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European energy security: An analysis of future Russian natural gas production and exports

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ABSTRACT

The widening gap between EU gas production and consumption may require an 87% increase of import volumes between 2006 and 2030, and there are great uncertainties regarding the amounts of gas that can be expected from new suppliers. The potential of increased production from Norway and Algeria is limited; hence, Russia is likely to play a crucial part of meeting the anticipated growing gas demand of the EU. A field-by-field study of 83 giant gas fields shows that the major producing Russian gas fields are in decline, and by 2013 much larger supplies from the Yamal Peninsula and the Shtokman field will be needed in order to avoid a decline in production. Gas from fields in Eastern Siberia and the Far East will mainly be directed to the Asian and Pacific Rim markets, thereby limiting its relevance to the European and CIS markets. As a result, the maximum export increase to the European and CIS markets amounts only to about 45% for the period 2015–2030. The discourse surrounding the EU's dependence on Russian gas should thus not only be concerned with geopolitics, but also with the issue of resource limitations.

1. Introduction

Russia is the principal heir to the Soviet gas industry that was developed at a rapid pace between 1955 and 1990. According to BP Statistical Review (2009), Russia has 23% of the world's total gas reserves, and Russian production equals 20% of global production. About 30% of the Russian gas production is exported.

Although the Soviet gas production began to develop as early as in the 1940s in the Ukrainian SSSR republic, large discoveries of gas within what today constitutes the European parts of Russia, were made in the 1950s at several sites along the Volga river and in the Urals area. However, during the Stalin era natural gas was not prioritized, thus representing only 2% of the Soviet Union's primary energy supply in 1950. The breakthrough for Soviet gas utilization came in 1958, with a resolution that gave instructions on the development of the Soviet natural gas industry. This was the result of an increasing awareness of the enormous gas deposits on Soviet territory, caused by increased exploration drilling for oil (Högselius, 2007). In the 1950s, major gas discoveries were made in the Krasnodar and Stavropol regions, and in the 1960s a number of "supergiant" fields were discovered in Western Siberia.

From late 1960s it became widely accepted that West European gas production would not be capable to meet anticipated demand by the 1980s and 1990s, and in 1963 the UK started to import LNG from Algeria (Högselius, 2007). Since huge gas reserves now were present in the Soviet Union, export pipelines were built to Europe, and large-scale gas exports began to the Soviet satellite state Czechoslovakia in 1967, followed by neutral Austria the subsequent year (Stern, 2005). In the early 1980s, plans to build a new pipeline intended for export of gas to the Western European nations were developed. This raised a storm of protest in the US, including the Reagan Administration, who saw the pipeline as a threat to Europe's security (Copulus, 1982; Hardt and Gold, 1982). The main reason for their concern was the perceived vulnerability of Western Europe to Soviet threats to cut off the gas in the case of a political crisis. However, European leaders dismissed the American concerns, arguing that the discoveries of giant natural gas fields in Norway opened a new import possibility, and that Norwegian gas could readily provide a substitute. In 2006, Russia supplied 41% of EU gas imports, and the Norwegian share of the EU-27 imports of natural gas amounted to 21% followed by Algeria with an 18% share (IEA, 2008a, 2008b).

1.1. The European dependence on Russian gas

The EU currently is the world's second largest energy market, and it is Russia's most important gas export market. The demand for natural gas has significantly increased in Europe over the last 15 years. The European Council has declared that the EU's

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greenhouse gas (GHG) emissions should be at least 20% lower than the 1990 level by 2020. Natural gas emits only half as much carbon dioxide as coal when used to generate power, and its increased use in the EU is potentially an important factor in limiting European GHG emissions. Furthermore, increased use of intermittent power generation sources, such as wind power, will require supplementary regulating power sources, of which gas is one of the most efficient. The Spanish government, for example, estimates that its wind capacity will need to grow by 70% to meet the EU GHG-emissions targets, which will require a 50% increase of its gas-fired generation capacity (Reuters, 2009; Solanko and Sutela, 2009).

The production of gas within the EU peaked in 1996. Thereafter followed a production plateau, and, in 2004, production entered a state of decline. In the World Energy Outlook (2008), the International Energy Agency (IEA) expects total natural gas output in the EU to decrease from 216 billion cubic meters per year ($10^9 m^3$/year) in 2006 to $90 \times 10^9 m^3$/year in 2030. For the same time-period, EU demand for natural gas is forecast to increase rapidly. In 2006 demand for natural gas in the EU amounted to $532 \times 10^9 m^3$/year. By 2030 it is expected to reach $680 \times 10^9 m^3$/year. The widening gap between EU production and consumption would require an 87% increase of import volumes between 2006 and 2030. There are great uncertainties regarding the amounts of gas that can be expected from new suppliers, either through pipeline or as LNG. The potential of increased production from Norway and Algeria is limited, see Söderbergh et al. (2009) and Campbell and Heapes (2008). Hence, it is obvious that increased Russian gas supplies are likely to play a crucial part of meeting the anticipated growing gas demand of the EU.

The current and potentially increasing European dependency on Russian gas has spurred an intense debate on the subject of the energy security of the EU. Two major worries concerning the European dependence on Russian gas supplies have been frequently voiced. Firstly, a fear has emerged among many Western policy analysts and commentators that gas might be used by the Russian elite as an "energy weapon" in the international geopolitical game. For some examples among many, see Umbach (2010) and Webb and Barnett (2006). Secondly, worries of insufficient Russian gas supplies, primarily due to lack of investments in the upstream sector and inefficient domestic use of gas, has been expressed, see among others, Goldthau (2008), Solanko and Sutela (2009) and Fernandez (2009).

1.2. Purpose and disposition

The objective of this article is to present forecasts of total Russian gas production based upon gas reserves in existing giant fields. In addition the potential of increased future gas supplies to the European markets and to the markets of the former Soviet Union countries, the Commonwealth of Independent States (CIS), is investigated.

Initially in Section 2 of this article, the Russian reserves classification system is described. This is followed by a description of Russia's gas reserves and production, including the main gas producers, and an explanation of the various causes for gas losses, primarily flaring. Then Russian gas exports and domestic sales of gas are examined as well as the present and planned transmission capacity of the Russian pipeline network. In Section 3, the present and future gas production areas in Russia are accounted for, and a short explanation of the geology of the main producing region of Western Siberia is also presented. In Section 4, the Giant Gas Field model is described as well as the data and information used for the creation of the forecasts in Section 5. In Section 5, a forecast of Russian gas production has been made using the model and the gathered data described in Section 4. Thereafter, a forecast of total Eastern Siberian and Far East production is presented, as well as potential scenarios for future gas exports to the European and CIS markets. Finally, key findings and conclusions are formulated.

2. Russia's gas situation

The Russian gas resource base is characterized by its high concentration of reserves in giant and semi-giant fields. A giant gas field is defined as a gas field that is able to ultimately produce more than 3000 billion cubic feet (3 tcf), the equivalent of 84 billion cubic meters ($10^9 m^3$), which corresponds to 500 million barrels of oil equivalents (Mboe) (Halbouty, 2001). Fields smaller than giant fields, although having estimated recoverable resources in excess of $15 \times 10^9 m^3$, have in previous works been referred to as semi-giant fields (Söderbergh et al., 2009).

2.1. Classification of reserves

Under Society of Petroleum Engineers (SPE) International standards, petroleum reserves are classified as Proved, Probable and Possible, based on both geological and commercial factors. SPE International standards take into account the probability that hydrocarbons are present in a given geological formation as well as the commercial viability of a given deposit pending on economic factors such as exploration and drilling costs, ongoing production costs, transportation costs and the prevailing prices for the hydrocarbons. In addition, the criteria around commerciality also include some evidence of commitment to proceed with development projects within a reasonable time frame, as well as confirmation of a market, production and transport facilities and required lease extensions (Etherington et al., 2005).

Proved Reserves are those quantities of petroleum, which, if probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. **Probable Reserves** are those additional reserves which are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the Proved plus Probable (2P) estimate. **Possible Reserves** are those additional reserves which are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to a high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate (SPE, 2007).

Russia has its own classification system of petroleum resources. The Russian classification system is focused on the actual physical presence of in-place volumes as well as the probabilities of their presence. The Economic Normally Profitable Geological Reserves are divided into Produced Reserves and Recoverable Reserves. The Recoverable Reserves are represented by categories A, B and $C1$, where A represents Reasonably Assured, B—Identified, $C1$—Estimated and $C2$—Inferred. The Russian system splits the undiscovered volumes into three categories that can be roughly described as Prospects—$D1$, Leads—$D2$ and Plays $D3$ (Etherington et al., 2005).

The Russian reserve classes A, B and $C1$ roughly correlate to SPE Proved Developed Producing (PDP), Proved Developed Non-Producing (PNP) and Proved Undeveloped (PUD), respectively, although the Russian reserve classes may include resources that do not qualify as reserves in the SPE-system due to economical factors. Reserves in category *B* have all the certainty of category *A* but are not in production. Category *C*1 corresponds to SPE PUD and some parts of SPE Probable reserves. Category *C*2 encompasses both partly SPE Probably and partly SPE Possible. However, to make comparisons a detailed examination of the specific information available is necessary. The Russian system has a much greater emphasis on volumetric analysis in all categories whereas the SPE International standards is more focused on production performance-based estimates in *Proved* and *Probable* estimations for mature deposits. The Russian system use the term reserves for all types of discovered volumes; in-place, economic and sub-economic, whereas the SPE system only uses the term reserves for the remaining commercially recoverable portions of discovered volumes (Etherington et al., 2005).

2.2. Reserves and production

BP Statistical Review (2009) reports the world's proven natural gas reserves at 179.8 trillion cubic meters (10^{12}m^3). According to Gazprom (2009c), Russia's gas reserves in 2008 amounted to 47.65×10^{12}m^3 (*ABC*1), the IEA (2009) gives a number of 45×10^{12}m^3 of proved reserves, while BP Statistical Review (2009) reports 43×10^{12}m^3. Garipov and Kozlovsky (2004), give a figure of 47×10^{12}m^3 of gas reserves present in Russia at the beginning of 2002.

The BP Statistical Review (2009), which excludes flared and re-injected gas, has Russian production in 2008 at 602×10^9m^3, the equivalent of 20% of global production. The dominant gas producer in Russia, Gazprom Group, produced 550×10^9m^3 in 2008, and the company reported total Russian production in 2008 at 665×10^9m^3 (Telegina, 2009). In the World Energy Outlook 2009, the IEA has Russian gas production at 657×10^9m^3 in 2008.

2.2.1. Gazprom and independent Russian gas producers

Gazprom is a majority state-owned and state-controlled company, although it is stock exchange-listed. Gazprom has a monopoly on all gas exports from Russia, and the company owns and operates the Russian natural gas transmission system. The company also imports gas from Central Asia, and Central Asian gas imports in 2008 was 66×10^9m^3, including 42.3×10^9m^3 of Turkmen gas, 14.2×10^9m^3 of Uzbek gas and 9.6×10^9m^3 of Kazakh gas. In 2008, Gazprom Group's natural gas *ABC*1 reserves were booked at 33.1×10^{12}m^3, while its 2P reserves were at 21.2×10^{12}m^3 (Gazprom, 2009a).

Production from non-Gazprom producers, so called independents, amounted to about 16% of total Russian production in 2008. Novatek is the major independent gas company. Gazprom has the exclusive right to develop large fields of strategic importance to Russia, and in general the independent companies have smaller giant fields and/or giant oil fields with associated gas. The major independent integrated oil and gas companies active in Russia, such as Lukoil, Surgutneftegaz, TNK-BP and Rosneft, have ambitious natural gas development plans for the next two decades. However, in most cases they also have large oil projects competing for the investment money. In addition, independent producers may be reluctant to initiate new projects that will increase their gas production capacity as long as Gazprom controls the market access through its ownership of the transmission system. As consequence, the modeling of production from giant gas fields owned and/or operated by independent companies may be surrounded with some additional uncertainties regarding planned start of production, compared with modeled giant fields owned by Gazprom.

2.2.2. Flaring and other losses

Gas flaring is a common practice in Russia, and the estimations of the amounts lost by the practice vary considerably. The IEA (2009) estimates flared volumes at some 38×10^9m^3/year, around 45% of the country's associated gas production. Elvidge et al. (2007) gives an estimation of total volumes flared annually during the period 1995–2006 varying between 34×10^9 and 55×10^9m^3 annually. According to official estimates flaring exceeds 17×10^9m^3 per year, and Russian policy strives to reduce flaring aiming to achieve a 95% use of associated gas (Vygon, 2009).

Other losses include gas leaked from pipelines during transmission and distribution and burned at compressor stations in the gas pipeline system. About 2% of Russian natural gas consumption is due to losses, and pipeline compressor stations annually consume some 6% of total gas consumption (Volkov et al., 2009). Because of Russia's geography and the fact that the major producing fields are located in extremely harsh environments with long distances from the principal gas consumers it is difficult to maintain the pipeline network. The transmission system is aging and 67% of the pipes are more than 20 years old. The majority of the network was built during the Soviet period at a relatively rushed pace with materials of lower quality corrosion protection than ideally required. In addition, Soviet-built compressor stations, compared to western standards, have relatively lower levels of efficiency and reliability (Gazprom, 2009c; Stern, 2005).

2.2.3. Exports and domestic sales

Of Russian gas production, about 70% is consumed domestically and 30% exported (BP, 2009). In 2008, of the total export amounts, together with gas from Central Asia, 34% was exported to the CIS states and 64% to the *Far Abroad*, i.e. European countries excluding the Baltic States and including Turkey (Gazprom, 2009a). Even though the European countries represent only about 30% of Gazprom's total sales volume, in 2008 they accounted for 60% of its revenues (Pugliaresi et al., 2009).

The EU is striving for a more competitive European gas market with spot markets and short-term contracts decoupled from the traditional oil products price link. Gazprom argues that long-term contracts (LTCs) constitute a firm basis for investments and ensure financing for the capital-intensive infrastructure and field developments. Of the 150×10^9m^3 of Russian gas exports to Europe in 2005, practically all was sold through LTCs with prices fixed to various oil products, and Gazprom has already signed contracts that will bring 2500×10^9m^3 to Europe over the next 15 years (Sagen Lund and Tsyngankova, 2008).

Russia is second only to the United States in total natural gas consumption, with gas demand representing 55% of total energy consumption, over 20% is met by oil, and about 15% by coal (EIA, 2009). Gas is used mainly for heating and electricity generation. Power companies are Gazprom's largest group of customers with 32.5% of Gazprom's sales, and gas consumption and electricity production therefore tend to move together. Besides power generation, the most important industrial consumers of gas are the metallurgy and agrochemistry sectors. Households are also important consumers with 17% of Gazprom's sales (Gazprom, 2009a). Approximately 41 million Russian households, out of the almost 53 million recorded in the 2002 census, are connected to the gas network. Moreover, households are heavy users of district heating, and district heating plants are predominantly fueled by natural gas (Sagen Lund and Tsyngankova, 2008).

The rapid growth of consumption for the period 1998–2007 has increased concerns among Russian authorities and outside observers about the adequacy of gas supplies, although consumption declined by 1.6% in 2008. Relative to the size of its economy, Russia is among the most energy inefficient countries in the world, and energy consumption per capita in Russia is considerably higher than in the European countries of the OECD. In Russia, the price of gas is not determined by the market. Instead the Federal Tariff Service sets fixed wholesale prices at which Gazprom must sell most of its gas. The tariff for households is significantly lower than the price charged to industrial users, and both are considerably lower than export prices. The Russian government has launched plans to increase the domestic prices of gas so that by the end of 2011 the domestic price for industrial users would equal the export price (less export tax and transportation costs) (Solanko and Sutela, 2009). Since this would be a major adjustment burden on the Russian economy, accustomed to cheap energy, a gradual deregulation of gas and electricity prices is intended to curb growth in consumption, and it is likely that the goal will be somewhat delayed.

However, there is a wide range of possible measures for reducing Russian gas consumption. The future growth of consumption as a result of economic expansion may be offset or dampened by the substitution towards other energy sources, the dynamics of structural industrial change towards less energy-intensive branches, and improvements in energy efficiency due to the modernization of equipment for processing, transporting, and consuming gas. However, it is difficult to assess the impact from these factors on consumption. Besides the usual difficulties with economic forecasting, such as evaluating the effects from growth dynamics and structural change, there are the added uncertainties related to the pricing system and the future regulation reform of the power sector. The uncertainties relate to the actual scope of announced measures as well as their impact on decision making (Fernandez, 2009).

Since most Russian households have no gas meters, it is very difficult to moderate consumption in the housing sector, and the major expectations from the effects of price increases are on the power and the industrial sector. For consumption in industrial activities, higher gas prices could lead to significant substitution effects, as well as energy savings. In addition, price increases could serve as an incentive for Gazprom to upgrade its transmission networks, especially the medium- and low-pressure gas networks that feed final consumers, in order to avoid unnecessary transmission losses. However, the biggest gas savings may be achieved in the power sector if old gas generated heat and electricity plants are replaced by new, combined-cycle turbines (Fernandez, 2009). In the 2003 version of the Russian Energy Strategy, the share of gas in energy consumption decreases significantly by 2020, as new generation capacity would rely increasingly on coal instead of gas (PRF, 2003). However, according to Solanko and Sutela (2009), a major increase in the share of coal in electricity and heat production is highly unlikely, as gas will remain the most inexpensive source of energy for the foreseeable future, and the construction of new nuclear and hydroelectric power plants will not be accomplished overnight.

2.2.4. *Transmission capacities*

The Gazprom owned Russian Unified Gas Supply System (UGSS), the world's largest gas transportation system, is comprised of 159,500 km of gas trunk pipelines. The average transportation distance in 2008 was 2900 km for gas supplied to Russian consumers and 3322 km for gas export utilities (Gazprom, 2009a). Almost 80% of Russian gas exports pass through Ukraine, and the remaining 20% goes through Belarus and then Poland. As consequence, Ukraine and Belarus have a potential leverage over Russia, and Europe, through their ability to independently disrupt Russian natural gas supply to Europe (Ericson, 2009). Lack of sufficient export transport capacity from Russia to Europe do not seem to be a problem for the foreseeable future. The already existing export pipelines can carry $168\times10^9 m^3$ of gas to Europe annually. In addition there are planned capacity expansions of some of the already existing pipelines during the next decade (Sagen Lund and Tsyngankova, 2008).

New pipelines are planned to increase export capacity and create diversification alternatives. The most significant new Russian-controlled gas pipeline is the German–Russian project North European Gas Pipeline (NEGP), or Nord Stream. The pipeline is will stretch 1200 km under the Baltic Sea from Portovaya, Russia, to Greifswald, Germany, and is planned to bring $55\times10^9 m^3$ annually to Western Europe, by 2012, avoiding any transit states. In addition to the already existing Blue stream pipeline crossing the Black Sea between Russia and Turkey, Gazprom also plans a new southern pipeline, the South Stream. The pipeline is planned to run under the Black Sea from the eastern Russian Black Sea coast to the Bulgarian coast. The total length of the offshore section will be around 900 km and full capacity $63\times10^9 m^3$ (Gazprom, 2009b).

Gazprom is also planning two major pipeline supply routes to China, the Altai project, named after the Altai region in Sothern Siberia where Russia, China and Mongolia meet, and the eastern routes from the Far East region of Russia. The Altai pipeline transmission system is planned to be integrated with the 2800 km Chinese West-East pipeline system, which will convey gas to Shanghai. In 2006, Gazprom and China National Petroleum Corporation (CNPC) signed a protocol on gas supplies from Russia to China. The protocol set out the major agreements for the gas supply timing, amounts, routes, and for the pricing formula principles. Feasibility study on supply routes has been performed and the investment options evaluated. Commercial talks and planning of the project is currently ongoing. According to Gazprom (2009b), gas for the western route will originate from the fields in Western Siberia and the Eastern routes from Eastern Siberia and the Sakhalin fields. The annual gas volumes are initially planned at $68\times10^9 m^3$, although the capacity will be $80\times10^9 m^3$, and the priority will be given to the Western route intended to supply $30\times10^9 m^3$ per annum. The western route is, according to Gazprom, prioritized "because of the proximity of Western Siberia's fields to the existing gas infrastructure thus enabling to launch gas supplies within a shorter period" (Upstream, 2008b).

The gas fields on Sakhalin and the Shtokman field are being developed as LNG projects. Three variables define the differences between LNG tanker and gas pipeline transportation costs: volume, distance to be covered, and natural gas pipeline capacity. As a rule of thumb, in the case of small distances (less than 1000 km), it is more preferable to use pipelines, whatever their diameter. Larger diameter pipelines are more efficient below 4000–5000 km over land and up to 1500–2000 km under sea (Reymond, 2007; Yegorov and Wirl, 2008).

3. Present and future production areas

The most prominent gas fields, Urengoy, Medvezhe, Yamburg, Zapolyarnoye and Orenburg – all fields owned and operated by Gazprom – were discovered in Western Siberia and in the Orenburg region of southern Russia in the 1960s. On the Yamal Peninsula, several giant fields, as Bovanenko and Kharasevey, were discovered in the 1970s, thus firmly establishing Western Siberia as the Russian center of natural gas resources and production. The Western Siberian area can be divided in two major regions: The Nadym Pur Taz (NPT) region, in which most of the currently producing gas fields are located, and the Yamal

Peninsula where there are large gas reserves in undeveloped fields. According to Garipov and Kozlovsky (2004), of the $47\times10^{12}m^3$ of gas reserves present in Russia (at the beginning of 2002) 77% were concentrated in Western Siberia, 10% in the European economic region, 8% at the shelf and offshore and 5% in Eastern Siberia and the Far East.

Since the West Siberian fields in the NPT-region are rapidly being depleted, the Yamal fields and the Shtokman field are Gazprom's planned next large-scale sources of supply. However, the cost of production and transportation to markets for both of these production areas is substantial. Gazprom's official plans are to increase its total gas output to $580–590\times10^9m^3$/year by 2020 and $610–630\times10^9m^3$/year by 2030, although these production targets are subject to adjustment in case of changes in general market conditions in Russia and abroad and the expected energy needs of the Russian economy (Gazprom, 2007a). The planned level of gas output of $524\times10^9m^3$ by 2012 will be provided both by already operating fields and by new fields being put on production in the NPT-region (Upstream, 2009g). To develop these fields during the period up to 2012 is said to be economically viable because of their proximity to the existing gas transportation infrastructure. In the period following 2012, the gas output targets are to be met by developing fields in the following areas: After 2011 the Yamal Peninsula, Eastern Siberia after 2017, the shelf of the Arctic seas after 2030 (Gazprom, 2007b, 2008b; Upstream, 2009f).

3.1. Western Siberia—general

The West Siberian basin holds one of the world's largest discovered gas resources. They are almost completely concentrated in about 100 fields in the northern-most part of the basin (Grace, 2005). The region is characterized by its arctic climate and the temperature is below zero for almost 250 days per year, and may drop to as low as $-60\,^{\circ}C$ (Baidashin, 2006).

3.1.1. Western Siberian geology

The majority of the Western Siberian gas reservoirs are in layers from the Cretaceous geological period. The Cenomanian age of the Cretaceous period stretched between about 94–99 million years ago. Roughly, about two-thirds of the northern parts of Western Siberias' original gas resources were dry gas deposited in Cenomanian reservoirs. The Neocomian epoch of the Cretaceous period lasted between about 125–140 million years ago, and it is in turn divided in into four ages: Barremian, Hauterivian, Valanginian and Berrassian, each about 5 million years long. The deepest oil, gas and condensate reservoirs in the northern parts of Western Siberia are in the Achimov formation, which was deposited over about a 15 million-year time period at the very end of the late Jurassic age and at the beginning of the early Cretaceous age (Stern, 2005). There are also significant amounts of gas accumulated in the Aptian and Albian horizons of the Cretaceous period, deposited some 100–110 million years ago, during the middle part of the Cretaceous era (Loukashov et al., 2008).

3.1.2. Cenomanian gas reservoirs

Since the 1960s, nearly all Western Siberian gas production has come from the shallow, usually between 1000 and 1400 m deep, Cenomanian reservoirs (Grace, 2005). The reservoirs are sandstone, which have very good production characteristics, with single well gas flows in excess of 1 million cubic meters per day (Mcmpd), which is the equivalent of 6300 barrels of oil per day (6.3 kbpd). The reasons for these production conditions are several. Firstly, the gas is almost pure methane with small amounts of heavier hydrocarbons. The absence of any significant volumes of hydrocarbon liquids is a result of the biogenic origin of the Cenomanian gas, generated by the bacterial degradation of the remains of plant matter. Secondly, the sand rocks are usually relatively thick, with up to 100–200 m of net pay of gas. Since the reservoirs are comparatively shallow the sand rocks are not exposed to high pressures, resulting in good permeability conditions (Loukashov et al., 2008; Stern, 2005; Grace, 2005).

3.1.3. Neocomian gas

At depths between 1600 and 3200 m are the Neocomian reservoirs, the same age rock that contains nearly all of the oil in the Middle Ob region, south of the Nadym Pur Taz region. The gas in the Neocomian reservoirs are thermogenic, that is, they were formed from the thermal cracking of marine organic matter in the same late Jurassic and Neocomian shales that have sourced the large oil fields in the Middle Ob region. However, the deeper burial of the upper Jurassic Bazhenov and Neocomian shales in the Nadym Pur Taz region exposed the marine organic matter to higher temperatures, thus yielding a more gas and condensate prone region in the northern parts of Western Siberia compared to the middle and southern parts (Grace, 2005).

3.1.4. Achimov gas

The third important geological play is the Achimov gas, which is a special case of the Neocomian gas reservoirs. Achimov is the name of highly heterogeneous rocks with similar regional sedimentation conditions even though they were deposited in different historical periods. The Achimov formation was deposited in an environment of complex coastal turbulence, which resulted in much more geological complicated reservoirs compared with the horizontal deposited Neocomian layers. The Achimov formation lies at depths of about 3500 to more than 4000 m. The horizon is characterized by abnormally high pressure and temperature, low reservoir properties of the pay beds with very low permeability and the presence of carbon dioxide. As consequence, very small amounts of gas have been produced from this formation, and its development will require new development technologies (Achimgaz, 2009; Lyle, 2006).

3.2. Western Siberia—the Nadym Pur Taz Region

At present, the NPT region is the world's largest gas production center, accounting for over 90% of gas production in Russia and approximately for 20% of global gas production (Gaiduk and Shlyapnikov, 2006). The production from the NPT region is dominated by the Urengoy field, Yamburg and Medvezhye, which have been the center of the Russian gas industry for the past two decades. These three fields accounted for approximately 50% of Russia's gas supply in 2004 (Gazprom, 2008b; Solanko and Sutela, 2009). However, these fields are in a state of decline, with declines averaging more than $22\times10^9m^3$/year over the period 1999–2004, and according to the Russian Energy Strategy (2003), the Cenomanian part of the Urengoy was depleted by 65.4%, the Cenomanian part of Yamburg by 54.1% and the Medvezhye field was depleted by 75.6% (Gazprom, 2005; PRF, 2003; Stern, 2005). Gazprom officials have also acknowledged that the basic fields of Gazprom are declining by $20–25\times10^9m^3$/year, and according to Russian officials the NPT-region's production could account for as little as 26–30% of total output by 2030 (IEA, 2009; Tsybulsky et al., 2006). To mitigate the declining production of the supergiants, several new fields are being commissioned in the NPT area, with Zapolyarnoye and Yuzhno Russkoye making the largest production contribution.

3.2.1. Urengoy

The Urengoy field, discovered in 1966, is a gas and condensate field. It extends over 230 km from south to north while its width varies between 30 and 60 km, and the field covers 2400 km^2. The Urengoy field may in fact be regarded as an accumulation of many different gas and condensate/oil fields, which are densely compressed in a broad elongated anticline, the so-called Urengoy arch, with production taking place from different reservoirs and horizons. At the Urengoy field the Cenomanian and Neocomian gas-and-oil columns are currently well studied and developed. A third horizon, the Achimovian, is the first development project from this horizon and it is being studied and prepared for development as a joint venture between Gazprom and Wintershall (Achimgaz, 2009; Lyle, 2006).

The Cenomanian reservoirs of the Urengoy field are all hydrodynamically connected, which means gas can flow between the reservoirs; the reservoirs are developed by Gazprom (Lyle, 2006). The sand of the Cenomanian reservoirs is scarcely cemented, resulting in very good permeability, which combined with the large net pay of the reservoir, results in excellent well flows. However, the reservoir rocks are sensitive to high production flows, and in the beginning of the 1980s problems occurred from overproduction of the field with water-breaks into the reservoir eroding the poor cementing of the sandstones. Rising water levels also resulted in by-passed gas traps. This, in combination with delayed compressor installations, meant that Cenomanian gas production entered declining production faster than what was originally expected (Lyle, 2006; Stern, 2005).

The Neocomian reservoirs of the Urengoy field are not integrated into one reservoir. The Neocomian reservoirs' properties are, in general, inferior to that of the Cenomanian reservoir, with respect to size as well as permeability of the rocks. Along with gas there are considerable amounts of oil and condensate. The Neocomian stratas are well explored and has been developed since 1984. However, they are substantially more difficult and expensive to develop than the Cenomanian reservoir, and they also require more expensive gas treatment facilities due to the higher liquid contents of the gas (Lyle, 2006).

The Achimovian horizon is characterized by abnormally high reservoir pressures, 400–600 atm, and temperatures, around 110 °C. The depths of the reservoirs are between 3500 and 4000 m. The gas is collected in very complex stratigraphic traps, with very poor reservoir properties of the pay beds and the presence of carbon dioxide. These conditions result in higher capital expenditures than for the development of the Cenomanian and Neocomian layers and new technologies need to be utilized (Achimgaz, 2009; Lyle, 2006).

3.3. Western Siberia—the Yamal Peninsula

The Yamal Peninsula is the most promising gas-bearing region in Russia, and the development of the Yamal gas fields is the key to securing steady gas supply in the long term, both domestically and for export. However Gazprom emphasizes that it will cost much more to extract gas on the Yamal Peninsula compared to existing gas fields, and Gazprom has said the region will need investment of more than USD 100 billion to fully develop its potential (Upstream, 2009d).

Although most of the fields on the Yamal Peninsula were discovered in the 1970s, start of development was not initiated until 2006, and start of production is estimated at the earliest in 2012 (Upstream, 2009e). The development delays of the Yamal Peninsula may seem to be unwise in regard to the declining production from Gazprom's currently producing fields. However, huge capital investment requirements for the Yamal development, in combination with very low domestic gas prices made such an undertaking impossible during the late 1990s and early 2000s.

3.4. The European region and the Barents Sea

European Russia has gas fields in the Timano Pechora region in the Nortwestern District of Russia, the Volga Urals region in the Volga Federal District and the Astrakhanskoye region in the Southern Federal district. The latter two regions are by far the most important of the three mentioned. The largest fields in the European region are the Astrakhanskoye field (Southern Federal District) and Orenburg (Volga Federal District).

The Shtokman field lies 600 km offshore to the north east of Murmansk at water depths of around 300–330 m. The field was discovered in 1988 and is estimated to hold $3.2 \times 10^{12} m^3$ of natural gas, making it one of the world's largest non-developed gas and condensate offshore fields (Gazprom, 2007a). The Shtokman project development costs are estimated at USD 30–40 billion (Novosti, 2009; Upstream, 2009a). At present, partners at the Shtokman development are StatoilHydro (24%), Gazprom (51%) and total (25%). The Ludlovskoye and Ledovoye fields are significantly smaller in size and situated further north of the Shtokman field.

3.5. East Siberia and Sakhalin

The most advanced major field development project in East Siberia is the development of the Kovykta field, located 430 km north of Irkutsk with estimated recoverable amounts of gas of $1.4 \times 10^{12} m^3$. Large fields are also located in the Sakha Republic of which Chayandinskoye, with $1.2 \times 10^{12} m^3$ of reserves, is by far the most important. Other significant giant gas fields are Sredne-Botuobinskoye and Tas Yurakhskoye. The main fields of the Krasnoyarsk region are Yurubcheno-Tokhomskoye and Sobinskoye. See Appendix A.

There are six different Sakhalin projects, known by their number, 1–6. The most advanced are Sakhalin I and II, both are already producing with foreign participation. The other Sakhalin projects are located in areas believed to contain substantial amounts of oil and gas, although requiring further exploration. The Sakhalin Island is characterized by harsh weather conditions. In winter the sea freezes and temperatures may drop to -40 °C. In addition, the Sakhalin Island is located in an area of high seismicity.

The Sakhalin I Project includes three offshore fields: Chayvo, Odoptu, and Arkutun Dagi. Exxon Neftegas Limited (ENL) is the operator for the Sakhalin I project (30%). Co-venturers include Rosneft (20%); the Japanese consortium SODECO (30%); and the Indian company ONGC (20%) (Rosneft, 2009). Sakhalin I is a production-sharing agreement (PSA), which excludes the project from Gazprom's legal monopoly on gas exports. In 2004, ExxonMobil signed a preliminary agreement to supply $8 \times 10^9 m^3$ of Sakhalin I gas to China and has also held talks with Japan and India, which want to import Sakhalin's gas as LNG. Gazprom and Russian state officials have repeatedly said that Sakhalin I's output should be diverted to the growing domestic market, and gas exports from the fields has been stalled for the time being, while most of the gas is being marketed to domestic customers (Volkov and Makaryan, 2007). By 2012 production is anticipated to increase by another $1.5 \times 10^9 m^3$ (Upstream, 2009c).

Sakhalin Energy is the operator of the Sakhalin II Project, a USD 22 billion project, and consequently one of the world's biggest LNG developments.(Upstream, 2009b) Sakhalin Energy is currently owned by a consortium comprised of Gazprom (50% plus one share), Shell (27.5%), Mitsui (12.5%) and Mitsubishi (10%). The Sakhalin II Phase 2 project is an integrated oil and gas project developing the Piltun-Astokhskoye oil field and the Lunskoye gas field, and LNG deliveries began in 2009, The fields are located

13–16 km offshore the north-eastern coast of Sakhalin Island in the Sea of Okhotsk (Sakhalin Energy, 2009).

The projected recoverable reserves from the Sachalin III project are estimated at about $700 \times 10^9 m^3$. The Sakhalin III project includes the Veninsky block, being developed by Rosneft and China's Sinopec, and the Kirinsky, East Odoptinsky, and Ayashsky blocks, which have yet to be assigned (OGJ, 2009).

BP and Rosneft are partners in Sakhalin 4 and Sakhalin 5 projects, with BP controlling the former and Rosneft the latter. Preliminary estimates suggest that the two projects together contain $1 \times 10^{12} m^3$, roughly equally divided among the two. However, the Sakhalin 4 and Sakhalin 5 projects are primarily focused on oil production, with gas as a later target. Sakhalin 6 is the only Sakhalin license with only Russian partners. Preliminary estimates of reserves stand at around 4 billion barrels of oil equivalent, of which around two-thirds is believed to be gas (Stern, 2005). Production from Sakhalin 4–6 have not been modeled since there are no reliable reserve estimates, and their developments are expected to start beyond 2020, and will most likely be targeting the Pacific-rim LNG markets, thus not directly affecting the gas supplies for Europe.

4. Methodology

The scenarios for the future natural gas production potential for Russia have been modeled utilizing a bottom-up approach, building field-by-field. Individual modeling has been made for 83 giant gas fields (see Appendix A). The modeling has been made with the Giant Gas Field model (GGF-model), described in Söderbergh et al. (2009). Production from giant gas fields with associated gas has been modeled by the same GGF-model as non-associated gas.

4.1. Data sources

Field specific data has been gathered from a variety of sources. Although reducing the risks of using non-accurate or old figures, it naturally causes traditional problems of data inconsistencies. Most data from sources like AAPG, EIA, Gazprom, independent gas producers and international oil companies are generally deemed to be of high credibility. When evaluating what data to use, on those occasions when these sources give significantly different values, one must ultimately use personal judgement.

Reserves and production data have its origin from scientific literature, governmental reports, geological reports, peer-reviewed articles, oil and gas industry journals, bond loans prospectus for the financial markets, Gazprom and its development partners, independent gas producers and international oil companies. For data concerning economy, geopolitics and infrastructure, the sources are in principle the same although with somewhat larger focus on peer-reviewed articles and oil and gas industry journals, although company sources still have been of great importance.

4.2. Limitations of this study

Undiscovered resources have not been included in the forecast of Russian production and potential exports capacity. Most of the anticipated undiscovered resources of Russia are situated in remote Arctic regions, with the exception of some expected volumes in the Caspian Sea. At present there are a large number of available giant gas fields to develop, and the bottle-neck is primarily financial resources and long project lead-times. Gas fields have an economical value only if they are within reach of existing infrastructure and have viable plans of bringing the gas to markets. This means that discovered giant fields in the Arctic Sea are not commercial in the near-term. Having that said, it is important to stress that Arctic production from discovered fields in the Kara Sea have been included in the forecasts since these fields have been deemed to be within sufficient range of already existing and planned infrastructure.

However, when the development of the gas resources of East Siberia and Yamal eventually starts, the attention from the gas industry will be re-directed to regions such as the Kara Sea, offshore Kamchatka, the Chukchi Sea, and other Arctic waters. Nonetheless, this process is not very likely to have any major impact on Russian gas production before 2030, although for the period after 2030 it probably will be of outmost importance that these regions are explored and developed if Russia is to avoid a looming decline in gas production in the post-2030 period.

4.3. Reserves

Most of the reserve estimations in this article are based on reported *ABC*1 (in some cases *ABC*1+*C*2) and 2P figures. There are several reasons for the use of 2P figures as an estimate for URR figures for sufficiently explored fields. For strategic planning many companies make a "best estimate" of how much petroleum they believe in time, be technically feasible and economically viable to recover, and this figure is generally represented by the sum of the proved and probable estimates (2P) (SPE, 2007). For mathematical reasons, when making aggregation of reserve estimates the SPE recommend the use of 2P figures. The use of aggregated 1P figures may yield a very conservative estimate of the total amount of 1P reserves, and the aggregate of 3P figures may end up with too optimistic results (Thompson et al., 2009). There are claims that Russian *ABC*1 reserve figures in reality even exceeds the corresponding 2P values. Laherrère (2004) refers to E.M. Khamilov claiming in 1993 that public Russian reserve figures are "grossly exaggerated" and further stating that *ABC*1 more corresponds to 3P and should be corrected to be more similar of 2P values by reducing the numbers by 30%. According to Grace (2005) there is absolutely no simple rule for translating Soviet/Russian reserves into SPE/WPC or SEC based classifications. The notion that generally $A+B+C1$ equals proved plus probable, or that $A+B+(0.3 \times C1)$ equals proved plus probable is not correct. Although, at very high level of aggregation such as for national statistics, such coarse rules of thumb may have some value. However, as previously described in Section 2.1, Etherington et al. (2005) state that the Russian reserves classes *A*, *B*, and *C*1 grossly correlate to SPE proved reserves. Category *C*2 encompasses SPE probable and possible, and can only be dissected by detailed examination of the information available.

All this taken together, it is not deemed reasonable to exclusively use a specific reserve estimation system or conversion method, but instead making an individual judgment for each field regarding which URR estimation that should be allotted for the field. The URR figure used for each field is stated in Appendix A. For sufficiently explored and delineated producing fields, the *ABC*1 and 2P figures theoretically will converge as the field becomes depleted.

4.4. Production data

There are some ambiguities and lack of transparency concerning Russian gas production partly because of unclear amounts of flared volumes and a Russian practice towards reporting gross production figures, that is, not excluding flared, vented and re-injected volumes (Goldthau, 2008; Laherrère, 2007).

The field-by-field study of this article for all Russian giant fields has a total Russian production from its giant fields of $650 \times 10^9 m^3$ in 2008, indicating conformity with the previously presented Russian gross production figures.

4.5. The vital role of Russian giant gas fields

According to Garipov and Kozlovsky (2004), Russia's gas resource base is formed by 787 gas fields, including gas and oil and gas condensate fields, and about 95% of Russia's gas reserves are contained in giant fields and semi-giant fields larger than $30 \times 10^9 m^3$. During the last three decades, the average size per discovered gas field has been decreasing. In 1971–1975, the average size of new fields in Russia amounted to $167 \times 10^9 m^3$, and in 1996–2000—only to $40 \times 10^9 m^3$. The exploration for gas is increasingly targeting deeper horizons and non-structural traps. In Western Siberia virtually all basic targets are prospects associated with wedge shapes and stratigraphic unconformities, and the role of non-anticlinal traps is predicted to increase significantly all over Russia in the future (Garipov and Kozlovsky, 2004).

The ultimate recoverable resources for 83 giant gas fields have been studied for this article. Their combined estimated URR figure amounts to $61 \times 10^{12} m^3$. A complete field list is presented in Appendix A, with discovery year, estimated URR figures and planed estimated plateau production level for fields not yet in production. In Fig. 1 the discovery profile for the 83 studied Russian giant gas fields is illustrated. It shows a peak of discovered volumes in the 1960s and since then a downward trend of smaller amounts of yearly total discoveries.

4.6. The giant gas field production model

When developing a gas field, a primary criterion is often to ensure a long sustainable plateau, in order to get the highest rate of return on capital invested. In addition, a long plateau production is often desirable since the customers usually require a stable supply at an agreed rate over several years (Söderbergh et al., 2009).

4.6.1. Definitions

The production for year t is denoted q_t and Q_t is the cumulative production at the end of year t. R_0 is the estimated URR figure, and the reserves that remain to be produced at the beginning of year t, are defined as R_t. Production of a finite resource always results in depletion. We define the *level of depletion D* as

$$D_t = \frac{Q_t}{R_0} \quad (1)$$

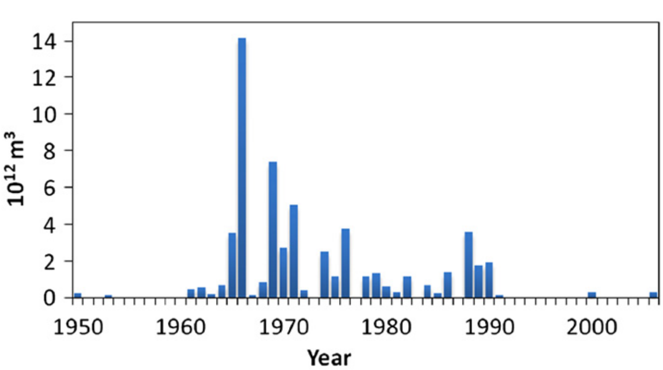

Fig. 1. Annual amounts of discovered gas in Russian giant gas fields. Giant fields with associated gas are included.
Sources: Own compilation of data. See Table A1

The *depletion rate of initial reserves* (d) denotes the relation between the annual production and the reserves originally present in the field, d_t is defined as the annual increase in depletion level

$$d_t = \frac{q_t}{R_0} \quad (2)$$

The *depletion rate of remaining reserves* ($d_{\delta,t}$), denotes the relation between the annual production and the reserves at the beginning of the year in question, defined as

$$d_{\delta,t} = \frac{q_t}{R_t} \quad (3)$$

The *decline rate* λ, denotes year-over-year change in production, and is defined as

$$\lambda_t = \frac{(q_t - q_{t-1})}{q_{t-1}} \quad (4)$$

4.6.2. The relation between depletion rates, decline rates and reserves

Observed decline rates and depletion rates for giant gas fields are correlated to the size of the field, and the depletion rates tend to be higher for smaller gas fields. Depletion rates, for production of associated gas, have in general tendencies to be lower on average compared to similar-sized non-associated gas fields. The GGF-model uses exponential decline for estimating future production for fields in decline (Söderbergh et al., 2009).

An important component of the GGF-model is to include a parameter for plateau production based upon depletion rate. The GGF-model uses the d-value to estimate planned plateau production levels. An analysis of d-values, can also be a useful tool when one has to decide if a field, already at what seems to be a plateau production, will remain at approximately the same production level as it currently produces. This procedure is used if there is a lack of official statements of planned future production levels. The GGF-model also uses the d_δ-value (Eq. (3)). When a production is modeled with exponential decline, the d_δ-value is the same as the λ-value (Eq. (4)). For more information on this, see Söderbergh et al. (2009).

4.6.3. Production phases

In the GGF-model, the life-cycle of a natural gas field has been divided into three separate phases. First is the Build-up phase, during which production rises, as new wells are put in production. For larger gas fields, the build-up phase is followed by a Plateau phase, when the rate of production is roughly flat as new wells are brought on stream, offsetting declining production from older wells in combination with the installations and use of field compressors. Finally, a Decline phase begins when the gas field's rate of production falls continuously until the field is decommissioned and abandoned. These phases have all been parameterized. A typical giant gas field production profile is presented in Fig. 2.

The Build-up phase (AB), is modeled as a linear increasing production curve from start-of-production q_A—until the planned plateau production level (q_B) is reached. The cumulative production from A to B is called Q_{AB}. The plateau production is modeled as a period of flat production, until the end of the plateau phase at year C–1 is reached. The decline phase is modeled with an exponential decline curve. The decline phase is set to start if the cumulative production until the onset of the Decline phase ($Q_{AB}+Q_{BC}$) plus the cumulative production during Decline phase, Q_{CD}, is equal to the URR figure of the field. If these criteria are fulfilled, the production should be in decline with a decline rate λ, which will be the same as d_δ at the time for the onset of the decline. When a field is already in its decline phase, as standard

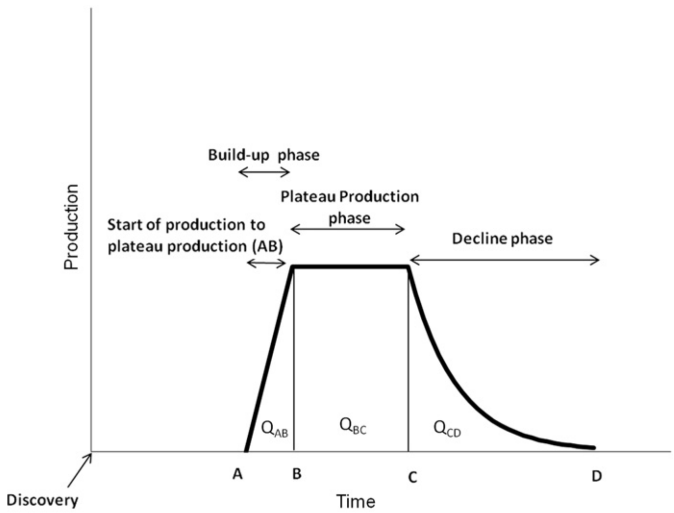

Fig. 2. Schematic illustration of the production profile of a giant gas field. Discovery is time = 0, followed by the chronological points in time *A*, *B*, *C*, *D*.

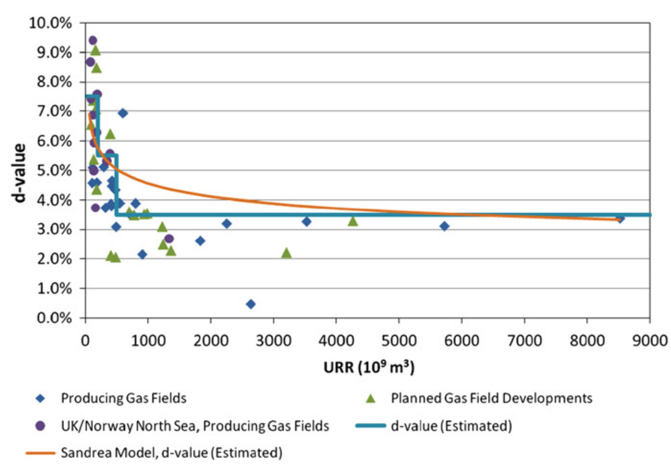

Fig. 3. Depletion rates for 42 Russian producing and planned fields. Data from 12 producing and planned UK and Norwegian fields of the North Sea have been included as well. Estimated depletion rates used for modeling fields which have not yet reached plateau production and where planned plateau production is unknown are illustrated with a staircase function.

procedure, the λ-value is set as the d_δ-value for the field. See Söderbergh et al. (2009) for more details.

4.7. Estimation of production profile parameters

To obtain the values for the parameters used in the GGF-model, a number of giant gas fields have been studied. The beginning of the *plateau production level* (q_p) is defined from when production reaches 85% of the observed *maximum production value* q_{max}. The plateau production is characterized by a period of more or less flat rate of plateau production. Of course, the production at plateau will vary within certain limits. When production is below 85% of q_{max} and declining, the field is considered to be in terminal decline, unless there are strong reasons to believe otherwise. Production during the decline phase is measured between 85% and 30% of q_{max}. The *d*-value is measured at q_{max}. In Fig. 3 the data set with the *d*-values of 54 giant gas fields is depicted against each fields URR figure. The *d*-values for 22 producing Russian fields and 20 planned projects have been included. In addition, data from 12 producing and planned gas fields of the UK and Norwegian North Sea have been included as well in order to get more data from smaller giant fields.

4.7.1. Plateau production

As illustrated in Fig. 3, the *d*-values tend to be higher for smaller fields than for larger giants, and the variance is higher for smaller fields. To discuss the reasons for the higher spread for *d*-values for giant gas fields with an URR figure between about 80 and $200 \times 10^9 m^3$ is beyond the scope of this article. However, some plausible explanations include distorted data for URR figures, differences in the reservoir qualities of the fields, high pressure and high temperature gas, infrastructure limitations and economic status of the developer(s) of the field.

For estimating the *d*-values for future gas fields developments a staircase function has been fitted to the data points illustrated in Fig. 3. It is important to stress that the purpose is to find the most likely mean depletion rates for future giant gas field developments. It has been assumed that the future *d*-values will be higher on average than the historical mean, mainly because of increased field development experience, technological advances and more efficient use of gas compressors. Further the creation of the staircase function has been guided by the principle to be higher than most historical *d*-values, although not higher than certain single outliers, who might deviate due to distorted data or exceptional reservoir and gas qualities. By this approach the estimated future *d*-values ought not to be underestimated but rather perhaps somewhat over-estimated, thus resulting in a higher production forecast than what may eventually be materialized.

4.7.2. Other methods for estimating plateau production

In order to have an estimate of the production potential of a newly discovered natural gas field, Sandrea (2009), has developed an algorithm for such early estimations. According to Sandrea, the correlation between production potential and ultimate recoverable reserves is one of a power relationship

$$q_{max} = aK^b \tag{5}$$

where q_{max} is the production capacity, K the estimated URR figure and a and b are constants. The model was applied to a suite of seven mature giant gas fields and two countries, the US and UK. The URR values were determined by decline analysis of their historic production data. The fields were chosen to cover a wide spectrum of K-values ranging from 250 to $2580 \times 10^9 m^3$. The resulting expression for gas fields was found to be

$$q_{max} = 0.21K^{0.8536} \tag{6}$$

With a correlation coefficient (r^2) of 0.980. The units for q and K are billion cubic feet per day (bcfpd) and thousand billion cubic feets (tcf).

Although it seems to be an acceptable approach of estimating the *d*-values for gas fields, Fig. 3 indicates that the method is too general to be applied for the specific purposes for this article. Sandrea's method is per definition an adjustment to the mean value of a certain data set. However, for the purposes of this article it is not desirable to find the mean of historical *d*-values but rather to try to estimate the highest possible mean-value for future gas field developments. The staircase method is deemed to provide greater flexibility for providing such estimation. Further, the Sandrea formula is derived from a data set of only 9 studied cases, seven giant fields and two countries. The data set may be too limited for drawing any conclusions and it is doubtful to include aggregate of field, in this case whole countries, to this data set. Fig. 3 shows the great variance between *d*-values, especially for smaller fields. This makes it potentially misleading to use the mean value as predictor for the *d*-value of future projects. In addition, uncertainties regarding the accuracy of certain URR figures may cause distorted *d*-values.

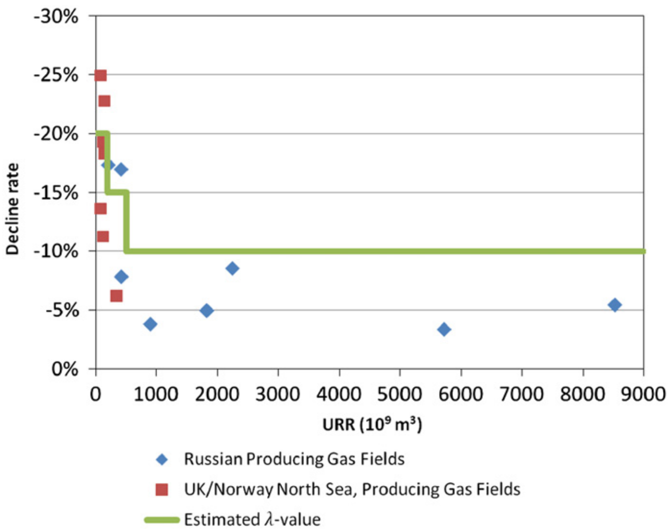

Fig. 4. Observed decline rates for 15 giant natural gas fields already in decline—eight Russian and seven fields in the Norwegian and UK areas of the North Sea. Estimated decline rates used for modeling fields that have not yet entered declining production are illustrated with a staircase function.

Table 1
Used parameter values for the creation of forecasts.

URR ($10^9 m^3$)	*d* (%)	*λ* (%)	*AB* (year)
URR > 500	3.5	10	5
500 > URR > 200	5.5	15	3
200 > URR > 80	7.5	20	3

4.7.3. Decline rate

Fig. 4 illustrates the decline rate values for fields that are in decline. When estimating the future decline rates for fields that have not yet entered declining production, it has been assumed that due to better planning, technological advances and more efficient use of compressors, it will be possible to keep fields at plateau production for a longer period of time. As consequence a staircase function has been applied to the data set to estimate the future decline rates for fields that have not yet entered declining production.

Since the Russian gas industry has been so dependent on the production from the three supergiant fields, relatively few giants have entered a state of declining production. In order to get more data for the estimation of the decline rate parameters, decline rates for seven Norwegian and UK giants have been included as well. For more information regarding Norwegian and UK fields, see Söderbergh et al. (2009).

4.7.4. Summary of assumed parameters

Since the build-up time (*AB*), is more a function of economic decisions, it is not deemed meaningful to perform more detailed historical analysis of build-up phases. However, very large fields tend to take longer time to ramp up to plateau production than their smaller peers. As consequence, based on already producing and announced field development plans, the estimated build up time of smaller fields and larger fields is 3 and 5 years, respectively. This means that a field smaller than $500 \times 10^9 m^3$ is at plateau production during its third producing year and a field larger than $500 \times 10^9 m^3$ is at plateau production during its fifth year. In Table 1, the *d*-, *λ*- and *AB*-parameters are presented.

4.8. Specific field and regional assumptions

Russian gas production has been divided into the eight entities:

1. All Russian producing giant fields and all planned giant field developments in Western Siberia.
2. The Gydan Peninsula.
3. The Barents Sea.
4. The Timano Pechora region.
5. The Arctic Sea.
6. The Yamal Peninsula.
7. The East Siberian region.
8. The Far East.

The production from all studied giant fields within an entity is presented as a unit. Since the Urengoy and Yamburg fields are of such importance for Russian gas production, providing 45% of the Russian production as late as in 2004, they have been given some special attention in order to motivate and explain their estimated URR figures. Ten producing giant associated gas fields have been modeled. Samotlor, Fedorovo-Surgutskoye and Lyantorskoye are the largest, all situated in Western Siberia, Middle Ob province, the main oil producing region of Russia. Their combined production is estimated at about $20 \times 10^9 m^3$.

4.8.1. Urengoy

The heterogeneous characteristics of the Urengoy field make the analysis of the field's production very complicated since Gazprom do not make public any detailed data regarding Urengoy's reserve base and production. Reserve as well as production figures are difficult to decompose and assign to individual sub-fields as well as reservoir formations. As consequence, there is great confusion regarding the URR values for the Urengoy field and the estimations have varied significantly over time see Table 2. The reasons for the large differences lie probably in the problem of how to evaluate the gas resources of the Achimovian formation.

The URR figure from 2006 has support from other data observations. Applying the historical production figures of the Urengoy field from Laherrère, 2004, EIA (1997) and Stern (2005) to the depletion levels of 48.7% for 2003, as given by Gazprom and cited by Stern (2005), and of 41% given for around the year 2000 by Garipov and Kozlovsky, gives a total URR estimation of 10–$11 \times 10^{12} m^3$. Therefore it is assumed that the URR-value of $10.5 \times 10^{12} m^3$, presented by the IHS (2006), is the most reasonable estimation with respect to the available data. However, when trying to trace the relative distribution of the total URR-figure to the different layers and reservoirs there are inconsistencies in the data and some assumptions are needed. For this article the estimations presented in Table 3, have been made for the URR-value for the different layers of the Urengoy field.

Table 2
Estimated URR figures of the Urengoy field from IHS and WoodMackenzie (WM), and the US Energy Information Administration (EIA). The URR figures have varied significantly between 2002 and 2006.

Forecaster and year	$10^9 m^3$
IHS 2006	10,482
IHS 2004	10,397
IHS 2003	6544
IHS 2002	9915
WM 2006	7564
WM 2004	6176
EIA 1997	9938

Table 3
Assumed URR values for the various reservoirs and production zones of the Urengoy field.

Reservoir(s)	URR (10^9m^3)
Urengoy, Cenomanian	6500
Urengoy, Valanginian	2000
Urengoy, Achimov	1200
Pestsovoye (Urengoy)	550
Yen-Yakhinskoye (Urengoy)	250
Urengoy total	10,500

Production from the Cenomanian layers of the Urengoy field started in 1978, and they have been Russia's most important gas source. However, by no later than 2002, the Cenomanian reserves of the Urengoy were depleted by 65.4% (PRF, 2003). By deducting the estimated ultimate production of Valanginian gas between 1987 and 2002 and apply a depletion value of 65.4% it is reasonable to assume a URR figure for the Cenomanian part of the Urengoy field of between 6×10^{12} and $7 \times 10^{12} m^3$, and the figure that is deemed to be most likely is $6.5 \times 10^9 m^3$ Production from Valangian deposits began in 1987. According to SCR USSR data cited by Lyle (2006), Neocomian gas amounted to $1885 \times 10^9 m^3$ in 1989. It is therefore deemed reasonable to assume a URR value of 2000. There are great uncertainties regarding the URR figure of the Pestsovoye field. Very low international estimates, in 2004 only $36 \times 10^9 m^3$ (Gazprom, 2005), is in sharp contrast to the substantial production levels of $27.5 \times 10^9 m^3$ per year Gazprom is expecting the field to produce. Due to the planned production level, the total URR-value of the field is assumed to be $550 \times 10^9 m^3$ of gas from Cenomanian and Neocomian layers.

The Achimovian deposits of the Urengoy field was in 2004 stated by Gazprom at $889 \times 10^9 m^3$ of 2P reserves (Stern, 2005). By assuming that the combined reserves of the Urengoy Cenomanian, Urengoy Valanginian, Pestsovoye, Yen-Yakhinskoye and the Achimovian deposits of the Urengoy field amount to $10.5 \times 10^{12} m^3$, the current URR of Urengoyskoye Achimov is estimated at $1.2 \times 10^{12} m^3$. Most likely the greatest uncertainties of the total URR resources of the Urengoy field lies in how to estimate the production potential from the Achimov, and it is important to closely monitor its future production development.

The described figures are based on a large number of different public sources, and they should be regarded as just estimations. However, they seem to be in coherence with, available Gazprom data (2006) and estimations given by Lyle (2006). Thus the estimated reserve figures seem sufficiently reliable for the aims of this article.

4.8.2. Producing giant fields, planned developments in Western Siberia and Gydan

The central part of the Yamburg field is declining, and despite increasing production from the southern, Kharvutinskoye, part and the northern, Aneryakhinskoye, part total production from the field is in a state of more or less continuously declining production. Laherrère (2004) gives estimations of Yamburg reserves of 4800 and $6700 \times 10^9 m^3$. EIA in 1997 had a value of $4900 \times 10^9 m^3$. According to the Russian Energy Strategy 2003 the Cenomanian reserves of Yamburg were depleted by 54.1% no later than 2002. Cumulative production by 2002 was about $2500 \times 10^9 m^3$, by which about 2400 can be assumed to be of Cenomanian gas (EIA, 2007; Laherrère, 2004). To this should be added that the Kharvutinskaya has an estimated plateau production of 4 years, producing $30 \times 10^9 m^3$ per year. The Aneryakhinskaya section has a planned plateau production of $10 \times 10^9 m^3$. Accordingly it has been deemed reasonable to set a total URR-value of Yamburg to $5700 \times 10^9 m^3$.

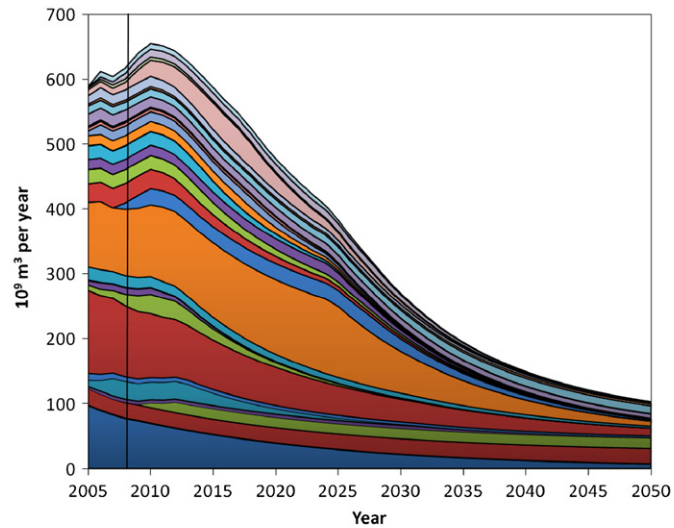

Fig. 5. Forecast for all producing gas fields in Russia. The five field profiles in the bottom are the five production areas of the Urengoy field: The Cenomanian reservoir, the Valangian reservoirs, the Achimov deposit, Yen-Yakhinskoye and Pestsovoye.

The development of new fields in the Nadym Pur Taz region has enabled Russia to increase its production during 2001–2008, despite the steady production decline of the three supergiant fields. Several fields such as Kharvutinskaya, Yety-Purovskoye, Petsovoye, South Russkoye and most importantly, Zapolyarnoye, have been brought on stream over the 2001–2008 period, and by 2012 Kharampurskoye and Khalmerpayutinskoye may be producing.

The combined production from the eight individually modeled fields in the Ob and Taz Bay and on the Gydan Peninsula has in the results section been presented as the separate entity Gydan. None of the eight fields has yet been put into production. The Gydan Peninsula is situated to the north east of the NPT-region, and the Ob and Taz Bay is the waters separating the NPT-region, the Yamal Peninsula and the Gydan Peninsula.

By 2004, Orenburg was depleted by 57% and production is now in decline. Astrakhan on the other hand still has remaining reserves of more than $2.5 \times 10^{12} m^3$, and in 2005 its level of depletion was only 4% (Stern, 2005). However, the development of the field is associated with some major challenges in form of high reservoir pressures and high hydrogen sulphide content, which is being removed at a gas processing plant nearby. The field produces about $12 \times 10^9 m^3$ per year, which is lower than its size would suggest. Gazprom hopes that the output from Astrakhan could eventually be increased to $60 \times 10^9 m^3$ per year (Afanasiev, 2007). Production from all studied producing Russian giant gas fields is presented in Fig. 5.

4.8.3. The Yamal Peninsula

The 16 studied giant gas fields of the Yamal Peninsula have be divided into three different groups, one for each future production zone, as described by Gazprom (2009d), i.e. the Bovanenkovo production zone (Central Group), the Tambey production zone (Northern Group) and the Southern production zone. The Central Group contains 64% of the Yamal gas reserves, the Northern Group 27%, and the Southern Group 9%. See Appendix A.

Gazprom (2009d) has presented the following development plan for the Yamal Peninsula. The Bovanenkovo production zone (Central Group), is projected to reach up to $220 \times 10^9 m^3$/year, the Tambey production zone (Northern Group) up to $65 \times 10^9 m^3$/year, and the Southern production zone $30 \times 10^9 m^3$/year. This gives a total Yamal production $315\times10^9 m^3$/year, but Gazprom also gives a higher production estimate of $360\times10^9 m^3$ (Gazprom, 2009d). The general concept for the Yamal Peninsula is that the Bovanenko and Kharasevey fields (from the central group) will be developed first, followed, by the Northern group and finally the Southern group (Stern, 2005). In June 2009, the start of development of Bovanenkovskoye field was announced to be postponed 1 year and begin in 2012. Projected production is $115\times10^9 m^3$/year, with a potential additional increase of $25\times10^9 m^3$/year if gas condensate layers are taken into account (Gazprom, 2008b; Upstream, 2009e).

The field-by-field modeling have been adjusted to approximately follow the same production curve as for the Gazprom Yamal forecast by adjusting the planned start-up year for fields where no such information have been communicated. This has been done since Gazprom will build the infrastructure for transport of the gas to market, and there will not be more gas produced than the infrastructure may accommodate. The values for planned production plateau levels have been set as given by available sources, and when no planned plateau production data are available, to the values generated by the model, see Appendix A.

4.8.4. The Barents Sea, Timano Pechora and the Kara Sea

Annual production from the Shtokman field is planned to occur over at least three phases. Phase 1 includes both liquefied natural gas and piped gas, starting with pipeline supplies and bringing on LNG production a year later (Upstream, 2009i). Expected annual gas output from Shtokman currently stands at 71 and $95\times10^9 m^3$ including production of 30–40 million tonnes of LNG a year (Afanasiev, 2008b; Upstream, 2008a). Gazprom initially announced the start of gas and liquefied natural gas production from the Shtokman field to 2013 and 2014, respectively, however the project is likely to be delayed to at least 2015 (Upstream, 2009k). The combined production from the Shtokman field, and the Ludlovskoye and Ledovoye fields is presented as the entity Barents Sea, in Fig. 7 in the Results section.

Although the Timano Pechora region has a relatively small proportion of Russian gas production, Gazprom has been active in the area for a long time. The Vuktylskoye field has been in production since the 1960s and is depleted by more than 80% (Garipov and Kozlovsky, 2004). Layavozhskoye, is one of the more important undeveloped gas fields of the region, owned by Gazprom. Also the Kymzhinskoye field is one of the major fields of the area although its development has been delayed due to a failed attempt by Soviet authorities to put an end to leaking gas and condensate by making the unprecedented measure of detonating a nuclear device below ground (Afanasiev, 2008a). The combined production from the Layavozhskoye, and Kymzhinskoye fields of the Timano Pechora region is presented as the entity Timano Pechora, in Fig. 7 in the Results section.

The Kara Sea is the Arctic waters off the Western part of the Yamal Peninsula. According to Gazprom (2007b) offshore Yamal production will begin in 2030. So far, Leningradskoye and Rusanovskoye are the largest discovered fields in the Kara Sea region, and the combined production from these two fields is presented as the entity Arctic Sea, in Fig. 7 in the Results section.

4.8.5. East Siberia and the Far East

The 2003 Russian Energy Strategy stressed the importance on the development of the East Siberian and Far Eastern gas resources. The nine East Siberian fields, whose combined production is presented as one entity in Fig. 7 in the Results section. Production from East Siberia is estimated to begin with the Kovykta field in 2018 (Upstream, 2009h). See Appendix A.

The combined production from Sakhalin I, II and III is presented in Fig. 7 in the Results section as one entity, the Far East. While Sakhalin is already exporting LNG, the development of Sakhalin II project is estimated to continue being hampered by gas exports disagreements between Gazprom and the Sakhalin I consortium, and the current production is expected to ramp-up in two stages, after 2012, and 2016. Sakhalin III is expected to come on stream in 2017–2020, according to Russia's draft Gas Industry Development Strategy, with peak production at $28.6\times10^9 m^3$/year of gas. The two most important fields of the Sakhalin III project are the Kirinsky and Veninsky fields, and start of production is assumed in 2017 and 2020, respectively (OGJ, 2009). See Appendix A.

4.9. Assumptions on gas use

The majority of Russian gas production will continue to be consumed domestically for the foreseeable future. Exports of gas from East Siberia and the Far East to Asian and the Pacific-Rim markets is the expected major change in the use of Russian gas for the coming 20 years.

4.9.1. Potential exports to Asia and China

Compared to West Siberia and the European part of Russia, the gas transport infrastructure in East Sibera is very limited, making the gas reserves stranded for the moment. There are only 11 million inhabitants in the Eastern Siberian and Far East regions of Russia, limiting the potential increase of domestic gas demand (Stern, 2005). Combined with great distances to Europe and Western Russia, and the relatively proximity to Asian markets, the only sensible economic decision is to export the gas to new Asian customers, primarily China. The Russian Energy Strategy (2003) also states that the production from East Siberia and the Far East in an optimistic scenario would give the region, by 2020, a combined gas output of $106\times10^9 m^3$, mainly to be directed for Asia-Pacific countries. A detailed field-by-field forecast of production from East Siberia and the Far East is presented in Fig. 9, in the Results section.

There are good reasons for the assumption that gas exports from East Siberia and Sakhalin will be directed to China and Asian markets. According to Ma Xinhua, a PetroChina vice president in charge of natural gas production, Chinese imports from Russia will total $80\times10^9 m^3$ per annum by 2020, and Central Asian countries will eventually be able to supply up to $60\times10^9 m^3$/year. PetroChina's former chief geologist Jia Chengzao, claims that by 2030, China's gas demand may reach $400\times10^9 m^3$/year, of which $250\times10^9 m^3$ will be supplied from domestic fields and $150\times10^9 m^3$ by imports (Yihe, 2009a).

Gazprom officials have also stated that there will be more emphasis on new Asian markets to diversify away from European markets. After 2020, Gazprom's exports to Asia could amount to 50% of its current supplies to Europe (Upstream, 2008b). In addition, Russia and South Korea has agreed on Russian exports from 2015 of $10\times10^9 m^3$/year for 30 years via a pipeline that will run across North Korea (Upstream, 2008c).

Talks on natural gas supply between China National Petroleum Corporation and Gazprom started in 2004, but a final supply agreement has been delayed primarily as a result of disagreements on price. The continuing delays have caused the initial time-frame of gas deliveries from Russia to China already in 2011, to look increasingly unrealistic (Yihe, 2009b). However, due to the expected increase in Chinese gas demand it has been deemed reasonable to expect the various issues eventually being overcome and a start of Russian–Chinese gas deliveries by 2018.

4.9.2. Russian domestic demand development

Assuming the Russian economy eventually recovers from the 2008–2009 economic crises and resumes its previous growth trajectory, Solanko and Sutela (2009) expect that the annual growth in gas consumption will be around 2% over the next 10–15 years. Fernandez (2009) says the high demand growth of 8.3% in 2005–2007 may be an indication that energy saving policies are not yet very effective. If this proves to be the case, Fernandez argues it is not unlikely that the domestic demand growth rate would be closer to 1.5% than 1%. Fernandez adds that the growth rate could be lower than 1.5%, if energy saving policies will be effective, or if average GDP growth will be below 5%, although gas consumption will hardly grow less than 1% per year, since neither structural changes nor capital renewal will advance as quickly as expected with low GDP growth. Lower demand forecasts are advocated by the IEA, and in the 2008 version of the World Energy Outlook (2008), Russian gas consumption is expected to grow by about 1.5% to 2015, thereafter slowing down to a growth of only 0.2% annually until 2030. In the 2009 version of the World Energy Outlook 2009, the IEA has significantly lowered its forecast with a zero percent growth to 2015, thereafter a slow growth of 0.3% to 2020 followed by a 1.1% growth from 2021 to 2025 and then from 2026 a decrease in demand growth to 0.6% annually until 2030. The reasoning for the latter forecast is an anticipated spreading and deepening of the 2008–2009 recession causing the use of gas in industry and for power generation to fall sharply, particularly in Russia, mainly because of weak demand for electricity and relatively high gas prices.

Since both Solanko and Sutela (2009) and Fernandez (2009) have higher growth rates of 1.5–2% and Volkov et al. (2009) a plausible growth rates of 0.5–1%, the World Energy Outlook (2008) demand forecast has been considered to be of sufficiently moderate nature to be used for this article. For the period beyond 2030, it has been assumed that the demand growth continues with a 0.2% annual increase.

4.9.3. Gas supplies available for Europe

The estimations of Russian gas exports are based on the assumption that the gas transmission pipeline network is expanded and serviced so that transportation capacity will not hinder growth in production or exports. With IEA figures Russian net export capacity in 2007 was $193\times10^9 m^3$ (IEA, 2009). According to BP (2009) figures Russian net export capacity in 2007 was $166\times10^9 m^3$. In 2007 in principle all Russian net export capacity was available for European and CIS exports since Sakhalin exports only began in small amounts from Sakhalin II in 2009. In 2007 Gazprom exported $168.5\times10^9 m^3$ to the Far Abroad, and gas sales to the CIS and the Baltic states amounted to $101\times10^9 m^3$ (Gazprom, 2008a) Gas imports from Central Asia, was $60\times10^9 m^3$ resulting in net Russian gas exports of $210\times10^9 m^3$, implying a domestic gas use figure of 447, provided no volume changes in gas storages. The field-by-field modeling gives a production figure of $635\times10^9 m^3$ in 2007, about $10–25\times10^9 m^3$ below estimations of total Russian gas supplies, this figure seems reasonable since semi-giant and small fields are not included in the modeling, the resulting net exports capacity in 2007, with a demand figure of $453\times10^9 m^3$ was $180\times10^9 m^3$. As shown, there are some inconsistencies between the production and consumption figures from different sources. However, the absolute numbers are of less importance compared to evaluating the coming general trends for available gas exports for Europe.

For reasons of simplification it has been assumed that all production from East Siberia and the Far East will be exported to the Asian and Pacific Rim markets, and therefore will be unavailable to European consumers. Due to the relatively small population in the East Siberia and the Far East regions, only 8% of the total Russian, domestic demand from these regions is not taken into consideration. Hence, all Russian demand is currently and in the foreseeable future assumed to originate from the West Siberian and European parts of Russia. However, to compensate for these, from a European point of view, somewhat pessimistic assumptions, much more optimistic assumptions have been assigned for the Shtokman development, where all gas is treated as available for European exports. The Shtokman volumes are quite substantial, compared with the demand volumes from East Siberia. More than half of Shtokman production may be in the form of LNG, and the US market has often been depicted as the main target for Shtokman LNG production (Afanasiev, 2008b; Upstream, 2009j). For these reasons, the amounts of gas available for European and CIS export are achieved by subtracting the production from East Siberia and the Far East and domestic demand.

5. Results

This section begins with the production forecast for all currently producing non-associated giant gas fields. Due to the high expectations on Yamal production, the forecast for this region is individually illustrated. Then follows the two production forecasts for all the 83 studied fields, and a separate forecast for the production from Eastern Siberia and the Far East region. Finally, the different outcomes for available gas for European and CIS exports is illustrated with three scenarios: One where the production develops with no delays, a second scenario where production from the Yamal Peninsula is delayed by 5 years, and a third scenario where start of production from the Shtokman field is delayed by 5 years.

5.1. Production from all currently producing giant fields

In Fig. 5, the production forecast for all currently producing giant non-associated gas fields is illustrated. The forecast includes the 16 individually modeled West Siberian fields, the Vuktylskoye field in Timano Pechora and the Astrakhan and Orenburg fields from the European part of Russia. The five production areas of the Urengoy field; the Cenomanian reservoir, the Valangian reservoirs, Pestsovoye, Yen-Yakhinskoye, and the Achimov deposit, have been modeled individually. The Aneryakhinskoye and Kharvutinskoye areas of the Yamburg field have been modeled individually. The production from all currently producing giant non-associated gas fields peaks in 2010 at $654\times10^9 m^3$ and the average decline rate measured from 2011 to 2050 is 4.5%. Fig. 5 also illustrates the forecasting method of field-by-field modeling used for the scenarios presented in Figs. 7 and 8.

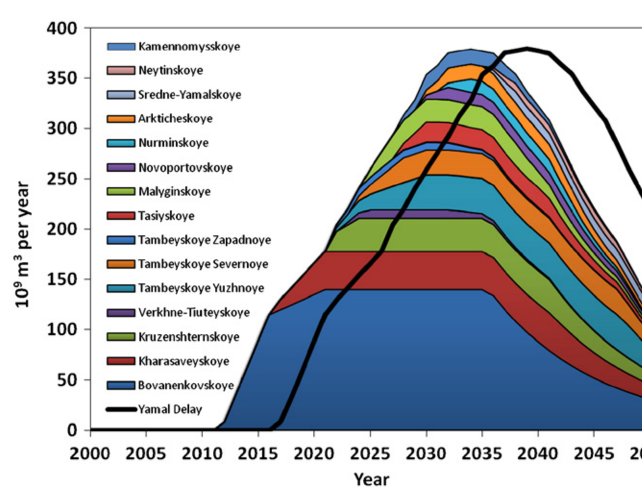

Fig. 6. Depletion based forecast for the Yamal Peninsula, including a 5-year delayed forecast. The forecast has been adjusted to follow the total development time-table for Yamal as given by Gazprom.

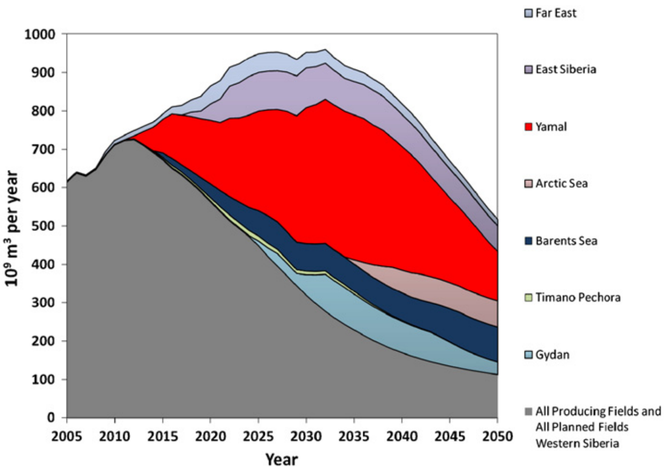

Fig. 7. Forecast for all producing fields in Russia and all planned production.

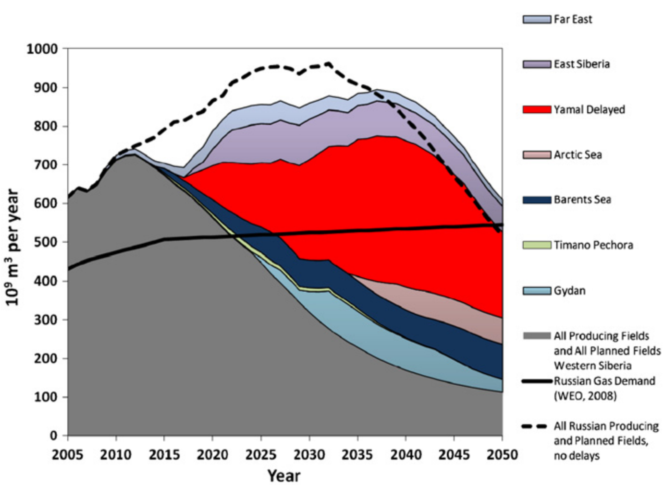

Fig. 8. Forecast for all producing fields in Russia and all planned production. Yamal production delayed by 5 years.

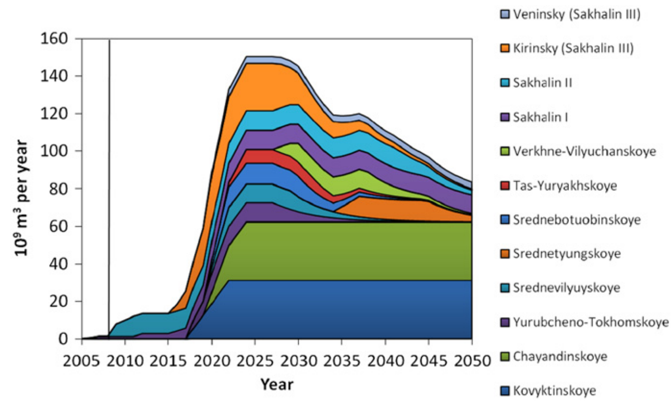

Fig. 9. Forecast for all the studied giants fields in Eastern Siberia and the Far East.

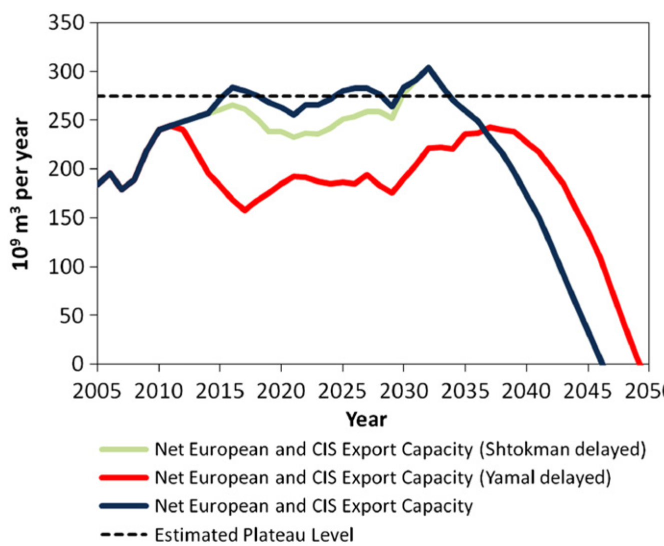

Fig. 10. Forecast for Available Net Exports Capacity for the European and CIS Markets. Exports to CIS markets were $101 \times 10^9 m^3$ in 2007 and Gazprom Central Asian imports of were $60 \times 10^9 m^3$.

5.2. Production from the Yamal Peninsula

The field-by-field modeling gives a maximum Yamal production of $379 \times 10^9 m^3$ by 2035, see Fig. 6. However, due to high costs and difficult environment for this production area, in Fig. 6, it has been added a total forecast for Yamal under the assumption of all projects being delayed by 5 years. The startup year, and peak year for each individual field have been put forward 5 years, keeping the individual production profiles otherwise intact. The purpose of this action is to get a time-span wherein it is reasonable to expect the production development of the Yamal Peninsula to materialize, and thereby study its effects, presented in Figs. 7 and 8, on total Russian gas production, as well as the gas exports capacity for the European markets.

5.3. Production from all giant fields and available net exports capacities

In Fig. 7 the production for all 83 individually modeled giant fields is presented in a production forecast divided into eight components. The total URR figure for the fields is $61 \times 10^{12} m^3$, see Appendix A. The first component, *All Russian Producing and Planned fields*, consists of 16 producing giant non-associated giant gas fields, 10 producing giant associated gas fields and 7 planned field developments in West Siberia. The other seven components are Gydan, Timano Pechora, Barents Sea, Arctic Sea, Yamal, East Siberia and the Far East.

The production reaches a plateau in 2025 at $949 \times 10^9 m^3$/year with the highest peak production in 2032 at $956 \times 10^9 m^3$. In Fig. 8, the effects from a 5-year development delay of the Yamal Peninsula is illustrated. In this scenario substantial production growth may occur by 2020, rising fast until 2025, and thereafter a slow development rate with a peak in production in 2037 at $890 \times 10^9 m^3$/year. In the forecast, the estimated development for Russian domestic demand, described in Section 4.9.2, has been included. The difference between the forecasts of total Russian gas production and the projected demand curve yields the available net export capacity of Russian gas.

The production from East Siberia and the Far East is the available net export capacity for the Asian and the Pacific Rim markets and the production from these two regions is illustrated in Fig. 9. The available net export capacity available for the European market and the CIS markets, have been derived by subtracting the production from East Siberia and the Far East from total Russian production. The results are illustrated with three forecasts in Fig. 10, one illustrating net exports for the Russian gas forecast with no delays, another showing the effects of the 5-year development delay of the Yamal Peninsula, and a third illustrating the effects of a 5-year delay in start of production of the Shtokman field. Fig. 10 shows that if the development of the Yamal

Peninsula is delayed by 5 years there is no available net increase of exports to the European and CIS markets. If there are no delays net exports capacity may increase from the 2008 level with about 45% to a plateau level of $275 \times 10^9 m^3$ by 2015–2016 lasting until 2030, followed by a short increase before the onset of decline. A 5 year delay of the Shtokman project results in a potential exports level increase of 40% by 2016, although by 2020–2025 it decreases to about 25%, followed by an increase after 2030.

6. Key findings and conclusions

Although the production figures from non-giant and yet undiscovered fields are not included in the forecast, the presented Russian gas production scenario should still be regarded as rather optimistic. The forecast has not been adjusted due to different types of losses, such as flaring and leakage. In addition, the estimated production parameters give a higher production level than had been the case if mean values would have been used, and given planned production levels are mostly from company sources and have not been risk-adjusted downwards. This approach has been chosen in order to get a high case forecast, that is, what production levels could be expected in a scenario with a stable growth in demand and favorable economic circumstances. The production is expected to develop according to plans with no capital constraints, technical difficulties, exports or transmission bottlenecks or other events that would negatively influence the production growth.

Within a few years, production increases from producing and new fields in the NPT-region will not be enough to compensate the decline in the old supergiant fields. By 2013 much larger supplies from the Yamal Peninsula and the Shtokman field will be urgently needed, if Russian production is to avoid a decline and be able to increase. It has been shown that it is of outmost importance that the Yamal Peninsula is developed as planned, since any longer delays will make a significant impact on potential exports volumes to the European and CIS markets. It has been optimistically assumed that all potential exports from the Barents Sea and Yamal will be directed to the European and CIS markets, disregarding planned LNG exports from Shtokman to the US market, and statements from Gazprom that West Siberian gas will supply the Altai pipeline to China. Despite these assumptions, the maximum export increase to the European and CIS markets amounts only to about 45% for the period 2015–2030. If an equal percentage increase for both markets is assumed, in real numbers a mere increase of about $70 \times 10^9 m^3$ of Russian export volumes to the EU can be expected. However, domestic production within the EU is expected to fall by $126 \times 10^9 m^3$ for the period 2006–2030.

There are a number of potential downside factors for future Russian gas supplies to the European and CIS markets. From a European energy security perspective, these factors should be closely monitored. In addition, there should be further research on how much demand for gas the fast growing economy of China may yield in the coming 20 years. The UK has about 61 million inhabitants and consumes $94 \times 10^9 m^3$. Since China has approximately 1.3 billion people, and only consumes $81 \times 10^9 m^3$, there is clearly a vast potential for a significant growth of Chinese gas demand, especially since it is a more environmentally friendly fuel than coal.

There is a lively discussion regarding the European dependence of imported gas from Russia. However, of equal importance would be to discuss whether there will be enough total gas volumes available to meet the projected future gas demand of the EU.

Appendix A. Studied Russian giant gas fields

See Table A1.

Table A1
***Sources*: Own compilation of data. Reserves and production data have its origin from scientific literature, governmental reports, geological reports, peer-reviewed articles, oil and gas industry journals, bond loans prospectus for the financial markets, Gazprom and its development partners, independent gas producers and international oil companies.**

Field	Region	Discovery year	Phase	URR ($10^9 m^3$)	Planned Plateau Production	Planned Production Start	Share of URR	Regional Share of URR
Urengoy	NPT (W. Sib.)	1966	d	10500	–	–	17%	
Yamburg	NPT (W. Sib.)	1969	d	5700	–	–	9.4%	
Zapolyarnoye	NPT (W. Sib.)	1965	b.u.	3500	115	–	5.7%	
Medvezhye	NPT (W. Sib.)	1966	d	2200	–	–	3.6%	
North Urengoy	NPT (W. Sib.)	1970	d	970	–	–	1.6%	
Komsomolskoye	NPT (W. Sib.)	1966	p	790	–	–	1.3%	
Yuzhno–Russkoe	NPT (W. Sib.)	1969	b.u.	720	25	–	1.2%	
Yurkharovskoye	NPT (W. Sib.)	1970	b.u.	600	41	–	1.0%	
Yamsoveyskoye	NPT (W. Sib.)	1970	p	420	–	–	0.7%	
Gubkinskoye	NPT (W. Sib.)	1966	p	460	–	–	0.8%	
Yubileynoye	NPT (W. Sib.)	1969	p	400	–	–	0.7%	
Vyngapurovskoye	NPT (W. Sib.)	1968	d	400	–	–	0.7%	
Beregovoye	NPT (W. Sib.)	1982	b.u.	320	12	–	0.5%	
Tarkosalinskoye Vost.	NPT (W. Sib.)	1971	p	420	–	–	0.7%	
Tarkosalinskoye Zapad.	NPT (W. Sib.)	1972	p	390	–	–	0.6%	
Yety-Purovskoye	NPT (W. Sib.)	1971	p	300	–	–	0.5%	
Nakhodkinskoye	NPT (W. Sib.)	1974	p	190	–	–	0.3%	
Vyngayakhinskoye	NPT (W. Sib.)	1968	p	100	–	–	0.2%	
Khancheyskoye	NPT (W. Sib.)	1990	p	110	–	–	0.2%	
Kharampurskoye	NPT (W. Sib.)	1978	b.u.	780	27	2008	1.3%	
Yaro-Yakhinskoye	NPT (W. Sib.)	1984	YTBD	180	8	2015	0.3%	
Samburg	NPT (W. Sib.)	1975	b.u.	120	9	–	0.2%	
Khalmerpayutinskoye	NPT (W. Sib.)	1989	YTBD	150	12	2009	0.2%	
Tazovskoye	NPT (W. Sib.)	1962	YTBD	90	8*	2017	0.1%	
Urengoyskoye Vost.	NPT (W. Sib.)	1978	b.u.	150	15	–	0.2%	
Muravlenkovskoye	NPT (W. Sib.)	1978	YTBD	160	4*	2008	0.3%	
Total Nadym Pur Taz				30120				49%

Table A1 (*continued*)

Field	Region	Discovery year	Phase	URR (10^9m^3)	Planned Plateau Production	Planned Production Start	Share of URR	Regional Share of URR
Orenburg	Volga Ural (Eur.)	1966	d	1800	–	–	3.0%	
Astrakhanskoye	Astrakhan (Eur.)	1976	p	2600	–	–	4.3%	
Total European Russia				4400				7.2%
Samotlor	Middle Ob (W. Sib.)	1961	p	–	–	–	–	
Fedorovo-Surgutskoye	Middle Ob (W. Sib.)	1962	p	–	–	–	–	
Lyantorskoye	Middle Ob (W. Sib.)	1966	p	–	–	–	–	
Komsomolskoye Sev.	NPT (W. Sib.)	1969	p	–	–	–	–	
Krasnoleninskoye	Middle Ob (W. Sib.)	1962	p	–	–	–	–	
Verkhne-Kolik-Yegan.	NPT (W. Sib.)	1981	p	–	–	–	–	
Van-Yeganskoye	NPT (W. Sib.)	1974	p	–	–	–	–	
Romashkinskoye	Volga Ural (Eur.)	1947	p	–	–	–	–	
Varyeganskoye	NPT (W. Siberia)	1967	p	–	–	–	–	
Anastasiyevsko-Troit.	Indol Kuban (Eur.)	1953	p	–	–	–	–	
Total associated gas				2000				3.3%
Bovanenkovskoye	Yamal (C)	1971	YTBD	4400	140	2012	7.2%	
Kharasaveyskoye	Yamal (C)	1974	YTBD	1260	38	2017	2.1%	
Kruzenshternskoye	Yamal (C)	1976	YTBD	960	33	2022	1.6%	
Verkhne-Tietuyskoye	Yamal (C)	1982	YTBD	110	8*	2030	0.2%	
Seyakhinskoye Zapad.	Yamal (C)	1989	YTBD	100	7.5*	2023	0.2%	
Tambeyskoye Yuzh.	Yamal (N)	1974	YTBD	1000	35	2022	1.6%	
Tambeyskoye Sev.	Yamal (N)	1982	YTBD	720	25	2022	1.2%	
Tambeyskoye Zapad.	Yamal (N)	1985	YTBD	100	7.5*	2021	0.2%	
Tasiyskoye	Yamal (N)	1988	YTBD	370	20*	2023	0.6%	
Malyginskoye	Yamal (N)	1979	YTBD	430	23*	2024	0.7%	
Novoportovskoye	Yamal (N)	1964	YTBD	200	12*	2030	0.5%	
Nurminskoye	Yamal (S)	1970	YTBD	180	13*	2032	0.3%	
Arkticheskoye	Yamal (S)	1968	YTBD	280	15*	2030	0.5%	
Sredne-Yamalskoye	Yamal (S)	1970	YTBD	200	11*	2036	0.3%	
Neytinskoye	Yamal (S)	1975	YTBD	110	8*	2036	0.2%	
Kamennomysskoye	Yamal (S)	1981	YTBD	200	15	2028	0.3%	
Total Yamal				10,720				17.6%
Kamennomysskoye Sev.	Gydan	2000	YTBD	280	13*	2030	0.5%	
Antipayutinskoye	Gydan	1978	YTBD	140	10*	2030	0.2%	
Tota-Yakhinskoye	Gydan	1984	YTBD	70	6*	2030	0.1%	
Geofizicheskoye	Gydan	1975	YTBD	140	10*	2030	0.2%	
Utrennyeye	Gydan	1980	YTBD	480	25*	2030	0.8%	
Semakovskoye	Gydan	1975	YTBD	540	30*	2025	0.9%	
Pelyatkinskoye	Gydan	1969	YTBD	180	11*	2041	0.3%	
Soleninskoye Sev.	Gydan	1971	p	70	–	–	0.1%	
Total Gydan				1900				3.1%
Vuktylskoye	Timano Pechora	1964	d	400	–	–	0.7%	
Layavozhskoye	Timano Pechora	1969	YTBD	130	7*	2020	0.2%	
Kumzhinskoye	Timano Pechora	1975	YTBD	90	6	2014	0.1%	
Total Timano Pechora				620				1.0%
Kovyktinskoye	East Siberia	1986	YTBD	1400	31	2018	2.3%	
Chayandinskoye	East Siberia	1989	YTBD	1240	31	2020	2.0%	
Sobinskoye	East Siberia	1980	YTBD	140	7.3	2020	0.2%	
Yurubcheno-Tokhom.	East Siberia	1985	YTBD	120	10*	2018	0.2%	
Srednevilyuyskoye	East Siberia	1963	YTBD	190	10*	2020	0.3%	
Srednetyungskoye	East Siberia	1976	YTBD	160	11*	2035	0.3%	
Srednebotuobinskoye	East Siberia	1970	YTBD	170	11*	2020	0.3%	
Tas-Yuryakhskoye	East Siberia	1970	YTBD	100	7.5*	2023	0.2%	
Verkhne-Vilyuchan.	East Siberia	1975	YTBD	140	5*	2028	0.2%	
Total East Siberia				3660				6.0%
Shtokmanovskoye	Barents Sea	1988	YTBD	3200	71	2015	5.3%	
Ludlovskoye	Barents Sea	1990	YTBD	230	13*	2044	0.4%	
Ledovoye	Barents Sea	1991	YTBD	90	6*	2042	0.1%	
Total Barents Sea				3520				5.8%
Sakhalin I	Far East	1979	p	490	10	–	0.8%	
Sakhalin II	Far East	1984	p	410	8.6658	–	0.7%	
Sakhalin III (Kirinski)	Far East	1979	YTBD	400	25	2016	0.7%	
Sakhalin III (Veninski)	Far East	2006	YTBD	320	3.6	2020	0.5%	
Total Far East				1620				2.7%
Leningradskoye	South Kara Sea	1990	YTBD	1600	55*	2035	2.6%	
Rusanovskoye	South Kara Sea	1989	YTBD	780	13*	2040	1.3%	
Total Kara Sea				2380				3.9%
Total all 83 fields				$61 \times 10^{12}m^3$			100%	100%

The current production phase, as of the year 2008, for a field is nominated as follows: plateau production (P), declining production (D), increasing production, i.e. build-up phase (b.u.) and field yet to be developed (YTBD). Planned plateau production levels marked with an asterisk *, indicates the value has been estimated. The following regional abbreviations are used: Western Siberia (W. Sib.), European region (Eur.), Middle Ob region (Mid. Ob), Yamal Central Group Yamal (C), Yamal Southern Group (S) and Yamal Northern group (N). Only an aggregate reserve figure for the 10 studied oil fields is given.

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