supply sour gas for enhanced oil recovery by gas injection in the Aghajari oil field.

The next largest field in Iran is the offshore North Pars field, located 53 miles north of the South Pars field. It contains reserves of 47.2 Tcf of recoverable sour gas, which is 80% of GIIP of 58.9 Tcf (Source- Pars Oil and Gas Company). In 2006, Iran signed a deal with China National Offshore Oil Corporation (CNOOC) to develop this field as an LNG export project. Under the contract, China will lift 50% of the gas. Other important gas fields in Iran include Tabnak, Kish (50 Tcf), Kangan (29 Tcf), Nar (13 Tcf), and Khangiran (11 Tcf). Oman has signed a contract in 2008 to jointly develop the offshore Kish field (EIA).

Iran is also investing in developing a pipeline system for domestic transmission of gas, called the Iranian Gas Trunkline (IGAT) to connect the producing regions to centers of demand and for gas re-injection into oil fields for enhanced recovery. This pipeline system is still under construction.

Iran seeks to become a major gas exporter to other countries in the region, such as Turkey, India, Pakistan, Oman, Bahrain, and China, but so far it has not achieved that goal. This appears to be due to the trade sanctions, and the unfavorable terms offered in the buy-back agreements.

Qatar

Qatar is the third largest country by natural gas reserves in the world, after Russia and Iran; and the world leader in LNG both in scale and economies of scale in the world. It is also a member of OPEC with its 2008 production of oil of 0.9 million bpd equal to 10% of Saudi Arabia's oil production.

Almost all of Qatar's natural gas reserves of nearly 890 Tcf reside in the North Field, which was discovered in 1971 and began development in 1988. This field alone accounts for nearly 14% of the world reserves and has not yet been fully assessed. It is being sequentially developed, first to meet local demand and then to meet two large LNG projects (Qatargas 1 and 2, and Rasgas 1 and 2), the Dolphin pipeline to United Arab Emirates, and the 34 kb/d gas to liquids (GTL) Oryx project it developed with Sasol in 2007. This field lies in the geologic basin of Qatar Arch. However, there is limited potential for additions to these reserves, with a reserve growth estimate of 7.1 Tcf and UTRR estimate of 53.1 Tcf[23].

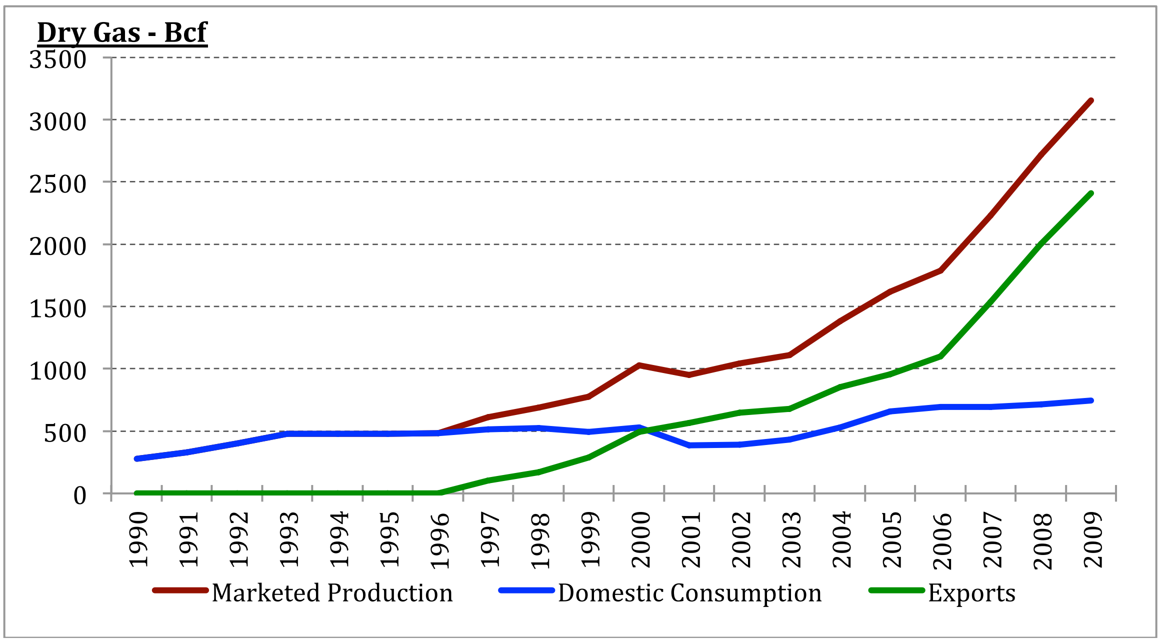

Figure 29: A time series of natural gas production, consumption and exports for Qatar is shown in this figure. (Energy Information Administration 2010b)

Qatar started exporting LNG in 1997 to Japan. Since 2006, Qatar has been the world's largest LNG exporter. It exported 1.4 Tcf of gas in 2008 via LNG. This was 17.5% of global LNG trade. Its biggest market was Asia Pacific where nearly 80% of its LNG exports went. Europe was the destination of the remaining LNG, with the North America only receiving less than half a percentage point (US: 3.2 Bcf, Mexico: 3.2 Bcf).

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[23] See Footnote 22 for details of data source.

Qatari LNG expansion in 2009-2011 will be the largest expansion worldwide, which will further solidify its position as the leading LNG exporter. It aims to increase its liquefaction capacity from 30 Mt[24]/year in 2008 to 77 Mt/year in 2011-2012, increasing the Qatari share of the global LNG market to 27%. For this expansion, giant LNG carriers (31 Q-Flex and 14 Q-Max) are being delivered from Korean shipyards.

Gas from Qatar's North Dome Field is exported from the refinery in Ras Laffan via the Dolphin pipeline to the port city of Taweelah in Abu Dhabi, part of United Arab Emirates. This project is owned and managed by Dolphin Energy of Dubai. The pipeline was planned in 2003, built by Mitsui of Japan starting in 2004 and completed in August 2006. The Dolphin pipeline is the largest and longest pipeline in the Middle East, with a maximum underwater depth of 165 ft.
This 48-inch, 364 km (227.5 mile) pipeline's current maximum throughput is 2 Bcf/d. Its maximum design capacity is 3.2 Bcf/d. The usage of the extra capacity of 1.2 Bcf/d depends on further agreements between Dolphin Energy and Qatari authorities (Source- Dolphin Energy). In 2008, Qatar exported 604 Bcf via pipeline or 1.65 Bcf/d (BP 2009).

The Qatari gas production is determined by matters of national interest for this small kingdom of 830 thousand people. A key national priority is to extend the productive life of the North Field, which officials have spoken of extending to a 100 years. This goal is set by the desire to create a sustainable legacy for future generations, and set the stage for long-term supply partnerships. In 2002 Qatar set a moratorium on further gas development until an assessment of the four productive Khuff layers was completed. There were several reasons for this moratorium: the unexpected differences in gas quality, and sulfur content in the different blocks, and two dry holes drilled in the field's northwest flank in the earlier part of this decade. This probably also speaks to the conservative approach taken in certain Middle East countries in the husbandry of their resources. The study being conducted will allow for a more careful analysis of the socio-economic impacts of rapid development of the North Field.

Figure 30: The sea lines transport produced gas from the North Field to the Ras Laffan industrial complex. The export pipeline runs from Qatar to Taweelah in Abu Dhabi, UAE (Source- Dolphin Energy).

[24] 1 million tonnes (Mt) of LNG is equivalent to 48 Bcf of natural gas. (BP 2009)

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