RUSSIAN GAS ABYSS ¹

Dmitry Volkov, Center for Energy Economics, Bureau of Economic Geology, University of Texas at Austin, 713-654-5403, dmitry.volkov@beg.utexas.edu
Ruzanna Makaryan, Center for Energy Economics, Bureau of Economic Geology, University of Texas at Austin, 713-654-5402, ruzanna.makaryan@beg.utexas.edu

Abstract

The mid-2000’s brought significant changes in commercial and regulatory frameworks for natural gas and electric power in Russia. These changes substantially broadened possible scenarios for natural gas supply/demand equilibrium in the region. This paper analyzes current and potential factors affecting development of the natural gas industry in the country, such as the major shift in the country’s energy balance to coal and nuclear replacing natural gas in power generation, scheduled liberalization of natural gas and electricity prices, evolving fiscal regimes for upstream oil and gas, and the emergence of LNG exports. Changing energy balance and rationalization of prices are expected to reduce domestic demand, while the fiscal regime changes and growing world market for LNG will likely influence the natural gas production by both Gazprom and independent oil and gas companies.

Recently, officials from the IEA and European Union (EU) raised serious concerns about overdependence on and long-term availability of Russian gas. We will revisit the validity of this widespread notion of a potential natural gas deficit in Russia and the possible negative implications for major consumers in Europe and Asia by major factors which might affect Russian natural gas balance and quantifying our observations above into a demand-supply scenario analysis. We believe that current catastrophic forecasts² on Russian domestic natural gas balance are somewhat exaggerated. Our base scenario calls for commodity markets to enter a downward trend in 2010-2011, while energy efficiency actions start taking effect at the same time.

Russian estimates for domestic supply are rather in line with foreign projections. Gazprom gives a range of 683.1-710.1 bcm for 2010 and 788.9-921.6 for 2030, while the Ministry of Economic Development and Trade projects 702 bcm for 2010 under its base scenario and 717 bcm for the same year, assuming unrestricted access to pipeline network for independent producers.

The U.S. EIA projects domestic production of 705 bcm in 2010, 776 bcm in 2015 and 997 bcm in 2030. We believe that a level of 710-720 is realistic for 2010, at the same time being a little bullish for 2015 with a 780-810 bcm projection.

Further research of the subject requires a major general equilibrium modelling effort. Currently, CEE-UT researchers are expanding the Center’s analysis resources and modeling activities to deal with complex issues and decisions. CEE-UT anticipates research outputs on energy/economy and energy/environment for special studies, ongoing assessments in the U.S., and new challenges stemming from carbon management and emerging new value chains.

¹ The research for this paper was supported by CEE-UT sponsors. For more information on CEE-UT research initiatives, please visit our website www.beg.utexas.edu/energyecon

²The range of domestic natural gas deficit is really impressive: from 40 bcm in 2010 according to RAO UES to Former deputy energy minister Vladimir Milov with 126 bcm as a worst case scenario (as cited in Riley & Umbach. Out of Gas. IP, Spring 2007, p.83).
RUSSIAN GAS ABBYSS

Introduction

The mid-2000’s brought significant changes in commercial and regulatory frameworks for natural gas and electric power in Russia. These changes substantially broadened possible scenarios for natural gas supply/demand equilibrium in the region.

This paper analyzes current and potential factors affecting development of the natural gas industry in the country, such as the major shift in the country’s energy balance to coal and nuclear replacing natural gas in power generation, scheduled liberalization of natural gas and electricity prices, evolving fiscal regimes for upstream oil and gas, and the emergence of LNG exports. Changing energy balance and rationalization of prices are expected to reduce domestic demand, while the fiscal regime changes and growing world market for LNG will likely influence the natural gas production by both Gazprom and independent oil and gas companies.

Recently, officials from the IEA and EU raised serious concerns about overdependence on and long-term availability of Russian gas. We will revisit the validity of this widespread notion of a potential natural gas deficit in Russia and the possible negative implications for major consumers in Europe and Asia by major factors which might affect Russian natural gas balance and quantifying our observations above into a demand-supply scenario analysis.

Major Natural Gas Supply/Demand Factors in Russian Federation in the Mid-Term Demand

Current energy mix in Russia is dominated by the natural gas (55%) followed by oil and coal (18% and 16% accordingly) (see Figure 1 below).

Natural gas was mostly consumed in 2006 in electric generation (39%) and industrial sectors (30%) with residential and communal heat demand at 20% (see Figure 2 below).

Figure 1. Domestic Energy Mix

Figure 2. Russian Natural Gas Balance: Demand

The new wave of interest of private sector to electricity generation originated few years ago on the tide of public enthusiasm about electricity sector reform. Generation, sales and repair companies were to be gradually shifted under private ownership, while transmission and dispatching were to remain under state control. Generation was consolidated into Territorial Generation Companies (TGK), containing primarily heat and power plants (CHPPs), and Wholesale Generation Companies (WGC), six of which representing thermal power plants and remaining one – hydro generation. There are also few assets excluded from TGK/WGC scheme – primarily newly built assets (Severo-Zapadnaya CHPP etc), isolated power companies (mainly in Siberia and Far East), and independent companies, existed from the beginning of 1990’s.

---

3 The research for this paper was supported by CEE-UT sponsors. For more information on CEE-UT research initiatives, please visit our website www.beg.utexas.edu/energycon


Recently announced liberalization of non-residential wholesale electricity market (see Figure 3 below) provoked massive investment into power sector and significantly raised appeal of the natural gas assets in Russia.

**Figure 3. Electricity Market Liberalization in Russia**

At the same time Russian Government recently approved a gradual shift to netback European natural gas prices by 2011, which in turn could change domestic energy mix, mostly in power sector (see Figure 4 below).

**Figure 4. Natural Gas and Coal Price Scenarios for Heat Stations**

Liberalization of gas prices with long-term reference points gives companies certain planning capacity. It is logical to suggest that with gas prices going up heat stations (TEC) and condensing power plants (CPP) will be willingly switching to coal since many of them have multi-fuel design and equipment is still in place. In fact, Gazprom suggested $500 million program of switching 33 gas-and-oil-burning power plants to coal as far back as 1999. Various estimates on the effect of fuel switching and replacement of obsolete equipment ranged from 8 to 27 bcm/year, yet RAO UES


7 Energy Research Institute at Russian Academy of Science provided an estimate of less then 8 bcm/year in 2000. In late 2006 Dr. Volkova from Energy Research Institute at Russian Academy of Science guessed that about 4 GW is possible to retrofit to coal, with 3-4 additional GW of capacity due to fuel switching at gas-and-coal-burning power plants. PAO E’S mentioned 27 gas-and-oil-burning and gas-and-coal-burning power plants that will release about 27 bcm/year.
management is pessimistic about the idea. Most recent list of power plants with switching capacity to coal has been jointly prepared by the Government of Kemerovo region and Gazprom and included 27 plants, which could release 27 bcm of natural gas and increase coal consumption by 30 mt annually, was later downsized to 16 plants and was introduced to Russian Government.8

Moreover, it is natural to expect that new owners of power generation assets with controlled stake would fully capitalize on switching strategy to corresponding fuels - coal for coal-mining SUEK and natural gas for Gazprom and other oil and gas companies (for more details on the latter see Oil and Gas companies in power sector below), if the economics and synergy effect are in place. This scenario is being confirmed by recent Gazprom bid to buyout control stake in biggest Russian coal-mining company SUEK (currently Russian Anti-Monopoly Committee is scrutinizing the case). The main caveat of such conclusion is that investment decision-making mechanism for both TGK’s and WGC’s is completely unclear at the moment. One of the major conditions for power sector restructuring was development by RAO UES and implementation of long-term General Scheme of Power Generation Objects till 2020, developed by RAO UES and partially approved by the Government in April 2007 (see Table 3 below). Initial concept suggested that private investors would undertake investment commitments, approved in the General Scheme, yet first tenders on power generation assets showed reluctance of new owners to follow original idea blindly. It is possible that some TGK’s and WGC’s will follow example of WGC-1, which is planning to run a tender for an independent technical agent, who would oversee and control utilization of funds in accordance with the General Scheme via escrow accounts. Currently investors are to sign a Memorandum that stipulates a list of major decisions to be coordinated with RAO UES. Such mechanism does not seem to contain an absolute legal guarantee, and some investors allegedly consider such Memoranda a mere non-committal formality.9 According to the most recent RAO UES directive10, investors in the person of TGK’s and WGC’s are to sign contract with both Wholesale Power Market Trading System Administrator and its subsidiary, Financial Settlement Center. Investors, especially the ones that own generating companies, are reluctant to sign those contracts due to significant liability exposure. Apparently, the parties will find a middle ground; the only question is the degree of such compromise: the General Scheme stipulates for whopping $35 billion of its own investments in 2007-2010, which is almost comparable with estimated total investments in hydrocarbon sector in Russia. Even if the companies find additional investments effective and legit, availability of funds seems to become a reasonable concern.

Power plant efficiency in Russia currently has a maximum of 38% for gas and 34% for coal if used as a main fuel for condensing power plants (CPP) versus 54% and 40% for European and US practice accordingly. There is also an efficiency resource for an obsolete gas-fueled power generation, which has been taken into account in the General Scheme, where replacements of 45.3 GWt are stipulated for thermal power plants.11

Table 1. Projections of Power Generation Demand by Fuel According to General Scheme of Power Generation Objects till 2020

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas (bcm)</td>
<td>143</td>
<td>162.9</td>
<td>166.9</td>
<td>174.8</td>
<td>186</td>
</tr>
<tr>
<td>Coal (million tons)</td>
<td>121</td>
<td>136</td>
<td>151</td>
<td>153</td>
<td>159</td>
</tr>
</tbody>
</table>

Source: Energetika: Tormoz ili lokomotiv Razvitiya economiki? Presentation by RAO UES Chairman A.B.Chubais, Moscow, 13.02.2007

There are several problems with natural gas demand prognosis by power sector, contained in the General Scheme, especially in the long run. Firstly, it is really difficult to project such factors as a work load of a particular power plant when there is an uncertainty in prices for electric power on the one hand and natural gas and coal on the other, due to liberalization in natural gas and electric power markets. One of the major means to reduce these uncertainties – long-term contracts – has just started to be introduced on the fuel supply side: beginning April 2007 power generation companies are to sign five-year gas supply contracts on the take-or-pay terms with natural gas suppliers. However, natural gas volumes, reserved by RAO UES till 2010 on behalf of TGK’s and WGC’s, were contracted on take-or-pay basis, and could serve a reasonably good benchmark for power sector demand.

Secondly, electricity consumption is expected to grow at 4.9% annually in 2006-2010, which is comparable to record single stage growth of 4.2% in 2006 (average figure for 2000-2005 equals 1.7%). Even if the GDP growth will be equitable with 6.7% level of 2006 (while 7.1% in January-April 2007), industrial growth will have to show the same

---

8 Interfax, May 18, 2005.
dynamics. As we expect Russian economy maturing structurally in coming years, it is likely that less power consuming service center will expand its share, and therefore overall electricity demand growth to be more subtle.

Thirdly, having Gazprom in charge of both majority of natural gas supply for power generation and gas main system operator created massive problems for ROA UES in recent years. Lack of coordination of development plans between the monopolies led to thermal power plants being built and then sitting idle due to lack of guaranteed natural gas supply. At the end of 2006 the Second Power Unit of highly efficient and ecologically friendly Severo-Zapadnaya TEC with planned annual consumption of 0.8 bcm was officially launched, yet as of May 2007 it has not produced a single kWh – Gazprom did not have supply planned in advance. In addition to that, the obvious mismatch of gas transportation system capabilities with soaring demand in certain regions of Russia degrades the situation. In case of Kaliningrad TEC-2, a 450 MW First Power Unit, which started operation at the end of 2005, is undersupplied 15% due to limited pipeline transmission capacity, while the construction of Second Power Unit with planned annual consumption of 0.75 bcm was shelved altogether.12

Industrial Demand

Industrial demand for natural gas have been showing strong growth in recent years and estimated to be about 120 bcm, about 27% of total domestic demand in 2006. Major consumer groups include metallurgy (about 25% of total industrial demand), followed by chemical and cement industries (16% and 5% accordingly).

Such factors as strong commodity markets driven by domestic and foreign demand, overall economic and personal real disposable income growth and capital investment boom became common for these industries and are likely to stay in the picture in the short-term.

Recent developments in energy regulation and strategy might change natural gas demand footprint. Some industries will be affected more than the others due to specifics of capital and production expenditures. As one can conclude from Table 3 below, chemicals, cement, aluminum, zinc and ferroalloys production are the most gas intensive industries that could be hit the most under liberalization of natural gas prices.

Most of the aluminum industry has a secured (through long-term contracts, equity participation or major investments in creation of new hydroelectric capacity, as in case of Boguchanskaya GES) source of cheap and reliable hydro electric power supply. More than eighty percent of aluminum in Russia is produced using hydro energy.

Other metallurgy sectors (such as zinc and ferroalloys production) represent only a small share of Russian industrial production (less then 1% of overall non-ferrous metals and 2.5% of overall ferrous metals production).

Cement industry is currently fueled by construction and investment boom in various industries, including power generation, creating ever-growing demand for its production.13 Low energy efficiency and increase in natural gas prices and electricity tariffs could potentially distress the industry. The market is very strong and even though capacity utilization is currently at 60%-14, there is a lot of new capacity on the way, which is expected to go online by 2009 – 2010 and increase production potential at least by 10%. At the same time, cement industry is highly profitable with net profit margins often exceeding 20%.

One could expect that, with looming increase in prices for gas and electricity, Russian cement companies will follow example of Ukrainian cement industry (owned mostly by the Russian companies anyway) which are running accelerated retrofit program from natural gas to coal; yet Russian cement players do not nurture such costly investment programs. Under these circumstances we expect that natural gas consumption in cement industry will steadily grow and will reach up to 10-15% increase by 2010.

---

Table 2. Share of Monopoly Products in Production Costs (%) and Consumption in 2006 (BCM) in Various Industries in Russia in 2006\textsuperscript{15}

<table>
<thead>
<tr>
<th>Industry</th>
<th>Natural Gas (%)</th>
<th>Electricity (%)</th>
<th>Railroad transportation (%)</th>
<th>Natural Gas Total (Natural Gas + Electricity)(%)</th>
<th>Demand in 2006 (BCM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipe manufacturing</td>
<td>3.5</td>
<td>8.3</td>
<td>6.3</td>
<td>9.14</td>
<td></td>
</tr>
<tr>
<td>Ferrous metals</td>
<td>4.6</td>
<td>7.4</td>
<td>21.1</td>
<td>9.63</td>
<td></td>
</tr>
<tr>
<td>Metal mining industry</td>
<td>1.7</td>
<td>15.4</td>
<td>22.8</td>
<td>12.17</td>
<td></td>
</tr>
<tr>
<td>Wire products</td>
<td>2.7</td>
<td>8.9</td>
<td>6.6</td>
<td>8.75</td>
<td></td>
</tr>
<tr>
<td>By-product-coking industry</td>
<td>2.8</td>
<td>4.7</td>
<td>12.8</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Refractory products</td>
<td>5.2</td>
<td>5.1</td>
<td>6.2</td>
<td>8.67</td>
<td></td>
</tr>
<tr>
<td>Ferroalloys</td>
<td>1</td>
<td>24.7</td>
<td>6.2</td>
<td>17.8</td>
<td></td>
</tr>
<tr>
<td>Aluminum</td>
<td>2</td>
<td>31</td>
<td>8</td>
<td>23.08</td>
<td></td>
</tr>
<tr>
<td>Copper</td>
<td>1.5</td>
<td>10</td>
<td>6</td>
<td>8.3</td>
<td></td>
</tr>
<tr>
<td>Zink</td>
<td>0.5</td>
<td>25</td>
<td>1</td>
<td>17.5</td>
<td></td>
</tr>
<tr>
<td>Cement</td>
<td>25</td>
<td>20</td>
<td>15</td>
<td>38.6</td>
<td>6</td>
</tr>
<tr>
<td>Fertilizers (Chemical industry)</td>
<td>40</td>
<td>12</td>
<td>15</td>
<td>48.16</td>
<td>21</td>
</tr>
<tr>
<td>Electricity</td>
<td>68</td>
<td>0</td>
<td>0</td>
<td>68</td>
<td>171</td>
</tr>
</tbody>
</table>

Chemicals manufacturing is primarily serving yet to be saturated domestic market, and following domestic consumption boom, industry is planning major capacity additions, that, if completed, would amount to 29.5 bcm by 2015\textsuperscript{16} (compared to 9.8 bcm in 2005). At the same time potential natural gas savings from modernization of all enterprises in the industry are estimated to reach 1.5 bcm at most.\textsuperscript{17}

Chemical production, and, above all, manufacturing of chemical fertilizers, could potentially be hurt by the end of the decade. We believe that the sector could withstand liberalization of natural gas and electricity prices due to above-average current profitability (Russian fertilizer companies had EBITDA profitability at around 25-30% versus 10-15% at their foreign counterparts), yet the “factor of safety” is likely to be completely wiped out by 2010.

Population and Communal Heat Consumption

Communal heat and power system was established in 1960-1980’s when the Government was implementing massive residential construction programs. In the distress of 1990’s little attention was paid to maintenance of public utilities’ infrastructure. As a result “wear and tear” in district heating, according to some estimates reaches 60-70%\textsuperscript{18}, and centralized heat supply system has a 30% loss rate or about 66 bcm of natural gas annually.

In 2005 Gazprom launched a massive $1.250 billion program of regional gasification, aimed to increase gas penetration from 53% in 2005 to 60% in 2007. Gazprom planned to lay 12,000 km of gas pipeline to reach to more than a thousand centers of population with over 11 million people. In fact, Gazprom claims to exceed these results, reaching 64% penetration in 2007.\textsuperscript{19} In addition to that, there is a program of regional gasification on LNG basis, but on a much smaller scale.

\textsuperscript{15} RosStat, FAS, MinPromEnergo, CEE estimates.
\textsuperscript{18} B.Nigmatullin, A.Gromov Kak Svesti Balans? IPEM, 2006.
Despite the apparent expected growth in natural gas consumption by population, there are several important details. Overall gasification rate together with liquefied gases is at much higher level - 74%, and most of the pipeline gas will simply replace liquefied gases. At the same time gas-meter penetration level in Russia is currently at paltry 15% (ranging from 5.2% in North-West region to 41.2% in South region). In order to reinforce population gas consumption accounting routine, the Government issued a decree, aimed at regulation and introduction of minimal natural gas consumption rates for consumers unequipped with gas meters.

Such data show that regional gasification program coordinated and partially financed by Gazprom is not a charitable action. We see it as a tremendous opportunity for Gazprom to improve its domestic sales economics on the one side and as a start for release of enormous energy efficiency resource in the country on the other. In fact, one of the main criteria to choose investment mediums was a 12% minimal internal rate of return. At the same time, average natural gas tariff for population is scheduled to increase from $39/mcm in 2006 to $55.5/mcm in 2009.

Implications for Exports

Gazprom possesses an impressive gas export pipeline network and is continuously expanding it. Annual export capacity to Eastern and Central Europe was increased to 196 bcm per year (including a 5-bcm pipeline to Finland and 16 bcm of Blue Stream to Turkey) and is expected to increase further to 267 bcm by 2015.

In recent years, Gazprom has showed opposite dynamics with respect to exports to foreign countries as opposed to “near abroad” (the former Soviet republics, CIS). While exports to the former steadily grew from 153.2 bcm in 2004 to 156.1 bcm in 2005 and 160.3 in 2006 (with an abnormally warm winter in 2006), exports to CIS declined -- from 47.12 and 47.3 bcm in 2004 and 2005 respectively to 40.5 bcm in 2006 (natural gas originated in Russia amounted to 27.4 bcm in 2005 and 20.2 bcm in 2006). This development, not surprisingly, was primarily due to Gazprom’s campaign to increase natural gas prices for these countries.

Export of natural gas, and in particular export to Western and Central Europe, was always considered a priority for both Gazprom and the Russian government, and this attitude is expected to remain in place in spite of projected deficits in the Russian natural gas balance.

Commonwealth of Independent States (CIS)

Ukraine is the biggest consumer of Russian natural gas among the CIS countries. In spite of gradual price increase, Ukraine did not curb its consumption much: medium-scale introduction of energy-saving technologies in industrial and power sectors gets balanced by industrial and overall economic growth due to favorable commodity markets. Ukraine’s own production has stabilized around 20 bcm a year (about 26% of domestic demand) and, although there are plans to ramp up production by 10-12 bcm a year primarily at Azov and Black Sea shelf, we do not expect these plans to become a reality earlier than 2014-2014. Despite the 5% drop in consumption, Ukraine went trough the natural gas price shock of 2005-2006 relatively easy.

Belorussia has not become an exception in new Gazprom course to bring all gas export prices in netback parity with West European benchmark. Gazprom has only pledged to deliver 21.8 bcm in 2007 as a compromise in the context of negotiation on the ownership of Belorussian gas trunkline network.

Gazprom has been trying to obtain control over Beltransgaz which governs gas export trunklines to Europe (to Poland and Germany) since 1994. Gazprom owns Yamal-Europe export pipeline, build in 1999, with full capacity of 34 bcm annually. Gazprom has finally arranged in May 2007 a phase purchase of control stake in the company for $2.5 billion (12.5% chunks annually in 2007-2010).

Europe

In spite of politically driven desire to reduce dependence on Russian natural gas, it does not seem as a realistic perspective in the mid-run. EIA estimates that OECD European natural gas consumption will reach roughly 600 bcm in 2010 and 650 bcm in 2015 (see Figure 5).
Such growth rate has been taken into account by Gazprom and the company projects exports to “far abroad” to reach 194 bcm by 2010. At the same time import from Central Asia is expected to grow from 60 bcm in 2006 to 63-90 bcm in 2010.

We don’t expect Gazprom to cover most of the European demand growth by 2015, taking into account export pipeline projects from North Africa and exponential growth in LNG consumption. Needless to say that looming EU initiatives related to energy sector liberalization, supply diversification and climate change are likely to amend Gazprom export capacity in the mid- and long-run.

At the same time we believe that Gazprom will be able to fully supply volumes, demanded by European customers in the medium-term perspective.

Caspian Natural Gas Pipeline

The last decade was marked by continues political struggles over hydrocarbon production and control of export routes in Central Asia.

The EU together with the United States pushed for a trans-Caspian oil and gas pipeline, while Russia was interested to maintain its political preponderance and import monopoly in the region.

An EU pipeline project, named Nabucco after the legendary Babylonian king, has been under discussion since the early 2000’s, and represents an alternative to Russian pipeline gas supply for European Union. There are five key country participants in the project: Turkey, whose membership is absolutely necessary from the transit point of view; and Bulgaria, Romania, Hungary and Austria. Some transit countries (Hungary and Bulgaria) and potential suppliers (Turkmenistan, Iran and Kazakhstan) announced strong support for the project while at the same time flirting with Russia, presenting assurances of their loyalty.

Russia had long pushed for construction of a Caspian natural gas pipeline in addition to the 25 bcm “Central Asia–Centre” pipe. The Caspian pipeline project with initial capacity of 30 bcm a year will follow the west Caspian shore and eventually interconnect with a proposed South-European natural gas pipeline (named so in accordance with the North-European natural gas pipeline). Success of the project is crucial for the Russian energy balance for the next decade. If constructed, the pipeline will effectively eliminate the need for a competing trans-Caspian (transient to Nabucco) pipeline, and therefore raise the risk that control over Central Asian natural gas supplies would be, at least from the European front. At time of writing, the Russians seem to have trumped European and American interests.

Prospective suppliers of the project, Kazakhstan and Turkmenistan, have both dealt at least doubly. Swearing loyalty to Russia and its pipeline system as the main means for hydrocarbons transport, these large producers are also in talks with the EU, China, and a few other current and potential customers. Russia is playing for high stakes in this game and realizes that compromises with Central Asian states are necessary and essential. The first stage of this multi-move game included gradual price increases for natural gas: from $40/mcm to $60/mcm in 2004 and 2006 respectively for Uzbekistan, from $50/mcm to $140/mcm in 2005 and 2007 respectively for Kazakhstan (for more detail see comments on Kazakhstan below) and from $44/mcm to $100/mcm in 2004 and 2006 respectively for Turkmenistan.

In May 2006 President Putin signed two separate agreements with the heads of Central Asian states. According to the first agreement Russia, Kazakhstan and Turkmenistan pledged to rehabilitate the natural gas pipeline Central Asia–Center (or CAC) 4 and ensure its capacity from the initial 10 bcm to 30 bcm annually (currently it only has about 3 bcm

---

25 This strategy was coined “happiness is multiple pipelines” as noted by CEE researchers on assignment in Central Asia during the late 1990s.

26 More on the project could be found at the project’s web-site at http://www.nabucco-pipeline.com/
capacity). The second agreement involved all the same countries plus Uzbekistan, and concerned reconstruction and upgrade of the Central Asia–Center 3. The details of these projects will be released after a feasibility study for both projects, due for completion by September 2007. We anticipate that Gazprom will insist on investments on a geographical basis (i.e., every country pays for the segment of pipeline on its territory), while trying to obtain pipeline operator status at the same time. As far as importance of these agreements for the regional and global energy balance, we consider it to be moderate. First of all, several attempts were made to reconstruct the CAC system, the most recent of which dates back to 2004. Secondly, the start-up date for full capacity (2014) more or less coincides with anticipated launch of the proposed trans-Caspian pipeline. Taking into account that leaders of both Kazakhstan and Turkmenistan have not dismissed the trans-Caspian project even after signing documents for CAC expansions, it is very likely that they considered the trans-Caspian to be leverage against CAC and other Russian-oriented export routes.

In sum, while the Russians appear to have won out over Kazakh and Turkmen interests, we believe that Nabucco will be built and used as leverage against China, Russia and EU simultaneously.

The most recent spin in the plot was introduced in July 2007 when Turkmen President signed an agreement to build a pipeline and export 30 bcm of natural gas to China in 2009-2038. Kazakhstan and Uzbekistan joined the project a month later and agreed that the pipeline would pass through their territory. In Kazakhstan a 10 bcm a year pipeline is planned to stretch from Beineu in the south-west to Chimkent in the south, where it merges with a major 30 bcm a year Turkmenistan – Uzbekistan trunkline and continues to Khorgos on the eastern Kazakh-Chinese border.

Taking into account that all three pipeline projects (Russian, European and Chinese) are to be financed mostly (or entirely) on the consumer side, Central Asian states, in particular Kazakhstan and Turkmenistan, could find themselves in a lucrative position to play consumers against each other and make them compete for their resources. We believe that all three pipelines with roughly identical capacity have equal chances to happen, allowing for a scenario with all three in place in 2015.

Asian and North American Markets

Western Siberia and the Far East appear to be obvious resource centers for Asian markets, as customers seek reliable supplies of natural gas. Sakhalin projects go back some 30 years ago, yet only a couple of projects based on the Production Sharing Agreement (PSA) model have been implemented. Sakhalin-2 is supposed to start deliveries in the amount of 9.6 mmt of LNG beginning 2008 primarily to Japanese customers.

In March 2006 Russia reached agreement with China on construction of an export natural gas pipeline through the Altai region. The pipeline, with planned 30 bcm capacity and almost 2,700 km of length, is expected to bring natural gas from Yamalo-Nenetsk Autonomous region to the Northwest of China. Gazprom is expected to start production in 2008 and begin deliveries in 2011. The Chinese have historically been very intractable on pricing: although the level of acceptable prices has grown from $40/mcm in 2004 to $100/mcm in 2007, we doubt that they will agree to exceed the effective netback price compared to current long-term LNG projects. Taking into account price liberalization for natural gas in the Russian domestic market, exports to China would become unattractive for Russian producers on a netback basis, and we consider the project to remain speculative (if politics prevail). At the same time, the significant potential of Kovikta and other natural gas fields in Eastern Siberia could result in a change of pipeline route and supply sources, and the Northwest China project could become a reality, although much later.

North American and potentially other Atlantic basin LNG markets could receive Russian gas in 2012-2013 at the earliest in our opinion, although Gazprom still considers a launch of Baltic LNG to be achieved by 2010.

Supply

Gazprom

Gazprom is the world’s biggest natural gas company, with 17 percent of world total reserves and quarter of the world’s natural gas export market.

Its importance and influence in the Russian natural gas industry is difficult to underestimate: with 85 percent of Russian natural gas production (see Figure 6 below) and 60 percent of total reserves, Gazprom is responsible for 6 percent of Russian GDP and about 8 percent of total tax revenue.

28 It was old news in a sense: late President Niyazov signed similar agreement in Beijing in April 2006.
29 CEE estimates.
30 According to DeGolyer & MacNaughton proved reserves amounted to 18,158 Tcm, while probable equaled 2,576 bcm.
The majority of Gazprom prospected resources are in the East Siberian region (77 percent), while offshore areas have the most potential over the long-run.

Gazprom has long been eyeing offshore licenses which, during the stormy 1990’s, passed to various Russian and foreign entities. Operating almost exclusively onshore in Soviet times, Gazprom is fully aware of the strategic importance of offshore reserves, and it is the same story with Russian authorities. In 2005-2006 government officials spoke favorably of giving state-controlled companies (namely, Gazprom and Rosneft) control over these resources. The trend started to take shape as early as 2004, when Rosneft became sole licensee of Sakhalin-3. It is possible that licenses for shelf reserves will be granted on an out-of-competition basis, i.e. directly to companies, as happened in case of the Shтокман and Приразломной fields in 1993 when Gazprom affiliate Rosshelf was granted licenses against Gazprom security to finance the projects.

While government strategy for offshore exploration is under development, we expect that Gazprom and Rosneft will effectively share Russian continental shelf production. Gazprom might seek resources in the Kars and Okhotsk Sea basins, where it had been actively conducting exploration, including unallotted licenses for Sakhalin-3 and Sakhalin-6. At the same time, Rosneft operated Veninsky Block of Sakhalin-3 and may claim other adjacent areas, as well as Barents, Okhotsk and Laptev Sea. Another option is that some or maybe even all of the disputed assets could once again be handed over to a joint venture similar to Sevmorneftegaz, which existed for three years, from 2002 to 2005.

For the last decades Gazprom’s old resource base was steady declining, yet talks about the end of giant field era are premature. New fields are taking place of Yamburg, Medveje and Urengoy: Zapolarnoye field (3.3 Tcm) with 100 bcm of annual production was launched in 2004; Bovanenkovskoye (4.3 Tcm and first stage of 15 bcm to be launched in 2011, while full capacity of 115 bcm will be reached); and Shтокман field (3.7 Tcm and the first stage to go on-line in 2014 with potential of 70-100 bcm at full capacity). Most of the Yamal fields are planned in general for the third decade of this century: Kharasovey field (1.26 Tcm) will start production in 2012, while Krušmenshern (0.96 Tcm) and the Tambey group of fields (about 3 Tcm) could be in production by 2021-2022 (178 bcm at full capacity). Meanwhile, smaller fields are filling the gap: in 2005 the Vyngayakhinskoye and Yety-Purovskoye fields reached its planned production capacity of 20 bcm, and the Kharvutinskaya structure will arrive at planned 25 bcm a year in 2008.

The major problem with outlook for new developments is constant lagging. Say, the only super giant field in works – Bovanenkovskoye – was discovered in 1971, and first announcement of its development was made only a decade ago – in 1997. In 2001 the company revisited plans and targeted 2008 as a start-up year. Current mark for Bovanenkovskoye – 2011 – was recently confirmed by additional $613 million investment in 2007, unfortunately at the expense of other projects. Thus, development of Pestsoviy area of Urengoy field is shifted to 2009, peak production levels for Kharvutinskaya structure are increased to 30 bcm, yet moved from 2008 to 2010, and Shтокman investments for 2007 are cut in half – from $670 million to $336 million.

Two major trends have shaped in Gazprom strategy in recent years.

First, the company has stabilized production and is going to maintain current levels through at least 2012-2013 (Gazprom has a 546.3-555.9 bcm production forecast range for 2010 and a 595.3-655.6 bcm range for 2030). Rather than emphasize exploration and production activities, Gazprom is going to concentrate on potentially more lucrative marketing activities at home, and more attractive penetration of end user markets around the world as compared to long-term contracts with intermediate agents. Europe is a center for such activities; Gazprom already has interests in the European power sector. Gazprom’s long-term energy strategy, as presented to the board of directors in April 2007, stipulates further expansion into electric generation and distribution. The company also aggressively

---

31 Independent natural gas producers account for another 22.8 percent (10.9 bcm), while 16.6 percent of reserves are unallotted.
34 Gazprom prognosis at the end of 2006.
invests in end user markets (residential, commercial and industrial) with related natural gas transportation and distribution, as well as in district heating and utility sectors.

Gazprom has been diversifying its marketing abroad at least for the last 15 years. In 2004 Gazprom created a “pan-European” marketing company in London – Gazprom Marketing and Trading (GMT) - which is in charge of Gazprom marketing activities in Europe. GMT does not limit itself to natural gas; the company’s portfolio includes oil and oil products, electric power, CO2, and even weather derivatives.

Gazprom is using several major strategies in this regard.

- **Asset swaps with natural gas producing companies.**
  Gazprom recently arranged an asset swap with BASF, where Gazprom owns 49 percent of Wintershall Holding, producing around 5 mty in Libya – in 2006 and 2007 respectively.
  We expect an announcement to be made soon on a Gazprom stake in ENI upstream assets in North Africa and probably some other regions as part of a global cooperation pact.

- **Participation in transportation and distribution assets.**
  GMT operates Gazprom transportation capacities and the Interconnector pipeline, which connects UK and Belgium: Gazprom has 2 bcm of capacity. Gazprom has an arrangement with GMT for a signed contract with Hydro for natural gas supply through Langeled pipeline from North Sea.

- **Entrance into electric generation in target markets.**
  Gazprom has long been eyeing the lucrative UK retail market and allegedly is discussing joint ventures with British power companies. It has already reached an agreement with Teesside Power – subsidiary of International Power – to supply natural gas and CO₂ quotas in exchange of electric energy. The most recent developments on this front include agreement with Soteg SA for joint construction of 800 MW natural gas-fueled combined-cycle plant in Germany by 2010. According to the MoU, electric power produced will be partially sold by the joint venture directly to industrial consumers under the long-term arrangements, while the rest will be marketed by Gazprom Marketing & Trading Ltd. and Soteg SA. Gazprom also (together with ENEL and the affiliate Greek company Prometey Gaz) submitted a bid to build a 430 MW power plant in Greece in April 2007.

- **Wholesale activities in local markets.**
  Gazprom has retail market access arrangements in the UK, Germany, Bulgaria and other countries. Most recently Gazprom obtained access to the local market in Italy. For years Gazprom through its subsidiary Gazprom Export had secured a share of the Italian gas retail market through joint ventures and MOU’s stipulated in a JV creation with ENI S.p.A, Centrex Europe Energy & Gas AG, Central Energy Italian Gas Holding AG and Gas Plus S.p.A. In November 2006 Gazprom and ENI signed a strategic agreement. According to the agreement Gazprom will continue supply ENI with natural gas until 2035, in exchange obtaining a market entry into the Italian retail sector beginning 2007 for the period of the long-term supply contract. Beginning in 2010 Gazprom will be entitled to sell 3 bcm/y directly to Italian consumers.

- **Direct sales to retail commercial and industrial customers.**
  In the UK, Gazprom Marketing and Trading Ltd acquired Pennine Natural Gas Ltd and sells natural gas to various retail commercial and industrial customers (soccer clubs and restaurant chains are among them). Overall in the UK, the company has about 1 percent of the retail market with more than a thousand individual consumers and hopes to reach a 5-10 percent market share by 2010. GMT has supplied 4 bcm in the UK and Belgium in 2005, and concluded 2006 with 7 bcm of sales in UK, Belgium, Holland and France. GMT has recently announced plans to increase sales in France by 2 bcm. The company is actively using Gazprom natural gas underground storage facility for arbitrage purposes (including interstate arbitrage operations) and effectively performs a dual buyer/seller role, using volumes from other non-Gazprom suppliers. In April 2007, a joint venture of Gazprom and Wintershall - Wingas - acquired the remaining 50 percent stake in UK natural gas trader HydroWingas (1.2 bcm of sales in 2006), increasing Gazprom’s overall stake in the company by 50 percent.

• Direct sales to residential customers

The “last mile” is probably the most difficult one, yet Gazprom is planning, and no doubt will work hard, to squeeze into this most lucrative market segment.

**Commercial Frameworks for Competition in Russia’s Natural Gas Sector**

The beginning of this century was marked by a shift in attitudes among Russia’s independent companies, most notably oil companies, toward natural gas production. Importantly, this shift in attitude included natural gas production outside of Russia. At that time most companies stated increases in natural gas production as their primary strategic goal. Lukoil, for example, made indicated 30-40 percent as a “key [production increase] target in the Company’s development strategy” in the mid-term.37

Major obstacles to increased natural gas production by non-Gazprom companies could be summarized as follows.

• Limited access to gas pipeline network.

• Peculiarities of price setting system for natural gas production within Russia.

• Restrictions on natural gas exports.

• Lack of a conducive environment for long-term contracts.

In theory local gas pipelines could be laid and owned by private companies, yet access for third party shipping is controlled by Gazprom. The Russian Anti-Monopoly Committee has long been pushing Gazprom for gas network access liberalization and introduced a draft government regulation in late 2006, developed together with the Ministry of Economic Development and the Ministry of Energy. According to that document Gazprom would have to provide data on available pipeline capacity and establish a transparent capacity allocation process.

Gazprom justified restricting natural gas access to its gas pipeline network by referring to its own capacity limitations (which was often the actual case). Finally, there is a light at the end of the tunnel. A recently approved *Complex Program of Technical Reconstruction and Re-equipment for 2007-2010* stipulates a 32 bcm increase in gas trunkline capacity, including 14 bcm of export capacity.

The natural gas price setting system in Russian Federation is not very straightforward, and is briefly explained here.

In 1998 the Russian government introduced a limited consumption system38, under which consumers were to cap their demand within short-term contracts. Gazprom is analyzing historical consumption volumes on a quarterly and annual basis, and brings those into correlation with requisitions for a sequential year, taking into account customers’ ability to pay. These caps typically do not reflect “peak” demand. If gas pipeline system capacity for both natural gas volumes contracted abroad and for domestic sales is sufficient, Gazprom can allot additional, “commercial” volumes to customers.

**Figure 7. Consumer Paying Capacity (percent) and Average Domestic Natural Gas Price ($)**

---


Prices for these natural gas volumes (“limit natural gas” or “non-commercial”) are regulated by the government, whereas “over-limit” or “commercial” prices are market-based and typically are 20-30 percent 39 higher on average. The third layer of the pricing system – natural gas sold at the exchange - was instituted less than a year ago, and so far has proved to be a successful experiment. Gazprom and independent producers are limited to marketing 5 bcm/year each through an electronic-based trading system, with a gradual increase in volumes sold.

In 2006, 67 percent of natural gas in the domestic market was sold at “non-commercial” prices, while 19 percent was sold at “commercial” ones.40

These factors, along with general liberalization of gas prices, would most likely inspire oil companies and independent producers to increase natural gas output in the mid-term. In our view, under such conditions, importance of the fact the natural gas export monopoly that was officially assigned exclusively to Gazprom in 2006 41 (with the exception of PSA’s in force at the time), has been reduced in significance for non-Gazprom companies at least in the mid-term.

**Novatek**

Novatek is currently the largest natural gas independent producer in Russia with over 650 bcm of proved reserves and 28.7 bcm produced in 2006. The main company assets include East Tarkosalinskoye and Khancheyskoye fields acquired from ITERA in 2004, and Yurkharovskoye field in Yamal-Nenets Autonomous District.

Having Purovskiy gas processing plant (GPP) among its assets represents a significant advantage for Novatek (see section on Associated Gas below for more detail), allowing it to process liquids. The company plans for a 5 mmt capacity expansion by 2009. Another plus for the company is the fact that it has been successful in marketing to end users, reaching a 44 percent benchmark.

Novatek has ambitious development plans to increase natural gas production by 45 bcm in 2010 and by 65 bcm annually by 2015, primarily from Yurkharovskoye and New Yurkharovskoye fields (24.6 and 41.3 bcm, accordingly). It is highly unlikely that having Gazprom among its shareholders (Gazprom signed a Strategic Partnership Agreement in 2005 and acquired a 19.4 percent stake in Novatek) will reflect on the company’s growth.

**ITERA**

During the late 1990’s, ITERA developed into the biggest independent natural gas marketer in Russia, also exporting Central Asian gas to FSU and Eastern Europe customers. After it sold some of producing assets to Nortgaz in 2004, the company was mainly involved in the gas wholesale business (19 bcm in 2005). At present, ITERA’s most valuable assets are located in the Yamal-Nenets region: Gubkinskoye field (390 bcm), launched in 1999 with the potential of 10 bcm annually and Beregovoye gas field with 324 bcm of gas reserves and 10 million tones of oil and NGL. After four years of stalemate (since 2003 Gazprom has denied pipeline access to the company) ITERA agreed to sell part of Sibneftegaz – license-holder for Beregovoye gas field (319 bcm and 12.6 mt of liquids) - to Gazprom, a move that got things going smoothly. In April 2007 Sibneftegaz started production at Beregovoye and pledged to deliver 5 bcm the same year with peak production of 12 bcm in 2009.42 In spite of becoming a stakeholder, Gazprom is not readily providing access to gas pipeline network: the company agreed to guarantee only 1.5 bcm in 2007 out of 5 bcm of planned production for that year.

Other plans also include development of Pyreinoye field (44.8 bcm and 4.8 mt of liquids) with planned capacity of 2 bcm/y to be reached in 2009-2010, as well as the small West-Zapalyarniy field (8 bcm of reserves).

**Nortgaz**

Nortgaz was formed in 1993 by Gazprom (51 percent), Bechtel (44 percent) and Tansli Trading Limited (5 percent) for development of Neocomian deposits in Northern Urengoy field (332.7 bcm and 52.4 mt of liquids). During the early 2000’s Gazprom’s share was reduced to 0.5 percent. In 2005 Gazprom restored control over the company through litigation and we expect more active development of Nortgaz E&P projects (in 2006, production amounted to a meager 5 bcm).

---

39 CEE-UT estimates.
40 The rest 14 percent were consumer by population at regulated prices. Source: Postavki Gaza na Vnutrenniy Rinok I Ego Liberalizatsiya. Speech of Gazprom Head of Marketing K. Seleznev, December 8, 2006.
41 Federal Law “On Gas Export”.
**The Role of Associated Gas**

Associated gas already represents a significant share of Russian natural gas production (42 bcm in 2006\(^{43}\)), yet due to both increased oil production and higher utilization of associated natural gas this resource could become an even more important factor, especially taking into account somber prospects for Gazprom output during the next decade.

The most recent report by World Bank reshapes a notion of scale of natural gas flaring in Russia (see Figure 8 below). Assuming the numbers are close to reality, flared associated gas represents a vast important and mostly untapped resource for both domestic and export markets. There are several drags on the way to its use, though.

**Figure 8. Natural Gas Flaring in Russian Federation, 1995 - 2006\(^{44}\)**

Currently greater utilization of associated natural gas is impeded for a number of reasons, the most important of which are:

- Gas gathering infrastructure is not in place due to weak economics, and
- Regional gas processing capacity is not sufficient for the companies’ needs.

Associated gas often differs considerably from the State pipeline natural gas quality standards. As a consequence, companies have to allocate significant funds to gas-processing facilities in addition to necessary pipeline infrastructure. In order to make such investments, companies had to have assurance of production distribution at reasonable levels, guaranteeing acceptable rate of return on investments (for more detail, see section on commercial frameworks for companies in the natural gas sector, above).

The majority of gas processing capacity (seven of 15 major gas processing plants, or GPPs, in Russia) has been monopolized by Gazprom affiliate SIBUR. The company is steadily increasing processing volumes (from 8.5 bcm in 2002 to 14 bcm in 2006) and plans to reach 20 bcm by 2011 due to modernization of the current capacity of Yujno-Balyskskiy GPP from 0.9 to 1.5 bcm and a 1.5 bcm expansion in 2008-2009 in close cooperation with Rosneft\(^{45}\). In addition to capacity superiority and a virtual monopoly on gas processing in major oil producing regions, which allows the company to dictate purchasing prices, SIBUR enjoys unlimited access to gas pipeline network. Yet his absolute advantage is likely to be challenged in coming years.

TNK-BP announced plans to dramatically increase investments into gas gathering infrastructure. It also established a Joint Venture with gas processing company SIBUR on the basis of Nizhnevartovsk and Belozerniy GPPs with 1.7 bcm capacity in early 2007, and will expand gas processing and liquids handling in Orenburg to resolve gas processing capacity constraints and a dry gas evacuation bottleneck. The company is working to establish long-term arrangements with consumers from power sector.

Gazprom has one of the lowest utilization rates in the industry (56% for all affiliates in 2006).\(^{46}\) GazpromNeft currently is developing a project together with SIBUR on construction of the 3 bcm per year Vingapurovskiy GPP in the Noyabrsk region of Russia.\(^{47}\) The effort is part of the major Gazprom program on utilization of associated gas to be developed, which targets 85-95% utilization rate by 2010 – 2012.

---

\(^{43}\) It is well worth mentioning that statistics of associated gas and its flared share contain a great degree of approximation around the world. Needless to say, oil and gas statistics, unreliable around the world, have the same if not lower dependability in the case of associated gas data in Russia and the FSU. For individual oil and gas wells, less than 50 percent of all flares in Russia are equipped with controlling and measuring devices.


\(^{45}\) Rosneft’s efforts in associated gas utilization are reflected in its recent agreement to develop a gas flaring reduction program jointly with the World Bank. As the largest Russian oil production company after acquisition of the UKOS assets in Spring 2007, Rosneft could deliver significant gas volumes to markets.

\(^{46}\) In 2006 Gazprom utilized 6.3 bcm of natural gas.

\(^{47}\) In August 2007 the companies established a Joint-Venture entity for these purposes. Source: GazpromNeft I SIBUR sozdali sovmestnoye predpriiatie po pererabotke poputnogo neftyanogo gaza. GazpromNeft, press-release, 08.16.2007.
The most ambitious program on associated gas utilization definitely belongs to Lukoil. The program, currently under development, aims to increase associated gas utilization rate from the current 75 percent to 95 percent by 2016, whereas development of new projects would imply a 100 percent rate. The plan provides for massive modernization of Lukoil’s Perm GPP, as well as construction of a new one at North-Gubkin field.\footnote{Za Schet Utilizatsii Poptuki Lukoil Dopolnitelnno Dobudet 5.6 mlrd Kubometrov Gaza. Neftegazovaya Vertikal, May 18, 2007.}

Associated gas could soon get a push from legislators. The Russian Duma is currently considering changes to taxation of associated gas\footnote{Bill “O Vnesenii Izmeneniy v Glavu 26 Chasti Vtoroi Nologovogo Kodeksa RF” bill was introduced in January 2007.}, which if implemented will repeal a zero percent rate of tax for companies with utilization rates of less than 95 percent and replace it with the current rate of 147 rubles ($5.72)\footnote{Exchange rate as of mid-May 2007.} per mcm while keeping it at current levels for everybody else.

Currently there are only two companies in Russia that can benefit from this innovation in the foreseeable future (see Figure 9 below) - Surgutneftegaz and Tatneft. The bill was sent back for revision, but knowing the lobbying capabilities of both Surgutneftegaz and Tatneft we believe that the bill has a chance to pass in one form or another. It is doubtless that Rosneft, Lukoil and others will object to the 95 percent hurdle, but they could compromise in the range of 60-65 percent. It is quite possible that a broad differentiation system will be introduced, potentially including such factors as company size and field depletion, chemical composition and access to relevant infrastructure.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure9.png}
\caption{Utilization of Associated Gas by Oil Companies, 2005\footnote{Source: Utilization of Associated Gas in Russia. Presentation by Alexander Savinov, December 2006.}}
\end{figure}

Our opinion is also supported by the fact that President Putin in his most recent Annual Address to the Federal Assembly gave attention to the problem and urged for such measures as a relevant accounting system, increased fines for environmental damage, and toughened license demands for natural resource users.\footnote{Annual Address to the Federal Assembly. April 2007.}

Historically taxation of associated gas in Russia was a rather ambiguous matter. Traditionally associated gas was not considered mineral wealth if it did not meet the State Standard (GOST) based on various requirements, and therefore was flared if not a taxable item. As a result, companies were paying fines for flared volumes of natural gas, a wasted resource.

In November 2005 the Supreme Court of the Russian Federation obligated the affiliate of TNK-BP – Saratovneftegaz – to pay Mineral Extraction Tax (MET) on flared associated natural gas. The argument was that since the company was utilizing part of the associated gas it therefore had technical capacity to utilize the rest of it.

The more important battle - for unassociated natural gas MET - is only starting.

The most recent proposals by the Ministry of Finance and Ministry for Economic Development and Trade suggest a gradual increase of this tax from the current $5.72/mcm to $12.26/mcm in 2008, $18.68/mcm in 2009 and $26.60/mcm in 2010.\footnote{Minfin i MERT Gotovi Dobit $26 mlrd. Kommersant, May 24, 2006.} At the same time government officials have been discussing MET exemption for offshore projects for both oil and gas for quite some time. Recent legislative changes, passed in July 2006\footnote{Federal “Subsoil” Law #151.}, differentiated MET for oil production in some East Siberian regions (Irkutsk and Krasnoyarsk and the Saha Republic) and for oilfields with depletion rates of 80 percent or more. Originally the draft extended these tax innovations to offshore areas, but later the idea was dropped.

\footnotesize

\begin{itemize}
\item TNK-BP – Saratovneftegaz – to pay Mineral Extraction Tax (MET) on flared associated natural gas. The argument was that since the company was utilizing part of the associated gas it therefore had technical capacity to utilize the rest of it.
\item The more important battle - for unassociated natural gas MET - is only starting.
\item The most recent proposals by the Ministry of Finance and Ministry for Economic Development and Trade suggest a gradual increase of this tax from the current $5.72/mcm to $12.26/mcm in 2008, $18.68/mcm in 2009 and $26.60/mcm in 2010.\footnote{At the same time government officials have been discussing MET exemption for offshore projects for both oil and gas for quite some time. Recent legislative changes, passed in July 2006, differentiated MET for oil production in some East Siberian regions (Irkutsk and Krasnoyarsk and the Saha Republic) and for oilfields with depletion rates of 80 percent or more. Originally the draft extended these tax innovations to offshore areas, but later the idea was dropped.}
\end{itemize}
Both Gazprom and independent companies along with the Ministry of Industry and Energy strongly oppose these plans, arguing that depletion of mature fields, containing inexpensive Cenomanian gas, will require massive investments in new E&P projects. Their favorite example of Yamal development incorporates a range of $25-$50 cost estimated per mcm produced.

Currently taxes represent 10-12 percent of the “grounded” price of gas, and future liberalization of domestic prices will reduce the tax burden even more with state revenue decreasing accordingly. The Russian federal budget will hardly withstand such a scenario. According to the recently passed Federal Budget for 2008-2010, the operating budget deficit will amount to 6.6 percent of GDP in 2008, 5.9 percent of GDP in 2009 and 5.3 percent of GDP in 2010. The operating deficit is supposed to be covered by the Surplus Fund (part of the former Stabilization Fund which will be split into a Surplus Fund and Future Generation Fund effective 2008). The Surplus Fund is to be formed by all oil and gas income, which in 2006 amounted to 11 percent of GDP yet, is forecasted to decline steadily in coming years.

The government could sweeten the MET increase by introduction of private ownership for gas trunklines and further liberalization of the domestic natural gas market. Most recent proposals by the Ministry of Industry and Energy of the Russian Federation contain such incentives as priority access to the pipeline network for associated gas and complete liberalization of associated natural gas prices. In terms of a “stick” motivation there are suggestions to significantly (up to 500%) increase fines for flaring by 2010-2011, introduce of mandatory utilization clauses in license agreements with oil and gas companies and establish control over associated gas utilization (the latter provides for inventory of gas flare systems, space monitoring and regular inspections of oil fields).

The Role of Oil Companies

Oil companies are primarily dealing with associated gas which, due to the specific regulatory and business practices in the country, is developed with great difficulty (see corresponding section above). Since Gazprom has a monopoly on gas trunkline transportation and exports, it has the oil companies over a barrel, so to speak. Appealing to insufficient domestic pipeline capacity, which is sometimes the actual case as noted previously, Gazprom forces the oil companies to sell their natural gas production at the wellhead at prices profitable enough to be delivered by Russian monopoly to the domestic market. Gazprom earns even more net revenue from the lucrative export business to Europe.

Figure 10. Hydrocarbon Production Growth by Russian Oil Companies

Oil companies are steadily increasing their natural gas production (see Figure 10), and this trend is expected to continue into the future. According to Gazprom projections, oil companies (jointly with independent natural gas companies) could produce 136.8-154.2 bcm in 2010 and 193.6-266 bcm in 2030. Oil companies themselves are more optimistic: they announced plans for about 110 bcm in 2010 and about 170 bcm in 2015.

TNK-BP

BP has long experienced bad luck with its main natural gas asset – Kovikta gas field in East Siberia. The project was consistently delayed due to Gazprom’s reluctance to coordinate and approve BP’s plans on the development of the field.

---

55 Gazprom, CEE-UT estimate.
57 Currently fines for flaring within the limit (typically based on 95% utilization rate) equal about $0.23 per Mcm and about $5.47 for over-the-limit flaring.
59 CEE-UT estimate.
Beginning in 2000 Russian officials threatened BP’s affiliate license holder Russia Petroleum with revocation. Gazprom’s objective is to push for development of its own small deposits, making development of Kovikta for the domestic market unnecessary, and thus pushing BP out of the project altogether via license revocation by the Ministry of Natural Resources. Technically, the Ministry has this privilege. Finally in February 2007 BP was given three months to fulfill all the license requirements. According to the license agreement Russia Petroleum was to produce 9 bcm of natural gas annually, while actual production in 2006 was equal only to 33 mcm.

The project implementation is also complicated by the rich helium content in the field which, if it were to be fully marketed, could crash world market prices for this commodity.

According to the deal structure in general details in June 2007, BP would sell its interest in the project to Gazprom for an undisclosed amount. The companies would then establish one or several Joint Ventures based on assets in various parts of the world, valued at least at $3 billion. Recent media pieces reported that BP is considering making its contribution in a form of liquefaction/regasification assets in the Atlantic basin, which would perfectly suit Gazprom’s overseas development strategy.

Ownership changes might speed up Kovikta development - despite the fact that the most recent version of Gazprom Eastern Gas Program still mentions 2017 as a start-up year, we believe that in case of financial compromise with Chinese companies (price is the most important stumbling block here) the project could be implemented earlier.60

Another major gas asset for BP is Rospan, which holds licenses for the Achimovsk gas formations of the East-Urengoi gas condensate fields in the Yamalo-Nenets Autonomous District, as well as Novo-Urengoi field and Valanzhin deposits.

**Lukoil**

While currently producing one third of natural gas in Western Siberia, Lukoil has most of its natural gas assets, amounting to 25 bcf in 200561, located within the Russian sector of Caspian region.

Lukoil plans to develop the Tsentralnaya structure in the Russian sector of the Caspian Sea (521 mt and 91.7 bcm of associated gas) jointly with Gazprom and KazMunaiGaz and start exploration drilling in 2007. Khvalinskoye field in North Caspian has 322 bcm of proved and proven reserves at 25-30 m sea depth. Lukoil established a joint venture with KazMunaiGaz in production and marketing areas and plans to start development drilling in late 2007.

Lukoil’s major natural asset in Western Siberia – the group of fields in Bolshekhetsk Basin with total reserves of about 600 bcm – produced 8.5 bcm in 2006 and is projected to add 25 bcm to 55 bcm of total Lukoil production by 2016.

**SurgutNeftegas**

Surgutneftegaz does not appear to consider the natural gas business as a strategic priority. Surgutneftegaz was exporting 1.7 bcm at the end of 1990’s. Following the increase in transportation tariffs for independent producers in mid-2002 and the ban against nondiscriminatory access to the gas pipeline network, Surgutneftegaz acquired Surgut Gas Processing Plant with 4.2 bcm of annual capacity from Sibur. With that acquisition, Surgutneftegaz became the only independent company in Russia to build a fully vertically integrated scheme of natural gas marketing.

The main goals of the company in the recent years and for the near future include highgrading its associated gas infrastructure and increasing its utilization rates and marketable gas production.

**Rosneft**

Being the biggest oil company in Russia, Rosneft appears to be pressured to establish an equivalent status in natural gas production among its peers. Right now Rosneft produces mainly associated gas. The recent launch of Sakhalin-1 provided the first major source of unassociated gas for the company. Total natural gas reserves are estimated at 1.57 Tcm in 2006. Major gas assets include Kharampur field (900 bcm of total reserves and planned capacity of 27 bcm annually) and a 20 percent stake in Sakhalin-1 (see section on PSA’s below). The company also holds 49 percent and 51 percent in the Sakhalin-4 and Sakhalin-5 projects accordingly.

In 2006 Rosneft produced 13.58 bcm and plans to ramp up natural gas output to 45 bcm by 2015.

---

60 Majority of experts cite (absolutely correctly) Gazprom financial constraints based on the current project line-up. We assume that other financing options are quite possible - suffice it to mention Rosneft crediting in Yukos case towards long-term future crude oil supplies and recent CNPC arrangement in Turkmenistan.

PSA’s

Currently only two PSA’s in Russia will produce significant amounts of natural gas – Sakhalin-1 and Sakhalin-2 (the Sakhalin-2 project is discussed in detail in the later section on LNG).

Sakhalin-1 was established by a consortium of ExxonMobil (30 percent and project operator), CODECO (20 percent), ONGC (30 percent) and Rosneft (20 percent). The project has 307 mt of oil and 485 bcm of total extractable resources. The consortium initiated natural gas production in October 2005 with 0.6 bcm a year and reached 1.3 bcm by 2007 with a potential capacity of 15 bcm annually. Most of the gas is being marketed to domestic customers in the Khabarovsk region through the Okha-Khabarovsk pipeline, and initial plans were to build an export pipeline to China, but until recently these plans were opposed by Gazprom. Gazprom sees these developments as a threat to its export monopoly and has been attempting efforts to take control over domestic the Okha-Khabarovsk pipeline, which could become a part of the Russia-China export route.

According to proposed changes by the current legislature, foreign investors might be banned from strategically important mineral and hydrocarbon deposits. A recent draft of changes prepared by Ministry of Natural Resources set a cap, still under discussion, on participation in oil fields with total estimated reserves of 70 mt and natural gas fields with more than 50 bcm of total reserves. Foreign companies which are currently working under PSA and Joint-Venture terms in Russia seem forced to say “good-bye” to all hopes for substantial new assets and are preoccupied with worries about whether these legislative changes will be grandfathered and affect their current positions in the country.

Implications for LNG Projects – perspectives

A little known fact is that Russia has been a member of the “LNG club” for a while. Russia is exporting LNG to Finland by truck (about 4,000 tones in 2006).

The oldest LNG project in Russia – Sakhalin-2 – was initiated in 1991 when Marathon, McDermott and Mitsui started preliminary talks with the Russian government. The PSA for the project was signed in 1994 and construction of a 9.6 mtpa, two-train terminal began in August 2003. In 2006 the project cost estimate was raised from $12 billion to $20 billion, which caused tensions between the project developers and the Russian Government over PSA implementation. The terminal targets primarily the Japanese market, as well as customers in Mexico (Pacific Coast) and South Korea. In December 2006, following months of dispute, Gazprom acquired a 50 percent stake plus one share in the project for a total cash purchase price of $7.45 billion.

Yamal LNG was a private project being developed by Tambeyneftegaz – an affiliate of the most prominent Russian independent gas company Novatek - since 2003. The project had an obvious advantage in its resource base; South Tambey gas field in Yamal Peninsula is one of the largest in the world and is estimated to have 43 tcf of natural gas and 60 mt of gas condensate. By December 2004 the company developed a project concept, which, in addition to the liquefaction facility of 10 mtpa capacity, comprised a liquids separation plant and an LNG carrier fleet. Total cost of the project was estimated to reach $5 billion.

Tambeyneftegaz was targeting the North American market and planned to either build a regasification terminal in Canada or to team up with one of the LNG players there. In March 2005 the company submitted an application for the project to the Russian Ministry for Economic Development and Trade and then almost simultaneously Novatek sold its 25.1 percent of Tambeyneftegaz to Gazprom. A few months later Repsol announced its interest in the project and started discussions on the joint-venture (Tambeyneftegaz planned to hold a controlling stake of 51 percent, Repsol and Shell would take 21 percent each and PetroCanada 7 percent). By this time the capacity of the terminal was reduced to 7.5 mtpa, while the project price tag surged to $6 billion. Repsol was planning to partner with Irving Oil and ship LNG to Irving’s St. John regasification terminal in New Brunswick (Atlantic Canada). Gazprom refused to participate in an additional stock offering and sued the Russian Federal Subsoil Use Agency for illegal transfer of the South Tambey gas field from Tambeyneftegas to the new entity, Yamal LNG. As a result of the additional pressure (including commencement of fraud prosecution and searches in the company’s offices) the major stockholder, businessman Nikolay Bogachev, sold his 74.1 percent in Tambeyneftegas to companies friendly to Gazprom. According to the latest announcements, Gazprom does not plan to build an LNG facility in Yamal Peninsula in the near future. The first Yamal gas field to be developed – Bovanenkovskoye - will go online in 2011 as a part of the Unified System for Gas Supply in Russia (USGS), the Russian gas transportation system.

Another private LNG project was announced in 2004 by oil and gas trader TransNafta. The terminal was planned to be built in Archangelsk on the White Sea with annual capacity of 8 million tons. TransNafta named Bechtel and Ferrostal

Gazprom has been studying LNG projects since the late 1990’s yet declared it to be important “new strategic branch of business” only in 2003. In addition to the traditional reasons for joining the LNG industry group, Gazprom referred to insufficient gas transportation capacity in the beginning of 2000’s as a rationale. The company historically considered two major strategies for entering the global LNG business: by swapping pipeline capacity in Europe for LNG cargoes and by developing its own LNG terminals both domestically and through participation in joint ventures abroad. Gazprom was particularly active in the latter; it expressed interest in participation in LNG regasification projects by the dozen from Chile in the West to Korea in the East. Gazprom always considered North America as a most lucrative market among its economically viable options and unsuccessfully tried to secure LNG regasification capacity in the US. Finally, Gazprom succeeded in Canada – in October 2004 the company signed an initial MoU with PetroCanada for cooperation along the entire LNG value chain including “liquefaction, re-gasification and the supply-demand fundamentals relevant to marketing arrangements”. The MoU also covered a possibility of joint development of a LNG plant in the Northwest of Russia (the so-called Baltic LNG project) and options for gas supplies to North America. A year and a half later the companies signed an agreement to proceed with initial engineering design for Baltic LNG to serve as a supply source for PetroCanada’s regasification facility in Gros-Cacouna, Quebec (St. Lawrence Seaway). The terminal was declared to have capacity of 3-5 mtpa and cost up to $1.5 billion with a start-up date of 2010. A few months later Mitsui and Mitsubishi expressed interest in the project, followed by BP in March 2007. In April 2007 Gazprom announced the shortlist for Baltic LNG with the final decision to be released in July 2007. The LNG liquefaction plant with capacity of up to 5 mtpa and a $3.7 billion price tag is supposed to go into operation by 2010. Gazprom started actively developing its LNG marketing business in 2005. The company opened an office in the United States and arranged several swap deals in both the Atlantic and Pacific basins (in September 2005 Gazprom delivered an LNG cargo to the Cove Point terminal in Maryland; in April 2006 it shipped LNG to the Isle of Grain terminal in UK; and in August 2006 to Chita terminal in Japan). Shtokman became Gazprom’s major LNG project and a battleground for all major world natural gas players. The field was discovered in the late 1980’s with reserves of 3.7 Tcm of gas and more than 31 mt of gas condensate. The development scheme has changed several times and there is still no clarity to it. The most recent statements of Gazprom officials hint at the creation of a commercial operator of the field, with Gazprom having a controlling stake in it. The operator will own the entire producing and transportation infrastructure, including the gas trunkline and the liquefaction facility, while Gazprom will retain the licenses and ownership of the resource. Shtokman was initially planned as a source for a new export route to Europe via the Nord-Stream pipeline, as well as an LNG plant onshore. Recently Gazprom announced that development of the gas field is to begin in 2011 in order to supply the Nord-Stream pipeline. Construction of the first stage of 25 bcm/year of capacity started in 2005 and is scheduled to go online in 2011. The second stage of the pipeline will increase its capacity from 28 mcmb/year to 55 mcmb/year and is to be operational in 2010, reaching a full capacity in 2013, while the first LNG is supposed to flow to the North American market in 2013 and 2014 accordingly. Initially the license pertained to Sevmorneftegaz, a joint-venture between Gazprom and Rosneft created in 2002 specifically for development of the Pechora and Barents seas shelf. In March 2005 Rosneft sold its stake in Sevmorneftegaz to Gazprom, and the project started to move forward. In September 2005 Gazprom announced a shortlist comprised of companies eligible for further negotiations on the project: Statoil (Norway), Total (France), Chevron (USA), Hydro (Norway) and ConocoPhillips (USA). Yet at the end of 2006 Gazprom reversed views and announced that it will develop the project without foreign partners. It is probably safe to say that tactics of exhausting talks finally bore fruits. By putting on a wild card image Gazprom managed to land one of the most experienced in the LNG business companies – Total, what is at least as important – a European one. Gazprom is trying to penetrate European and LNG regasification markets and having French company as its partners and was trying to obtain Gazprom’s support for the project, yet canceled the project soon after its announcement – probably due to lack of the above-mentioned support.

63 Russia Gazprom seeks Japan's help in LNG business. Reuters, 06.27.03.
64 The Press Conference of Alexander Ryazanov, Deputy Chairman of Gazprom’s Management Committee and Alexander Medvedev, Gazprom’s Management Committee Member and Gazexport’s Director General - "Russian Gas Deliveries to Domestic and Foreign Consumers". Available at: http://www.gazprom.com/eng/articles/article10162.shtml.
a partner could significantly ease this complicated task. The deal presumably implied that Total would have 25% in the operator of Shtokman-1 (23.7 bcm a year). The operator of the project (formed as a Special Investment Vehicle) would own the project’s infrastructure for 25 years and bear all financial, geological and technical risks related to the production, while Sevmorneftegaz retains license and marketing rights. Total would also be able to book proportional share of Phase 1 reserves (25% of 1.22 Tcm), possibly for additional payment. The compensation method for participation in the project is unclear: Total could swap some of its assets for share in Shtokman – the way Gazprom wanted to structure the deal initially.

Arrangements with Total still leave some maneuvering space for other companies. There is little doubt that Gazprom would like to control Phase 1, as that it is interested in Experience and technologies of Norway companies, which potentially leaves up to 24% in the company-operator of Phase 1. We consider US companies to be outsiders in the short list due to numerous reasons, emphasizing two major ones: not many would negative political tensions between Russia and US, while alleged talks with BP (for more information on swap of regasification projects see Kovikta discussion above) and Total accomplish a task of penetration LNG regasification business in the Atlantic basin.

Gazprom has long nurtured plans for LNG terminal on the basis of Kharasavey field in Yamal Peninsula with the first train of 3 mtpa. The project has been shelved due to reallocation of supply in favor of current (Europe) and potential customers in Asia (China). In addition, tough climate conditions will require an ice-breaker LNG fleet, while complete lack of any infrastructure for hundreds of miles makes the project uneconomically expensive.

Conclusions

Results of our analysis are presented in the table below and are clustered in high and low Russian natural gas exports cases for both mid-term and long-term perspectives:

<table>
<thead>
<tr>
<th>Mid-term</th>
<th>Low Natural Gas Exports Case</th>
<th>High Natural Gas Exports Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Temporary slump in commodity markets around 2009-2011 with rapid recovery</td>
<td>• End of commodity cycle by 2010-2011</td>
<td></td>
</tr>
<tr>
<td>• Delays in wholesale electricity market reform</td>
<td>• Liberalization of non-residential wholesale electricity market by 2011 and natural gas market</td>
<td></td>
</tr>
<tr>
<td>• Rapid growth in domestic electricity demand</td>
<td>• Switching from natural gas to coal generation (5-25 bcm/year)</td>
<td></td>
</tr>
<tr>
<td>• Gazprom delays LNG projects in European part of Russia</td>
<td>• Investment commitments, approved in the General Scheme of Power Generation Objects till 2020, are confirmed and undertaken by private investors</td>
<td></td>
</tr>
<tr>
<td>• Limited access to gas pipeline network for non-Gazprom companies</td>
<td>• Introduction of long-term natural gas and power contract frameworks</td>
<td></td>
</tr>
<tr>
<td>• Restrictions on natural gas exports</td>
<td>• Oil and gas companies expand into power generation based on their own supply or swap deliveries</td>
<td></td>
</tr>
<tr>
<td>• Monopoly on gas processing capacity by Sibur persists</td>
<td>• RAO UES falls behind the schedule of new gas power generation</td>
<td></td>
</tr>
<tr>
<td>• Current pricing system on associated gas stays in place</td>
<td>• Continuation of retrofits and upgrades to energy efficient technologies and equipment in industrial sector</td>
<td></td>
</tr>
<tr>
<td>• Introduction of new tax regime (MET) for non-associated natural gas China establishes a long-term relationship with Central Asian suppliers</td>
<td>• Improvements in natural gas consumption tracking in residential sector (from current 15% to at least 40-50%)</td>
<td></td>
</tr>
<tr>
<td>• Insufficient gas pipeline network capacity</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Gazprom successfully continues marketing and distribution efforts in Europe</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Implementation of Caspian natural gas pipeline is postponed</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

---

69 According to the media.
<table>
<thead>
<tr>
<th><strong>Long-term</strong></th>
<th><strong>Low Natural Gas Exports Case</strong></th>
<th><strong>High Natural Gas Exports Case</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• High economy growth rate</td>
<td>• Moderate consumption rate with significant market volatility</td>
</tr>
<tr>
<td></td>
<td>• Continuation of regional gasification program</td>
<td>• Current trend of population loss (1.4%) continues</td>
</tr>
<tr>
<td></td>
<td>• Natural gas exchange trade remains insignificant or winds up</td>
<td>• Implementation of announced shift to coal and nuclear generation</td>
</tr>
<tr>
<td></td>
<td>• Rapid development of domestic refining and petrochemical sectors</td>
<td>• Gradual replacements of obsolete gas-fueled power generation</td>
</tr>
<tr>
<td></td>
<td>• European consumers increasingly switch to new supply alternatives (LNG, Nabucco, Trans-Sahara pipelines)</td>
<td>• Gazprom remains a major decision maker in allotments of natural gas volumes for both industrial and power sector, while expanding in both lines of business</td>
</tr>
<tr>
<td></td>
<td>• Gazprom procrastinates on new large-scale E&amp;P projects in Yamal Peninsula and Offshore</td>
<td>• Shift of FSU countries from imports of Russian natural gas to alternative suppliers/technologies</td>
</tr>
<tr>
<td></td>
<td>• Gazprom and independent companies continue E&amp;P expansion abroad to the prejudice of domestic projects</td>
<td>• Central Asian countries ramp up natural gas production and export</td>
</tr>
<tr>
<td></td>
<td>• Implementation of GHG mitigation system in Russia is delayed</td>
<td>• Implementation of economically non-feasible new natural gas export routs to Far East and Asian markets</td>
</tr>
<tr>
<td></td>
<td>• Plans to develop major fields in Eastern Siberia are shelved</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Centralized heat supply system remains inefficient and outdated</td>
<td></td>
</tr>
</tbody>
</table>

We believe that current catastrophic forecasts\(^7\) on Russian domestic natural gas balance are somewhat exaggerated. Our base scenario calls for commodity markets to enter a downward trend in 2010-2011, while energy efficiency actions start taking effect at the same time.

**Figure 11. CEE "Commodity Cycle" Forecast of Russian Natural Gas Consumption**

![Figure 11. CEE "Commodity Cycle" Forecast of Russian Natural Gas Consumption](image)

Russian estimates for domestic supply are rather in line with foreign projections. Gazprom gives a range of 683.1-710.1 bcm for 2010 and 788.9-921.6 for 2030, while the Ministry of Economic Development and Trade projects 702 bcm for

---

\(^7\)The range of domestic natural gas deficit is really impressive: from 40 bcm in 2010 according to RAO UES to Former deputy energy minister Vladimir Milov with 126 bcm as a worst case scenario (as cited in Riley & Umbach. Out of Gas. IP, Spring 2007, p.83).
2010 under its base scenario and 717 bcm for the same year, assuming unrestricted access to pipeline network for independent producers.

The U.S. EIA projects domestic production of 705 bcm in 2010, 776 bcm in 2015 and 997 bcm in 2030. We believe that a level of 710-720 is realistic for 2010, at the same time being a little bullish for 2015 with a 780-810 bcm projection.

Our forecasts for both the 2010 and 2015 benchmark years somewhat differs from Russian prognoses, presented both by authorities and companies. In 2006, Gazprom estimated total domestic demand in a range of 460-462 bcm for 2010 and 470-505 bcm in 2030, while the Ministry of Economic Development and Trade suggested an increase by 72 bcm by 2010, thus bringing the domestic demand forecast to 521 bcm.

Further research of the subject requires a major general equilibrium modelling effort. Currently, CEE-UT researchers are expanding the CEE-UT’s analysis resources and modeling activities to deal with complex issues and decisions. CEE-UT anticipates research outputs on energy/economy and energy/environment for special studies, ongoing assessments in the U.S., and new challenges stemming from carbon management and emerging new value chains.

References