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Russia's Natural Gas Export Potential up to 2050

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Russia’s Natural Gas Export Potential up to 2050

Sergey Paltsev*

Abstract

Recent increases in natural gas reserve estimates and advances in shale gas technology make natural gas a fuel with good prospects to serve a bridge to a low-carbon world. Russia is an important energy supplier as it holds the world largest natural gas reserves and it is the world’s largest exporter of natural gas. Energy was one of the driving forces of Russia’s recent economic recovery from the economic collapse of 1990s. These prospects have changed drastically with a global recession and the collapse of oil and gas prices from their peaks of 2008. An additional factor is an ongoing surge in a liquefied natural gas (LNG) capacity and a development of Central Asia’s and the Middle East gas supplies that can compete with Russian gas in its traditional (European) and potential (Asian) markets. To study the long-term prospects for Russian natural gas, we employ the MIT Emissions Prediction and Policy Analysis (EPPA) model, a computable general equilibrium model of the world economy. While we consider the updated reserve estimates for all world regions, in this paper we focus on the results for Russian natural gas trade. The role of natural gas is explored in the context of several policy assumptions: with no greenhouse gas mitigation policy and scenarios of emissions targets in developed countries. Scenarios where Europe takes on an even more restrictive target of 80 percent reduction of greenhouse gas emissions relative to 2005 by 2050 and reduces its nuclear-based generation are also considered. Asian markets become increasingly important for natural gas exports and several scenarios about their potential development are considered. We found that over the next 20-40 years natural gas can still play a substantial role in Russian exports and there are substantial reserves to support a development of the gas-oriented energy system both in Russia and in its current and potential gas importers. In the Reference scenario, exports of natural gas grow from Russia’s current 7 Tcf to 10-12 Tcf in 2030 and 15-18 Tcf in 2050. Alternative scenarios provide a wider range of projections, with a share of Russian gas exports shipped to Asian markets rising to 30 percent by 2030 and more than 50 percent in 2050. Patterns of international gas trade show increased flows to the Asian region from the Middle East, Central Asia, Australia and Russia. Europe’s reliance on LNG imports increases, while it still maintains sizable imports from Russia.

Contents

| | |
|--|----|
| 1. INTRODUCTION | 1 |
| 2. DOES RUSSIA HAVE ENOUGH GAS TO EXPORT UP TO 2050? | 4 |
| 3. HOW MUCH GAS CAN RUSSIA EXPORT? | 7 |
| 4. HOW MUCH NATURAL GAS DOES EUROPE NEED? | 13 |
| 5. CAN RUSSIAN NATURAL GAS GO TO NON-EUROPEAN MARKETS? | 24 |
| 6. CONCLUSION | 29 |
| 7. REFERENCES | 31 |

1. INTRODUCTION

Energy sectors, including natural gas, play an important role in Russian economy. Energy exports were one of the driving forces of Russia’s economic recovery from the collapse of 1990s. The country enjoyed more than 5 percent annual real economic growth in 2000-2008. However,

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over-reliance on the revenues from energy exports was also one of the major factors for Russian economic downturn during a global recession of 2008-2009, when a reduction in demand for fossil fuels, and a collapse of oil and energy prices greatly contributed to an almost 8 percent GDP loss in 2009. Demand and prices recovered in 2010, leading to a 3.7 percent GDP growth. The IMF (2011) forecasts 4.5 percent annual GDP growth for Russia for 2011-2012, but the concerns about the viability of Russian growth based on fossil exports remain.

Natural gas exports from Russia get special attention in comparison to other energy exports, because Russia has less diversified ways to export natural gas in comparison to oil and coal, which are in general easier to transport. On the demand side, it is also relatively easier to switch from one oil or coal supplier to another, hence the importers have fewer concerns about relying on a single supplier or a limited number of suppliers. As a result, Russian oil and coal exports have not had the disruptions seen in the gas transit routes through Ukraine and Belarus. Russia tries to find a way of reducing reliance on transit countries as disputes with them hurt stable gas supplies. Europe, as the largest importer of Russian gas, tries to find a way of reducing reliance on Russia by moving to liquefied natural gas (LNG) imports by tankers from Africa, the Middle East, and Latin America. The development of shale gas in USA has resulted in a substantial price differential between North American and European (and Asian) natural gas markets. This price differential creates a potential for LNG exports from USA. Future LNG development and emergence of shale gas pose questions about the ability of Russia to keep gas exports to Europe at the recent levels, when about 5.5 trillion cubic feet (Tcf)¹ out of a production of 19-21 Tcf were destined to European markets.

In the mid-2000s there were many popular predictions of a potential shortage of Russian gas exports due to the seemingly inadequate investments in Russian gas infrastructure (see, for

¹ In USA natural gas volume is measured in cubic feet, while in Europe it is measured in cubic meters. 1 cubic meter = 35.31 cubic feet. In this paper we report most volumes in trillion cubic feet (Tcf) and also provide some number in billion cubic meters (Bcm) and million tons of oil equivalent (mtoe). Publications use different assumptions for calorific value of natural gas in different regions. They also use different assumptions for temperature and pressure for measurement of gas volumes. For example, for 2008 IEA (2010) reports EU-27 natural gas consumption as 536 bcm and 440 mtoe (with an implied conversion factor 0.821 mtoe/bcm), BP (2011) reports 489.7 bcm and 440.7 mtoe (with 0.9 mtoe/bcm), while Eurogas (2009) reports 516.9 bcm and 433.4 mtoe (with 0.838 mtoe/bcm). IEA (2010) also has a conversion factor varied by region, from 0.81 mtoe/bcm for Russia to 0.86 mtoe/bcm for India, with a global average of about 0.825 mtoe/bcm. IEA (2011) uses the same implied conversion factor for the global average as IEA (2010), but provides 0.9554 mtoe/bcm in the list of general conversion factors for energy. BP (2010) has 0.9 mtoe/bcm for all regions except USA, where it is set at 0.91 mtoe/bcm. In this paper we follow the conversion factors from BP (2010) for reporting in Tcf and mtoe. We also provide some references to the IEA-style numbers for bcm when we compare to IEA and Russian publications. The implied conversion with IEA-style numbers is 1 Tcf = 31.5 bcm.

example, Victor, 2006; Goldthau, 2008; Tsygankova, 2008). Those predictions of shortages are now transformed into the predictions of an excess of Russian gas exports (and switching away from them in Europe) due to LNG and shale gas competition (see, for example, Denning, 2010). Indeed, in 2009-2010 Russian gas exports to Europe decreased to about 5 Tcf due to the global recession and an increased LNG availability in Europe. Economic recovery in Europe and uncertainty about nuclear power, with a decision by Germany to close its nuclear plants in a decade, have made the longer-term prospects for natural gas use in Europe brighter.

Due to the importance of Russian gas imports in the European energy mix, many researchers have analyzed different aspects of Russian gas production and export structure (see, for example, Stern, 2005; Victor et al, 2006; Hartley and Medlock, 2009; Yegorov and Wirl, 2010). In this paper we focus on a potential for Russian gas exports in the long-run, up to 2050. As we look forward over the next several decades, there will be several major drivers of future gas production and use:

- 1) The domestic gas resources that exist: with production from the current Russian gas fields stagnant or falling, will relatively new areas, such as Yamal, Shtokman, and even less developed fields in Siberia and the Far East allow Russian gas production to continue to grow at reasonable prices?
- 2) The state of world gas production and trade: could other regions see a similar increase in shale gas production as the U.S., and will the gas market transition to a fully integrated global market like that for crude oil or will costs and other limits on intercontinental gas transport lead to the persistence of national and regional markets where forces to resolve interregional price differences are dampened?
- 3) The structure of greenhouse gas policies that may be put into effect in the coming years: what form will emissions reductions policies take and how stringent will the control levels be? Here natural gas also can be affected in different ways. Climate policies might increase the demand for natural gas due to a substitution from more carbon-intensive coal to natural gas. However, tighter emissions constraints can reduce the usage of natural gas.
- 4) The recent concerns about nuclear energy: will nuclear generation be reduced and, if nuclear stations are planned to be closed as in Germany, how will power generation be replaced?

5) The development of Asian gas markets, especially in China and India.

To explore these interactions, we apply the MIT Emissions Prediction and Policy Analysis (EPPA) model (Paltsev et al., 2005, 2011), which is a global general equilibrium economic model that resolves key countries, including Russia, and includes details of natural gas resources, energy demand, and competing energy supply technologies. In comparison to many previous studies of natural gas markets, a global economy-wide model allows to account explicitly for interactions between natural gas markets and the rest of the economy. At the same time, as any model simplifies many details of market structure, the results should be viewed not as predictions where confidence can be attributed to the absolute numbers but rather as illustrations of the directions and relative magnitudes of various influences on the role of gas, and as a basis for forming intuition about likely future developments.

In addition, while in the model we account for monopoly rents in resource markets, an experience of natural gas markets so far has shown that economic decisions are heavily influenced by political considerations. In the long run, though, it is difficult to maintain policies based on political goals without appropriate economic fundamentals. In this paper, based on an economic model we illustrate the broad insights about the gas markets in the coming decades and explore if Russia has a potential for sustainable gas exports in the next 40 years.

The paper is organized in the following way. In the next section we explore the current estimates of Russian gas reserves and resources in the context of the global estimates. Section 3 focuses on the ability of Russia to export gas by pipelines and LNG, and discusses the current infrastructure and future projects. In Section 4 we consider how much Russian gas might be needed by Europe, the major market for Russian gas. Section 5 studies the prospects for non-European exports of Russia and in Section 6 we conclude.

2. DOES RUSSIA HAVE ENOUGH GAS TO EXPORT UP TO 2050?

According to BP (2010), more than 50 percent of the global gas reserves of 6600 Tcf lie in three countries: Russia, Iran, and Qatar. Russia has about 1570 Tcf of natural gas in proved reserves, which are the largest in the world. If gas production remains at the current levels, Russia has gas for more than 80 years. **Figure 1** shows a distribution of reserves aggregated by large regions, where the former Soviet Union has 2074 Tcf of natural gas in reserves, second to the Middle East reserves of 2690 Tcf. Asia Pacific and Africa have about 500-600 Tcf each,

while North America and South America have about 300 Tcf each. Europe (including Norway) has about 150 Tcf, which is about 15-20 years of production at the current levels.

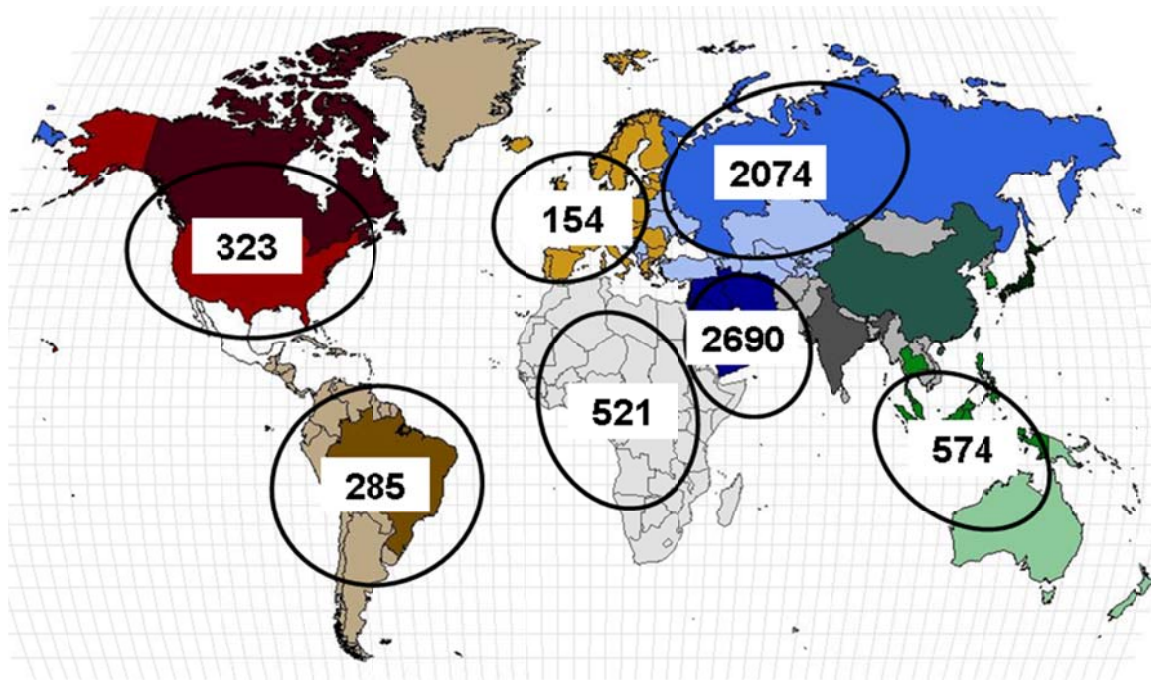


Figure 1. Proved Reserves of Natural Gas by Region, Tcf (Data source: BP, 2010; Regional map: EPPA).

Gas resources, a more uncertain category as it includes not only gas that can be recovered under existing economic and operating conditions but also reserves growth and undiscovered gas, are much bigger than the proven reserves. The MIT Future of Natural Gas study (MIT, 2011) has estimated the resources aggregated by the EPPA model regions, which are provided in **Figure 2**, where the four biggest regions in terms of gas resources are the Middle East with about 4,700 Tcf, Russia with about 3,400 Tcf, USA with around 2,000 Tcf with a substantial contribution of shale gas, and Africa with around 1,000 Tcf.

MIT (2011) does not assess shale gas resources and their costs outside North America, considering them highly uncertain at this time, but the U.S. Energy Information Administration (EIA, 2011) released a report that provides an initial volumetric assessment of shale gas resources in 14 regions outside the U.S. It does not include regions with large conventional gas resources, such as Russia and the Middle East. Even with this restriction, the estimate is for around 5,000 Tcf outside of USA and Canada, which is a substantial fraction of the approximately 16,000 Tcf mean estimate of global resources presented in Figure 2. IEA (2011) projects that by 2035, outside North America, unconventional gas can be economic in China,

Australia and Russia, but admits that while understanding of unconventional resources is improving, the complex issues related to unconventional gas lead to a large degree of uncertainty in their projections.

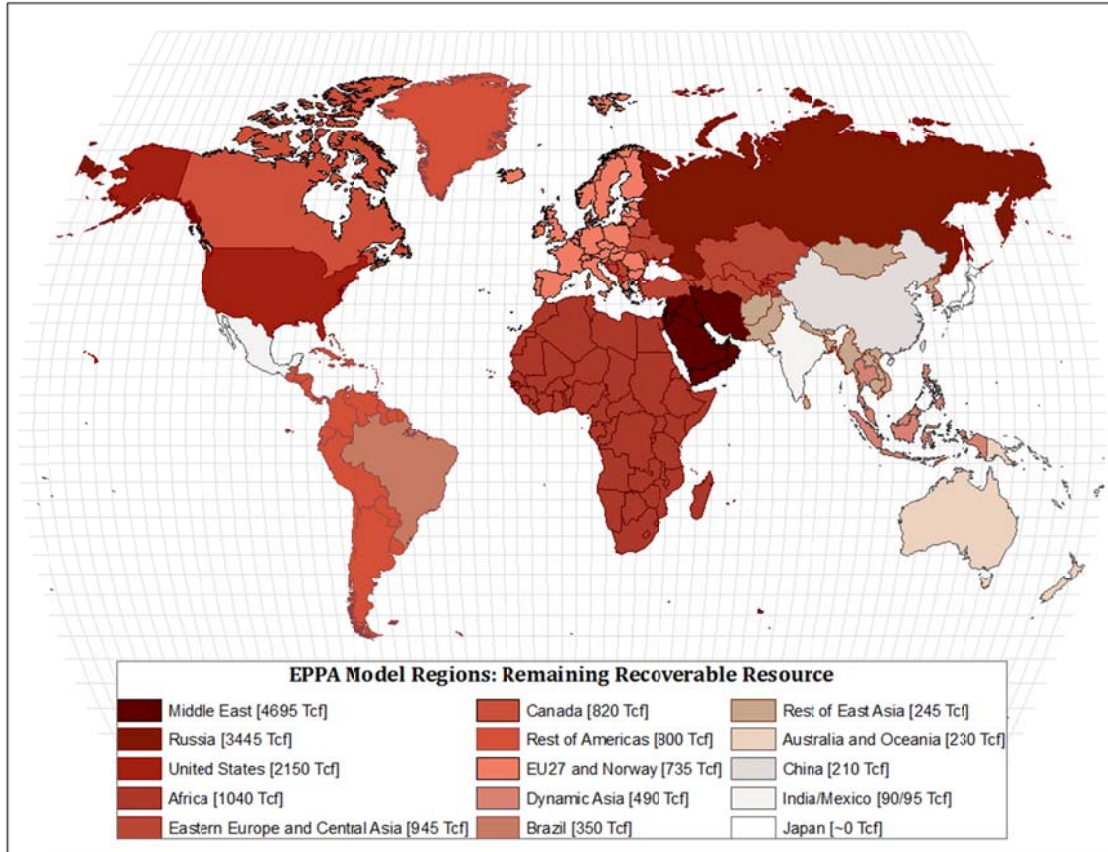


Figure 2. Map of EPPA Regions and Natural Gas Resource Estimates, Tcf (MIT, 2011).

In terms of natural gas availability, Russia has plenty, both for domestic markets and exports that, as mentioned, currently are more than a third of production. Despite the large reserves, many projections actually show little increase in the Russian gas share in Europe because of the increasing availability of gas supplies from North Africa and the Middle East (EMF, 2007). Some analysts also question Russia’s ability to develop new supplies due to unstable legal environment, inefficient investments (EMF, 2007) or simply high transport costs (Holz *et al.*, 2008). A recent enthusiasm about shale gas has also added to uncertainty about the prospects for Russian export volumes. In estimating a potential for gas production, it is important to consider not only how much gas is available, but what a cost structure of gas supplies is. In addition to production costs, transportation costs are important as low energy density of gas makes it costly to transport and store. We discuss cost and competitiveness issues in Sections 4 and 5, reiterating

that Russia has enough reserves to export up to 2050 and beyond, even with a projected increase in global gas use that we discuss later.

3. HOW MUCH GAS CAN RUSSIA EXPORT?

To assess the current export possibilities, we begin with historic numbers for production and exports. USA and Russia are the two largest gas producers with about 20 Tcf volume of annual production. The next two, Canada and Iran, are producing about 5-6 Tcf per year. Qatar and Norway produced about 4 Tcf in 2010. **Figure 3** provides the production volumes for Russia and USA for 1990-2010. After the break-up of the Soviet Union, Russian gas production declined by almost 10 percent from its peak in 1990 to its lowest point in 1995. It grew then by 13 percent between 1995 and 2008. In 2009, Russian production declined by 12.3 percent in comparison to the previous year (BP, 2011), the largest one-year reduction in the BP data for Russia. It increased by 11.5 percent in 2010. USA production also has had its ups and downs, with an 8 percent decline between 2001 and 2005 and an almost 20 percent increase between 2005 and 2010 due to increased shale gas volumes.

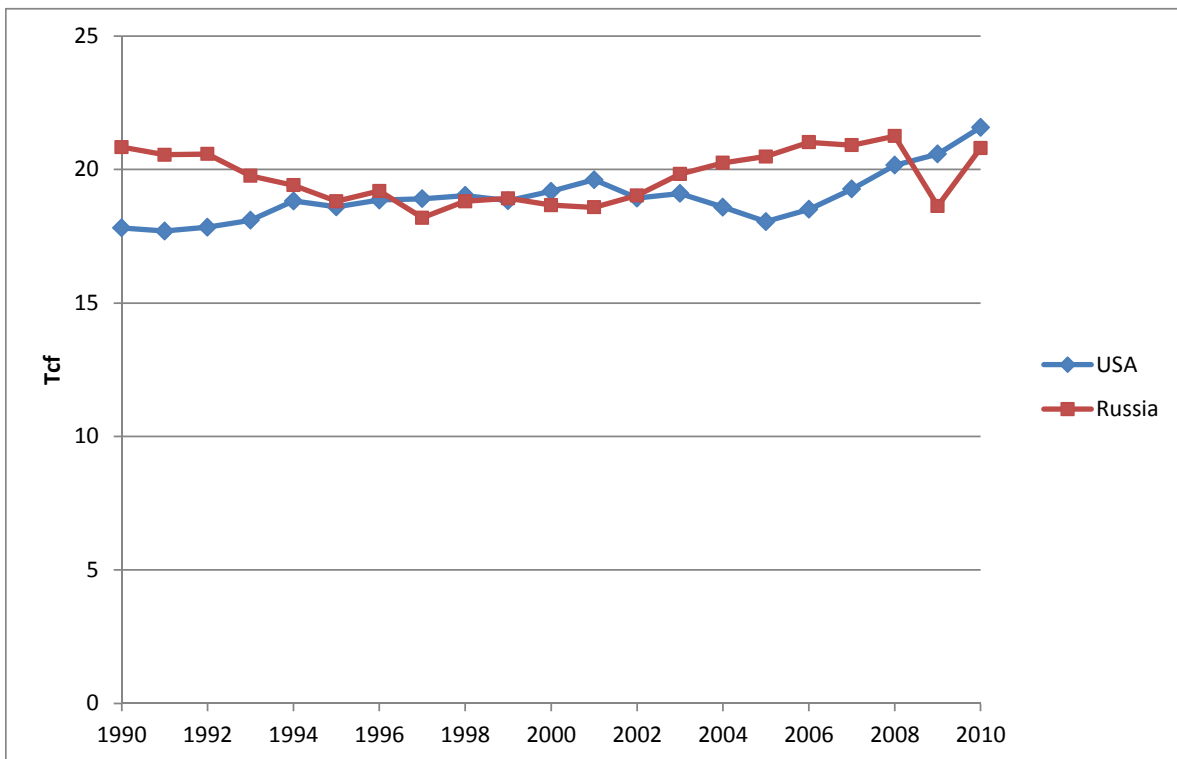


Figure 3. Natural Gas Production in Russia and USA in 1990-2010, Tcf (BP, 2011).

Even with the variations depicted in Figure 3, Russian gas production was relatively stable, in contrast with its oil production which exhibited a sharp decline in mid-1990s (a 46 percent drop in oil production in 1998 relative to the 1988 level) due to the break-up of the Soviet Union, uncertainty about the ownership of assets, and to the low world oil prices during that period. A difference with the Russian oil sector, where several big players exist (such as Rosneft, Lukoil, TNK-BP, Surgutneftegas), is that most of the Russian gas reserves and pipelines have become an asset of a state-owned company Gazprom. The biggest independent gas producer, Novatek, is growing fast but still has only about 6 percent of the total gas production (1.14 Tcf out of 18.6 Tcf of the total Russia's production in 2009) and relies on Gazprom pipeline network for gas transportation. Status of a monopoly for Russian gas exports was granted to Gazprom by Russian government and Novatek is trying to break-up the monopoly by moving to LNG with a plant in Yamal planned to be open in 2016.

As for the current possibilities for exports, Russian gas is exported mostly to Europe by pipelines via Ukraine and Belarus, with Ukraine-bound pipeline capacity of around 4.5 Tcf and Belarus-bound capacity of 1 Tcf. Another export pipeline, The Blue Stream, is connected to Turkey, and it has a capacity of around 0.5 Tcf. In the north-western part of Russia, Finland gets about 0.15 Tcf of Russian gas by a pipeline there. The Baltic states of the EU (Latvia, Lithuania, and Estonia) are supplied by separate pipelines. They use about 0.2 Tcf of Russian gas. Other former Soviet Union countries are also connected by a network of pipelines. Looking at another gas export destination, Asia, an LNG plant in Sakhalin has started its gas supplies to Japan and South Korea. Part of these LNG supplies is also intended for Mexico and the west coast of USA via Mexico. The current capacity of the plant is about 0.5 Tcf (9.6 Mt LNG), with a proposal to expand to about 0.7 Tcf (14 Mt LNG). Based on the information from IEA (2009, 2010), **Figure 4** shows a map of the major Russian gas fields and pipelines with a coloring scheme depicting the regional aggregation in the EPPA model. It also shows the location of existing and planned LNG plants: Sakhalin, Yamal, Vladivostok, and Murmansk.

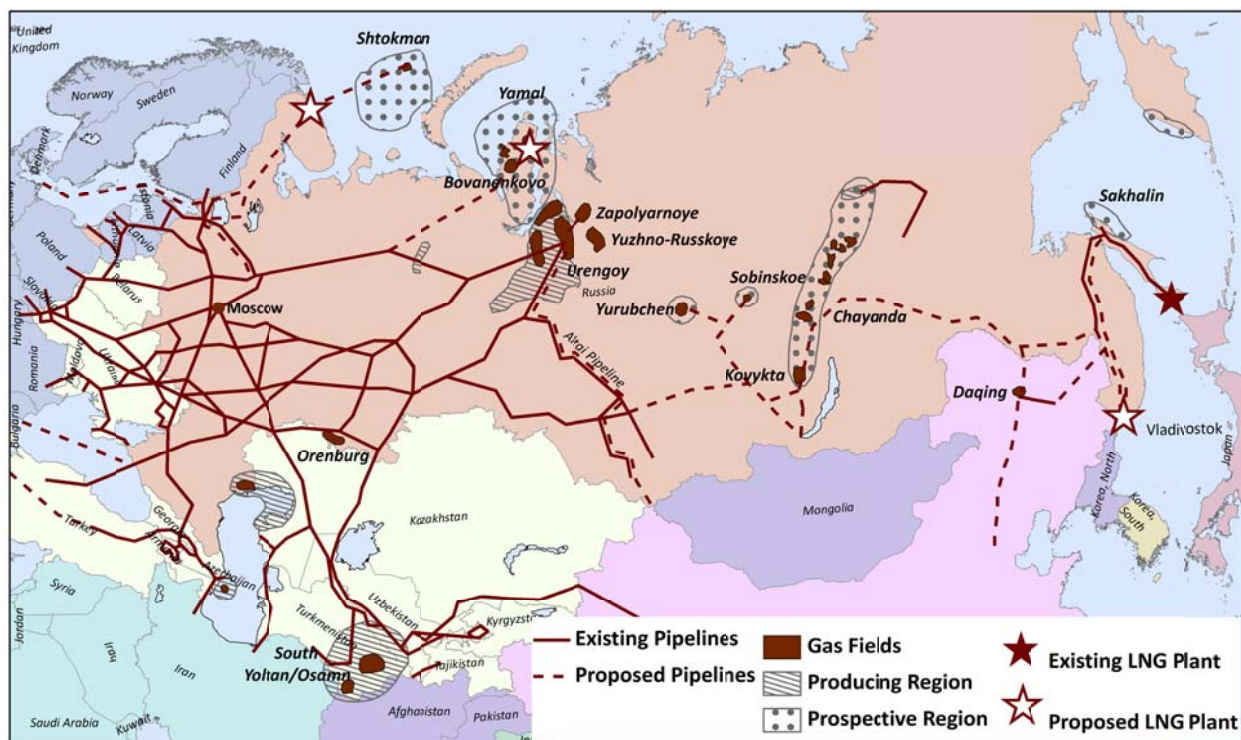


Figure 4. Major natural gas fields and supply infrastructure in Russia (Data source: IEA (2009, 2010), Gazprom (2010); Regional Map: EPPA).

In terms of export volumes, the latest publicly available detailed data from Gazprom are for 2008 (Gazprom, 2010), where it reports 5.5 Tcf sold to the EU-27, 3.2 Tcf to the CIS countries (former Soviet Union republics except the Baltic States), and 1 Tcf to the non-EU European countries including Turkey. **Table 1** summarizes the export data based on BP reports from different years. BP did not report CIS trade before 2009, and there were no Asian exports from Sakhalin LNG before 2009. For 2008, there is a difference of 1.1 Tcf between BP and Gazprom for the exports to the EU-27, which is mostly due to the sales to UK, Belgium and the Netherlands recorded by Gazprom but not by BP. Gazprom’s numbers for exports to Ukraine and Belarus in 2008 are also substantially higher than in BP reports for these countries in 2009 and 2010. Gazprom reports exporting 2.7 Tcf in 2008, and BP reports 1.4 Tcf in 2009 and 1.9 Tcf in 2010 to these two countries. Part of the difference can be attributed to reduced use in these countries due a reduction in economic activity in 2009-2010, and to gas disputes with Russia in 2009. The EU-27 exports were in the range of 3.8-4.4 Tcf in 2007-2010 and exports to the non-EU countries and Europe were 0.7 – 1 Tcf in the same period. Asian exports started in 2009 with majority of the supplies destined to Japan and South Korea.

Table 1. Russian Natural Gas Exports in 2007-2010, Tcf (BP, 2008-2011).

| | 2007 | 2008 | 2009 | 2010 |
|-------------------|------|------|------|------|
| EU-27 | 4.2 | 4.4 | 3.8 | 3.9 |
| non-EU and Turkey | 1.0 | 1.0 | 0.7 | 0.7 |
| CIS | n.a | n.a | 1.7 | 2.0 |
| Asia | - | - | 0.2 | 0.5 |
| Total | n.a | n.a. | 6.5 | 7.1 |

Note: BP does not report the CIS trade for 2007 and 2008.

Turning again to export capacity, in addition to the existing pipelines shown in Figure 4, Russia is building the North Stream (“Nord Stream”) pipeline, which is going to connect Russia and Germany directly via the Baltic Sea. It is expected to be completed at the end of 2011 with a capacity of 0.9 Tcf, and the full capacity of 1.8 Tcf (55 bcm) is expected to be reached by the end of 2012. With North Stream already under construction, another pipeline, South Stream, is planned to be online by 2015 with a capacity of about 2.2 Tcf (63 bcm). South Stream would connect Russia and Bulgaria via the Black Sea and continue to Hungary, Greece, Serbia, Austria, and Italy.

In total, with North Stream online, Russian export capacity to the European market will be about 7.3 Tcf. If Russia goes ahead with South Stream as planned, the capacity would be increased to 9.5 Tcf by 2015-2020. As a stated goal for North Stream and South Stream is a divergence of the gas flows from the transit routes of Ukraine and Belarus, Russia would be able to supply 4.5 Tcf to Europe and Turkey via new pipelines and Blue Stream that do not depend on the CIS transit countries. Recent political changes in Ukraine that have brought into power more Russian-friendly politicians opened discussions of closer cooperation between Russian Gazprom and Ukraine’s Naftogaz, which controls transit routes. Despite Gazprom’s declared optimism about a better cooperation with Ukraine, however, plans for South Stream to by-pass Ukraine are progressing as well.

Even with Russia’s export orientation, its domestic gas sales should not be neglected. According to BP (2010), domestic consumption was steadily rising from 12 to 15 Tcf from 1997 to 2007, while Gazprom was not able to charge the full “market” prices in a domestic market. According to Jensen Associates (Jensen, 2010a), in the early 2000s domestic gas prices were as low as a quarter of export prices. Gazprom (2010) reports that even in 2007 and 2008, average natural gas sales price for Russian customers were about 50 percent of the prices for the CIS and

Baltic states, and about 21-25 percent of the prices for the European customers. Russian domestic gas prices in 2008 increased to an equivalent of around \$2/Mcf (dollars per thousand cubic feet) from \$1.50/Mcf in 2007. Gazprom is planning to increase its domestic prices even further by 2014 to “meet the principles of equal yield of gas supplies to the foreign and domestic markets” (Gazprom, 2010). It estimates that such price would be around \$4.50/Mcf in 2014. This price is still lower than the expected price for European exports as it does not include export duties and transportation cost.

A domestic gas price increase will incentivize Gazprom to send more gas to Russian users. At the same time, an increase in prices would decrease the domestic demand for gas. In many countries, coal is a primary source of energy for electricity and the role of gas is seen as moving from coal to a less carbon-emitting fuel. In Russia, the share of natural gas in total energy consumption is already more than 50 percent, and the same is true for electricity, so there is not as much room for an increase in gas usage as in the economies which currently rely on coal. Gazprom is trying to boost its gasification efforts (Gazprom, 2010) in the areas where gas is currently unavailable, so a major increase in domestic gas usage can be expected in residential and commercial uses for heating and cooking purposes. According to Gazprom, the degree of gasification, defined as a number of houses with access to natural gas to the total number of houses, increased in Russia from 54 percent in 2005 to 62 percent in 2008. Thus, the domestic market is growing, but its volumes are not expected to affect Gazprom’s ability to sustain or increase its export volumes for a while.

In 2010, the Government of Russia discussed the General Scheme for Natural Gas Sector Development for a period up to 2030 (Government of Russia, 2010) with ambitious 2030 targets of gas production of 31.8 Tcf (1000 bcm), domestic gas use of 17.5-19 Tcf (550-600 bcm) and exports of 14.5-16.5 Tcf (455-520 bcm). The Scheme also projected that by 2030 a non-Gazprom natural gas production in Russia will reach 30 percent in comparison to 17 percent in 2008. As 2009-2010 were difficult years for Russian gas exports, – when spot prices in Europe were lower than the prices for Russian gas, substantially reducing Gazprom’s sales to Europe, – many experts were skeptical about the numbers announced in the General Scheme. Since then a resumed economic growth in Europe, an increase in gas spot prices there, and concerns about the future of nuclear power made the Russian government’s projections a bit more plausible. The IEA (2011) has increased its projections for gas production in Russia in 2030 from 772 bcm to

842 bcm, and for gas consumption in 2030 from 503 bcm to 522 bcm, in comparison to the 2010 outlook (IEA, 2010).

As mentioned above, in the next ten years Russia's gas export potential to Europe is about 10-11 Tcf, mostly based on pipeline-based exports. The actual sales to Europe were 4.5-5.5 Tcf at the end of the 2000s. It looks like Russia has a choice to make for a more distant future – to continue to rely on pipelines for gas transportation, or to start moving to LNG markets more aggressively.

In terms of pipelines, most long-term planning is focused on how to connect to the Asian market. In the mid-2000s, the Altai pipeline with a capacity of 1 Tcf was included in plans for quite a while, with a goal to connect Nadym-Urengoy gas production region with China (to China's West-East gas pipeline). The project is currently on hold as Russia and China have not been able to resolve gas pricing disagreements and China has built a pipeline from Turkmenistan instead. Another projected pipeline would connect Kovykta gas production region (near the Russian city Irkutsk) to China (serving Beijing area) and further to South Korea. In addition to the unresolved pricing issue with exports to China, for a long time a problem with this pipeline is that the Kovykta gas field did not belong to Gazprom, and as a result it had no incentives for this project. With a recent purchase of Kovykta by Gazprom, pipeline exports to China might be closer to reality. Talks about the Altai pipeline have been also resumed with the reports that the volumes of gas have been largely agreed upon, but the prices are still under negotiations².

Further East, Sakhalin gas fields, in addition to an existing LNG plant, are projected to be connected with Japan and Korea directly by pipeline, or indirectly via Vladivostok, where another LNG plant might be built to ship gas for exports. An additional source of gas for the proposed Vladivostok LNG plant might be the Chayanda gas field in Yakutia. This is part of an ambitious Siberia – Pacific Ocean gas pipeline project, which is planned to be built next to the East Siberia – Pacific Ocean (ESPO) oil pipeline that is currently under construction. Such a project, if fulfilled, would connect major Russian gas fields in Nadym-Urengoy-Yamal area both with the European and Asian markets, which will give Russia flexibility and bargaining power.

Turning to other LNG projects, in the plans are LNG facilities in Yamal, where Gazprom is developing its Bovanenkovo field with estimated reserves of 170 Tcf. Gazprom expects that in

² For a discussion about gas demand in China and issues related to price negotiations between Russia and China, see Jensen (2011a).

the long-run Bovanenkovo will be producing 4-5 Tcf per year, which will be sufficient both for pipeline and LNG transportation. The Russian independent gas producer Novatek, which has the 46 Tcf South Tabei field in Yamal, is also considering an LNG plant there. Another LNG project near Murmansk will serve Shtokman gas field, which has an estimated 135 Tcf of natural gas. Shtokman was planned to be developed mostly for the U.S. market, where a recent U.S. shale gas production increase drastically reduced the prospects for its LNG imports. Most likely, the Shtokman project schedule will be adjusted and its gas destination will be re-routed to other markets.

The pipelines and LNG projects are expensive. For example, initial estimates for the cost of North Stream is \$15 billion (\$9 billion for an offshore part), South Stream is even more expensive – at the estimated \$20-25 billion (\$9 billion offshore). These estimates are likely to increase. In comparison, at a peak of gas prices in 2008, Russian gas export revenue was \$69 billion, while in 2009 it was reduced to \$42 billion, close to annual gas export revenue in 2006-2007 (Central Bank of Russia, 2010). The Altai pipeline was expected to cost around \$15 billion, probably an optimistic estimate, but the Turkmenistan-China pipeline that was built has approximately the same cost. LNG plants are also expensive. For example, an existing Norway's Snohvit plant with a capacity of 0.2 Tcf (about 4.3 Mt LNG per year) cost around \$5.3 billion. An original price tag for Sakhalin LNG with 0.5 Tcf capacity was \$10 billion, while there are reports that actual costs might be doubled³. Yamal LNGs might be even more expensive as they will be built in even more harsh Arctic climatic conditions.

Combining the projects discussed above, a rough estimate for Russian gas export capacity in the next ten to fifteen years is around 10 Tcf in pipeline exports to the European destinations, 1-2 Tcf in pipeline exports to Asia (China and Korea), and 2-3Tcf in LNG that mostly would serve the Asian market. Do Europe and Asia need that much gas? We turn to explore this question in the following sections.

4. HOW MUCH NATURAL GAS DOES EUROPE NEED?

In the previous section we have estimated that, if both the North Stream and South Stream pipelines are built, then by 2015-2020 Russia will have a capacity to export about 9.5 Tcf to Europe (including Turkey), which is almost twice the current capacity of 5.5-6 Tcf. Looking at

³ The reported cost of the Sakhalin 2 project includes not just the LNG plant but the related field development and a pipeline to the port.

the EU-27 countries, in 2008 their gas consumption was 17.3 Tcf, including 12.1 Tcf in the countries where Russian gas is imported, with Russian imports of about 4.5 Tcf (BP, 2009). EU gas consumption was growing at an average annual rate of 1.7% during the 10 years before 2008. In 2009, the EU-27 consumption declined to 16.2 Tcf and Russian imports reduced to about 4 Tcf. EIA (2010) projects that gas consumption in OECD Europe will grow more slowly in the future, at a rate of 0.5%, reaching about 22 Tcf by 2035. The IEA (2010) shows a similar trend projecting gas consumption in OECD Europe of about 20 Tcf (628 bcm) and the EU-27 gas consumption of about 19 Tcf (598 bcm) by 2035. More recently, IEA (2011) increased the projected use by around 1.2 Tcf (38 bcm) by 2035 citing lower growth in nuclear power and cheaper natural gas prices due to the addition of unconventional gas supplies.

In 2008, the EU imported about 8.5 Tcf of natural gas: 4.5 Tcf from Russia, about 2 Tcf from Africa by pipelines, and another 2 Tcf by LNG mostly from Africa and the Middle East. As Norway, which sends about 3.3 Tcf to the EU-27, is much closer to the EU economically, we include it into our definition of the European region in the rest of the paper. Considering the current 8.5 Tcf of imports to Europe, projections for the EU demand at 19-20 Tcf and a projected decline in European natural gas production to about 7-9 Tcf, it means that there might be room for an additional demand for imports at about 1.5-4.5 Tcf. Recall that the capacity of North Stream and South Stream is 4 Tcf.

Looking at the projections for the European gas consumption and considering the Middle East and Africa's LNG expansion, in 2009-2010 many analysts criticized Russia's urge to build both North and South Stream pipelines. An increase in shale gas production in the U.S. and prospects of shale gas production in Europe do not seem to change the attitude of Russian gas industry officials, who project an increase in gas prices by 2012-2015 in comparison to relatively low spot prices in 2009-2010. Indeed, at the beginning of 2011, spot prices in Europe were closer to Russian long-term gas prices and purchases of Russian gas were increasing, partly in anticipation of even higher oil-indexed prices for Russian supplies later in 2011 as they are tied to oil prices with 6-8 month lag.

A stringent greenhouse gas (GHG) policy would favor gas relative to other fossil fuels as it has a lower carbon content. The fate of climate policy negotiations is highly uncertain, however. Russia, like the other G8 countries, has agreed to cut its GHG emissions by 50 percent by 2050, but without specifying a baseyear against which the reduction is counted. Russia also submitted a

proposal (Copenhagen Accord, 2010) for a reduction of its 2020 GHG emissions by 15-25 percent relative to 1990, conditioning this reduction on accounting of a Russian forestry contribution and the undertaking by all major emitters of legally binding obligations to reduce GHG emissions. As 2007 GHG emissions in Russia were about 30 percent below 1990, the proposal is unlikely to be binding by 2020; therefore, in the policy scenarios described below Russia does not reduce its GHG emissions before 2020.

Europe seems to be willing to implement substantial targets despite a lack of support for substantial cuts from other regions of the world. The EU Commission (EC, 2011) recently proposed a “roadmap” to a low carbon economy where GHG emissions are reduced by 2050 by 80 percent relative to 1990.

To illustrate potential developments, we explore three scenarios simulated to 2050:

- *Reference* which assumes no climate policy.
- *50% GHG Reduction*, which imposes an economy-wide price on CO₂ and other greenhouse gases (GHG) that gradually reduces GHG emissions to 50 percent below 2005 by 2050 in Europe, USA, Canada, Japan, Australia and New Zealand. China, India, Russia, Mexico, and Brazil beginning in 2020 on a linear path to 50 percent below their 2020 levels by 2070. The rest of the developing countries delay their action to beyond 2050.
- *80% GHG Reduction*, which imposes the same constraints for non-EU countries as the previous scenario, but after 2020 Europe is on a more stringent path reducing 80 percent of its GHG emissions relative to 1990 by 2050.

Natural gas production and consumption in Europe in the Reference scenario is presented in **Figure 5**. The data for 2000-2009 is from BP (2010), which shows a historic decline in the EU natural gas production. Counting production in Norway, a non-EU country, which consumes only 0.15 Tcf and exports most of its gas to the EU, slows down a decline in the European production. The data for 2010 is from Eurogas (2011), which shows a recovery of the EU gas consumption to 2008 levels. The data for 2015-2050 are the projections from the EPPA model. The Europe region in the model includes the EU-27, Norway, Iceland, Switzerland and Liechtenstein. As the non-EU countries in the EPPA’s Europe region contribute about 1.5

percent to the gas consumption in the aggregated Europe region, these trends approximate the EU consumption as well.

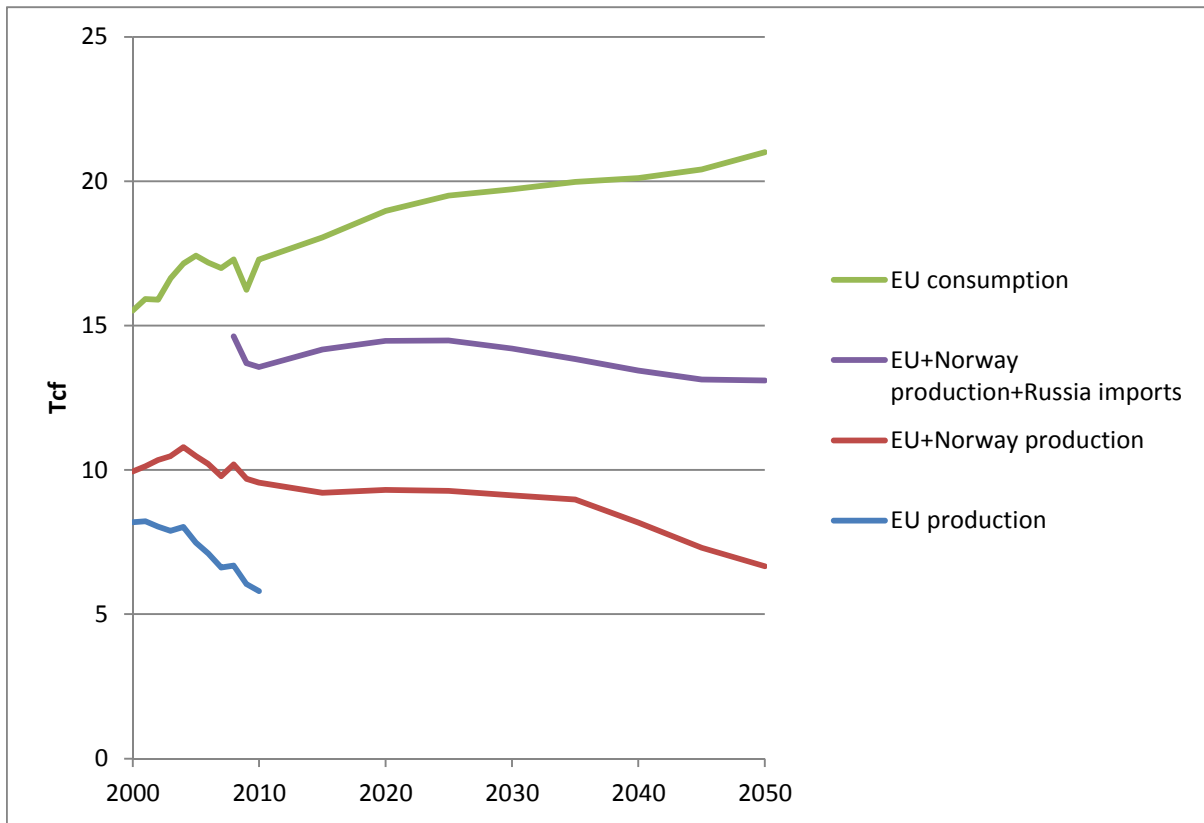


Figure 5. Natural gas production and consumption in Europe in the *Reference* scenario and historic data.

The projections show a decline in Europe’s production and a gradual increase in its consumption. Adding Russian imports to the EU production results in a roughly constant amount of around 13-14 Tcf of natural gas. The difference between the top two lines shows the amount for non-Russian and non-Norwegian imports to the EU. It grows from about 4 Tcf in 2010 to about 5.5 Tcf in 2030 and about 8 Tcf in 2050. The major suppliers that out-compete Russian exporters are the Middle East and Africa.

Our EU+Norway natural gas production projection presented in Figure 5, where it stays at about 9 Tcf (or about 230 mtoe) up to 2035 and then drops to about 6.5 Tcf (or about 170 mtoe), is somewhat more optimistic than projections from other sources. For example, Eurogas (2010) foresees a reduction in the EU+Norway production from 225 mtoe in 2015 to 145 mtoe in 2030. The supply curves in the EPPA model in this study are based on the mean values from MIT

(2011). We also performed a sensitivity analysis where we consider the EU reserves from a Low scenario in MIT (2011). A lower reserves assumption results in a production profile more consistent with Eurogas (2010) projections, but it does not greatly affect Russian imports, while it slightly increases non-Russian imports and reduces natural gas consumption in the EU.

Figure 6 shows Europe’s natural gas consumption in different projections from 2010 forward. As mentioned, natural gas use grows gradually in the *Reference* scenario, reaching about 19.7 Tcf (or about 500 mtoe, or about 620 bcm in the IEA-style) by 2030 and about 21 Tcf (or about 535 mtoe) by 2050 from 17.3 Tcf (or about 440 mtoe) in 2010. In a *50% GHG Reduction* scenario, natural gas use grows modestly till 2020 reaching 18 Tcf, and then is reduced to around 13 Tcf by 2050. A difference with the *Reference* case is about 2.6 Tcf (or 67 mtoe) in 2030 and 7.9 Tcf (or 200 mtoe) in 2050.

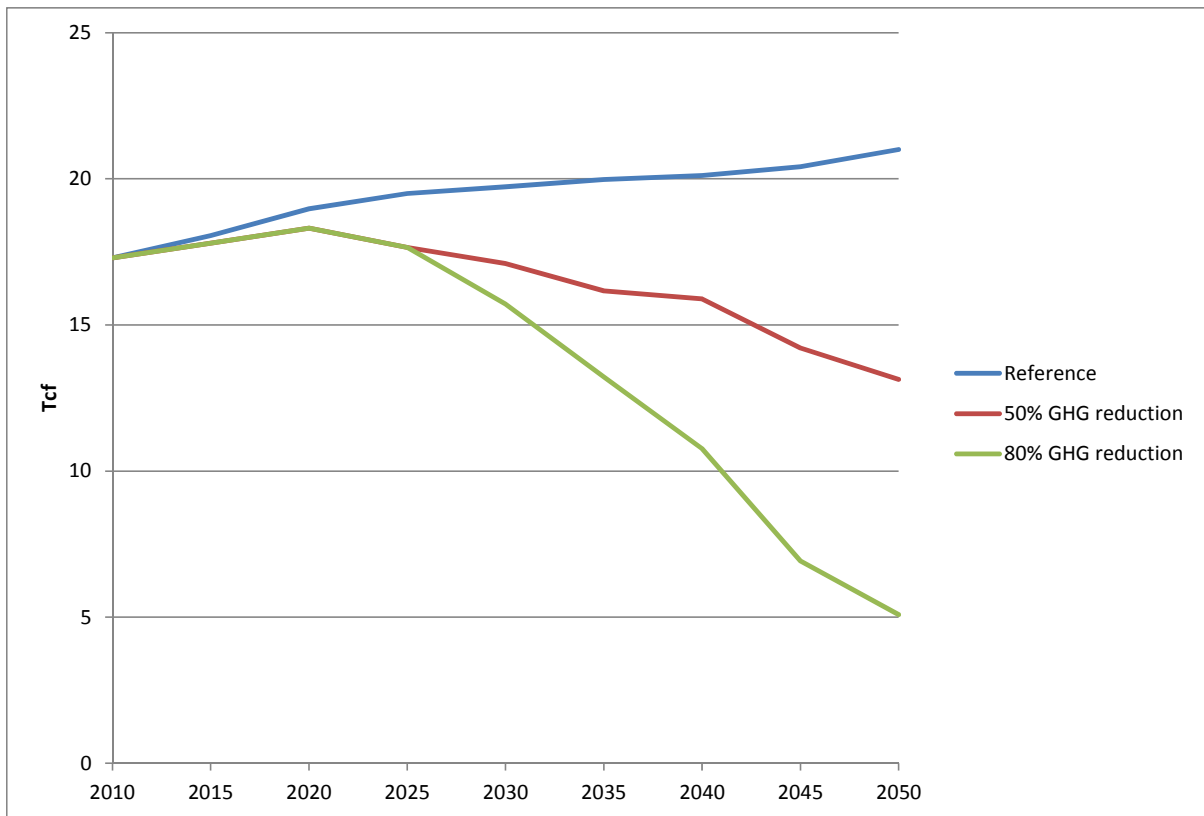


Figure 6. Natural gas consumption in Europe in different scenarios.

The IEA (2010, 2011) in its projections for New Policies Scenario and GAS Scenario includes some energy and climate-related policies, but in these scenarios the EU does not achieve 50 percent GHG reduction by 2050, so the trajectories are not directly comparable. In comparison,

the EU-27 natural gas consumption in 2030 is 591 bcm in IEA (2010) and 621 bcm in IEA (2011) where more and cheaper gas is assumed. These IEA numbers correspond to 18.8 Tcf (or about 480 mtoe) and 19.7 Tcf (or 500 mtoe), accordingly.

In the *50% GHG Reduction* scenario presented here, because of higher energy prices that reflect the CO₂ penalty needed to achieve emissions reductions, the overall energy use is lower, and gas use is lower than without the policy. An overall reduction in energy demand in the policy case is attributed to higher energy prices and higher energy efficiency. In this scenario, most of the changes happen in electricity and transportation sectors. Gas-based generation replaces a large part of coal-based generation, while nuclear, hydro and renewables (solar, wind and biomass) provide most of the remaining electricity production. After 2040, a carbon capture and storage (CCS) technology becomes economic and enters the market for power generation. In transportation, natural gas does not seem to contribute significantly, rather reductions in emissions are achieved mostly by biofuels, electric vehicles, and an increased efficiency of internal combustion engines.

In the *80 % GHG Reduction* scenario, a stringent emissions target drives down the natural gas use even further; by 2050 it is equal to about 5 Tcf. In this scenario, solar and wind energy play a greater role, and CCS technology for coal and gas enters in 2030. Differences in natural gas use in comparison with the *Reference* case are even bigger. In 2030, the EU consumes about 4 Tcf less (or about 100 mtoe), and in 2050 the reduction is about 16 Tcf (or 400 mtoe) in comparison to a scenario with no GHG reduction policy.

In the scenarios above, the reductions are achieved by applying an economy-wide cap-and-trade system. To show the sensitivity of the results to the way how the policy to reach GHG reduction goals might be implemented, we consider scenarios where additional constraints on nuclear and coal-based generation are imposed. Recent decisions to close nuclear plants in Germany by 2022 and in Switzerland by 2034, and the results of the referendum in Italy on the fate of nuclear power, pose a question on the future trajectory for nuclear power. In addition, health impacts of air pollutants associated with coal use might impose an additional pressure on coal-based generation. The share of Germany in the EU-27 nuclear generation in 2009 was about 16 percent. Switzerland is not in the EU, but their corresponding share would be around 3 percent. We provide scenarios where, by 2025, 20 percent of nuclear capacity in Europe is retired, and nuclear generation is further gradually reduced by 2050 to about 60 percent of

nuclear generation in 2005. In addition, air pollution restrictions on coal reduce its use to the levels of the corresponding cap-and-trade scenarios, but by 5 years earlier, that is the levels of 2030 are achieved by 2025, the levels of 2035 are achieved by 2030, and so on. Alternatively, more nuclear generation can be reduced instead of additional coal restrictions.

Figure 7 presents the results of *50% GHG Reduction* and *80% GHG Reduction* when these additional constraints on nuclear and coal are imposed. In comparison to the non-policy *Reference*, instead of reduction in natural gas use Europe demands more gas for an extended period of time. The exact increase in demand, of course, depends on the policy design. In these particular scenarios, by 2030 natural gas use in Europe is increased to 23.3 Tcf (or about 595 mtoe) with 50 percent GHG reduction goal and to 18.7 Tcf (or 475 mtoe) with the 80 percent goal.

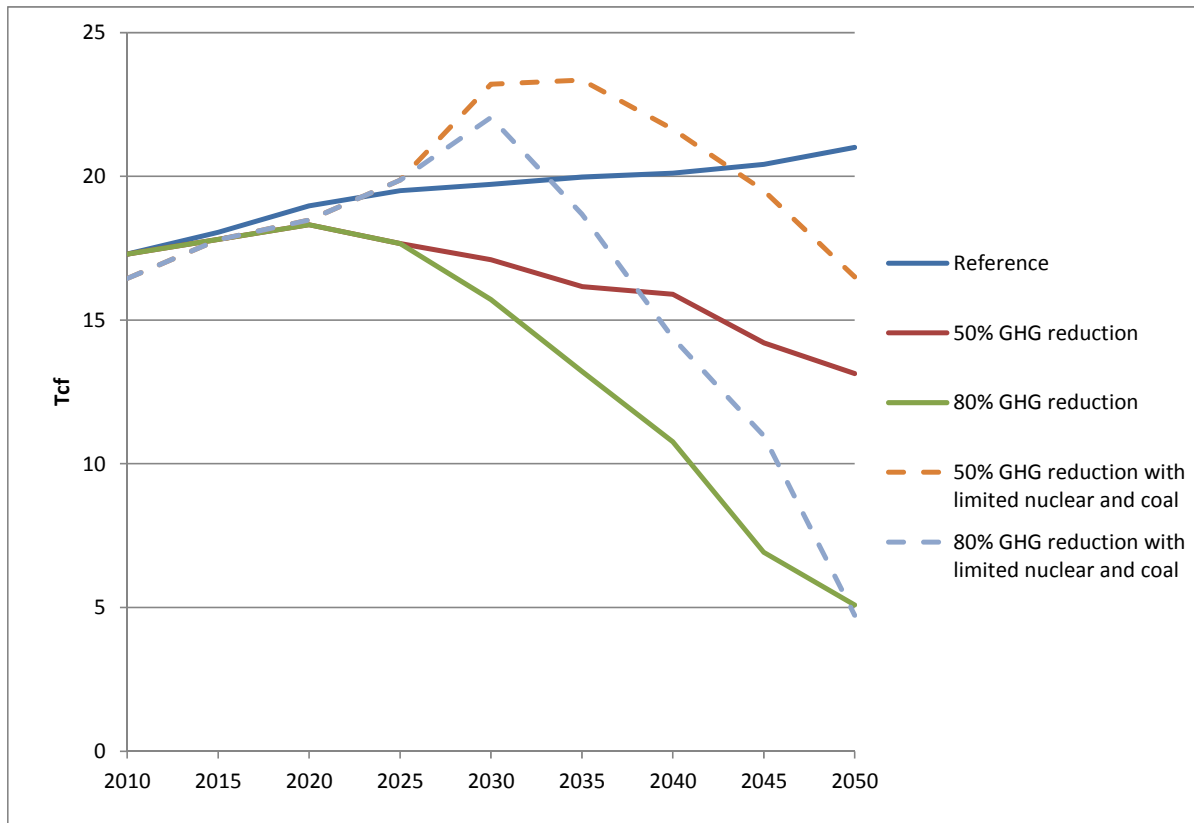


Figure 7. Natural gas consumption in Europe in scenarios with limited nuclear power and additional restrictions on coal generation.

Gas usage is decreasing after 2030-2035 due to higher energy prices, increased share of renewables and an overall decrease in energy use. That decrease is especially challenging for natural gas in the *80% GHG Reduction* scenario, where its use is again decreased to 5 Tcf by

2050. Even more challenging is a relatively short peak between 2025 and 2035 when natural gas units need to be built to replace coal and nuclear. Severe carbon constraints, in turn, replace natural gas by renewables. An earlier push for a larger share of renewables would increase economic cost as a back-up generation with low capacity factors needs to be built to support intermittent generation from solar and wind.

Natural gas imports to the EU-27 from Russia in these scenarios are presented in **Figure 8**. In all scenarios imports up to 2025 are in the range of 4.5 – 5.5 Tcf (or 140 – 175 bcm). After that, the range is more uncertain. Gradual GHG targets with nuclear limitations increase Russian imports to about 7 Tcf (or 220 bcm), while very restrictive GHG reduction reduce natural gas use and imports from Russia. In 2030, the range is between 4 Tcf (or 125 bcm) and 6.8 Tcf (or 215 bcm). By 2050 the range is between 1.4 Tcf (or 45 bcm) to 6.4 Tcf (or 200 bcm). As we are doing a scenario exercise, we do not assign probabilities to this range, and obviously this range does not cover all possibilities. For example, one can imagine different targets of GHG reduction or even more drastic limits on nuclear and coal use based on other considerations.

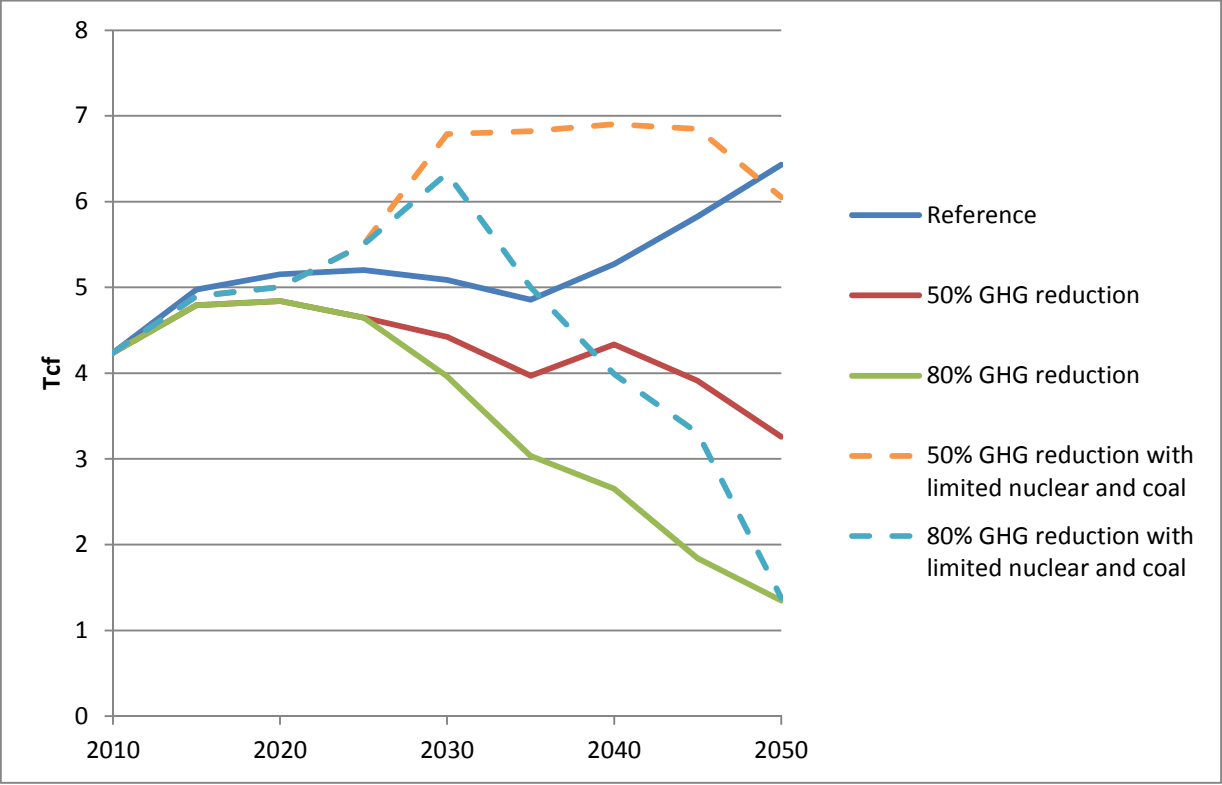


Figure 8. Natural gas exports from Russia to the EU-27 in different scenarios.

A dip in exports in 2035 and a gradual increase afterwards in the Reference scenario can be illustrated based on Figure 5. Russian imports' share in the total EU imports declines over time, driven by a competition with LNG and natural gas from other sources. The production profile in Europe changes after 2035, giving room to additional imports from Russia. Recall that with North Steam, South Steam, and Ukraine, Belarus, Baltic and Finland pipeline systems still online, the capacity for Russian exports to the EU is about 10 Tcf. The projected exports in the best case scenarios are around 4-7 Tcf. This means that with more favorable economic conditions for Russian gas than projected here, Russia can increase its exports to the EU without additional capital investments.

It is even more challenging to predict natural gas usage in the European countries that are currently not part of the EU. They all (including Turkey, Ukraine and Belarus) have some aspirational goals towards the EU. Some of them are close to that goal, like Croatia, while the prospects for some other countries in this regard are more questionable. Those that will be part of the EU or close to joining are most likely to take on the EU targets as well. The others might decide to avoid economic costs related to GHG reductions. In the scenarios considered in this paper, the non-EU European countries and Turkey follow the actions of the BRIC countries (Brazil, Russia, India, and China) of delayed participation in the carbon policy. As there are currently no discussions about nuclear shut-down or air pollution related coal restrictions, we consider only one policy scenario.

Figure 9 presents the results, where in the *Reference* scenario natural gas exports from Russia to these countries gradually increase from 2.7 Tcf in 2010 to 5 Tcf in 2050. In the *Policy* scenario, exports stay at roughly current levels throughout the period of modeling. In 2030, exports are between 3 Tcf (or 95 bcm) under the Policy regime and 3.6 Tcf (or 115 bcm) under the no-policy Reference case. Combining projections presented in Figures 8 and 9, the total numbers for Russian exports to Europe, CIS and Turkey are changing from about 7 Tcf in 2010 to 7-9.9 Tcf (or 220-310 bcm) in 2030 and to 4-11.5 Tcf (or 125-360 bcm) in 2050.

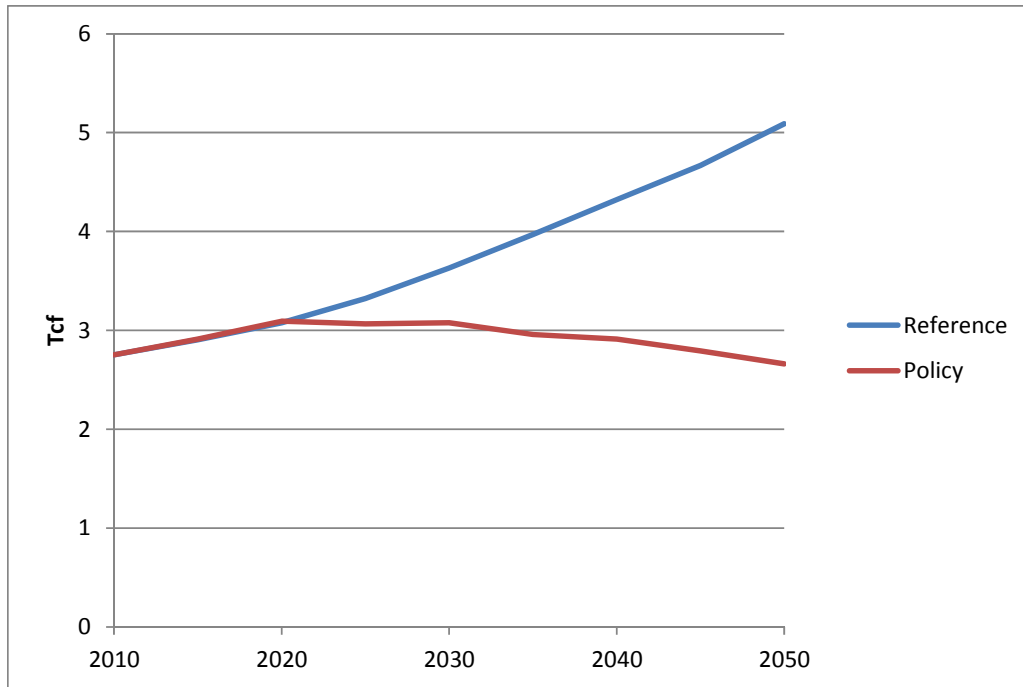


Figure 9. Natural gas exports from Russia to non-EU and Turkey in different scenarios.

Table 2 provides the total exports from Russia by destination in the *Reference* scenario, where about 10 percent of exports go to Asia by 2030 and about 20 percent by 2050. There are also some small exports flows to North America starting in 2020. The total exports grow to 10.4 Tcf (or about 330 bcm) in 2030 and 15.3 Tcf (or about 480 bcm) in 2050. Recall that the Russian General Scheme for Natural Gas Sector Development for a period up to 2030 (Government of Russia, 2010) projects exports of 14.5-16.5 Tcf (455-520 bcm) in 2030. It looks like western-oriented exports do not support the projected volumes. Therefore, in the next section we turn to the prospects for natural gas exports to Asian markets in different scenarios.

Table 2. Russian Natural Gas Exports in 2010-2050 in *Reference* Scenario, Tcf.

| | 2010 | 2020 | 2030 | 2040 | 2050 |
|---------|------|------|------|------|------|
| Europe | 6.6 | 8.2 | 8.7 | 9.6 | 11.5 |
| Asia | 0.5 | 0.8 | 1.3 | 2.1 | 3.4 |
| America | | 0.3 | 0.3 | 0.3 | 0.4 |
| Total | 7.1 | 9.3 | 10.4 | 12.0 | 15.3 |

In addition, as mentioned in Section 2, there are estimates that France and Poland might have about 180 Tcf of shale gas. If shale gas is economic, it might reduce the EU need for gas imports. So far, France has banned shale gas development for environmental reasons. Some initial drilling

activity is reported in Poland with current estimates that cost might be substantially higher than shale gas cost in the U.S. Environmental concerns are also a factor in Poland and other European countries. Another potential development that might affect the projections is coal-bed methane (CBM) in Ukraine. There are reports of TNK-BP activities in this area, but again at this point the estimates of the volumes and the cost of production are very speculative. If Ukraine is able to produce CBM at a reasonable cost, it already has the existing pipeline infrastructure to deliver natural gas to Europe.

Yet another point of consideration for the Russian natural gas trade balance is imports to Russia from Central Asia (Turkmenistan, Kazakhstan, and Uzbekistan) and Azerbaijan, mostly for re-exports to European customers. In 2010, Russia imported about 1 Tcf from these countries, while in 2007 the imports were twice as big at 2 Tcf. Azerbaijan is a source of natural gas for the planned Nabucco pipeline, that is projected to reduce a dependence of the EU from Russian supplies. Turkmenistan is another potential source of gas for Nabucco, but now it looks to be more oriented for exports to China. If Nabucco is planned as a geopolitical rather than an economic project⁴ (for example, based on the political considerations of the prospects of increased Russian gas supplies due to a reduction in nuclear generation in Europe), then China's policy towards natural gas can increase a price of European geopolitics. For more discussion about Caspian gas, see IEA (2010). In the projections described above, gas imports to Russia from Central Asia and Azerbaijan in 2015-2050 stay roughly constant at about 1.5-2 Tcf per year.

Figure 10 presents the major global trade flows among the EPPA model regions for 2030 in the *Reference* scenario, where most of Russian gas still goes to the European markets. As mentioned, in this scenario in 2030 Russia exports about 5.1 Tcf to the EU-27, another 3.6 Tcf to non-EU European countries, non-Baltic former Soviet Republics, and Turkey. It also imports about 1.7 Tcf from Central Asia and Azerbaijan.

⁴ As mentioned, in this paper we focus on economic fundamentals rather than geopolitical considerations that motivate many projects. For a discussion of geopolitics of South Stream/Nabucco competition, see, for example, Jensen (2010b, 2011b), where both North Stream and South Stream are described as a Ukrainian bypass scheme, but South Stream has the added advantage of additional capacity from the Caspian region. The problem with Nabucco is that there is not enough reliable gas supply without access to the large reserves in Turkmenistan. Jensen (2011a) also provides a perspective of Turkmenistan that has been unable to supply to Europe without dealing with the Caspian seabed jurisdictional dispute and welcomed the attention of China.

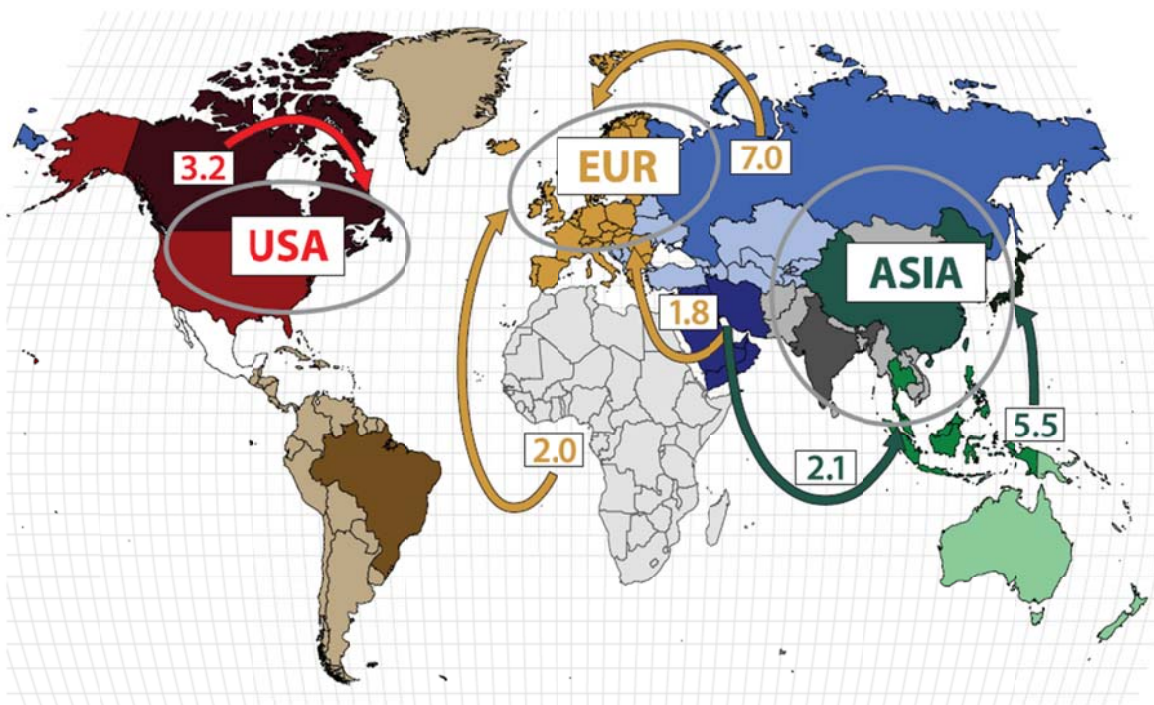


Figure 10. Major trade flows of natural gas among the EPPA regions in 2030 in *Reference Scenario* (Tcf).

MIT (2011) provides a discussion of regional versus global natural gas markets, where in the regional markets case trade tends to increase among partners where trade already exists, locking in patterns determined in part by historical political considerations. Currently world gas trade is concentrated in three regional markets: North America; Europe - served by Russia and Africa; and Asia - with a link to the Middle East. There are significant movements of gas within each of these markets, but limited trade among them. Different pricing structures hold within these regional markets⁵. For some transactions, prices are set in liquid competitive markets; in others they are dominated by contracts linking gas prices to prices of crude oil and oil products. As a result, gas prices can differ substantially among the regions. These relatively isolated, regionalized markets could be sustained for many more decades. On the other hand, it is possible that LNG or pipeline transport could grow, linking these three regions, with the effect of increasing interregional gas competition, loosening price contracts tied to oil products and moderating the price deviations among the regions.

⁵ More discussion about the natural gas pricing in different regions and prospects for price regime developments can be found in IEA (2011), Jensen (2011b), Stern and Rogers (2011).

5. CAN RUSSIAN NATURAL GAS GO TO NON-EUROPEAN MARKETS?

As mentioned above, in 2009 natural gas from Sakhalin LNG started to serve the Asian market, primarily Japan and South Korea. The Asian gas consumption in 2010 was about 20 Tcf, a volume comparable to the total Russian gas production. According to BP (2011), China overtook Japan as the largest natural gas consumer in Asia with a use of about 3.9 Tcf. Japan consumed about 3.3 Tcf. Other big consumers in Asia in 2010 were India with 2.2 Tcf, Thailand with 1.6 Tcf, South Korea with 1.5 Tcf, Indonesia and Pakistan with 1.4 Tcf, and Malaysia with 1.3 Tcf of natural gas use.

The recent shut-down of nuclear power plants in Japan increased the need for gas there, but Russia currently is not in a position to increase its exports in the short run. To serve an increasing demand from Asian countries, substantial investment in infrastructure is needed. In Section 3 we discussed some of the projects that are currently under consideration. The biggest unknown is how China's demand for natural gas will develop over time. Natural gas is more expensive than coal, but China promotes its use in residential and commercial sectors. There are also plans for an increased natural gas-based electric generation. Natural gas use in China has risen from 1.6 Tcf in 2005 to 3.9 Tcf in 2010, but it is still just a small fraction of total energy use in China that is dominated by coal. China's gas production also grows rapidly and currently about 85 percent of its gas use is produced domestically. To expand gas use further, China needs to increase both production and imports. In fact, IEA (2011) in its updated outlook, where natural gas prospects in the world are uplifted, attributed the biggest increase in gas use to China, where by 2035 it grows to 20 Tcf, the volume equivalent to the current U.S. natural gas consumption.

China has ambitious plans for natural gas in its 12th 5-year plan. Deutsche Bank (2011) estimates that the plans by China translate into 9.2 Tcf of gas usage by 2015 from its 2010 use of 3.9 Tcf. It also estimates that 2015 imports will be 1.15 Tcf of LNG and 1 Tcf of pipeline gas from Turkmenistan. IEA (2011) projects that by 2035 China would need to import about half of its natural gas use, or about 10.5 Tcf. EIA (2011) estimates 1275 Tcf of shale gas resources in China. Again, the costs are unknown at this point. It is reported that major international companies like ExxonMobil and Shell are searching for the big discoveries of shale gas in China, but so far no game-changing announcements have been made.

In addition to building pipelines from Turkmenistan and Kazakhstan, China is developing LNG facilities to receive gas. As mentioned before, negotiations with Russia are still under way

with a major obstacle being the price of gas. India has also expressed an interest in Yamal LNG, where the Russian independent gas producer, Novatek, is working with a French company, Total SA, on the development of the proposed plant.

In this paper we run two scenarios for the Asian gas markets, focusing on the impacts of alternative scenarios for natural gas development in China.

- *Reference* which assumes no natural gas policy in China and no climate policy, so this scenario is the same as the Reference case discussed in Section 5.
- *Asia Gas Policy* scenario that assumes an increased natural gas use in Asia while other regions of the world have no climate policy.

Figure 11 illustrates natural gas use in Asia in these scenarios. It also provides the historic data for 2000-2010 from BP (2011) and projections for the Asian region from IEA (2010) and IEA (2011). Most of the increase in the IEA (2011) “Golden Age of Gas” study is driven by China. In this paper we also target a similar increase in natural gas consumption, mostly driven by an increased gas use in China. There are also increases in gas use in Dynamic Asia (South Korea, Thailand, Indonesia, Taiwan, Philippines, Malaysia, and Singapore) and Japan in comparison to Reference case, but these increases are modest.

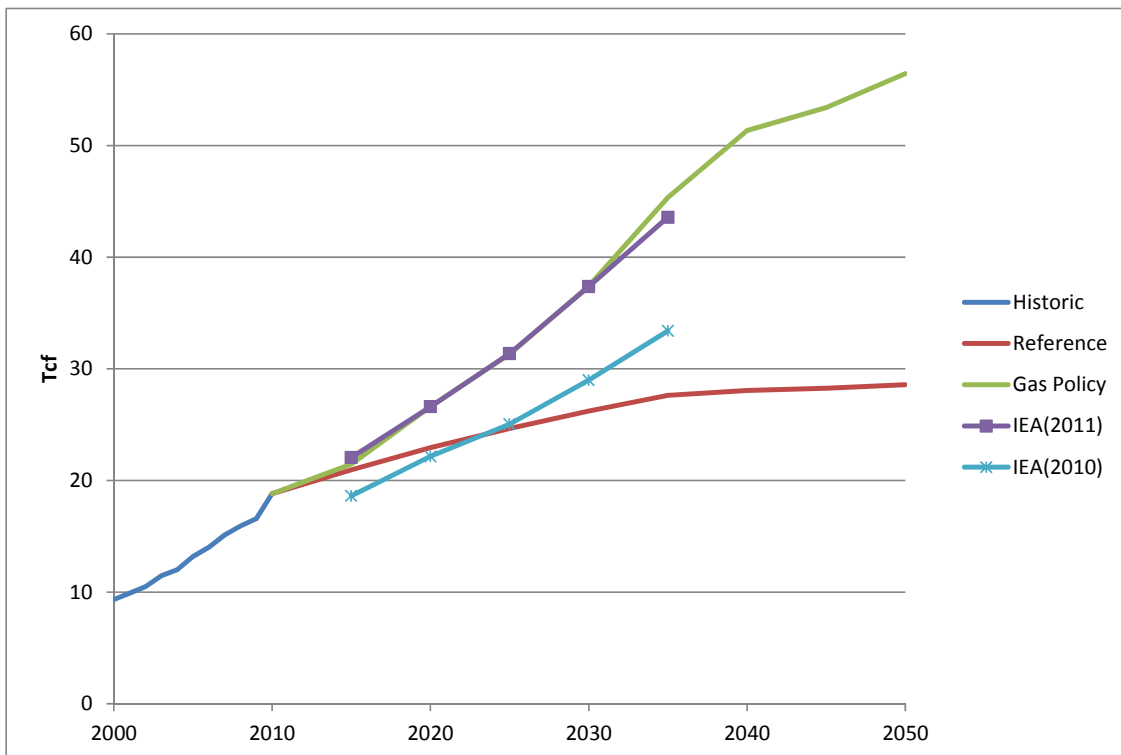


Figure 11. Natural gas consumption in Asia in *Reference* and *Asia Gas Policy* scenarios.

Figure 12 shows the projected export flows from Russia in the *Reference* and *Asia Gas Policy* scenarios. With more demand from Asia, Russia’s exports to the region increase substantially. In the gas policy scenario, by 2020 exports to the Asian markets are about 15 percent of total Russian natural gas exports. By 2030, about a third of Russian natural gas exports are destined to Asia, and by 2050 this share reaches more than 50 percent.

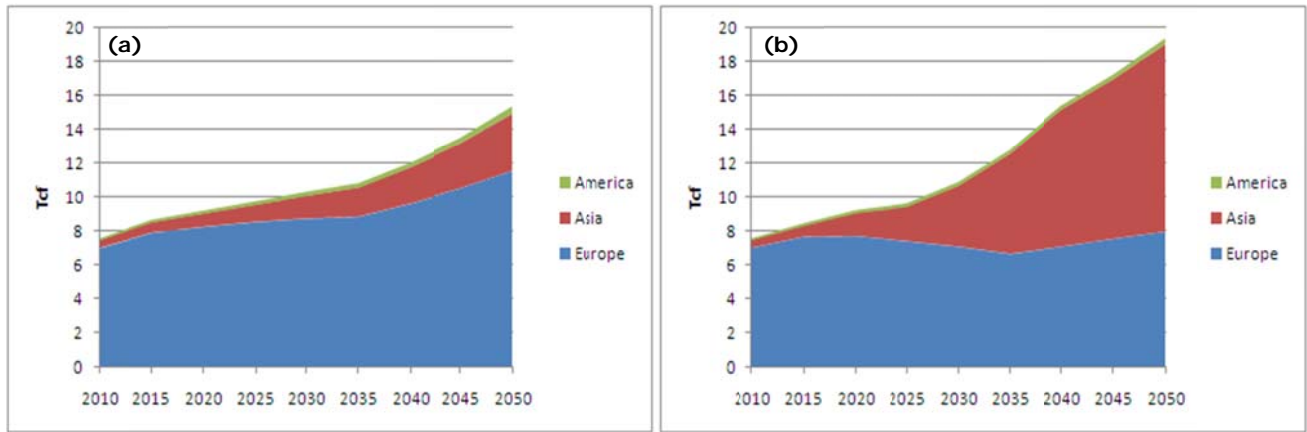


Figure 12. Exports of Russian gas by destination: (a) *Reference Scenario* and (b) *Asia Gas Policy* scenario (Tcf).

As can be seen from Figure 12 and **Table 3**, European exports are lower with higher demand from Asia in comparison to the Reference scenario provided in Table 2. With an increased demand, higher natural gas prices lead to a lower gas use in Europe and Russia re-allocates gas exports from Europe. This re-allocation is rather slow and by 2020 exports to Asia are about 1 Tcf, a volume that can be covered by Sakhalin and Yamal LNG, and/or one pipeline. The model results actually show a minor decrease in total exports from Russia in 2020, mostly due to higher gas prices. Part of the reduction in exports to Europe can also be attributed to lower re-exports of natural gas from the Central Asian countries, as they supply natural gas to China instead of sending gas to Europe directly or via Russian transit.

Interestingly, up to 2030 the total exports from Russia are not very different between the scenarios. From 2030, economics favors more gas exports from Russia, and these increased volumes require additional pipelines and/or LNG plant construction. Retuning again to the stated goal of 14.5-16.5 Tcf in the Russian General Scheme for Natural Gas Sector Development, it is reached in this scenario, but 10 years later than planned. As for another goal, 31.8 Tcf (1000 bcm) of gas production by 2030, it is reached by 2040-2045 in the scenarios considered here.

Russian domestic consumption grows both in *Reference* and *Asia Gas Policy* scenarios, reaching 15.9-16.5 Tcf (500-520 bcm) in 2030 and 16.8-17.8 Tcf (530-560 bcm) by 2050.

Table 3. Russian Natural Gas Exports in 2010-2050 in *Asia Gas Policy* Scenario, Tcf.

| | 2010 | 2020 | 2030 | 2040 | 2050 |
|---------|------|------|------|------|------|
| Europe | 6.6 | 7.7 | 7.1 | 7.1 | 7.9 |
| Asia | 0.5 | 1.3 | 3.6 | 8.1 | 11.0 |
| America | | 0.2 | 0.2 | 0.3 | 0.4 |
| Total | 7.1 | 9.2 | 10.9 | 15.5 | 19.3 |

As stressed by MIT (2011), there is a substantial uncertainty in the estimates of unconventional reserves even in North America, where a development of these resources is more advanced. Uncertainty about unconventional reserves in China is much larger, and we do not cover the wide range with a limited number of scenarios provided in this paper. The *Reference* scenario, which is based on the MIT (2011) estimates of natural gas in Asia, does not include unconventional resources there, and while gas use in Asia is increasing even under this assumption, economics still favors coal use, which increases even faster. A share of natural gas in Asia's energy system can be increased if lower cost supplies are available, or if gas is forced by a policy that directly favors natural gas use or restricts coal use due to GHG emissions or air pollution. Opinions about a success of the proposed policies towards the natural gas vary (for example, see Deutsche Bank (2011) for their estimate for a viability of natural gas goals in China). For the *Asian Gas Policy* scenario considered in this paper, we force natural gas use in Asia to the volumes consistent with a recent high estimate from the IEA (2011). That estimate in turn is based on optimism about lower natural gas prices and substantial unconventional reserves in China available at a relatively low price. As discussed earlier, China plans for a larger natural gas use in its energy system, the decision which is not economic at the current coal and gas prices. If lower natural gas prices do not materialize (for example, due to higher cost of development of unconventional reserves, inability to secure LNG and pipeline imports, or an increased demand for natural gas to replace nuclear generation), a political will to promote a relatively expensive fuel might be altered. Then, the gas use in Asia will be lower than in the *Asian Gas Policy* scenario considered here. Other aspects that might affect natural gas use in Asia are the willingness to impose the GHG constraints by the countries in the region, the stringency of GHG reductions, an attitude towards the expansion of nuclear power, and cost

competitiveness of renewables. A difference between the *Reference* and the *Asian Gas Policy* scenarios provides a wide range of different potential options for future natural gas use in Asia. On the other hand, if Asia has no GHG constraints and/or natural gas is supported by subsidies for its use, or penalties for coal use, then GHG policies in developed regions, discussed in Section 4, reduce gas use there and increase gas use in Asia even further. Asian gas use then increases by additional 1-5 Tcf in 2030-2050 and Russian exports to Asia grow by up to 1.5 Tcf by 2050 in comparison to the *Asian Gas Policy* scenario.

With a shale gas boom in the United States, nobody expects any sizable natural gas exports going there anytime soon. A current price difference between the U.S. market and European and Asian markets makes the U.S. a potential natural gas exporter rather than importer. However, just five years ago large LNG projects were developed and planned for supplying gas to the U.S., mostly from Qatar. The Russian Shtokman field in Arctic Barents Sea was also mostly planned for a development in connection with Murmansk LNG to supply the North American market. In the scenarios that are considered in this paper, there are no sizable exports from Russia to North America.

However, MIT (2011) studied a potential situation where truly integrated natural gas markets are developed, where suppliers and buyers interact based on economic principles and do not restrict supply or engage in geopolitically driven trade. The study shows that with updated supply information for shale gas in North America, there is a potential for small natural gas exports from the U.S. in the next decade. However, with global natural gas markets, by 2030-2040 relatively cheaper shale resources in the U.S. will be already produced and lower cost suppliers like the Middle East and Russia will be competitive again on the U.S. natural gas market. This results in lower gas prices for customers in the U.S. and an increased gas usage.

A swing from being perceived as a potential gas importer to gas exporter and to gas importer again can be viewed as a caution that the present day euphoria might turn sober. Great expectations about domestically produced shale gas or Russian gas prospects in no-nuclear Europe and increased gas demand from China should be tested against the long-term economic fundamentals.

6. CONCLUSION

A majority of natural gas exports from Russia are destined for Europe while Europe actively tries to reduce its dependence on fossil fuel imports and on Russian gas in particular. The attitude

in Europe towards the prospects for Russian imports seems to be periodically changing from a perceived dominance of Russian gas imports for years to come and a threat to a European energy security, then to perceived inadequate investments in Russian gas infrastructure and the resulting projections for a deficit in future supplies, then to a perceived LNG replacement for a majority of Russian gas imports, then to perceived substantial shale gas resources in Europe that would reduce drastically, if not eliminate, the need to natural gas imports, and then to a development of wind, solar, and biomass-based generation that would eliminate the need for fossil fuel use.

Responding to an increased demand for natural gas from Asian countries, Russia, in turn, tries to diversify its export destinations by planning LNG expansion and new pipelines. The prospects for natural gas become even more appealing after active nuclear power expansion plans in Asia become questionable with the Fukushima accident in Japan.

In this paper we have tested some of these prospects and found out that while interdependence between Russia and the EU is reduced over time, on the one hand, with increased exports of Russian natural gas to the Asian markets and, on the other hand, with LNG supplies and an increased share of non-fossil based energy in Europe, Russia and the EU still will be important natural gas trading partners for decades to come. Potentially, shale gas can play a role in Europe, and especially in China, thereby reducing the need for imports from Russia and other countries. Currently, however, the estimates of shale gas outside the North America are extremely speculative. The energy system requires long-term capital intensive investments. Therefore, there is a need for long term projections. The model simulations that are offered in this paper provide a solid start for studies that explore economy-wide market interactions, and that focus on gas use in all sectors of the economy and its international trade while competing with other fuels. As with any modeling, the exact numerical values should be treated with a great degree of caution as many aspects of the markets and industry details are simplified or beneath the level of model aggregation. On the other hand, the model projections allow testing the viability and implications of the proposed policies and scenarios. It helps to see the impacts of the policies that are not based on solid economic fundamentals as the long-term imbalances will be corrected over time one way or another.

In the scenarios considered here, we found that over the next 20-40 years natural gas can still play a substantial role in Russian exports and there are substantial reserves to support a development of the gas-oriented energy system both in Russia and in its current and potential gas

importers. In the Reference scenario, exports of natural gas grow from Russia's current 7 Tcf to 10-12 Tcf in 2030 and 15-19 Tcf in 2050. Alternative scenarios provide a wider range of projections, with many potential paths after 2020 considering the fate of nuclear and coal regulation in Europe and a level of support of natural gas in Asia. Projections of shale gas development in China (and in Europe) are still highly uncertain. Depending on the costs of these resources and environmental regulations in place, they may displace higher cost imports to these regions. At the same time, larger gas reserves in China would facilitate a shift from coal to gas and further induce gas use in different sectors of the economy, opening a door for additional lower cost imports. By 2030, about a third of Russian natural gas exports might be destined to Asia, and by 2050 this share can reach more than 50 percent. Patterns of international gas trade show increased flows to the Asian region from the Middle East, Central Asia, Australia, and Russia. Europe's reliance on LNG imports increases, while it still maintains sizable imports from Russia.

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