

BULGARIA:

Options to Improve Security of Gas Supply



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Acronyms and Abbreviations

bcm	Billion cubic meters
BEH	Bulgarian Energy Holding Company
Capex	Capital expenditure
CCGT	Combined cycle gas turbine
CEE	Central and East Europe
CNG	Compressed natural gas
CO ₂	Carbon dioxide
ECA	Economic Consulting Associates Ltd
EC Gas Ring	Energy Community Gas Ring
ENTSO	European Network of Transmission System Operators
ERGEG	European Regulators' Group for Electricity and Gas
EU	European Union
FEED	Front end engineering decision
FID	Final investment decision
GDP	Gross domestic product
GoB	Government of Bulgaria
IC	Interconnector
ICGB	Interconnector Greece-Bulgaria
ITGI	Interconnector Turkey-Greece-Italy
LDC	Load duration curve
LNG	Liquefied Natural Gas
MEET	Ministry of Economy, Energy and Tourism
mmcm	Million cubic meters
MW	Megawatt
NPP	Nuclear power plant
Opex	Operating expenditure
ROR	Rate of return
SDII	Shah Deniz II
SGC	Southern Gas Corridor
SoS	Security of supply
TANAP	Trans-Anatolian pipeline
TAP	Trans-Adriatic pipeline
TGI, ITGI	Turkey-Greece-Italy, Interconnector TGI
ToP	Take or Pay

TPA	Third party access
TPP	Thermal power plant
TPES	Total primary energy supply
UGS	Underground gas storage
UIOLI	Use it or lose it

Glossary

Interconnector	Major pipeline interconnecting regional sub-systems
Linepack	Using gas pipelines for storage by operating at higher pressure than necessary for standard operation
Nabucco	International pipeline consortium proposing a pipeline that stretches from eastern Turkey to Austria via Bulgaria, Romania and Hungary to deliver Caspian and Middle East gas to Europe
Nabucco West	Pipeline project that consists of the section of the Nabucco project from the Bulgarian-Turkish border to Austria
Reverse flow	Ability to operate a pipeline so that gas flows in the opposite direction of the normal flow
South Stream	Gazprom backed pipeline project crossing the Black Sea and connecting Russia directly with Bulgaria to deliver Russian gas to Europe
White Stream	Proposed pipeline crossing the Black Sea from Georgia to Romania to deliver Caspian gas to Europe

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Executive Summary

This Report presents the findings of a study aiming to define the least cost short (up to 2015) and medium term (up to 2020) measures that the Government of Bulgaria (GoB) can implement to meet gas security of supply requirements seen in the light of Bulgaria's vulnerability to gas supply disruptions and its increasingly important role for regional gas cross-border transmission and trade.

Background

The January 2009 gas crisis. The impetus for this study arose from the serious impact of the January 2009 Russian gas supply interruption to Ukraine due to an unresolved commercial dispute between Naftogaz (Ukraine) and Gazprom (Russia). This resulted in a 16-days interruption of all Russian supplies to Ukraine adversely affecting all downstream markets. The negative consequences of the interruption for Bulgaria were considerable. In fact, Bulgaria was the worst affected EU country from the Ukraine-Russia gas dispute with losses to the industrial sector alone estimated at €250 million.

Gas in Bulgaria's supply mix. Bulgarian gas demand is of modest size (3.0 bcm in 2011) and natural gas only plays a small role in Bulgaria's energy mix (14% of the total primary energy supply). Over the next ten years gas demand patterns are likely to change, however, and consumption levels are expected to grow steadily. The growth rate of gas demand and its importance in the supply mix will be driven by choices of electricity generation strategy and the rate of household gasification.

Need to diversify gas supply sources and delivery routes. There is a significant risk that a gas-focused electricity strategy would reduce Bulgaria's overall security of supply. However, this would only be the case if the new gas supply was contracted from the same sources and routes as the existing contracts (from Russia via Ukraine) and if the gas-fired power plants did not have back-up fuels. Conversely, if Bulgaria is able to secure new gas contracts from other sources delivered via new routes, and if back-up fuels are provided at those plants, then Bulgaria could increase its gas consumption while increasing its overall energy security of supply. This issue is at the core of the present report.

Future role of natural gas in Bulgaria

The pattern of gas consumption in Bulgaria is likely to change over the next ten years. Currently industrial consumers and heating plants make up the largest share of consumption (they account respectively for 42% and 24% of demand). Depending on the chosen electricity generation strategy and the expansion of distribution networks, households and the power generation sector are likely to play an increasingly important role in gas demand. Key drivers of future medium term gas demand in Bulgaria are:

- o The *electricity strategy*. A GoB decision in March 2012 to scale down plans for expansion of nuclear power generation facilities in favor of new gas-fired power generation facilities, if necessary, means that gas demand could grow substantially over the next ten years.

- o Increasing *household gasification* could raise overall demand for gas in Bulgaria. According to GoB's energy strategy¹, 30% of households are targeted to be gasified by 2020, up from current value of less than 3%.
- o Higher *energy efficiency* levels in the heating, industry and power generation sectors are likely to reduce gas intensity (i.e. gas consumption per unit of GDP). GoB has set ambitious and clear targets up to 2020, reducing total primary energy demand by close to 20% compared to the business-as-usual scenario.

For the purpose of modeling and analysis of supply options, the Bulgarian stakeholders provided a *base case*, *low case*, and *high case* gas demand scenarios. The base case scenario corresponds to the base case in the GoB's Energy Strategy's and the remaining two are compatible with the above mentioned demand drivers. As it can be seen from the table below and according to policy choices implemented by GoB, annual gas demand growth can range from 1.1% to 10% while its share in country's total energy supply (TPES) can growth from 14% now to up to about 29% by 2020.

Scenarios	Annual growth rate	Gas demand by 2020 (bcm)	Share of gas in TPES by 2020	Compatibility with gas demand drivers		
				1000 MW of new gas-fired generation	Household gasification reaches 30%	Higher energy efficiency
Base case	1.1%	3.4	14%	✘	✓	✓
Low case	4%	4.3	18%	✓	✓	✓
High case	10%	6.8	28.5	✓ ✓ (exceeding 1000 MW)	✓ ✓ (exceeding 30%)	✘

Options to improve security of gas supply and meet EU standards

In order to provide guidance to GoB on how to ensure security of supply in the medium term, a scenario approach was applied, based on a demand and supply balancing model. The approach is based on the three gas demand scenarios outlined above (base case, low, and high) together with different investment options, which principally include:

- *Chiren Underground storage expansion*. Chiren is the only existing underground storage facility in Bulgaria. It is presently being expanded, which will increase capacity from around 0.5 gradually to 1 bcm/year. This option could be available as early as 2015.
- *Galata conversion*. This investment option consists of the conversion of a depleted offshore gas field to an underground storage facility.

¹ Government of Bulgaria: Energy Strategy for the Republic of Bulgaria till 2020 for Reliable, Efficient, and Cleaner Energy. June 2011

- **CNG tanker imports.** Under this option Compressed Natural Gas (CNG) originating from Azerbaijan would be transported via specialized container ships from Georgia (or imports from outside the Black Sea subject to shipping constraints in the Bosphorus) to Bulgaria.
- **Maximize usage of linepack.** By increasing the pressure in the existing gas transportation system, a greater volume of gas can be stored in the system.
- **Interconnector to Greece.** The interconnection to Greece with an initial capacity of 3 bcm/year is currently under FEED phase. It will be co-financed by a grant of €45 million by the European Energy Programme for Recovery of the European Commission.
- **Interconnector to Turkey.** This interconnector would have an initial capacity of 5 bcm/year. It is being discussed as part of a plan to bring Caspian gas to South East Europe.
- **Interconnector to Romania.** This interconnector is currently under construction and is expected to be operational in late 2013. It will have a capacity of 1.5 bcm/year and is planned to operate bi-directionally.
- **Interconnector to Serbia.** The feasibility study of this project was completed in early 2013. According to the study the interconnector could be operational by 2015 at the earliest and would have a capacity of 1.8 bcm/year.
- **Reverse flow agreements with Greece and Turkey.** This implies using the existing pipelines designed to flow from north to south in a northern direction and formalizing the agreements made hastily during the January 2009 crisis. Energy demand in Turkey is growing fast, and while there was a temporary tightness of gas supply in early 2012, in the medium term there is no serious impediment to increased supply to match both Turkish demand growth and the potential for export.
- **Crisis gas flow Romania** would consist of connecting the internal Romanian transmission system with the transmission pipeline crossing Romania to deliver gas to Bulgaria and beyond in case of disruptions to the flow through the cross-border transmission pipeline.
- **Nabucco West and South Stream projects** – Nabucco West is a strategic EU gas transport corridor and part of the Southern Gas Corridor that will increase capacity and security for natural gas supplies to Bulgaria, the region and Europe by diversification of the sources, routes and suppliers, while South Stream is a Russian initiative to deliver more Russian gas to the same region by a new pipeline route through the Black Sea. Both pipelines are expected to supply a proportion of their capacity to Bulgarian gas market. Announced year of completion of South Stream is before 2019. Expected year of commissioning of Nabucco West is 2017.

EU Security of Supply regulation (EC Regulation 994/2010) requires two standards to be met in case of an interruption of the largest supply route: (i) gas demand on

the coldest day for a 1-in-20 year case and (ii) full demand levels of protected consumers over a sustained 30 day period under average winter conditions in case of a supply disruption of the largest supply source (in the case of Bulgaria, gas from Russia transited through Ukraine and Romania).

Investment strategy to ensure security of supply at least cost. Assuming the low gas demand scenario (annual growth of 4%), the modeling showed that to meet EU regulations for security of supply it is advisable that the GoB:

- (i) *pursue efforts to develop a new southern interconnector to Greece,*
- (ii) *ensure bidirectional flows on the currently developed interconnector to Romania are available in the short term, and*
- (iii) *make maximum use of linepack capabilities*

The interconnector to Greece is well advanced. Currently it is under the market test phase for capacity allocation and authorization procedures for construction in Bulgaria and in Greece are expected to be completed by the end of 2013. The project has been identified by both GoB and the EC as highly strategic to improve diversification and security of supply. As a result, it will be co-financed by a grant of €45 million by the European Energy Programme for Recovery.

To ensure the bidirectional flow of the Romania-Bulgaria interconnector (measure ii above), significant additional investment costs in the Romanian transmission network are required. As a result, in the short term gas flows into Bulgaria are not ensured. If these investments do not materialize, the *formalization of reverse flow agreements with Greece* and development of *dual fuel capabilities in the power generation and district heating sectors* would be the second best alternatives to ensuring security of supply.

In addition, for the interconnector solutions to be feasible, contractual arrangements need to be put in place so that gas can be sourced from/via Greece and Romania in a crisis situation, e.g. by using interruptible contract arrangements for cross-border transmission gas.

Sensitivity analyses assuming the high demand growth scenario (annual 10% growth) show that the above recommended infrastructure options would have to be complemented with the *interconnector to Turkey* by 2017.

The annualized² costs of the suggested measures would be around €19 million in a base case demand scenarios and €31 million with the interconnector to Turkey in a high case scenario.

It is also relevant to consider *full self-sufficiency*, i.e. the case where all cross border supply routes are disrupted or no gas can be made available for import so Bulgaria has to rely only on its own supply sources. In this case it would be necessary to *extend the existing gas storage in Chiren to its maximum*. When assuming a hypothetical 10% gas demand growth it would be necessary to also develop the

² Annualized costs include the capital costs spread over the lifetime of an asset plus operating costs.

Galata field into an underground storage facility to ensure security against a total disruption, however only by 2018. The total annualized costs for full self-sufficiency would amount to €87 million without Galata and €169 million with Galata.

Commercial opportunities and investment strategy in the regional context

Most developments to strengthen Bulgaria's security of supply, including improved interconnections with neighboring countries would also offer commercial opportunities to benefit from growing regional gas trade.

A central part of the EU's current energy strategy is to develop a Southern Gas Corridor (SGC)³ to enable Caspian and Middle Eastern gas resources to be supplied via Turkey or the Black Sea to the EU. As the only EU country to share a border with Turkey *and* have access to the Black Sea, Bulgaria plays an integral part in future EU gas policy. Furthermore, the future development of the EC Gas Ring⁴ linking Bulgaria and Romania with the Western Balkans would mean that a large integrated Balkan gas market will emerge to which Bulgaria will be directly interconnected.

While Serbia, Romania and FYR Macedonia are likely to face considerable import gaps, Greece and Turkey look to have adequate supply from well diversified gas sources in the medium term. Turkey will act as key transit country for Caspian, Middle Eastern or LNG gas over the next decade. This positions Bulgaria in a favorable cross-border transmission location for countries in the Central and West Balkans.

To maximize the commercial benefits from this location, efforts should be made to fully develop interconnections with Serbia and Romania in parallel with developing southern interconnector(s). The analysis shows that total annual revenues from transit fees of gas flowing through the Greece interconnector on to Serbia and Romania could be as high as €55 million/year with net benefits amounting to €10 million/year when annualized costs from the necessary interconnectors are subtracted⁵.

The development of these interconnectors would potentially open options for diversification of imports while at the same time allowing gas supplies from southern interconnectors (with spare capacity) to be transmitted to growing and increasingly interconnected West Balkan or Central and Eastern European (CEE) gas markets.

By following this strategy, Bulgaria's infrastructure investments would be strongly supportive of regional gas market developments such as the EC Gas Ring, substantially increase Bulgaria's involvement in the European gas market, while significantly contributing to improved domestic security of supply.

³ Including the more recent development of proposals for the TANAP project

⁴ More information about the Energy Community (EC) Gas Ring is provided in Section 3.2 of this report

⁵ Benefits arise from the increased utilisation of Bulgaria's transmission network through cross-border flows

The major existing constraints for the commercial benefits to accrue are (i) the limited capacity of the planned northern interconnectors, (ii) the uncertainty of demand developments in Serbia and Romania and (iii) gas supply infrastructure developments in Romania. Active supply diversification strategies away from Russian gas by both Serbia and Romania could provide enough anchor load for Bulgaria's commercial gas trade and cross-border transmission opportunities to be maximized. Otherwise, and depending also on other infrastructure developments, Central European or Western Balkan countries could be possible offtake markets for gas transmitted via Bulgaria, although some of these markets are currently small and would themselves require significant infrastructure developments⁶.

⁶ For example, FYR Macedonia could become a small but important offtake market for gas transmitted through Bulgaria; however this will depend on the ambitious gas market infrastructure developments in the country to be implemented.

1 Introduction

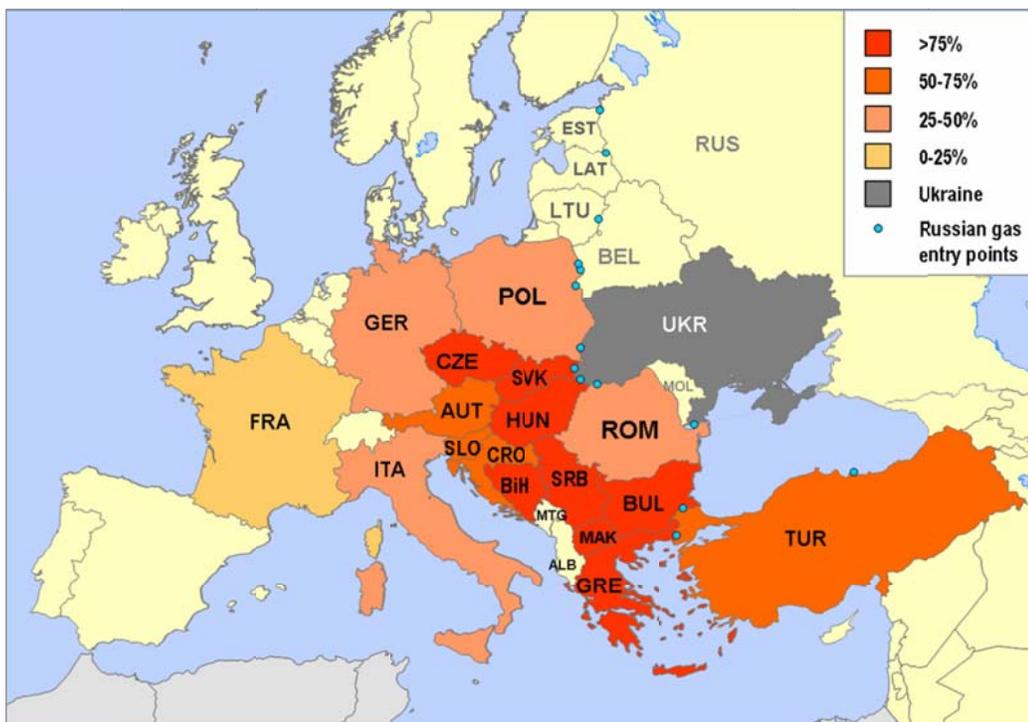
1.1 The gas crisis of January 2009

In January 2009 Bulgaria faced an unprecedented gas crisis due to an unresolved commercial dispute between Naftogaz (Ukraine) and Gazprom (Russia). This resulted in an interruption of Russian supplies to Ukraine adversely affecting all downstream markets, including Bulgaria. The crisis stretched for 16 days and caused Bulgaria to have a major disruption of its gas imports with a loss of up to 100% of its import supply.

The gas crisis exposed Bulgaria's vulnerability to Russian supply interruptions. By reviewing the measures taken to minimize adverse effects on consumers and the economy as a whole, valuable lessons for future interruptions can be learned. These include the urgent need for Bulgaria to seek alternative supply routes and sources and stricter enforcement of dual fuel obligations for heating plants and other large customers.

Figure 1 shows the effect of the interruption on gas supplies for all EU member countries.

Figure 1 Percentage of EU gas supplies interrupted in January 2009



Adapted from Jean-Arnold Vinois, *The January 2009 Gas Dispute and Recent Developments: The Role of the Gas Coordination Group*, DG TREN, 4th Gas Forum, Ljubljana, 10-11 September 2009

Consumption had to be rationed and adjusted from 13 mmcm/day to 6 mmcm/day. During the interruption supplies were covered by storage facility

withdrawals, linepack, small volumes of domestic production levels and a reverse flow agreement with Greece. The Bulgarian authorities interrupted industrial customers (mainly fertilizer plants) and district heating companies as these were deemed interruptible (industrial customers) or having alternatives to gas (district heating companies).

District heating plants in Bulgaria are required to have two weeks' worth of alternative stocks of heavy fuel oil to compensate for gas interruptions. Most heating plants, however, were slow in switching to alternative fuels resulting in some areas to an almost week-long shortage of heating supply. Consequently, residential consumers switched to electricity heating sources. This meant that pressure was put on the electricity system, as it had to cope with both a substantial increase in demand as well as a shortage of supply, because of the interruption of gas fired power plants. Although only contributing to 6% of total electricity supply, the shutdown of the gas fired combined heat and power plants required drastic measures to be taken to meet electricity demand. These included the re-activation of previously shut-down coal fired power generation capacities.

Even though natural gas only represented 12 % of total annual primary energy consumption, the negative consequences of the interruption for Bulgaria were considerable. In fact, Bulgaria was the worst affected EU country from the Ukraine-Russia gas dispute. This was mainly due to the following factors:

- o *A lack of alternative supply sources and undiversified gas import mix.* No infrastructure (interconnections, LNG facilities) is in place that can provide gas supply from alternative sources. Only small domestic production levels (maximum 1 mmcm/day) slightly reduce Bulgaria's otherwise full dependence on Russian supplies.
- o *Insufficient gas storage capabilities.* The Chiren underground storage is the only storage facility in Bulgaria and has a peak deliverability of 4.2 mmcm/day, which only covered 32% of daily demand.
- o *Slow response of heating plants to switch to alternative fuel.* The reasons for a slow switch included technical difficulties, logistical difficulties of bringing the oil from central government depots to the plants and a lack of adequate reserves due to financial shortages. This suggests that heating plants were in partial violation of their legal requirements as they were not able to continuously provide heating services.

Despite implementing both demand and supply measures to minimize adverse effects of the interruption, including some reverse gas flow from Greece, the negative impact on the population and economic activity was considerable. A substantial part of Bulgarian homes had no heating in the first days of the interruption and this was compounded by the difficulty for consumers to switch to

electricity for heating. Industry was also severely affected with the loss to the industrial sector attributed to the interruption estimated at €250 million⁷.

1.2 The Response to the Crisis: Security of Gas Supply in Focus

The crisis triggered tighter European Union (EU) regulations on gas security of supply and from January 2014 onwards all EU member countries must meet a range of criteria that ensure that sufficient alternative supply sources exist to meet demand. The new regulations prompted policymakers in EU Member countries to identify those investments that will meet these criteria at least cost.

As an important cross-border transmission country, Bulgaria is strongly interconnected with Romania and Turkey and has connections used to supply Greece and FYR Macedonia. However, the current configuration of transit lines and cross-border interconnections are of little or no use in the event of disruption to flows of Russian gas via Ukraine. Therefore, Bulgaria cannot be considered in isolation from the situation in neighboring markets, particularly of countries that are part of the EU single gas market and the Contracting Parties of the Energy Community Treaty.

In the longer term, major new pipelines to and through the Balkan Peninsula would be expected to improve the situation. In the meantime, it is important not to overlook the potential for Bulgaria to improve its gas security of supply through suitable regional co-operative strategies, combined with new cross-border infrastructure and interconnections.

The regional context described above is part of a wider international picture. Security of supply is one of the major considerations in the alternate scenarios for gas supply to Europe. Each of the major proposed infrastructure projects has distinctive implications for security of supply and the competitiveness of gas in the European single gas market. On this level, the possibilities tend to fall into one of two scenarios:

- o *opening up of the market via diversification* of gas sources and routes under the European Commission's Southern Corridor plan, and
- o *consolidation of market power* as the dominant supplier increases market share.

Examples of large projects with a public profile include the Nabucco gas pipeline; South Stream, in which Bulgaria has been in discussions with the proponents Gazprom and ENI and White Stream at very initial phase. Several large projects make up the Southern Corridor, including TANAP, Nabucco West, TAP and White Stream.

⁷ Kardejak, P (2009) *The January 2009 Gas Crisis: What Happened in Central and South Eastern Europe?*

Implementation of one or more of these major gas transmission projects clearly has the potential to change the security of supply outlook for Bulgaria. However, all of these projects are at various stages of development prior to the final investment decision to proceed and the timeframe for operation of the projects is beyond 2016. While these projects will be considered in the analysis, the main focus of this report is on options available in the shorter term.

1.3 Study objectives

The objective of the Study is to identify the *least cost short and medium term measures (up to 2020) that the Government of Bulgaria (GoB) can implement to meet gas security of supply requirements.*

The findings and recommendations presented in this report should enable GoB to balance security of supply considerations with the commercial benefits of short to medium term infrastructure projects.

The outputs of the Study are:

- (i) An interactive model that simulates the supply-demand balance through a load duration curve in any given year with the existing supply measures, the addition of various investment options ranked by costs for a given supply disruption scenario, and
- (ii) A report with analytical interpretation of different scenario results using the model.

2 Bulgaria's gas market

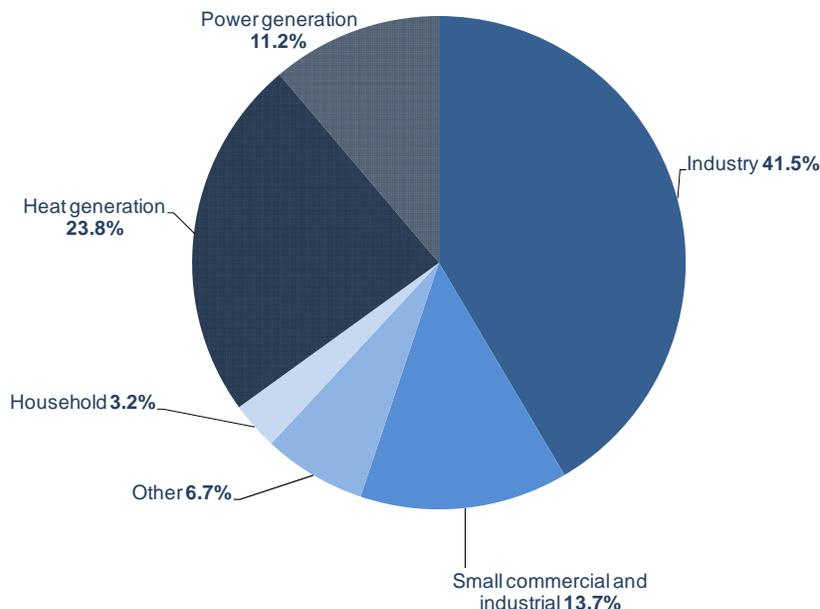
With an annual demand of around 3.0 bcm in 2011, Bulgaria is a relatively small gas market. Natural gas only constitutes 14% of total primary energy supply (TPES) since Bulgaria, unlike many other European countries, has made limited use of gas for either power generation or households. The heavy industry sector accounts for 41%⁸ of all consumption, which is largely made up by the chemicals industry⁹ and in particular fertilizer plants. The second largest consumer is the energy sector (35% of total consumption) divided between district heating plants (24%) and power generation (11%)¹⁰. Sales to distribution companies account for 16% of total consumption with small industrial, commercial and household users making up the largest consumer groups. Household consumption is not specified as a separate sector and is estimated at making up just over 3% of consumption based on other data sources. Figure 2 summarizes the split in consumption levels for 2011.

⁸ These data were obtained by Bulgargaz and complemented with data from the *Bulletin on the state and development of the Energy in the Republic of Bulgaria*, March 2012, MEET

⁹ 30% of total consumption 2011

¹⁰ This split is based on data from the *Bulletin on the state and development of the Energy in the Republic of Bulgaria*, March 2010, MEET

Figure 2 Gas consumption in Bulgaria in 2011



Source: Bulgargaz data and *Bulletin on the state and development of the Energy in the Republic of Bulgaria*, March 2012, MEET

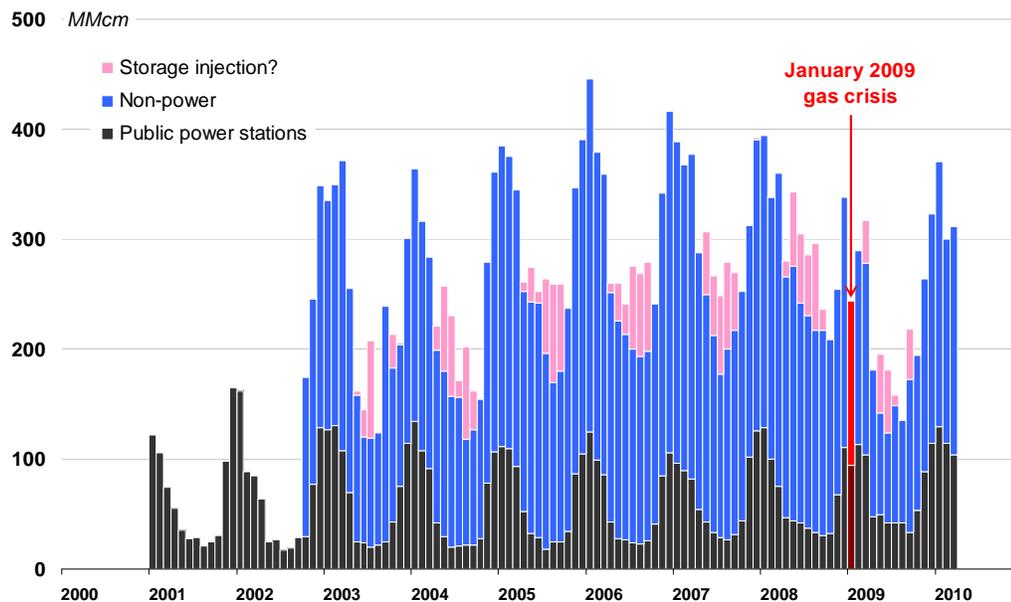
At an estimated 0.4 to 0.6 bcm over the next few years, annual domestic production is small in relation to total demand. Bulgaria is therefore highly dependent on Russian import contracts. Long term supply contracts are currently being renewed, presumably on shorter terms to the previous contract although the details of the revised terms including quantity of the supply contract are not yet determined.

Existing domestic gas reserves are mainly located in onshore Deventsi fields (probable reserves of 6.6 bcm) and the Kavarna and Kaliakra fields in the Black Sea (combined total reserves of 1.7 bcm¹¹). Shale gas could also contribute to Bulgaria's future gas reserves, however its availability and quantity is uncertain as there is no confirmed plan for its extraction.

There is also a distinct pro-seasonal pattern to gas consumption in Bulgaria, which increases the seasonal swing of gas demand. Both power as well as non-power gas consumption is considerably higher in winter as can be seen in Figure 3. The figure also shows possible storage injection volumes, which are data discrepancies between imported and consumed data. The effect of the January 2009 gas crisis is evident: monthly consumption levels were only around 240 mmcm in January 2009 when they have been between 320 mmcm and 430 mmcm in the first month of the preceding years.

¹¹ <http://www.melroseresources.com/bulgaria>

Figure 3 Monthly gas consumption in Bulgaria by sectors



Source: data from Eurostat

3 Gas demand and potential alternative supply sources

The first policy question is to assess the role natural gas will play in Bulgaria over the medium to long term. The report covers the following issues:

- o The identification of key demand drivers to project three future gas demand scenarios
- o An assessment of gas demand growth in the region and opportunities for cross-border gas trading, particularly in light of the future development of the EC Gas Ring and other new gas infrastructure in nearby countries.

3.1 The drivers of future gas demand

The pattern of gas consumption in Bulgaria is likely to change over the next ten years. Currently industrial consumers and heating plants make up the largest share of consumption. Depending on the chosen electricity generation strategy and the expansion of distribution networks, households and the power generation sector will play an increasingly important though as yet uncertain role in gas demand.

The key drivers of future medium term gas demand in Bulgaria are:

- o The *electricity strategy* that will be followed by GoB until 2020. A GoB decision in March 2012 to drop construction of 2,000 MW of new nuclear

power facilities in Belene and instead add a new 1,000 MW nuclear unit at the existing Kozloduy nuclear power plant means that gas fired power will partly replace the originally planned nuclear power facilities leading to substantial gas demand increases. Furthermore, if the Kozloduy expansion fails to materialize or gets delayed an even bigger gas demand expansion may be the result.

- o Increasing *household gasification* could raise overall demand for gas in Bulgaria. According to GoB's energy strategy¹², 30% of households are targeted to be gasified by 2020, up from current value of less than 3%.
- o Higher *energy efficiency* levels in the heating, industry and power generation sectors are likely to reduce gas intensity (i.e. gas consumption per unit of GDP). Although not legally binding in these sectors, GoB has set ambitious and clear targets up to 2020, reducing total primary energy demand by close to 20% compared to business as usual. However, it is not yet clear how these targets will be met.

The way these options will actually play out could lead to widely divergent gas demands. Units 1 and 2 of the Kozloduy NPP were decommissioned in 2002 as were Units 3 and 4 prior to Bulgaria's entry into the EU in 2007, which has left Units 5 and 6 with a total of 2,000 MW. This and an ageing fleet of fossil fuel (mainly lignite) power plants (excluding new TPP AES Galabovo) mean that Bulgaria is expected to need new base load generation capacity in the future. The main options for this are: a new nuclear plant, more coal-fired plants or gas-fired combined cycle plants. Discussions on construction of a second nuclear power plant in Bulgaria started in the early 1970s and a site at Belene on the Danube River was approved by the GoB in 1981. After difficulties in finding and retaining financial investors, construction at the site started in 2008¹³. However in June 2010, the construction of the plant was halted by the GoB due to uncertainty of financial and commercial feasibility of the project.¹⁴ In March 2012 GoB decided that the Belene nuclear plant should be substituted by a new nuclear 1,000 MW Unit 7 in Kozloduy and a 1,000 MW gas fired plant at the Belene site.

There is clearly a significant risk in the gas-focused option that additional gas-fired power plants would reduce Bulgaria's overall security of supply, since an interruption to the gas supply (such as the January 2009 crisis) would then affect both the industry and power sectors. However, this would only be the case if the new gas supply was contracted from the same sources and routes as the existing contracts (from Russia via Ukraine) and if the gas-fired power plants did not have back-up fuels. Conversely, if Bulgaria is able to secure new gas contracts from other sources delivered via new routes (see below for a discussion on possible supply sources), anchored by demand from new base load gas-fired combined cycle plants, and if back-up fuels are provided at those plants, then Bulgaria could increase its

¹² Government of Bulgaria: Energy Strategy for the Republic of Bulgaria till 2020 for Reliable, Efficient, and Cleaner Energy. June 2011

¹³ <http://www.belene-npp.com/stages.php?lang=2&stage=8>

¹⁴ http://www.sofiaecho.com/2010/06/11/915612_bulgaria-scraps-bourgas-alexandroupolis-pipeline-shelves-belene-nuke-pm

gas security of supply without reducing its overall energy security of supply. In the context of the EU main aims for energy policy (the ‘pillars’) in the Energy Roadmap to 2020, an overview of the pros and cons for the different power generation expansion options is provided in Table 1.

Table 1 Base load power options			
EU energy policy pillar:	Security of supply	Competition	Sustainability
Nuclear	Positive, although may retain dependence on dominant gas supplier, Russia	No evidence that this is the least-cost option, likely to maintain state-ownership role in the sector	Negligible CO ₂ emissions, but nuclear is still controversial as a ‘sustainable energy option’
Coal (domestic lignite)	Good	Expected to be cost-competitive with other options	Highest CO ₂ emissions (conflict with EU climate policy)
Gas-fired CCGT	Reduces overall energy security unless gas supply sources are diversified.	Lower capital cost, but expected to have higher fuel and operating costs than lignite plant	High: much lower CO ₂ emissions than lignite, overall low environmental impact

For the purpose of modeling and analysis of supply options the *base case demand scenario* (1.1% annual demand growth) is the GoB Energy Strategy’s base case scenario, where the above mentioned policy objectives of gasification and energy efficiency are successfully met and no new gas fired electricity generation is foreseen. Total demand increases to 3.4 bcm in 2020, which is entirely driven by increased household demand. The share of gas in TPES by 2020 would remain constant at 14%. However, this scenario is not compatible with the recent GoB decision on electricity generation expansion, so it is supplemented by two scenarios provided by Bulgarian stakeholders with higher gas use assuming 4% and 10% annual gas demand growth respectively.

The *low demand scenario* (4.0% annual demand growth), is largely compatible with the decision to construct a new 1,000 MW gas fired power plant and achieving the planned energy savings and a household gasification of 30% of all households. In this scenario total demand increases to 4.3 bcm in 2020 where gas will be making up close to 18 % of TPES.

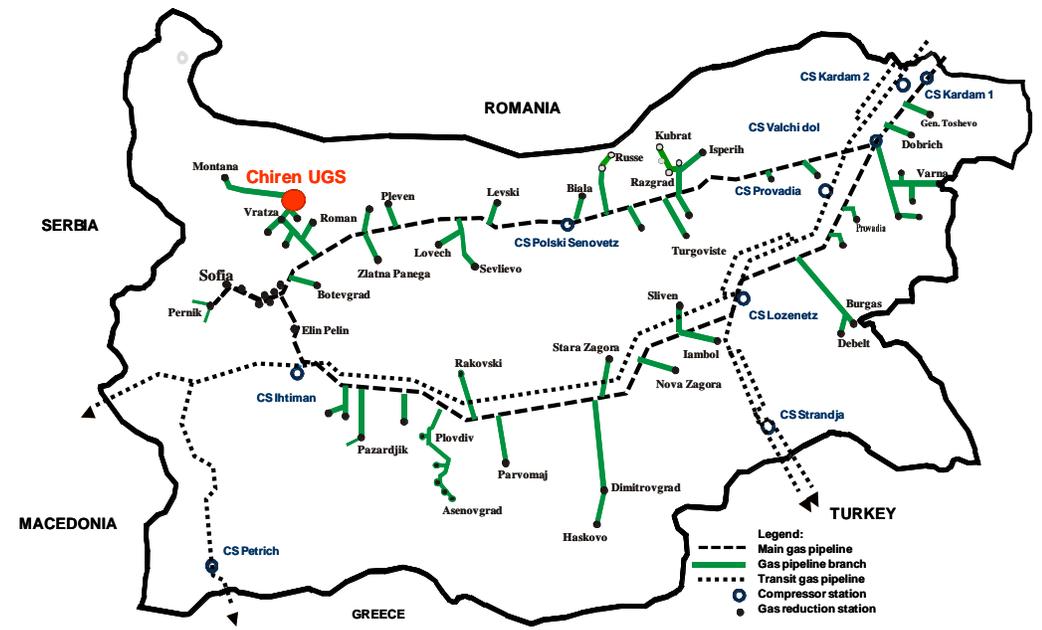
The *high demand scenario* (10% annual demand growth) is a very “conservative” scenario for security of supply purposes, i.e. a scenario that assumes the highest imaginable gas utilization. This scenario would cover a situation where the entire electricity demand expansion will be gas fired, where the household gasification rate will exceed 30% and where energy efficiency targets for the heating, industry and power generation sectors are not met and therefore bringing no reductions of primary energy demand by 2020 compared to business as usual. In this scenario

total demand increases to 6.8 bcm in 2020 where gas will be making up 28.5% of TPES.

3.2 Regional gas demand and the Energy Community Gas Ring

To identify possible offtake markets for gas transmitted or traded through Bulgaria, the study assessed gas demand developments in the region with a particular focus on those countries connected or able to be connected to the Bulgarian transmission grid: Romania, Serbia, FYR Macedonia, Greece and Turkey. Figure 4 provides a schematic overview of Bulgaria's transmission grid and existing interconnections with neighboring countries.

Figure 4 Bulgarian gas transmission system schematic map



Source: Angel Semerdjiev, *The Bulgarian Natural Gas Market: the TSO's point of view*, Sofia, 30 January 2009

Bulgaria's most promising markets for cross-border transmitted or traded gas in the medium to long term are likely to lie in the West Balkans. In particular Serbia and FYR Macedonia could become important offtake markets. Although both gas markets are currently small and underdeveloped, policymakers in the two countries target increased gasification over the medium term. One of the investment options assessed in this study is the interconnector to Serbia, which would be the most likely way for Serbia to diversify its supply sources away from Russian gas under the premise that one of Bulgaria's southern interconnectors will be built. An interconnector to FYR Macedonia currently exists and in light of ambitious growth demand forecasts by the Ministry of Economy, Bulgaria could benefit from expanding its transportation capacity to FYR Macedonia if the Macedonian gas market is going to be developed.

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The interconnectors to Serbia and FYR Macedonia would enable Bulgaria to supply markets beyond its direct neighbors to include Bosnia and Herzegovina, Croatia and Albania. The interconnection of Western Balkan countries is planned in the framework of the Energy Community Gas Ring (EC Gas Ring). Box 1 provides an overview of the EC Gas Ring and highlights the infrastructure already in place and yet to be developed. FYR Macedonia and Serbia both form part of the EC Gas Ring and would act as entry points to the Ring for Bulgarian transmitted gas.

With 10.9 bcm covering 78% of domestic demand, Romania has a high level of domestic production. The country is also planning to invest heavily in improvements of its gas networks.¹⁵ Romania is likely to have sufficient available gas supplies in the medium to long term. Until new Romanian gas supply routes are developed, however, there will be demand for gas transmitted through Bulgaria in the short term, if a gas diversification strategy is followed by the Government of Romania. Over the longer term, however, markets beyond Romania (e.g. Poland, Czech Republic, Hungary) are increasingly likely to be trading partners for Bulgarian transmitted gas rather than Romania itself.

Through diversity of supply sources, Greece and, in particular, Turkey are largely expected to be able to meet their own gas demand requirements (see more on this issue in the next section). In fact, the current supply in Greece and Turkey would mean that the southern interconnectors of Bulgaria could be filled in the short term by gas originating from Greek and Turkish LNG terminals or from the Caspian region, Iran or, in the longer term, Iraq or other Middle East countries.

3.3 Alternative gas sources for Bulgaria

In the longer term, major new pipelines to and through Bulgaria such as Nabucco, and South Stream, would be expected to improve the SoS situation and make gas available to support increased regional demand. In the meantime, it is important not to overlook the potential for Bulgaria to improve its gas security of supply and increased regional trade through suitable co-operative strategies, combined with new cross-border infrastructure and interconnections. Examples of infrastructure include a southern interconnector to Greece or Turkey that could be in operation as early as 2014.

The gas crisis demonstrated the potential for delivery of LNG through Greece to Bulgaria. If and when the Greece-Italy interconnection ('Poseidon') and/or the proposed Trans Adriatic Pipeline (TAP) interconnection are in place¹⁶, backhaul and physical reverse flow of Algerian gas via Italy could be possible. The more likely reverse flow agreements however will come from the existing pipelines to Turkey and Greece. The prospects for sourcing gas from one or both of these countries in the future, after proper reverse flow facilities are in place, are summarized below:

¹⁵ But imports will grow as domestic gas declines

¹⁶ Although the TAP project may be less likely if TANAP goes ahead

Turkey

Turkey has managed its long term supply-demand balance with a significant reserve margin for the last 30 years and this situation is expected to continue into the foreseeable future, given:

- o Ample gas supply available to Turkey from diverse suppliers
- o Turkey's ambition to be a 'gas hub' or significant supplier to Europe

Bulgaria's requirement for SoS purposes would be a very small percentage of Turkey's total gas supplies. Contractually this could come from any one of Turkey's 5 or 6 current suppliers or from the national gas company, BOTAS, itself.

Turkey is one of the most diversely supplied gas systems among those of the world's countries that are largely or wholly import dependent. The serious problem of Turkey is relatively small gas storage capacity to cover the winter peak demand. In every winter peak demand period Turkey highly depends on extra/additional supplies from Gazprom through Bulgaria and Blue Stream routes. Despite the fact that Turkey has a negligible amount of its own gas production and essentially relies on imports for its gas supply, it has managed its import contracts to provide a secure supply and adequate reserve (in some years an excessive reserve) for the last 30 years. Its margin of available supply over domestic demand could provide scope for Bulgaria to source occasional imports for SoS purposes, considering that Bulgaria's total demand is less than 8% of Turkey's current demand and little over 5% of Turkey's current maximum supply.

Turkey's strategy and long term vision is to develop as a gas hub with large supplies from surrounding producer countries being traded through Turkey. This has been a factor in Turkey's reluctance to proceed with the Nabucco pipeline project and the recent trilateral signing of an agreement with Azerbaijan and the Shah Deniz II (SDII) partners for the Trans-Anatolian pipeline project (TANAP), which will give Turkey more control over the flow of Caspian gas into Europe.

Turkey's current main supply routes are shown on Figure 5 which also illustrates its 'gas hub' strategy:

- o Pipelines for Russian gas on the Western route via Bulgaria and directly across the Black Sea (Blue Stream pipeline)
- o By pipeline through Georgia for gas supplied from Azerbaijan
- o By pipeline from Iran
- o LNG import terminals for Algerian and Nigerian LNG

Figure 5 Turkey's gas hub strategy



Source: Mürside TAYMAZ, BOTAS,

www.unece.org/energy/se/pp/wpgas/20wpg_0110/20Jan10/12_Turkey.pdf

Turkey's gas supply comes principally from seven existing long term import contracts which, apart from two, expire after 2020. Future supply is likely to require extension of existing contracts and/or new contracts during the period 2015-2020. Turkey has recently signed a contract with the SDII partners for an additional 6 bcm/year of gas for Turkey's own use and 10 bcm/year transit through the TANAP pipeline after 2017. The current contract position is shown Table 2.

Energy demand in Turkey is growing fast, and while there was a temporary tightness of gas supply in early 2012, in the medium term there is no serious impediment to increased supply to match both Turkish demand growth and the potential for export into Europe, including Bulgaria. However, there are currently no negotiations for Turkish supply for Bulgaria. Bulgaria has an agreement for SOCAR gas as well as its negotiated gas volumes from SDII. Turkey has also recently concluded an agreement with Azerbaijan for 6 bcm/year of new gas through the existing South Caucasus pipeline route, produced from Phase II of the Shah Deniz field development in the Caspian Sea and a new agreement with the SDII partners for the transit of 10 bcm/year for the TANAP pipeline. However, for Turkey to become a major trans-boundary supplier of gas there would be a need to upgrade the capacity of its compressor stations.

Table 2 Sources of Turkey's gas supply (long term import contracts)

Source	Delivery	Contract	Signed	Operational	End	Duration
	<i>From</i>	<i>bcm /year</i>	<i>Date</i>	<i>Date</i>	<i>Date</i>	<i>Years</i>
Russia ¹	West	6	Feb 1986	Jun 1987	2012	25
Algeria	LNG	4	Apr 1988	Aug 1994	2014	20
Russia	West	8	Feb 1998	Mar 1998	2021	23
Nigeria	LNG	1.2	Nov 1995	Nov 1999	2021	22
Iran ²	South-east	10	Aug 1996	Dec 2001	2026	25
Russia	Black Sea	16	Dec 1997	Feb 2003	2026	23
Azerbaijan	East	6.6	Mar 2001	2006	2021	15
TOTAL (firm)		51.8				
TANAP	East	6+ ³	Dec 2011	2017	2037	10
TOTAL incl TANAP		57.8				
Turkmenistan ⁴	East	16	May 1999	n/a		30

¹ The first Russian contract has ended in 2012. With the permission of the Turkish Energy Regulator EPDK some Turkish private gas suppliers have signed long-term contracts with Gazprom Export for the same quantities of natural gas according to the first Russian contract. BOTAS has transferred the right of renewal to private parties. BOTAS has agreed that this capacity is available to private suppliers to enter into their own new contracts (eg with Gazprom).

² The Iranian contract is understood not to be performing as intended with delivery capacity about 3 to 4 bcm/year, and around 7 bcm/year last two years, rather than the 10 bcm/year originally envisaged and actual delivery has frequently been less.

³ TANAP will initially transport 10 bcm/year through Turkey to Europe and supply 6 bcm/year to Turkey, though its maximum capacity will be 31 bcm/year

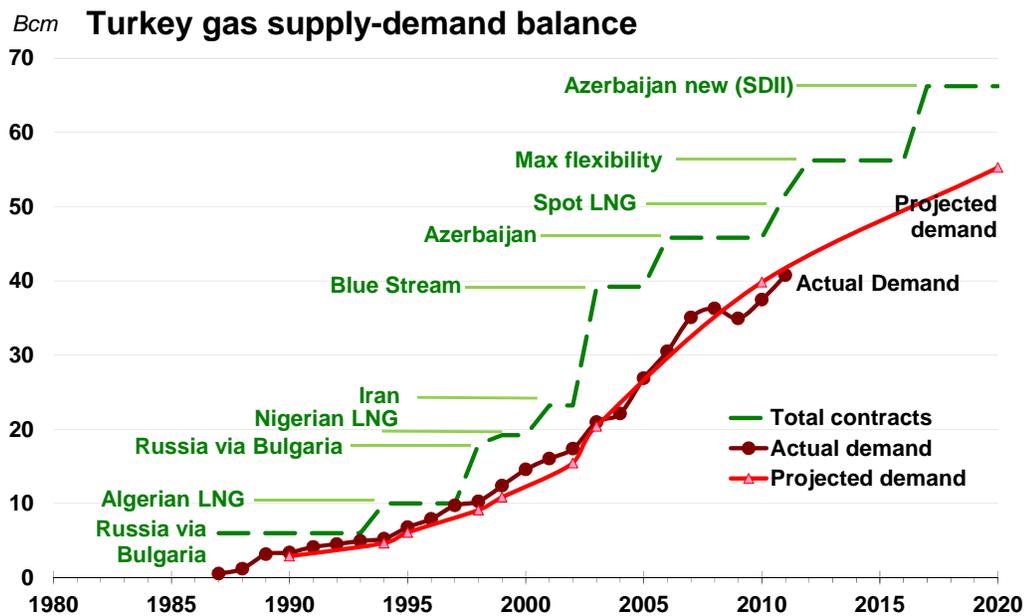
⁴ The Turkmenistan contract was dependent on construction of the Trans Caspian gas pipeline (TCP), which did not proceed; this capacity is effectively not available although there are recent agreements to revive the TCP project

The supply-demand projection to 2020 is shown in Figure 6 which includes the contracts in the table above as well as noting the possibility of available LNG import terminal capacity to import more LNG on short term arrangements (Spot LNG¹⁷). Also included is the amount that could be imported by exploiting the maximum upward flexibility on the contract quantities (typically up to 10-15% on top of the annual contract quantity). The figure therefore shows the case where Turkey takes the maximum supply available on existing and already announced new contracts, renewal of recently expired or expiring contracts, and use of its LNG import terminals.

Given the recent and ongoing discussions for new long term gas supplies there is no reason to expect any significant shortfall in supply or reduction in the reserve margin of supply over demand, other than the normal difficulties of ensuring supply-demand balance on a year-to-year basis with uncertainty in demand growth.

¹⁷ No account has been taken of plans to expand LNG capacity, which is a distinct possibility over the next few years

Figure 6 Turkey’s projected gas supply-demand balance, maximum supply



Source: ECA calculation

Greece

Greece’s gas supply comes from Russian gas sources by pipeline and a small amount through the Revithoussa LNG terminal.

Given the current low capacity utilization of the LNG facility (around 10%) and the plans to expand the facility’s storage capacity, there appears to be significant capacity for Bulgaria to contract for some capacity with LNG suppliers for SoS purposes.

The LNG terminal has a capacity of a little over 5 bcm/year and two storage tanks with a total capacity of 130,000 cubic meters. The terminal can receive LNG tankers of up to 155,000 cubic meters.

A third storage tank is planned and a contract has been awarded to Sofregaz for a feasibility study. The additional storage capacity would be 95,000 cubic meters increasing the ability of Revithoussa to receive large LNG tankers given its planned total storage capacity of 225,000 cubic meters; the terminal’s jetty’s capacity is also planned to be expanded so it will be able to accommodate large Q-Max LNG tankers of around 260,000 m³

Some gas is supplied under contract from Algeria's Sonatrach, of a little over 0.5 bcm/year until 2020; hence firm utilization of the capacity has been only about 10% with 90% of the capacity unutilized/un-contracted.

There is also a contract with Italy's ENI to supply gas, though not currently used. Egypt LNG (EGL) has recently supplied a small quantity (assumed to be a spot LNG

purchase). Qatargas has also supplied a spot cargo (one LNG tanker) to Revithoussa.

In conclusion, on the national and regional gas demand developments:

- (i) Gas demand developments are principally driven by (i) the electricity generation strategy, (ii) the rate of household gasification and (iii) energy efficiency gains.
- (ii) Since gas fired power capacity will need to replace part of the originally planned nuclear expansion, gas demand will grow substantially over the next ten years to represent 18% or more of total primary energy consumption by 2020, up from currently 12%. As a consequence Bulgaria's gas and energy security of supply would deteriorate if no alternative supply routes are developed.
- (iii) At the regional level, although the outlook for gas demand in each specific market is uncertain, the overall development of gas demand and trade in the region is likely to grow both because of increasing demand and the availability of new sources of supply.
- (iv) Bulgaria's strategic location bordering several of the relevant countries as well as being on one or more of the cross-border transmission routes for Caspian and possibly Middle East gas indicate growing opportunities to benefit from investment in interconnectors and supporting infrastructure.
- (v) Bulgaria's infrastructure investment options can both support and benefit from potential regional infrastructure developments such as the EC Gas Ring and the Southern Corridor.

4 Ensuring security of supply at least cost

The second key policy question concerns the options for meeting the EU security of supply (SoS) standards. With the range of different supply and infrastructure investment options available to GoB, this Report aims at prioritizing those options that meet EU SoS standards while incurring the lowest cost. This section provides the following:

- o Definitions of security of supply, overview of the available main investment options as used in the subsequent analyses
- o A brief outline of the applied modeling methodology and concepts used to analyze this policy question
- o A suggested investment strategy that is most likely to meet the EU regulation on SoS at least cost
- o Going beyond the EU SoS regulation: an investment strategy to meet full demand

4.1 Definition of Security of supply

The first key issue is to define the term ‘security of supply’. The most recent European Commission regulation concerning safeguarding security of gas supply, Regulation 994/2010, requires two standards to be met to ensure gas supplies:

- The *n-1 infrastructure standard* requires EU Member States to meet demand on the coldest day for a 1-in 20 year in case of disruption of the largest supply source. Applying this standard, this Report therefore defines security of supply as ensuring that gas can be supplied for a sustained period of time in any given year if the largest single supply source is interrupted on those days of the year where gas consumption is highest. The severity of such an event is greater in a system, like Bulgaria’s, with little indigenous production, limited storage deliverability, and without cross-border interconnections that are able to serve as entry points for alternative imports.
- The *30-day gas supply standard* requires EU Member States to have sufficient supply sources to cover ‘protected customers’ over a 30 day period in case of disruption of the single largest supply source under average winter conditions. GoB has not yet defined ‘protected customers’ so for the sake of this analysis, this Report defines them as households (1.5% of annual consumption in 2010) and district heating companies (24% of annual consumption)¹⁸. As per the EU regulations ‘protected customers’ can mean all household customers connected to a gas distribution network and *can in addition include* small and medium-sized enterprises, essential social services and district heating installations without access to alternative fuels¹⁹. Therefore, the definition of protected consumers chosen in this Report can be considered conservative.

In 2012 Bulgaria does not satisfy the n-1 infrastructure standard. However, the 30-day gas supply standard is satisfied due to the Chiren underground storage, domestic production, linepack and partially existing dual fuel capabilities.

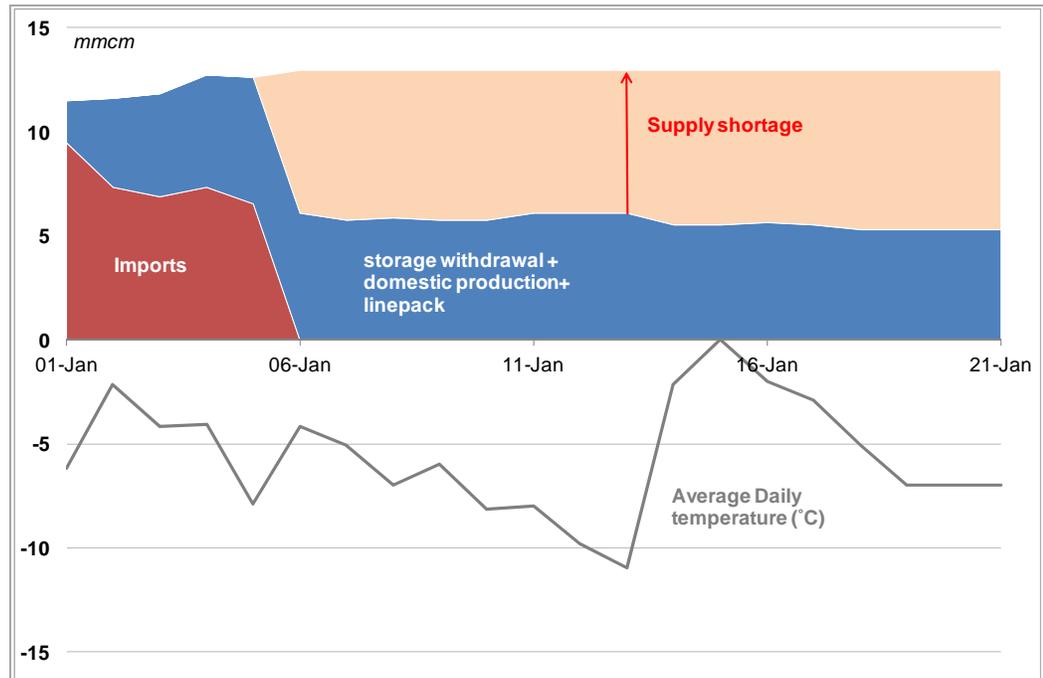
Figure 7 shows imports, domestic supply (storage withdrawal, linepack, domestic production) and average daily temperatures over the period January 1 - 21, 2009.

¹⁸ The EU regulations also require Member Countries to be able to meet demand from protected customers *without any disruption of gas supplies* under two different conditions: (i) during a 7-day peak period occurring with a statistical probability of once in 20 years and (ii) any period of at least 30 days of exceptionally high gas demand occurring with a statistical probability of once in 20 years. Both requirements are already met by Bulgaria and in future will largely depend on the contract flexibility negotiated on supply contracts. . As they do not assume the loss of external gas supplies, in this case the Russian gas supply which has adequate capacity for meeting Bulgaria’s demand, these conditions are easily met and there is no need to analyse them in the model. The 30-day gas supply standard is the worst case scenario for Bulgaria and the modelling therefore focuses on this condition.

¹⁹ Although officially required to have access to fuel oil for five days, district heating companies did not have sufficient access to alternative fuel sources during the January 2009 crisis. Due to the lack of precise information regarding the share of DH operators with access to alternative fuels in case of a gas supply disruption, we conservatively assume all district heating companies to be included in the category of protected customers.

The graph highlights that domestic supply measures were only able to cover close to 45% of daily demand levels and not the EU required 100%. The severity of the import interruption was accentuated by the particularly cold temperatures over this period resulting in above average daily demand (estimated at 13 mmcm per day).

Figure 7 Imports, domestic supply and supply shortage in January 2009



Source: adapted from Kardejak, P (2009) The January 2009 Gas Crisis: What Happened in Central and South Eastern Europe? Presentation to the seminar on European gas supply security, E-Control and Florence School of Regulation, Vienna, 3 April 2009.

4.2 Bulgaria's infrastructure and supply management options to improve security of gas supply

Following consultations with Bulgarian gas stakeholders, this Report identifies twelve possible investment and gas supply management options that could contribute to gas supply security in the short to medium term, some of which also bring possible commercial benefits. Figure 8 summarizes all investment/management options and shows their location. The options all have cost implications though some mainly involve management of resources (such as use of linepack or requirement to have dual firing capability).

The options are briefly described below in five categories: storage facilities, production, interconnections, reverse flow and demand side measures. Their abbreviations as used on various charts are given in brackets in the following text.

Figure 8 Location of identified investment/management options

1. Chiren UGS expansion
2. Galata conversion
3. Karvama and Kaliakra production
4. CNG tanker imports
5. Interconnector Greece
6. Interconnector Turkey
7. Reverse Flow Greece
8. Linepack usage
9. Dual Fuel capabilities
10. Crisis Flow Romania
11. Interconnector Romania
12. Interconnector Serbia



Storage facilities

Chiren Underground storage expansion. Chiren is the only existing underground storage facility in Bulgaria. The ongoing expansion will increase the deliverability from 4.2 mmcm/day (giving a working volume of 450 mmcm/year) to 10 mmcm/day (1 bcm/year) and could be available as early as 2015.

Galata conversion (Galata conversion A & B). This investment option consists of the conversion of a depleted offshore gas field to an underground storage facility. At a capital cost expected to range between €350 and €450 million the daily deliverability could range between 9 mmcm/day (600 mmcm/year) and 12mmcm/day (800 mmcm/year).

CNG tanker imports (CNG). Under this option Compressed Natural Gas (CNG) originating from Azerbaijan would be transported via specialized container ships from Georgia (or imports from outside the Black Sea subject to shipping constraints in the Bosphorus) to Bulgaria. This would either be done via a land-based or floating receiving terminal. Total costs are estimated at €1,160 million and maximum withdrawal could reach 10.3 mmcm/day (2000 mmcm/year).

Maximize usage of linepack (Linepack). By increasing the pressure in the existing gas transportation system, a greater volume of gas can be stored in the system. This can then be released in case of a supply disruption. Although only a short term option, increased usage of linepack can be a significant contributor in covering peak daily demand levels on the days of most shortage. This Report assumes that maximum deliverability could be as high as 2.6 mmcm/day, however, with total capacity of only 11.3 mmcm/year at an annual cost of €0.1 million.

Production

Kavarna and Kaliakra gas fields (K&K). Kavarna and Kaliakra are two producing gas fields that form part of the Galata field. The two gas fields began operation in November 2010 and are currently producing around 400 mmcm/year. Production from these fields is expected to rise gradually to close to 700 mmcm/year by 2016. Post 2016, production levels are uncertain and, conservatively, they are assumed to be zero for the purpose of this Report. Production from the recently developed *Deventsia field* will also contribute to local production, however precise production levels are not yet known and, conservatively, they are assumed to be zero for the purpose of this Report.

Interconnectors

It is important to note here that the development of interconnectors alone will not ensure security of supply. Contractual arrangements need to be put in place that will guarantee a minimum supply of gas in case of a major disruption of gas supplies. Details of the key contractual issues are discussed in Box 2.

Interconnector to Greece (IC Gre). The interconnection to Greece with a capacity of 3 bcm/year and deliverability of 9 mmcm/day is currently planned to be an offshoot from the Interconnector Turkey-Greece-Italy (ITGI). With a length of 160 km, the interconnection is estimated to cost up to a total of €150 million and could be operational by 2014. It will be co-financed by the European Commission, so liabilities to Bulgaria will be closer to €75 million. The interconnector is assumed to be operating at full capacity under normal conditions, with 90% reserved for cross-border transmission countries, 10% reserved for domestic Bulgarian use. It is assumed that the cross-border transmission gas is on interruptible contracts where full capacity could be used to cover domestic Bulgarian demand in case of a disruption of supply through existing pipelines.²⁰

Interconnector to Turkey (IC Tur). The interconnector to Turkey would have a capacity of up to 5 bcm/year and would give similar security of supply benefits as the interconnector to Greece: access to large Caspian gas sources²¹ and LNG spot markets via Turkish LNG terminals (Marmara Ereğlisi and Izmir, and other potential new terminals). The interconnector is assumed to be operating at full capacity under normal conditions, with 90% dedicated for cross-border transmission and 10% reserved for domestic use. In case of a supply disruption, the full capacity could be used to cover domestic demand (as in the case of the Greece interconnector).

Interconnector to Romania (IC Rom). The 15 km interconnection of Romanian and Bulgarian gas transmission systems is currently under construction and it is expected to be operational in late 2013. With a capacity of 1.5 bcm/year and an assumed deliverability of 4.1 mmcm/day, the pipeline would cost €28 million to be constructed. Costs associated with the Bulgarian section, deducting European grant

²⁰ The lower commercial values resulting from the interruption agreement are taken into account in the analysis by applying a discount factor to transportation charges (contract flexibility multiplier).

²¹ Though not necessarily available much before 2020

funding would however only amount to €11 million. The interconnector is planned to be bidirectional. It is important to note that considerable investments are still needed on the Romanian side to ensure the interconnector allows for flows into Bulgaria. For the purpose of this analysis it has been assumed that these investments will be made in the short term and that the interconnector is bidirectional.

Interconnector to Serbia (IC Ser). A feasibility study for this project was completed in early 2013. The interconnector would be operational by 2015 at the earliest and is expected to have a capacity of 1.8 bcm/year with an assumed deliverability of 5.5 mmcm/day. The project is estimated to cost €120 million and is expected to flow in two directions.

Reverse flow²²

Reverse flow agreements with Greece and Turkey (RF Gre and RF Tur). This implies using the existing pipelines designed to flow from north to south in a northern direction and formalizing the agreements made hastily during the January 2009 crisis (see box below). For the purpose of this analysis it is assumed that these arrangements could provide up to 2.4 mmcm/day. Reverse flow agreements with Greece could be available as early as late 2013, whereas in Turkey it is more likely to be in 2018. In case of an interruption of Russian gas supplies including those that could come via Turkey, gas is assumed to be sourced from the Revithoussa LNG terminal in Greece. However, contractual arrangements would be needed to secure this amount of LNG in a crisis situation.

Crisis gas flow Romania (Crisis Flow Rom). Currently planned by the Romanian Transmission System Operator, this relatively small-sized investment (capital cost of €3.2 million), would consist of connecting the internal Romanian transmission system with the transmission pipeline crossing Romania to deliver gas to Bulgaria and beyond in case of disruptions to the flow through the cross-border transmission pipeline. In crisis situations, it is assumed that up to 2.6 mmcm/day of gas could be sourced from the Romanian own production, storages or other supplies and directed from the Silistea compressor station via the Romanian system (in reverse flow), through this interconnection into the transmission pipeline towards Bulgaria.

²² Interconnections with other EU or Energy Community countries that do not yet have reverse flow are required to undergo a market test to identify needs. Bulgartransgas had a brief market consultation in 2012 though the full results are not yet known.

Box 2: Gas sources for interconnectors and contractual arrangements

During the 2009 interruption Bulgaria was able to receive some gas supplies from Greece, despite the fact that much of Greece's gas supply originates from Russian gas. Reverse flow was able to be activated on the interconnector, even though it had been implemented for 'export' flow only. The constraints on the speed of implementing reverse flow were related to control/valve arrangements and, more critically, the metering for measurement of flows for subsequent financial settlement.

The prospects for sourcing gas from Turkey or Greece or both of these countries in the future for SoS purposes are discussed separately in this report. Options to put in place the contractual arrangements for the Turkish and Greek interconnectors, are summarized below.

Security of supply would only be achieved if it is possible to put in place a contractual framework with firm capacity on all parts of the supply chain:

- o Gas supply (gas sale and purchase agreement)
- o Transportation agreements (for all pipeline systems)
- o LNG carriers and LNG terminals (LNG delivery)
- o Interconnector capacity (generally separate agreements with the parties on either side of the border)

Clearly, it makes no economic or financial sense to reserve capacity that would not be required 99% of the time.

There are two ways this can be handled:

- o For capacity in Bulgaria's control, i.e. part of the Bulgarian national transmission system, one could have a non-firm contract for use of pipelines and other infrastructure, and rely on the use of emergency conditions in the grid code to give the transmission entity the right to use of capacity when an emergency is declared. This would presumably not be a problem since the emergency would arise as the normal suppliers would not be delivering gas and the capacity would be idle
- o UIOLI provisions (use-it-or-lose-it). Contracts for capacity in other countries (e.g. LNG terminal capacity), pipelines, interconnector capacity could be on a UIOLI basis, with notice variously being required say 1 day or 1 week in advance

There could also be a combination of terms, with small amounts of capacity being reserved on a firm basis (eg for say 10% of Bulgaria's normal requirement) and the rest of the minimum requirement being on UIOLI basis. The firmly reserved capacity could then be on-sold to other suppliers when not needed for SoS, on a spot basis.

Demand side measures

Dual fuel capabilities (Dual Fuel). This investment and regulation option considers the installation of diesel/fuel oil backup fuel for all existing gas fired power plants and district heating plants. While all other investment options have a supply side effect, dual fuel capabilities is a demand side measure. This means that in case of an interruption, gas demand of district heating and gas fired power generation could

be fully replaced with alternative fuels. This would correspond to a daily reduction in gas demand of 5.5 mmcm. Total capital cost (including reserve storage) for dual fuel capabilities for both district heating and power generation are estimated at €58.1 million.

Summary of investment options

Table 3 summarizes all investment options and their key parameters.

Table 3 Possible investments to ensure security of supply				
Investment Option	Capital costs	Deliverability	Max capacity	Possible start date
	<i>€ million</i>	<i>mmcm/day</i>	<i>mmcm/year</i>	
<i>Storage facilities</i>				
Chiren UGS expansion	200	10	1,000	2015
Galata conversion (A)	350	9	600	2015
Galata conversion (B)	450	12	800	2015
CNG tanker imports	1,230	6.8	2,500	2015
Max use of linepack	-	2.5	12	2013
<i>Interconnectors</i>				
IC Greece	75	9	3,000	2014
IC Turkey	100	13.7	5,000	2014
IC Rom	11	4.1	1,500	2013
IC Serbia	120	5.5	1,800	2015
<i>Reverse Flow</i>				
RF Greece	0.2	2.4	-	2013
RF Turkey	0.2	2.4	-	2018
Crisis gas flow Romania	3.2	2.6	-	2013
<i>Demand side measures</i>				
Dual fuel capabilities	45.6	5.5	900	2013

4.3 Meeting EU regulations at least cost

To meet EU SoS criteria, investments must be made that meet the previously defined *n-1 criterion* and the *30-day standard* by early 2014. The *n-1 criterion* requires Member countries to meet demand on the coldest day for a 1-in 20 year and the *30-day standard* requires Member countries to meet demand of protected customers on 30 days for average winter conditions²³. As noted previously, protected customers account for 28% of daily demand.

The preferred investment options will hinge on future demand developments and the required investment options are presented for the three demand scenarios. The

²³ Protected customers in this analysis are households and district heating companies.

least cost investment options to meet EU criteria, their annual costs²⁴ and the year of implementation are summarized in Table 4.

The recommendations are in addition to the forecasted domestic production levels. The table is split into the n-1 and 30-day standard requirement and for each, separate demand scenarios are applied. The dots in the table represent the preferred investment option for the respective criteria and demand forecast. The dates beside the dots represent the year in which the investment option would be needed to meet the criteria. If no year, the investment option is needed by 2014.

Table 4 Investment recommendations to meet EU criteria

Criteria >	Annual Cost (€M)	n-1 (for 1-in 20 year)			30 day standard (for mean year)		
		High	Low	Base Case	High	Low	Base Case
Chiren	4.5	●	●	●	●	●	●
Linepack	0.1	●	●	●	● ²⁰¹⁵	● ²⁰¹⁹	
Reverse Flow Greece	0.9	● ²⁰¹⁹			● ²⁰¹⁷		
Interconnector Romania	2.0	●	●	●			
Interconnector Greece	12.3	●	●	●			
Interconnector Turkey	11.8	● ²⁰¹⁷					

A central assumption underlying this analysis is that in case of a supply disruption Turkey and Greece will have sufficient excess gas to supply Bulgaria, e.g. through pipeline imports (Turkey) or LNG (Turkey or Greece). This assumption is challenged in the subsequent section, where a scenario of no availability of gas sources from neighboring countries ('self-sufficiency' scenario) is analyzed.

The analysis until 2020 shows that *to meet the N-1 EU criteria the existing Chiren storage facility, the interconnectors to Greece and Romania and the maximum use of linepack are required.* These options will be largely sufficient to meet the 30 day standard, while Chiren alone would even be sufficient in the Low and Base case scenarios until 2019. The estimated additional cost of gas from the reverse flow agreement in the N-1 analysis, although likely to be heavily marked up, will still be lower than installation and fuel costs of dual fuel capabilities and should therefore be prioritized. Under the unlikely high demand assumptions the *formalization of the reverse flow agreements with Greece²⁵ and the interconnector to Turkey* are additionally required.

The required total costs for the investment options would be between €31.6 and €19.8 million (depending on the demand scenario) in a year with a supply interruption. As will be discussed in subsequent sections, these costs may be

²⁴ The costs presented for reverse flow options are those of a 30 day interruption and therefore include CAPEX, OPEX and additional costs of short term LNG purchases from Greece and Turkey

²⁵ Note that as per EU requirements all transit pipelines between Member States have to be operating bi-directionally.

outweighed by potential commercial benefits that can accrue from the gas transmitted or trading through the interconnectors²⁶.

The most feasible of the southern interconnectors will be to Greece, despite it being at marginally higher cost than the Turkey interconnector. Compared to the Turkey IC, the Greek IC is already at quite advanced stages of development and benefits from EU support politically as well as financially (€45 million EU grant).

In the short term, efforts should be directed towards the development of the Greek interconnector and ensuring the bi-directional flow capabilities of the Romanian interconnector. As the EU regulations must be met by early 2014, the development of these options should be done as early as possible.

It is important to note that significant additional investment costs in the Romanian transmission network are required to ensure the bidirectional flow of the Romanian interconnector, implying that in the short term gas flows into Bulgaria cannot be ensured. If these investments do not materialize in the short term, the *formalization of reverse flow agreements with Greece* and development of *dual fuel capabilities in the power generation and district heating sectors* would be the second best alternative to the Romanian interconnection.

4.4 Beyond EU regulation: meeting full demand at least cost

The EU regulations focus only on meeting demand in case of a supply disruption for one day (1-in 20 criterion) or for a prolonged period of time but only for a small share of consumers (protected consumers). It is interesting, however, to assess what investment options are needed to meet demand for a prolonged period of time for *all* customers. Although this goes beyond the EU requirements, this would minimize the overall economic impact of a supply interruption as occurred in January 2009. To this end, the study analyzes two alternate scenarios:

- o The *alternative supply route scenario*, where no restrictions are put on available supply options in case of a disruption of the largest supplier
- o The *self-sufficiency* scenario, where no other alternative supply routes exist and Bulgaria relies entirely on its own supply. This scenario needs to be considered since, in case of a Russian supply disruption, Bulgaria's neighboring countries would also face supply shortages.

Assuming a 30 day interruption in a mean year under the three demand scenarios presented in the previous section, the identified investment options and their timing are presented in Table 5. The investment option is needed by 2013 if no year appears beside the dot.

The selected investment options in the scenario where alternative supply routes are available largely coincide with those needed to meet the EU regulation. *The two interconnectors to Greece and Romania are again the key investment option to*

²⁶ Bulgaria can recover some costs from the underutilised capacity of its transmission network through increased cross-border transmission flows.

secure supply in case of a disruption of supplies. The reverse flow agreement with Greece would only be needed by 2019 and in the case of high demand. The Greek interconnector is prioritized over the Turkish interconnector in this scenario for the same reasons outlined in Section 4.3.

It is important to note here again that additional investment costs in the Romanian transmission network are required to ensure the bidirectional flow of the interconnector, in the short term gas flows into Bulgaria are not ensured. If these investments do not materialize in the short term, the *formalization of reverse flow agreements with Greece* and development of *dual fuel capabilities in the power generation and district heating sectors* would be the least cost alternatives to ensure security of supply.

Table 5 Investment recommendations to secure full demand

Scenario >		Alternative supply routes			Self sufficiency		
Demand >	Annual Cost (€M)	High	Low	Base Case	High	Low	Base Case
Chiren	4.5	●	●	●	●	●	●
Linepack	0.1	●	●	●	●	●	●
Reverse Flow Greece	0.9	● ²⁰¹⁹					
IC Romania	2.0	●	●	●			
Interconnector Greece	12.3	● ²⁰¹⁴	● ²⁰¹⁴	● ²⁰¹⁴			
Dual Fuel capabilities	28.1				●	●	●
Chiren expansion	54.6				● ²⁰¹⁵	● ²⁰¹⁷	● ²⁰¹⁷
Galata conversion (A)	82.4				● ²⁰¹⁸		

The contribution of interconnectors and reverse flow agreements to SoS in Bulgaria will depend on the availability of gas in neighboring countries in case of a Russian gas supply disruption. While Greece and, in particular, Turkey’s supply sources are well diversified, it is doubtful that they could supply gas to Bulgaria during a prolonged supply disruption unless contractually obliged. In the case where supply is disrupted to all neighboring countries Bulgaria may therefore have to rely entirely on its own domestic supply. The self-sufficiency scenario models this situation.

The modeling identifies the need for expansion of the Chiren underground facility to its maximum capacity of 1,000 mmcm and installation of dual fuel capabilities if “self-sufficiency” is to be achieved. Galata as an underground storage would only be required by 2018 in the high demand scenario and is therefore not indicated to be a priority investment option. The total annual costs for self-sufficiency would amount to €87 million without Galata and €169 million with Galata.

Hence, to be self-sufficient and meet demand fully in case of a supply disruption of 30 days Bulgaria should expand the Chiren storage to its maximum and ensure that all power plants and district heating plants have operational dual fuel capabilities.

To summarize regarding the recommended investment options to secure gas supply:

- (i) To meet the two main EU security of supply criteria, the n-1 standard and 30-day standard, Bulgaria will need to develop the interconnectors to Greece and Romania (pending additional investments in the Romanian transmission network) and make the maximum use of linepack in addition to its existing underground storage capabilities at Chiren. Under an unlikely high demand assumption the formalization of the reverse flow agreements with Greece and the interconnector to Turkey are additionally required.
- (ii) The required total annual costs for the investment options to meet the EU security of supply requirements would be between €31.6 and €18.9 million (depending on the demand scenario).
- (iii) Going beyond the requirements set by the EU regulations to assess what investments are needed to meet full demand for 30 days in case of the interruption of the largest supply source, two scenarios are constructed:
 - Supply sources and routes from neighboring countries are available and not constrained by supply interruptions (“Alternative routes scenario”)
 - Supply routes from neighboring countries are also interrupted and Bulgarian demand needs to be covered by domestic supply or storage options (“Self-sufficiency scenario”).
- (iv) The selected investment options in the scenario where alternative supply routes are available largely coincide with those needed to meet the EU regulation. The two interconnectors to Greece and Romania (pending additional investments in the Romanian transmission network) are again the key investment option to secure supply in case of a disruption of supplies.
- (v) To ensure self-sufficiency, the Chiren underground facility must be expanded to its maximum capacity of 1,000 mmcm and dual fuel capabilities in the heating and power sector need to be installed. Galata as an underground storage would only be required by 2018 in the high demand scenario and is therefore not indicated to be a priority investment option. The total annual costs for self-sufficiency would amount to €87 million without Galata and €169 million with Galata.

5 Benefits of investments beyond security of supply

This section presents the analysis of the third key policy question and identifies the options that maximize the benefits from exploiting commercial opportunities in light of planned regional gas infrastructure projects. This section covers:

- o An outline of the *possible commercial opportunities* to Bulgaria
- o *Investment options that maximize commercial benefits*

5.1 Overview of possible commercial opportunities

Bulgaria's investment options open up the possibility for Bulgaria to transmit gas to its neighboring countries, or to provide other commercial uses of its gas infrastructure assets such as contracting some capacity to gas traders. The possible interconnectors with Greece and Turkey, together with the potential CNG imports from Azerbaijan via Georgia would have the capacity to transport considerably more than enough gas to meet Bulgaria's domestic demands. Figure 9 shows Bulgaria's existing and planned interconnectors.

Figure 9 Existing and planned interconnectors



Three possible commercial trade opportunities arise from these interconnectors extending trade from southern routes to countries to the north and west of Bulgaria:

- o Gas cross-border transmissions to *Romania and Serbia*

- o Gas cross-border transmission to *FYR Macedonia*
- o Gas cross-border transmissions to *countries beyond the directly neighboring countries*.

Gas cross-border transmission to Serbia and Romania

The possibilities of transmitting gas to Serbia and Romania will largely depend on the realization of infrastructure investments and policy of supply diversification in these countries. As noted previously, *Romania's* domestic gas production and planned infrastructure developments suggest that sufficient alternative supply sources can be secured in the medium and long term without relying on gas transmitted through Bulgaria. The analysis suggests that demand will grow moderately to a level of around 17 bcm by 2020. Russian contracted gas supplies amounting to close to a maximum of 7.5 bcm/year are expected to continue to make up the level of demand above domestic production. This would leave an import gap of the order of 3.5 bcm in 2020. More details are provided in Annex 1, where Figure 13 shows planned and existing infrastructure projects will be sufficient to cover both the potential import gap and the renewal of contracts of Russian supplies.

However, if Romania seeks an import diversification strategy and Russian import contracts are not renewed at full volumes, then demand for gas transmitted through Bulgaria could increase substantially.

Gas cross-border transmission to FYR Macedonia

The gas market in FYR Macedonia is underdeveloped and only a small part of the northern part of FYR Macedonia is gasified. The only natural gas interconnection pipeline is currently at the border of FYR Macedonia and Bulgaria, with a capacity of 0.8 bcm/year (with possible extension to 1.2 bcm per year), transporting Russian gas into FYR Macedonia. The current gas infrastructure is under-utilized, with only 10% load factor up to 2007 and 15% in 2008.

If official gas growth demand forecasts are realized (1 bcm/year by 2020), FYR Macedonia is likely to face a supply shortage in the medium term while being fully reliant on Russian gas supplies delivered through Bulgaria. If the EC Gas Ring projects are not implemented in the medium term, additional interconnector capacity would be needed and new interconnector capacity to Bulgaria could be an alternative.

More information about the gas market in FYR Macedonia is provided in Annex 1.

Gas trade beyond surrounding countries

In the *West Balkans*, Croatia is the largest natural gas consumer, consuming around 3 bcm of gas per annum. With diversified supply sources and 60% of demand covered by domestic production, Croatia is unlikely to be a significant gas market for gas transmitted through Bulgaria. Bosnia's supply gap could be of the order of 0.2 bcm by 2015. In combination with a policy of supply diversification, Bosnia

could become a realistic offtake market for gas transported through the Serbia-Bulgaria interconnector. However, there are some capacity constraints at the interconnector Serbia-Bosnia, and in Bosnia's national transmission system is largely undeveloped.

The most direct route for gas transmitted through Bulgaria to reach the *Central European countries* of Hungary and Slovakia would be strengthening the south-north interconnections through Romania. For that end Romania would need to make additional investments ensuring that the existing interconnector to Hungary can flow from south to north. Once this is possible, there will be offtake markets for gas transmitted through Bulgaria, with both Hungary and Slovakia as well as countries further north (e.g. Poland, the Baltic countries) pursuing an active gas diversification strategy away from Russian gas dependency.

5.2 Investment options for maximizing commercial benefits

For security of supply reasons capacity will be established that is not fully utilized for much of the time and is therefore able to be utilized for commercial benefit²⁷. The analysis focuses on the commercial benefits from transmitting gas through Bulgaria. Primarily four possible investment options must be considered for commercial benefit maximization from transmission of gas from alternative supply sources: the southern interconnectors to Greece (3 bcm) and Turkey (5 bcm) as supply sources and the northern interconnectors to Romania (1.5 bcm and currently under construction), Serbia (1.8 bcm) and FYR of Macedonia²⁸ (1.2 bcm) as export routes.

The uncertain volumes of future cross-border trade make developing interconnectors a risky proposition, as high capacity utilization is desirable to ensure commercial feasibility. In Bulgaria's case, the development of both southern interconnectors is constrained by two factors: (i) the ability to find offtake markets for excess gas not consumed in Bulgaria and (ii) the capacity of northern and western interconnectors to transmit gas northward or westward. These current constraints increase the risk that a considerable share of the capacity of southern interconnectors may not initially be utilized at a level that would be commercially viable.

For Bulgaria, the two southern interconnectors combined could provide 8 bcm of gas. With rising demand levels and take-or-pay constraints on Russian import contracts²⁹, it is estimated that Bulgaria could use close to 0.8 bcm/year from these new supply routes, representing only 10% of total capacity. This would correspond to available capacity for cross-border transmission agreements of up to 90% of capacity on both interconnectors. Consequently, a total of 7.2 bcm of southern

²⁷ Generally, one would expect security of supply to have priority use of capacity under defined operational security terms, and therefore commercial arrangements would be on non-firm, i.e. interruptible contracts

²⁸ The Macedonian interconnector is assumed to be supplied by Russian gas.

²⁹ There are indications that Bulgaria has renegotiated its contracts with Russia, after the FID on South Stream, which reduces the TOP obligation and gives more flexibility. No precise details are currently available, but this could also increase the attractiveness of the Revithoussa LNG supply option

interconnector capacity would be available to be transmitted through Bulgaria if both southern interconnectors were to be developed and fully utilized.

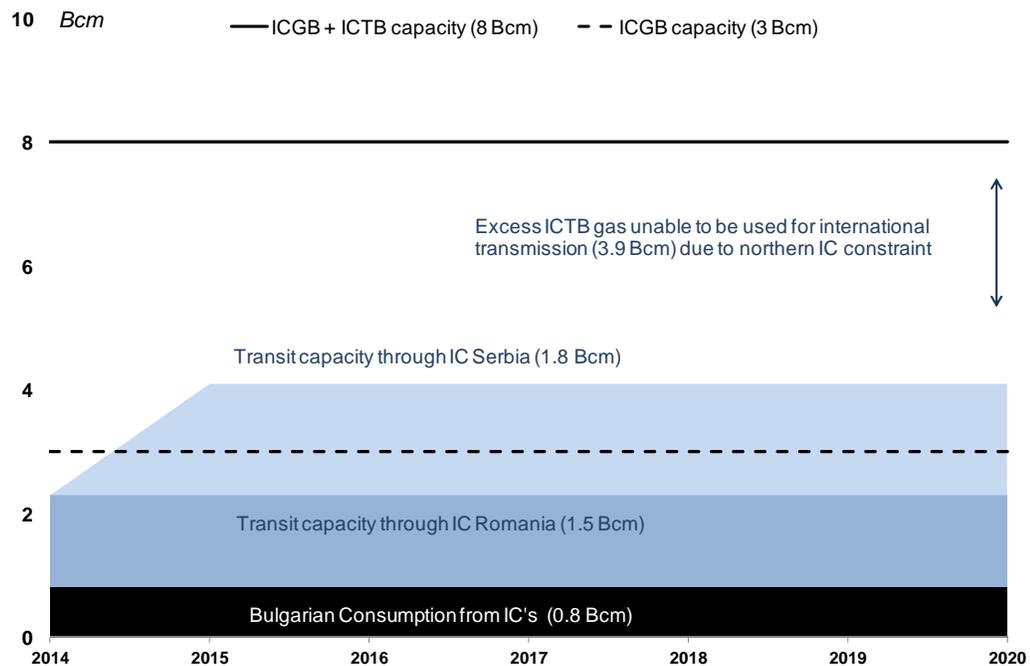
A key question, however, is whether sufficient capacity on northern (and western) interconnectors can be developed to make full use of the potential 7.2 bcm gas cross-border transmission capacity. The capacity of the planned northern interconnectors amounts to a total of 3.5 bcm (planned Serbia IC, currently constructed Romania IC). Even if offtake markets are secured for the full capacity, this would probably not be sufficient to warrant the development of both southern interconnectors in the short term unless additional northern and western interconnector capacity is developed. Figure 10 illustrates the mismatch between planned southern and northern interconnector capacities.

The diagram and analysis suggest that only one of the southern interconnectors should be developed in the short term³⁰. This is mainly because the combined capacity of northern interconnectors is substantially smaller than that of the two southern interconnectors. When only developing one southern interconnector, say to Greece, the capacity to export (1.5 bcm) through the Romania interconnector, together with a 0.3 bcm offtake for domestic consumption would leave spare capacity of 1.2 bcm of the southern interconnector. To avoid this capacity being idle, the second northern interconnector (to Serbia) would need to be developed to reach a total export capacity of 3.3 bcm.

This means that the development of the Romanian, Serbian and Greece interconnectors would allow Bulgaria to diversify its own supply sources further (an estimated 0.3 bcm/year), while fully serving the Romanian interconnector (1.5 bcm) and parts of the Serbian interconnector (1.2 bcm of 1.8 bcm capacity). The remainder of the Serbian interconnector could be fed by Russian gas.

³⁰ The preferred option is the Greek interconnector that has already secured EU funding and is at advanced stages of its development. However the Turkey interconnector is slightly larger and an option that is reinforced by the decision to develop the Trans-Anatolian Pipeline (TANAP) transporting 10 bcm of Azeri gas into Turkey.

Figure 10 Capacity constraints on northern interconnectors



The total annual revenues accruing to the Greece, Serbia and Romania interconnectors could be as high as €55 million per annum with net benefits amounting to €10 million. The commercial gains would accrue from charging transportation tariffs for each interconnector. These have been calculated on a cost-reflective basis from capital and operating cost together with offtake market dependent mark-ups applied to the assumed ROR on capital and discounts for the interruptibility of cross-border transmission agreements³¹.

³¹ The revenue calculation for the interconnection capacity applies a cost-reflective approach where the rate of return on capital is related to the degree of (or lack of) competition in the off-take market. In addition, a discount factor is applied reflecting the interruptibility of the contract. These factors may be varied by the user to reflect the expected commercial terms of the cross-border transportation agreements and the anticipated frequency and size of any interruptions.

To summarize regarding benefits beyond security of gas supply:

- (i) With the possible development of pipelines bringing new supplies of Caspian gas to Europe and the development of the EC Gas Ring, Bulgaria finds itself in a strategically important position in the medium term. To maximize the commercial benefits from this location, efforts should be made to fully develop interconnections with neighboring countries.
- (ii) The development of interconnectors would potentially bring two benefits to Bulgaria:
 - Southern interconnectors can contribute to diversify imports, which would reduce the vulnerability of Bulgaria to gas interruptions from existing sources (i.e. Russia);
 - Gas supplies through southern interconnectors (with spare capacity) could be transmitted to growing and increasingly interconnected West Balkan or Central Europe gas markets and thereby earning Bulgaria cross-border transmission fees;
- (iii) The major existing constraints for the commercial benefits to accrue are (i) the limited capacity of currently planned northern interconnectors, (ii) the uncertainty of demand developments in FYR Macedonia, Serbia and Romania and (iii) gas supply infrastructure developments in Romania. Active supply diversification strategies away from Russian gas by both Serbia and Romania could provide enough anchor load for Bulgaria's commercial gas trade and cross-border transmission opportunities to be maximized.
- (iv) Consequently, in the short term there is limited commercial benefit to be gained by developing both the Turkey and the Greece interconnectors unless additional capacity is developed on northern interconnectors.

A1 Annex 1: South East Europe gas market opportunities

This annex provides brief overviews of the gas sectors in the nearby countries which are most likely to be the counterparts for gas trade with Bulgaria. The countries covered are Romania, Serbia, FYR Macedonia, Greece and Turkey. Clearly there are also wider market opportunities for trade with countries not directly connected to Bulgaria through third party access arrangements with cross-border transmission countries under rules of the EU Directive 2009/73³².

The country gas market snapshots summarize the medium term gas supply and demand situation in each country and give some projections to 2020³³. A final subsection outlines the main considerations for developing a regional gas market including the operation and regulation of interconnection infrastructure.

Romania

Romania has a very long-established gas industry, with indigenous on-shore production, a mature gas transmission network, a high degree of gas distribution development and a portfolio of underground gas storage facilities. Its gas production levels are substantial and have contributed to over 80% of consumption in 2010. The balance of demand is met by imports of Russian gas under contracts with Gazprom. Over the 1990-2002 periods, imports of natural gas from Russia were between 20-25% of total consumption.

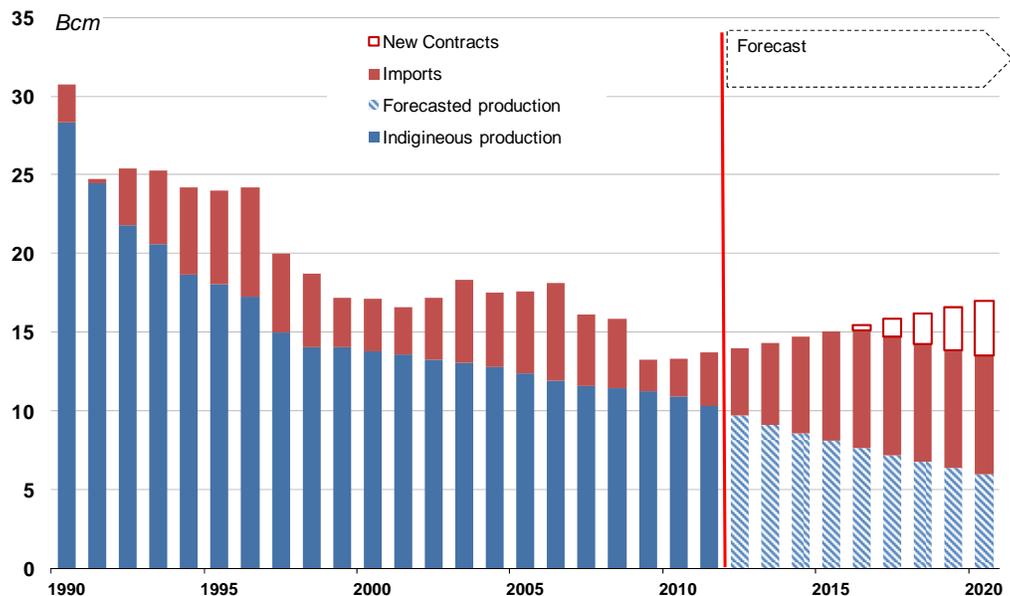
Demand has been declining over the past ten years and stood at 13 bcm in 2010. It is expected to grow moderately to a level of around 17 bcm by 2020³⁴. The existing Gazprom contracts of an estimated 7.5 bcm/year are understood to run out in 2030, leaving only a small un-contracted gas volume (import gap) of 1 bcm in 2018 and 3.5 bcm by 2020.. The historic and forecasted demand, production and import volumes are presented in Figure 11, highlighting the possible import gap in the medium to long term.

³² Bulgaria's under-utilised transmission network can recover some costs through the additional cross-border flows.

³³ The analysis in this report is mainly based on national gas and Energy Strategies and counterchecked with data from the Energy Community Strategy (<http://www.energy-community.org/pls/portal/docs/1810178.PDF>),

³⁴ <http://www.agentschapnl.nl/onderwerp/roemeni%C3%AB-olie-en-gas-kwartaal-ii-2011>

Figure 11 Romania's natural gas demand, production and imports

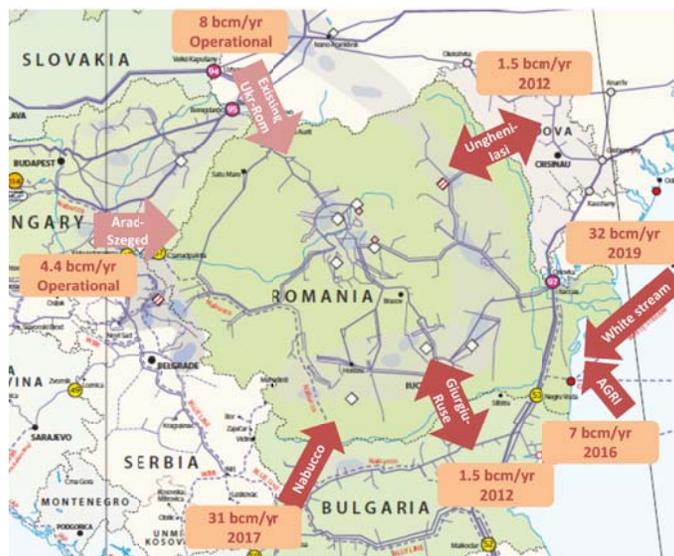


Sources: data from ANRGN, BP Statistics 2011 and other sources

This initial assessment suggests that Romania is in need of additional supply routes over the next ten years to ensure a diversification of supplies and enough import capacity to cover future demand gaps. However, Romania's planned infrastructure program implies that a number of options will be available in the short to medium term to cover this gap. All large scale planned interconnectors are shown on the map in Figure 12³⁵ and include the existing 4bcm Hungary interconnector and the AGRI (Azerbaijan, Georgia, Romania interconnection) LNG project, which is proposed to deliver up to 7 bcm/year by 2016.

³⁵ Though it is highly unlikely that all these projects would be realised in the medium term

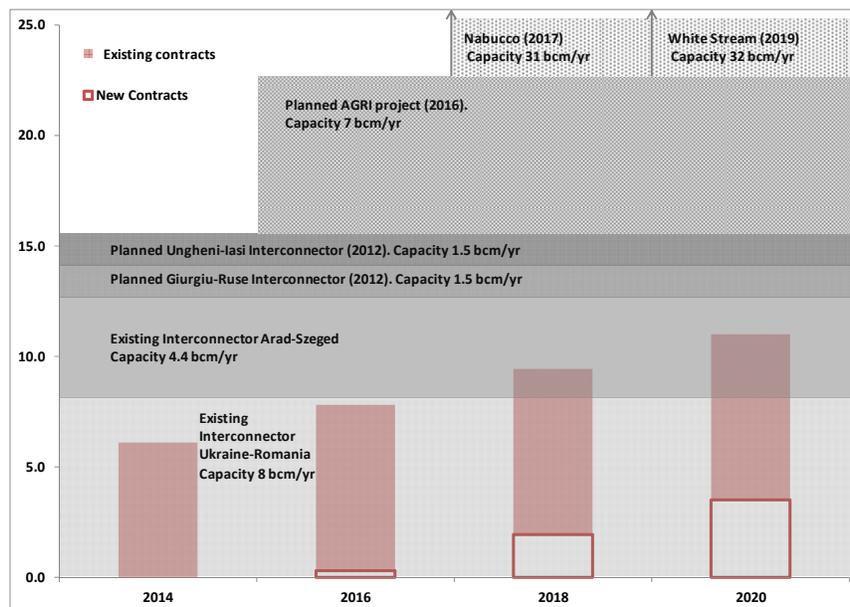
Figure 12 Romania's current and planned interconnectors and supply corridors



Furthermore, Romania is a cross-border transmission country for Nabucco and is the planned landing point for the White Stream pipeline, delivering gas from the Caspian region across the Black Sea directly to Romania. The combined capacity of these projects far surpasses any possible import gap over the next ten years. Longer term, it is believed that Romania's shale gas sources are among the highest in Central Eastern Europe and could provide additional sources of gas. Due to the uncertainty of shale gas reserve estimations and shale gas exploration in Europe however, it would be too speculative to include this in the current analysis.

There is a possibility that if all infrastructure investment plans are indeed implemented in the short to medium term, Romania could find itself in a position of excess gas supplies (see Figure 13). For Bulgaria this would mean that the Romanian interconnector represents a viable additional route to secure its gas supplies. From a commercial perspective however security of demand could not necessarily be ensured from Romania for the utilization of the full capacity of the interconnector that is currently being built. This would suggest that for Bulgaria to maximize its commercial benefits from infrastructure plans, markets beyond Romania could be the long term trading partners for Bulgarian cross-border transmission gas rather than Romania itself. The potential for realizing these benefits would however depend on the Romania-Hungary interconnector to become bi-directional, which has been assured by the Romanian government to be the case by 2013.

Figure 13 Romania's import demand and planned infrastructure capacities



Source: data from ANRGN, BP Statistics 2011 and other sources

Serbia

Serbia is only partially gasified, with only one supply corridor into its transmission network at the Serbian-Hungarian border. Although natural gas only accounts for 13% (2.5 bcm consumption in 2011) of final primary energy consumption, it is expected to be the future and complementary alternative for renewable energy sources to help meet carbon emission reduction targets. Industrial consumers account for 63% of consumption, followed by households (20%) and district heating companies (17%).

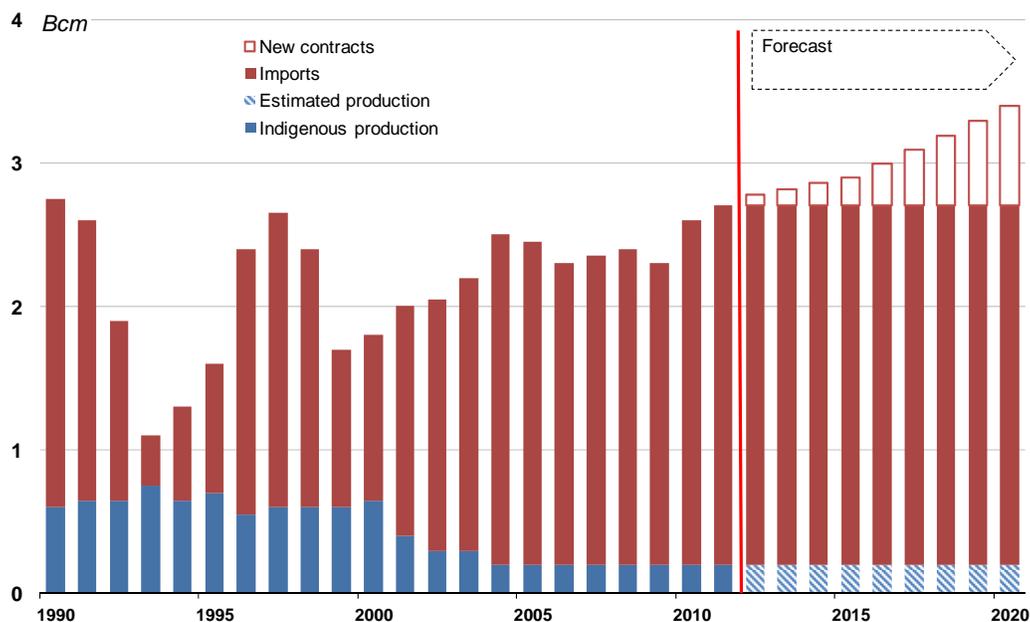
A World Bank financed study, the *South East Europe Regional Gasification Study*³⁶, forecasts gas demand for 2015 to be 2.9 bcm, and 3.4 bcm in 2020. Demand is expected to be driven by increased household consumption and industrial demand through planned developments in distribution networks. This is underlined by the existing energy strategy of the Government of Serbia³⁷ which will be revised shortly.

Serbia relies heavily on imported gas from Russia and in 2011 imported well over 90% of gas from Russia. In mid-2012 Serbia signed a long term supply contract with Gazprom for up to a maximum 2.5 bcm/year until 2020. With these contract terms in place, gas import gap over the short to medium term are likely to arise and they could be as large 0.7 bcm by 2020. This is shown in Figure 14.

³⁶ Available from the World Bank on <http://issuu.com/world.bank.publications/docs/9780821378649/1?zoomed=&zoomPercent=&zoomX=&zoomY=¬eText=¬eX=¬eY=&viewMode=magazine> and from the Energy Community on <http://www.energy-community.org/pls/portal/docs/254188.PDF>

³⁷ Energy sector Development Strategy of the Republic of Serbia by 2015, Belgrade 2005

Figure 14 Serbia's natural gas demand, production and imports



In light of recent supply interruptions due to a variety of reasons, Serbia is looking to diversify its gas supply and increase security of supply through gas storage and interconnections with neighboring gas markets. Figure 15 shows Serbia's current and planned supply corridors and infrastructure developments, which include:

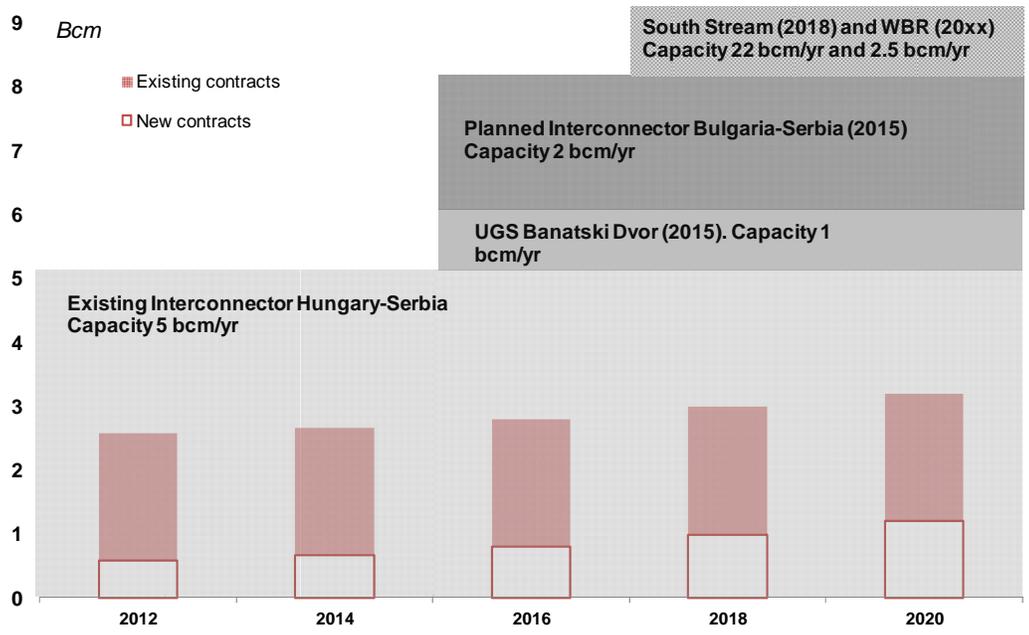
- o The existing *interconnector Hungary-Serbia* with a maximum capacity of 5 bcm/year, with around 0.8 bcm/year transmission capacity to Bosnia. However, Serbia contracts only 1.8 bcm/year to be transported through this interconnector, leaving spare capacity in the pipeline.
- o *The Banatski Dvor underground gas storage (UGS)* is expected to be completed by the end of 2011 with an initial capacity of 450 mcm/year and a planned expansion in 2015 to 1 bcm/year.
- o The *interconnector Bulgaria-Serbia*, which has the capacity of 1.8 bcm/year and is expected to be completed in 2015.
- o The Russian planned *South Stream pipeline* is also expected to supply a proportion of its capacity to Serbia.
- o The *EU Gas Ring interconnector* with FYR Macedonia has been delayed, with no estimation of when it will be completed.

Figure 15 Serbia's current and planned interconnectors and supply corridors



Comparing the possible import gap in the short to medium term with planned capacities in Serbia, shows that Serbia has enough spare capacity to cover its potential future import gap. Figure 16 shows the timing for renewal of contracts and required new contracts for Serbia to cover future demand as stacked columns against the backdrop of possible import capacities.

Figure 16 Serbia's import demand and planned infrastructure



The figure shows that the interconnector to Bulgaria will be the only way to diversify Serbia's supply sources away from direct Russian gas supply under the premise that one of Bulgaria's southern interconnectors will be built. There is therefore considerable scope for Bulgaria to export gas to Serbia in the short to medium term if Serbia pursues a policy of supply diversification. With the planned interconnector Bulgaria-Serbia, Serbia will eventually have the alternative to contract gas from the Caspian region. However, the amount contracted will be limited to the capacity of the interconnector (1.8 bcm) and also the ability for Bulgaria to contract sufficient gas through its southern interconnectors.

FYR Macedonia

The natural gas market in FYR Macedonia is underdeveloped and only a small part of the northern part of FYR Macedonia is gasified. The only natural gas interconnection pipeline is currently at the border of FYR Macedonia and Bulgaria, with a capacity of 0.8 bcm/year, transporting Russian gas into FYR Macedonia. The current gas infrastructure is under-utilized; in 2012 only around 10% to 15% of the capacity was utilized.

Natural gas consumption has increased steadily since 2004 but is still at a very low level, reaching 120 mcm in 2012. Natural gas is mostly used in industries (final consumption) and by district heating companies (heat production). Currently, there is no gas distribution network to serve households in FYR Macedonia, although two municipal authorities are planning the development of gas distribution networks providing access to 20,000 households at a cost of €10 million.

The Ministry of Economy estimates that consumption will increase significantly over the next few years due to the construction and operation of several combined heat and power plant (CHP) expected to be operational post 2014 and increased domestic gas consumption. Although natural gas only accounts for 3% of FYR Macedonia's Total Primary Energy Supply (TPES), it is estimated that demand for natural gas in the period 2015-2020 could reach around 1 bcm/year.³⁸

FYR Macedonia only has one supply corridor, the interconnector Bulgaria-FYR Macedonia. There are no confirmed plans for new interconnectors apart from those as part of the proposed EC Gas Ring, connecting FYR Macedonia with Serbia and Albania, each with proposed capacity of 2.5 bcm/year.

If these growth demand forecasts are realized, FYR Macedonia is likely to face a supply shortage in the medium term while being fully reliant on Russian gas supplies delivered through Bulgaria. FYR Macedonia's prospects for diversifying its sources of supply depend on developments in other countries and the region, such as the EC Gas Ring proposals. If the EC Gas Ring projects are not implemented in the medium term, additional interconnector capacity would be needed and new interconnector capacity to Bulgaria could be an alternative. This might also allow

³⁸ Ministry of Economy (2010), Strategy for Energy Development in the Republic of Macedonia until 2030

FYR Macedonia to diversify its supply sources, depending implementation of the import options being considered in Bulgaria.

Greece

Greece is an important gas partner for Bulgaria with pipeline connections to Turkey and LNG import terminal and storage facilities in Revithoussa. Currently, Bulgaria has one interconnection with Greece in Kula. This interconnection serves as an entry point for Greece to receive Russian gas, and as shown in the January 2009 crisis, reverse flow on this interconnector is possible.

Consumption of natural gas has increased significantly over the last decade, more than doubling to reach 4 bcm in 2008. In 2009 and 2010, due to a severe economic slowdown, consumption dropped significantly to 3.4 bcm and 3.7 bcm respectively. A large share of natural gas demand came from electricity generation, averaging around 71% of demand between 1999 and 2009. Although Greece produces a small amount of natural gas, most of its consumption is covered from imported gas (75% of total consumption) which in 2009 came from LNG sources at domestic terminals (22%), Turkey (20%) and Russia (57%).

The Public Gas Corporation (DEPA) provides several demand forecasts for Greece ranging from estimated levels of 5.9 and 8.1 bcm by 2015 and 6.2 and 8.8 bcm by 2020. In light of the most recent economic and political events in Greece, it would seem more prudent to adopt a cautious approach to demand developments and assume the lower range of demand forecasts.

DEPA has three long term contracts with Russian Gazexport, Algerian Sonatrach (LNG) and Turkish Botas for natural gas supply with a total volume of 4.2 bcm/year until 2016. The long term contract with Russia for 2.4 bcm/year of gas will end in 2016. This means that Greece has a certain volume of gas of 6.6 bcm/year until 2016. At a current demand of 3.5 bcm/year estimated for 2011, this would suggest that no supply shortage is to be expected in the medium term in Greece.

Figure 17 Greece's current and planned supply corridors



Figure 17 shows Greece's supply corridors and planned infrastructure. Greece has a diversity of supply sources, which it can utilize to increase supply. The LNG terminal in Revithoussa is not yet used to its full capacity and has spare capacity for gas storage and supply; Greece has long terms plans to expand its role in import and as a trading facility with other countries. Similarly, the Turkey-Greece interconnector (TGI) has a large capacity of 11.6 bcm/year, as it is planned to be part of the Interconnector Turkey-Greece-Italy (ITGI), and it is not used to its full capacity. In addition, in May 2010, Greece signed a non-binding Memorandum of Understanding with Qatar for LNG import, which includes plans to import Qatari LNG and to construct a €3.5 billion LNG terminal with a capacity of 7 bcm/year in western Greece.

This would suggest that Greece has ample potential supply sources to cover its domestic demand and is very likely also to be in a position to export alternative supply sources or provide access to its LNG facilities to its neighboring countries. For Bulgaria the interconnector to Greece would therefore not only give access to Caspian (Mainly Azeri) sources via transit from Turkey but also to the LNG spot markets.

Turkey

Turkey is situated between the gas-rich Caspian region with extensive resources and gas-consuming Europe. In this strategically placed position, Turkey plays an increasing role in the transit of oil and gas supplies from Russia and the Caspian region into Europe and its East-West pipeline route is part of the EU's Southern Corridor policy.

Gas consumption in Turkey has grown at a rapid rate since the late 1980's reaching 39 bcm in 2010. Natural gas makes up over 30 % of total energy consumption with the main consumer being electricity generators (56% of total consumption) and industrial and household consumption making up over 20% each. Demand is expected to continue to increase in the future, as Turkey plans to develop more gas fired power plants. Household and industrial consumption is also expected to grow along with the development of more distribution pipelines and expansion of distribution areas following privatization of the distribution companies.

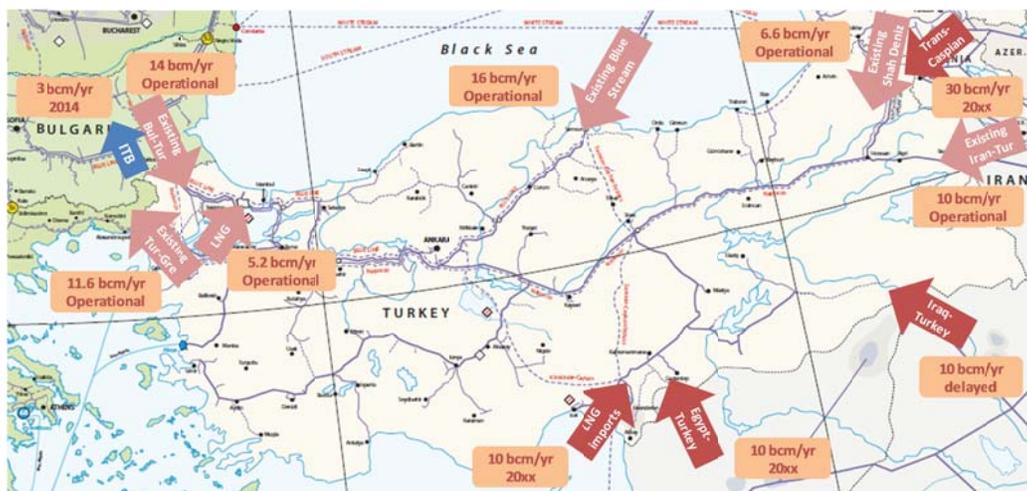
Turkey produces small amounts of natural gas, covering only around 3% of domestic consumption between 1999 and 2009. Natural gas production in 2010 was 0.7 bcm. Turkey imports natural gas mainly from Russia. However, the share of Russian imported gas has been declining in recent years (54% if imports in 2010), as Turkey diversifies its gas supply by importing from Iran (15% maximum contract but actual import volume much lower) and Azerbaijan (15%, though with an agreement signed to double this supply), and also importing LNG from Algeria (13%) and Nigeria (3%). LNG capacity accounted for roughly 22% of gas imports in 2010.

Comparing future demand levels with contracted future supply levels shows that Turkey could face an import gap by 2015 onwards (Figure 19). The first Russian contract expired in 2012, and was not renewed, possibly resulting in a small supply gap after 2014³⁹. The contract for LNG from Algeria will expire in 2014, which would result in supply gaps of 7 bcm in 2015 and up to 18.2 bcm in 2020. There is however little doubt that these contracts (except for the West Bulgarian route contract that already expired) will be renewed in light of significantly rising demand levels.

Similar to Greece, Turkey has highly diversified supply sources, and the capacities of the existing supply corridors, shown in Figure 18, can accommodate further increases in supply. The existing infrastructure allowing gas to flow into Turkey allows a volume of 53 bcm/year to be imported (6.6 bcm/year from Azerbaijan, 10 bcm/year from Iran, 16 bcm/year from Blue Stream, 5.2 bcm/year from LNG, 14 bcm/year from Russia via Bulgaria). This would be sufficient to cover demand levels until 2018. If all planned other projects are added to this, such as the interconnector to Iraq (10 bcm/year), the Trans Caspian pipeline (as part of the supply to the Southern Corridor pipelines including Nabucco) and a new LNG terminal on the South coast (10 bcm/year), it becomes clear that Turkey can and will play an important role, not only as transit country for Caspian gas but also as exporting country and major gas transporter to its neighboring countries in Europe.

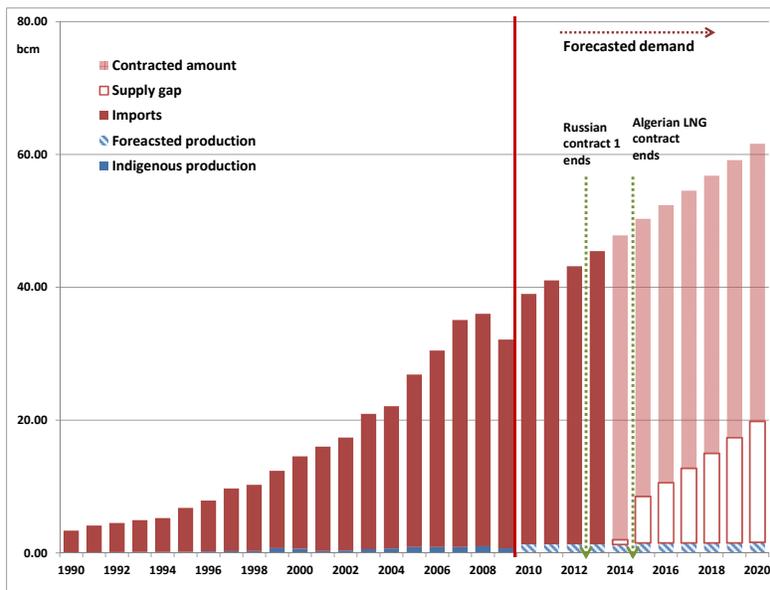
³⁹ Although supply shortages are unlikely if Turkey is able to import to the maximum amount on its contracts, which generally allow 15-20% above the annual contract quantity.

Figure 18 Turkey's current and planned supply corridors



A sign of Turkey's potential to export gas is that Turkey was having problems with meeting its imported gas contract commitments (take-or-pay) as per the long term contracts in 2008 after a drop in demand. In 2009, total imported gas volumes exceeded domestic consumption, and Turkey had to pay for the undelivered amount to Russia and Iran as per the take-or-pay clauses of their contracts. Anticipating this situation of oversupply, Turkey started to re-sale⁴⁰ and export natural gas in 2007. The amount of natural gas exported increased since then, from only 0.03 bcm in 2007 to 0.66 bcm in 2010.

Figure 19 Turkey's historical and forecasted natural gas demand



Source: data from BP Statistical Review of World Energy Sources 2010, International Energy Statistics (IEA), and various other sources

⁴⁰ Resale is only allowed on some of its contracts, e.g. the Azeri contract

Regional integration and creation of a gas market

Bulgaria and its surrounding countries will need to coordinate and harmonize their legal and regulatory environment in order to create a competitive regional gas market or, more simply, promote bilateral cross-border trade. Regional or at least bilateral cooperation on resolving several issues related to operation of interconnected networks is required, covering issues such as:

- o Creation of an investment friendly regulatory environment
- o Consideration of capacity needs for cross border transport
- o Defining and agreeing capacities of new pipelines
- o Joint companies or clearly defined project responsibilities for project companies in each country for development of cross-border infrastructure
- o Capacity allocation mechanism and congestion and other operational management procedures (generally defined by the relevant EU organizations (CEER/ERGEG and ENTSO)
- o Interoperability, such as quality, interconnection agreements, operational balancing agreements etc.
- o Treatment of storage, regulated storage tariffs and harmonizing access to foreign storage capacities

A key part of the guiding framework for cross-border gas trading among Bulgaria and its surrounding countries is the EU Directive 2009/73/2 concerning common rules for internal markets in natural gas and other related directives. Bulgaria, Greece and Romania are EU members and must fully comply with the Directive. Serbia and FYR Macedonia are Contracting Parties of the Energy Community and must also comply with the Directive⁴¹. Turkey is not a Contracting Party and is not bound by the provisions of the Directive⁴².

One of the key provisions in the Directive is Third Party Access (TPA). TPA requires open and non-discriminatory access to the gas networks by those who do not own the physical network infrastructure. While TPA establishes the basis for open and competitive gas trading across interconnectors, it also may inhibit market development by making it more difficult for new investment (in interconnectors and other cross-border pipelines) to be financed, since the guaranteed pipeline revenues required for debt financing are not assured under TPA.

The Directive specified regulated TPA for gas transmission, distribution and LNG assets, while negotiated TPA is allowed for gas storage. TPA to transmission and

⁴¹ Though transitional arrangements could have more flexibility

⁴² Although in many of its energy market issues it is tending to follow the EU approach - though this applies less to gas than, say, electricity

distribution systems and LNG facilities must be based on published tariffs, applicable to all eligible customers, including supply undertakings. These tariffs or the methodologies used to calculate these tariffs shall be approved by the national regulator and published before it comes into force. In the case of interconnectors between countries, the transmission system operators shall have access to the network of the other transmission system operators.

Existing infrastructure

Much of the gas network infrastructure in Europe, especially in South East and Central Europe, was constructed in conjunction with long term gas contracts and access to capacity was arranged under associated long term capacity contracts. This means that TPA in these existing infrastructures, if there are any, is offered on a negotiated basis rather than the required regulated basis.

EU Directive 2003/55 allowed long term legacy contracts to remain valid and implemented under the terms applied at the time of their conclusion. Hence, pipelines transit agreements used under existing long term contracts fell outside the TPA regulation till Directive 2009/73 came into force.

New infrastructure projects

New infrastructure projects, such as interconnectors, storage and LNG facilities, will fall under and will have to comply with the Directive's TPA regulation. However, the Directive allows for exemption from the TPA rules⁴³ under the following conditions:

- o The investment must enhance competition in gas supply and enhance security of supply
- o The level of risk attached to the investment is such that the investment would not take place unless an exemption was granted
- o The infrastructure must be owned by an entity that is separate, at least in its legal form, from the system operators in whose systems that infrastructure will be built
- o Charges are levied on users of that infrastructure
- o The exemption is not detrimental to competition or the effective functioning of the internal gas market, or the effective functioning of the regulated system to which the infrastructure is connected.

The exemption also applies to significant increases of capacity in existing infrastructures and to modification of such infrastructure that enable the development of new sources of gas supply.

⁴³ Many new pipeline projects, especially cross-border projects, have been permitted partial exemption from TPA to facilitate the guaranteed capacity allocation and pipeline revenues necessary for project financing

Annex 1: South East Europe gas market opportunities

Exemptions to TPA rules will be granted by relevant regulatory authority on a case-by-case basis. Project developers must apply for a TPA exemption, providing documented reasons for its application, to the regulatory authority. In the case of interconnectors, any exemption decision will be taken after consultation with the other regulatory authority concerned. The details of the exemptions, such as whether the exemption covers all or only part of the project, the duration of the exemptions and other conditions for the exemptions will be made on a case-by-case basis.

In this sense, the Directive provides room for regulatory authorities to provide exemption to TPA rules under different conditions across Europe. Some harmonization will be required if a regional gas market is to be developed.

A2 Annex 2: Modeling details

This annex outlines the analytical concepts and methodology used as well as the modeling approaches of each of the three building blocks (Demand, Supply, Investment options) and the commercial and cost calculations.

Analytical concepts and methodology

The identification of those investment options that minimize costs or maximize commercial benefits while meeting the defined security of supply criteria in any given year are analyzed using ECA's gas storage and supply/demand balancing model. This has been adapted to fit the Bulgarian data and investment options. The gas model is an Excel based model to simulate the balancing of supply and demand for gas on given (high demand or low supply) days, over a period of years. Two key concepts are used in the model, which warrant particular attention:

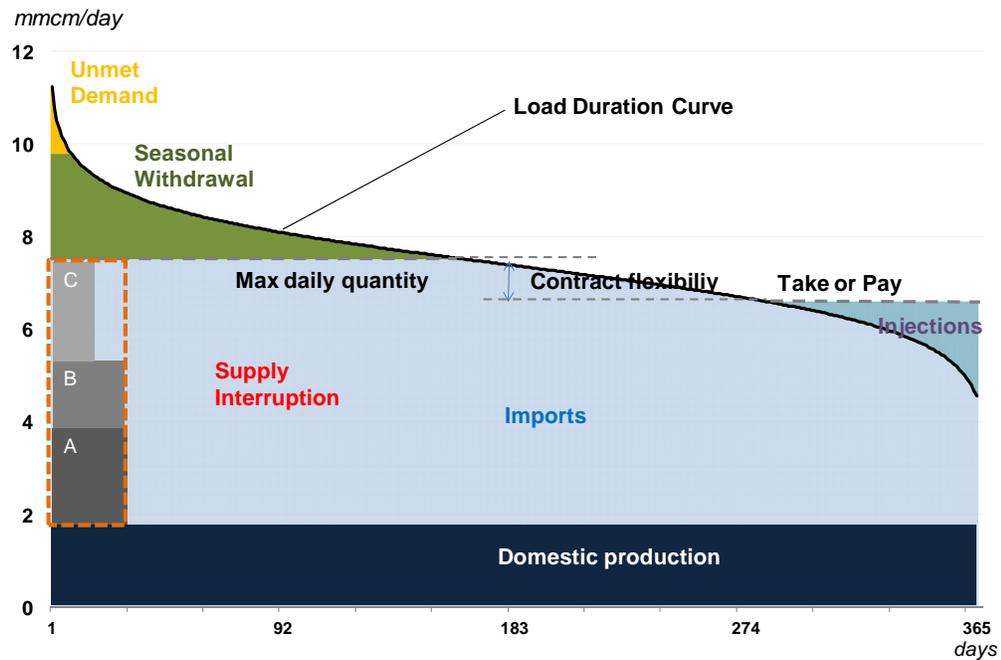
- o *The load duration curve (LDC)*
- o *The cost curve*

Each will briefly be described in this section.

Load duration curve

The load duration curve (LDC) is a representation of the balancing of daily demand with available supplies. Daily demand levels in any given year are ranked from left to right by their demand (load) levels. The height of the black curve in Figure 20 shows the daily demand, with the day of maximum demand (usually the coldest day) shown first and the day of least demand shown last. The volume under the curve is total annual demand.

Figure 20 Illustrative load duration curve for SoS



Supply volumes are represented by the lighter area in the figure. The area of the rectangle for each supply option reflects the total volume of gas for that option, while the height of the rectangle is the maximum daily deliverability. Supply is constrained upward by the maximum daily quantity in the supply contracts and maximum daily production and downward by the minimum take or pay volume as specified in import contracts. The seasonal withdrawals, even though represented as one block in the figure, will be a combination of available storage options⁴⁴ to help balance supply and demand on the days of maximum demand.

To ensure security of supply, enough storage must be available to cover a 30 day interruption of the main gas supply contracts on peak demand days. In the diagram, this is represented by the dashed rectangle. A set of storage options must therefore be readily available that are able to fully cover the block of gas that would have been supplied by the largest supplier had there not been an interruption. In the diagram the illustrative three options A, B and C are not sufficient to cover the full interruption.

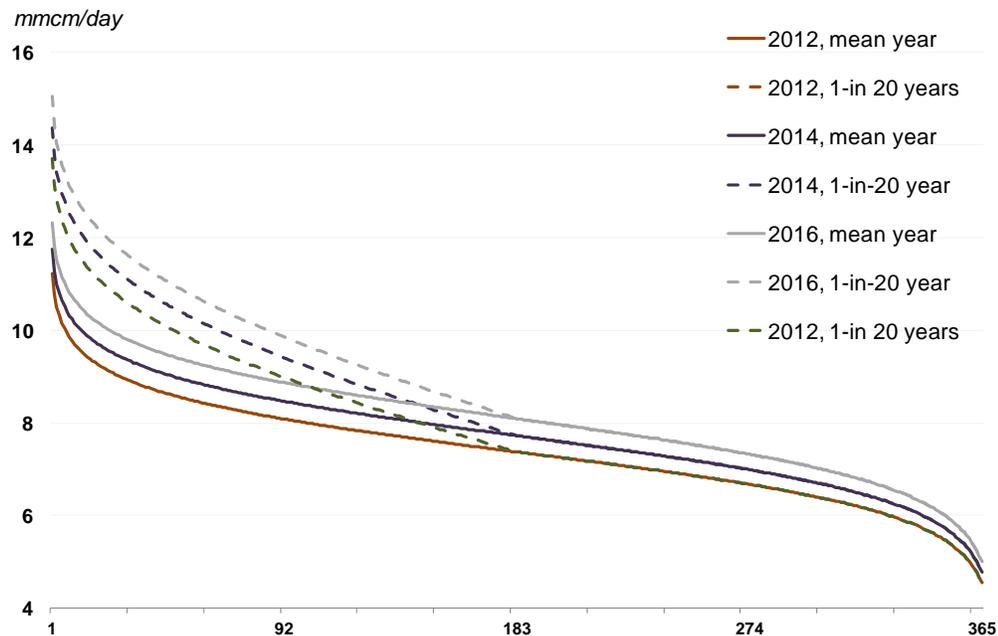
The shape of the LDC for Bulgaria will depend on a variety of factors including demand scenarios, what type of year is simulated (mean year, 1-in 20 year) and for which year the LDC is simulated. Figure 21 presents LDC's for three example years (2012, 2014, 2016) under the base case demand forecast presented in the previous section for both 1-in 20 years and mean years. As the diagram shows, the base case demand scenario only assumes marginal increases in the peak day demand over the next four years (from 11.2 mmcm to 12.3 mmcm). The increased period demand for the 1-in-20 year is a 22% mark-up. The total load that would have to be covered in

⁴⁴ For simplicity, the term 'storage' is used to indicate collectively all the options which allow demand in excess of contractual supply to be met.

Annex 2: Modeling details

case of a 30 day supply disruption is 288 mmcm (2012), 300 mmcm (2014) and 315 mmcm (2016) for the mean year.

Figure 21 LDCs for Bulgaria

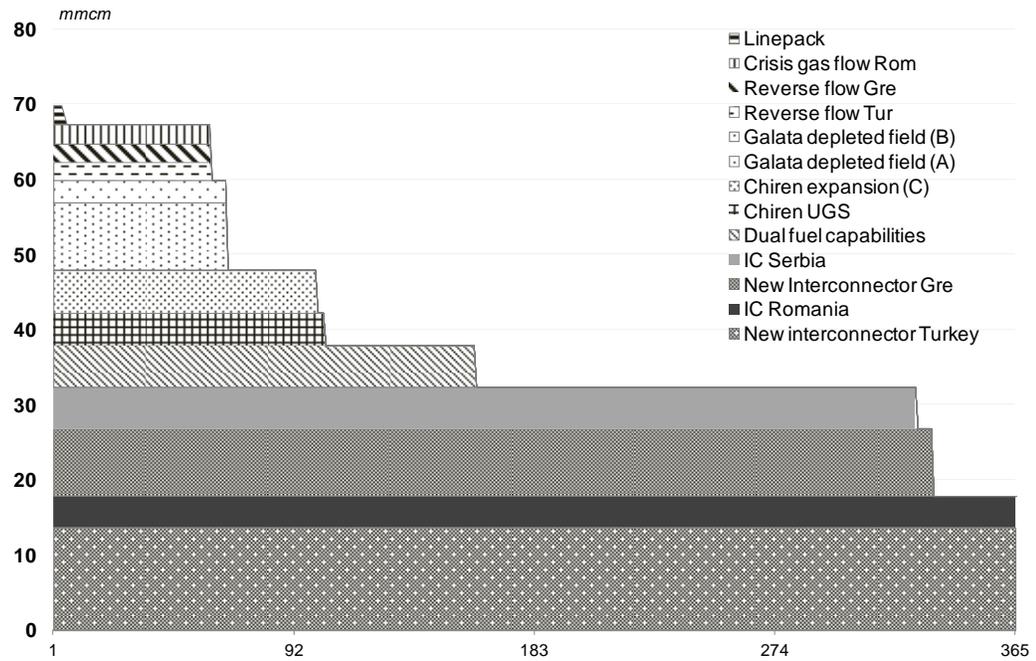


To fully cover the 'gap' that a possible interruption creates, two key requirements must be met:

- o The combined *daily maximum deliverability* of all investment options must be sufficient to cover peak daily demand on the coldest days. In the diagram this translates to the *height* of the supply interruption rectangle.
- o The investment options in combination must provide enough *storage to cover the length of the interruption*. In the diagram this is reflected in the width of the rectangle. The total amount of gas available to meet the supply interruption (storage and other options) is equal to the *area* of the rectangles that fit under the load curve.

Besides selecting those investment options that meet the technical criteria, the modeling approach seeks to identify those options that can be realized at least cost, meet the technical requirements *and* (especially in section 5) offer most additional commercial benefits. Figure 22 shows the assumed deliverability of each investment option included in the analysis.

Figure 22 Duration of deliverability of each option

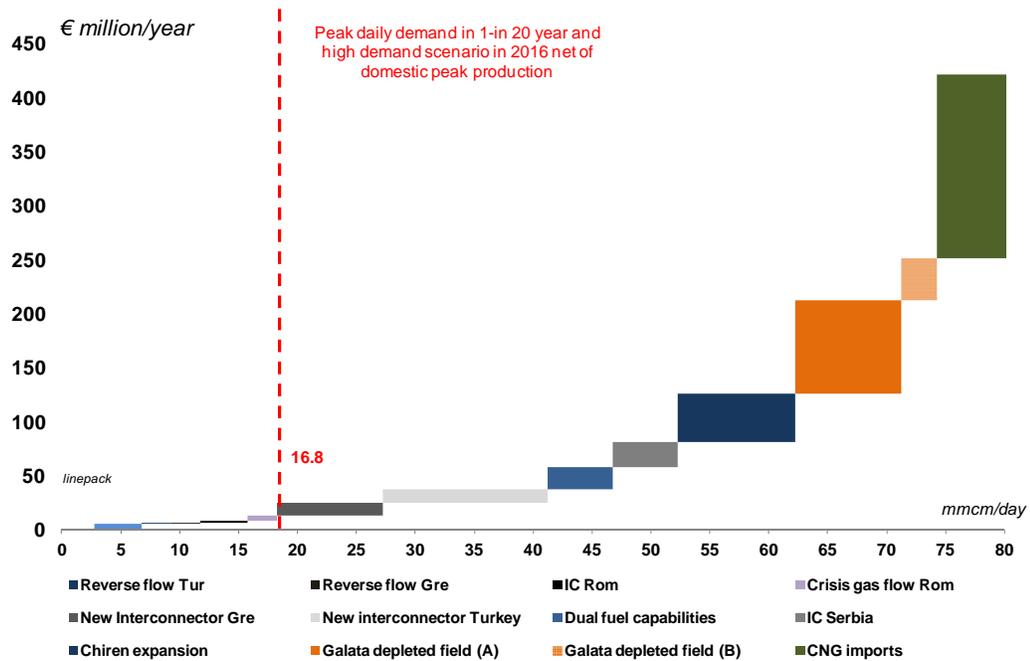


Cost curve

As a key challenge is to identify the least cost options, it is necessary to obtain annual cost estimates based on amortized investment costs and operation and maintenance costs for each available option. These annual cost estimations can then be used to prioritize the respective investment options for every year.

A cost curve helps to visually present this concept as it shows all options that contribute to meeting peak day demand in case of a supply disruption. All investment options are ranked by annualized costs and drawn against their peak deliverability. Figure 23 depicts all investment options as individual blocks where the height of each block shows the annual costs of each investment option (in 2012 values) and the width shows the maximum daily deliverability of the option.

Figure 23 Cost curve of options



The dashed line in the above figure represents maximum peak daily demand for an interruption on the coldest day of the year 2016, assuming it is a particularly cold winter (occurring with a 5% probability, i.e. a 1-in-20 cold year) and a high demand forecast has been applied. In this particular case peak day demand is 19.6 mmcm/day, but we deduct expected domestic production (1.8 mmcm/d) to draw the threshold curve. Where the dashed line crosses one of the investment options indicates the 'marginal investment option' required. In other words, all investment options to the left of the dashed line would be required to cover the presumed one-day supply interruption in 2016. In this case only a small share of the interconnector to Greece would be needed to cover peak day demand. The combined annual cost of all investment options in this case (assuming very high future gas demand) would be around €25 million. This could be partly outweighed by the commercial benefits accruing from the Greece interconnector. This would, however, depend on the construction of northern interconnectors.

The curve shows that domestic production and linepack are the lowest-cost investment options at close to zero costs. This is followed by the reverse flow agreements, mainly because of their low investment costs. The costs of Chiren and the crisis gas flow from Romania follow. The dual fuel option is marginally cheaper than the two interconnectors. The Chiren expansions and Galata conversions follow.

The cost curve is insightful in that it can be used to identify the minimum annual cost figure for the set of options covering peak day demand in any given year. However, care should be taken when drawing conclusions from this curve on its own due to its limitations⁴⁵. These include the lack of the time dimension and

⁴⁵ These include the fact that the curve does not take account of the year of construction of each option; it only shows the daily deliverability and fails to take into account the length of deliverability of each option.

Annex 2: Modeling details

thereby length of availability of each option, as shown in Figure 22. The cost curve in Figure 23 also shows all available options, however not all options are available every year. This means that the cost curve drawn for each year would look different and they would also vary for the scenario being simulated. It is only used in this report as a visual representation of the modeling approach; it is not directly used in the model. The study's modeling approach consists of a cost minimization procedure that selects those options that in combination meet the peak day demand and the demand over the length of the interruption at the lowest possible combined costs in the selected year. The model allows the simulation of different interruption scenarios (7, 15, 30 or 60 days), for different years (2012 to 2020), for different type of years (1-in 20, mean year) and with different demand projections (High, Low, Base Case).

Demand

The time horizon of the analysis is taken to be until 2020. Demand over that time is expected to vary along two dimensions

- o **Expected annual growth of gas demand until 2020:** For the purpose of this analysis and based on gas stakeholder consultations, we have constructed a High (10% p.a. growth), Low (4%) and Base Case (1.1%) growth scenario⁴⁶. This will shift the entire load duration curve up or down.
- o **Number of heating degree days:** Gas demand will vary across years in relation to the coldness in any particular year. In Bulgaria's case, this means the colder the temperature in a year, the higher are consumption levels in that year. The concept of a 1-in-20 year is introduced in the analysis to take this possible demand side variation into account. A 1-in-20 year is defined as a year that lies in the top 5 percent of coldest years. A regression analysis of heating degree days against annual consumption was used to identify the added demand level for the 1-in-20 year. Diagrammatically, the 1-in-20 year demand scenario translates into a kink of the load duration curve on the 180 coldest days of the year.

The variants of the different demand scenarios at the example of the load duration curve in the year 2015 are shown in Figure 24. Evidently the worst case scenario for a supply interruption is in the High demand scenario for a 1-in-20 year, as the combined maximum deliverability of all storage options must add up to 20 mmcm/day to avoid un-served demand.

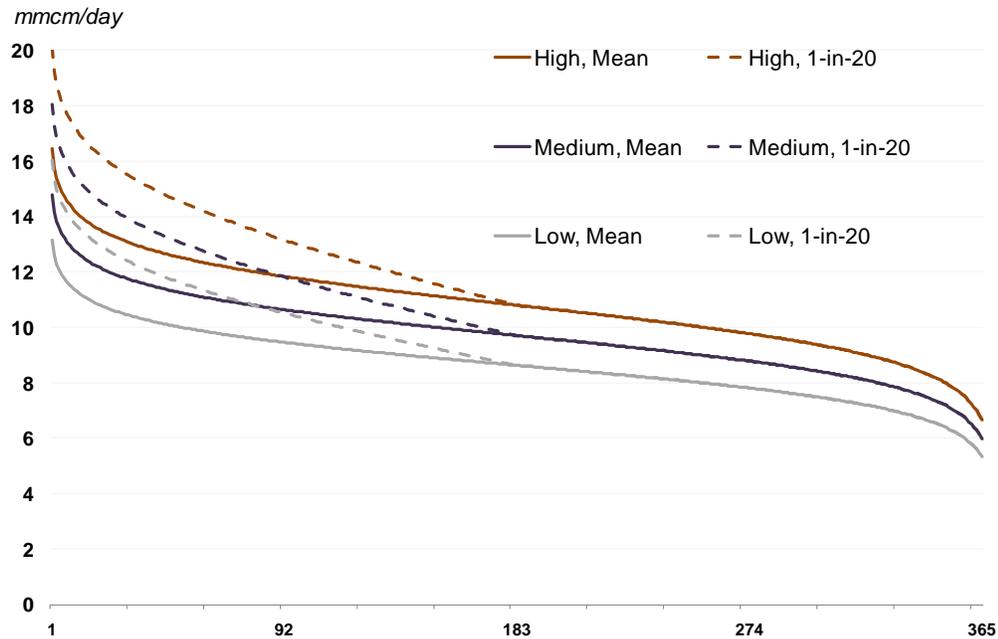
The variation in the demand scenarios helps in conducting sensitivity analyses to identify the investment options that are required. For the purpose of this analysis, we will focus on the best case scenario (low demand, mean year) and the worst case scenario (High demand, 1-in-20 year). This will give an indication as to the

⁴⁶ While the High and Low demand scenarios were provided by Bulgarian stakeholders, the Base case demand scenario was presented in Section 3.1 and is the benchmark demand case according to GoB's Energy Strategy. The so-called Upper and Lower scenarios derived from the Energy Strategy have not been modeled since they are considered less relevant from a gas SoS point of view

Annex 2: Modeling details

minimum investment options required and the maximum of investment options needed.

Figure 24 Demand variations: example for LDC in 2015



Supply

Gas supply in Bulgaria comes from two sources:

- o **Domestic production** from the Kavarna and Kaliakra field. The reserves of this field are estimated to be relatively small and annual production over short and medium term is estimated to be at a level of 0.1 bcm/year. This represents roughly 4% of annual consumption. We acknowledge that efforts are currently made to increase domestic gas production at other fields and gas exploration activities are currently underway, however due to the uncertain nature of these developments, we have decided to exclude them from the analysis.
- o **Russian gas contracts** provide all gas that is not covered by domestic production. Hence, Bulgaria is almost entirely dependent on Russia for its gas supply. Bulgaria has is expected to renew its gas contract with Russia. Due to confidentiality reasons, details of the contract cannot be disclosed. On the basis of industry experience and with confirmation from Bulgarian counterparts, we assume key parameters of the supply contracts. The key features include take-or pay minimum value, maximum daily quantities and annual contract volumes.

For each scenario that is assessed in the sections below, a supply interruption is simulated. This will either be a 7, 15, 30 or 60 day supply interruption. As noted previously, regulations require this to be simulated on the days of the year where demand is highest. This will therefore determine the width of the supply

Annex 2: Modeling details

interruption rectangle in Figure 20. The longer the interruption, the larger will be the rectangle that possible storage options will need to fill.

As with the different demand scenarios, the variability of length of supply interruptions provides a further dimension along which the sensitivity of results can be tested. Evidently, a 60 day interruption in a High demand scenario for a 1-in-20 year will be most challenging and costly to bridge.

Investment options

For each investment option, key features can be changed in the model to gauge the sensitivity of the costs and commercial benefits for each option. They are:

- o Assigning a share of the capacity to different activities
- o Changing price mark-up parameters to account for demand levels in offtake markets or contractual parameters.

Besides the key technical parameters of the investment options the following parameters are also of vital importance to identify the costs and benefits for each investment option:

- o Share of total capacity (storage or throughput) dedicated to commercial operations if there is no interruption. Chiren underground storage capacity for example could be split into a share that will be rented for commercial use, say 20%, and a share dedicated to security of supply (80%).
- o Of the share dedicated to security of supply (80% of total capacity in this example), a sub-share can be directed to seasonal variations (90%) and another to strategic variations (10%). This would imply that in case of a supply interruption 10% of the storage facility would be directly deployable to bridge the supply gap.
- o Of the share dedicated to commercial activities (20%), a sub-share can be defined to be interruptible. For ease of analysis, this has been chosen to be 100%, meaning that in case of a supply interruption all commercial contracts are annulled and capacity is available for to cover domestic demand.

All three parameters will affect the profitability of the investment option and its effect on security of supply differently. The allocation of capacity to commercial operations will increase profitability: the greater the proportion of storage allocated to commercial activities, the greater are the commercial benefits of the investment options. The seasonal and strategic split will not be decisive for the effect on security of supply, as all available storage would be used during a supply interruption in any case. The interruptible share will determine both profitability and security of supply of investment option: the greater the interruptible share, the smaller the working volume available to cover the supply shortage, commercial benefits however would be higher through a higher tariff (contract firmness multiplier) and delivered gas during supply interruption.

Cost and commercial benefits calculation

For the purpose of this analysis, costs are defined as the annuitized capital and operating costs for each option spread over the lifetime of the storage option. The cost figure is therefore not a cash flow but rather an annual economic cost estimation. The advantage of using this type of costing is that it is independent of the payment period, which is still uncertain for many of these projects as of mid-2011.

The capital costs are therefore annuitized i.e. spread over the whole lifetime of the asset discounted at the chosen rate of 10%. Annual OPEX figures are added to obtain a present value figure of annual costs of the storage option. These cost figures are used to prioritize investment options by costs to identify the set of investments that will ensure security of supply while minimizing costs.

The analysis however goes beyond minimizing cost subject to daily and storage deliverability requirements in case of a supply interruption. Commercial benefits for each option are also assessed. The calculation of the commercial benefits follows a three step procedure:

- o A commercial per unit tariff is calculated. The total present value fixed costs of the investment are annuitized over a commercial discount rate (15%), which is higher than the market discount rate (10%). This takes into account the commercial risk associated with the operation, resulting in a higher annual fixed costs than if 10% were used. Variable OPEX is added to the annual costs and the sum is divided by the storage volume dedicated to commercial operations. This gives an annual cost recovery tariff.
- o The cost recovery tariff is multiplied by a contract firmness multiplier, which will be determined according to the share of commercial volume that can be annulled in case of a supply interruption. The mark-up on cost recovery tariffs for commercial operations can be higher, the firmer the contract is.
- o Given that commercial benefits will accrue from either exporting or transmitting gas to further markets downstream, the tariff for each investment option also includes a market specific mark-up. These have been set in light of the gas market analysis in surrounding gas markets. So, for example increasing forecasted demand in Romania falling domestic production levels would suggest that gas flowing through the interconnector from Bulgaria to Romania could be priced at a premium.

The calculated cost in combination with the commercial tariff gives a net benefit value for each investment option. This is not presented in this report, however, it can be used in the model as a prioritization criterion.