DIW BERLIN

1338

Discussion Papers

Deutsches Institut für Wirtschaftsforschung 2013

From Boom to Bust?

A Critical Look at US Shale Gas Projections

Philipp M. Richter

IMPRESSUM

DIW Berlin
German Institute for Economic Research
Mohrenstr. 58
10117 Berlin

Tel. +49 (30) 897 89-0
Fax +49 (30) 897 89-200
http://www.diw.de

ISSN print edition 1433-0210
ISSN electronic edition 1619-4535

Papers can be downloaded free of charge from the DIW Berlin website:
http://www.diw.de/discussionpapers

Discussion Papers of DIW Berlin are indexed in RePEc and SSRN:
http://ideas.repec.org/s/diw/diwwpp.html
http://www.ssrn.com/link/DIW-Berlin-German-Inst-Econ-Res.html

From Boom to Bust?

A Critical Look at US Shale Gas Projections

Philipp M. Richter*

November 22, 2013

Abstract

US shale gas production is generally expected to continue its fast rise. However, a cautious evaluation is needed. Shale gas resource estimates are potentially overoptimistic and it is uncertain to which extent they can be produced economically. Moreover, the adverse environmental effects of ever more wells to be drilled may lead to a fall in public acceptance and a strengthening of regulation. The objective of this paper is hence twofold: providing a critical look at current US shale gas projections, and investigating in a second step the implications of a less optimistic development by means of numerical simulation. In a world of declining US shale gas production after 2015, natural gas consumption outside the USA is reduced from its reference path by at least as much as US consumption. Trade flows are redirected, and the current US debate on LNG export capacity requirements becomes obsolete.

JEL Codes: Q37, L71, Q41, Q33, C61, Q53,

Keywords: Natural Gas, Shale, USA, Scenarios, Equilibrium Modeling

* German Institute for Economic Research (DIW Berlin), Mohrenstraße 58, 10117 Berlin, Germany; Email: prichter@diw.de. This work is carried out within the research project "RESOURCES: International Energy Resource Markets under Climate Constraints - Strategic Behavior and Carbon Leakage in Coal, Oil, and Natural Gas Markets" funded by the German Ministry of Education and Research. I would like to thank Brian Reed, Franziska Holz, Daniel Huppmann, Anne Neumann, Christian von Hirschhausen and Ruud Egging for great assistance and helpful feedback.

1. Introduction

In the last decade, the USA has seen an unexpected increase in natural gas production. Since 2005, annual production has increased by a third, reaching an all-time record in 2012. This rise in domestic production has been led almost entirely by a boom in shale gas extraction, as technological advances and the combined use of horizontal drilling and hydraulic fracturing have allowed an economic production of natural gas from shale formations. Despite current low natural gas prices, production further increases. Moreover, this recent rise has changed projections on US natural gas production and the US trade balance. Instead of largely relying on foreign natural gas supply, envisaged less than a decade ago (e.g., EIA, 2005), the USA is now projected to become a significant exporter of Liquefied Natural Gas (LNG; e.g., IEA, 2012 or EIA, 2013), i.e. to enter a golden age of gas (IEA, 2011).

While partly backed by realized production growth, it is in doubt whether the current shale gas boom can continue for three reasons. First, there is uncertainty whether the underlying estimates of shale gas resources will prove accurate. Resource estimation crucially relies on assumptions on the potential area of shale production, on wells spacing and well productivity – all factors that are highly uncertain.

Second, these estimates describe the technical potential, not the economically producible amounts of shale gas. Given the global abundance of conventional reserves, it is yet to be determined to which extent US shale gas can compete on the international market. Moreover, driving forces of the current high production level are of short-term nature, such as the shift to most productive shale gas plays.[1]

Finally, ever more wells need to be drilled, affecting a large area of land. Following potential adverse environmental effects, a fall in public acceptance and a tightened regulation may impede further increases of shale gas production. For instance, a reduction of the land area admissible for shale gas production or of the well density directly lowers future production possibilities.

This paper analyzes current optimistic projections of US shale gas production. Moreover, I investigate the implications of alternative developments of US natural gas production on its domestic market and on global trade flows. To this end I make use of the Global Gas Model (GGM), a large scale partial equilibrium model that allows analyzing trade flows and infrastructure expansions along the natural gas value chain. A reduction in US shale gas production is partly compensated by natural gas production outside the USA. However, it mainly leads to lower consumption of natural gas – in the USA but also in other countries. LNG trade flows are shifted towards the USA, which competes with European and Asian countries for international supply. Existing US LNG import capacity is utilized at higher rates and even extended to meet regional demand.

While others have highlighted uncertainties underlying a continued shale gas boom (cf. Kerr, 2010a, Hughes, 2013, McGlade et al., 2013, Johnson and Boersma, 2013 or EWG, 2013), the implications of low US shale production have not been analyzed in a world different to the pre-shale era. Solely, Jacoby et al. (2012) approach this issue, following a different motivation. By constructing a counterfactual non-shale scenario they analyze the effect of US shale gas on GHG emissions reductions. Their findings indicate both a shale-induced increase in US economic activity, and the important role of shale gas as a flexible measure to meet emissions reduction targets at low costs.

[1] According to the EIA, a play is a "set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type". See http://www.eia.gov/tools/glossary/index.cfm, Accessed in November, 13th, 2013.

Here, this work is complemented by taking a global perspective to analyze the impacts of different paths of US shale gas production.

To this day, shale gas has been a US story only, as no other country has been able to produce it at commercial scale (IEA, 2013a). However, large resources of shale gas are estimated for many countries across the globe, e.g., for China, Argentina or Algeria (see EIA, 2013b). Nevertheless, some US idiosyncrasies that promote the shale gas boom are in their entirety not present in other countries: the beneficial tax environment, the specific land ownership legislation, geological characteristics, the low population density in (at least some) potential shale areas, and a sufficient water endowment. In contrast, environmental concerns motivated bans of hydraulic fracturing (at least temporarily in place) in France, Czech Republic and Bulgaria. Public acceptance as well as regulatory, infrastructural and geological obstacles may disappoint hopes in Poland (Johnson and Boersma, 2013), or the UK (Rogers, 2013). Large challenges in China are the lack of technical knowledge for geologically demanding conditions and scarce water supply in regions with major shale gas potential (cf. Gao, 2012 and Hu and Xu, 2013). In the following, the focus consequently lies on shale gas projections for the USA.

The remainder of this paper is organized as follows. Section 2 discusses the recent development in US shale gas production and current official projections. These projections are then critically examined in Section 3. Section 4 analyzes two alternative, less optimistic US shale gas production paths. Changes in consumption and production patterns are highlighted in addition to the implications on trade flows and infrastructure expansions. Section 5 concludes.

2. US shale gas production

2.1. A brief look at the US shale gas boom

For three decades US natural gas production was relatively constant, until it began its recent rise in the mid-2000s. The all-time high of 680 bcm in 2012 (IEA, 2013a) is even more striking considering the decline in conventional production.[2] Offshore production in the Gulf of Mexico has reached maturity (MIT, 2011), and declined by more than 60% between 2001 and 2011. Total conventional production is on a declining path for a long time and halved between 1990 and 2011. However, the increase in unconventional production has reversed this trend.[3]

Figure 1 shows the historic development of total production, together with the year-to-year incremental changes by type of natural gas according to the classification and data from the EIA (2013a). Until the early 2000s, it was the increase in tight gas production that offset the decline in conventional natural gas production; shale gas production remained insignificant. It accounted for less than 2% of total US natural gas production at the beginning of the 2000s, and still less than 5% until 2005. However, a tenfold increase of shale gas production between 2005 and 2011 has outperformed all expectations. It increased from below 10 bcm in 2000 to 260 bcm in 2012 (IEA, 2013a), and currently accounts for more than a third of total US natural gas production.

[2] Note: bcm = billion cubic meter = 1,000,000,000 m³; tcm = trillion cubic meter = 1,000,000,000,000 m³ and mcm = million cubic meter = 1,000,000 m³. One unit of bcm approximately corresponds to 35.31 bcf.

[3] In addition to shale gas, tight gas and coalbed methane (CBM) are generally classified as unconventional natural gas. See Rogner et al. (2012) for a concise definition.

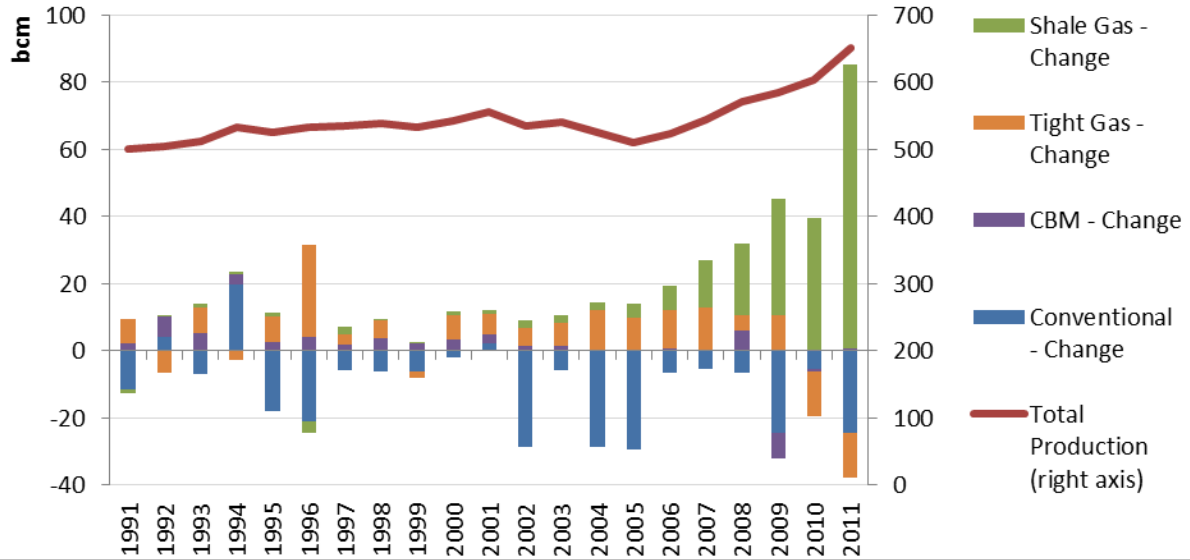

Figure 1: Total natural gas production in the USA (right axis) and year-to-year changes by type based on EIA (2013a), in bcm.

Shale gas production is not a new phenomenon, as it started as early as 1821 (MIT, 2011). However, due to the specific characteristics of shale formations, large-scale production has only recently become technically and economically possible. Shale, a sedimentary rock, mainly contains natural gas in pores that are poorly connected (Rogner et al., 2012). The low permeability due to insufficient natural fractures does not allow an easy extraction with conventional techniques. Well stimulation is needed that makes the process more complex and costly.

Horizontal drilling, well-known from offshore production, is employed to increase the contact with the rather thin gas-containing shale formation (Zoback et al., 2010). After a few thousand meters of vertical drilling—depending on the deposit the depth ranges from 300m in the Fayetteville to more than 3km in the Haynesville play (MIT, 2011)—the direction is changed to continue horizontal drilling. Again, a length of a few thousand meters is possible, averaging at around 1km for the Barnett shale for instance. Here, almost all wells are drilled horizontally today, following a sharp rise since the early 2000s (Gülen et al., 2013).

Additionally, hydraulic fracturing or fracking, is employed to increase and enlarge fractures in the shale formation. It has been commercially applied in the late 1940s in Oklahoma and Texas for the first time, and is used for the production of conventional natural gas and oil, and more recently at unconventional formations, like shale (Montgomery and Smith, 2010). By injecting fracturing fluid, the pressure is increased to create artificial fractures that reach out around 200m from the horizontal wellbore (Zoback et al., 2010), i.e. microseismic events increase the permeability of the formation which allows the gas to be captured more easily. Fracturing fluid usually contains water, additive chemicals and sand as proppant in order to keep the fractures open. The exact composition often is not disclosed and the chemicals can pose environmental problems (see Section 3.3).[4] Before the actual production takes place, a well might be fractured a dozen of times at different locations of the horizontal well; refracturing is possible when the production rate has substantially declined (Zoback et al., 2010).

[4] An amendment by the Energy Policy Act of 2005 to the Safe Drinking Water Act exempts the "underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations […]" from federal oversight. This is commonly referred to as the "Halliburton Loophole". See Energy Policy Act 2005, Title III—Oil and Gas: Subtitle C—Production: Sec 322, http://www.gpo.gov/fdsys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf. Accessed on September 20th, 2013.

In addition to technical advances, other factors have led to the US shale gas boom (cf. Wang and Krupnick, 2013). In particular, high natural gas prices until 2008 have played an important role to encourage well drillings in shale formations (Davies, 2010a). Specificities of the US mineral rights law, i.e. the ownership of minerals in the ground by the private surface land owners, have increased public acceptance through participation of rents. Moreover, open access to the interstate pipeline network has allowed an easy supply of natural gas from new shale gas formations.

Production of shale gas is characterized by a high variability in productivity both across and within plays (MIT, 2011). The exploration risk of conventional natural gas deposits is replaced by a risk of productivity at shale formations (cf. Jacoby et al., 2012). Furthermore, production levels peak early and decline fast. Depending on the play, up to 60% of total production may take place within the first year; up to 85% within the first two years (cf. EIA, 2012a). Just as conventional natural gas, shale gas mainly consists of methane but also contains other hydrocarbons like ethane, butane or propane. These can be additionally marketed as Natural Gas Liquids (NGL; cf. NETL, 2013). Their occurrence varies across and within plays.

US shale production is highly concentrated at only a few producing plays. In the first half of 2013, more than two thirds have jointly been produced at the Marcellus play in Pennsylvania and West Virginia, at the Haynesville play in Louisiana and Texas, and at the Barnett play also in Texas. The largest six fields even contribute to more than 90% of total shale production. However, production patterns differ across plays. Figure 2 shows daily production levels per play on a monthly average until June 2013.

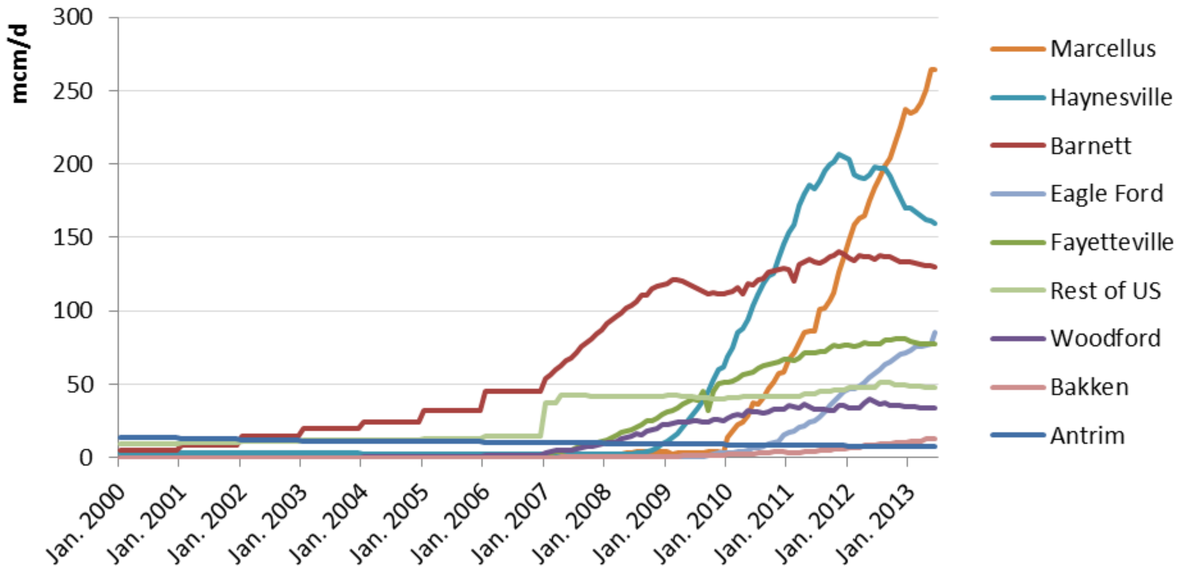

Figure 2: Daily dry shale gas production per play (based on EIA, 2013g), in mcm/d

In some major plays, e.g., the Barnett, Fayetteville and Woodford plays, shale production is currently stable, while production at the Haynesville play has been on a declining path since the end of 2011. By contrast, shale gas production at the Marcellus and the Eagle Ford plays increases significantly. Together, they drive total US shale gas production. Table 1 summarizes up-to-date information for the most important shale gas plays in the USA. It shows recent production levels, and the technically recoverable resources (TRR), which are composed of unproved resources and proved reserves.

Table 1: Production, unproved resources and proved reserves, in bcm or percentages. Own calculations based on EIA (2013a, 2013c and 2013g).

Play	Production in 2012 (EIA, 2013g)		Unproved Resources (EIA, 2013a)		Proved Reserves (EIA, 2013c)		Technically Recoverable Resources (TRR)	
	bcm	share	bcm	share	bcm	share	bcm	share
Barnett	50	18%	834	5%	923	25%	1,757	9%
Fayetteville	29	10%	442	3%	419	11%	861	5%
Woodford	13	5%	426	3%	306	8%	732	4%
Haynesville	70	25%	2,114	14%	835	22%	2,950	15%
Marcellus	69	25%	4,202	27%	903	24%	5,106	27%
Eagle Ford	22	8%	1,559	10%	238	6%	1,796	9%
Other US shale gas plays	24	9%	5,438	35%	102	3%	5,540	29%
US total	276	100%	15,371	100%	3,726	100%	19,097	100%

Production values are extrapolated from average daily production levels. Moreover, unproved resources are estimates for the end of 2010; data for proved reserves rely on recently updated data for the end of 2011.

The already materialized increase in shale gas production has important implications for the US economy. It leads to local and nation-wide benefits in increasing the employment level and wage rates in concerned counties (Weber, 2012), and in reducing energy imports and their burden on national security (Joskow, 2013).

Currently low US natural gas prices driven by the shale gas boom have led to a pronounced shift in the electricity generation mix in the USA.[5] While the share of natural gas in net electricity generation has been below 20% until the mid-2000s, it increased to 34% in July 2012 approaching the share of coal. This short-term shift was possible due to large idle natural gas generation capacity (Lafrancois, 2012). Moreover, it has led to reduced US CO_2 emissions since the emission factor of combusting natural gas is relatively small compared to other fossil fuels, like coal (cf. IPCC, 2006). Therefore, Paltsev et al. (2011), for instance, highlight the role of natural gas as a bridge technology in the US electricity system. Jacoby et al. (2012) show the cost-reducing effect of high usage of natural gas in meeting GHG emission targets. Likewise, Logan et al. (2013) see a cost advantage of natural gas power generation to meet clean energy standards. Finally, Jenner and Lamadrid (2013) highlight the trade-off between coal and shale gas fueled power generation on various dimensions, and conclude with a pro-shale gas development.

However, there is an ongoing debate whether indirect greenhouse gas (GHG) emissions of shale gas extraction and procession are of significant size (cf. Howarth et al., 2011 and 2012; and Cathles et al., 2012). Depending on which well completion technique is used, a large amount of methane, a powerful GHG, may be released during the flow-back phase, before the actual production starts (cf. O'Sullivan and Paltsev, 2012). However, recent EPA regulation requires 'green completion' techniques as of 2015 to reduce GHG emissions such that natural gas can facilitate the transition towards a low carbon energy system. In these considerations future shale gas production necessarily plays an important role.

[5] The average Henry Hub spot market price in 2012 has been below 3$/mmBTU after yearly average prices between 6.5 and 9$/mmBTU from 2005 to 2008 (cf. EIA, 2013d). One mmBTU (Million British thermal unit) approximately corresponds to 28.32 m³ of natural gas.

2.2. Projected US shale gas production and US trade of natural gas

The fast increase in US shale gas production is well reflected in the evolution of official projections. Figure 3 shows the continuous upwards revisions in the EIA projections of shale gas production. Of particular note, where the Annual Energy Outlook 2009 (AEO; EIA, 2009) projects a moderate shale production increase to about 120 bcm by 2030 in its reference case, this level was actually reached in 2010 already.

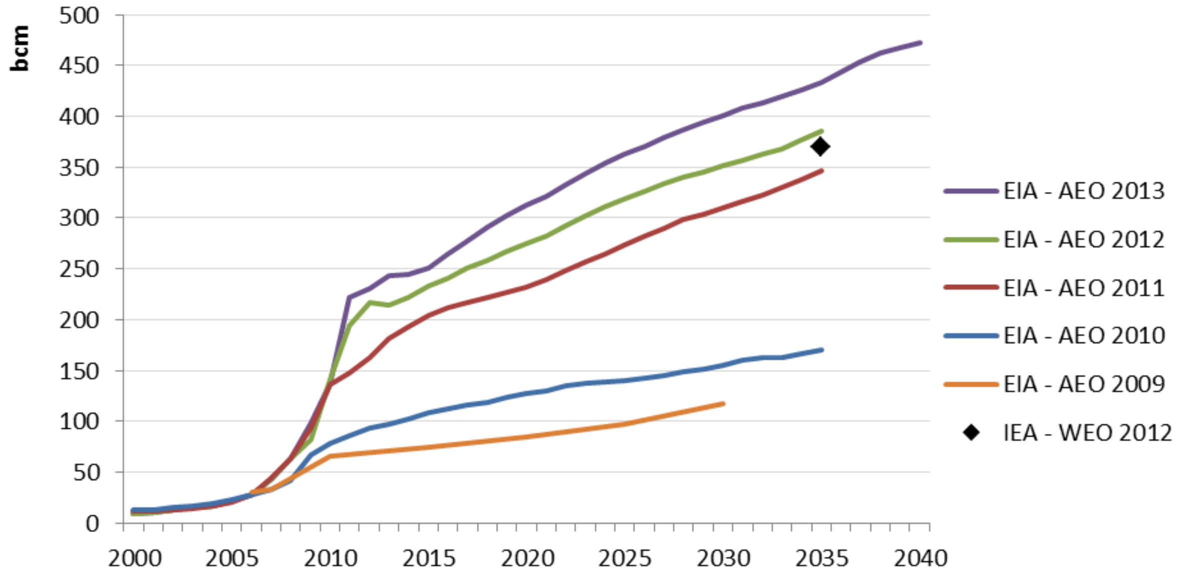

Figure 3: Projected shale gas production in the USA according to the reference cases of the IEA (2012a) and the EIA (2009 – 2013a), in bcm.

In its latest AEO, the EIA (2013a) foresees shale gas production at a level of almost 500 bcm by 2040, i.e. almost twice as high as today. This corresponds to an average annual growth rate of roughly 3% starting in 2011 and leads to a share in total US natural gas production of more than 50% (cf. EIA, 2013a). Together with a stable production level of natural gas from all other types (around 450 bcm), this would ensure that the USA maintains its position as a leading production region. Similarly, the IEA (2012a and 2013b) projects a shale gas production of 370 bcm in 2035 in its World Energy Outlooks (WEO);[6] a value that lies between the levels published in the AEO of 2011 and 2012 (EIA, 2011a and 2012a).

Since consumption increases to a smaller extent, the USA is projected to become a net exporter of natural gas – a view which stands in sharp contrast to previously projected US import needs (see Figure 4). While the USA was once projected to net import almost 250 bcm in the mid-2020s (EIA, 2005), in its latest annual report, the EIA (2013a) sees the USA net exporting LNG as of 2016, and becoming a net exporter of LNG plus pipeline gas as of 2020. For the year 2040, net exports of 100 bcm are envisaged, thereof 41 bcm LNG exports.

[6] This value is not specifically stated in the latest edition of the WEO (IEA, 2013b). However, according to Figure 3.6 in IEA (2013b, p. 118), shale gas production is around 150 bcm higher than in 2011, where it amounts to around 220 bcm (cf. EIA, 2013a).

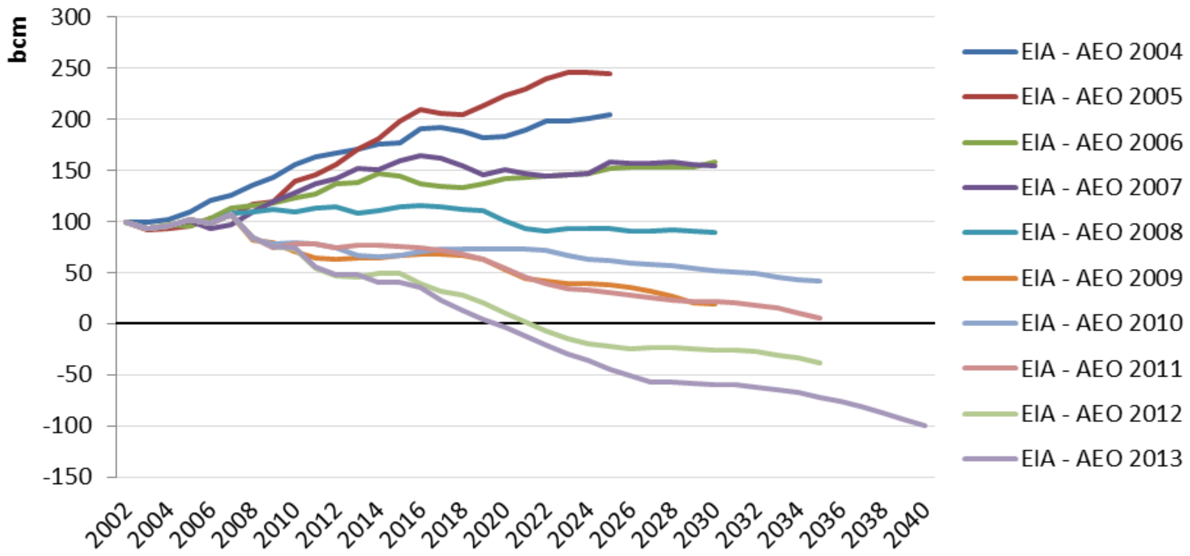

Figure 4: US net trade balance according to projections from various EIA Annual Energy Outlooks (EIA, 2004 – EIA, 2013a), in bcm.

Expectations of future LNG trade flows are crucial in deciding on necessary capacity expansions. This could be well observed in the USA in the mid-2000s. According to Ruester and Neumann (2008, p. 3163) there was a "general consensus that LNG imports will [...] rise as domestic production stagnates and declines, and imports from other sources (Canadian pipeline gas) decline". Hence, in accordance to a projected continuation of this increase in imports (e.g., in EIA, 2004 to EIA, 2008), a substantial investment in the restart and expansion of regasification terminals took place (cf. Jacoby et al. 2012).

Most of this new capacity went online between 2008 and 2010; hence, at a time when LNG imports had already peaked and projections started to change.[7] While the International Energy Outlook 2008 (IEA; EIA, 2008b) still projects a need for LNG imports in the decades to come, the AEO 2009, published only a few months later (EIA, 2009), was the first report forecasting a decline in LNG imports, eventually followed by LNG exports. Since then, projections for net LNG exports have been increased steadily, up to 41 bcm in the most recent AEO (EIA, 2013a). Today regasification terminals have only marginal utilization rates and have never been used close to their maximal nominal import capacity of more than 180 bcm (GIIGNL, 2013).

Similar to the waiting list for regasification terminal approvals by the FERC at that time (Ruester and Neumann, 2008), several companies currently have applications pending for a non-FTA export approval by the DOE today. The Department of Energy (DOE) particularly needs to approve exports to countries with which the USA does not have a free trade agreement (FTA), among these importing countries in Europe or Japan. There is an ongoing discussion on whether it is in the "public interest" to allow large quantities of LNG to be exported.[8] Gains from trade by benefitting from large

[7] Between the late 1990s and 2007, annual US imports were about 100 bcm higher than US exports. Since then US net imports declined to 43 bcm; LNG net imports dropped from 20 bcm in 2007 to no more than 4 bcm in 2012 (cf. EIA, 2013e).

[8] The Natural Gas Act (15 U.S.C. 717b) from 1938 mandates the consistency with public interest of any exportation of natural gas (see http://fossil.energy.gov/programs/gasregulation/2011usc15.pdf, Accessed on October, 25th, 2013). There are no trade export restrictions with those 15 countries that have a free trade agreement with the USA, because exports to them are "consistent with the public interest" by the Energy Policy Act of 1992 (Sec. 201. See http://www1.eere.energy.gov/femp/regulations/epact1992.html, Accessed on October, 25th, 2013). However, among these countries only Singapore has prospects of importing small amounts of LNG.

price differentials (cf. NERA, 2012) stand in contrast with the potential harm from increasing prices on domestic final consumers.

Today all applications sum up to an export liquefaction capacity of more than 340 bcm. Through September 2013, four company applications for a general license have been approved – with a joint export volume of about 68 bcm per year (0.19 bcm/d; DOE, 2013). All of them are going to be converted from regasification to liquefaction facilities. Three of them are located at the Gulf of Mexico: Sabine Pass, Freeport and Lake Charles; one terminal, Cove Point, is planned in Maryland. However, their utilization rates and economic benefits crucially depends on future shale gas production.

3. Critical assessment of current shale gas projections

There are three reasons why it is necessary to consider alternative and thereby less optimistic paths of US shale gas production. First, there is uncertainty in the amount of technically recoverable shale gas resources. Second, it is unclear to which extent US shale gas can be produced economically. Third, public acceptance potentially drops, followed by a tightening of regulation.[9]

3.1. Resource availability

Future production of shale gas crucially depends on the available resource base. However, there is a great variability of shale gas resource estimates across various sources (McGlade et al., 2013). This stems from the fact that large-scale production has started only recently and increased fast. For many plays there is consequently only a short production history that can be exploited for estimation purposes. Furthermore, estimates of the technically recoverable resources (TRR) rely on different approaches.

According to McGlade et al. (2013) there exist three commonly used estimation techniques with their advantages and shortcomings: selective literature reviews, bottom-up analyses and the extrapolation approach. Bottom-up analyses rely on geological expertise and are best used for undeveloped regions as done in the assessment of world shale deposits by ARI (Advanced Resources International, Inc., cf. EIA, 2013b). Variation mainly comes from different estimates of success and recovery factors.

The extrapolation approach in turn is suitable for developed regions where the TRR are estimated by extrapolation of actual production data (as the name of this approach suggests). For instance, the EIA's estimates rely on this approach. For each specific play the EIA calculates the TRR by the product of (1) the potentially usable area for shale gas production, (2) the number of wells per square miles and (3) the average estimated ultimate recovery per well (EUR; cf. EIA, 2013a). The EUR is estimated by fitting a declining curve (e.g., exponential or hyperbolic in form) on historical production data (McGlade et al., 2013). It is thus implicitly assumed that observed characteristics of drilled and producing wells are representative for the total assessed area.

Extrapolation of potential "low-hanging fruits" may lead to an overestimation of the TRR, thoiugh. Shale production has indeed concentrated on the most productive areas and on plays with a high share of NGL like the Marcellus and the Eagle Ford plays (McGlade et al., 2013). Current low

---

[9] Rogers (2011) uses a similar classification to describe the uncertainties of transforming the global unconventional natural gas resources into economic production. He distinguishes three types of risks: geological risk, technology and viability risk as well as regulatory and public acceptance risk.

prices of natural gas intensify this effect (Gülen et al., 2012). Hence, historical production is not representative. To partly compensate for a significant overestimation of the EUR and thereby of the TRR, plays are decomposed into smaller tiers. However, a large uncertainty of the TRR still remains and estimates have changed significantly over time, as can be seen in Figure 5 depicting the estimates published in various editions of the AEO. The latest estimate by the EIA (2013a) amounts to about 18 tcm; 15% are classified as proved.[10]

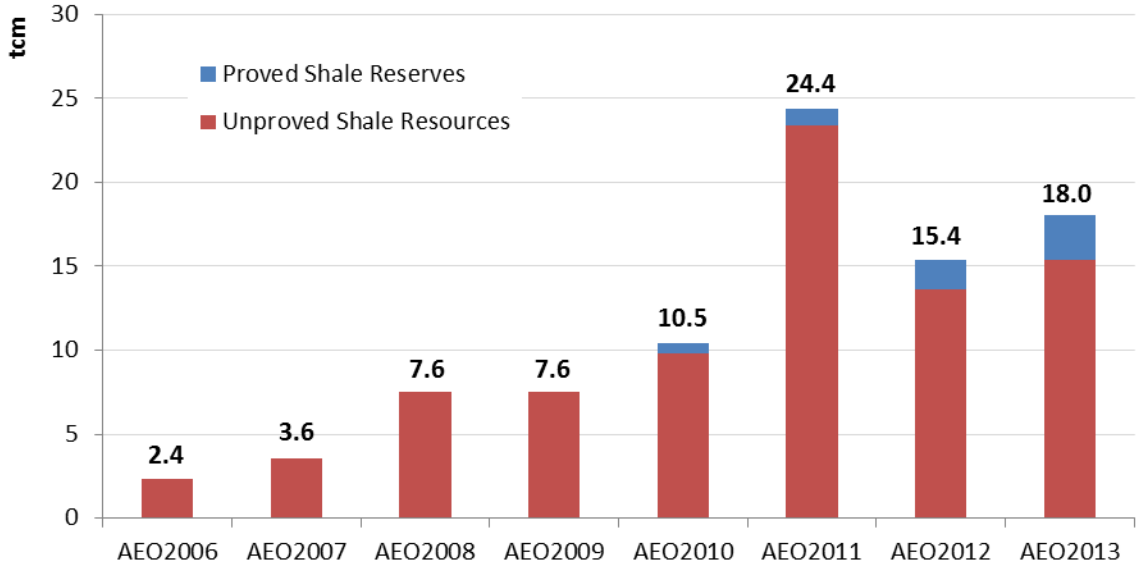

Figure 5: US technically recoverable shale gas resources according to various EIA AEO reports (EIA, 2006 – 2013a), in tcm.

The estimates follow an upward trend, with the AEO 2011 level being an outlier. Nevertheless, it is instructive to look at the reduction from the 2011 to the 2012 edition. This large decrease of unproved resources by 42% is mainly explained by the devaluation of the Marcellus basin by more than 7 tcm or 65% to only 4 bcm. With about 27% of total unproved US shale resources (EIA, 2013a) the Marcellus shale play is the largest play in the United States and its estimated level is crucial for the total US shale TRR. It is noteworthy that this reduction in TRR is not due to a significant change in the EUR, but the consequence of a reduction in both the assumptions on the potential land use and the well density. While the assumed value for the former has been reduced by a third from more than 30 thousand square miles to about 20 thousand, the number of wells per square miles has been reduced from 8 to 4.9. McGlade et al. (2013) point out that in addition the assumption of the EUR per well is 68% higher compared to the USGS estimate, with all other assumptions being equal. The USGS mean TRR estimate for the Marcellus plays is thereby smaller than 2.5 tcm.

Besides the extrapolated unproved resources, the values of proved reserves cannot be taken for granted. Notably, they are gathered from company reports to the SEC (Securities and Exchange Committee) and the EIA. Weijermars and McCredie (2011) argue that the reported reserve levels may be overstated due specificities of the SEC accounting rules. Many wells are only recently drilled and the lack of experience potentially leads to a wrongly estimated life-cycle productivity and total production possibilities. Furthermore, companies have an incentive to over report their reserve base to increase the company's value and ensure lower capital costs.

In conclusion, TRR are potentially overestimated due to the extrapolation from non-representative production history. Moreover, there is particular uncertainty regarding the well

[10] This corresponds to 2.7 tcm of proved shale gas reserves. The latest revision of proved reserves for the end of 2011 is 3.7 tcm (EIA, 2013c). The MIT (2011, pp. 30-32) lists US shale resource estimates in the range between 12 to 24 tcm. In comparison, total US natural gas resources are estimated at 52 tcm (DERA, 2012).

spacing as well as the size of potential land to be used for shale gas production. On the other hand it should be noted that TRR estimates disregard any technological progress (McGlade et al., 2013). Using longer horizontal wells or multi-lateral horizontal drillings may increase the recoverability of resources in the future (MIT, 2011).

3.2. Economic considerations

In its reference case, the EIA (2013a) projects a cumulative shale gas production of 10.7 tcm in the period from 2011 to 2040. This projected production path is supported by the estimated TRR—at least technically, if not economically. It is a highly optimistic projection, though, given the share of roughly 60% of the current TRR estimate to be extracted until 2040, or put differently a cumulative production almost three times as large as currently proved reserves. In general, TRR estimates represent the technically, but not economically recoverable resources. Depending on the relative cost structures between producing areas, other deposits of the abundant worldwide natural gas resources may be developed earlier.

Production costs of shale gas production largely depend both on the productivity of a specific tier of a play, and on the share of liquids, the condensate ratio (MIT, 2011). Estimated break-even prices start as low as 0.55$/mmBtu for shale gas with a high share of liquids in the most productive areas of the Barnett shale generating a 10% return (Gülen et al., 2013). A large share of US shale production is only profitable at prices at least as high as 4 to 8$/mmBtu, though (MIT, 2011). Gülen et al. (2013) show that less productive tiers of the Barnett shale play are only economically extractable at prices well below this range.

In essence, short-term factors can explain high shale gas production despite current low prices. First, production takes place at the most productive shale plays, or at play that contain large amounts of liquids, making a production more attractive in times of high NGL and oil prices (Gülen et al. 2013); hence, the current shift towards the Marcellus and Eagle Ford plays.

Furthermore, costs are sunk for many wells drilled in the last years. These cannot be kept idle for a long time due to state regulation (cf. Richardson et al., 2013), and thus production continues. For instance, the state of Texas permits an idle time of 12 months but no further temporary abandonment. Finally, we follow the reasoning of Holahan and Arnold (2013, p. 130) in arguing that US land-lease requirements advance drilling effort on a too high level; they speak of an "over-capitalization of drilling operations". A common pool problem can be observed, due to geological characteristics of shale formations, e.g., the low basin pressure and the observation that shale formations are often thin layers over long horizontal distances. Current developments are beyond what could have been expected but these short-term substantial production increases could be followed by a plateau, or worse, by a long-term decline.

High shale gas production cannot be maintained at current low prices that can partly be observed already. On the one hand, drilling activity is low (EIA, 2013g), which will eventually be followed by lower production rates, all other things being equal. On the other hand, it is observed that firms active in well drilling and shale gas production make losses that cannot be compensated for a long time (Hughes, 2013). Apparently, market participants expect a shift to higher cost tiers in the next years, as is suggested by Henry Hub forward prices of more than 6$/mmBtu for the early 2020s.[11]

[11] Henry Hub forward prices have been retrieved at http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_settlements_futures.html. Accessed on November 13, 2013.

In sum, there are explanations of the maintained high shale gas production despite current low prices. However, these are short-term factors and prices need to be sufficiently high to maintain large future shale gas production. Hence, US shale gas production may lose its comparative costs advantage to natural gas supply from conventional sources in other world regions.

3.3. Public acceptance and regulation

A large number of shale gas wells will have to be drilled, affecting a large area of land, in order to reach the projected production level by the EIA (2013a). Even to maintain a certain production level requires heavy drilling due to the fast declining production per well (MIT, 2011). Hughes (2013) estimates that more than 7,000 wells need to be drilled each year just to maintain the current level of US shale gas production. To reach the projected production levels, up to 360,000 shale gas producing wells are needed between 2011 and 2040. This assumes the weighted average EUR of 30 mcm per well across all fields in the USA of the latest EIA (2013a) unproved resource estimates. Due to observed fast declining rates of shale gas fields (cf. MIT, 2011) these wells have to be almost completely newly drilled. In comparison, roughly 7,000 shale gas wells have been drilled in 2011 (API, 2013). Moreover, assuming a number of well per square miles of around 4 to 8, this corresponds to an area affected in the range of 45,000 to 90,000 square miles (118,000 to 235,000 km²). This is equivalent to the size of Ohio, or Minnesota respectively. It is questionable whether such large numbers of well drillings and land usage can be attained despite a potential fall in public acceptance, and strengthening of regulation.

Shale gas production has adverse effects, particularly on society and the environment. During drilling and well completion, the drilling site of around 16,000m² for a single well (MIT, 2011) changes to a “heavy industry site” (Kerr 2010b, p. 1625). For a single well around 1,000 truck journeys are necessary to bring the equipment and material to the site (MIT, 2011), associated with traffic, noise and emissions (Zoback et al., 2010). This particularly includes transportation of water for drilling and fracking that is needed in large quantities (Soeder and Kapper, 2009). Depending on the play around 11 to 15 million liters of water are used per well (NETL, 2009). While the MIT (2011) argues that on a per energy level these are comparably low amounts, Jenner and Lamadrid (2010) show that shale gas only has a lower water-intensity over the lifecycle than coal when including combustion for electricity generation. The NETL (2009) points out that the water for shale gas production is required during a short time period before production takes places, which may cause stress for local water supply. Furthermore, it is unclear how much water will return to the surface and can be recycled. EPA (2012) gives a broad range from 10 to 70% of the injected fluid to be recovered, with only a small share within the first 30 days (e.g., 8 to 12% at the Marcellus play).

There is a non-negligible risk of contamination of drinking water (cf. NETL, 2013 or Vidic et al., 2013). Osborn et al. (2011) relates methane contaminations in aquifers within the Marcellus paly region to natural gas extraction and in particular the use of hydraulic fracturing. By contrast, Davies (2011) points out that a causal link between fracking and water contamination remains unproven. Although rare, methane leakage can occur due to insufficient casing, i.e. inadequate cementing, of gas wells (Vidic et al., 2013). A higher risk of drinking water contamination is associated with the potential spill of chemicals used for hydraulic fracturing and of the fracking fluid coming back to the surface, possibly including ‘naturally occurring radioactive material’ (NORM; NETL, 2009). According to EPA (2012) about 1,000 different chemicals used for fracking have been identified that need to be treated or injected underground.

Moreover, in line with resource availability, shale gas production eventually shifts to more densely populated regions than those where current production takes place. Figure 6 relates the population density at the county level to the location of shale gas basins and plays. In contrast to producing plays in the US Southwest or Central, the Marcellus field, in particular, is located in a more densely populated area. Local adverse effects consequently become more present in areas which are additionally less accustomed to oil and natural gas production and where infrastructure of wastewater treatment or underground injection is less available.

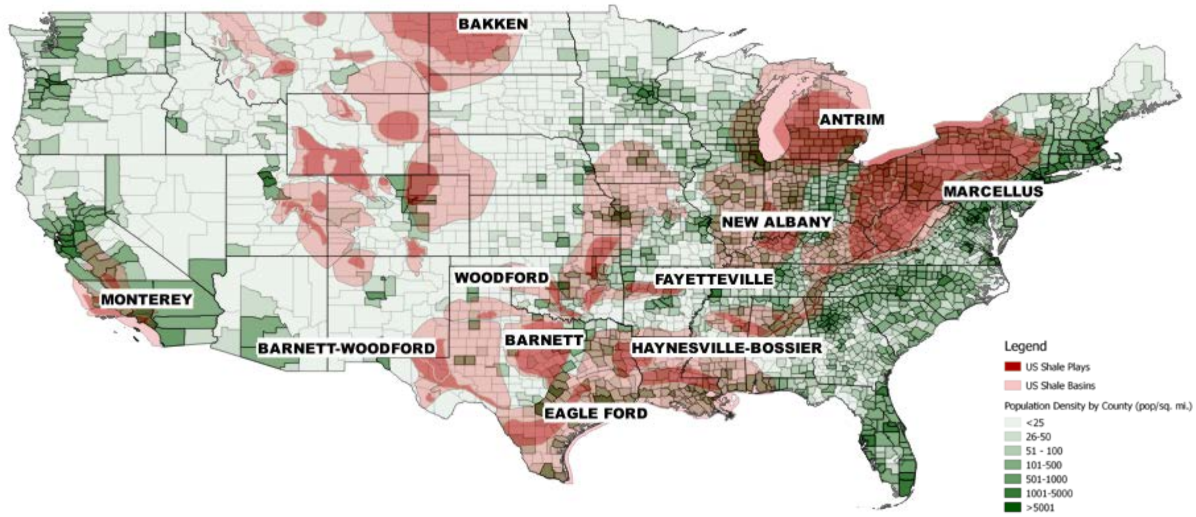

Figure 6: Population density and shale gas plays in the US. Own illustration; calculations of population densities based on Census 2010 data; locations and shapes of shale basins and plays provided by the EIA, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm.

Regulation is under review and is likely to be adjusted to the special characteristics of shale gas. The IEA (2012b) addresses environmental concerns by defining a set of "golden rules" whose implementations can lower the local environmental footprint and accommodate the increase in unconventional natural gas production. According to Jacoby et al. (2012, p. 43) "tightening of regulatory standards is likely in some states", presumably in the Marcellus play areas (Kerr, 2010b). Changes in regulation can already be observed in some states that tends to get more stringent (Richardson et al., 2013). For instance, the well density is reduced in Pennsylvania and New York by regulating the distance of one well to another, to populated areas or to aquifers (Holahan and Arnold, 2013). Assuming an expiration of the New York state moratorium on fracking, there is still an increasing number of municipalities having bans (64 municipalities) or moratoria (109) for fracking in place.[12]

For instance, Blohm et al. (2012) argue that current land usage patterns and state regulations are not sufficiently taken into account in the estimate of potential area for shale production. Conducting a detailed analysis of local policies including bans and moratoria at the community level, they conclude that large areas of the Marcellus play in New York (84%) and Pennsylvania (31%) are unavailable for shale gas extraction. Similarly, Rogers (2011, p. 133) argues that "[a] 'sweet spot' of the Marcellus shale—the Delaware river watershed […] that provides drinking water for 17m people […]—is virtually off-limits to drilling at present". It is unclear, though, to which extent these restrictions at the local level are already taken into account by the EIA (2013a) regarding the assumptions on potential land area and well density. On the other hand, technological progress may reduce water and land use and further increase the number of drilled wells per rig. But the upper limit of wells per hole seems to be reached already (Weijermars and McCredie, 2011, p. 37).

[12] See http://www.fractracker.org/maps/ny-moratoria/, accessed on October 20, 2013.

In sum, regulatory changes obviously have an increasing effect on supply costs of shale gas production, and tend to reduce the resource availability. Or put differently, "[a]ny adverse change in the generally favourable regulatory and operating environment in the United States could have a material impact on the outlook for unconventional gas production" (IEA, 2013b, p. 118). Hence, taking the critical assessment into account, in the following section, two alternative scenarios are derived that depart from the optimistic projections for US shale gas production. These should not be read as forecasts but rather as "what-if-analyses". They particularly serve to investigate the implications for international trade of natural gas and subsequent infrastructure expansions.

4. Modeling a less optimistic development of US shale gas production

4.1. The Global Gas Model and its Base Case

Implications of alternative production paths are investigated by means of a partial equilibrium model of the natural gas sector. The Global Gas Model (GGM; Egging, 2013) simulates natural gas production, consumption and trade patterns and determines infrastructure needs to accommodate these (for an application see Holz et al., 2013). The entire value chain of the natural gas sector is modeled by representative profit maximizing agents, namely producers, traders, transmission and storage system operators (TSO and SSO). Moreover, seasonality and market power exertion by selected traders is included. One distinguished feature is the endogenously determined capacity expansions of storage and transportation infrastructure. The model is set up as a mixed complementarity problem (MCP; cf. Facchinei and Pang 2003) and solved using the PATH solver by means of the software GAMS (Ferris and Munson, 2000). For a detailed model description in a stochastic framework we refer to Egging (2013).

The GGM database consists of information for 98 countries (represented by 119 nodes) regarding reference consumption and prices, production capacities and costs as well as current capacities of storage and the transportation network.[13] Model results are reported in 5 year steps until 2040, based on the starting year 2010. The "Base Case" has been calibrated to match the New Policy Scenario (NPS) of the WEO 2012 (IEA, 2012a). Here, current climate and energy policies are taken into account and are supplemented by an assumed moderate implementation of plans and initiatives. This scenario can thus be characterized as a moderate climate scenario with climate policies concentrating in Europe respectively OECD countries, where emissions in 2035 decrease to about 30% (7%) below the 1990 level, though. Global emissions are still on an increasing path reaching a level 77% above the 1990 value. While the optimally determined fuel mix is taken from IEA (2012a), the GGM detailed look at trade flows and infrastructure expansions.

In line with the NPS, the GGM Base Case is characterized by an increase in world natural gas consumption of about 60% between 2010 and 2040. Consumption increases in all world regions but the rise is particularly pronounced in non-OECD countries and heavily driven by Asia Pacific. Production further increases in North America, keeping its leading position, and increases sharply in Asia Pacific, though, not as fast as consumption. Hence, imports are increasingly directed towards Asia Pacific that becomes by 2025 the largest consumption region. As of 2020, the USA becomes a net exporter of natural gas with moderate volumes of around 50 bcm in 2040.

[13] We use data from various, mainly public sources. Among others the IEA, the EIA, GIIGNL, national statistics offices, company reports as well as the European Network of Transmissions System Operators for Gas (ENTSOG).

Natural gas production from unconventional sources is inherent in the NPS results (cf. IEA 2012a, p. 142). About 25% of the global production in 2035 is projected to originate from unconventional sources, half of it from shale formations largely extracted in the USA (370 bcm). The projected shale gas production path, however, is not published but can be deduced by interpolation in line with EIA (2012a). According to the NPS (IEA, 2012a) shale production plays a non-negligible role also in China (90 bcm) and Canada (60 bcm). Particularly in the former, production of CBM and tight is more important; likewise, in Australia and Russia.

4.2. Scenario assumptions

The first scenario, "Constant Shale", assumes a constant shale gas production after 2015, i.e. a shale gas production level of 224 bcm throughout the remaining model horizon.[14] This scenario serves as an intermediate between the Base Case and the second scenario, "Low Shale". The latter is constructed in line with a fast declining rate of shale production as of 2015, following EWG (2013), both the production level and the transition phase differ, though. In both shale gas scenarios, US production of conventional, tight natural gas and CBM is kept at the same levels as in the Base Case. In addition, changes in natural gas production outside the USA, and consumption levels in all countries are determined endogenously.

Figure 7 depicts total US natural gas production for the three GGM scenarios in comparison to two recent EIA (2013a) scenarios—the reference case and a low (EUR) gas scenario. While our Base Case is in line with recent optimistic projections of shale gas production (see also Figure 3), the two alternative shale scenarios deviate considerably. Both result in a declining production path - as of 2020 in Constant Shale and after 2015 in Low Shale. In the latter the production level in 2040 is less than half the level of the EIA (2013a) reference case.

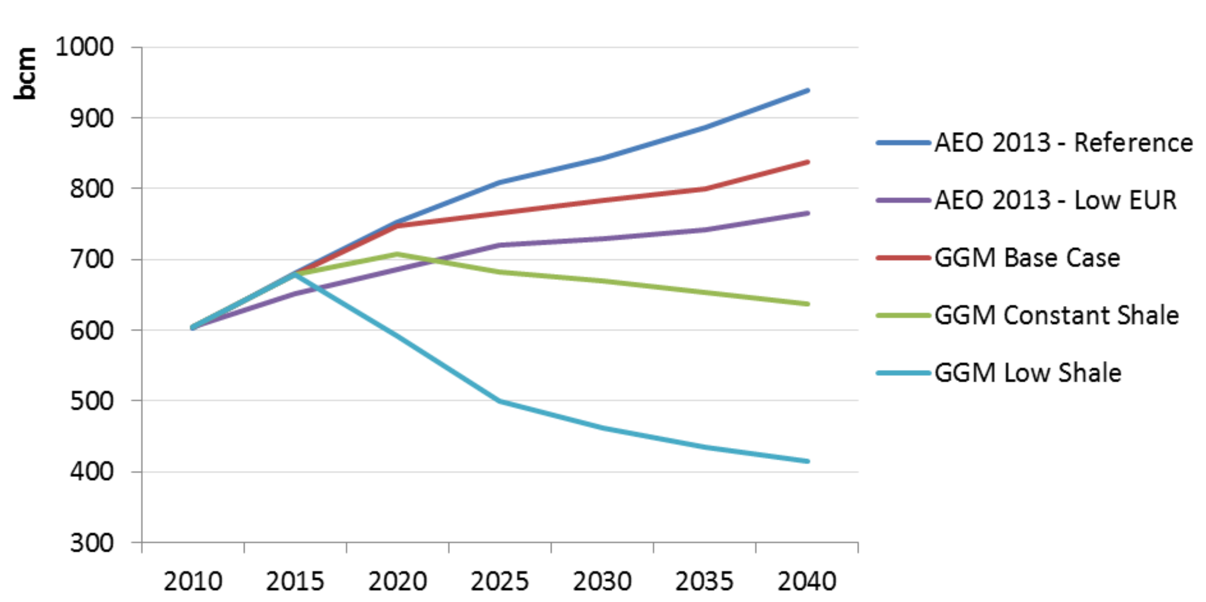

Figure 7: US total natural gas production – comparison between EIA (2013a) results and GGM modeling assumptions, in bcm

The GGM data base decomposes the USA in ten regions according to the US census division (see Table 2). In order to get an accurate picture, the regional paths of shale production have to be extrapolated. This has been done by using the information on current regional shares in shale gas

[14] This value comes from the interpolated path for the WEO 2012 and lies between projected levels of AEO 2011 and 2012 (EIA, 2011a and 2012a). However, the actual production was already higher in 2012.

production, and in the US technically recoverable shale resources. A long-term convergence of production shares towards TRR shares is assumed.

Table 2: US regional shares of shale production, and technically recoverable shale resources. Own calculations based on EIA (2013f, 2013a and 2013c).

Census Division	States included	Shale Gas Production in 2010	US TRR of Shale
New England	CT, ME, MA, NH, RI, VT	0.0%	0.0%
Middle Atlantic	NJ, NY, PA	7.4%	14.8%
East North Central	IL, IN, MI, OH, WI	2.2%	20.0%
West North Central	IA, KS, MN, MO, NE, ND, SD	1.2%	0.5%
South Atlantic	DE, DC, FL, GA, MD, NC, SC, VA, WV	1.5%	4.1%
East South Central	AL, KY, MS, TN	0.1%	2.3%
West South Central	AR, LA, OK, TX	87.1%	51.1%
Mountain	AZ, CO, ID, MT, NV, NM, UT, WY	0.4%	5.4%
Pacific	CA, OR, WA	0.0%	1.9%
Alaska	AK	0.0%	0.0%

In 2010, most of the shale gas production, around 90%, took place in US West South Central, including the Barnett, Haynesville and Eagle Ford plays, while this region accounts for about half of US shale TRR. On the other hand, US Middle Atlantic and East North Central have higher shares in US shale resources, including parts of the Marcellus and Devonian plays, compared to their 2010 production shares. According to the assumed convergence process, relative production, for instance, expands in these regions and contracts in West South Central.

4.3. The effects of alternative US shale gas developments

A reduced US natural gas production, relative to the Base Case, leads to three partial effects. First, US consumption of natural gas is lower compared to the Base Case. Second, the international patterns of trade in natural gas are changed; flows may be diverted towards the USA and lead to lower consumption levels in other world regions. Third and finally, production levels outside the USA increase, partly offsetting the drop in US production.

While by construction US production differs substantially across scenarios, the resulting consumption levels are less affected. In Figure 8 one can see that in the Constant Shale scenario consumption hardly declines from its 2020 high level and stays above 700 bcm, although production levels continue to fall. In contrast to the Base Case, the USA relies on imports to satisfy future demand levels. Even in the more extreme Low Shale scenario, consumption values stabilize. They reach a level of around 620 bcm and tend to increase after 2030, despite the fast decline in natural gas production. In both cases, one can speak of a decoupling between production and consumption levels. Instead of being a net exporter as in the Base Case, US imports substantially increase to more than 200 bcm in 2040 in Low Shale, thereof 118 bcm by LNG imports.

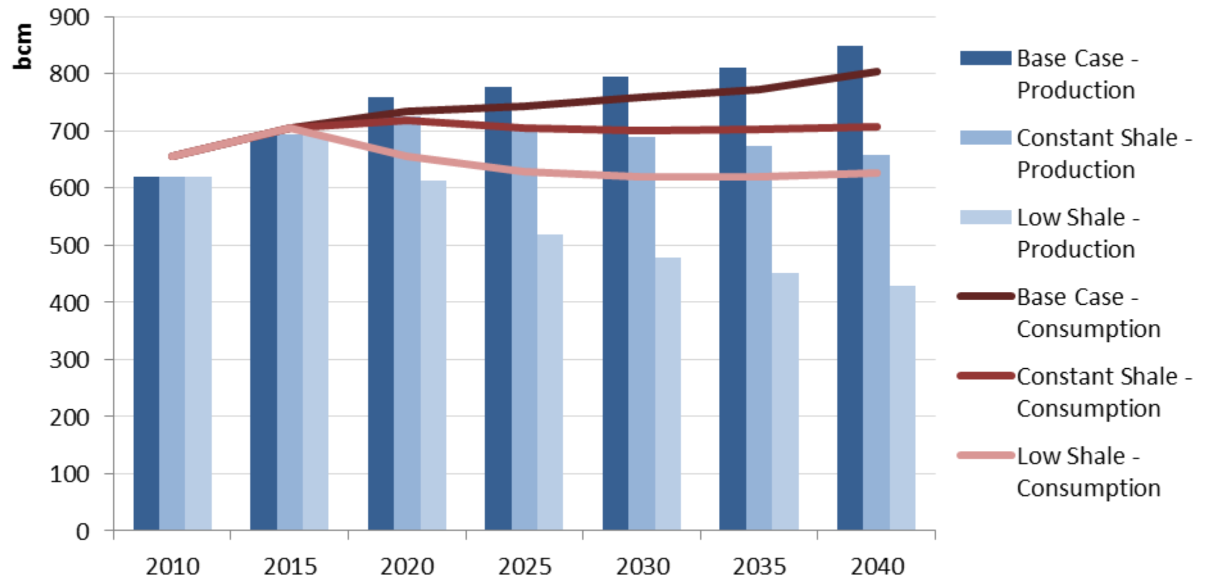

Figure 8: Consumption and production paths in the US by scenario, in bcm.

Hence, only a part of the production difference between the two reduced shale scenarios and the Base Case is borne by a reduction in US consumption levels. For instance, in Low Shale, although US production in 2040 is 420 bcm lower than in the Base Case, consumption only is 179 bcm below the reference value. In Figure 9 the effect of the reduced US production relative to the Base Case is decomposed in the three described partial effects. Overall, the combined reduction in US and non-US consumption largely dominates the increase in the production outside the USA.[15] In Low Shale, production outside the USA in 2040 is 59 bcm higher than in the Base Case. This increase mainly comes from only a few countries, namely Canada, Qatar, Nigeria and Algeria. Russia, in contrast, cannot significantly increase its production due to reference production close to capacity limits. Nevertheless, by reducing its domestic consumption it can increase its exports.

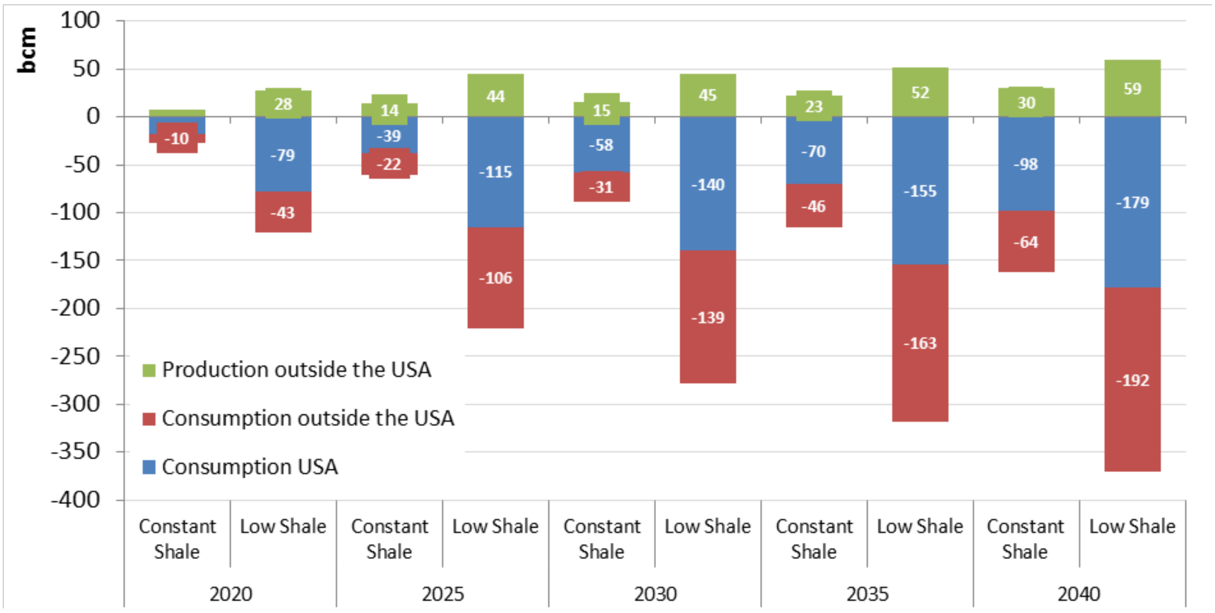

Figure 9: Decomposition of the impact of reduced US production relative to the Base Case, in bcm.

15 The relatively small adjustments in production levels outside the USA are partly due to the model construction. Since the GGM version used for this paper does not feature endogenous investments in production capacity, restrictions made for the Base Case are also effective in the shale gas scenarios.

In Constant Shale, the reduction in US consumption (relative to the Base Case) is always larger than the fall in consumption levels outside the US. Interestingly, this does not hold for the Low Shale scenario. As of 2035, the difference to the Base Case consumption is more pronounced in the rest of the world than in the US (e.g., 192 bcm compared to 179 bcm in 2035). Hence, consumption is significantly diverted towards the US. This hints to a sizeable shift in the international trade of natural gas.

One can distinguish different reasons for the lower than Base Case levels of consumption outside the USA. Each can best explain the situation for some of the affected countries. First, there is a direct effect of lacking US exports relative to the Base Case. This particularly affects Mexico. In Low Shale, US exports by pipeline are reduced over time and phased-out as of 2035, whereas in the Base Case exports reach a level of 30 bcm in the same period. Second, export countries which cannot unlimitedly increase their production levels, are characterized by lower consumption levels to earn profits from higher exports. In particular Canada and Russia fall in this category. In Russia, consumption in 2040 is about 40 bcm lower in Low Shale relative to the Base Case in order to sustain an increase in LNG exports towards North America of the same order. Finally, there is an increasing competition for internationally supplied natural gas, mainly LNG, due to the increasing import needs of the USA and the high US willingness to pay for natural gas. For instance, China’s LNG imports in 2040 are roughly 20 bcm lower in Low Shale than in base (but still a lot higher than in 2010). Although this is partly balanced by increased pipeline imports from the West (Russia, Uzbekistan and Kazakhstan), Chinese natural gas consumption increases on a slower path in the setting of low US shale gas production.

The global volume of traded LNG is largest in the Low Shale scenario. Compared to the Base Case, the LNG export volume is by about 75 bcm higher in 2040 despite fewer LNG exports from North America. In addition, trade flows are altered, which is depicted in Figure 10.[16] North America becomes a major importing LNG region next to ASP and Europe.[17] Both, US and Canadian LNG exports to Europe and Japan that are present in the Base Case cease to exist. In total, US LNG imports, coming from Africa (Nigeria and Algeria), South America (Venezuela and Trinidad & Tobago) and from Russia, reach a level of more than 100 bcm in 2040. Although total US LNG import capacity is sufficiently available in size, it is regionally concentrated in the southern parts of the USA (Gulf Coast). Hence, small expansions of regasification facilities take place in the North East.

Figure 10 also shows that exports from Australia, Russia and the Middle East to Asia are stable across scenarios. By contrast, a significant part of African exports is redirected towards North America. Similarly, the main destination of exports from South America is shifted from Europe to the USA. Russia more than doubles its LNG exports, with 40 bcm directed to North America.

[16] Note that LNG trade flows are calculated based on the optimal behavior of all agents. Long-term contracts are not included.

[17] Australia as LNG exporting country has been separated in Figure 10 from ASP for illustrative reasons.

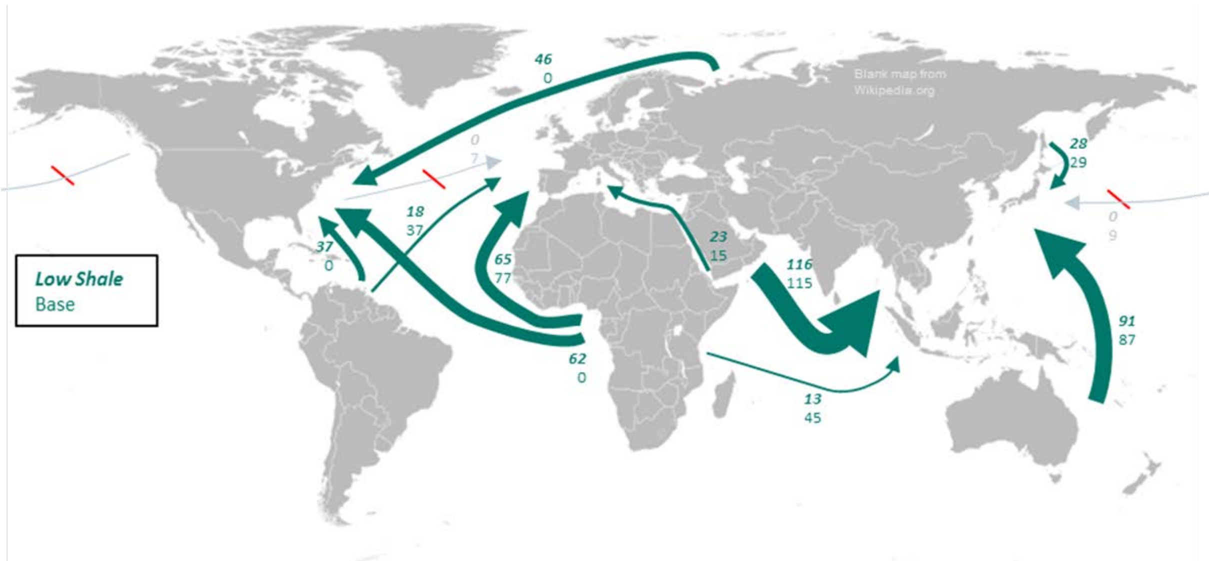

Figure 10: LNG trade flows in 2040 by region in the Low Shale scenario. The arrow sizes correspond to scenario results, which are given by the bold figures next to the respective arrow in bcm. Note, Australia is separated from ASP for illustrative reasons.

Both in Europe and in Asia, there are tendencies to balance the reduced LNG imports by pipeline imports from neighboring regions. The EU 27 imports 30 bcm less LNG. However, total imports are only reduced by 17 bcm due to more imports via Turkey mainly from the Middle East, leading to additional pipeline expansions. China, in turn, is also an interesting case of regional balancing tendencies. As reduced LNG imports (by 20 bcm in 2040 relative to the Base Case) mainly affect the South East, regional pipeline flows are changed to balance consumption. More pipeline imports from Russia and the Caspian region arrive in China West and the North East. Subsequently, the flow from China West is increased to the South Eastern parts via China South West. Here an additional pipeline expansion is necessary to sustain the increased intra-country flow.

Worldwide pipeline expansions are (by 2.5%) marginally higher than in the Base Case mainly due to the described expansions towards central Europe and major consumption regions in Asia in response to lower LNG imports. On the other hand, no pipeline expansion from the USA towards Mexico is needed in the Low Shale scenario compared to a small expansion of 5.2 bcm in the Base Case. Moreover, cumulative expansions of regasification capacity until 2040 are virtually the same in all scenarios. However, as the trade flows indicate, 40 bcm of expanded capacity are shifted from Europe (NLD, POL) and Asia Pacific (CHN, THA) towards North America in Low Shale relative to the Base Case.

In conclusion, the analysis has shown the importance of US shale production for future global natural gas markets and trade flows. A lower than expected US production does not only lead to a reduced domestic consumption but substantially changes trade flows and infrastructure expansions. Notably, the currently discussed construction of large LNG export capacities would be obsolete when shale gas production does not continue its rise. Even when future shale gas production is maintained at current levels, export facilities are not necessary at a large scale.

5. Conclusions

US natural gas production has grown substantially between 2005 and 2012. This increase is driven almost entirely by the production of shale gas which recently becomes economically extractable at large-scale. Projected future production levels have followed this development and have become more and more optimistic every year.

However, there are at least three reasons that hint to a cautious evaluation of future US natural gas production. First, estimates of US shale resources are highly uncertain. In particular, assumptions on the potential land area usable for shale gas production, the well spacing and the productivity per well are controversial but crucial. Second, these estimates describe the technical potential, and are not an economic evaluation. Recently projected production levels can indeed be sustained by the - currently estimated - resource base but may not be economically. Finally, future high shale gas production may be impeded by a reduced public acceptance and strengthened regulation. Ever more wells will have to be drilled accompanied by adverse environmental effects. Moreover, regulation directly affects technically recoverable resources and future production possibilities, as far as well spacing and the potential area of extraction are concerned.

This paper has discussed these arguments and has subsequently investigated the implications of a less optimistic development of shale gas production in the USA by means of a numerical simulation. Natural gas production outside the US can only partly compensate for lower US shale gas production levels. However, instead of bearing the total reduction in domestic production, US consumption stabilizes by attracting an increasing amount of imports, while consumption in other countries will be lower than in the Base Case. LNG trade flows from South America and Africa are redirected towards the USA, while Asia Pacific and Europe have to rely on pipeline imports to a larger extent.

In particular the investment choice of liquefaction and regasification facilities is heavily influenced by the future US shale gas production. In contrast to the current debate on US export capacity needs, the US LNG import infrastructure in place will be utilized, and may even be extended if shale gas production cannot meet the hopes pinned on it.

References

API (American Petroleum Institute). 2013. Investment in U.S. shale well drilling surges in 2011. http://www.api.org/news-and-media/news/newsitems/2013/april-2013/investment-in-us-shale-well-drilling-surges-in-2011. Accessed on September 4th, 2013.

Blohm, A., Peichel, J., Smith, C. and A. Kougentakis. 2012. The Significance of regulation and land use patterns on natural gas resource estimates in the Marcellus shale. Energy Policy no. 50: 358-369. doi: http://dx.doi.org/10.1016/j.enpol.2012.07.031

Cathles, Lawrence M. III, Larry Brown, Milton Taam, and Andrew Hunter. 2012. "A commentary on The greenhouse-gas footprint of natural gas in shale formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffea. Climatic Change no. 113 (2): 525-535. doi: 10.1007/s10584-011-0333-0.

Davies, Richard J. 2011. Methane contamination of drinking water caused by hydraulic fracturing remains unproven. Proceedings of the National Academy of Sciences no. 108 (43): E871. doi: 10.1073/pnas.1113299108.

DERA. 2012. DERA Rohstoffinformation. Energiestudie 2012. Reserven, Ressourcen und Verfügbarkeit von Energierohstoffen. BGR, Hannover.

DOE (US Department of Energy). 2013. Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of August 19, 2013). Washington, DC. http://energy.gov/fe/downloads/summary-lng-export-applications. Accessed on September 10th, 2013.

Egging, Ruud. 2013. Benders decomposition for multi-stage stochastic mixed complementarity problems – Applied to a global natural gas market model. European Journal of Operational Research 226: 341-353.

EIA (US Energy Information Administration). 2004 – 2010. Annual Energy Outlook. Various editions. EIA, US Department of Energy. Washington, DC.

EIA. 2011a. Annual Energy Outlook 2011. EIA, US Department of Energy. Washington, DC.

EIA. 2011b. World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States. EIA, US Department of Energy. Washington, DC.

EIA. 2012a. Annual Energy Outlook 2012. EIA, US Department of Energy. Washington, DC.

EIA. 2012b. Effect of Increased Natural Gas Exports on Domestic Energy Markets. EIA, US Department of Energy. Washington, DC.

EIA. 2013a. Annual Energy Outlook 2013. EIA, US Department of Energy. Washington, DC.

EIA. 2013b. Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States. EIA, US Department of Energy. Washington, DC.

EIA. 2013c. US Crude Oil and Natural Gas Proved Reserves. EIA, US Department of Energy. Washington, DC.

EIA. 2013d. Henry Hub Gulf Coast Natural Gas Spot Prices. http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm. Accessed on September 20th, 2013. EIA, US Department of Energy. Washington, DC.

EIA. 2013e. US Natural Gas Imports by country / US Natural Gas Exports by country. http://www.eia.gov/naturalgas/data.cfm#imports. Accessed on September 10th, 2013. EIA, US Department of Energy. Washington, DC.

EIA. 2013f. Shale Gas Production. http://www.eia.gov/dnav/ng/ng_prod_shalegas_s1_a.htm. Accessed on October 20th, 2013. EIA, US Department of Energy. Washington, DC.

EIA. 2013g. Natural Gas Weekly Update (for week ending November 6, 2013). Daily Dry Shale Gas Production by Play. http://www.eia.gov/naturalgas/weekly/. Accessed on November 13th, 2013. EIA, US Department of Energy. Washington, DC.

EPA (US Environmental Protection Agency). 2012. Study of the Potential Impacts of Hydraulic fracturing on Drinking Water Resources. Progress Report. US Environmental Protection Agency, Office of Research and Development. Washington, DC

EWG (Energy Watch Group). 2013. Fossil and Nuclear Fuels – the Supply Outlook. Berlin.

Facchinei, F. and J.-S. Pang. 2003. Finite-Dimensional Variational Inequalities and Complementarity Problems. Vol. 1 and 2, Springer, New York.

Ferris, M.C. and T.S. Munson. 2000. Complementarity Problems in GAMS and the PATH Solver. Journal of Economic Dynamics and Control no. 24 (2): 165-188.

Gao, Fan. 2012. Will There Be a Shale Gas Revolution in China by 2020? Working Paper NG 61. The Oxford Institute for Energy Studies.

GIIGNL (International Group of LNG Importers). 2013. The LNG Industry in 2012. Paris.

Gülen, Gürcan, John Browning, Svetlana Ikonnikova, and Scott W. Tinker. 2013. Well economics across ten tiers in low and high Btu (British thermal unit) areas, Barnett Shale, Texas. Energy no. 60 (0): 302-315. doi: http://dx.doi.org/10.1016/j.energy.2013.07.041.

Holahan, Robert, and Gwen Arnold. 2013. An institutional theory of hydraulic fracturing policy. Ecological Economics no. 94: 127-134. doi: http://dx.doi.org/10.1016/j.ecolecon.2013.07.001.

Holz, Franziska, Philipp M. Richter, and Ruud Egging. 2013. The Role of Natural Gas in a Low-Carbon Europe: Infrastructure and Regional Supply Security in the Global Gas Model. DIW Discussion Paper 1273. Berlin.

Howarth, Robert W., Renee Santoro, and Anthony Ingraffea. 2011. Methane and the greenhouse-gas footprint of natural gas from shale formations. Climatic Change no. 106 (4): 679-690. doi: 10.1007/s10584-011-0061-5.

Howarth, Robert W., Renee Santoro, and Anthony Ingraffea. 2012. Venting and leaking of methane from shale gas development: response to Cathles et al. Climatic Change no. 113 (2): 537-549. doi: 10.1007/s10584-012-0401-0.

Hu, Desheng, and Shengqing Xu. 2013. Opportunity, challenges and policy choices for China on the development of shale gas. Energy Policy no. 60: 21-26. doi: http://dx.doi.org/10.1016/j.enpol.2013.04.068.

Hughes, J. David. 2013. A Reality Check on the Shale Revolution. Nature no. 494: 307-308. doi: http://dx.doi.org/10.1038/494307a.

IEA (International Energy Agency) 2011. Are We Entering a Golden Age of Gas? Special Report. World Energy Outlook 2011. OECD/IEA, Paris.

IEA. 2012a. World Energy Outlook 2012. OECD/IEA, Paris.

IEA. 2012b. Golden Rules for a Golden Age of Gas – World Energy Outlook special report on unconventional gas. OECD/IEA, Paris.

IEA. 2013a. Medium-Term Gas Market Report 2013. OECD/IEA, Paris.

IEA. 2013b. 2013b. World Energy Outlook 2013. OECD/IEA, Paris.

IPCC (Intergovernmental Panel on Climate Change). 2006. IPCC Guidelines for National Greenhouse Gas Inventories. Volume 2 Energy. IPCC Geneva.

Jacoby, H. D., F. M. O'Sullivan, and S. Paltsev. 2012. The Influence of Shale Gas on U.S. Energy and Environmental Policy. Economics of Energy and Environmental Policy 1 (1): 37-51.

Jenner, Steffen, and Alberto J. Lamadrid. 2013. Shale gas vs. coal: Policy implications from environmental impact comparisons of shale gas, conventional gas, and coal on air, water, and land in the United States. Energy Policy no. 53 (0): 442-453. doi: http://dx.doi.org/10.1016/j.enpol.2012.11.010.

Johnson, Corey, and Tim Boersma. 2013. Energy (in)security in Poland the case of shale gas. Energy Policy no. 53 (0): 389-399. doi: http://dx.doi.org/10.1016/j.enpol.2012.10.068.

Joskow, Paul L. 2013. Natural Gas: From Shortages to Abundance in the United States. American Economic Review no. 103 (3): 338-43. doi: 10.1257/aer.103.3.338.

Lafrancois, Becky A. 2012. A lot left over: Reducing CO_2 emissions in the United States' electric power sector through the use of natural gas. Energy Policy no. 50 (0): 428-435. doi: http://dx.doi.org/10.1016/j.enpol.2012.07.038.

Logan, Jeffrey, Anthony Lopez, Trieu Mai, Carolyn Davidson, Morgan Bazilian, and Douglas Arent. 2013. Natural gas scenarios in the U.S. power sector. Energy Economics no. 40 (0): 183-195. doi: http://dx.doi.org/10.1016/j.eneco.2013.06.008.

Osborn, S. G., Vengosh, A., Warner, N. R. and R. B. Jackson. 2011. Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing. Proceedings of the National Academy of Sciences. 108(20): 8172-6.

O'Sullivan, Francis, and Sergey Paltsev. 2012. Shale gas production: potential versus actual greenhouse gas emissions. Environmental Research Letters no. 7 044030 (6pp).

Kerr, Richard A. 2010a. Natural Gas From Shale Bursts Onto the Scene. Science no. 328 (5986): 1624-1626. doi: 10.1126/science.328.5986.1624.

Kerr, Richard A. 2010b. Not Under My Backyard, Thank You. Science no. 328 (5986): 1625. doi: 10.1126/science.328.5986.1625.

McGlade, Christophe, Jamie Speirs, and Steve Sorrell. 2013. Methods of estimating shale gas resources – Comparison, evaluation and implications. Energy no. 59 (0): 116-125. doi: http://dx.doi.org/10.1016/j.energy.2013.05.031.

MIT (Massachusetts Institute of Technology). 2011. The Future of Natural Gas. An Interdisciplinary MIT Study. Massachusetts Institute of Technology, Boston.

Montgomery, Carl T., and Michael B. Smith. 2010. Hydraulic Fracturing: History of an Enduring Technology. Journal of Petroleum Technology.

NERA (Economic Consulting). 2012. Macroeconomic Impacts of LNG Exports from the United States. Washington, DC.

NETL (National Energy Technology Laboratory). 2009. Modern Shale Gas Development in the United States: A Primer. EIA, US Department of Energy. Washington, DC.

NETL. 2013. Modern Shale Gas Development in the United States: An Update. EIA, US Department of Energy. Washington, DC.

Paltsev Sergey, Henry D. Jacoby, John M. Reilly, Qudsia J. Ejaz, Jennifer Morris, Francis M. O'Sullivan, Sebastian Rausch, Niven Winchester, Oghenerume Kragha. 2011. The future of U.S. natural gas production, use and trade. Energy Policy no. 39: 5309-321.

Richardson, Nathan, Madeline Gottlieb, Alan Krupnick, and Hannah Wiseman. 2013. The State of State Shale Gas Regulation. RFF Report. Resources for the Future. Washington, DC.

Rogers, Howard. 2011. Shale gas—the unfolding story. Oxford Review of Economic Policy no. 27 (1): 117-143. doi: 10.1093/oxrep/grr004.

Rogers, Howard. 2013. UK Shale Gas - Hype, Reality and Difficult Questions. Oxford Energy Comment. The Oxford Institute for Energy Studies.

Rogner, H.-H., R. F. Aguilera, C. Archer, R. Bertani, S. C. Bhattacharya, M. B. Dusseault, L. Gagnon, H. Haberl, M. Hoogwijk, A. Johnson, M. L. Rogner, H. Wagner and V. Yakushev. 2012. Chapter 7 - Energy Resources and Potentials. In: Global Energy Assessment - Toward a Sustainable Future. Cambridge University Press, Cambridge, UK and New York, NY, USA and the International Institute for Applied Systems Analysis, Laxenburg, Austria, pp. 423-512.

Soeder, D.J. and W.M. Kappel. Water Resources and Natural Gas Production from the Marcellus Shale. United States Geological Service (USGS). Fact Sheet 2009–3032.

Vidic, R. D., S. L. Brantley, J. M. Vandenbossche, D. Yoxtheimer, and J. D. Abad. 2013. Impact of Shale Gas Development on Regional Water Quality. Science no. 340 (6134). doi: 10.1126/science.1235009.

Wang, Zhongmin, and Alan Krupnick. 2013. A Retrospective Review of Shale Gas Development in the United States: What Led to the Boom? RFF Discussion Paper 13-12. Resources for the Future. Washington, DC.

Weber, Jeremy G. 2012. The effects of a natural gas boom on employment and income in Colorado, Texas, and Wyoming. Energy Economics no. 34 (5): 1580-1588. doi: http://dx.doi.org/10.1016/j.eneco.2011.11.013.

Weijermars, R. and C. McCredie. 2011. Inflating US shale gas reserves. Petroleum Review, Dec. 2011.

Zoback, Mark, Kitasei, Saya, and Bradford Copithorne. 2010. Addressing the Environmental Risks from Shale Gas Development. Worldwatch Institute. Washington DC.