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Oil and Gas Sector of GEORGIA in the Transition Period

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OIL AND GAS SECTOR OF GEORGIA IN THE TRANSITION PERIOD
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The publication deals with the current state of oil and gas sector, prospects for its development and energy security of Georgia; it also focuses on regional oil and gas potential, production and delivery prospects to the European market. Special attention is paid to the transit and inland transmission pipelines, their reliability and safety, preconditioning security of supply to local and European markets. It also highligths the issues of harmonization of Georgian energy legislation with the European one and institutional structures as well as the integration of the market into the single energy space, discussing the corresponding legal grounds.

The information presented in this publication, including assessments of the current state of the sector and scenarios for the development of the natural gas market, reflects only the personal opinion of the author, is not related to his job responsibilities and not reproduce the views or positions of his employer or government bodies

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ABREVIATIONS AND PHYSICAL UNITS

ACER - European Agency for the Cooperation of Energy Regulators
AGRI – Azerbaijan-Georgia-Romania Interconnctor
AMBO - Albania-Macedonia-Bulgaria Oil Pipeline
BAP - Burgas–Alexandroupolis (Oil) Pipeline
BAU - Business As Usual
Bcm – billion cubic meter
BS – Blus Stream Pipeline
BTC – Baku-Tbilisi-Ceuhan Oil Pipeline
CAC – Central Asia – Center Pipeline
CACGP – Central Asia – China Gas Pipeline
CCGT – Combined Cycle Gas Turbine
CNG – Compressed Natural Gas
CNPC – China National Petroleum Company
DSO - Distribution System Operator
DWT - Deadweight tonnage
EAOTC – Euro-Asian Oil Transportation Corridor
EASC - Euro-Asian Council for Standartization, Metrology and Certification
EnC - Energy Community
EWGP – East-West Gas Pipeline System
FLNG - Floating Liquefaction of Natural Gas Plant
GE Power – General Electric (Manufacturer of Power Generation Equipment)
GEE - Georgian Energy Exchange
GGTC – Georgian Gas Transportation Company
GOGC – Georgian Oil and Gas Corporation
GNERC – Georgian National Energy and Water Supply Commission (Commission)
HHI - Herfindahl-Hirschman Index
HPP – Hydro Power Plant
IGAT – Iranian Gas Trunk Pipelines
ICP - Intra-Caspian Pipeline
ISO – Independent (Transmission) System Operator
ITO - Independent Transmission Operator
kWh- kilo watt hour
LEWS – Law of Georgia on Energy and Water Supply
LNG – Liquefied Natural Gasd
LPG – Liquide Petroleum Gas
Mcm – million cubic meter
Mbd – Million barrels per day
Mta – million ton per anum
NS – Nord Stream Pipeline

NSGP – North-South Pipeline System
OIES - Oxford Institute for Energy Studies
OTC – Over-The-Counter (trade)
PEOP – Pan-European Oil Pipeline
SCP – South Caucasus Pipeline (Baku-Tbilisi-Erzerum Gas Pipeline)
SCPX - South Caucasus Pipeline Expansion Project
SGC – Sothern Gas Corridor
SOCAR – State Oil Company of Republic of Azerbaijan
SSO - Storage System Operator
TANAP – Trans-Anatolian Pipeline
TAP – Trans-Adriatic Pipeline
TAPI – Turkmenistan-Afganistan-Pakistan-India Pipeline
TBP – Trans_Balkanian Pipeline
TCP – Trans-Caspian Pipeline
TNO - Transmission Network Owner
TPP – Thermal Power Plant
TS – Turkish Stream Pipeline
TTF - Title Transfer Facility (European Gas Trading Hub in Holland)
TYND-Ten Year Network Development Plan (of Transmission Infrastructure)
MCR - Market Concentration Ratio
ULCC – Ultra Large Crude Carrier
VIU – Vertically Integrated Utility
VLCC - Very Large Crude Carrier
WREP – Western Route Exsport Pipeline (Baku-Supsa Oil Pipeline
WS – White Stream Project

FOREWORD

Energy of Georgia faces significant challenges and opportunities. Demand on the main energy products: electricity, natural gas and petroleum products has significantly increased during the recent period. Hindering of construction of large hydro power generation facilities and scarcity of local oil and gas resources predetermine unfavorable tendency of growth of the country's dependence on import. At the same time the process of active implementation of the European legislation into the energy sector of the country has been commenced which is associated with new challenges and significant opportunities.

Ensuring energy security and guaranteed supply of the country's population and economy with affordable energy resources represents a task of critical significance, which is complicated by the geographic location of the country isolated from the partners of the Energy Community and the EU and, inability of supply diversification of the natural gas, which is one of the main components of the total energy balance, will significantly complicate the process of formation of an open and transparent competitive market.

On the other hand, favorable location of the inland territory and seaports connecting to the international supply routes of hydrocarbons between the Caspian region rich in resources and Europe dependent on import of energy resources predetermines successful implementation of the transit projects through the territory of the country, which are playing an important role in ensuring security of supply to word's energy markets. Potential of the neighbor Azerbaijan and other countries of the Caspian region creates further opportunities for the development of new oil and gas transit projects, implementation of which will increase the significance of Georgia as the key player of the international energy market.

The sensible implementation of the new Law of Georgia on Energy and Water Supply, which represents an adapted version of the European Energy Acquis allows to establish competitive market(s) based on organized trade in the relatively short period of time and integrate the energy sector of the country into European structures. As a result, the role of local content in ensuring the energy security of the country will be increased and the threats related to the dominance of state companies of foreign countries in significant segments of the market will be minimized.

Presentment of a systemized results of the studies on the current state of oil and gas sector in such conditions, prospects for its development and energy security of Georgia, as well as the brief but significant information on the regional oil and gas potential, production and delivery to the European markets is extremely important. Special attention has to be paid to transit and inland transmission pipelines, their reliability and safety, preconditioning security of supply to local and European markets. Harmonization of the Georgian energy legislation with the European one and integration into institutional structures of the Energy Community's single energy space, based on the corresponding legal grounds, also represents a highly significant issue and the first priority of Georgia's energy sector structural reforms.

The publication is dedicated to review of the above issues and it consists of the following sections: regional and local oil and gas markets, transit and transmission infrastructure, challenges of the current period of the energy sector of Georgia and some solutions to these challenges.

In fact, it is the first time that the publication has presented concise but comprehensive descriptions and analyses of development of one of the leading branches of the Georgian energy - natural gas sector, geology and potential reserves of indigenous oil and gas fields, projections of demand/supply of natural gas and production of thermal power generation, Georgian natural gas market's possible development scenarios, in English language.

The publication is mainly based on the analysis of activities related to harmonization of the energy legislation, including materials prepared with direct participation and/or under guidance of the author, as well as on scientific papers published in recent years and on information related to the design of the significant engineering projects, such as the Georgian energy strategy project (gas sector), 10-year infrastructure development plans, Feasibility Studies of Strategic Underground Gas Storage and Combined Cycle Gas Turbine Thermal Power Plant, planning and design of transit and transmission pipelines on the territory of Georgia, etc.

Familiarization with key findings of the publication will do an invaluable service to experts and institutions interested and involved in the regional economic and geopolitical issues, and dealing with strategic decisions for the country with regard to the prospects of the development of the Georgian oil and gas potential and transit routes passing through the territory of the country, as well as making decisions in relation to energy market organization and security of supply of the energy resources to Georgia and the entire region. The monograph includes useful information for private foreign investors interested in the oil and gas sector and infrastructural projects of the region.

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CHAPTER I

1. REGIONAL OIL AND GAS MARKET

1.1. GENERAL TRENDS OF DEVELOPMENT

Guaranteed supply of raised economies and growing population with energy resources in parallel with the critically changing climate conditions, is an important challenge to humanity. Global welfare largely depends on the wide use of energy-efficient technologies and renewable, low carbon energy resources. Elaboration and introduction of effective technologies for exploration and the use of hydro, wind and solar power have become priority directions for energy market development. However, the analysis show, that in the next 25-30 years, fossil fuels will maintain the status of a dominant energy resource. At the same time, Significant changes are expected to be made in the overall balance of fossil fuels: natural gas will become the most important source of energy. Due to strong requirement to decarbonize the industry and other fields of human activities. Fossil fuels will continue to dominate the global energy mix, accounting for 71% of all energy sources in 2050, compared with 81% in 2018 [1]. Oil will remain an important energy source, but its share in global energy is expected to decline to 26%, demand for coal will fall intensely to 18%. Natural gas will remain the only resource that will significantly increase its share in the energy balance from almost 22% at present to 27% (1.3% growth annually), reaching 5,966 trillion cubic meters by 2050.

Power generation is expected to experience significant growth; 70% of incremental consumption of primary energy recources will be used for that. Instead of historically dominant oil and coal, power generation will consume renewable resources and relatively low carbon natural gas. The share of coal in power generation will drop for at least 10% by 2040, while the total share of renewable energy resources and natural gas will exceed 40%.

The oil will still retain its leading position among the most used primary energy sources after NG thanks to increased demand from the transportation sector, caused by tripling the number of cars worldwide, despite increasing the popularity of electric cars.

More than half of proven oil reserves of the world are concentrated within the territories adjacent to the Caucasus, in particular, in the Middle East and Caspian region. Saudi Arabia, Iran, Iraq, Kuwait, UAE, and Kazakhstan are among the top ten oil-rich countries having a total of 110 bln tons of consolidated proven oil reserves. The Middle East and Caspian region having significant production and export prospects are considered to be the important sources of supplying oil resources to the international market in the next 20-25 years [2].

As mentioned above, the most intensive growth is expected in gas consumption. The demand for gas will rise to 4,15 TCM by 2030 and to 4,70 TCM by 2040. Dominant trends related to the increase of natural gas consumption have already been observed globally - in 2018, the share of natural gas prevailed 45% in the global growth of energy consumption[3]. In addition, the demand for liquefied natural gas (LNG) was growing on average 3 times faster (annual 6.2% in 2000-2017) [4]. LNG is becoming increasingly important energy source providing new opportunities in terms of energy security, competition and sustainability as well as in terms of new services to customers such as bunkering, transshipment, inter-modal and road transport. The role of LNG is highly important in reducing gas prices, contributing to the switch from coal to gas and diversifying energy services especially during the energy transition. The higher demand growth trend for LNG is expected to be continued in the future (annual LNG production will increase to 530-540 Tones by 2050 with the 50-60% growth) [5].

The increase of the share of natural gas in the global balance of primary energy resources is triggered by its cost-effectiveness and simplicity of usage for power and heat generation compared to other fossil fuels, also by the possibility of effective transportation in liquefied form. In addition, it should also be taken into consideration, that the competitiveness of renewables increases and they will become commercially more attractive in the future. Gas-fired power plants currently working under dominant baseload mode of operation may gradually shif to the balancing mode of operation, which ensures the perspective to increase the role of gas in achieving agenda for Sustainable Development and the Paris Agreement including synergy between gas and renewables through its combination [6].

1.2. REGIONAL ENERGY MARKET

The regions adjacent to the Caucasus are known with the significant gas reserves. Iran, Russian Federation and Turkmneistan are among top five gas-rich countries of the world. On the other hand, the EU gas market develpment forecast shows that the demand for additionally imported gas may increase by significantly. The Middle East, mediterenean countries and Caspian region are considered to be the main supply sources for delivering additional volumes of natural gas to Europe. Apart from environmental factors, the main driver of increasing demand for natural gasin Europe can be the demand for gas for power generation sector [7].

Rich oil and gas resources of the countires in the region, including South Caucasus and Caspian oil and gas producing and transit countries represent one of the ponetial sources for ensuring the security of of supply of the South-East and Eastern European consumer countries and entire international energy market. However, isolated location of some states and the lack of direct connection to the sea ports or major energy consuming centres, as well as the existence of critical sections of transportation controlled by separate states and limited capacity of transportation infrastructure create significant barriers to utilize full potential of region.

Estimated reserves of the Caspian Sea bassin and surrounding land area totals to 6,3 bcm of oil and 8,3 tcm of natural gas. Oil fields are mainly located to the north of the sea, and gas fields to the south.

At times, the Caspian Sea is referred to as the lake due to its isolated location from the world ocean, however unlike the lake, it is not filled with fresh water. Determination of legal status of the Caspian Sea has formal as well as great practical significance. In case it is granted the status of the sea, internationally recognized rules for delimitation of the continental shelf shall be applied in relation of economic activities.

The Caspian sea is surrounded by 5 littoral states: Russia, Kazakhstan, Turkmenistan, Iran and Azerbaijan. The seabed contains oil and gas reserves divided by several shallow zones - north and middle basins are divided by the Mangyshlak shelf and middle and south basins by shallow water Absheron shelf.

In case the Caspian water area is divided into national sectors [8], estimated and proven reserves of Azerbaijani sector can be [9]: oil - 8.5 billion barrels, gas - 51 trillion cubic feet, Iran: oil -0,5 billion barrels, gas- 2 trillion cubic feet; Kazakhstan: oil - 31,2 billion barrels, gas - 104 trillion cubic feet; Russia: oil - 6,1 billion barrels, gas - 109 trillion cubic feet; Turkmenistan: oil -1,9 billion barrels, gas -19 trillion cubic feet. However, these indices may be revised as a result of final delimintation of the Caspian seabed in the southern part of the sea. The division of the northern part of the sebed is almost agreed with Russia, Kazakhstan and Azerbaijan, as well as with Kazakhstan and Turkmenistan and the agreement envisages equal division of bordering blocks. In the south, no formal agreement has been reached between Turkmenistan, Azerbaijan and Iran over the Kiapaz/Serdari and Alov/Araz/Sharag disputable fields.

On August 12, 2018, at the summit of government officials of littoral countries signed the covention on the Status of the Caspian Sea [10]. which envisages the agreement on the establishment of inner and territorial waters, also adjacent (fishing) zones for littoral states having exclusive rights.[1] Gettng the positions closer, in terms of dividing the Caspian water areas into sectors, significantly increases the likelihood of the development of the fields located in disputable areas of the seabed as well as the the prospects of building the TransCaspian oil and gas pipelines. The conventione has been ratified by 4 signatory countries. According to the available information, Iran will soon finalizae ratification procedures.

Article 8 (1) of the convention legalizes the principe of delimitation of the Caspian seabed and subsoil into sectors. it leaves the matter of delimination within the competence of neighbouring countries and supports the idea of regulating the disputable issues through bilateral agreement. Littoral states will presumably agree on the principle of delimitation of the south part of the Caspian sea into national sectors with middle dividing line in the way it is applied in the northern part of aquatory between Russia, Kazakhstan and Azerbaijan and Kazakhstan and Turkmenistan [11].

According to Article 8 (2) of the convention, a coastal state has an exclusive right to conduct ecomonic activities in its own sector or to give permission for such activity.

By signing the convention, formally, submarine cable and trunk submarine pipeline project can be implemented without any hindrance (Article 14 of the convention), for which only two bordering littoral states shall mutually agree.[2]

It is also noteworthy that the convention has practically legalized the military hegemony of littoral states on the Caspian water area (clause 3.6 of the Convention), which can become a hindering factor for the implementation of international economic projects due to the positions of Russia and Iran, despite the fact that, generally, encouraging the development of hydrocarbon potential of the Caspian sea, minimizing possible obstrunting techniological factors for new supply projects is considered to be one of the significant leverages for increasing the security of the International energy market.

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[1] The Convention also prohibits presence of military forces of any country other than a littoral state in the Caspian Sea

[2] In the Environmental Pact which was simultaneously put into operation, it is mentioned that other littoral states have a right to control ecologic compliance of the project with norms established by international agreements (source: Туркмен Довлет Хабарлы, Август 15, 2018

Export of Caspian Energy resources is especially significant for Europe in order to prevent critical dependenence on dominant energy suppliers. therefore, to ensure the security of European energy market, diversify supply sources and routes, the development of the Southern Gas Corridor is really crucial, as it envisages the development of hydrocarbon resource delivery routes from Caspian fields to Europe passing through the South Caucasus and Turkey (or the Black Sea) which will be independent from traditional supply sources of Norway, North Africa and Russia.

Traditionally Europe is one of the major consumer of energy resources along with North America and Far East, despite being the leader in terms of highly developed and energy efficient technologies. Nowadays natural gas represents some 24% of the primary energy consumption of the EU.. Gas is emitting less greenhouse gases than any other fossil fuel. It is widely used by industry, power generation, household and transport sectors (in form of CNG and LNG). After a some decline caused mainly by world financial crisis, natural gas demand is on the rise from 2014 thanks to the substitution of coal and nuclear in many European countries.

Accoridng to BP World Energy Outlook, the use of primary energy resources in the EU member states from 2025-2030 will increase by 4% (1780 M tonnes) compared to 2010 [12], however, pursuant to IEA basic development scenario which envisages sharp reduction of harmful emissions, total demand for energy may reduce by 6% for the same period. Gas demand supposed to decrease slowly from 2025 but would still represent about 90% of the present consumption in 2040 [13].

The key instrument for the reduction of emissions thrugh the realisation of ambitious plans of development of renewable energy resources and replacement of coal and partially oil, is wide implementation of natural gas (see figure), along with the introduction of modern energy efficient technologies. According to the main development scenario, the volume of emissions in the EU countries will reduce by 35% which will provide twice as low energy intensity in Europe compared to the world average indicator.

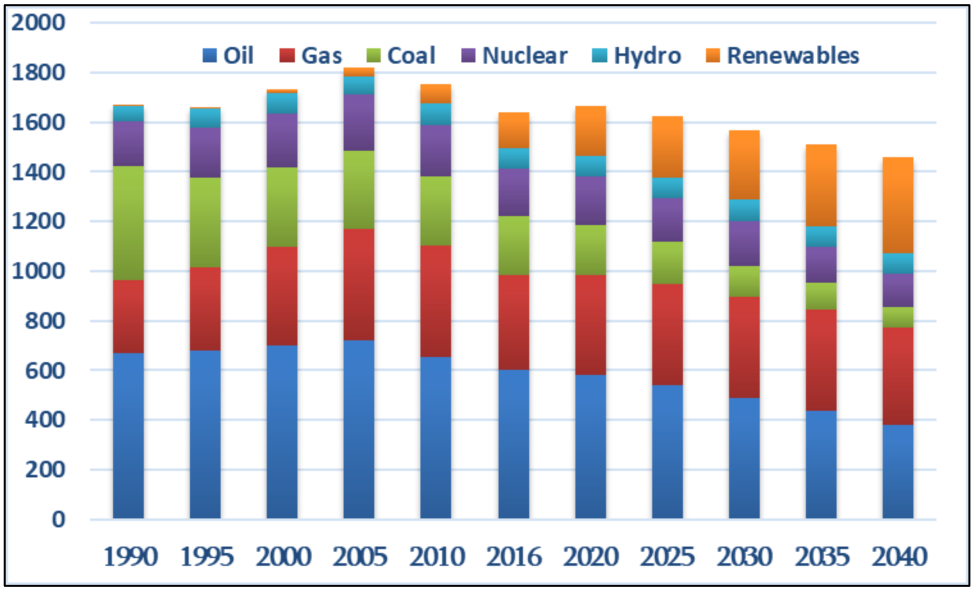

Figure 1.1. Historic and projected primary energy resources consumption in the EU, bln tonns

Production of primary energy resources in Europe is gradually decreasing due to the lack of local resources and depletion after their extensive exploitation, also as a result of strict restrictions set by the environmental policy, impeding the development of non-traditional and offshore fields. Therefore, the import of energy resources is the main source to meet the energy demand in Europe. The dependence of EU (including Britain) on oil imports in 2017 increased up to 80% and gas up to 75%.

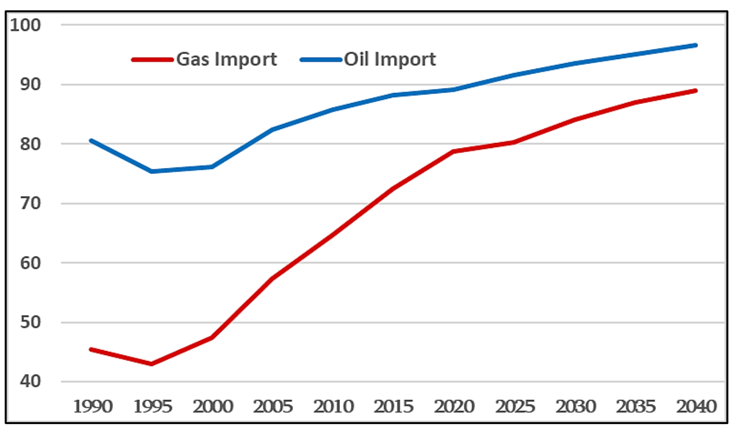

Figure 1.2. Dependence of the EU on oil & gas imports, %

The analysis confirm that the demand for oil in Europe has significantly decreased since 2000, however due to the reduction in local production, the demand for imported oil for the same period increased by 125 ml tons [14]. Main sources of oil supply of the EU remain middle East, Russia and Africa. Among gas importers, Russia, Norway and Algeria (Russia 35-40 % of consumption, Norway 20-25 % and Algeria 7-10%). Gas is supplied through the offshore and onshore pipelines, traversing outside and inside the EU territories. LNG coming from Qatar, Nigeria, Trinidad and Tobaggo, USA and Russia to EU receiving terminals is satisfying some 15% of share the EU consumption in total.

In order to balance the demand for oil, in the coming decade, within the conditions of reduced local production, it is expected to significantly increase the demand for imported oil, including for southeast and central European oil refineries, that are potential consumers of supplies from Caspian fields [15].

Growing import dependence trend is also obvious with regard to natural gas [16], the share of which in the total consumption will exceed 80% by 2025-2030. Critical situation is observed in the Energy Community Contracting Parties whereby import dependency from Russian sources continues to prevail. In Bosnia and Herzegovina and North Macedonia import from Russian sources represented 100% of the final consumption, in Moldova up to 99% and in Serbia 86%. Georgia relies mostly on imports from Azerbaijan (95-98% of gas demand was covered by gas from Azerbaijan). In Ukraine 35% of the gas consumed in 2018 depended on import from EU Member States while 65% came from indigenous production; in turn this means that Ukraine was not depending from Russian imports in 2018 at all. The numbers of supply sources per Contracting Party are shown in the table below [17].

Table 1.1. Sources of supply to the Energy Community Contracting Parties

Country	Number of Supply Sources	Comment
BIH	1	Russia
Moldova	3	Import from Russia and Romania 99%, whereby less than 0.5% from Romania; domestic production added up to 0.01%
Georgia	3	Import from Russia 2.5% and Azerbaijan 97% (there are two sources from Azerbaijan: Socar and Shah Deniz Consorcium); Local production around 0.4 % of demand
North Macedonia	1	Russia
Serbia	2	Local production 14%, Russia 86 %
Ukraine	Several	35 % from EU member states, 65 % local production

In 2017, the demand for natural gas increased by 5% compared to the previous year's indicator. The Balkan and south east European countries representing the target markets for Caspian resources have been characterized with higher increase in gas demand [18], in particular: in Bosnia-Hertogovizna it is 7,6 %, Croatia - 17,9 %, Greece 20,5 %-ს, Hungary 10,2 %-ს, North Macedonia 29,0 %-ს, Romania 9,2 %, Serbia 11,8 %, Turkey 15,3 % (In Slovenia, Albania and Bulgaria lower than average increase was observed 4,7 %, 2,9 % and 2,8 %, respectively). Similar trend will presumably be maintained in the short and middle terms periods assuming that average per capita consumption in these, countries (460 m^3/y) will approach average European level (839 m^3/y). Gas consumption trend in the Energy Community Contracting Parties (see Figure 1.3) [17] shows total growth more than 30% during 2012-2018. Only in Ukraine consumption decreased by more than 40% and in Moldova by 6%. The substantial decline in Ukrainian's gas consumption caused by lower operation of industries in the occupied parts of the country, increased gas prices and intentional lowering of import dependence.

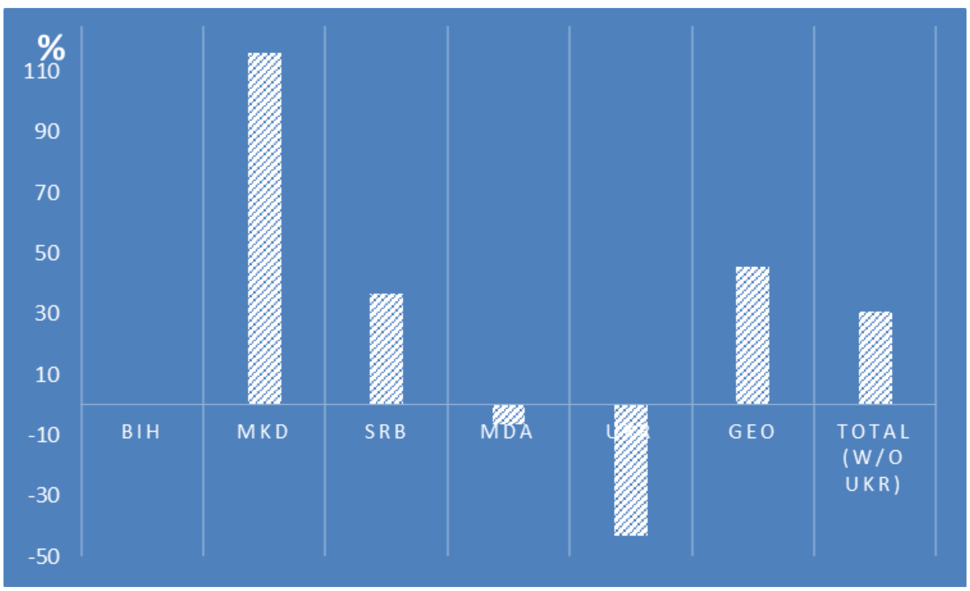

Figure 1.3. Gas Consumption Growth Rates in Energy Community Contracting Parties (2012-2018)

The demand for imported gas will significantly increase within the transitional period until the development of renewable energy resources aimed to replace coal and oil, mainly in power generation sector. The situation is complicated by the fact that most of the existing long-term supply contracts expire and will be impossible to update all of them. As a result, additional increase in the demand of imported gas is also projected (approx.150 bcm for 2025 and 200-215 bcm by 2035) [19].

The Caspian region, considering its increasing production and export potential, will gain more significance for the EU energy market. In the next decades, the increase of oil (Kazakhstan will be a leader in this segment) and gas production (Iran, Turkmenistan, and Azerbaijan [20]) is envisaged.

According to the forecasts, oil production in the Caspian region will significantly increase after development of the Kashagan oilfiled. It is projected to increase oil extraction to 220 M tonnes, and export potential may rise to almost by 50%, to 180-190 M tonnes. Gas production in Caspian exporting countries may reach (except Iran and Russia) 320-340 bcm after 2030, and export may increase to 225 bcm. As a result, the Caspian region will become one of the main sources for satisfying energy deficit in European market, especilly in the South-East Europe.

The global trend of growing demand for primary energy resources, especially in rapidly developing Asian countries will significantly intensify the competitition for access to energy resources. According to IEA, by 2030 total demand for oil in China and India is expected to be twice as much than in Europe, while in 2015, oil consumption in Europe and China/India was almost equal. According to forecasts, demand for gas may increase 2.5-3.5 times [20] which will weaken the significance of EU, influencing of the rest of the world in the fight for energy resources. Therefore, one of the goals of the EU foreign energy policy is to attract energy resources from new supply sources through the promotion of internal, competitive and transparent single energy market, creation and development of energy infrastructure connecting to alternative supply sources.

In order to ensure the security of supply, the EU ascribes more importance to the enhancement of the role of energy policy. Therefore, the internal market rules of the EU requires to modify functioning methods for the third country supplying companies and implementation of standards and energy legislation is the main tool for cooperation with them. In order to create a more competitive internal gas market EU suppotrs an reconsidering of gas market rules of neighbouring countries, including regulations releated to all pipelines entering the EU from non-EU countries. In February 2019, the EU reached an agreement to amend the third energy package to make it applicable – including its provisions on transmission unbundling, third party access, and tariffs – to pipelines from non-EU countries[3], i.e. these pipelines become accessible to other operators, as it already was the rule for internal gas pipelines and final consumers would benefit from more competition and hence lower prices.

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[3] Source: Yafimava, 'Gas Directive amendment: implications for Nord Stream 2', *OIES Energy Insight 49*, OIES 2019

Following to the opening of the EU market after the implementation of third energy package, market has become more liquid and prices have been more set at gas trading hubs such as TTF setting the European NG prices. As a result, prices become more flexible and set according to the offer and demand balance on a growing liquid market, trading with gas from various sources (during last years spread between TTF prices and of Gazprom's pipeline gas constitute a narrow range ±10 % only[21]).

More flexibility to gas prices added by LNG supplies, demonstrating its advantage on the rigidity of pipeline gas. Therefore, the main external suppliers of gas to EU, are adapting gas prices to the new situation, for the benefit of the EU customers - according to publicly available data import prices for European market felt close to $100/1000 m^3 in summer period, below $150 in November-December of 2019 [22], and futures at TTF traded below $110 till September 2020 and slitly increasing (up to $150) in IV Q and 2021 [23]. Moreover, while the European market remains well-supplied with pipeline and LNG supplies, the current storage and pricing situation in Europe dictates that prices could fall even further in the summer of 2020. An assessment done by the Oxford Institute for Energy Studies (OIES) of the impact of the rising LNG imports coming onto the market shows the possibility of $2/MMBtu gas in Europe during 2020 (broadly a price close to $(2-3) per MMBtu would be the same as a price below €(70-90) per 1000m^3). The key factors which triggered such lower prices are Gazprom's transit deal with Ukraine, a mild winter in Europe, LNG imports of the Americas and the Middle East and pipeline gas imports into Europe remaining roughly at 2019 levels and lower LNG demand in Asian markets due to the effect of coronavirus on economic activity in the world [24].

EU security of gas supply standards have been also established by the regulation requiring [25]:

- mandatory reverse flows of all pipelines,
- each Member State to rely on three different sources of supply,
- harmonized supply standards for consumers,
- the N-1 infrastructure standard (to enable Member State to rely on sufficient infrastructure or demand management tools to face a major supply disruption), and
- the implementation of solidarity in case of emergency.

To maintain guaranteed supply security, EU carries out the legislative control on foreign investments in strategic energy infrastructure projects as well, including the screening of their relevance to the goals and restrictions of ownership [26]. The goal of the screening is to evaluate foreign investment related risk towards state and social interests. As a result, three possible results can be observed: approving the investments, approving the investmments with certain conditions and banning the planned transaction (or terminating, if the investment has already been made).

In order to to support the supply security, the legislation regulates the issues of gas transmission infrastructure ownership and control. 18 member states have ownership restriction norms, in addition, in 9 countries the law establishes the list of strategic transportation infrastructure for natural gas 100% of which is owned and controlled by the state. In other countries, more liberal legislation is applied in terms of strategic infrastructure ownership and control, such as restricting the share of foreign investments, owning “golden shares” by the state (in 3 countires), control on alienability (including privatization) considering the state interests without restricting the investments and etc.

The EU long term strategy by 2050 (April 2019) and the European Green Deal (December 2019) are securing EU political decarbonization strategies, which provide a roadmap with actions including new legislation in all sectors of the economy, stronger investment tools and emphasize the global dimension of a more consistent and stronger use of EU energy and climate diplomacy and trade relations including in the Neighbourhood. Affordable and competitive LNG has its place in the EU energy policy for members states and their neighbors from Energy Community, notably under the heading of security of supply and international action. According to EnCS analysis, due to geographic conditions, it is not expected that massive LNG capacity will be installed in the eastern partner countries of EnC, but that LNG could rather become an additional source for the existing energy mixes. Arangement of natural gas liquefaction and export terminals or traversing the Turkish straits by LNG tankers without delay and construction of receiving terminals in the Black Sea aquatoria are determined as a key prerequisites and success factors for LNG projects implementation in the region. Countries of the region, in the experts’ opinion, need to decide if they want to consider LNG as a game changer for the sake of security of supply, diversification and increasing competitiveness in the region [27].

Governments of the EU member states, in most cases are the key sharehoders of LNG terminals and underground gas storage facilities, although many other investors may participate in the implementation of projects. In many cases, LNG terminals and gas storage facilities are owned and controlled by the state transmission system operator companies. There are only 5 cases in Europe, where the third country company is a shareholder of LNG terminals.
Currently the EU energy policy on the provision of energy security is mainly focused on the peripheries which also comprises enhancing bilateral relations with non-member producing and transit countries [28]. These relations are discussed within the frames of major economic and political agreements which will significantly increase the efficiency of their implementation. The example of such approach is introduction of energy related issues in EU Georgia framework agreements on economic relations.

The commission encourages boosting multilateral relations by involving neighbouring non-member states in the independent, single institution - Energy Community, representing the best means for reforming and integrating the markets. In addition, it should be noted, that the Energy

Community as well as dissemination of concept of the EU energy market model have some restrictions, conditioned by the difficulty of the countires in the region to have relations with some of the neighbouring states, such as Russia[5]. Therefore, it has been defined the goal for every individual partner of the Community, by elaborating ways to fulfil the obligations and tailor the work plans in the way to consider specific geographic location of each of tham, political orientation and economic conditions.

The experience gained during crisises played a crucial role in shaping the energy policy of the EU and associated countries. In in 1999-2000 sharp increase in oil prices, 2006, 2009 and 2014 Russia-Georgia[6] and Russia-Ukraine political conflict causing gas crisises, in 2011 Fukushima nuclear power plant disaster, created problems of local or global character and established new trends (reduced demand for certain energy resources, more accessibility to LNG, prospects of the development of non traditional gas industy and etc.). However, as a result of specific measures related to energy security taken during the last decade regional market gained more sustainability and currently it is less depenedent on external risks.

1.3. OIL AND GAS BEARING AND SUPPLY POTENTIAL

In the South Caucasus oil and gas deposits are mainly located within intermontane lowlands surrounded by the Caucassus mountains ranges from the north and the Lesser Caucasus mountains ranges from the South. In the west there are the Rioni molasse troughs which extend to the Black Sea basin. In the east there is more extensive the Mtkvari molasse trough, which incrementally widens first at the narrow Upper Mtkvari (kartli) section endings and then at middle Mtkvari and lower Mtkvari subdepression endings and finally integrates into vast and deep south Caspian sedimentary basin. The strength of the sedimentary cover increases to the same direction. In Kartli (Georgia) section, its strength is 4-6 km and in mid-Mtkvari section on Georgia-Azerbaijani border it is about 13-14 km, and in lower Mtkvari section and south Caspian hollow it exceeds 20km.

Georgia's proven oil reserves as of 2018, total to about 1.5 billion tons and gas reserves - about 21.52 bcm. Estimated reserves of oil is 4,81, possible reserves are 21,52bln tons, gas 4,59 and 5,87 bcm respectively (see detailed information below). Georgia is net importer of oil and natural gas.

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[5] Russia has occupied or maintains political control over tve significant part of Ukraine, Georgia and Moldova

[6]Crisis of the energy system of Georgia in 2006 which was predetermined by simultaneous damage of gas and electricity supply infrastructure on the territory of Russia as a result of terror attacke is less known to the international community

Main suppliers of Georgia with imported hydrocarbons are Azerbaijan and other litoral countries of Caspian sea.

Azerbaijan played a significant role on the market even between XIX-XX centuries and remained main oil producing region even within the first decades of the existence of the Soviet Union.

In 70-80-ies of last century significant deposits were discovered in the Caspian Sea water area adjacent to Azerbaijan. The most successful period for Azerbaijani hydrocarbon production was the Post-Soviet era. As a result, oil and gas production in that period sharply rose with the involvement of major transnational oil companies that carried out large scale high technoogical activities in the offshore deposits of Caspian Sea.

Azerbaijani oil and gas deposits in terms of geographical location and geological composition can be divided into several groups. In the western part, bordering Georgia, there are several small oil deposits which are located in the south edge (Armenia and Karabakh region) of Lesser Caucasus foothill in the south of the Middle Mtkvari depression.

In the eastern part, in the centre of the Middle Mtkvari depression, within the pre-molasse sediments there is the Kurdamir uplift, where another group of deposits was revealed. In this area, the Mesozoic sediments are located in the depth that are comfortable for drilling and their oil and gas bearing potential has been proven numerously.

In the far east, within the wider lower Mtkvari depression area, through the Absheron molasses depression merges in the north with the molasses depression line of the North Caucasusa, a number of fields have been discovered. The high hydrocarbon bearing capacity of the area is related to the strong (more than 4000) middle plyocene era productive strata.

Productive strata are distinguished in the pericline depression zone of the Absheron peninsula where it is constructed with the high collector quality quartz sand stone strata. At the sea extension of the same section, within Absheron-Balakhani enbankment, one of the major complex of fields Azeri-Chirag-Giunshli is discovered.

In the southern direction to the central part of the lower Mtkvari depression, the strength of productive strata and the share of sandstone in their composition is significantly lower. In this section there are several anticline chains spread to the south-east direction which deeply enter into the Caspian Sea area. The folds in this section are quite complicated with diaprism and mud-volcanisms. The discovered complex of fields is related to the local uplifts. At their sea extension, there are several deposits discovered among which the Shah-Deniz gas condensate field is the largest.

The number of fields of different sizes which were discovered within the lower Mtkvari depression and in the Caspian water area located adjacent to it, exceeds 80.

Proven reserves of Azerbaijani oil made up 1 billion tons by 2018. It is mainly located in Azeri-Shiragi-Giunshli) field. The field is being developed by Azerbaijani International Operation Company (AIOC) led by BP.[7]

The extension of the ACG PSA to 2049 was agreed in 2017. More than $36 billion has been invested into the development of the ACG area since the original PSA was signed in 1994. To date, more than 3.5 billion barrels of oil have been produced from the field. In 2018, total production from ACG averaged 584,000 barrels per day.The steering committee for the field has sanctioned the next stage of the development. The $6 billion Azeri Central East (ACE) project will include a new offshore platform and facilities designed to process up to 100,000 barrels of oil per day. The project is expected to achieve first production in 2023 and produce up to 300 M bbl over its lifetime [29].

The peak of oil production in Azerbaijan was recorded in 2010 and made up 51 million tons. In 2018 production amounted 38,8 million tons. The current analysis of the data and forecasts confirm that this level of production will be maintained in the future [30] and will grow after the development of the next stage of Azeri central eastern block of the Azri-Chirag-Giunshli field. The oil produced in Azerbaijan is mainly Azery light type which is delivered to international markets via the Baku Tbilisi-Ceyhan and/or the Baku-Supsa oil pipelines. URALS oil from Azerbaijan is primarily transported through the Baku-Novorosiisk Oil pipeline.

Table 1.2. Types of Azerbaijani oil [31]

Name	*API*	*Sulfur content*
Azery BTC (BTC)	*36,6*	*0,16 %*
Azery Light (WREP)	*35,2*	*0,14 %*
Urals (NREP)	*31,0*	*1,4 %*

Annual capacity of oil refinery facilities of Azerbaijan is about 205 thousand barrels (≈10 Mta). During last years oil refining industry was loaded by 60% roughly.

[7]ACG field owners comprise BP (operator) - 30.37 %, SOCAR -25 %, Chevron - 9.57 %, INPEX - 9.31%, Equinor - 7.27 %, ExxonMobil 6.79 %, TPAO - 5.73 %, ITOCHU - 3.65 % and ONGC Videsh Ltd - 2.31 %.

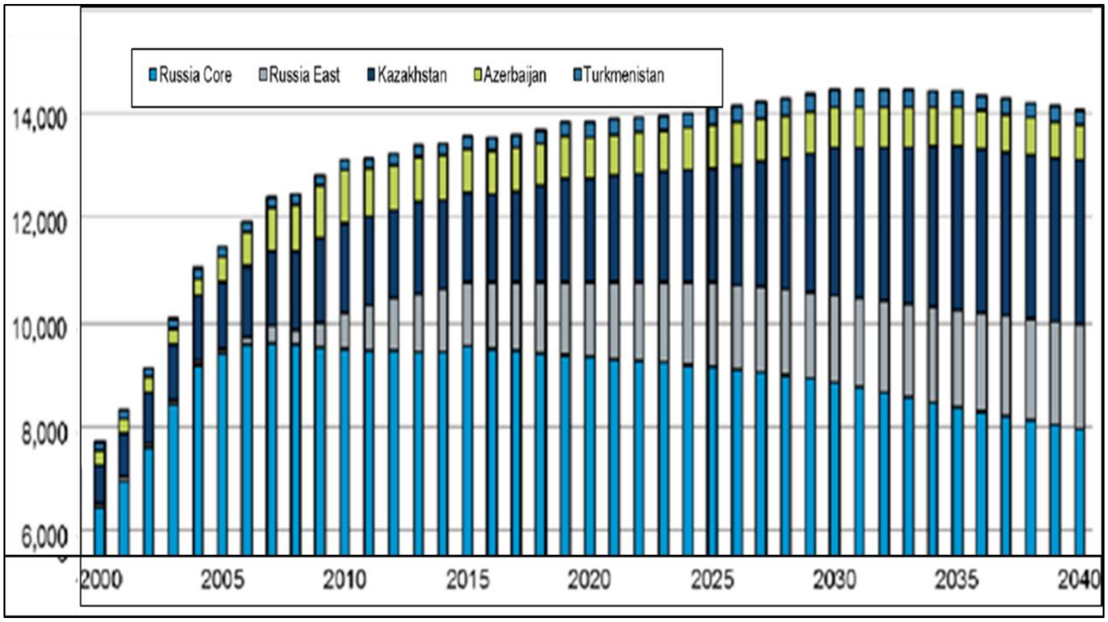

Figure 1.4. Oil production (historical and planned) in the countries of region, 1000bbl/d (Source: IHS)

Proven natural gas reserves of Azerbaijan totals to 1300 bcm. Main part of the reserves are located in the Shah-Deniz Gas Condensate Field. Gas production from Shah-deniz field started in 2006 and export started in 2007[8]. The second stage of field developemnt has already been completed. As a result annual extraction of gas will be increased by 16 bcm, out of which 6 bcm is to be supplied Turkey and 10 bcm – markets of the European countries.

BP (operator) announced that the first exploration well was already spudded on the Shafag-Asiman block in Azerbaijan sector of the Caspian Sea [32]. In the near future, Azerbaijan plans to start operating the Absheron (operator TOTAL), as well as the Nakhchevani, Arazi-Alov-Sharag, Umid-babek and other prospective fields. BP along with SOCAR works on the project to extract gas from the Shah-Deniz deep water horizon, within the third stage of the project development. The project envisages production of approximately 500 mcm additonal resoucres from 2032 [33].

As a result, peak gas production of 50 Mm^3 per annum can be reached in Azerbaijan, 70% of which will be envisaged for export.
In 2018, 19,2 bcm of commercial gas was produced in Azerbaijan, about 8 bcm of which was exported (to Turkey and Georgia).

[8] Currently, the field owner partners are: BP (28,8 %, operator), AzSD (10%), SGC Upstream (6,7%), Petronas (15,5%), Lukoil (10%), NICO (10%), TPAO (19%)

Considering priorities of economic and geopolitical factors, for Azerbaijan the most favorable export route is the southern corridor passing territories of Georgia and Turkey (or the Black Sea). This route excludes the necessity to travers Russia, Iran or Central Asian producing countries, being competitors in export of energy resources to the international markets.

The gas sectors of Central Asian countries have traditionally been of interest because of their connection to Russia, but over the past decade this link has increasingly become less relevant as exports to China have started to dominate. This has had significant commercial and political consequences across the region. Therefore, the issue of the future gas production in Central Asia and export potential growth from region remains a vital significance.

Over the last decade, China has replaced Russia as the main export destination for Central Asian gas. Total exports in 2018 were 46.8 Bcm to China, 16.1 Bcm to Russia and 5.7 Bcm of intra-regional trade [34]. Due to strong growth in gas demand in China, the Central Asia-China pipeline corridor will be used more intensively (close to its total capacity - 55 Bcm/year). In 2017-2019, gas consumption in China increased from 240 bcm to 310 bcm (average 15% annual growth). By 2030, projected demand for natural gas in China will reach 540 bcm, half of which will be met by exported resources [35]. Therefore an expansion of CA China export direction to 85 Bcm/year is possible, by construction of Line D from Turkmenistan via Uzbekistan, Tajikistan and Kyrgyzstan to China, probably in the late 2020s.

Turkmenistan will be The main source of additional volume to China (Kazakhstan has committed to 10 Bcm/year until 2023, after which its exports to China will fall and Uzbekistan will probably contribute around 10 Bcm/year).

Proven reserves of Turkmenistan is 19,5 trillion cubic meteres and the country ranks fourth the world in terms of gas reserves. Turkmenistan produces about 60-70 bcm of natural gas (66,95 bcm in 2018) significant part of which is used to meet its own needs (28,4 bcm in 2018).

Government’s strategy envisages the sale of energy resources at the border of country without participation in the development of transportation infrastructure and consumer market. Besides, Turkmenistan has started production at the supergiant Galkynysh field, which is considerd as a main source of incremental production and export from country. But, Turkmenistan has some restrictions for foreign companies to get access to the onshore fields, which hinders the development of the country’s export potential and there are some doubts about Turkmenistan’s ability to manage development of new fields. One possibility is that activity of foreign investors in the upstream will further increase. Projects operated by CNPC of China and Petronas of Malaysia now account for more than one quarter (28 % об 2018) of Turkmen output (CNPC, namely, has undertaken field development and construction of processing capacity at Galkynysh).

Turkmenistan remains heavily dependent on hydrocarbon export revenues and its autarchic and dysfunctional political system is under strain, that may support some political changes in the 2020s [34].

Currently, Turkmenistan exports its products to China, Russia, Iran and Kazakhstan. It is notable, that the existing contract envisages supplying China with 65 bcm of turkmen gas annually, however, so far, the country manages only loading the pipeline partially (in 2018 actual load was 33,3 bcm) [35].

The country envisages implementation of the next stages of the Galkynysh giant field development, which will increase the production of commercial gas to 93 bcm [36]. Russia is consided to be the traditional export route for Turkmen gas (or reexport via Russia). The long term agreement between Turkmenistan and Russia (to 2028) envisaged exporting 30 bcm gas to Russia. In 2009, due to unforeseen failure of export pipeline system Cetral Asia- Centre (CAC) connecting the country to Russia (according to Turkmen side, the failure was inspired by Russian "Gazprom"), gas export to Russia significantly decreased and in 2016-2018 it was entirely suspended. Gas supply to Russia (or via Russia for reexport purposes) has been resumed since April 15, 2019 with the capacity of 15 Mm^3 a day with prospects of further increase [37]. Accoridng to the latest information, Gazprom and Turkmenistan have concluded a 5-year contract (up to July 2024) to export 5,5 Mm^3 Turkmen gas annually. To transport Turkmen gas to Russia or reexport it via Russia, traditional Central Asia - Centre (CAC) pipeleine system can be used as well as the Trans Caspian pipeline (if constructed) with its further expansion via the pipelines on territories of Azerbaijan and of the North Caucasus region of Russian Federation [38]. According to the expert's opinion, resuming the import of Turkmen gas for Gazprom, is beyond of commercial deal and it can be used to meet the requirements of the EU Gas directive which requires loading of the trans-border pipelines entering EU territory (among tham Turkish Stream and Nord Sream 2 pipelines avoiding Ukraine), for at least 50% with gas of the alternative supplier) [39] and, at the same time, to maintain Gazpom's obligation retain certain transit volumes through the Ukrainian transmission system [40].

In general, among other supply routes, Turkmenistan prefers the development of currently partially loaded China and under construction Turkmenistan-Afganistan-Pakistan-India (TAPI) pipelines, also the western routes passing through the territories of Azerbiajan-Georgia or Russia to European markets. At the same time, according to the estimates, export routes suggested for Central Asian gas via a Turkmenistan-Afghanistan-Pakistan-India and via a Trans Caspian pipeline to Azerbaijan, Georgia, Turkey and Europe – remain economically infeasible [34]: the transport costs mean that Turkmen gas simply cannot reach these markets and compete with other supplies.

Even if political obstacles to the route are overcome, geographical and, above all, economic obstacles remain. In a world of a growing LNG business, there are simply no grounds for believing that there will be a long-term change in the trend of gas prices, sufficient to perform TCP into attractive investment propositions.

With these limitations, a solution now being more actively worked on by the government, is to use gas resources as feedstock for petrochemicals production. The launch of the Kiyanli complex with substantial financial and engineering support from east Asian companies, marking a significant turning point in this respect. While the Turkmen government has been vocal in support of pipeline projects, it has actually attracted billions of dollars of foreign investment into gas processing plants to produce petrochemicals and gasoline. This alternative diversification of markets may prove to be a better way of raising export revenues country.

Turkmenistan has relatively smaller proven reserves of oil - about 100 million tons according to 2018 data. Its annual production is about 12 million tons 60% of which is processed localy. The capacity of Turkmen oil refining industry is 13.5 million tons/y and factual load 6,3 ml t/y. Turkmen petroleum products are mainly supplied to the European market, via the infrastructure, including the ones located on Georgian territory. Turkmen oil (API =330) belongs Average density low sulfer content type (016-0,29 %) and it can be transported via main export pipelines along with Azeri's oil.

Proven oil reserves of **Kazakhstan** is 3.9 billion tons and the most of them are located in the north-west, on 5 Caspian onshore fields (Tengiz, Karachaganak, Aktobe, Mangustau and Uzen) and two offshore fields (Kashagan and Kurmangaz) of the country. Kazakhstan is the largest oil producing country in the Caspian region (91,2 M tons in 2018) that will increase to 100 million tons by 2025 [41], with respective growth of export potential.

The giant Kashagan oil field with 4.8 billion tons of geological reserves was discovered in 2000 in the northern part of the Caspian Sea, near the city of Aturau.[9] Total extractable reserves of the field is 10 billion barrels of oil and 1 trillion cubic meters of gas. Oil production at Kashagan oil field started in 2013, however, it was soon suspended due to natural gas system failure. Production works at the field resumed in 2016 and presumably by 2020 it will reach 15-19 million tons a year, and by 2030 production will exceed 40 milion tons (see figure above).

[9] The consortium owners include: Kazmunaigaz (16,81%), Eni (16,81%), Total (16,81%), Exxon Mobile (16,81%), Royal Dutch Shell (16,81%), Conoco Phillips (8,4%), Inpex (7,56%)

The second major Tengiz oil field of Kazakhstan was discovered in 1979. Total explored reserves of the field is 26 billion barrels. Currently annual oil production at the field is about 25-27 millon tons which after the completion of the expansion project will increase to 39 million tons. As a result, after 2030 export potential of Kazakhstan may exceed 120 million tons a year instead of current 70 million tons.

Due to the peculiarities of geographical location and limited possibilities of transport infrastructure, Kazakhstan exports its energy resources mainly via the territory of Russia. Relatively smaller amount of oil and gas is supplied to China and insignificant volumes are delivered to the neigbouring countries of the region, Iran (swap) and European market. In order to deliver crude oil and petroleum products Kazakhstan, among others, uses railroad via Southern Caucasian countries and BTC oil pipeline. In future, the country intends to export 20-25 million tons of oil through the southern energy corridor using Caspian Transportation System (CTS), comprising with: the Eskene-Kiuruk oil pipeline, Trans-Caspian sea transportation route, South Caucasus onshore routes and Black or Mediterenean sea ports. Implementation of the concept will be enhanced by the existence of new ports in Kiuruk (Kazakhstan), Turkmenbashi (Turkmenistan), Absheron and Alyiat (Azerbaijan) and Anaklia (Georgia) and also Trans-Caucasian international transoportation route (TCITR-„Middle Route")[10], implementation of which will free the capacity of existing ports in terms of getting and delivering crude oil and petroleum products.

In case of necessity, a new pipeline of 830 km length DN800 from Azerbaijan to the Black Sea port of Georgia can be built or Georgia-Azerbaijan railway can be used after its reconstruction with total capacity of 48 million tons [42], including the transportation of oil and petroleum products with annual capcity of 20-25 million tons. Existing Black Sea oil terminals will also be expanded in order to ensure additional throughput and large tonnage tanker service (total throughput of Batumu, Supsa, Poti and Kulevi Ports currently is about 14, 7, 1,4 and 6 million tons annualy, respectively).

The capacity of about 18 million tons of oil refineris of Kazakhstan is practically fully loaded. Majority of localy produced petroleum products are envisaged for the local market and part of it (basically heavy petroleum products) is exported to neighbouring countries and Europe

[10]The project is founded by railways of Georgia, Azerbaijan, Ukraine and Kazakhstan, as well as the Black Sea and Caspian sea. Source: Argus Caspian and Black Sea Transportation Corridor 2018, Tbilisi, September 2018 Tbilisi, September 2018.

Table 1.3. Types of Kazakh crude oil [43]

Type	*API*	*Sulfur composition*
CPC Blend	*45,3*	*0,56 %*
Tengiz	*46,4*	*0,51 %*
Kashagan	*42-48*	*0,80 %*

Kazakhstan is predominantly an oil producer and works closely with international oil companies, different from Turkmenistan in this respect. Proven resereves of natural gas of Kazakhstan is 1000 billion cubic meters, production of commercial gas exceeded 30 bcm in last years, major part of which was traditionally exported to Russia and other part to China (see Table below) [44].

Gas is of secondary importance and most gas is produced in association with oil at the three major projects (Tengiz, Karachaganak and Kashagan). Until the mid-2010s, the volume reinjected to support pressure in oil reservoirs was in a similar range to that produced as sales gas. The proportion of sales gas has risen in recent years but the government projects that sales gas volumes, and consequently volumes available for export, will fall between now and at least the mid-2020s. At the same time, domestic consumption is expected to grow. Having completed the Beineu-Shymkent pipeline linking the western producing areas with the main consuming areas in the south-east, Kazakhstan is investing further in gas transportation infrastructure and gasification. Thus its exports will probably fall, from 7-8 Bcm each to China and Russia in the early 2020s, to less than half that in the late 2020s (export volumes to China rose, after the completion of the Beineu-Shymkent pipeline, from 0.4 Bcm/year in 2014 up to 5.8 Bcm in 2018. In 2018 Kaztransgaz and PetroChina International signed a contract providing for up to 10 Bcm/y of exports in the five-year period 2019-2023).

In order to fully meet the country needs, Kazakstan imports gas from neighbouring countries (Russia, Uzbekistan, Turkmenistan) that is caused by the fact that the south-eastern regions of the country (Alma-ata and Jambuli urban areas) are far from the main gas producing regions of country. According to the forecasts of the country's Energy Ministry (October 2017) it is planned to increase gas production to 60 bcm by 2025 and to 88 bcm by 2040 [45], main part of sales gas of which is considered for domestic use[11]. In the longer term, a series of agreements signed in 2018–19 for exploration in the Kazakh sector of the Caspian Sea and the reduction of flaring[12] may also support to rise incremental gas production in Kazakhstan

[11] Gas production is limited due to the comparative costs of reinjection and gas processing. The associated gas has a high sulphur content, 18-19 per cent at Tengiz and Kashagan: reinjection not only supports higher oil output, but is also cheaper than processing the high Sulphur gas and storing and utilising the sulphur

[12]The World Bank GGFR initiative estimates Kazakhstan's total Gas Flaring at 2.8 Bcm in 2017 and 2.0 Bcm in 2018

Table 1.4. Gas Production and Export/Import Data of Kazakhstan, Bcm/y

		2010	2015	2016	2017	2018	2025	2030	2035	2040
Production (Total)		*37.3*	*45.3*	*46.4*	*52.9*	*46.3*	*61,0*	*59,8*	*80,3*	*87,9*
Reinjected & flared		*18.7*	*12.3*	*11.4*	*13.4*	*13.0*	*38,8*	*38,8*	*51,9*	*51,5*
Production of Commercial gas		**18.6**	**21.3**	**28.5**	**31.6**	**33.3**	**22,2**	**21,0**	**28,4**	**36,4**
Import		**4.5**	**5.7**	**6**	**6.3**	**7.7**				
	From Russia	1.8	2.8	3.1	3.3	1.4				
	From Turkmenistan	1,0	1.3	1.5	1.5	1,0				
	From Uzbekistan	2.9	1.9	1.7	2.9	3.7				
Total domestic consumption		**10.4**	**13.8**	**21.1**	**22.7**	**22.6**	**19,6**	**20.1**	**23.4**	**27.6**
Export (total)		**12.7**	**13.2**	**13.4**	**15.2**	**18.4**				
	To/through Russia	12.6	12.7	13.8	12.3	10.9				
	To Kyrgyzstan	0.23	0.27	0.30	0.30	0.23				
	To China	0.4	0.4	1.1	5.8	0.4				

Iran

Proven oil reserves of Iran is 155,6 billion barrels (21,4 M tons) and it lags behind only Venezuela, Saudi Arabia and Canada. According to the 2018 statistics [46], the country produced 220,4 M tons of oil (6,5% less than in 2017), 40% of which was used locally. Irans favorable geographical location enables the country to export oil to international markets via the Persian Gulf and Hormuz strait sea ports. According to the International Energy Agency information, the country extracts export oil mainly from Ahvaz-Asmar and Gasharan fields. Irans crude oil is characterized by average sulfur content and 19-36 API gravity (see table)

Table 1.5. types of Iran crude oil [47]

Type	*API*	*Sulfur content*
Iranian Heavy	*29,3*	*2,29 %*
Iranian Light	*33,0*	*1,58 %*
Nowruz Sour	*19,0*	*3,89 %*
Doroud	*34,0*	*2,5 %*
Foroozan Blend	*30,5*	*2,28 %*
Lavan Blend	*34,2*	*1,93 %*

Iran tries to play an active role to ensure oil export from Caspian fields to International markets and receive additional transit revenues. In late 90-ies of the last century, the country regularly has receiving oil from Kazakhstan and Turkmenistan in the Caspian port of Neka,[15] which was processed in the oil refineries located in northern regions of the Iran and, in return, the country exported its oil to International markets from the Hormus strait. During 1997-2010, from these

[15]Oil was supplied to Iran by exchange from Azerbaijan too during the Russian military agression in 2008, when oil transit via the territory of Georgia was temporarily suspended

operations, the country received additional 146 M USD revenue, however after 2010 UN security council sanctions, these type of operations (swap) has practically suspended [48].

Iran's abundant oil reserves create prospects to significantly increase production in the future and turn the country into one of the main suppliers of the international markets. Unfortunately, nuclear ambitions of the government and international sanctions related to that, as well as the the restriction established by the country's legislation for international companies to manage resources, makes it impossible to conduct constructive cooperation with Iran at the moment. In 2018, according to the evaluation of the American Investment Bank Morgan Stanley, due to resumed sanctions imposed on Iran, daily production of oil in Iran drop to 2,7 barrels (instead of average 4,98 in 2017). According ot the International Energy Agency, Irans oil export decreased to 2,19 million barrels a day even before the sanctions were enforced. For the 2019 Q2 the export has significantly decreased to less than 1 M bbl a day.

Proven gas reserves of Iran is about 31,9 tcm. Primary reserves of gas is located in the South Fars field which is the largest natural gas field in the world. Major part of the field is on the territory of Iran and part of it is in Qatar. 40% of the total volume of gas in the country is extracted at this field.

In 2018, Iran produced 239,5 bcm of gas which is 8,8 % more than in the previous year. Internal consumption of the country made up 225,6 bcm and total export (Turkey, Azerbaijan, Armenia etc.) 12,1 bcm.[16] In order to balance the consumption of the north-eastern part of the country, in 2018, 1,9 bcm gas was imported form Turkmenistan.

Iran has an great potential for LNG production and export due to the favourable locations of South Fars, North Fars, Kish, Golshan, Karagan, Nar, Khangiran fields in the south, near the Persian Gulf. In case the resuming of the contracts with "Royal Dutch Shell", „Repsol" and „Total" on the LNG terminal constructions, that were suspended during sanctions, it will be possible to export 40 million tons of LNG without transit through the third country to Asia-Pasific deficit markets as well as to European markets [49].

Iran may potentially become serious competitor on the International gas markets, however Russian Gazprom, with current contracts and developed export infrastructure securely maintains the position of the maijor supplier of the EU market unlike Iran, which is being isolated and needs

[16] In 2018, Iran exported gas to Baghdad and Basra provinces of Iraq too

large volume of investments in order to build infrastructure and develop the undeveloped fields, which is practically impossible within the conditions of current sanctions.

The record shows that large part of Iran's gas reserves (non associated) is located in the south of Iran and in case of the construction of respective infrastructure from south to north, the country can export it to several bordering (along land or marine borderline) countries including Turkey, Iraq, United Arab Emirates, Syria, Oman, Pakistan, India, Armenia, Azerbaijan. Iran already has a connecting pipelines to Turkmenistan, Turkey, Armenia, and Azrbaihjan.

Theoretically it is possible to export gas from Iran to Georgia using Iran-Azerbaijan transit route. However, it is practically impossible to use current infrastructure due to restrictions related to technological and commercial deals. This routes can be considered only a temporary alternative in crisitical situations[17], using swap deal, as it was exercised in 2006.

Iran Armenia gas pipeline may be considered as another alternative route to transport gas from Iran to Georgia, with further transportation with Armenian branch of the North-south main gas pipeline of existing system of trunk pipelines, in case it's operation into the reverse regime. However, due to fact that North South Gas Pipeline can not be used in the reversed regime, its usage for transporting Iranian gas to Georgia is practically impossible. This route can only be considered as temporary means for transporting gas in the period of crisis using swap deal. Therefore, the readiness of the Irani as well as Armenina Government to trasport Iranian gas to Georgia under commercial contracts [50] has more political assignement and not the real practical preconditions.

[17]In 2006, Russia has provoked the energy blockade in Georgia. During the crisis, Iran was supplying gas to Azerbaijan which on its part, supplied gas to Georgia for several days

CHAPTER II

2. TRANSPORATION INFRASTRUCTURE

2.1. SUPPLY OF OIL FROM CASPIAN FIELDS TO EUROPE

Economic advantage of transportation of hydrocarbons by pipelines preconditions their wide dissemination all over the world. It is known that, for example, main pipelines use only average of 0.4% of transported oil at each 1000 km of distance, while 1.0% is spent for transportation by railway and about 3.2% is spent for transportation by tank trucks [51]. Pipeline transport does not require free movement of empty vehicles backwards, nor expenses of transshipment operations.

A) Oil pipelines

The trend of significant increase in the export potential of the region, including particularly intense planned increase of oil production in Kazakhstan after completion of the full scale development of Kashagan gigantic oil field, will create significant problems in terms of its delivery to the international market due to the limited capacity of existing infrastructure.

Today various oil pipelines and sea routes are used to deliver crude oil and petroleum products to the target markets of Europe. Demand of the East and Central European market is currently met mainly by the Russian REBCO[18] (Russian Export Blend Crude Oil) oil which is transported by Northern (via Poland) and Southern (via Ukraine) branches of Druzhba pipeline inherited from the Soviet period, as well as with the Baltic pipeline systems (BSP-1 and BSP-2) and sea routes.

For export of oil from Caspian fields, with few exceptions,[19] regional trunk oil pipelines and the Black or Mediterranean Sea terminals are used. Oil is delivered from the Caspian region to the Black sea ports of Novorossiysk (Russia) and Supsa (Georgia) via the Caspian Pipeline Consortium (CPC), Baku-Supsa or Baku Novorossiysk pipelines and to the Mediterranean Sea Port of Ceyhan (Turkey) via Baku-Tbilisi-Ceyhan oil pipeline. After delivery of oil to the European market ports of Odessa (Ukraine), Trieste (Italy), Omishal (Croatia), Constanza (Romania), Rostok (Germany), Gdansk (Poland) and etc. via sea routes, it is supplied to the target market consumers through internal trunk pipeline systems: TAL (Trans-Alpine pipeline), Adria (via Croatia, Bosnia-

[18] REBCO, or Urals represents an average density sulfur-containing oil obtained by mixing of dense oil of Ural and Volga regions with the light oil of the west Siberia. Urals is a Russian oil brand and it is used for establishment of export prices.

[19] Small part of the Kazakh oil is exported to Russia and is mixed with REBCO

Herzogovina, Serbia, Hungary and Slovakia territories), IKL (The Ingolstadt–Kralupy–Litvínov pipeline) and Pomerania (Gdansk-Plotsk) pipelines, respectively.

Trunk oil pipelines inherited from the Soviet period are operating on the territories of the region and adjacent to it:

- ●Adria trunk pipeline system on the territory of the former Yugoslavia;
- ●Trunk pipelines passing through the territories of Azerbaijan, Georgia, Russia to the Black sea coast terminals as well as to Poti and Novorossiysk (Russia) ports[20];
- ●Trunk pipeline system of Uzen-Aturau-Samara located on the territories of Kazakhstan and Russia.

After disintegration of the Soviet Camp, trunk oil pipelines newly constructed in the region or trunk oil pipelines rehabilitated after reconstruction include:

- ●Caspian Consortium Trunk Pipeline (CPC) from Kazakhstabn to Novorossiysk;
- ●Baku- Novorossiysk Oil Pipeline (NREP) after its rehabilitation-reconstruction;
- ●Baku-Supsa Oil Pipeline (WREP) after rehabilitation-reconstruction;
- ●Baku-Tbilisi-Ceyhan Oil Pipeline (BTC) from Azerbaijan to the Mediterranean Deep Sea Oil Terminal via the territory of Georgia and Turkey;
- ●Odessa-Brody oil pipeline on the territory of Ukraine;
- ●Kazakhstan-China Trunk Pipeline System (KCP)

The total length of **Baku-Tbilisi-Ceyhan** (BTC) oil pipeline is 1798 kilometres, 248 km, DN 1167 (46 inch) section with 12,7-23,88 wall thickness is located on the territory of Georgia. The pipeline starts at Sangachal terminal and ends at Ceyhan deep water terminal on the Mediterranean coast via the territories of Georgian, Azerbaijan and Turkey. At the terminal, oil is loaded onto the large tonnage VLCC ocean tankers, with deadweight of 300 000 tons and more. The pipeline is served by eight pumping stations (two in Azerbaijan, two in Georgia and four in Turkey). Pumping stations on the territory of Georgia are located within 3.6 km from the border near the village of Jandara (Gardabani municipality) and at KP 87, on the territory of Tetritskaro municipality. Each pumping station is equipped with four working and one reserve pumping facility. The pressure of the incoming flow is 7 bars and exit gas -115-117 bars. On the Georgian section of the pipeline there are 16 block valves and 11 protection valves (along the entire pipeline route there are 101 block and protection valves in total).

[20] Railway transport is used on certain sections of the route.

Construction of BTC pipeline was carried out and is being operated by BTC Pipeline Company (BTC Co)[21] established by 11 shareholders and led by BP[22]. Total cost of the pipeline project implementation amounted to 41,1 billion USD [52] (including 960 million USD for the Georgian section of the pipeline: 854 million USD - cost of construction and 70 million USD for purchasing the territory, its preparation and etc.).

The pipeline starts at Sangachal terminal which can process 50 million tons of oil annually (1 million barrels a day). The terminal has been operating since 1997. It contains 8 reservoirs, with total capacity of 480 thousand tons. The terminal is equipped with pumping facilities and metering systems. Sangachal terminal serves WREP, NREP and BTC pipelines.

Operation of BTC pipeline was launched in 2006. Its design throughput is 50 million t/y (1 mln barrels/day). Currently the pipeline throughput has been increased to 60 million tons annually (1,2 million bbl/d). The pipeline is designed to be exploitated for 40 years.

BTC pipeline mainly transports Azeri Light blend oil extracted from Azerbaijani offshore Azeri-Chirag-Giunshli field, as well as oil supplied from neighbouring countries. In 2018 the pipeline transported 33,83 million tons of Azeri oil (81,5 % of total export).

It is considered to increase volumes of oil delivered from Central Asian countries to 20-25 million tons annually [53] for the pusposes of its further transportation through the route passing through the South Caucasus including through BTC oil pipeline. To this end, corresponding infrastructure, in particular, ports and tanker fleet in Kazakhstan and Azerbaijan must be prepared; Construction of Trans-Caspian Oil Pipeline to Baku is also possible and the capacity of BTC may be increased up to 80 million tons a year.

Oil extracted from the Azeri-Chiragi-Giunshli field located in Azerbaijan sector of the Caspian Sea was first exported to the world market through ***Baku-Supsa Western Route Export Pipeline (WREP)*** via Supsa Terminal of the Black Sea Coast of Georgia. The diameter of the pipeline is 530 mm and annual design throughput is about 7 million tons. The oil pipeline has been operational since April 1999. WREP has transported about 4-5 million tons of oil annually in the recent years.

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[21] BTC Co.'s shareholders are: BP (30,10%); AzBTC (25,00%); Chevron (8,90%); Statoil (8,71%); TPAO (6,53%); ENİ (5,00%); Total (5,00%), itochu (3,40%); İnpex (2,50%), GIECO (2,50%) and ONGC (BTC) Ltd (2,36%). Technical operator of the pipeline is BP, commercial operator is SOCAR.

[22] The Turkish section of the pipeline was built and is operated by the State Turkish Pipeline Company BOTAS.

The length of Baku Supsa Oil Pipeline from Sangachal terminal to Supsa Terminal of the Black Sea Coast of Georgia (including the floating loading platform) is 833 km. 376 km, DN530 section of the pipeline is operational on the territory of Georgia. Georgian section of the pipeline is built on the basis of the existing Samgori-Batumi oil pipeline.[23] It is owned by Georgian Oil and Gas Corporation and has been transferred to the managing company AIOC,[24] which was established by an international consortium, for 50 years with operation and ownership as well as rehabilitation and development rights.

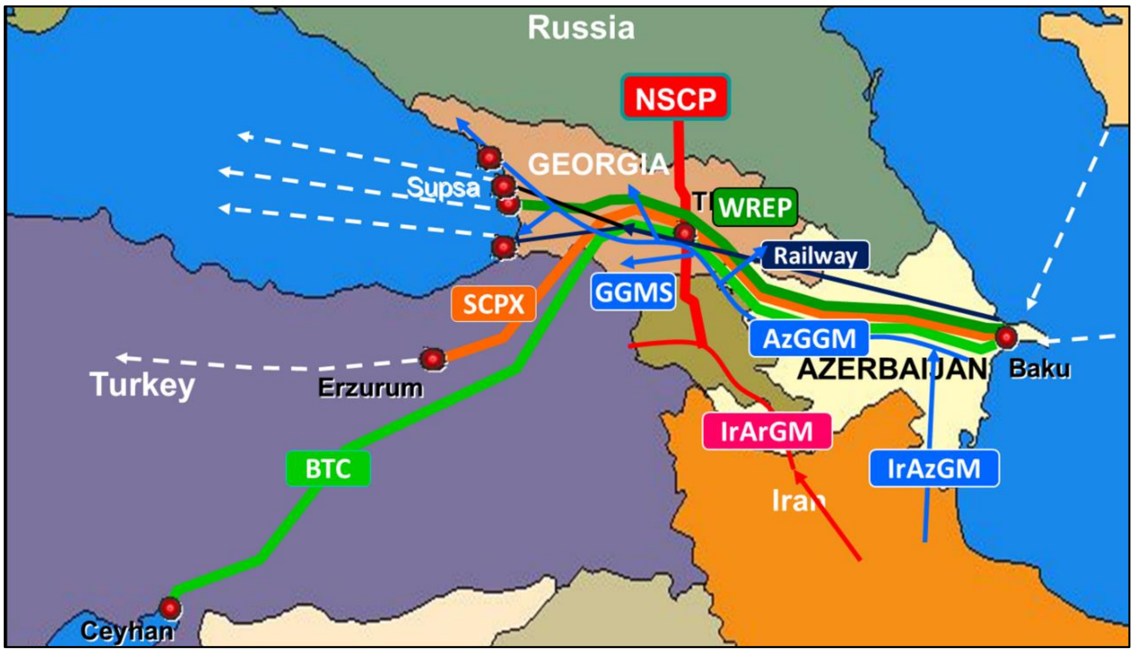

Figure 2.1. Transit Infrastructure on the territory of Georgia

Supsa onshore terminal which is the part of the system was also built in the country within the frames of the project (4 reservoirs, with total volume of 195 000 cubic meters) with 2 pressure reduction and 3 pumping stations, 28 block and 5 control/ckeck valves as well as sea loading facility.

Oil is loaded onto sea takers with a floating oil platform which is located at 3 km distance from the coastline and is attached to the anchors. DN 914 mm (36") pipeline delivers oil from the coast terminal to the collector located on the sea bed where two DN 406 mm (16”) flexible pipelines

[23] DN-530 mm, appox. 425 km long "Samgori-Batumi" oil pipeline with design capacity of 3.5 mln. tons per year was put into operation in 1980 and was functioning until 1993 for transportation of oil produced in Georgia.
[24] BP (34,1%), Statoil (8,6%), Unocal (10,3%), Inpex (10%), ExxonMobil (8%), TPAO (6,8%), SOCAR (10%), Devon (5,6%), Itochu (3,9%), Amerada Hess (2,7%).

deliver oil to the floating platform, from there oil is loaded into tankers using two (each 508 mm (20") floating flexible pipes.

Supsa marine terminal is designed for serving 100-150 ton displacement tankers which along with limited capacity of Turkish straits significantly limits geography of oil transportation. From Supsa terminal, oil can be transported to the Black Sea and Mediterranean sea water ports on the most favourable conditions.

Baku-Makhachkala-Novorosiysk Northern Route Export Pipeline (NREP) is also designed for delivery of Azerbaijani Azeri-Chiarh-Giunshli field oil to the Black sea water area consumers via Novorosiysk export terminal. Its throughput capacity on the territory of Russia is 15 million tons per year [54].

After reconstruction of NREP, which envisaged change of the initial route in order to bypass the unstable region of Chechnya being part of Russian Federation, the length of the pipeline is 1411 km, with DN 720. Makachkala-Novorossiysk section of the system is also used to transport Kazakh and Turkmen oil delivered by the Caspian Sea.

The transportation tariff via NREP is about 50% higher than that via WREP [55]. Besides, while transporting Azeri Light high quality crude oil through Novorosiysk terminal, it is mixed with lower quality URALS brend as well as impure Kazakh oil as a result of which the price of Azerbaijan's crude oil generally decreases by 1-2 USD per barrel. Therefore, Azerbaijan gives preference to WREP over NREP, but uses NREP for export of relatively low quality oil.

According to the contract, NREP can transport up to 5 million tons of Azerbaijani crude oil, however due to high costs of service and problems associated with the quality, actual load of the pipeline has not exceeded 2.3 million tons a year.

Caspian Pipeline Consortium (CPC) export pipeline has been operating since 2003. It connects the Tengiz field to the Black Sea Terminal of Novo-Ozereevka (near the port of Novorossiysk). Total length of the pipeline is 1511 km, the capacity after its expansion is 67 million tons a year (MMTA) including the capacity of 55 MMTA on Kazakhstan section.[27] The pipeline is mainly envisaged for transportation of the blend of oil produced from Tengiz and other fields - "CPC

[27] The pipeline's current throughput is 67 mln. tons per year, and its 78% is designed for Kazakh oil. 10 new pumping stations were built according to USD 5.4 billion pipeline extension project.

Blend". It is envisaged to transport 65-67 million tons of Kazakh and 11 million tons of Russian oil annually through this pipeline.

CPC service terminal has two docks at the Black sea coast with capacity of loading of up to 300000 tons of displacement tankers. Oil is delivered to the docks with DN 1067 mm underwater pipeline. There are four tanks at the terminal, each tank consists of 100000 cubic meter reservoir.

31% of the Caspian Pipeline Consortium is owned by the Government of Russia (24% through the Russian Federal Ownership Fund and 7% through CPC Co), 20,75 % is owned by the Kazakh Government (19 % plus 1,75 % through Kazakh pipeline Ventures LCC). The second portion of shares is divided among private companies.[28] Each owner has a proportional quota corresponding to its share in the pipeline capacity. In addition, in order to fully recover the costs spent on the last expansion (5,4 billion USD), the Consortium members will transport the oil produced by them only via CPC.

Odessa-Brody Oil Pipeline is designed to deliver the Caspian oil to the European market and diversify supply of Ukrainian refineries with raw materials which on the one hand will promote discharging Turkish straits, and on the other hand, will enable the producer countries to go to the attractive Central and North Eastern European markets directly. Connecting Brody to the Polish section of the Druzhba oil pipeline near Plotsk enables to transport Caspian oil to the markets of Poland, Germany and the Baltic Sea countries (The main oil pipeline system "Druzhba" (Friendship) exports oil produced on the territory of the former Soviet Union to the European market. The system is divided into two, "northern" and "southern" branches near the city of Mozur on the territory of Belorussia. The northern branch of the oil pipeline supplies Poland and Germany. The southern route will deliver oil to Slovakia, Czech Republic and Hungary via Ukraine)

Length of the pipeline is 674 km, diameter - 1020 mm, planned throughput – 30 mln. tons/year, current actual throughput - 14 mln. tons/year. The pipeline construction was finalized in 2001, however it is not possible to operate it due to the lack of interest from the consumers. For several years the oil pipeline worked in the reverse mode to deliver Russian Urals from Brody to Odessa with 9 million tons of annual throughput. In 2011, the system worked in the normal, averse mode

[28] Chevron Caspian Pipeline Consortium Co. (15 %), LUKARCO (12,5 %), Mobile Caspian Pipeline Co. (7,5 %), Rosneft-Shell Caspian Ventures Ltd (7,5 %), Eni int N.A.N.V. (2 %), BG Overseas Holdings Ltd (2 %), Oryx Caspian Pipeline LLC (1,75 %).

and delivered Azeri Light Azerbaijani crude oil received in tankers from the Black Sea ports of Georgia to Ukraine and Belorussian refineries.

Kazakhstan-China Crude Oil Pipeline (KCP) with the total length of about 2230 km connects Kazakh fields from Atyrau to Xinjiang region in the north west part of China. The throughput capacity of the pipeline after its reconstruction at Kenkiyak-Kumkol-Kumkoil Atasu-Alashankou section is about 20 million tons. Within the reconstruction project, several new pumping stations were added to the system and additional pipeline was added at Kumkoil-Atasu section. The pipeline is mainly used to deliver oil from the Kazakh Aktobe and Kumkoil fields. The pipeline is operated by joint venture "Kazakhstan-Chinese Pipeline Co” established by KazTransOil (KMG’s subsidiary) and CNPC.

Atyrau-Samara Pipeline connects Kazakh fields to the city of Samara located in the Russian Federation where it is connected to Transneft pipeline system. It enables transportation of Kazakh crude oil to the international market via Russian sea ports. In recent years, Kazakh oil transported by the Atyrau-Samara pipeline was mainly delivered to the Novorossiysk and Odesa sea terminals. The pipeline with design throughput of 12 million tons per year was built in the Soviet period to pump high viscosity oil to the Russian refineries. After reconstruction and adding special supplements to the flow, throughput of the pipeline has currently increased to 17,5 million tons and its factual load exceeds 15 million tons annually [56].

549 km section of the pipeline is located on the territory of Kazakhstan, 154 km section lies from the border compressor station of Cheknogovka to Samara in the territory of Russia. The pipeline diameter is 720 mm and it is operated by KasTransOil.

Prospetive Crude Oil Pipeline Projects

New oil pipeline projects are mostly envisaged to diversify supply routes and rationally develop export potential of the region. Initiation of new transport route projects was also preconditioned by frequent delays/hindrance of supply of oil to the market and/or quality assurance requirements. The reason for delay of supply of oil from the region to the international market is mostly connected with limited capacity of Bosporus and Dardanelles straits, due to which, according to September 2018 data, downtime in Turkey was about two days on average [57] and during winter period, downtime sometimes exceeded even 10 days).

In April 2019, crude oil containing excessive harmful impurities was delivered from Russia to Eastern and Central European countries through Druzhba pipeline. As a result, for about two months, oil treatment enterprises either fully or partially stopped receiving Russian oil, which created significant technical and financial problems. Analysis of causes and effects of uncontrolled delivery of contaminated oil from Russia confirms the necessity of alternative supply routes for those countries of Europe which mainly depend on import of energy resources.

Political support from the EU can may also be considered to be a potential factor contributing to oil pipeline project implementation[29]. Considering the fact, that significant changes occurred in the region in terms of a new geopolitical situation in recent years, after occupation of East Ukraine and Crimea by Russia, supply of raw materials to oil treatment enterprises of the region (Poland, Germany, Ukraine, Lithuania) from Russia became risky and implementation of planned projects will play a significant role in reduction of dependence on the dominant suppliers to the eastern and central European countries.

Table 2.1. Main technical parametres of oil pipelines [55]

Oil pipeline, country	Receipt-delivery terminals	Diameter, mm	Distance, km
Makhachkala-Novorossiysk, Russia	Makhachkala - Novorossiysk	720/720	774
NREP, Azerbaijan, Russia	Baku -Novorossiysk	720/720	1411
CPC, Kazakhstan, Russia,	„Tengiz"-Novorossiysk	1016/1067	1511
Odessa-Brody, Ukraine	Brody-Odessa	720/1020	1039
KCP, Kazakhstan	Atasu-Alashankoy	813/813	962
Kirkuk–Ceyhan, Turkey	Kirkuk-Ceyhan	1168/1016	656
BTC, Azerbaijan-Georgia-Turkey	Sangachal-Ceyhan	1168/1016	1776
WREP, Azerbaijan-Georgia	Baku Supsa	530/530	827

Key requirement for implementation of the project is also the development of Caspian fields at the projected scale. In particular, Kazakh oil must be considered as a possible source of supply for loading the new routes after projected full development of the Tengiz field and completion of the development works at Kashagan field [58]. The agreement concluded between Azerbaijan and

[29] For instance, Brody-Adamovo pipeline project is included in the list of EC's Projects of Common Interest (PCI), as well as the Priority Projects of Energy Community (PECI) which is a guarantee of its political support by the EU.

Kazakhstan envisages delivery of Kazakh oil to Azerbaijan for that period and from Azerbaijan oil will be pumped through Baku-Tbilisi-Ceyhan and Baku-Supsa Oil Pipelines or other alternative transportation system to the Mediterranean and the Black Sea ports [59].

In order to deliver Kazakh crude oil to the west coast of the Caspian Sea and then to European markets, it is considered to use Caspian Transport System (CTS).[30] Design throughput capacity of CTS at the first stage is 20-23 mln. tons/year, in case of expansion - 35-37 mln. tons/year.

CTS project has been suspended since 2014, by decision of the Kazakh Government, mainly due to delay of the second stage of Kashagan field development. From February, 2017 Kazakhstan returned to the issue of possible implementation of the project which is related to development of the Tengiz field and completion of the full-scale development of Kashagan field. It also envisages the possible impact of international sanctions imposed on Russia on the oil transportation infrastructure of the country. Besides, after some progress has been achieved in terms of construction of trunk pipelines on the Caspian Sea bed, if the volume of oil to be transported exceeds 20-25 mln. tons/year, the question of construction of Aktay-Baku Trans-Caspian Oil Pipeline may arise once again based on the agreement signed with Azerbaijan in Alma-Ata in May 2003.

Currently existing oil pipelines and marine terminals (including CPC Kazakh section, Kazakh-China, Atyrau-Samara, Aktay port/Makhachkala-Novorossiysk, Aktau port/Azerbaijan BTC and Aktau Port/Iranian Neka) may be not sufficient for transportation of projected increased volumes of Kazakh oil to be exported with favorable commercial conditions. Besides, different physical-mechanical properties of Kazakh oil should be taken into consideration, which makes its transportation together with oil of a higher quality as a mixture ineffective.

Therefore, in case of implementation of Kazakh oil field development plans, and for delivery of part of increased export volumes to the Eastern and Central European markets using Azerbaijan-Georgia land routes and the Black Sea water area, it will be necessary to use new routes. In addition, it is implied that current volume of (roughly 40 mln. tons/year) total export potential of Azerbaijani and Turkmen fields will be maintained through Azerbaijan-Georgia route.

One of the possible options for transportation of increased volumes of Caspian crude oil and petroleum products to the European markets is construction of pipelines envisaged by EAOTC project, i.e. Eskene-Kuryk, Trans European PEOP (Konstanza-Triste), AMBO (Burgas-Vlore),

[30] CTS project was initiated by the agreement of the Presidents of Kazakhstan and Azerbaijan dated June 16, 2008.

BAP (The Burgas–Alexandroupoli pipeline) and Trans-Anatolian (Samsu-Ceyhan) pipeline (commercially, it is less effective to transport Kazakh oil through the Railway to Ukrainian Odessa or Baltic Sea Russian export terminals. Based on information of ILF Consulting Engineers, transportation of oil by railway from Tengiz field to Odessa, at the distance of 1940 km costs 60 $ per ton, while transportation of Kazakh oil to Odessa through CPC pipeline and the Black Sea will cost about 41$ per ton. In addition, consolidated cost of transportation of oil from through Baku-Supsa pipeline and via Black Sea using standard Aframax tankers will be 4 times lower compared to the cost of use of railway instead of pipelines).

Euro-Asian Oil Transportation Corridor (EAOTC) project aims to enhance the energy security of the European Union member states through creating a secure route for transporting oil from the Caspian Sea Region through Azerbaijan, Georgia and Ukraine. EAOTC mainly comprises of the existing oil transportation infrastructure. Additionally, construction of a new DN 700 pipeline from Brody (Ukrane) to Adamovo (Poland) is also envisaged, with further use of the existing system of the Druzhba pipeline. Distance from Brody to Adamovo pumping station is about 397 km, including 127 km on the territory of Ukraine and 270 km – on the territory of Poland.

EAOTC project is planned to be implemented in stages with annual capacity of up to 20 mln. tons. At the first stage of the project implementation, it will be technically be possible to deliver up to 10 mln. tons of oil from the Caspian Sea region to the European countries, including in emergency situations, in case delivery of oil to refineries of the target countries from traditional sources stops or significant decreases due to any reason, including political reason or deterioration of quality, like it happened when poor quality oil was supplied to Europe from Russia in April 2019 [60]. At the second stage of development, it is also envisaged to build a new 830 km oil pipeline on the Azerbaijani-Georgian section or to increase throughput capacity of the railway.

Delivery of the Caspian crude oil through the EAOTC will increase the security of oil supply to the countries along the route and safety of transportation. It will enhance the diversification of supply routes to the EU by diminution of critical dependency from a single supplier in the region. Such connections would result in a high level of interoperability of the regional oil pipeline network, thus ensuring continuous oil flows to the depending refineries in case of supply disruption through the conventional supply route.

The Project will provide for integration of Azerbaijani, Georgian and Ukrainian oil transportation systems[31] with Polish and European ones increasing European Energy Solidarity and improve the

[31] Azerbaijan-Georgia-Black Sea-Ukraine route was repeatedly used for delivery of the Caspian oil to the oil refineries of Belorussia in small volumes.

economic ties between the EU and Energy Community partner countries, participants of the Project. It will strengthen partnership with the producing and transit countries and give way to better promotion of EU policies outside its borders.

The Brody - Adamovo pipeline section creates the possibility to transport the crude oil in reverse mode – from Baltic Sea to the consumers in Ukraine, Slovakia and the Czech Republic. It will enhance the interoperability of the European oil transportation system and allow to minimize the risks of the crude oil delivery interruption. The project contributes to avoidance of ecological risks related to oil shipping, risks of significant delay at the “choke points” (Turkish, Gibraltar and Danish Straits) and emissions arising from tanker traffic which would be the transport alternative in case the EAOTC project is not realized.

EAOTC will enhance the compatibility of European oil transportation system and the decrease of oil delivery risks at the expense of changing current dead-land supply system with high quality ring-type system in the central part of Europe and will link the Baltic and the Black sea water area oil terminals through uninterrupted chain.

EAOTC project is operated by MPR „Sarmatia" Sp. Z.o.o. Its shareholders are: SOCAR (Azerbaijan), Georgian Oil and Gas Corporation (Georgia), JSC Ukrtransnafta (Ukraine), PERN S.A. (Poland) and AB "Klaipedos Nafta” (Lithuania).

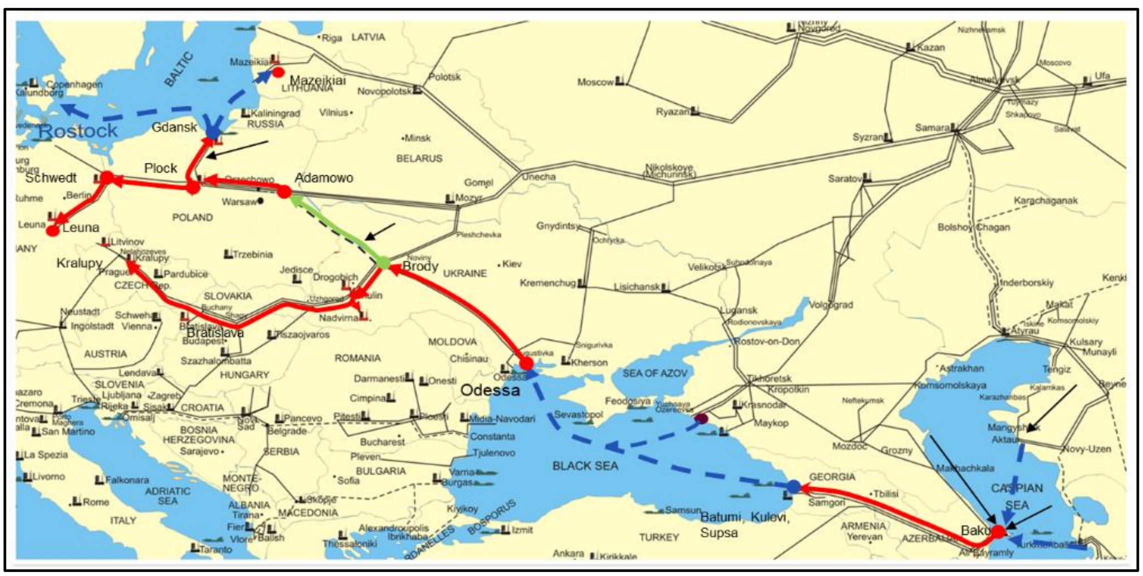

Figure 2.2. Euro-Asian Oil Transportation Corridor (EAOTC)

There are also some pipeline projects considering the delivery of Caspian oil to the European markets from the ports of the west coast of the Black Sea, aiming to release the straits of Bosphorus and Dardanelles from the tankers:

- **Samsun-Ceyhan Oil Pipeline** project from Samsun (Turkey) to the Mediterranean Sea coast to Ceyhan and Yumurtalik terminals;
- **Pan-European Oil Pipeline** from the Romanian Black Sea port of Constanza via Serbia, Croatia and Slovenia to the Adriatic Sea port of Trieste (Italy);
- **Albania-Macedonia-Bulgaria Oil Pipeline** from the Bulgarian port of Burgas via Macedonia to the port of Vlore in the Adriatic Sea (Albania);
- **Burgas–Alexandroupolis Pipeline** from the Bulgarian port of Burgas to the city of Alexandroupolis (Greece) in the Aegean Sea.

Prospects of further development of these projects are questionable in the current conditions of the global oil trade tendencies.

b) Other types of oil transportation

Maritime transport represents the most effective ways to transport liquid hydrocarbons at particularly long distances. As a rule, tankers used to transport oil and petroleum products are double-hulled which ensures high level of operational safety.

Relatively small tonnage tankers are used for transportation of the petroleum products. They are differentiated by sizes: <40000 tons, 40000-50000 and 50000-60000 tons of deadweight vessels belong to small size vessel types (Handysize, Handymax and Supermax classes). They can easily maneuver in shallow water ports (like Georgian Black Sea ports) and are important part of the cargo fleet for river navigation facilities of very low tonnage (≤5000 tons) and sinking depth (up to 3,5-4 m), which are used for transportation of the Caspian region oil products from Caspian northern port Astrakhan (Russia) to the Sea of Azov, with the unit cost of transportation about $4/100 tkm) [61].

Dead weight tonnage (DWT) of the Panamax tankers amounts 60000-80000 tons, standard draft is 12 meters, the dimensions are limited according to pre-reconstruction size of **Panama Canal** (290 m in length, 32.3 m in width, and 12.04 m in-depth, though after reconstruction, the Panama Canal can transport new Panamax class tankers with a deadweight of up to 120 thousand tons and a draft of up to 15,2 m).

DWT of the Aframax tankers (standard) ranges between 80,000 and 120,000 tons. The dimensions are limited in accordance with Average Freight Rate Assessment (AFRA) system.

Panamax and Aframax tankers due to their limited dimensions and high manoeuvre capability are effectively used in various oil terminals of the world including the Black Sea oil terminals of Georgia.

DWT of the Suezmax tankers have maximum deadweight of 150000–160000 (rarely 200000) tons and meet the restrictions of the Suez Canal (Maximum draft 20,1 m, Beam 77,5 m).

Tankers with deadweight of 180-320 thousand tons and length of 330 m are classified as VLCC, (Very Large Crude Carrier), and tankers with deadweight of 320000-550000 tons and average length of 415 m belong to Ultra Large Crude Carriers (ULCC). The most well-known, longest ocean vessel "Knock Nevis" (also referred to as "Mont") was an oil tanker with the length of 458 meters, deadweight of 564,7 tons, draft - 24,6 meters, speed - 16,5 knots (30,6 km/hr). The tanker has been transformed into an oil storage since 2010. VLCC and ULCC class tankers are mainly used for the North Sea, West African waters and the Mediterranean Sea, including port of Ceyhan (Turkey) to carry large volumes of oil at particularly long distances.

Liquified natural gas (LNG) and compressed natural gas (CNG) can be transported at long distances in marine tankers. The costs of LNG tankers make up a significant part of the whole investment of the LNG project (after the investment necessary for the construction of the liquifiactin plant) which is conditioned by the safety requirements, and envisages use of specific materials and welding technologies for their construction[32]. Moreover, materials for the construction shall have high insulating properties in order to maintain low temperature during transportation and minimize the losses of vaporing. Typical LNG tanker costs 200-250 million USD. It can carry 145-155 thousand cubic meters of LNG which is equivalent to about 100 mcm of natural gas. Carrying capacity of the New Generation „O-Flex LNG" tankers is about 200-250 thousand cubic meters. Their speed is 18-20 knots (≈37 km/h) which is higher than the speed of a standard oil tanker (14 knots). Loading of a standard LNG tanker takes about 18 hours, unloading takes 12 hours.

CNG is produced by compressing natural gas at approx. 200 bar pressure which is stored in special high pressure reservoirs. CNG is comfortable means for supplying natural gas to the market to meet a relatively lower demand (1-2 bcm/y) and transport at 500-1500 km distance when construction of gas pipeline (especially offshore) is not economically justified. Besides, the facilities for CNG production, storage and transportation are far simpler and cheaper than cryogenic systems used for LNG. In order to simplify its consumption, by reducing pressure, the

[32] To be liquefied, natural gas must be cooled at the temperature of -161°C. Standard steel is fragile at such a low temperature.

gas regains its initial properties before it is supplied to the distribution network. Special high-pressure transportation vehicles (tankers) are used for CNG transportation to final consumers.

Special category of marine vessels are used for transportation of liquedfied petroleum gas (LPG). LPG is produced in refineries, natural gas processing and liquefaction plants. LPG tankers are not costly as they do not need the use of low temperature resistant construction materials and special construction technologies.

Table 2.2. Railways for Caspian crude oil

Route	Country	Supply source	Capacity, mln. tons per year
Aturay-Astrakhan	Kazakhstan, Russia	Kazakhstan	10
Astrakhan- Volgograd-Rostov	Russia	Kazakhstan, Russia	15
Rostov-Odesa	Russia, Ukraine	Kazakhstan, Russia	15
Makhachkala-Novorossiysk	Russia	Kazakhstan, Turkmenistan	10
Baku-Tbilisi	Azerbaijan, Georgia	Azerbaijan, Kazakhstan, Turkmenistan	10
Tbilisi-Batumi	Georgia	Kazakhstan, Turkmenistan	15
Tbilisi-Kulevi	Georgia	Azerbaijan	10

Crude oil and petroleum products are transported by land with 60-120 tons railway tanks made of special steel. The cost of railway transportation of oil is significantly higher than the trunk pipeline transportation costs [62]. Tariff of transportation through the regional trunk pipelines fluctuates on average from 1-2,5$/tx100km[34], while railway transportation tarrifs range between 3-5,5 $/tx100km [63]).

Tank cars are used to transport oil, petroleum products, liquefied and compressed natural and liquefied petroleum gas at shorter distances or in cases when it is impossible to use other means of transportation. They are the most expensive means of transportation of oil and liquefied hydrocarbons. For instance, according to the information, unit cost for transit from Caspian

[34] Transit tariff of approx. 1 $/t100 km is observed at the sections of the oil pipeline "Druzhba" in Ukraine, Belorussia and Poland and 2,5 $/t100 km – on the Russian section of CPC pipeline.

Region to Afghanistan and during large scale transportation of oil products on the territory of Afghanistan fluctuates ranges between $(12-15)/t*100km [61].

Pipelines, road, and rail tank cars can be used for transportation of LNG onshore. Tanks are double-walled vacuum insulated reservoirs similar to a thermos. LNG can be stored in similar vessel for several days without any loss [64].The inner tank and the connecting pipeline are made of strong stainless steel with a minimum heat absorbing super-insulation with a deep vacuum. The tanks are also capable to avoid catastrophic results during transportation accidents.

LNG rail tank is a 120 cubic meter reservoir. The typical volume of road tank is 40-50 cubic meters which enable transportation of about 25 000-30 000 cubic meters of natural gas equivalent LNG at one time.

Introduction of transportation technologies of natural gas conversion products (LNG, CNG) and liquefied petroleum gas (LPG) in Georgia is particularly favorable in order to supply relatively cheap and ecologically pure fuel to regions that are not covered with gas pipelines, are not densely populated and mountainous regions, which are not expedient to be provided with pipeline gas (potential consumers in Georgia 20%).

These products can be effectively used as the fuel for trucks and sea transport, also. Replacement of diesel internal combustion engines with LNG (CNG) engines increases initial capital expenditures by 10-20%, however, due to significant reduction of operational costs within 20-40%, the investment payback period is less than 2-4 years. Use of liquified gas fired engines for tugboats in the port area is considered effective due to the simplicity of arranging a fuel recharging spot. Moreover, using LNG instead of traditional fuels such as Diesel, Heavy Fuel Oil (HFO) and Marin Gasoil (MGO) by maritime transport and heavy tonnage trucks significantly reduces pollutant emissions (nitrogen oxide emissions decrease at least 8 times and sulfur oxide and solid particles exhaust practically equals to zero) [65].

c) Marine terminals

Crude oil extracted from the Caspian oil fields and petroleum products produced in the region (in the perspective, natural gas transformation products, such as LNG, SNG, NLG) are exported to international markets through marine terminals. The table below provides the characteristics of marine terminals of the region, as well as the main European consumer regions of Caspian crude oil.

Table 2.3. Marine terminals

Terminal/ port	location	Max. DWT 1000t	Length or sea route	Volume of reservoirs 1000 m³	Hourly load m³/h	Capacity, Mta
Supsa terminal	Black Sea, Georgia	120-150	Odessa ≈565 Trieste≈1740	195	1 000	6
Poti port	Black Sea, Georgia	110	Odessa ≈565 Trieste ≈1740	118	250-500	1,5-2
Batumi port	Black Sea, Georgia	80-100	Odessa ≈600 Trieste ≈1700	570	3 000	15
Khulevi Terminal	Black Sea, Georgia	80-100	Odessa ≈550 Trieste ≈1750	320	6 000	10
Novorossiysk port and CPC terminal	Black sea, Russia	300	Odessa≈362 Trieste ≈1608	1 000	15 000-20 000	≈125
Ceyhan terminal	Mediterranean Sea, Turkey	300	Trieste ≈1550	1 000	10 000	50
Aktay port	Caspian Sea, Kazakhstan	70	Baku≈250 Makhachkala≈200			≈30

d) Offshore Zones and Choke Points

To ensure a guaranteed supply of liquid hydrocarbons, international standards and restrictions for sea navigation must be taken into consideration. In particular, for the safe delivery of hydrocarbons from the region by maritime transport the division of seawater area for economic purposes and restrictions of chokepoints have to be considered.

The International agreements are setting the rule for division of continental shelf. In particular, sovereign rights of coastal states unlimitedly apply to internal waters and territorial waters within the coastline. The maximum area of territorial waters may extend to 12 nautical miles from the coastline.

Restricted sovereignty of coastal state applies to the area beyond the internal and territorial water areas, adjacent and exclusive economic zones, within the 200 nautical miles (the adjacent zone, with the maximum width of 24 miles from territorial waters is allocated in case of special necessity and restrictions of the exclusive economic zone apply to it – the littoral state has a right to control compliance with fiscal, emigration and sanitary norms and riles in this zone and take measures to prevent and eliminate their violation). In particular, a coastal country has the right to apply the restricting legal regime for the natural resource exploration and production activities, fishing and etc. recognized by the 1982 UN Convention. In addition, the Convention does not restrict international air and sea navigation, laying cables and construction of pipelines in the zone (considering the internationally recognized safety and environmental protection norms) and other activities in open waters prescribed by the international law.

There are several critical choke points for oil transportation to the international market[35] through which, more than half of oil trade operations are carried out. Some of them [66] are directly related to supply of resources from producing country of the region to the target markets.

Security of narrow choke points and exercising effective control over them are significant factors contributing to free trade of Caspian crude.

Bosporus and Dardanelles straits through which mainly Russian and Caspian oil and oil products are exported to the Mediterranean Sea region markets, are controlled by Turkey. Navigation in straits and generally, in the Black Sea water area is regulated by the 1936 Montreux Convention, however, the Turkish government has introduced additional regulations for enhancing ecological safety of straits and to a certain extent, enhancing its dominance in the straits, which sometimes becomes the reason for the ineffectiveness of the straits.

Due to the restrictions imposed on the Turkish straits, development of the LNG receipt terminal in Ukraine was became complicated and it also hampered timely delivery of international humanitarian aid to Georgia during 2008 August military conflict with Russia. In addition, it should be noted that today the Montreux Convention does not correspond to the reality formed after the disintegration of the Soviet Union as it does not consider interests of Ukraine and Georgia being coastal states of the central and eastern part of the Black sea.

Generally, straits including the Hormuz strait [67] near Iran, which provides transportation of 17 mbd of petroleum – 20% of global demand & 42% of trade and 82 million tons of LNG pa – 30 % of global demand are formally governed by the 1982 International Maritime Convention, however, Iran, which is not a signatory party to this Convention, sometimes neglects the regulation rules established by the Convention.

[35] Narrow straits connecting the regions owning rich resources with open international marine/ocean transport routes are called „Global Choke Points". Closure of each of them causes extension of the delivery route by thousands of kilometers and accordingly, sharp fluctuation of prices.

2.2. THE SOUTHERN GAS CORRIDOR

The fourth, EU-supported Southern Gas Corridor concept is being intensely developed for the purpose of enhancing security of European energy market and diversification of supply sources and routes. The concept envisages development of independent supply routes passing through South Caucasus and Turkey (or Black Sea) in order to transport natural gas (and/or LNG-CNG) to Europe from the region.

Implementation of the Southern Gas Corridor concept will facilitate compensation of the reduction of indigenous gas production in Europe. At the same time, the supply sources and routes will be diversified, first of all for the Balkan countries and those countries of Europe, that are critically dependent on the Russian gas import. During the first Russia-Ukraine gas crisis, on January 1, 2004, when Gazprom suspended gas delivery to Ukraine, transit flow to Europe was immediately reduced by 105 and 119 Mcm/d, on January 2 and 3, respectively. As a result, gas delivery decreased by 40% to Hungary, 30% to Austria, Slovakia, and Romania, 20% to France, 14% to Poland and partly to Germany.

During the second conflict, from 6 January 2009, approximately 300 Mcm Russian gas was not delivered to Europe. As a result, Gas consumption in some countries of Europe decreased by 25-75% and more [68,69].

The crisis showed that Russia using energy resources to settle political disputes and/or economically backmail neighbouring countries [70], which become one of the motivations to develop the Southern Gas Corridor.

One of the significant designations of the Southern Gas Corridor is enhancement of competition on the European markets. As it is known, Russia often manipulated with gas price in order to exert political or economic pressure upon post-Soviet Republics as well as some of the countries of EU: traditionally, the Russian gas price in Ukraine, Moldova, Georgia, Baltic countries and Poland, was higher than in Central and West European countries delivered there via the abovementioned countries and in other countries that are loyal to the Russian politics. Besides, The Corridor will ensure supply of several Balkan countries which have no (or low) natural gas consumption yet, with comparatively cheaper and ecologically safe natural gas.

Currently, the Southern Gas Corridor (SGC) is devoted to delivering Azeri Shah-Deniz natural gas to Turkey and Europe via the territories of Azerbaijan, Georgia, Turkey, Greece, and Albania.

The Corridor consists of the South Caucasus Pipeline Expansion (SCPX), Trans-Anatolian Pipeline (TANAP) and Trans-Adriatic Pipeline (TAP) projects.

Figure 2.3. Southern Gas Corridor (Source: Wikipedia)

Shah-Deniz is an offshore Gas condensate field of the Caspian Sea. It is located on the deep water shelf of the Caspian Sea, 70 km south-east from Baku, in water depths ranging from 50 to 500 m. The territory of the field is 149 square kilometers and proven reserves are 1.2 trillion cubic meters of gas (240 million tons along with condensate). The field was discovered in 1999 and was launched in 2006. Until 2020, about 100 bcm of natural (and 25 M tons of condensate) gas was produced on the field.

The second stage of the field development is aimed at producing additional 16 bcm of natural gas in stages: 6 bcm - from 2018 for the Turkish market and 10 bcm – from 2020 for the European market. The project envisages construction of two platforms, the drilling of 26 subsea wells, the laying of 500-kilometer underwater interconnected pipelines at the depth of 550 meters, connected to the Sangachal terminal. Two treatment lines (capacity of each line is 8 bcm) are installed at the terminal to obtain adequate quality of gas.

Total estimated cost of the project is 23,8 billion USD, along with the South Caucasus Pipeline Expansion project cost (4,9 billion USD). The shareholders are: BP (operator) -28,8%, AzSD – 10 %, SGC Upstream - 6,7%, Petronas – 15,5 %, LukOil – 10 %, NICO- 10 %, TPAO -19 %.

The South Caucasus Pipeline Expansion (SCPX) Project is one of the key projects of the Southern Gas Corridor which enables to deliver gas extracted from Azerbaijani fields and, in the future, possibly from the central Asian fields, through the territory of Georgia to Turkey and European energy markets.

The South Caucasus Gas Pipeline system with the throughput capacity of 7,4 bcm has been operational since 2006 to serve the phase one of the Shah Deniz development project. It is envisaged to transport gas to the city of Erzerum in Turkey via Georgia. The length of the Georgian section of the pipeline is 248 km (690 km total length), pipeline diameter is 1067 mm (42 inch). Two metering stations (at Azerbaijan-Georgia and Georgia-Turkey borders) and gas off-take point are installed on the Georgian section of the pipeline for gas supply of Georgia.

In order to increase the pipeline throughput by approx. 16,5 bcm,[36] and receive additional gas from stage 2 of the Shah-Deniz development project, according the SCPX project, 48 inch pipeline (loop) with total length of 487 km is built in parallel to the South Caucasus Pipeline, including 3 new pipeline sections in the territory of Georgia with the total length of 63,8 km (56, 5,3 and 2,5 km) and Gardabani 61 MW compressor station (similar compressor station located in Tsalka is planned to be commissioned).

Estimated cost of pipelines, compressor stations and additional infrastructure of the SCPX Project located in Georgia equals to approx. 2 billion USD.

Trans-Anatolian Pipeline (TANAP) connects the South Caucasus Pipeline at the Georgian border, near the city of Posof and the Trans-Adriatic Pipeline at the Turkey-Greece border. The pipeline is aimed to deliver Azerbaijan gas extracted from Shah-Deniz field to Turkey and transit it to the European countries.

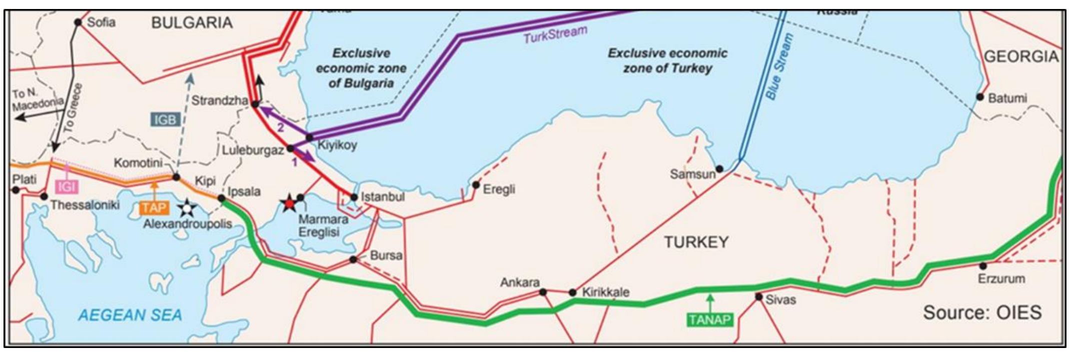

Figure 2.4. Trans-Anatolian Pipeline[37]

Trans-Anatolian Pipeline with the length of 1839 km, incudes: 1345 km 1400 mm (56 inch) diameter pipelines from Ardahan to Eskişehir (to Turkish off-take), 459 km 1200 mm (48 inch) diameter pipeline from Eskişehir to Edrine and 2x17,5 km 900 mm (36 inch) diameter pipeline

[36] Total expandable capacity of SCPX pipeline 31 Bcma

[37] Source: OEIS, Energy Insight: 65 by S.Pirani, J.Sharples, K.Yafimava, V.Yermakov, March, 2020

at the Dardanelles strait seabed, at the depth of about 100 m from the sea level near the city of Chanakale.

Two compressor stations were built at Georgian border and Eskishehir at the first stage of the project implementation, which is sufficient for transportation of at least 16 bcm of natural gas. In order to transport 30,7 bcm of gas, the project envisages arrangement of 7 compressor stations, 4 metering stations, 12 pigging and diagnostic and 49 valve stations. On the territory of Turkey there are two off-take stations in Eskishehir (Central Anatolia) and Thrace (European part of the country) provinces.

After completion of the first stage of the Trans-Anatolian Pipeline construction to the city of Eskişehir in 2018, it became possible to deliver 6 bcm of natural gas envisaged for Turkey. In 2018, from the Shah-Denis phase 2 production about 1 bcm of natural gas was delivered to the Turkish market. According to the plan, roughly 3 bcm of additional gas (9,2 bcm in total) was delivered in 2019, at least 4 bcm will be delivered in 2020 and 6 bcm will be delivered in 2021 [71]. In parallel, TANAP will be linked to the Trans-Adriatic Pipeline and from 2020 delivery of gas to the European market will incrementally increase to 10 bcm.

According to the evaluation of the Trans-Anatolian Pipeline project owner consortium (SOCAR 51%, BOTAS 30%, BP 12%, SOCAR Turkiye Enerji 7%) the construction cost is about 9,3 billion USD, among tham planned cost of the first stage - about 8 billion USD (according to the information, actual expenses of the pipeline construction are significantly reduced).

Trans-Adriatic Pipeline (TAP) is a part of the Southern Gas Corridor passing through Greece, Albania and Adriatic Sea to the south Italy. Its length is 830 km (551 km on the territory of Greece, 216 km - on the territory of Albania, 105 km – in the Adriatic Sea bed and 8 km - on the territory of Italy). Initial capacity of TAP is 10 bcm/y, with further increase to 20 bcm/y, after commissioning of 4 compression stations.

Along the pipeline route, **the Greek-Bulgaria Interconnector (IGB) and Ionian-Adriatic Pipleine** (IAP) will be linked to the Trans-Adriatic Pipeline to deliver gas according the contract concluded by Greece-Bulgaria and Albania [71].

Length of IGB is 182 Km (151km – in Bulgaria; 31km – in Greece); Pipe Diameter - 32”; Capacity 3 bcm/y; upgrade up to 5 bcm/y; Entry point Komotini (Greece) connecting TAP and DESFA pipelines, Exit point: Stara Zagora (Bulgaria) connected to Bulgartransgaz pipelines.

516 km long IAP will connected to TAP at the city of Fieri, Albania, will pass through Montenegro, Bosnia-Herzegovina and will end in Croatia. It will deliver gas to oher countries of the south-east Europe, in addition to Albania.

Through the metering station (capacity of 25 mcm/day) and off-take station and the pipeline network located on the territory of Italy, the Southern Gas Corridor will be linked to the many gas market of Europe. On the basis of the existing contracts, the Turkish company Botas and 9 companies of EU member states: Shell Energy Europe (UK), Hera Trading (The Netherlands), Uniper (Germany), AXPO (Switzerland), Engie, Enel, Edison (Italy), Depa (Greece) and Bulgargaz (Bulgaria) will start receiving up to 16,2 bcm of gas from Shad Deniz field from 2020.

The shareholder and key investor of the pipeline project is Trans-Adriatic Pipeline AG (TAP) consortium consisting of several international energy companies (BP-20%, AzTAP (SOCAR subsidiary)-20 %, SNAM-20%, Fluxys-19%, Enagas-16%, Axpo-5%). The cost of the project is about 6 billion USD. The project is scheduled to be completed in 2020.

The prospects for the development of the Southern Gas Corridor

Geographical location, existing transportation infrastructure and prospects of its development, as well as wide experience in construction and management of major transit projects and successful partnership relations with international companies, supported establishment of Georgia as a favorable country for construction and operation of diversified routes of supply from Caspian sources to the international energy market (see Figures 2.5 and 2.6). In addition, Georgia’s clear aspiration to be integrated into the western political and economic structures and internationally recognized attractive business environment creates guarantees for attraction of large-scale investments in development of transit infrastructure of Southern Gas Corridor.

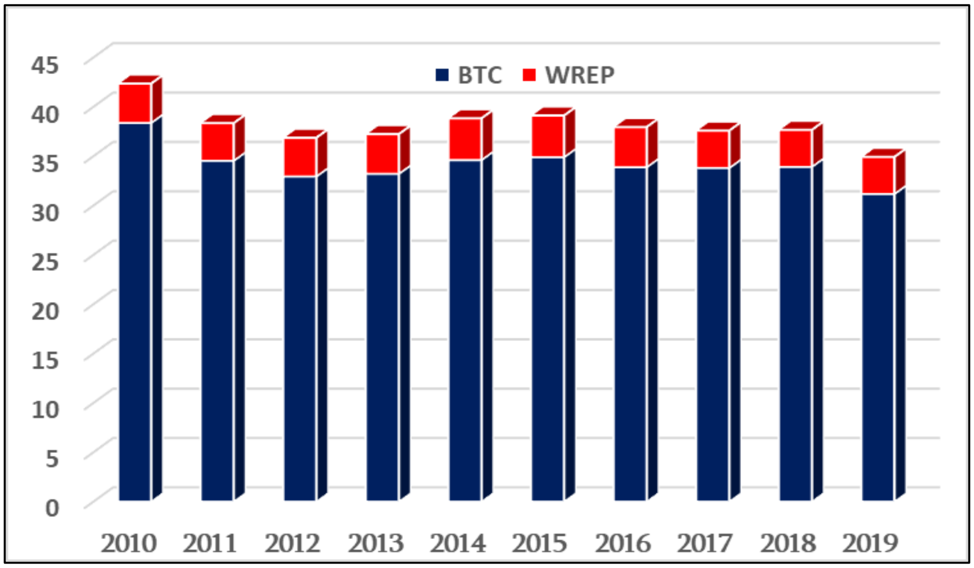

Figure 2.5. Oil transit through Georgia, Mta

Oil and gas infrastructure existing as well as planned or considered to be developed on the territory of Georgia, is directly connected to the Black Sea and via Turkey to the Mediterrenean sea terminals or South Eeast European countries and they may become a significant part the Southern Gas Corridor and part of LNG (and/or CNG) terminals.

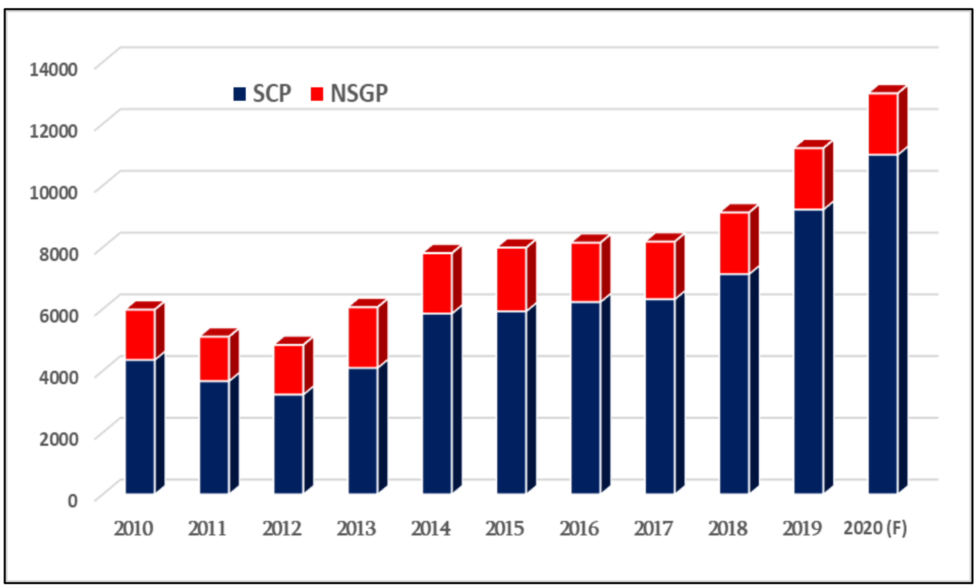

Figure 2.6. Natural Gas Transit through Georgia, bcm/y

Planned projects

a) White Stream (WS)[38]

The Black Sea offshore "White Stream" (WS) pipeline project is envisaged to deliver Turkmen Gas to Romania through the Trans-Caspian Gas Pipeline, via the territories of Azerbaijan and Georgia and the Black Sea.

Initially, two options of the project development were considered: a) through the intermediate intake point on the territory of Ukraine and b) direct delivery to the Romanian port of Constanza. After Russia occupied Crimea, the idea of the arrangement of intermediate intake point in Ukraine was practically excluded. Moreover, de-facto partition of the Black Sea water area as a result of the Russian aggression, may become one of the hindering factors for the project implementation.

The Black sea water area is divided according to the contract concluded between the Soviet Union and the Turkey. After breakdown of the Soviet Union, according to the conventional division of the water area into marine economic zones (which was significantly changed after occupation of Crimea by Russia – see dotted lines on the figure), the zone belonging to Georgia is not directly connected to the waters of Ukraine and Romania, while Russia (or Turkey) practically entirely controls the zone of location of assumed offshore pipeline route of the WS project. For Russia and Turkey, WS is considered to be a competitive project (against Turkish stream and TANAP) and they will not easily agree to grant the corresponding ecological permission.

Russia, as the legal successor of the Soviet Union is a signatory party of the 1982 United Nations Convention on the Law of the Sea, but it will have the opportunity to hinder the implementation of the competitive project as the Convention on the Law of the Sea does not directly apply to the Black Sea water area, including due to the fact that the Black Sea, like the Caspian Sea is not a classical open sea. Also, its minimum width in the narrow area is about 320 km and therefore, there are no neutral waters with the possibility of performing unlimited economic activities. Meanwhile, Turkey does not have a direct obligation to pass pipelines through its territory.

[38] WS project is included in the preliminary list of PCI/PECI projects of Energy Community of the 2020 call

Figure 2.7. De-facto division of the Black Sea water area into economic zones (Source: Wikipedia)

It is also notable that in addition to politicized ecological problems, implementation of the White Stream Project may face technological problems [72], which may also include the problem of obtaining a permission from the competitive party (Russia) for crossing the existing "Blue Stream" and "Turkish Stream" pipelines by the "White Stream" pipeline at the Black Sea bed. The issue related to the consent of transit and recipient countries (Azerbaijan and Romania, respectively) required for implementation of "White Stream" project is also unclear.

Besides, the project implementation may be hindered if Russia resumes import of large volumes of Turkmen gas from Turkmenistan which is considered to be potentially the main source for WS project [73].

b) Azerbaijan-Georgia-Romania Interconnector (AGRI) Project

Azerbaijan-Georgia-Romania Interconnector (AGRI) project envisages arrangement of a natural gas liquefaction plant with throughput of 2,5 or 8 bcm at the Black Sea coast of Georgia and its transportation to the Romanian port of Konstanza by tankers, where LNG will be received and regasified. AGRI feasibility study report determines the project implementation feasibility, however, today the fact that there are no free gas volumes in the region hinders its implementation (therefore the decision of suspension of the activity starting with 1 May 2020, for a duration of 3 years, has been made by project`s promoter company).

In case of new fields of Azerbaijan are successfully developed or transportation projects of Turkmen gas to the east coast of the Caspian Sea are implemented, it will be necessary to deliver additional volumes of gas to the international market and realization of AGRI LNG project will be activated. In addition, it should be noted that expediency of implementation of the AGRI project is especially vital in case of smaller volumes of additional gas (up to 5-8 bcm) which can be obtained from implementation of intra-Caspian, relatively smaller capacity, offshore pipeline project between two neighboring, small capacity Turkmen and Azerbaijani extracting sea platforms.

Support from the participant EU member state – Romania and its intention (as well as intention of Ukraine) to build LNG receiving (regasification) terminal at the west coast of the Black Sea should be considered as a factor contributing to the project implementation. Infrastructure for delivery of gas from the Black Sea coast to the continental Europe already exists or is being constructed.

It is noteworthy that according to the experts of the Energy Community one of the hindering factors of AGRI project implementation is the need for large-scale investments. It is conditioned by high costs of arrangement of onshore liquefaction plant - according to the initial project: 4,65-7,65 B€ by 5 bcm or 8 Bcm capacity corespondingly) [74]. At the same time, it can be observed that capital costs for LNG liquefaction plants have dropped significantly in the last years, after the period of higher costs (2010-2014), opening new opportunities [75]. In fact, costs have fallen from higher values of 2010-2012 years period, when AGRI project feasibility study was elaborated, for an average of 30 – 50 % [76]. This has happened mainly due to:

- reduction of the cost of LNG processing plants and construction costs globally due to the increasing competition between contractors and equipment suppliers;
- a move away from bespoke company standards to the functional industry standards and specifications while implementation of LNG projects;
- introduction of floating liquefaction plants;
- building of identical, modular trains to capture the economy of scale;
- building plants on the existing import terminal sites, utilizing the existing infrastructure and processing clean pipeline gas from local grid (e.g. utilizing of Azerbaijan's pipeline gas for AGRI project in the Georgian Black Sea onshore liquefaction plant).

According to the latest information, the actual cost of the Floating Liquefaction of Natural Gas Plant – FLNG equipped with modern technologies is significantly lower than the cost of the respective onshore plant [77], which significantly increases the prospects of successful implementation of such projects.

The intention of possible production of LNG and implementation of the project of its delivery to the European market by Azerbaijan-Georgia-Black Sea route was declared at the Caspian Economic Forum in 2019 [78] by “Edison Technologies LTD" which also considers the opportunity of transportation of up to 1 million tons of methanol per year by a small diameter pipeline from Turkmenistan to the EU market.

High pressure CNG production technology can be considered to be an alternative of LNG, envisaging compression of natural gas at approximately 200 bar pressure. CNG is the most convenient way of supplying natural gas to the market in case of small demand and transportation at a short distance, when a pipeline construction (especially in offshore or mountaineous regions) is economically unjustiafieable. Besides, the facilities for CNG production, storage and transportation are particularly simple and cheap.

Generally, introduction of technologies for production and transportation of natural gas conversion products (LNG, CNG) and liquid petroleum gas (LPG) in Georgia is an effective alternative of construction of new pipelines due to the need of minimum initial investments, as well as possibility of using high pressure of gas taken from transit pipelines for partial energy supply of the conversion process (in case of CNG production).

c) Additional sources of supply

- Azerbaijan

Apart from the Shah-Deniz field, offshore Absheron, Shafag-Asiman, Umid, Azeri-Chirag-Gunashli (associated gas and deep, gas-containing horizon), Babek, Karabagh, Bahar and other Caspian Sea offshore fields of Azerbaijan are considered to be additional sources of supply.

Estimated reserves of Absheron field equal to 326 bcm of gas and 108 million tons of gas condensate. At the first stage, about 1,6 bcm (4,3 Mcm/d) of gas and additional 4,4 million tons of condensate are planned to be produced from the field annually, which are envisaged to supply the internal gas market. At the second stage, presumably from 2026, production will grow to 4 bcm. Additional gas will be used mainly for export [79]. The field operator is Joint Venture JOCAP and its shareholders include SOCAR-40%, TOTAL-40% and Engie 20%.

Production wells already function on Umid field. Annual production is planned to be increased to 4-7 bcm in 2024-2026. The field is operated by SOCAR.

Development of Azeri-Chirag-Gunashli gas containing horizon is considered to be one of the prospective projects among BP operated fields (planned production from 2027-2028).
Drilling works at Shafag-Asiman field (reservoir depth 7000 m, the total area of the block 1100 square km) are planned to be commenced from soon and intensive extraction is projected to begin from 2027 with peak production of 5-6 bcm by 2034.

Possibilities of Shah-Deniz field phase 3 implementation are also being considered [80], where estimated annual production will exceed 5 bcm. Investment decision about development of deep horizon of the field will presumably be made in 2025.

Significant growth of Azerbaijan's export potential, according to projections, will be possible from 2026, and by 2035, when total production reaches 50 bcm, it will be possible to export about 25 bcm of natural gas annually [81].

- ***Turkmenistan***

The largest fields of Turkmenistan are gathered in the eastern part of the country in the Mary Region including giant Galkynysh[39] and Dauletabad gas fields. The Caspian Sea coast and adjacent offshore fields also contain significant reserves, development of which, unlike onshore fields, is related to significant challenges. Constraints of effective gas monetization in this part of country are also problematic.

Turkmenistan plans to significantly increase gas production and export up to 180 bcm by 2030 [82], for which the existing and planned infrastructure will be used.

The Central Asia-China Gas Pipeline (CACGP) delivers Turkmen gas and gas of other Central Asian countries to China. The pipeline length is about 1833 km. According to the existing contract with the Chinese company CNPC, it is planned to increase delivery to China pro-rate the production growth to 40 and later to 60-65 bcm/y.

[39] According to the estimations of the British Company - Gaffney, Clain & Associates, initial gas reserves at the field equal to 21,2 trillion cubic meters.

Turkmenistan is connected to the western markets through the pipeline system CAC 2-5 passing through the territories of Kazakhstan and Russia with the total capacity of 65 bcm. Turkmenistan is connected to Iran with two separate pipelines with design capacity of 20 bcm.

Turkmenistan owns 85% shares in the Turkmenistan-Afghanistan-Pakistan-India (TAPI) [83] Gas Pipeline Consortium and is actively involved in the project implementation (according to the information, pipeline construction-preparation works to supply gas to Afghanistan at the first stage have begun). Total length of the pipeline is 1735 km, design capacity is 33 bcm. Likelihood of the project implementation has particularly increased after China decided to connect to Xinjiang province through Pakistan-China branch of TAPI to transport Turkmen gas to the province [84].

Currently, Turkmen gas is basically purchased by the CNPC which, according to the contract, can purchase up to 65 bcm/y of gas. The Russian Gazprom resumed import of Turkmen gas within the frames of 25-year contract which envisages import of up to 30 bcm gas annually [85]. The contract between Turkmenistan and Iran is still in force, under which 7 -10 bcm of natural gas is delivered to Iran annually (1,9 bcm in 2018).[40] It is notable that peak historic production in Turkmenistan was observed in 2015 and equaled to 72,8 bcm.

Approximately 30 bcm/y is local consumption and about 80-85 bcm/y of gas is already agreed to be exported from Turkmenistan. This might be associated with certain problems in the future. In addition, it should be taken into consideration that total throughput of Turkmenistan's pipelines that are operational or under construction equals to 175 bcm. These factors may significantly hinder implementation of new routes, because at least during the next decade the existing infrastructure may be used for export via China, Russia or Iran-Turkey without making any additional investmnets.

Trans-Caspian Pipeline and other alternatives to supply Turkmen gas to Europe

The European Commission has, for many years, supporting plans for the construction of 30 bcm capacity Trans-Caspian offshore pipeline to deliver Turkmen gas westward by the expanded southern gas corridor of Europe.

Prospects of realization of TCP projects significantly increased after signing the Convention in August 2018 at the summit of the littoral countries of the Caspian Sea. The Convention granted sovereign right to any of the littoral states to construct pipelines or other infrastructure on the

[40] Sharp reduction of export in 2017 is related to the debts accumulated by Iran.

Caspian sea floor, but specified that this would have to be agreed bilaterally and that the consent on environmental grounds would have to be given by all littoral states (P. 14.2).

The Convention clarified the legal status of the sea, emphasizing that the littoral states are jointly and solely responsible for the sea's security (no forces other than the littoral states could use it) and demarcated the territorial waters. The Convention did not, however, clarify how the seafloor and the subsoil are to be delimited, nor did it resolve border disputes between Azerbaijan and Turkmenistan (with respect to the border across the Serdar-Kiapaz oil field) or between Azerbaijan and Iran (with respect to their dispute on the Sardar-Jangal gas field).

Signing the Convention clearly moves a possible construction Trans-Caspian pipeline one step closer. Nevertheless, there are hurdles to overcome. First, in practice, the consent of Russia and Iran still needs to be secured, on environmental grounds and, as long as those countries have strategic reasons to deter substantial westward exports of Turkmen gas, it may not be forthcoming. Second, and more importantly, this political shift does not change the unfavorable economics of westward Turkmen exports.

Despite the above, interest in export of Turkmen gas increasing gradually. Specifically, perspectives of Trans-Caspian Pipeline construction was discussed between EU and Turkmenistan's representatives at the meeting of the Consultative Board of Southern Gas Corridor Project (Baku, February, 2020).

Besides, consortium of European and Chinese companies, including Edison Technologies GmbH, MMEC Mannesmann GmbH, Air Liquide Global E&C Solutions (EU), together with SINOPEC Engineering Group (China), expressed a desire to build 300 km of Trans-Caspian Gas Pipeline. This was announced by the representatives of the consortium with the representatives of Government of Turkmenistan at the Caspian Economic Forum, 2019 [86].

The planned pipeline should connect Turkmenistan to Azerbaijan. According to some sources, it is also planned to connect a gas pipeline from Tengiz in Kazakhstan to the network and connect it to TCP, which will provide for the transportation of natural gas from Turkmenistan and Kazakhstan through Azerbaijan to Georgia and Turkey and, further, to the European market. As a part of the project, the consortium is ready to design and build the necessary infrastructure, including gas treatment plants and compression stations.

However, on the other hand, the agreement of Germany on the support of the Russian Nord Stream 2 project and the directive of the EU, according to which internal regulations are applied to the infrastructure coming to EU from non-member states as well [87], may become a significant hindering factor for a large-scale Trans-Caspian pipeline project as 50% of the Nord Stream load has to come from non-Russian gas. Besides, in order to maintain the obligation to transit gas via Ukraine and load the Turkish Stream pipeline, Russia will presumably use the Turkmen gas, purchase of which has already been resumed by Gazprom since April 2019.

In addition, various technological and ecological aspects related to the construction of pipelines at the bottom of the Caspian Sea, including the issue of entry and operation of pipelaying vessels in the water area and the concern expressed by the Government of Iran and Russia at the Caspian Economic Forum still remain unresolved problems.

According to the Energy Ministry of Azerbaijan (April 2016), there is an effective option for delivering Turkmen gas through the Southern Corridor by connecting Azerbaijani and Turkmen producing platforms located in the Caspian Sea via 80-100 meter long Intra-Caspian Pipeline (ICP) which will have initial throughput capacity of 5 bcm with further growth prospects in the future. The project can be easily implemented as construction of the pipeline connecting the platforms is relatively cheap and SCPX, along with TANAP and TAP can transport up to 8-9 bcm of natural gas apart from the the already contracted volume (22 bcm) based on the existing inter-government agreements). Besides, one of the operators of the Turkmen sector of the Caspian Sea is a Malaysian company Petronas with annual production of approx. 10 bcm, which owns 15,5% share in the South Caucasus Pipeline Consortium purchased from Norwegian Statoil.

Feasibility of Intra-Caspian Pipeline project implementation is confirmed by several significant factors:

- The issue of monetization of the natural gas extracted at onshore fields of Turkmenistan is already agreed by contracts and is fully ensured by the existing infrastructure, or infrastructure under construction. Effective monetization of gas extracted from the offshore Turkmen fields is relatively complex due to the lack of corresponding infrastructure and more importantly, guaranteed consumers;
- In case of redirecting natural gas extracted from offshore fields westward, using a small-scale Intra-Caspian Pipeline, its unhindered supply to the European market will be possible using the existing infrastructure and infrastructure under construction on the territories of Azerbaijan, Georgia and Turkey without significant additional costs.
- Based on the Decision of the Ministerial Council of the Energy Community (D/2018/11/MC-EnC), Trans-Caspian, South Caucasus (with its extension) and TANAP

pipelines are recognized as the projects of common interest[41], which indicates that for further transportation of gas received from Turkmenistan, free volumes of the SCPX and TANAP will be used.

- The owner of the main gas receipt point in the west coast of Caspian Sea - Azerbaijan, lobbies the project, to provide utilization of the existing export infrastructure with design capacity.

To export 30 bcm of Turkmen gas to Europe through the large-scale Trans-Caspian Pipeline, it will be necessary to construct a new infrastructure on the territories of Azerbaijan and Georgia and then to Europe, which requires multi-billion investments. After resuming the Russian export direction for Turkmen gas and due to high competitiveness of the existing infrastructure or infrastructure under construction, and more importantly, due to high costs of production, construction of Trans-Caspian Pipeline and transporting the gas across SGC to EU markets, which can't be repaid on the basis of any reasonable assumptions for future European gas prices, the expediency of construction of the large-scale Trans-Caspian Pipeline remains under question.

Theoretically, it is also possible to deliver the Turkmen gas to the European market via alternative routes, through Iran's transborder pipelines, by Iran-Turkey, Iran-Azerbaijan-Georgia-Turkey, Iran-Armenia-Georgia-Turkey pipelines (see Table below). Also, besides the existing onshore pipelines, the option of exporting Turkmen gas in the form of LNG or via offshore pipeline is also considered, however, there is no infastructure for that (see the details about WS and AGRI project above).

Table 2.4. Iranian transborder pipelines

Pipeline	DN, mm	Length, km	Design capacity, bcm/y	Load bcm\y
Iran-Armenia	700	140	2,3	0,4-05
Iran-Azerbaijan	1220	1475	10	0,2-0,3
Iran-Turkey	1062	2557	14	7-8
Turkmenistan-Iran	1120 1000	182 200	12 8	2-8

Natural gas pipelines on the territory of Iran connect the gas rich south-west region to industrial centres, that are mainly located in the north of the country, as well as supply gas through Tabriz-

[41] See the List of the Energy Community Projects of Common Interest: Gas_20&21&22 – Infrastructure and associated equipment for transportation of natural gas from new sources from Caspian Region, crossing Azerbaijan, Georgia and Turkey and reaching EnC markets, including Trans-Caspian Pipeline, South Caucasus Pipeline (further) Expansion and Trans-Anatolia Pipeline Expansion.

Dogobayazit export pipeline with annual throughput of 14 bcm. The latter is connected to Iran - Azerbaijan and Iran-Armenia trunck pipelines.

Azerbaijan is connected to Iran with DN 1220, 1475 km long (1290 km on the Iranian Terrritory) Abadan-Astara- Hajigabul pipeline. The design capacity of the pipeline is 10 bcm, design pressure -55 bars (in fact it works on 18 bar and throughput is reduced significantly). The pipeline needs substantial reconstruction-rehabilitation as it has not functioned with its design parametres for many years. Currently, the pipeline is used to meet the obligation of the swap contract concluded between Iran and Azerbaijan, pursuant to which Azerbaijan can export up to 500 mm^3 of gas to Iran and Iran will provide gas to Nakhchevani anclave in return for 15-17% commission. Therefore, today, there is no ready and free infrastructure to transport Turkmen gas to Europe via Azerbaijan and Iran because apart from commercial factors, also includes the political content.

The design capacity of DN 700, 140 km long pipeline connecting Iran to Armenia is 2.3 bcm, but actual load - 0,4-0,5 bcm of gas exported to Armenia, is delivered to thermal power plants and Iran receives the generated power instead. To transit Turkmenistan's gas to Europe, Iran-Armenia interconnector and afterwards, the limited capacity Armenian pipeline system and section of North-South Gas Pipeline System (in the reverse mode), followed by pipelines on the Georgian and Turkey territories have to be used. Due to the limited capacity of existing infrastructure, quite a long distance of transportation (around 1500 km to Georgia and more than 2000 km further to Europe) and 5 transit countries to be engaged, this is problematic and inexpedient. Besides, Gazprom fully controls the gas pipeline system on the territory of Armenia, i.e. its use requires the agreement of the Russian Federation.

As the analysis shows, the shortest, commercially justifiable way to transport Turkmen (or Iranian) gas to Europe via onshore pipelines passing the territory of only one transit country is the Turkish route. The capacity of Iran-Turkey pipeline is 14 bcm, out of which 6 bcm per year can be used for export of gas westward.

Theoretically, in order to transport Turkmen gas (or Iranian gas, instead) via Azerbaijan, Trans-Caucasian Pipeline (towards Turkey) or SOCAR-owned, limited capacity Hajigabul-Karadagh-Tbilisi pipeline and thereafter, the North-South Caucasus Gas Pipelines (towards Russia) can also be used. However, SCP is envisaged for transporting Shah-Deniz gas. It is exempted from the third party access obligation under international agreemenets. After completion of stage 2 of the Shah-Deniz field development, its capacity has increased to 22 bcm and in case of development of stage 3 of the field, or development of other fields of Azerbaijan (by 2026-2030), the actual load will reach 30 bcm, which is a limited maximum capacity according to the pipeline contract. Therefore, the likelihood of using the SCP for reexport of large volumes of Turkmen gas is practically very low.

- Iran

Iran ranks second in gas reserves after Russia. Despite abundance of reserves, Iran's gas sector is quite ineffective due to the sanctions imposed by the west: development of fields requiring large-scale investments and funding of infrastructure projects are quite complicated. In addition, large volumes of produced gas are injected in the fields for stimulating extraction of oil[42].

There are other high technical losses (gas blow and burning), which according to rough estimation, makes up to 15% of total production. Besides, main gas fields of Iran are located in the south of the country, in the Persian gulf and adjacent regions, far from industrial regions located in the northern part which are main consumers of gas (industrial regions of Tehran, Tavriz, Kazvin, Hamadan and etc). The capacity of the existing infrastructure can not supply consumers with necessary volumes within the country and satisfy export requirements. Considering the aforesaid, Iran considers it expedient to export gas from the Persian gulf mainly as an LNG, where it can be delivered directly to the deficit markets of Japan, Korea-China, and Europe without the third country involvement [88].

Sanctions of Iran have critical geostrategic significance for the west, especially amid the geopolitical confrontation between Russia and the USA, to exclude creation of the North/South (Russia/Iran) economic and military-strategic axis and establishment of full control at the Hormuz strait and the Caspian Sea waters by Russia and Iran, which will pose a serious threat to implementation of projects of gas supply from new sources of the region, including Turkmenistan (after the sanctions, Iran has established closer relations with Russia and China. As a result, the Russian military fleet obtained permission for entry into Iran’s seaports and stay there for a certain time. According to August 12, 2018, Convention, entry and/or basement of military-marine or air forces of any non-littoral Caspian state was restricted).

Development of the planned pipeline and LNG projects of Iran is currently suspended mainly due to imposed economic sanctions.

[42] It was assumed to reinject 64 bcm of gas in 2015 and it is planned to increase this volume up to 80 bcm and more by 2030.

d). Competitive projects

- ***The Turkish Stream***

Traditionally Russia tries to protect its share of Europe's natural gas market. To this end, Russia's state-owned natural gas company Gazprom builds a new transportation infrastructure in order to halt the implementation of the projects not controlled by itself . The existing Blue Stream and Turkish Stream offshore pipelines in the Black Sea connecting Russia and Turkey, Nord Stream offshore pipeline in the Baltic Sea connecting Russia to Germany, as well as „Nord Stream 2" pipeline under construction, in order to export gas to Europe, bypassing Ukraine and other Eastern European countries (see Figure). Along with the controversial Nord Stream 2 project, the TurkStream project strengthens Gazprom's position in the southern European market.

The TurkStream project consists of two parallel pipelines with a total capacity of 31.5 bcm/y. The pipelines enter the water in Anapa, Russia, and makes landfall in Kiyikoy, close to Turkey's border with Bulgaria. The first pipeline supplies natural gas mainly to Turkey. The second TurkStream line is to transport Russian natural gas from the Turkish landing point to southeastern and central European markets via Bulgaria, Serbia, and Hungary.

TurkStream's subsea portion was completed in November 2018. The Kiyikoy receiving terminal was completed in 2019 and inaugurated on January 8, 2020.

Realisation of new projects becomes a serious reason for concerns of some of the European countries. Ukraine, in cooperation with Poland and Baltic States, is extremely opposing the new natural gas mega-pipelines that Russia is building under the Baltic Sea and the Black Sea, to protect its own energy security in line with their national interests.

According to the European Parliament resolution, "Nord Stream 2" is a "political project posing threat to the energy security of Europe". Members of Congress and the Administration of USA have expressed concern over Nord Stream 2, TurkStream, and other projects they assert would deepen Europe's reliance on Russian natural gas, reduce Ukraine's role as a transit state, and potentially be a source of increased leverage for Russia. The FY2020 National Defense Authorization Act (NDAA, P.L. 116-92) includes as Title LXXV the Protecting Europe's Energy Security Act of 2019 (PEESA). This act mandates sanctions related to the laying of Nord Stream 2 and TurkStream subsea pipelines, and possible successors[43].

[43] Source: TurkStream: Russia's Newest Gas Pipeline to Europe, by Sarah E. Garding, Michael Ratner, Cory Welt, Jim Zanotti, Congressional Research Service, February, 2020

Figure 2.8. Russian export pipelines bypassing traditional transit countries of Eastern Europe

Since 2006, when the idea of building the Nord Stream 1 was first initiated, Gazprom's main goal has been to bypass the Baltic states and Poland and deliver gas directly to the Western European markets. Russia simultaneously laid the ground for rerouting the gas transit from Ukraine and Central and Eastern European countries to the Baltic Sea and later Black Sea[44]. Realization of the Nord Stream and TurkStream projects would undermine European energy security by limiting the diversity of both, supply and transport options for other suppliers, in order to make the EU markets more dependent on Russian gas and allow Moscow to exert greater influence on Western Europe. Hence, all along, contrary to Moscow's claim that the new projects are purely commercial, Kremlin is actually pursuing geopolitical objectives, along with the economic and commercial benefits. Moreover, according to the expert's estimation, with huge volumes of Russian gas bypassing current transit countries and flowing from West to Central and Eastern Europe, for the alternative gas suppliers (including LNG), it will be difficult to access the European gas market. Thus, Nord Stream 2 and TurkStream pipelines will undermine the creation of competitive gas markets in EU.

To protect their energy security and national interests, Poland, the Baltic states and Ukraine have initiated projects to diversify their gas supplies, upgrade pipelines, build LNG facilities and new gas storages, launch new regional initiatives, such as the Three Seas Initiative and the Baltic Pipeline Project.

Having started the commercial operation on January 2020, Turk Stream is delivering Russian gas tu Turkey and southeastern countries of Europe. According to Gazprom, about 54% of export

[44] Combined capacity of the Nord Stream 2 (55 bcm/y) and TurkStream (32.5 bcm/y) roughly match the volumes transmitted to Europe via Ukraine (86.8 bcm in 2018)

volume was delivered to the Turkish gas market and about 46% - to the Turkish-Bulgarian border. Average flows into Turkey so far equal to 20 Mm^3/d and 17 Mm^3/d - into Bulgaria, corresponding to 6.2 bcm per year.

TurkStream aims to expand the Bulgarian network and connect it to Serbia to transfer the Russian gas to the Serbia-Hungary border. It is estimated that the annual 25 bcm flowing through the TBP will drop and up to 19 bcm per year will be removed from Ukrainian transit throughout 2020 [89].

The Turk Stream will deliver Russian gas to EU via Turkey, similar to the Southern Gas Corridor. The possibility of gas delivery via the southeast European countries to the European hub of Baumgartner in Austria is also considered, for which the new “TESLA" pipeline project initiated by Hungary and “Eastring" pipeline project supported by Slovakia may be used. Considering these factors, the TurkStream gas pipeline may comprise a serious competition to the Southern Gas Corridor pipelines.

- North-south export route

The main version of the gas transportation north-south axis project envisaged delivery of the Russian, Turkmen gas and gas of other producer countries of the region to the northern part of Iran and in return, export of Iranian gas from the Persian Gulf terminals in the form of liquefied gas or by pipelines to the Mediterranean Sea ports in Syria and afterwards their transportation to the international markets by a pipeline (or after liquefaction).

Use of the existing infrastructure of Russia-Azerbaijan-Iran or Russia-Georgia-Armenia-Iran was considered as a priority option for delivery of Russian gas to the northern regions of Iran (after performance of the adequate rehabilitation works, the pipeline throughput may be increased by additional 8-10 bcm).

Under conditions of unstable political situations in Iran and Syria and economical restrictions, further discussion of the concept has been removed from the agenda.

- The benefits of the development of the Southern Gas Corridor

The South Caucasus Pipeline located on the territory of Georgia, together with TANAP and TAP, ensures delivery of the Caspian gas to the Turkish and European markets.

Under the valid intergovernmental and host government agreements and the respective purchase and sale agreements, the country receives gas from the South Caucasus Pipeline project at preferential rates. Currently, 2 contracts are in force: Optional Gas and Supplemental Gas Contracts. An Optional Gas Contract allows for purchasing of up to 5% of transited gas annually.

The contract validity period is 60 years. Supplemental Gas Contracts is valid until 2025 and under this contract, Georgia receives 500 Mcm of gas annually.

Until 2018, before finalization of the Southern Gas Corridor first stage works and commencement of operation, Georgia could receive maximum of 330 mcm of optional gas, based on the maximum delivery defined by the agreement made with the Turkish company "Botas" (6,6 bcm per year). After commissioning SCPX and TANAP, the volumes of gas transited through the Southern Gas Corridor, including through the territory of Georgia, are gradually increasing. By 2024-2026 and thereafter, the gas volumes will increase up to 22 bcm and more, which will allow Georgia to receive up to 1,1 bcm/y of gas (about 45% of the total consumption of country) at a preferential price.

The respective annual fiscal effect, in case of commencement and full-scale operation of the Southern Gas Corridor will exceed approx. 300 M GEL.

The more important is the political and social effect which will follow the development of the SCP, TANAP and TAP projects of the Southern Gas Corridor. Earlier Georgia represented a transit country of regional importance only (it transited Azerbaijani gas to Turkey and Russian gas to Armenia), but it is forming as an international player. The gas transited through the territory of Georgia will play a significant role in diversification of international, mainly EU's energy markets and increasing security of supply. As a result, the perspective of integration of Georgia into progressive international economic and political structures will be considerably increased.

As for the social aspects of the fiscal effect of the SGC project implementation, the increased volumes of gas purchased considerably cheaper compared to the market price, will allow maintaining the price of gas delivered to the Georgian households and gas-fired strategic thermal power plants at the minimum level, which will facilitate the further improvement of the population's welfare and replacement of the increasing import (mainly from Russia) with locally produced power and significant increase of the energy security of the country.

CHAPTER III

3. OIL AND GAS SECTOR OF GEORGIA

3.1. MAIN PROBLEMS OF THE SECTOR

The share of resources imported in the total consumption of the primary energy of Georgia is very high (more than 73 % in 2017, including: 66,1% coal, 67,1% crude oil, 100% petroleum products, 99,6% NG and imported electricity), while main suppliers are state-owned monopolies of foreign countries. Therefore, one of the main challenges of the energy security of the country is critical dependence on expensive, imported hydrocarbons.

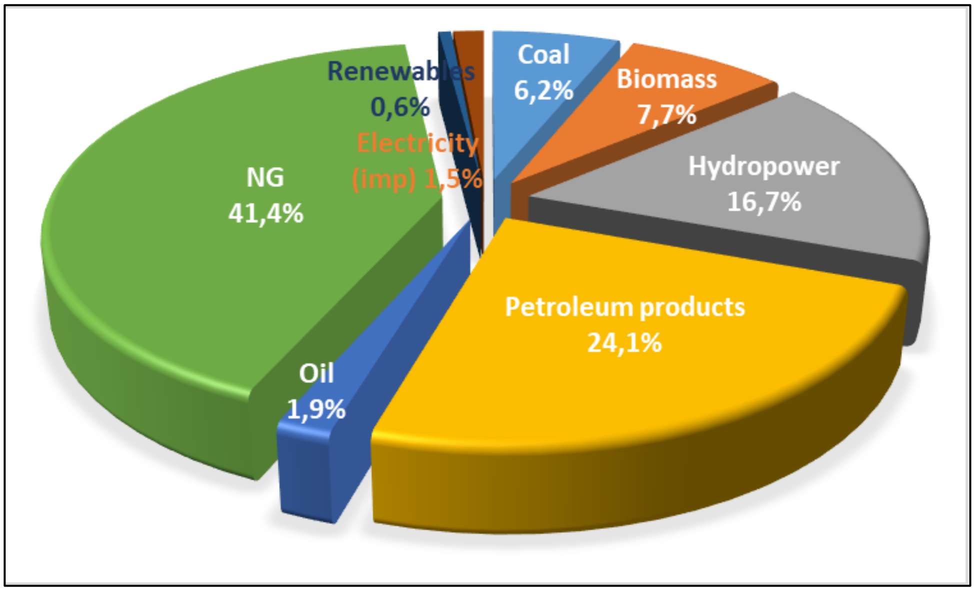

Figure 3.1. Total primary energy resources supply of Georgia

At the same time, Georgia has its own hydrocarbons potential and its use can make a substantial contribution to the growth of energy security of the country and economy in general. According to the forecast estimations, total reserves of 2P category discovered in Georgia in 2018 are as follows: oil – 4,8 million tons, natural gas – 4.9 bcm, contingent resources of 2C category: oil – 59,5 million tons, natural gas – 5.2 bcm. In addition, total volume of prospective oil resources estimated on the up to 50 promising exploration areas delineated on the onshore and the Black Sea offshore of Georgia equal to 909,2 million tons, natural gas – 230,3 bcm.

The resource potential allows for significant increase of own production of oil and gas; however, it is necessary to carry out significant and expensive works for this purpose. In particular, it is required to:

- use modern production technologies (directional drilling, multistage hydraulic fracturing) in the fields being developed most of which are already substantially depleted;
- explore and use of new, deeply sunk prospective formations;
- conduct appraisal drilling to evaluate commercial value on a number of newly discovered fields;
- conduct large-scale exploration works (2D and 3D seismic exploration, exploration drilling) on prospective areas.

In addition to the fundamental problem related to import of critical volumes of the fuel resources, other significant challenges of the country's oil and gas sector should also be mentioned. In particular:

- The country does not have strategic reserves of oil and/or petroleum products and natural gas, which in case of occurrence of extreme situation would allow for satisfying own demand on these resources for at the least certain time defined by the EC legislation [90];
- The country through which large volumes of crude oil transit flows are passed and has a significant potential to largely increase own oil production, practically does not possess any oil refining capacities until present;
- A foreign state companies dominate in the natural gas sector, despite the fact that the supply conditions and regime are governed on the basis of several independent agreements. This significantly hinders formation of a competitive market;
- When carrying out import of gas, there are certain restrictions caused both by contractual terms and conditions and technical parameters of trunk pipelines, leading to creating risks to reliable gas supply of the country, especially, in the peak demand period;
- Natural gas consumption has almost doubled in Georgia during the recent decade. Increase of consumption is planned within the next 5-10 years when one of the significant, long-term contracts on supply of supplemental gas from Shah Deniz field expires in 2026 and it will become necessary to balance the country's demand on energy from other source of supply.

3.2. PERSPECTIVITY OF OIL AND GAS DEPOSITS[45]

- **Geological structure of the territory**

In terms of geological structure, the territory of Georgia may be divided into 3 large tectonic units which extend sub-latitudinally. Mountainous structures of the Greater and the Lesser Caucasus of overthrust-folding and folded-block type are located to the north and to the south. A rather large depressed line is located among them. It expands westwards and enters the Black Sea basin.

Mountainous systems are mostly built with Jurassic-Cretaceous sediments, however, fragments of fold-metamorphic basement of mostly Late Proterozoic-Paleozoic age are denudated on the surface of separate, particularly elevated sections in the forms of ridges.

The depressed line in the western and eastern parts is expressed inter-mountain troughs of Rioni and Mtkvari rivers filled with Molasse sediments of Oligocene-Anthropogenic age. At the central section they are separated from each other by elevation of pre-Molasse basement of Dzirula-Imereti which is mostly built with Jurassic-Cretaceous sediments on the surface and a fold-metamorphic basement of pre-Jurassic age is denudated on the surface in the form of Dzirula ridge.

Detailed information about geological structure of Georgia and the adjacent Black Sea offshore is provided in the monograph: T.Gochitashvili, S.Gudushauri, Oil-and-Gas Bearing Potential of Georgia, Tbilisi, 2019 – in a systematized form. The monograph contains information about geological structure and oil and gas bearing potential of the main tectonic units of the Greater Caucasus Mountain Range, intermountain depressed line of the South Caucasus, the Lesser Caucasus and the Georgian part of the Black Sea offshore.

- **General characterization of the discovered fields**

16 fields are discovered on the territory of Georgia where reserves are estimated and their production occurs more or less regularly. 5 new fields have been discovered in which existence of commercial reserves are not finally confirmed yet due to various reasons. Effective oil and gas shows of various nature have also been observed in the form of natural, superficial effusions as well as during the drilling process.

[45] The information has been collected and the manuscript of Par. 3.2 has been prepared by Dr. Soso Gudushauri

Proven oil reserves of all deposits of Georgia, as of 2018, total to about 1.5 million tons and gas reserves - about 4.0 bcm. Probable reserves of oil is 4,81, possible reserves are 21,52bln tons, gas - 4, 9 and 6.8 bcm respectively.

3 oil fields are located in the Western Georgia, within the territory of Rioni trough: two fields – Supsa and Shromisubani, are discovered in the southern part of the trough, within Guria depression and one field – Eastern Chaladidi, in the axial part of the trough. Also, 1 oil and 1 gas field are discovered but their reserves have not been estimated yet. Okumi oil field is located on the northern part of the trough, at the section of its junction with Gagra-Java elevation. Goraberozhouli gas field is located in the southern part of the trough, on the eastern periphery of Guria depression.

13 fields are discovered in the eastern Georgia: 5 fields are located on the adjacent territory of Tbilisi, mostly within Tbilisi-Sagarejo elevation (Norio, Satskhenisi, Teleti, Samgori South Dome, Samgori-Patardzeuli-Ninotsminda). Out of the remaining 8 fields, Mtsarekhevi, Baida, Taribani, Mirzaani, Patara Shiraki and Nazarlebi are located on the main territory of South Kakheti depression and 2 fields- West Rustavi and Rustavi - are located at its western end, in the line of junction with Tbilisi-Sagarejo elevation.

3 new fields are discovered but their commerciality has not been evaluated yet. Norio-Martkopi and Manavi fields are discovered within Tbilisi-Sagarejo elevation, and Vedzebi-Ildokani field is located in the mountainous Kakheti, on Gombori range dividing South Kakheti and Alazani depressions.

The fields of the east Georgia are united into two groups. One group is located on the territory adjacent to Tbilisi and the second group is located within of Outer Kakheti trough.

On the territory adjacent to Tbilisi, 2 fields (Norio and Satskhenisi) are discovered in the northern part and are related to the Molasse tectonic naps located at the east end of Kartli trough. Also, in overthrust Oligocene and Eocene sediments, in the western part of the line, Norio-Martkopi anticline was discovered within which oil was obtained from Oligocene sediments during the drilling process and signs of presence of oil was observed in the Middle Eocene sediments.

The most significant and high-debit fields of the country are related to the axial, horst uplift of Tbilisi-Sagarejo elevation. Within them, the main productive stratum is presented by volcanogenic-sedimented fractured rocks of the Middle Eocene age (Teleti, Samgori South Dome, Samgori-Patardzeuli-Ninotsminda). On certain sections of these fields, Upper Eocene and

Oligocene porous rocks contain oil, while Lower Eocene porous rocks contain gas. On the eastern extension of this line, on Manavi Area, short-term flow of oil was first obtained from the Upper Cretaceous carbonate strata.

Two more, West Rustavi oil field and Rustavi gas condensate field were discovered in the southern line of the territory adjacent to Tbilisi. The productive strata on these fields are presented by the Middle Eocene volcanogenic-sedimented fractured rocks.

The main characteristics of the fields discovered in Georgia and hydrocarbons accumulated in them are shown in Tables 3.1 and 3.2. As the analysis shows, the discovered fields belong to the category of small-size fields by the volume of initial, extractable reserves. Only Samgori-Patardzeuli-Ninotsminda medium-size field is an exception.

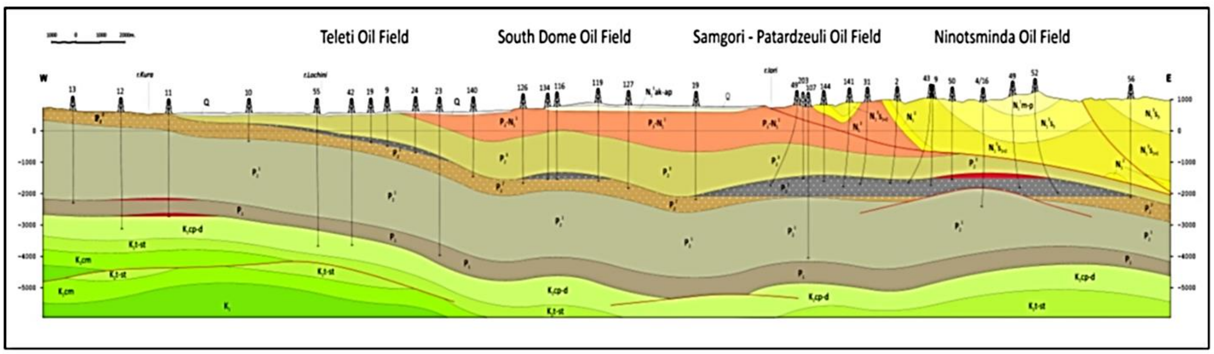

Figure 3.2. West-East schematic cross-section of Middle Eocene hydrocarbons fields in Near-Tbilisi Oil Bearing Region

By the initial daily debits of wells, most part of fields are small-debit (daily debits: oil – up to 10 tons, gas – up to 100 thousand m^3). Only Samgori-Patardzeuli-Ninotsminda field belongs to the category of high-debit fields (daily oil debits > 100 tons), while the Middle Eocene deposit of Teleti and Samgori South Dome belong to medium-debit fields (daily oil debits range between 10-100 tons).

Oil produced in Georgia mostly has low sulfur and methane-naphtha content. As a rule, total content of these groups of hydrocarbons largely exceeds 50%. Only Shromisubani and Patara Shiraki oils are an exception, with their total content within the range between 40-45%. Most oils are characterized by small or average content (<6%) of solid paraffins. Their increased content is common only for Okumi, East Chaladidi and Nazarlebi oils. Content of resins and asphalts is also average for most of oil. Only Okumi oil has their very low content (1.45%) and their number is generally increased to 15-20% in heavy and very heavy oils of Georgia.

Oil of all deposits of Okumi, Samgori-Patardzeuli-Ninotsminda, Teleti Upper Eocene deposit, Samgori South Dome and Satskhenisi is light (0.791-0.831 gr/cm^3) and has low viscosity (1.28-4.06 ps.sec·10^{-3}); Oil of Teleti Upper Eocene deposit, West Rustavi, Taribani, Patara Shiraki and Nazarlebi has an average density. Oil of East Chaladidi, Supsa, Norio, Baida and Mirzaani is heavy (0.864-0.880 gr/cm^3). As a rule, they have increased viscosity (4.02-17.9 ps.sec·10^{-3}). Oil of Shromisubani and Mtsarekhevi is very heavy (0.926-0.935 gr/cm^3) and viscous (29.68-79.39 Pa.s·10^{-3}). Taribani and Nazarlebi oil also have increased viscosity (5.97-11.52 Pa.s·10^{-3}).

Table 3.1. Main characteristics of oil and gas fields of Georgia

Field and number on the map	Year of discovery	Productive layer age	Phase condition	Sinking depth, m	Total production	
					Oil, 1000 t	Gas, Mm^3
1. Supsa	1939	Lower Sarmat	Oil	500-900	59.272	2.62
2. Shromisubani	1974	Lower Pliocene	Oil	2800-3600	97.998	2.692
3. Goraberezhouli	1979	Oligocene	Gas	700-900	-	-
3. East Chaladidi	1970	Upper Cretaceous	Oil	1800-2200	20.513	1.225
6. Norio	1939	Middle Miocene	Oil	350-1500	273.493	58.646
7. Satskhenisi	1956	Lower Miocene	Oil	300-1800	48.994	9.363
8. Teleti	1977	Middle Eocene	Oil	260-1300	515.035	17.652
	1989	Upper Eocene	Oil	750-1050	51.905	1.288
9. SSD	1979	Middle Eocene	Oil	2180-2400	1160.258	124.482
10. Samgori-Patardzeuli-Ninotsminda	1989	Lower Eocene	Gas	3600-4000	-	33.343
	1974	Middle Eocene	Oil	2200-2900	24150.727	2512.388
	1978	Upper Eocene	Oil	1250-2700	137.145	18.326
	2000	Oligocene-Lower Miocene	Oil	2534-2622	18.745	3.052
	2000	Middle Sarmat	Oil	1900-1923	2.211	0.917
13. West Rustavi	1988	Middle Eocene	Oil	2000-2350	63.546	10.301
14. Rustavi	1983	Middle Eocene	Gas	3300-3600	25.574	293.202
15. Mtsarekhevi	1989	Upper Pliocene	Oil	280-350	37.36	18.777
16. Baida	1989	Upper Sarmat	Oil	650-1000	1.432	0.008
17. Taribani	1963	Upper Sarmat	Oil	2000-2600	95.908	3.688
		Lower Pliocene	Oil	2300-3300		
18. Mirzaani	1930	Lower Pliocene	Oil	5000-1500	1137.604	170.004
19. Patara Shiraki	1932	Lower Pliocene	Oil	80-1000	76.961	7.268
20. Nazarlebi	1988	Lower Pliocene	Oil	800-1160	8.516	0.113

Most of the gases of Georgia are associated gases of oil and methane is dominating in their content. At the same time, total number of heavy gaseous hydrocarbons is rather increased and has a wide range. Associated gas of Okumi is an exception where content of methane is reduced to 36.2% but content of nitrogen reaches 55.4 %. High content of methane (≥95%) in associated gases of East Chaladidi and Mtsarekhevi approximates them to the category of "dry" gases. Gas of Samgori Lower Eocene deposit and Goraberezhouli fields is methane-containing (96.69-98.76%) and contains small number of heavy gaseous hydrocarbons which is common for typical gas deposits. Content of gas on Rustavi field (methane - 89.19%; heavy gaseous hydrocarbons – 10%) shows that the field contains gas condensate.

Table 3.2. Estimated reserves and contingent resources of oil (1000 t) and gas (Mm^3)

Current status	Reserves						Contingent resources					
	Oil			Gas			Oil			Gas		
	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
Rioni Trough 1. Guria depression												
1.Developing	87.8	999.7	338.2	5.1	11.3	26.6	-	-	-	-	-	-
3.Estimation	-	-	-	-	-	-	-	-	-	145	-	-
2. Kolkheti depression												
4.Conservat.	374	1019	-	-	-	-	-	-	-	-	-	-
Mtkvari Trough 1. Tbilisi-Sagarejo zone												
6.Developing	-	-	-	-	-	-	4231.5	10015.1	22561.8	-	-	-
8.Conservat.	1.0	1.0	1.0	0.4	2.8	14.7	360	2820	14680	54	423	2202
9.Developing	190	558.1	1392	28.5	83.7	208.8	135	610	1490	20.3	91.5	223.5
	216.8	994	1451.1	32.3	148.9	457.5	1154.5	3316.1	8815.3	172.9	496.2	1315.4
	601.1	1186.1	1814.1	439.9	107.7	161.4	32.2	86.5	177.8	3	8	18
10.Conservat				2467.2	3361.4	4398.9	-	-	-	-	-	-
11.Estimat.				-	-	-	14400	28400	63400	2160	2460	9510
12.Estimat.				-	-	-	3100	9430	25900	515	1565	4300
2. Outer Kakheti depression												
13.Estimat.	39.4	54.7	422.2	1001.3	1230.9	1507.9	234	1400	3870	-	-	-
15.Develop.	-	-	-	-	-	-	92.9	157.3	251.8	8.4	14	21
16,17,18,19,20 Processing	-	-	16102	-	-	-	1126.4	3263.5	7277.1	-	-	-
Total	1510	4813	21521	3975	4847	6776	24867	59499	148424	2933	5203	17588

- **Prospects of new discoveries** [91]

Reserves and resources of various classes and categories of hydrocarbons have been estimated for oil and gas fields discovered in Georgia and identified prospective structures.

Location of explored structures and structures on which prospective resources have not been estimated at this stage is shown on Figure 3.3 by tectonic zones.

On the basis of collected information several principal conclusions may be made:

- Almost entire intermountain depressed line of the country and its offshore extension within the Black Sea have oil and gas bearing potential. Only the basement high on Dzirula-Imereti uplift and its adjacent periphery are an exception where the basement is located under a very thin sedimented cover;
- Mountainous regions of the Greater and the Lesser Caucasus ranges located within the territory of Georgia must be considered as territories of unestablished prospects and/or unpromising territories. First of all, those territories of these regions are unpromising on whose surface basement high is denudated or they are covered with sediments of small thickness;
- High-mountain, inaccessible sections on which it is impossible to conduct the necessary oil and gas exploration works (field geophysics, drilling) also are unpromising. In addition, the most part of the southern slope of the Greater Caucasus range is also unpromising because intensely folded-fractured sediments and Jurassic sediments being at the stage of highly catagenic transformation are widely denudated on the surface here and they are characterized by unfavorable conditions of formation of traditional oil and gas fields;
- At the current stage of study on the territory of Georgia, major part of the Lesser Caucasus range must be primarily considered as the territory of unestablished prospects, which in a number of cases is preconditioned by comparative complex terrain conditions (Adjara-Trialeti high-mountain sections) or rather thick young lava sheets widespread on the surface (Javakheti Plateau) which significantly restricts certain types of exploration works to be conducted and/or their efficiency.

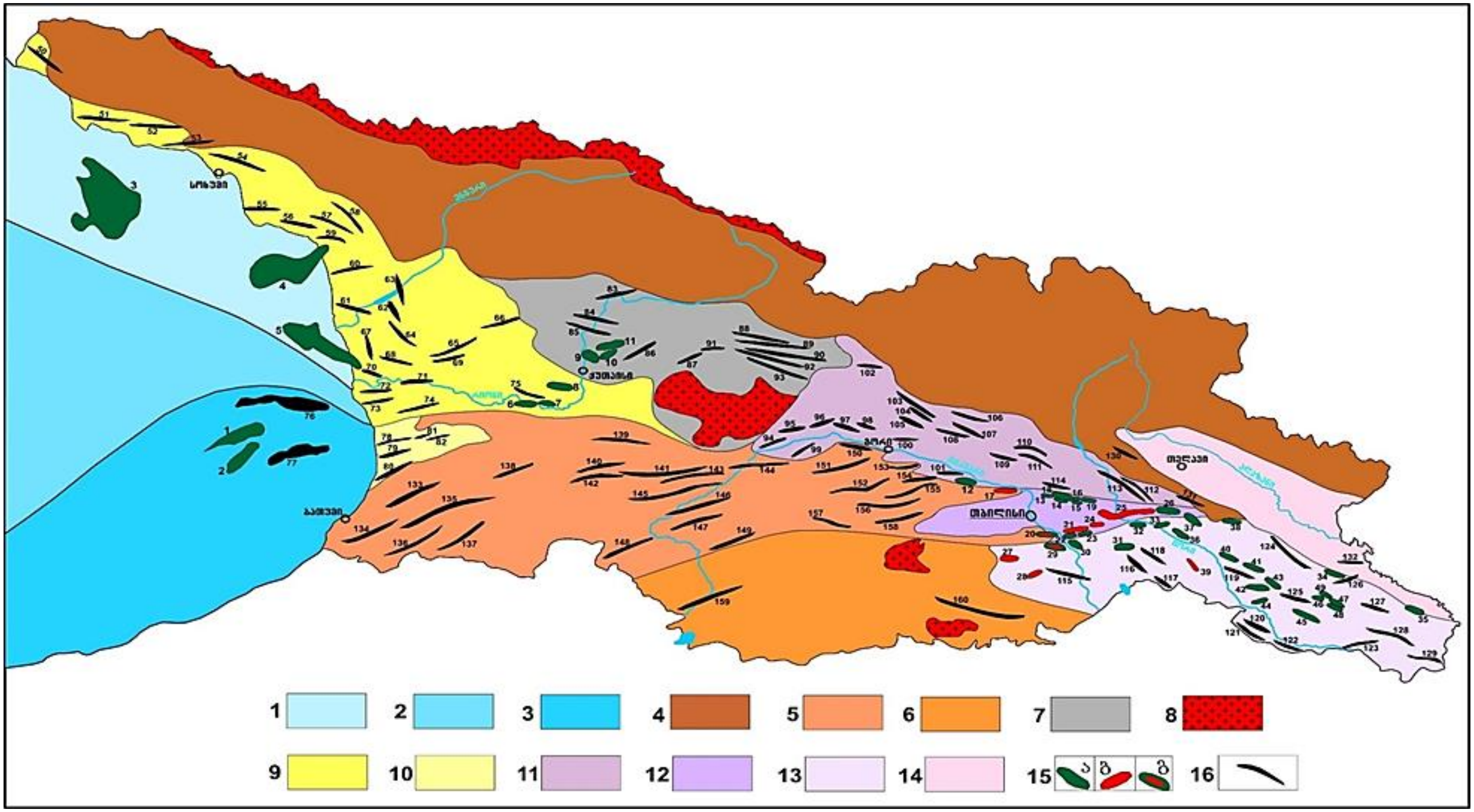

Figure 3.3. Location of oil and gas prospective structures within tectonic zones

<u>Legend</u>

1 – Shatsky Rise 2 – East Black Sea recess; 3 – Marine part of Guria depression; 4 – Caucasus Mountains; 5 – Adjara-Trialeti folded zone; 6 – Artvin-Bolnisi uplift; 7 – Dzirula-Imereti uplift; 8 – Shows on the surface of the foundation; 9 – Rioni trough; 10 – Onshore part of Guria depression; 11 – Zemo Mtkvari-Kartli trough; 12 – Tbilisi-Sagarejo uplift; 13 – Outer Kakheti trough; 14 – Alazani trough; 15 – Structures on which prospective resources are estimated (Fig. ## 1-49, A- Oil, B-Gas, C-Gas-Oil); 16 – Structures without estimation (## 50-160).

Prospective resources calculated within the groups of structures studied at the relevant level are presented in the Table in a generalized form.

Table 3.3. Estimated prospective resources as of the early 2018 (optimal version).
Oil (Mt), gas (bcm)

Structures (number on the map)	Discovery method	Prospective horizon	Oil	Gas
Kolkheti (1); Iberia (2)	Seismic exploration 2D,	Sarmat	83, 562	-
Gudauta (3); Ochamchire (4); Anaklia-Kulevi	Seismic exploration,	Cretaceous	351,200	-
Mtisdziri (6); Vani2 (7); Maghlaki (8)	Seismic exploration 2D	Jurassic-Paleogene	15,548	-
Courses-1 (9), Courses 2 (10), Courses 3 (11)	Seismic exploration 2D	Lower Jurassic	12,110	-
Eastern Kavtiskhevi-Akhalkalaki (12)	Seismic exploration 2D, Structural and exploration drilling	Upper Eocene Middle Eocene Cretaceous	25,890 7,534 96,986	-
Norio (13); Martkopi (14)	Seismic exploration 2D, Structural and exploration drilling	Lower and Middle Miocene	11,508	-
Mtskheta (17); Norio-Martkopi (18); Zhati (19); West Teleti (20); Teleti (21); S-W Teleti (22); South Teleti (23); SSD (24); S-P-N. (25); Manavi (26).	Seismic exploration ОГТ, 2D, 3D, Structural and exploration drilling	Oligocene, Upper Eocene, Middle Eocene, Lower Eocene, Upper Cretaceous	2,520 4,241 72,360 - 4,290	0,378 - 8,319 20,328 181,803
Shavsakdari (27); Marabda (28); West Rustavi (29); Rustavi (30); Natsvaltskali (31); Nakarali (32); Nazvrevi (33).	Seismic exploration ОГТ, 2D, 3D, Structural and exploration drilling	Maikop, Upper Eocene, Middle Eocene, Lower Eocene, Upper Cretaceous	6,014 30,678 37,535 - 10,770	- - - 9,300 10,107
Dedoplistskaro (34); Kedebi (35).	Seismic exploration 2D	Sarmat , Cretaceous	37,398 42,192	- -
Tsitsmatiani (36); Kakabeti (37); Phkoveli (38); Mtsarekhevi-East (39); Lambalo (40); Mlashis Khevi (41); Kila-Kupre (42); Olis Khevi (43); Iori (44); Taribani (45); Mkrali Khevi (46); Mirzaani Deep (47); Mirzaani South. (48);	Seismic exploration ОГТ, 2D, 3D, Structural and exploration drilling	Upper Pliocene, Lower Pliocene, Sarmat	0,099 56,756	0,029
Total			909,202	230,264

3.3. EXPLORATION AND PRODUCTION STATUS

Oil extraction history in Georgia from 1930 to present shows significantly increased during 1975 to eighteenth of last century (to average 3.3 M tons per annum), reaching its peak in 1981-1983. After that extraction dropped sharply first of all due to deposits' depletion and, from the beginning of 90-ies, due to the demolition of the existing economic relations, managed from the centre. In total, from 1930 to present, approximately 28 M tones of oil has been extracted in Georgia.

In the second half of 90-ies, after introduction of oil and gas sector regulating legislation in independent Georgia, favourable preconditions were created to attract new investors to the oil fields and introduce new technologies in existing fields, which was reflected in the increase of oil production for that period. However, contractor companies, except some rare cases, were mostly focused on the development of the reserves of the field (some of which have been developed since 30-ies of the previous century) and they did not pay enough attention to upstream operations in order to discover new fields which resulted in the decline of oil production from 2004.

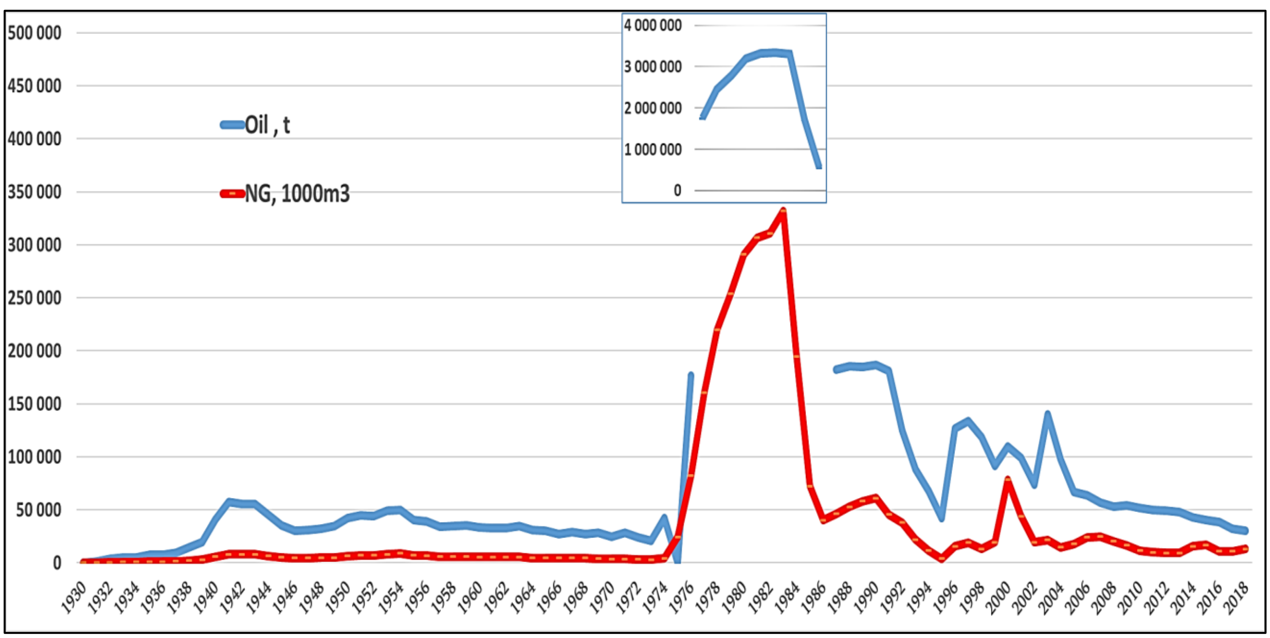

Figure 3.4. oil and gas production, 1930-2018

The analysis of historic data of natural gas (free and associated) shows that peak production (332 Mm^3) was recorded in parallel with the intensive oil production period, however later the decreasing trend of oil production resulted in significant decline of associated gas production. In 2018, commercial gas was extracted only from Ninotsimnda and Mtsarekhevi fields and made up about 13 Mm^3. From 1930 to present 3,3 bcm of gas has been produed in Georgia in total.

Currently, 16 fields are being developed in Georgia, including 15 oil fields and 1 gas-condensate field (see the Figure): Eastern Chaladidi, Supsa, Shromisubani, Norio, Satskhenisi, Samgori-Patardzeuli-Ninotsminda, Samgori South Dome, Teleti, West Rustavi, Mtsarekhevi, Baida, Taribani, Mirzaani, Patara Shiraki, Nazarlebi, Rustavi (gas condensate).

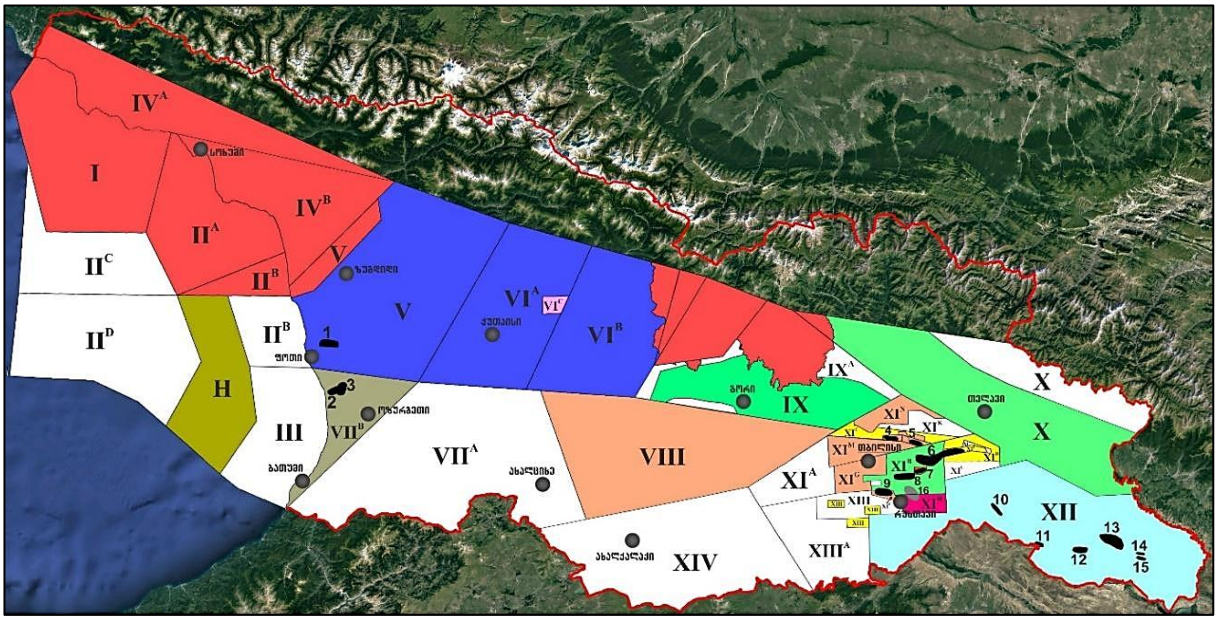

Figure 3.5. License Blocks of Georgia

Oil and gas operations are conducted by the following contractor companies in Georgia:

- "KBOC" (former "Canargo Georgia") - License Blocks: XI^C XI^D, XI^E, XI^F, XIII;
- "Frontera Eastern Georgia" - License Block XII;
- "WGPEC" – License Block V;
- "GCE Ltd" - License Blocks VI^A, VI^B;
- "Schlumberger Rustavi Company" - License Blocks IX, X, XI^B;
- "Georgian Oil and Gas" (Consortium) - License Blocks VIII,XI^G, XI^M, XI^N , XI^C Martkopi, XI^C North Satskhenisi;
- "Vectra Investment" - License Block VII^B;
- "Elenilto Georgia" - License Block XI^H
- Georgian Oil and Gas Corporation - License Block XI^B (Samgori South Dome)
- Block Energy - License Block XI^F , XI^C Norio-Satskhenisi, XI^C Satskhenisi (Norio and Satskhenisi small depth (up to 2000 m) fields);

Activities of the companies are carried out on the basis of Production Sharing Agreements (PSA) and during the activities Georgian Oil and Gas Corporation, with the status of the National Oil

Company, supervises the works at the stage of planning and performance and manages the state share of oil and gas produced on the license area.

Oil and gas production indicators for the recent 10 years are shown on the Figure below.

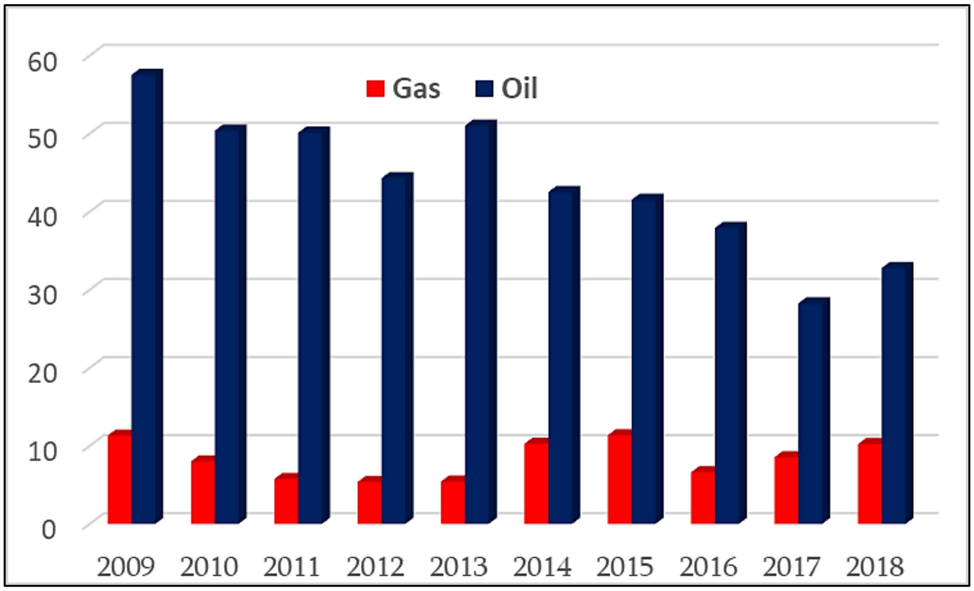

Figure 3.6. Natural Gas and Oil Production (Mm^3/y & Mta)

The plans of the closest period envisage making comparatively more investments in oil exploration and production works for the recent period. It is planned to facilitate activation of geological-exploration works on the territories of Georgia with oil and gas bearing potential, as well as increase of the forecast annual total production. The main focus of the activities is made on extensive performance of seismic exploration and drilling for the purpose of discovery of new fields, and on extensive use of new technologies of oil production for the purpose of noticeable increase of production on the existing fields. Therefore, oil and gas production may be significantly increased in Georgia in the nearest future, if the exploration results confirm at least one of the forecast resource data out of prospective areas.

3.4. GENERAL OVERVIEW OF GAS SECTOR

3.4.1. NATURAL GAS MARKET

Natural gas market structure is shown on the figure below. The natural gas sector consists of gas suppliers (producers, importers and retail suppliers), transmission and distribution licensees, direct business consumers, thermal power plants and commercial or household retail consumers.

The sector is governed by the Law of Georgia on Electricity and Natural Gas, the Order of the Minister of Energy of Georgia on Approval of the Natural Gas Market Rules, and the Georgian National Energy and Water Supply Regulatory Commission (GNERC) resolutions and other regulatory documents.

Operation of the natural gas transmission system is carried out by Georgian Gas Transportation Company LLC (GGTC), a state-owned company that is a natural gas transmission licensee. At the same time, the gas mains and related equipment and structures are the property of JSC Georgian Oil and Gas Corporation. Under the lease contract between GGTC and GOGC, the system of gas mains is operated and maintained by GGTC and the planning and construction of new gas pipelines and the major overhaul of the network are carried out by GOGC. GOGC is responsible for the transportation system prospective development plan.

Natural gas is supplied to a regulated part of the household sector and thermal power plants (so-called social sector) at a regulated tariff. Retail and wholesale prices for the rest of the consumers are deregulated – such consumers buy gas at prices and subject to terms publicly offered by a supplier.

The upcoming structure and regulation of the market in natural gas envision separation regulated, naturally, monopolistic network activities (transmission and distribution) from deregulated competitive supply activities on both retail and wholesale levels. Nowadays the gas supply business is actually separated from the gas distribution business only in the wholesale market segment, but almost all the distribution licensees in the retail segment are concurrently suppliers for consumers within their coverage areas. As the gas supply for the commercial consumers of Georgia is deregulated and formally opened for competition, but practically they are dependent to a single distributor/supplier, there are neither regulated tariff nor conditions for competition. As a result, gas prices in the commercial sector of Georgia are higher than in the other countries of the region.

The long-term vision for the development of the natural gas sector provides for the transformation of the international best practice into the Georgian gas natural sector by having regard to local specifics. In particular, it's about introducing the European Energy Union's core principles for organizing the internal market in natural gas to Georgia that in the long-term will help create a favorable environment for competitive trade in natural gas. Transparent and competitive energy markets maintain low prices on energy resources for a long period, thus safeguarding the interests of a vulnerable segment of consumers (details see below).

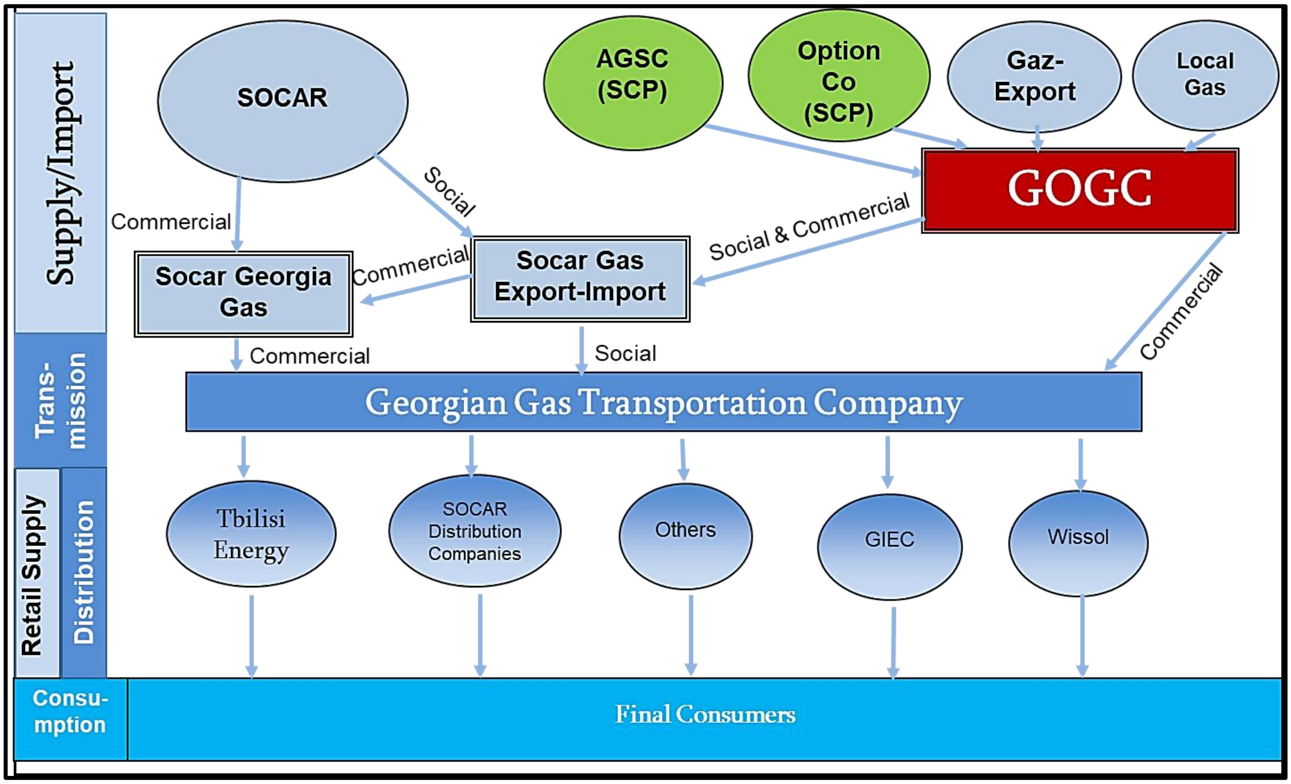

Figure 3.7. Structure of Natural Gas Market

Liberalized markets are an effective means of raising investments needed for infrastructure projects and meeting a growing demand for gas consumption. The development of a clearly defined market structure and regulatory system and ensuring a non-discriminatory access to transmission and distribution networks would facilitate a successful development of the Georgian gas sector and its integration with regional systems that is one of the critical conditions for enhancing the national energy security.

Besides, in addition to new infrastructure projects, the development of the national gas sector requires the improvement and essential refinement of the legislative/regulatory framework. It should be mentioned that the Georgian natural gas market is presently dominated by some major players who concurrently operate in a competitive as well as natural monopoly segments of the market. Therefore, the introduction of effective instruments for improving the legislative framework and monitoring the market, with safeguards against any direct interference with regulation activity on the part of the state, would help achieve the ultimate goal of liberalization – full opening of the market where any gas consumer can freely choose a supplier and the supplier have unfettered access to transmission and distribution networks.

Subject to the requirements for trade in energy under the EU Association Agreement, Georgia has undertaken to approximate her legislation with the EU legislation stage by stage within defined terms. Georgia has to implement the provisions of the binding European directives within the terms agreed with the Energy Community.

Directive 2009/73/EC is mainly aimed at prompting competition within the unified internal EU market, **unbundling the competitive activities of production and supply**, and stimulating transborder interconnections through undistorted market prices, which would lead, in the long term, to price convergence.

Regulation (EC) No 715/2009 sets out main requirements for providing a third party with a non-discriminatory access to transmission networks. In particular, the directive establishes the need for ensuring the transparency and publishing tariffs (including trans border tariffs), using approved and universally accessible tariff calculation methods, the objectivity of the technical or economic criterial limiting the access of third parties to the network and the possibility for consideration of related disputes.

Generally, natural gas is one of the cheapest, easy-to-use and ecologically safest fossil fuel in Georgia. Its consumption began in 1959. Russia was the main supplier until 2007, until Shah Deniz field of Azerbaijan was put into operation.

The yearly peak gas consumption, approx. 6 bcm, was observed in Georgia in the early 1990s, which was preconditioned by ineffectively consumed fuel resources and using energy-intense technologies in the last years of existence of the Soviet Union [92].

Since the economic revival in the post-soviet period (with the exception of the crisis period of 2008-2010), there has been a growing trend in the supply and consumption of natural gas.

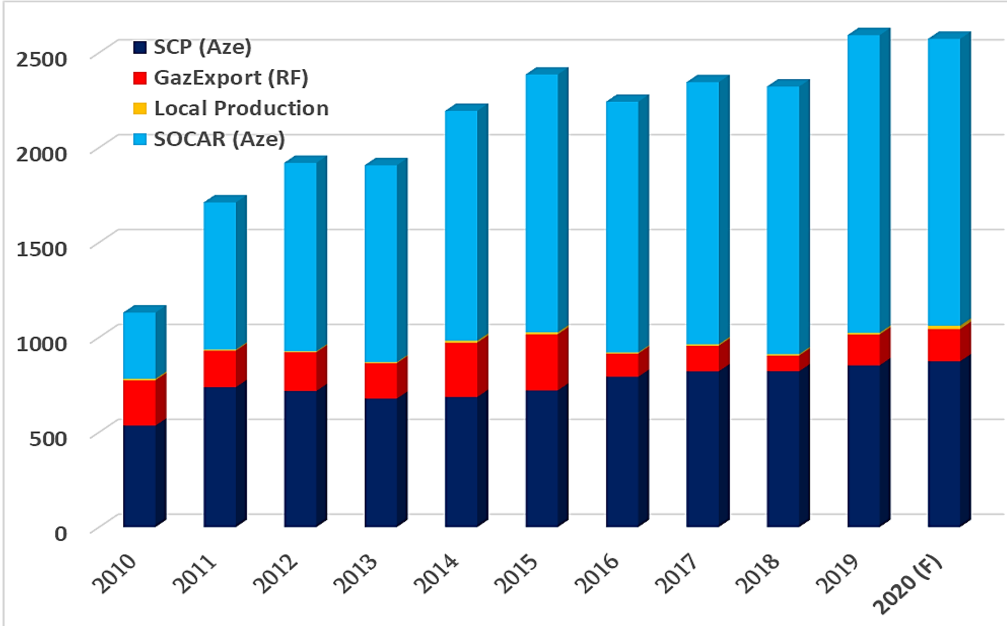

Figure 3.8. Natural gas supply, Mm^3/y

The share of natural gas in the total energy balance accounts for approximately 40% (according to Geostat). Natural gas is the most widely consumed energy resource in Georgia. According to GNERC [93], Georgian Gas Transportation Company received 4 339 Mm^3 of natural gas in 2017, out of which 1 996 Mm^3 was transported to Armenia and 2 343 Mm^3 was distributed through the Georgian internal system. In 2017, 1066 Mm^3 of natural gas was delivered to direct customers, 1301 Mm^3 to gas distribution companies, including 884 Mm^3 to household customers and 355 Mm^3 to non-household customers (loss in the distribution network was 60 Mm^3).

2,287 bcm of natural gas was supplied to Georgia in 2018, 848,2 Mm^3 to household sector (37% of total supply), 488,6 Mm^3 to power generation sector (21,5%) and 915,9 Mm^3 to commercial sector (40% including 14,8% used by transport). 1940 Mm^3 of Russian gas were transported to Armenia (losses in the internal transmission networks equaled to 1,2%).

According to the gas transmission system operator, 2,592 bcm of natural gas was supplied in 2019 to Georgian market, including 853 Mm^3 supplied from Shah Deniz field, 1568 Mm^3 from SOCAR , 163 Mm^3 from GazExport (Russian Federation) and 9 Mm^3 from local producrs. Approximatelly 874 Mm^3 gas was consumed by hoseholds, 678 Mm^3 by power generation and 892 Mm^3 by commercial sector.

Unprecedented high consumption of gas was fixed in January 2020. Total supply amounted to approx. 427 Mm^3, while observed maximum monthly supply during the last 20 years was 361 Mm^3 (in 2019). 18 % of the yearly increase of consumption caused by the intense operation of thermal generation units, to fulfill the increased demand of country on electricity (gas consumption in power generation sector has been increased by 41,3 % in comparison with 2019 data and by 27,6 % in comparison with the historical maximum consumption by the sector).

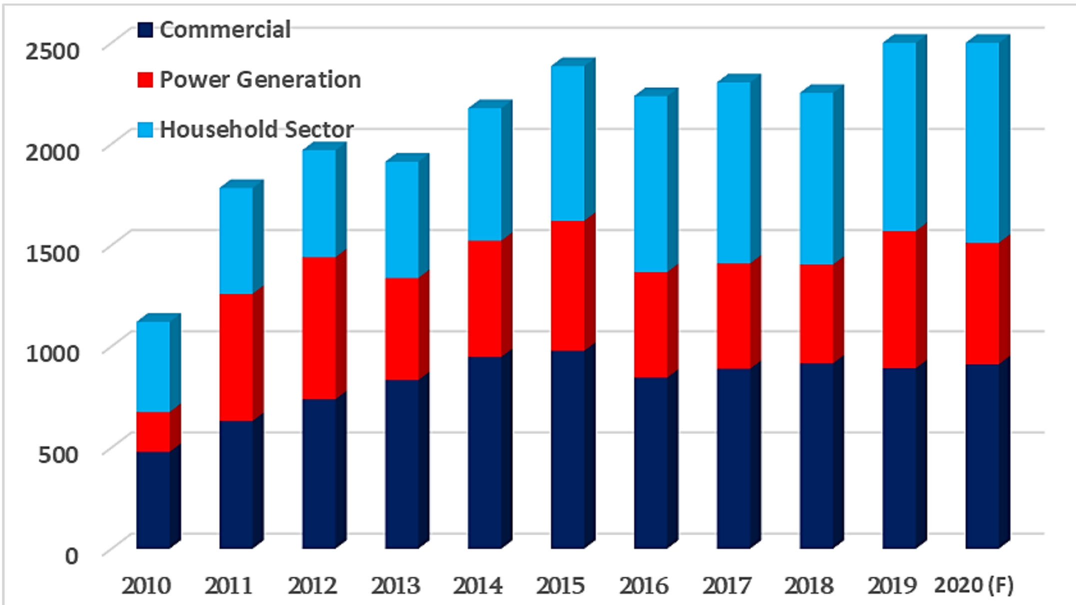

Figure 3.9. Gas consumption, Mm^3/y

Natural gas sector of the country is one of the most dynamically developing segments. According to the information of the Ministry of Economy and Sustainable Development of Georgia, 3 year plan of the Government envisages gasification of those settlements that will be considered commercially expedient [94]. As a result, by 2021, gas will be available to more than 1,2 mcm household consumers which makes up to 84% of the total households of country. Also 6 operating power generating facilities and approximately 34 thousand commercial users are consumers of natural gas in Georgia.

In some mountainous regions of Georgia - Upper-Svaneti, Pshav-Khevsureti, Tusheti and etc., not covered by natural gas pipeline system it is appropriate to develop decentralized systems based on the exploitation of autonomous energy sources instead of constructing costly and economically unjustified pipelines. To this end, natural gas transformation products (liquefied natural gas-LNG and compressed natural gas–CNG) or propane-butane (liquefied petroleum gas-LPG) can be used to supply these off-grid regions along with the use of local renewable energy resources. It is noteworthy that in the 1980s, about 75 thousand consumers in Georgia consumed more than 200 thousand tons of CNG and LPG annually.

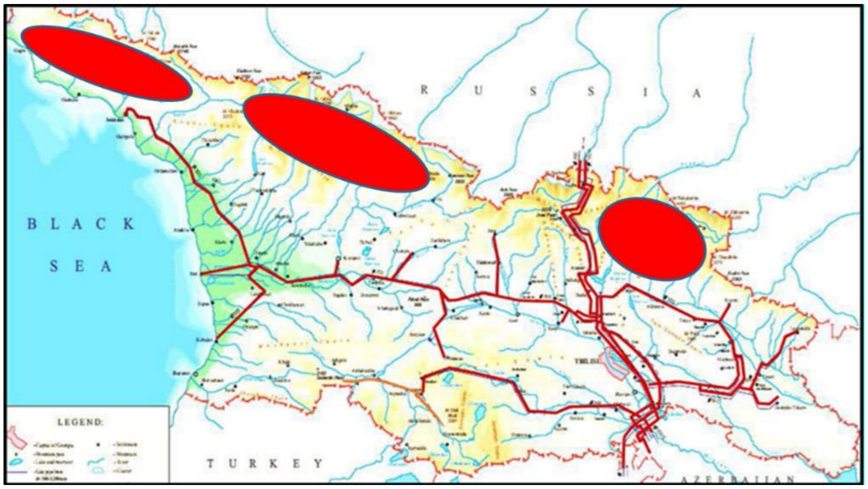

Figure 3.10. Off-grid regions of Georgia

According to the information provided by GNERC [95], an average annual consumption of one family in 2016 was 773 m^3/y, among them 1011 m^3/y in Tbilisi and 596 m^3/y in the rural regions. Consumption of one commercial customer in 2016 was about 25 000 m^3/y.

Georgia's demand for natural gas is mainly balanced by imported gas (see Figure). Local gas production is negligible, and its share of the total consumption is less than 0.5%. At present, natural gas supply is carried out through 3 foreign sources (SOCAR of Azerbaijan, BP lead Shah Deniz International Consortium and Russian "GazpromExport"), on the basis of 4 independent contracts.

The main gas supplier of the local market is Azerbaijan. In 2019, the total volume of natural gas exported from Azerbaijan to Georgia amounted to about 93,5% of the total volume of consumed gas (compared to 98% in 2018), that creates critical situation due to the lack of competition on the market. Commonly accepted international measure for assessing market competititvness - the Herfindahl-Hirschman index (HHI) for Georgian market is twice a higher than recommended for competitive markets internationally, with a quite higher it's concentration.

Gas from Shah-Deniz field of Azerbaijan is transmitted to Georgia through the South Caucasus Pipeline (SCP). Under the Host Country (Government) Agreement and Option Gas Contracts between the SCP Project participants and the Government of Georgia, Georgia has the option to buy up to 5% of the gas volume transited via SCP. The contract is valid for 60 years.

According to a forecast, the volume of option gas will significantly increase after the Shah-Deniz Field development, phase II is fully completed and the supply contracts of additional gas to Turkey and Europe is realized.

The Supplemental Gas Purchase and Sale Contract defines the volumes and prices of gas to be supplied additionally in the period up to 2026. Under this contract, Georgia currently receives 500 mcm of gas per year. The prices under the option and supplemental gas contracts are considerably lower than those at the gas market in the region.

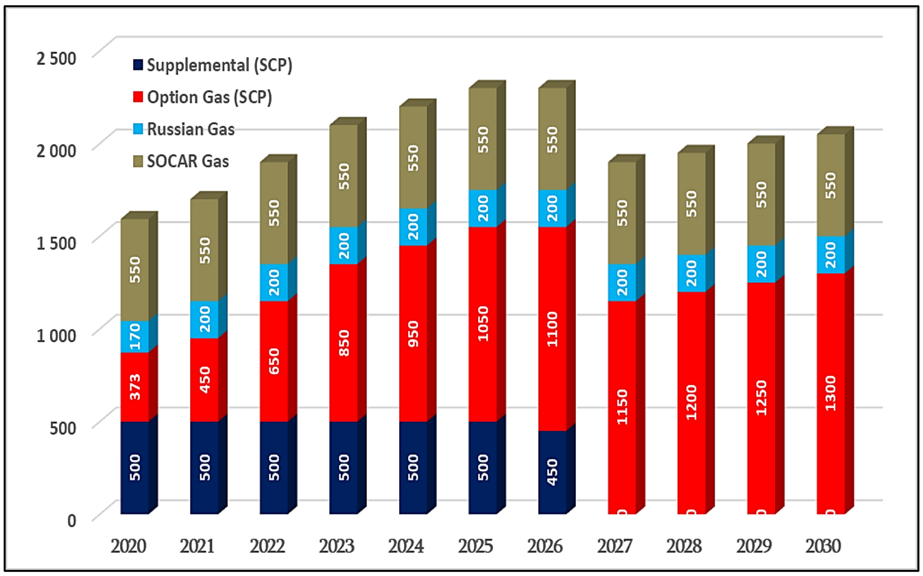

Figure 3.11. Projected natural gas import Mm³/y

Until 2018, prior to finalization of the first stage construction works of the Southern Gas Corridor, Georgia could have received a maximum 330 Mm^3 of gas under the Optional Gas Agreement, based on the maximum volume of supply defined by the agreement amongst the Shah Deniz Consortium and Turkish "Botas" (6,6 bcm per year). Currently, when two main pipelines constituting the Southern Gas Corridor – South Caucasus Pipeline and Trans-Anatolian Pipeline - are put into operation, the gas volumes transited through the territory of Georgia are gradually increasing. In 2018 and 2019, gas transit (and accordingly, 5% volume of gas to be received under the Optional Gas Contract) increased by one and two bcm. consequently. According to the plan of Shah Deniz field development phase II, 4 bcm gas will be supplied to Turkey in 2020 and 6 bcm - in 2021 [96]. In parallel, gas supply will start to EU consumers beginning from 2021, after construction of TAP pipeline completion. By 2024-2026 and in next period, gas transit via Georgia may increase up to 22 bcm and more, which will allow Georgia to receive up to 1,1 bcm of option gas annually at a preferential price.

To fully meet the demand of household and power generation consumers, natural gas is supplied to Georgia under the Memorandum for Supply of Natural Gas between the Government of Georgia and Azerbaijani State Oil Company (SOCAR)[48]. Under the relevant gas purchase and sale contract GOGC with SOCAR, the terms for supply of gas to the Georgian market have been negotiated, the contract with current terms is valid until 2021 and the contract expires in December 2030.

Almost the whole volume of natural gas supplied from the above sources (jointly referred to as “Georgian Gas”) is directed at meeting the demand of household and power generation consumers who form the so-called “social consumers” of the market.

Besides, natural gas is supplied at market prices to meet the demand of the Georgian industrial and commercial sectors mainly from Azerbaijan. Periodically small volumes of Russian gas has been imported. The contract with “GazExport” considers possibility to receive limited volumes of additional Russian gas with the market prices. In 2019 162 Mm^3 gas was supplied from Russia.

Costumers of the “social sector” are supplied with the natural gas at the regulated tariffs. Tariff of household customers is regulated by GNERC. TPPs are supplied with the tariffs based on the memorandum and the relevant contract between the Government of Georgia and SOCAR. For all other customers retail and wholesale prices are deregulated and gas is supplied through publicly offered conditions.

3.4.2. TRANSIT AND TRANSMISSION INFRASTUCTURE

The transit corridor located in the territory of Georgia is one of the most attractive routes to deliver hydrocarbons of the Azerbaijan and Central Asia to international markets. This corridor is used to transmit oil, oil products and gas through pipelines, railway and Georgian seaports [97].

[48] SOCAR plays role of virtual storage for balancing of supply/demand disparity

Gas mains ensure the transit of natural gas towards Turkey and Armenia. The gas from Shah-Deniz Field of Azerbaijan is delivered through the Baku-Tbilisi-Erzurum South Caucasus Pipeline (SCP). The actual load of SCP in 2014-2017 amounted to about 6 bcm per year. In 2018 transit of gas has been increased to about 7 bcm, and in 2019 - more than 9 bcm. By 2025 -2030, the transit of Azerbaijani gas is scheduled to be increased to 22-24 bcm a year.

North-South Gas Pipeline system (NSGP) is used to transit Russian gas to Armenia. Last decade have seen a considerably lower load of NSGP compared to its design capacity. In 2017-2019 the pipeline transported approximately 2 bcm Russian gas, mostly to Armenia.

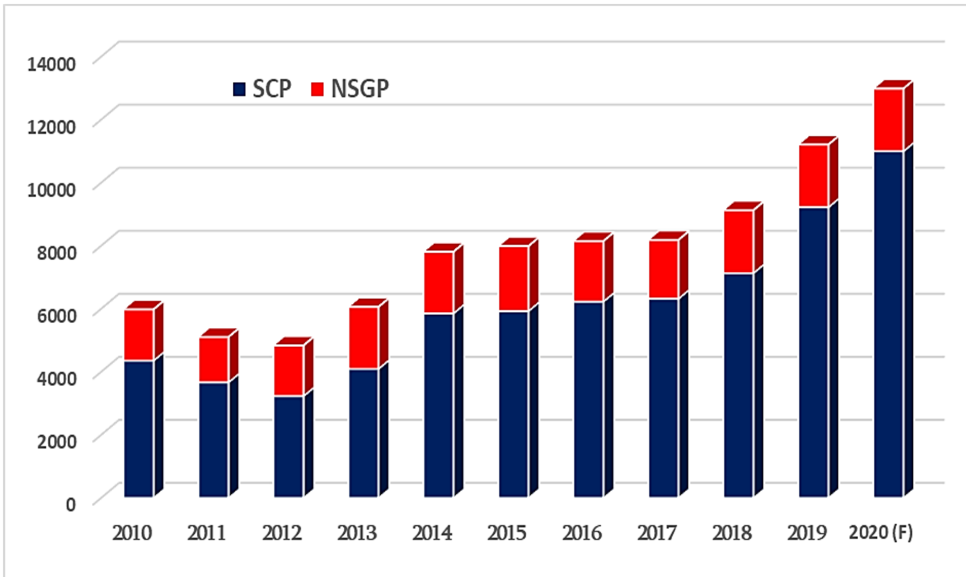

Figure 3.12. Natural gas transit, bcm/y

Georgia is supplied by gas through the system of main transmission pipelines. The main gas transmission system of Georgia consists of two main parts:

- The North-South Gas Pipeline system that supplies gas from north (Russian-Georgian border) to South-East (Georgian-Armenian border). The North-South Gas Pipeline System is connected to Russian system at the Georgia-Russia border and to Armenian system with the 11,5 km length interconnector to Armenia near the Georgian-Armenian border.
- The East-West Gas Pipeline system with several terminals is used to supply gas from South-East (Georgian-Azeri border) to West (towards Poti Industrial Zone, the Autonomous Republics of Abkhazia and Ajara). The East-West Gas Pipeline system is connected to the Azerbaijanian system at the Georgian-Azeri border and to the South Caucasus Pipeline with the 12,5 km length of interconnector (**Area 72 of SCP -Rustavi section)** nearby of city of Gardabani ajacent to the border.

The transmission system includes also Northern (Kazbegi), Kakheti, Southern, Adjara and Poti branches. The total length of the internal Georgian gas-main pipelines is about 2000 km. The integrated gas supply system also includes gas distribution pipelines with total length about 20000 km, gas distribution stations, metering units, and currently inactive two compressor stations (detales see below).

Construction of the gas transmission system started in 1959 and had high intensity in the 1970s and 1980s. In the initial period of the country's independence, due to the former Soviet Union's centralized economy degradation, the pace of infrastructure construction fell sharply. Main pipeline construction and rehabilitation work resumed in 2007 with the financial assistance of foreign donors (US MCC and USAID) at the first stage.

Diameter of the country's internal main gas pipelines ranges between 90 and 1220 mm, design pressure – within 25-56 bar. Distribution of main gas pipelines by diameters is shown in the Table.

Table 3.4. Main gas pipelines

D, mm	L, km	%
1220	133,6	8,6
1020	89,0	5,7
820	20,2	1,3
762	12,4	0,8
720	785,6	50,7
529	368,4	23,7
325	47,8	3,1
273	12,5	0,8
219	81,1	5,2
108-159	Negl.	0,1
Total[49]	1551	100

[49] The table indicates the length of pipeline routes. Length of parallel pipeline sections are not accounted

The aim of the current pipeline construction-rehabilitation and development works is basically to increase the system's reliability of functioning by using new, high throughput capacity sections and interconnectors. Development of the infrastructure projects are currently financed mainly from GOGC's sources.

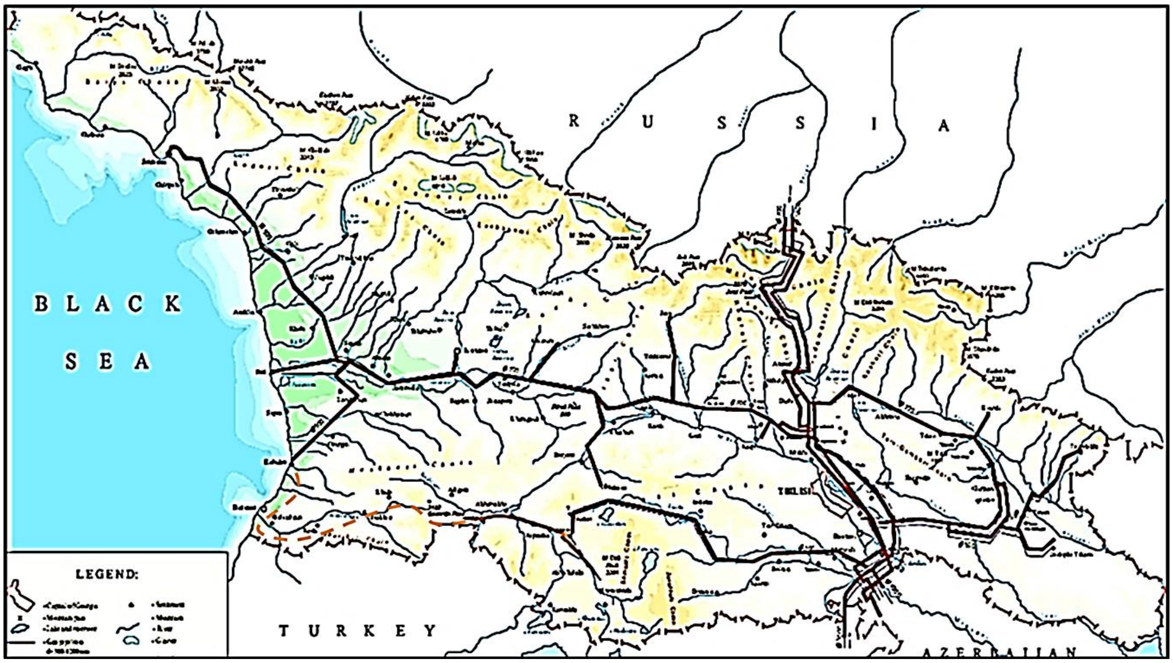

Figure 3.13. Georgian gas-main pipeline system

The table below shows design capacity and actual load data of Georgian Main Gas Pipelines. Design capacity, actual load, peak load ratio and forecasted load of Georgian trunk gas pipelines are used for preparation of transmission system's development plan [98].

North-South Gas Pipeline System (NSGP)

The system comprises of the North Caucasus-South Caucasus and Vladikavkaz-Tbilisi paralel and Kazakhi-Saguramo gas pipelines. The system can receive gas from Chmi (Russian Federation) metering station trough the North Caucasus-South Caucasus pipeline (D=1200mm). NSGP starts on the territory of Georgia at the border of Russia (about 1380 m above the sea level). It starts in the river Tergi channel, crossing several mountainous rivers and mudflow canyons with right instable hydrology, passes over Jvari Pass (about 2430 m above the sea level) and continues to the Southeast along the channels of Aragvi and Mtkvari rivers down to Georgian south-eastern border. A part of the pipelines traverses a high mountainous region of the rough terrain that becomes often a reason for the accidents. In this part of the route, several tunnels and riverbank protection structures are arranged to guard the pipelines from natural disasters.

DN 1000 mm Kazakhi-Saguramo pipeline sections along the river Mtkvari channel are placed partly in the wetlands and soils with intensive agricultural operations, causing very high corrosion activities of the ground. Pipeline are functioning without anticorrosion protection during the last 20-25 years that causes corrosion of pipelines and is often the reason for gas leakage. Only during the last 10 years almost 60 M$ was spent on the rehabilitation works of the system.

The Georgian section (D=1200 mm, L≈133 km, P_0=55 bars) of the **North-South Caucasus Gas Pipeline** was built in 1988-1994. The pipeline is located in 8 tunnels with the 4.6 km total length. Currently, the pipeline is used mainly to transit gas from Russia to Armenia. Pipeline includes 16 linear valves, located with average intervals 8 km.

The Georgian section (D=1000 mm, L=90 km, P_0=55 bars) of **Kazakhi-Saguramo Gas Pipeline** was built in 1980. It is an extension to North-South Caucasus Gas Pipeline from Saguramo to the Georgian-Azeri and Georgian-Armenian border. The territory of Georgia accommodates its ≈90-km section and an 11.5-km branch to Armenia. Pipeline includes 6 linear valves, located with average intervals 11 km. The gas pipeline is used to transit Russian gas to Armenia. Tsiteli Khidi and Khrami Metering units are connected to this pipeline in order to measure volumes of gas transported to the Western Georgia and Armenian directions accordingly.

The construction of the Georgian section (D=720/529 mm, L=166 km, P_0=55 bars) of **Vladikavkaz-Tbilisi Gas Pipeline** was completed in 1966, with some of its sections being rehabilitated/upgraded from time to time. Four sections of the route with a combined length of about 1.3 km are situated in tunnels. The pipeline is composed mainly of 700 mm pipes. The gas pipeline is connected with the North-South Caucasus Gas Pipeline parallel sections by eleven 500 mm diameter connection lines and is considered as a for 1200 mm transit pipeline. The gas pipeline is connected to Gveleti and Saguramo Metering stations, and Kvesheti compressor station, which is inactive at the moment.

East-West Gas Main Pipeline System (EWGP)

Saguramo pressure regulation and metering station is gathering place of the pipelines of different directions. From this point gas is redistributed across the whole territory of Georgia. Accordingly, the East-West Gas Main Pipeline System can conditionally be divided into two parts: Azerbaijan (South-East) Border – Center (Figure 3.13) and Center – Sukhumi (with branches towards Ajara and Poti (see Figures 3.14 and 3.15).

South-East Border – Center Group of pipelines includes: Karadaghi-Tbilisi, Azerbaijani border-Gardabani, Gardabani-Navtlugi, Navtlugi-Saguramo Gas Pipelines, the pipeline connecting Area 72 of South Caucasus Pipeline nearby Rustavi, Kakheti Branch and Southern Branch of main pipelines. The Georgian section of **Karadaghi-Tbilisi Gas Pipeline** consists of two parallel lines. Currently Azerbaijan border-Gardabani new 700-mm section and an old 800 mm pipeline's 24 km length section up to Rustavi are in operation, which continues with 700 mm section up to Vladikavkaz-Tbilisi pipeline connection. Pipeline provides uninterrupted supply of Azerbaijani (SOCAR's) gas to the local market with a maximal throughput capacity up to 8 Mm^3/d. Southern branch, connected to Karadaghi-Tbilisi pipeline supplies gas to Kvemo Kartli and Samtskhe-Javakheti regions of Georgia.

Gardabani-Navtlugi (D=700 mm; L=30.2 km, P_0=55 bar) **and Navtlugi-Saguramo** (D=700 mm; L=50.6 km, P_0=55 bar) sections have total length of 80.8 km. Gardabani-Navtlugi Pipeline is connected to Vladikavkaz-Tbilisi Pipeline and the latter's 188-kilometer benchmark is connected to Navtlugi-Saguramo section at 41 kilometer point with 500 mm connector. Navtlugi-Saguramo pipeline lies in parallel to Vladikavkaz-Tbilisi pipeline in densely populated areas of Tbilisi and provides significant enhancement of the operational reliability and increases throughput capacity of the system.

The Area 72 of SCP -Rustavi section (D=762 mm, L=12.5 km, P_0=55 bar) **connecting EWGP to South Caucasus Pipeline** was built to supply gas for the Georgian market provided under option and supplemental gas sale-purchase contracts. Maximal throughput capacity of system currently total to 5,5 Mm^3/d (232,5 th.m^3/h)

Kakheti-branch of EWGP (D=200/300/500 mm, L=212.9 km, P_0=25/55 bar) is connected to Gardabani-Navtlugi Gas Pipeline (at KP 486 km of Karadaghi-Tbilisi Gas Pipeline) through the D=300 mm, L=25 km Rustavi-Sagarejo section to guarntee gas supply to the Kakheti region by a circular (ring-shaped) system (second supply point is entry to Vladikavkaz-Tbilisi Gas Pipeline nearby Saguramo). The branch has several internal regional branches, the most important of which are: Kvareli Branch and Kiziki Branch (which splits into two – Dedoplistskaro and Lagodekhi –sub-branches).

Southern (Tsiteli Khidi-Akhalkalaki) **Branch of EWGP** (D=300/500 mm, L=195.6 km, P_0=12/25/55 bar) is connected to Karadaghi-Tbilisi Pipeline and supplies natural gas to household and commercial consumers in Marneuli, Bolnisi, Dmanisi, Tsalka, Aspindza, Akhalkalaki, Ninotsminda, Akhaltsikhe and Adigeni municipalities. At KP 182 km, the pipeline is connected to Aspindza-Akhaltsikhe-Ude-Adigeni Branch that comprises Kotela-Aspindza, Aspindza-Akhaltsikhe, Akhaltsikhe-Ude-Goderdzi sections (later enables to supply Ajara mountaneous resorts and Khulo region with natural gas and in addition to the existing gas pipelines will ensure circular supply of the Adjara region - from Kobuleti and Akhaltsikhe branches).

East-West Gas Pipeline System Center-Sukhumi Group of pipelines comprises Saguramo-Khashuri-Kutaisi, Kutaisi-Sukhumi, Zestafoni-Senaki-Poti (parallel to Kutaisi-Sukhumi) Gas Pipelines and their branches, including Tskhinvali, Bakuriani, Ajara and Sukhumi Branches (see Figures 3.14 and 3.15).

Saguramo-Khashuri-Kutaisi Gas Pipeline (D=500/700/800 mm, L=212.5 km, P_0=55 bar) starts from Saguramo Gas Metering Station. The pipeline is intended to supply gas to Mtskheta-Mtianeti, Shida Kartli, Imereti, Samtskhe-Javakheti and Tskhinvali Regions. In different sections the gas pipeline changes internal diameter within the range of 700/800/500 mm. In some areas, it is represented with parallel sections. At KP 85 km of the gas pipeline, there is a connection for one of the most important branches (Gomi-Khashuri-Bakuriani) to supply gas to consumers in Borjomi-Bakuriani resort and recreation zone. The gas pipeline also has Akhalgori, Kaspi, Gori, Tskhinvali-Java, Sachkhere, Chiatura, Zestafoni and Kutaisi branches.

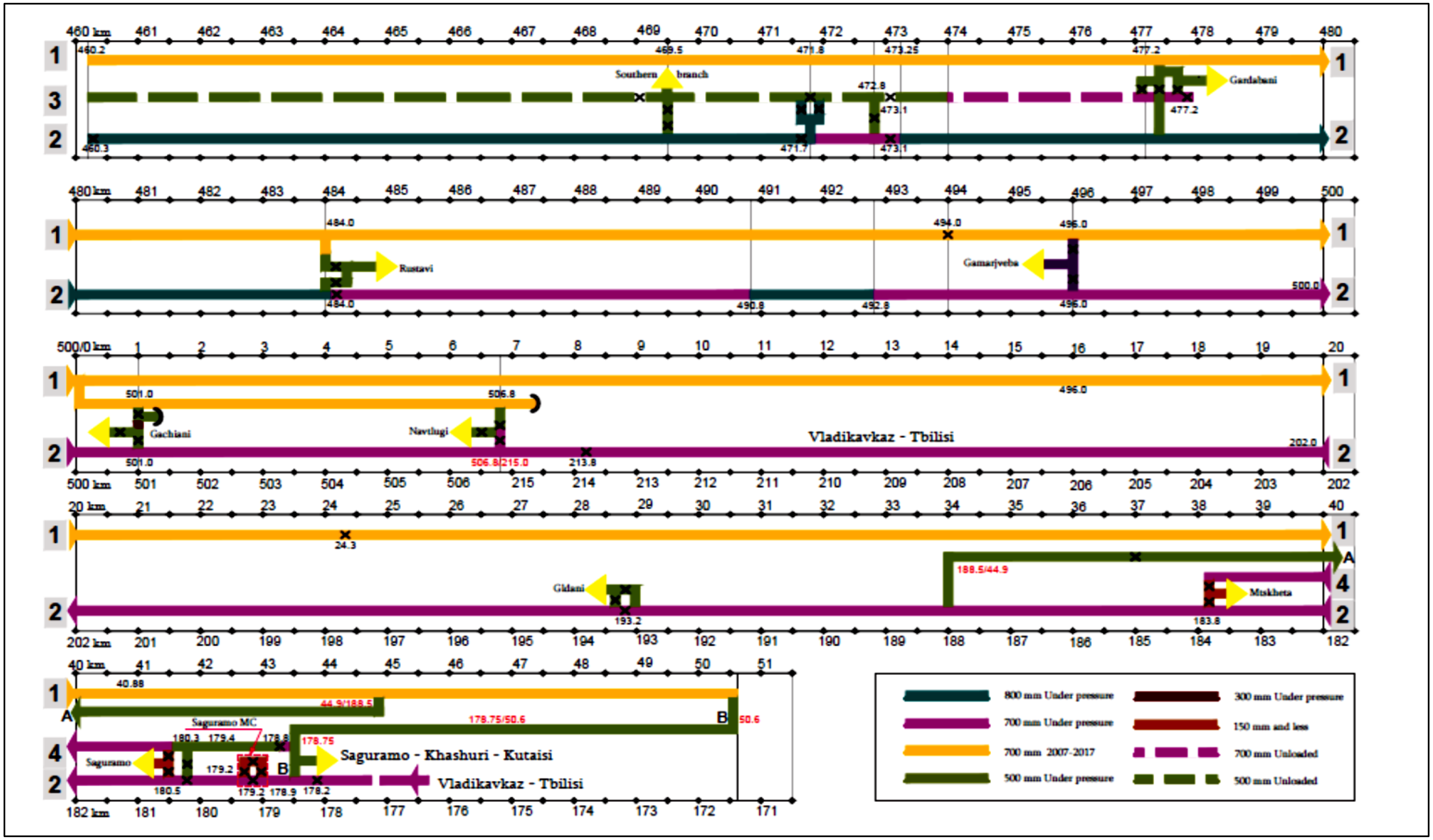

Figure 3.14. Azerbaijan Border- Saguramo section of EWGP Pipeline System

500 mm pipeline sections were replaced by new Gori-Kareli-Khashuri D-700 mm pipeline sections, which are placed in parallel to the existing “Saguramo-Kutaisi” pipeline’s 57.4-90.6 km point section. This significantly increased the transmission capacity and enhanced the operational reliability of the pipeline.

Khashuri-Bakuriani Branch of EWGP (D=300/500 mm L=52.8 km, P_0=55 bar) starts from Vaka Metering Station at KP 98 km of Saguramo-Khashuri-Kutaisi Gas Pipeline. It supplies gas to consumers in Khashuri and Borjomi municipalities, including Bakuriani.

Kutaisi-Sukhumi Gas Pipeline (D=500/700 mm, L=212 km, P_0=55 bar) is an extension of Saguramo-Kutaisi Gas Pipeline. It is intended to supply gas to Western Georgian regions. At the KP-51 of the pipeline starts a D=500 mm Kobuleti Branch to supply gas to Guria and Ajara Regions.

Khashuri-Bakuriani Branch of EWGP (D=300/500 mm L=52.8 km, P_0=55 bar) starts from Vaka Metering Station at KP 98 km of Saguramo-Khashuri-Kutaisi Gas Pipeline. It supplies gas to consumers in Khashuri and Borjomi municipalities, including Bakuriani.

Kutaisi-Sukhumi Gas Pipeline (D=500/700 mm, L=212 km, P_0=55 bar) is an extension of Saguramo-Kutaisi Gas Pipeline. It is intended to supply gas to Western Georgian regions. At the KP-51 of the pipeline starts a D=500 mm Kobuleti Branch to supply gas to Guria and Ajara Regions.

Zestaphoni- Poti Gas Pipeline (D=700 mm, L=128.7 km, P_0=55 bars) includes newly built Zestaponi-Kutaisi (23.2 km), Kutaisi-Abasha (47 km), Abasha-Senaki (29 km) and Senaki-Poti (29.6 km) sections. It is situated parallel to the existing D=500 mm Kutaisi-Sukhumi Gas Pipeline. Old and newly constructed pipelines are connected to each other through the several connectors. To the newly built Zestaphoni-Senaki-Poti Gas Pipeline is also connected the existing and under construction Kobuleti Branches.

The main gas pipeline system of Georgia includes gas metering units and gas distribution stations. The points of location of the main metering units of the pipelines connecting to transborder pipelines are shown in the Table 3.5 (additional 7 main metering units are installed at various points of internal main gas pipelines of Georgia).

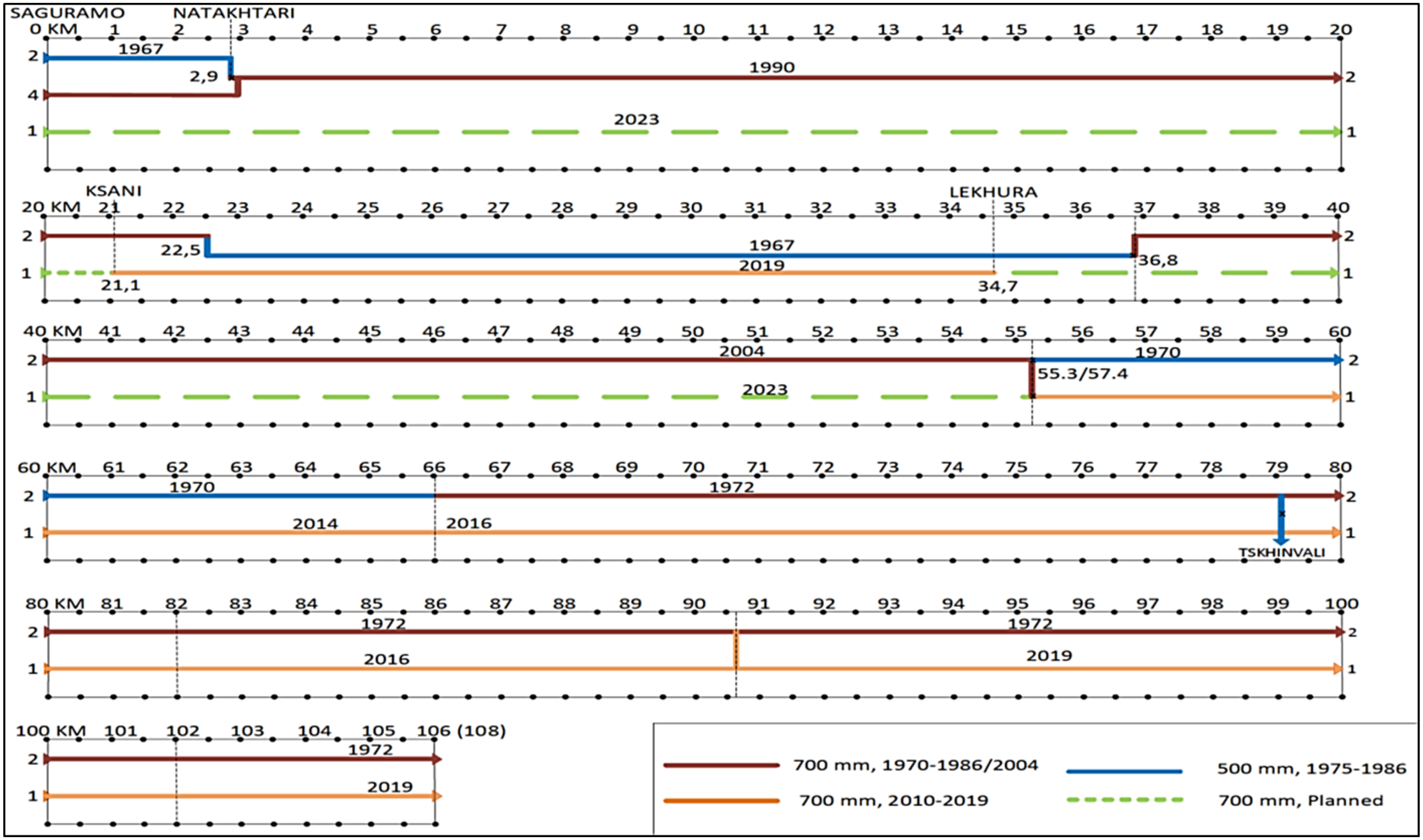

Figure 3.15. Saguramo-Khashuri

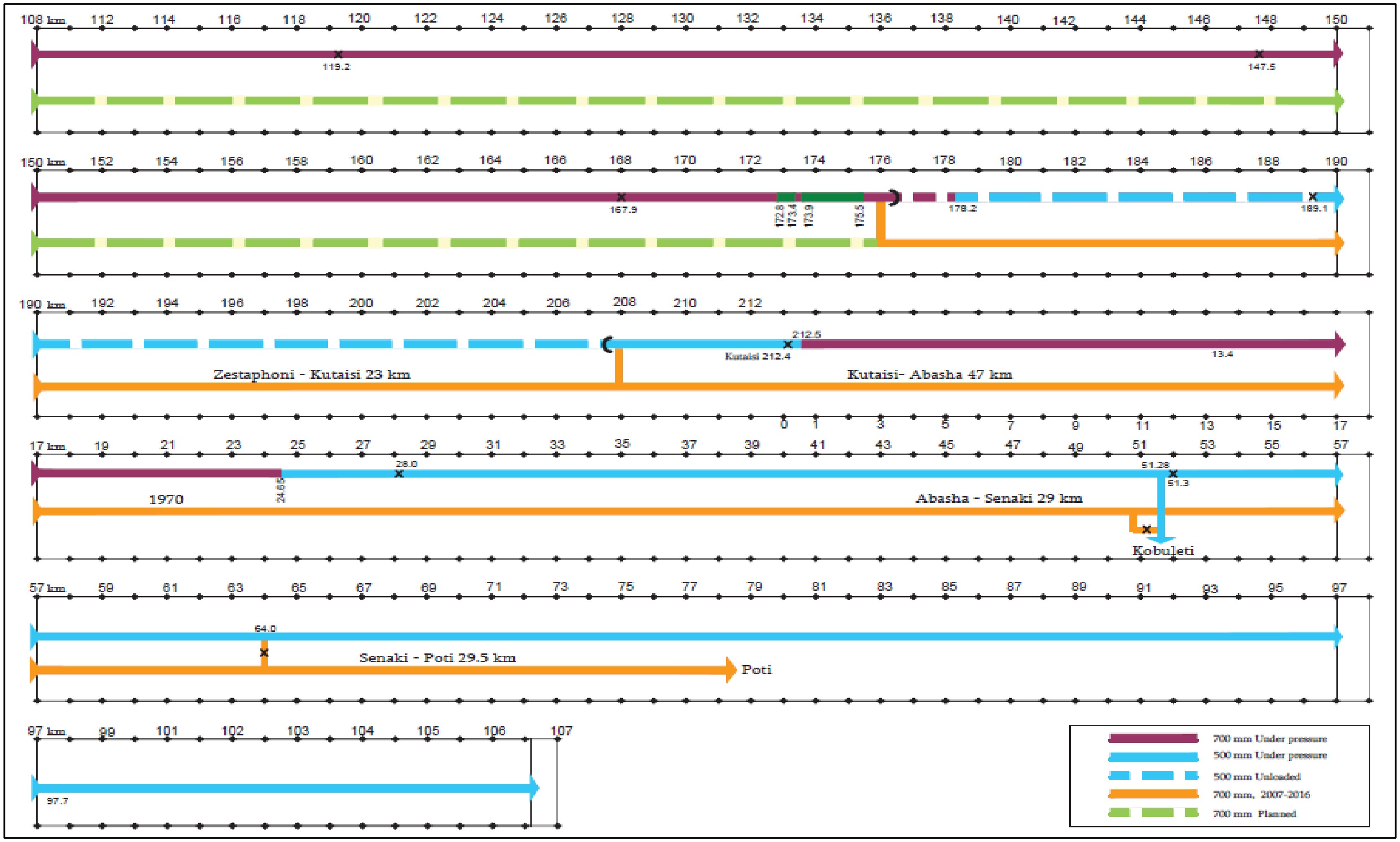

Figure 3.16. Khashuri-Poti section of EWGP

Table 3.5. GPRMS on Transborder Pipelines

	Name/designation	Location/pipeline name
1	Gveleti, Gas import from Russia	NSCGP, Russian Border
2	Thiteli Khidi, Transit to Armenia	Georgia-Armenia, Armenian Border
3	Khrami, Gas import from Azerbaijan	Kazakhi-Saguramo, Azerbaijani Border
4	Shah Deniz Gas Georgian off-take on SCP	South Caucasus Pipeline, Area 72 of SCP, Jandara (Gardabani)
5	Shah Deniz Gas Turkey off-take on SCP	South Caucasus Pipeline, Area 81 of SCP, Vale
6	Shah Deniz Gas TANAP off-take on SCPX	South Caucasus Pipeline, Turkey Border

The main functions of gas pressure reduction and distribution stations (GRS) is to reduce/maintain pressure of gas received from the main gas pipeline and to be delivered for distribution and regulate gas flow considering the demands of industrial and household consumers.

About 80% of GRS which are currently in operation operate with a high reserve by capacity. Actual load of 65 GRS does not exceed 5% of design capacity (only GRS serving large cities and large industrial facilities, including: Gardabani, Gldani, Navtlughi, Gachiani, Kaspi, Rustavi, Kutaisi, Gurjaani, Sagarejo, Kvareli etc., operate close to design modes).

Automatized GRSs with block performance are widely used when consuming gas within the range of about 100-150 thousand m^3/hour. In case of a supply to smaller industrial, household and other facilities, cabinet-type automatic gas distribution stations are used for the pressure control.

The list of 83 gas distribution stations owned by the main gas pipeline owner – Georgian Oil and Gas Corporation is presented in the Table. In addition, 27 gas distribution stations owned by the Georgian Gas Transportation Company are included into the main gas pipeline system of Georgia. Also 10 gas measuring units are installed on the main gas pipeline system of Georgia to ensure metering of gas received from the supplier and delivered to the consumer, including GPRMSs at the borders of three neighbor countries (see the Table 3.5).

Table 3.6. Gas Presure Reduction and Distribution Stations

Location	Year of Constr.	Type	Q_d, m^3/h	P_d, bar	Actual load, m^3/h
Rustavi	2020	Bespoke company standard	65000	1.2-5.4/1.2;	≈45000
Kaspi	1970	TR-885	61 000-300 000	1.2-5.4/0.3-1.2;	19188
Gori	1970	TR-885	61 000-300 000	1.2-5.4/0.3-1.2;	3333
Navtlughi	1959	TR-884	61 000-300 000	1.2-5.4/0.3-1.2;	75000
Borjomi	1975	AGDS-80	21 000-110 000	1.2-5.4/0.3-1.2;	3478
Gardabani	2007	TR-884	61 000-300 000	1.2-5.4/0.3-1.2;	206591
Gldani	1963	TR-884	61 000-300 000	1.2-5.4/0.3-1.2;	31250
Zestaponi	1975	AGDS -30	12 000-70 000	1.2-5.4/0.3-1.2;	1530
Khashuri	1972	AGDS -30	12 000-70 000	1.2-5.4/0.3-1.2;	1173
Kazbegi	1971	AGDS -1/3	1 100-4 750	1.2-5.4/0.3-1.2;	1005
Bakuriani	1989	AGDS -30	12 000-70 000	1.2-5.4/0.3-1.2;	1558
Kutaisi-1	1975	AGDS -150	61 000-300 000	1.2-5.4/0.3-1.2;	8758
Marneuli	1978	AGDS -80	21 000-110 000	1.2-5.4/0.3-1.2;	2293
Telavi	1974	AGDS -30	12 00070 000	1.2-5.4/0.3-1.2;	1934
Sachkhere	1974	AGDS -10	10 000-38 000	1.2-5.4/0.3-1.2;	1814
Tskaltubo	1975	AGDS -10	10 000-38 000	1.2-5.4/0.3-1.2;	1648
Mtskheta	1966	TR-645	10 000-38 000	1.2-5.4/0.3-1.2;	1227
Nacharmagevi	1970	AGDS -3	2 750-11 200	1.2-5.4/0.3-1.2;	1250
Gurjaani	1970	TR-645	11 000-38 000	1.2-5.4/0.3-1.2;	1086
Mejvriskhevi	1970	AGDS -1/3	1 100-4 750	1.2-5.4/0.3-1.2;	1045
Gachiani	1970	AGDS -80	21 000-110 000	1.2-5.4/0.3-1.2;	25000

The main gas pipeline system of Georgia also includes two compressor stations in Kvesheti and Saguramo, however, due to the fact that the pressure of imported gas is sufficient for the proper functioning of the local system, compressor stations are currently put out of commission.

Approximately 20 cathodic protection stations are connected to the main gas pipeline system of Georgia to protect main gas pipelines from corrosion. Cathodic protection of gas pipelines is carried out on all directions of EWGP system (see the Table), as well as on the southern branch and NSGP system (the latter requires monitoring and restoration).

Table 3.7. Cathodic protection stations of EWGP

Pipeline Section and KmP of Station location	
Gardabani-Navtlughi, 0.0	Zestaponi-Kutaisi, 5.2
Gardabani-Navtlughi, 14.0	Kutaisi-Abasha, 5.2
Navtlughi-Saguramo, 0.0	Abasha-Senaki, 4.6
Navtlughi-Saguramo, 33.3	Senaki-Poti, 10.1
Navtlughi-Saguramo, 50.0	Senaki-Poti, 29.5

3.5. GAS CONSUMPTION TRENDS AND FORECAST

Natural gas is one of the cheapest, simple to use and ecologically less damaging natural resources in Georgia. Its supply-consumption during the country's independence, except for 2008-2010 global economic crisis and the 2008 military conflict with Russia is characterized by growing trends.

Analysis of gas consumption dynamics by consumer categories shows a continued trend of increased supply of gas in the household sector, which is connected with the improvement of the living conditions of the population and implementation of intensive gasification plans in new regions of the country. As by reasonable assessments, share of gasified regions will reach the rational margin by 2021, it is expedient to plan conservative growth of gas consumption in the sector – within the scope of 3% until finalization of the state gasification program and thereafter 1-1,5% annual growth which corresponds to the tendency observed in international practice and is connected with routine improvement of living conditions. Considering such an assumption it is accepted that demand on gas in the household sector of the country will increase from 875 Mcm in 2019 to about 970 Mcm in 2025 and to about 1020 Mcm in 2030.

Significant imbalance of gas consumption is observed in power generation sector, which is preconditioned by hydrologically variable years. In particular, in the years of drought with small flow of rivers, to balance the demand of consumers on electricity, extended load of thermal generation facilities is required, while in the years of high precipitation, with increased river runoff, it is possible to balance almost entire demand on electricity by hydro power generation. In addition, gas consumption growth during recent years is preconditioned by a significant increase in power consumption, which cannot be satisfied by the already utilized potential of hydropower capacities, and construction of new seasonal regulation HPPs is significantly behind the schedule still. In addition, extensive use of local hydro- as well as other renewable resources due to their critical dependence on climate conditions makes necessary to construct backup capacities of thermal generation in a timely manner.

To forecast gas consumption for the thermal power generation, the electricity consumption planned moderate (basic) growth scenario data are used, which are reflected in the 10-year development plan of Georgian (electricity) transmission network. Plan is establishing annual 5% growth of electricity consumption, for the basic scenario. About 18-19 billion KWh of electricity will be required by 2025 and 22-23 billion KWh of electricity will be required by 2030 accordingly.

In particular, it is envisaged that:

- 230 MW Gardabani combined cycle gas-fired (CCGT) TPP has been operating since 2015. It is intended for operation in the base load mode. Annual electricity generation changes from 1.2 to 1.6 billion KWh. Thermal efficiency of the power plant is 52-54%;
- The second 230 MW combined cycle gas-fired Gardabani 2 TPP started operation at the beginning of 2020;
- According to the existing plan it is envisaged to ensure operation of additional 2 new TPPs which will replace the old, low-efficiency blocks [99] (and/or import). Particularly, it is envisaged to construct a new, approximately 250 MW combined cycle gas-fired TPP by 2022 [100] and additional new, approximately 250 MW TPP by 2023.
- Accordingly, the total installed capacity of combined cycle gas-fired TPPs, together with the existing gas turbine capacity of 80 MW, will reach 1030-110 MW by 2025 and the possible annual generation considering the design load factor will reach about 5.5 billion KWh (25% of the forecast demand on electricity in 2030).
- Considering the fact that the new TPPs generate 70-75% more power than the old, low-efficiency blocks with the same gas consumption, demand on gas will not increase from 2020 prorate the thermal generation. Considering the rationally estimated load of CCGTs about 1,3-1,5 billion KWh/year, each new TPP will consume about 230-250 Mcm of gas which ensures saving of about 150-180 Mcm of gas annually compared to generation of the same volume of electricity by old units.
- Considering the above, gas consumption for power generation purposes will increase from 678 Mcm in 2019 to 1000 Mcm in 2030.

Growing consumption tendency is observed in the commercial sector, where, apart from the 2008-2010 crisis period, relatively favorable environment was created for development of industrial production and commercial activities. Relatively sharp increase of consumption after 2010 is connected with extensive use of compressed natural gas in the transport sector, however, this increase is not so sharp due to achievement of the actual peak value and in the future, moderate growth of demand of compressed gas filling stations, possibly prorate the annual growth of vehicles, should be planned.

In general, commercial sector consumption growth is predetermined by market relations and is related to many uncertainties. However, as it is known, dynamics of energy resource consumption in the production sector is correlated to growth of produced goods or services. Therefore, forecast data may be established on the basis of the correlational analysis of the actual tendency of the past period. The figures below show the parameters of trend established by the regression analysis method between GDP and gas consumption in the commercial sector, including industry, during 2004-2019 and the forecast consumption data (Mcm/year) calculated using these parameters for the period until 2030, considering the forecast growth of the total revenues (GDP) of the country.

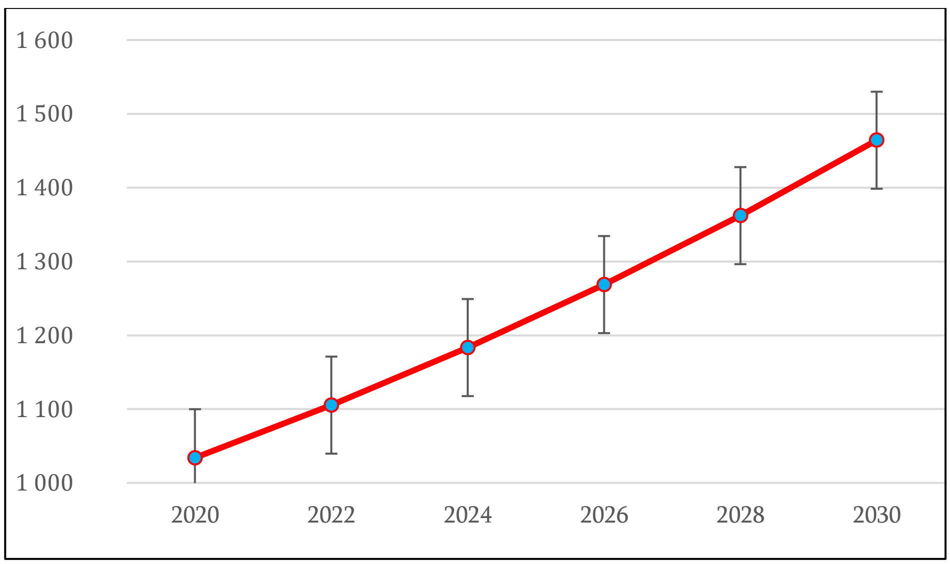

Figure 3.17. Forecasts of consumption in the commercial sector based on regression analysis, Mm^3/y

Summarized natural gas consumption forecast data by sectors are shown on Figure 3.18.

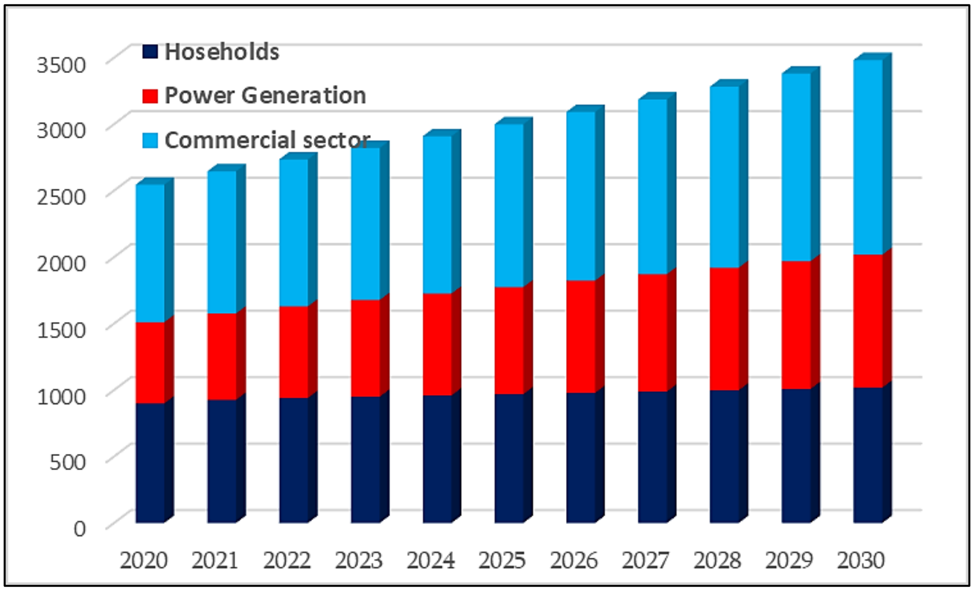

Figure 3.18. Natural gas consumption forecast by sectors, Mm³/y

For comparison, results of the country's energy sector development simulations performed under guidance and with direct participation of the former Ministry of Energy using Business As Usual (BAU) scenario are used [101]. Results of the Report "Low Emission Development Strategy – Energy Sector" (July, 2016) prepared by Sustainable Development Center 'Remission" are also considered.

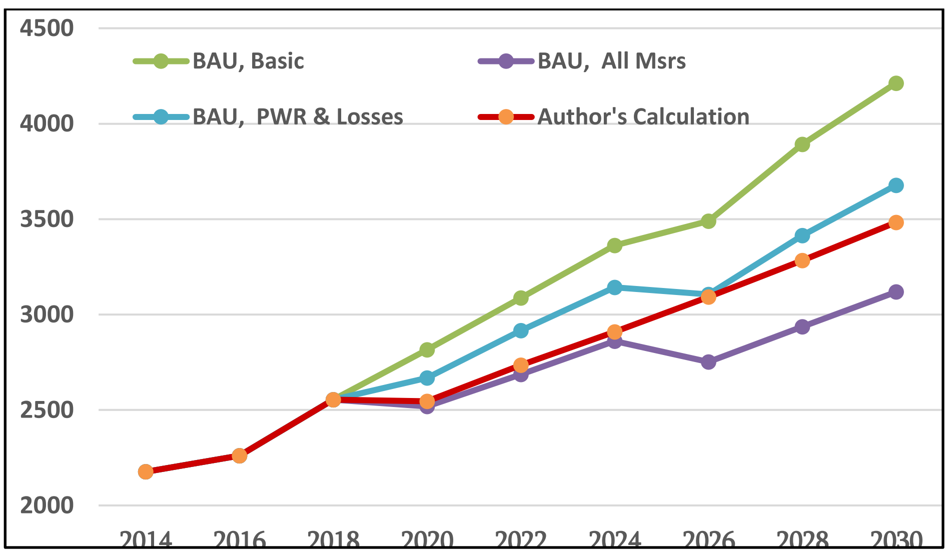

Figure 3.19. Forecast demand on gas, Mm³/y

Comparative analysis shows satisfactory compliance of the forecast results of simulation by using MARKAL modeling program with the results calculated considering current period consumption and the planned development scenarios of gas market. In particular, demand on gas, by evaluation of MARKAL project, in case of minimization of losses and optimization of power generation (BAU PWR & Losses Scenario) for the nearest decade practically coincides with the estimated evaluations. If the implementation of possible measures of intensive growth of energy efficiency and use of renewable resources (BAU All Measurers Scenario) will be simultaneously considered, gas consumption after 2025-2026 will be annually reduced by about 10-11%, compared to the case when effective measures of the system optimization are not carried out according to BAU Basic Scenario, which will lead to increase of gas consumption to 4.2 bcm and more by 2030.

The forecasts for the demand of natural gas and transit to Armenia as well as for the transportation of corresponding volumes of natural gas through Georgian Main Gas Pipelines are set forth in Table 3.8.

Table 3.8. Forecast for natural gas transportation and transit through Georgia[51], Mm³/y

	2016	2018	2021	2024	2027	2030
Local market	2260	2285	2650	2900	3200	3500
Transit to Armenia	1870	1940	1980	2050	2100	2200
Total	4130	4225	4630	4950	5300	5700

Analysis of the forecast of gas supply to be provided under long-term contracts confirms that the estimated total volume of gas supply can meet the demand of the social sector only provided that new, highly efficient power plants will replace the existing ones and new, seasonally controlled hydropower plants are put into operation so as to appreciably reduce demand for gas for electricity generation needs. However, such issues, as seasonal consumption disparities and guaranteed gas supply to protected consumers in critical situations are still unresolved, mostly due to insufficient capacity of the critical gas infrastructure sections.

3.6. SPECIFIC ASPECTS OF SECURITY OF SUPPLY, CHALLENGES AND THREATS

3.6.1. SUPPLY DEFICIT

The Energy Strategy of Georgia 2020-2030 identifies the following key gas sector challenges and contains policies and measures to address each of them [102]:

- Critical natural gas supply import dependency;
- Possible natural gas supply shortages;

[51] Except SCP's transit volumes

- Lack of strategic fuel reserves;
- Obsolete and decrepit transport infrastructure components;
- Gas supply issues in the country's temporarily occupied territories;
- Process deficiencies in establishing a competitive market and developing regulatory legislation.

The main risks and challenges of the current gas market of Georgia and possible ways of their mitigation are discussed below (see also Publications [103] &[104], discussing diffent aspects of security of Georgian oil and gas infrastructure).

One of the main challenges of gas supply of Georgia in the long-term period is connected with significant growth of the forecasted gas demand and expiration of part of supply contracts. The figure below shows charts of forecasted demand and guaranteed supply ensured by the existing gas supply contracts for Basic (Realistic) Scenario, which considers prolongation of the existing contracts Russia (Gazprom Export)-Georgia, Azerbaijan (Socar)-Georgia and Azerbaijan-Turkey (gas from Shah Deniz phase I to Turkey), but suspension of Azerbaijan-Georgia Sale Purchase Agreement for Shah Deniz Suplemental gas.

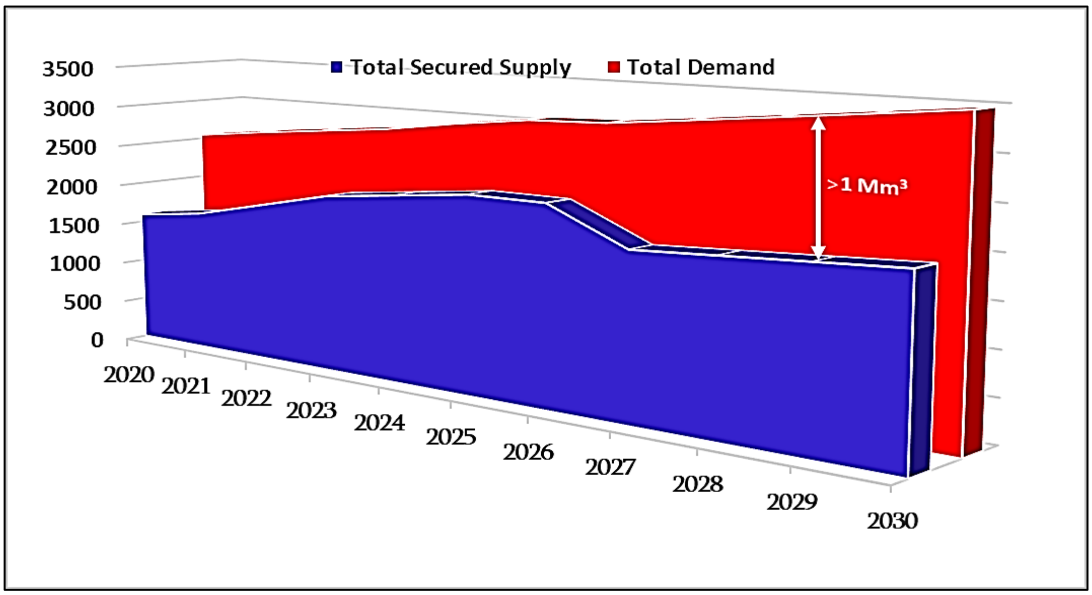

Figure 3.20. Comparison of total secured supply with projected demand (Basic Scenario), Mm³/y

The analysis shows that in the period of 2020-2026, 2/3 and more of the total demand of the country on natural gas is ensured by the existing contracts. Assumingly, the supply/demand deficit of this period will continue to be covered by annual 850-1050 million cubic meters of gas supplied by SOCAR to the commercial market.

After 2026, when the term of Supplemental Gas Contract for supply of gas from Shah Deniz expires, deficit of total demand will increase significantly, by approx. 45% or op to 1,2-1,5 bcm/year (according to the pessimistic scenario, which envisages termination of all expired contracts, the estimated deficit will be equal to 2 bcm and in case of the optimistic scenario, if all valid contracts, including Supplemental Gas Contract for supply of gas from Shah Deniz will be prolonged after the expiry of the term, the deficit will be reduced to 1.2 bcm. In reality, the likelihood of development of pessimistic and optimistic scenarios is very low).

Due to limited capacity of the existing transport infrastructure of Azerbaijan, as well as lack of additional sources of gas in Azerbaijan for this period, it becomes problematic to cover the total deficit from SOCAR’s own sources. On the other hand, under conditions of the current political relations with Russia, for the purpose of ensuring the security of the country, it is expedient to maintain limited access of the Russian state monopoly – "Gazprom" on the market (presently, up to 200 Mcm per year is traded with Gazprom). Accordingly, a new source of supply to substitude supplemental gas volumes, or prolongation of the existing Supplemental Gas Contract with Shah Deniz Consortium will become necessary, considering the demand growth and respective changes of the market situation.

The opportunity of receiving gas from new sources, mainly on the basis of so-called "swap" contracts, may be considered as an alternative option.

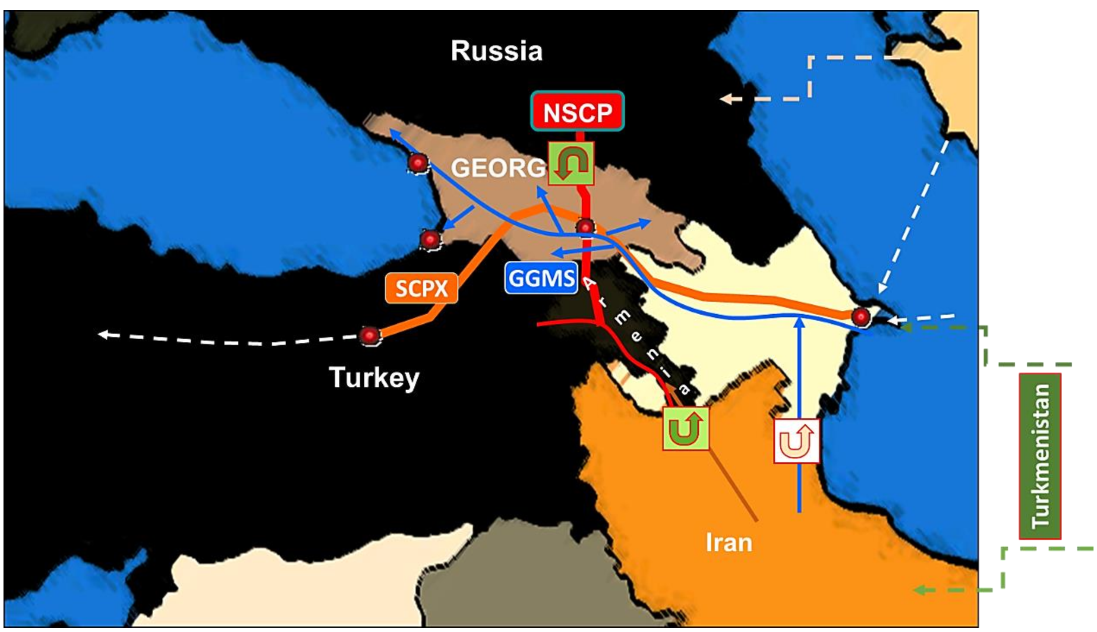

Figure 3.21. Diversification of supply prospects

Considering the geographic location of Georgia and interconnectors with the neighbor countries, the following countries may be considered as new potential sources of gas supply based on "swap" contracts:

- Turkmenistan - with the involvement of Iran and Azerbaijan;
- Turkmenistan - with the involvement of Iran, Armenia, and Russia;
- Kazakhstan – with the involvement of Russia.

The existing contracts between Turkmenistan and Iranian companies which are performed incompletely (in 2018 Iran used less than 20% of the total contractual volume), simplify supply of gas from Turkmenistan both with participation of Azerbaijan and Armenia, from commercial point of view. However, in fact, realization of supply schemes based on "swap" transactions" is complicated:

- As realization of multilateral swap transactions which are difficult to be carried out, requires co-participation of Turkmenistan, Iran or Kazakhstan, Azerbaijan or Armenia, Georgia and Russia;

- In connection with the Iran's sanctions;

- Due to inevitability of inclusion of the Russian "Gazprom", which is unjustifiable from political point of view;

- Due to restrictions of technological potential of the existing infrastructure or contractual restrictions (see the details above).

For actual diversification of supply sources for the purpose of increasing the energy security of the country, the project based on use of LNG on the local market may appear attractive in terms of the existing geopolitical condition and commercial efficiency[52]. Feasibility of implementation of such project is confirmed by the Turkish gas market development trend in the recent period [105].

For a long time, Turkey has critically relied on pipeline gas, predominantly from Russia, also from Azerbaijan and Iran (in 2016, 63% of Turkey's total pipeline gas imports came from Russia). Turkey's imports of LNG have steadily grown since 2016, but previously only to meet demand growth. Since late 2018, however, Turkey's LNG imports have surged, hitting a monthly record of 2.34 bcm, including 400 Mm^3 of LNG from the USA, in January 2019, met 40 % of total monthly demand of country and LNG started replacing declining pipeline gas imports. LNG exports are

[52] See Report: Technical expertise to assess the prospects of LNG markets in the Eastern Partner countries, Stantec, 2019

also ramping up in Europe, notably in Lithuania, Poland and Bulgaria, which have historically relied on natural gas from Russia. Recently Ukraine also initiated a project envisaging utilization of Polish regasification terminal and transmission infrastructure for LNG import.

The LNG option has some obvious benefits, such as supply diversification, but, in reality, it is difficult to estimate the reasonability of LNG regasification project realization in Georgia. The absence of liquefaction facilities and the special rules established by the Turkish authorities for Turkish Straits are limiting access of the countries of the Black Sea water area to the global LNG markets. Also, significant additional investments needed for the arrangement of regasification terminal, compressor station and transmission infrastructure between the LNG receiving terminal at the Georgian Black Sea coast and the major market consumers of country, are limiting factors.

Considering the current context of the region the project, based on the deal of reversed “swap” LNG from European regasification terminals eastward to Georgia, by utilization of Georgian off-take from the SCP pipeline, might be more realistic option technologically and commercially, moreover, according to forecasts, the market will be oversaturated with the LNG supply - in a worst-case scenario for the market (less gas withdrawn from storage as in 2019, slower growth of the Asian markets, even assuming European consumption grows again (which may be impacted negatively by the potential effect of coronavirus) and the decline of the indigenous production), the global LNG Surplus will rise to almost 40 bcm—representing 14 % of the total export capacity [24].

3.6.2. DEMAND/SUPPLY IMBALANCE

Significant difficulties exist due to impossibility of rational management of gas flows and the seasonal balancing, in terms of comparable stability of gas consumption with inequality and imports. Gas consumption in Georgia is characterized by sharp imbalance in winter and summer periods: in winter months the country consumes 2,5-3,5 times more natural gas than in summer.

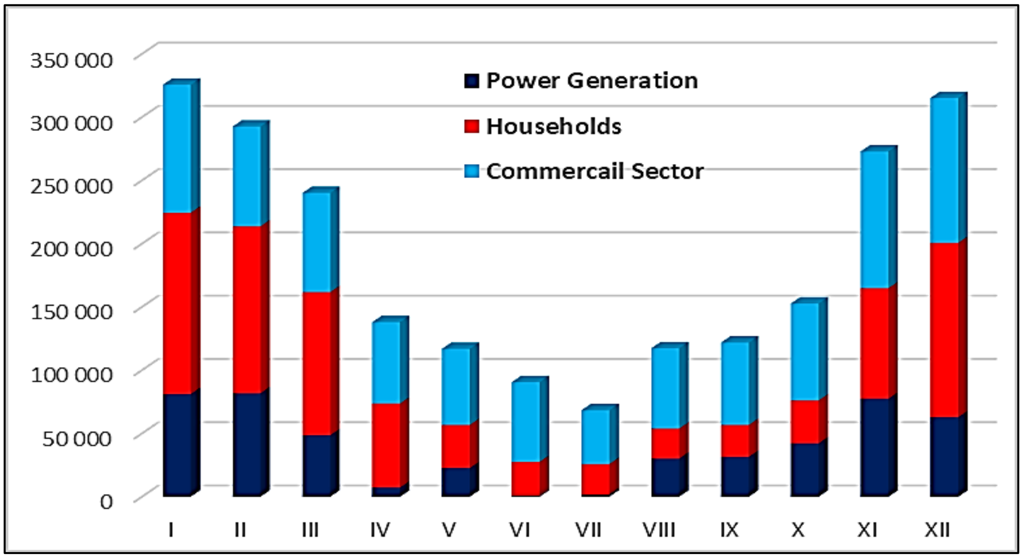

Figure 3.22. Gas Consumption Seasonal Imbalance, 2018 data, 1000 m³/month

It is notable, that disparity trend in gas consumption according to seasons has remained practically the same during several years of observation.

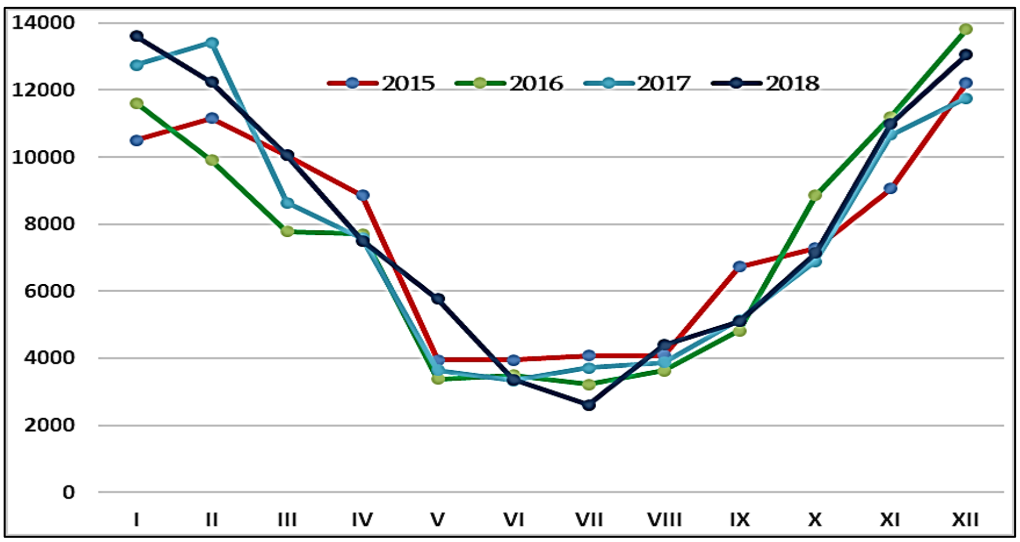

Figure 3.23. Gas Consumption fluctuation, Mm³/day

Variation in volumes between the daily consumption during peak load and minimum consumption in summer period (see figure 2.12, 2018 data) is more significant and it seriously complicates designing the pipelines with rational parameters and effective management of gas flow.

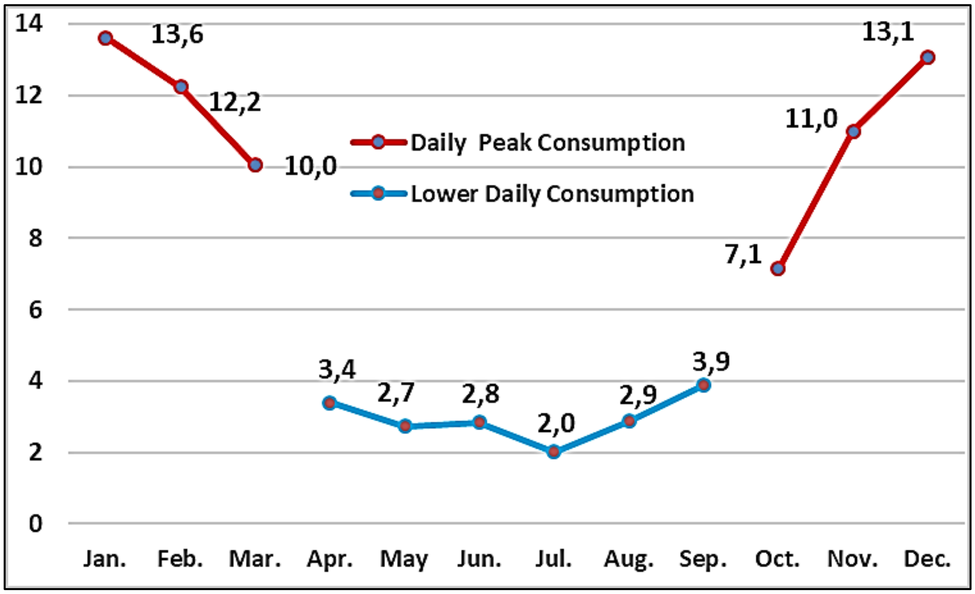

Figure 3.24. Gas consumption during winter peak load and summer minimum consumption periods, Mm^3/day

Gas consumption seasonal asymmetry is predetermined by the necessity to involve a part of thermal power plants in the generation of electricity predominantly in the winter season when low water flow sharply reduces hydroelectric generation and the household sector switches to an intensive heating mode. Seasonal imbalance of gas consumption has practically continuous trend indicating roughly 3,5 times more monthly demand for natural gas during winter peak load in comparison with the summer months demand. Imbalance between daily consumption during peak load (13,5-15,5 Mm^3/d) and minimum load in summer period (2-2,5 Mm^3/d) is more significant [91], which seriously complicates operation of pipelines with rational parameters and effective management of gas flows.

As the analysis shows, significant deficit may arise, if special measures are not taken, during peak demand for gas in winter period. According to the last year's winter season data, 13,5-15,5 Mcm/d was peak days actual demand of Georgia. Contractual and/or physical capacity limitations for NSGP, SCP and SOCAR pipelines can incompletely satisfy the requested demand in the future.

At present, the problem has been addressed under the Memoranda of the Government of Georgia and SOCAR and the relevant contract. SOCAR is acting as a virtual storage for balancing Georgian market's supply/demand imbalances currently. According to the Memoranda, the latter's responsibility is to satisfy Georgia's demand on "social" gas (considered for supply of household consumers and TPPs) under any circumstances, which are manageable only through the special measures taken by SOCAR, following which additional gas is received via the Russian pipeline (up to 2,2 mcm/d) and/or SCP Georgian off-take point (above contractual volume). As a rule, it happens during January-February and December peak consumption periods, when the demand specified by long-term contracts is impossible to meet, but the price of gas purchased at commercial basis, is significantly higher than the price envisaged for the household sector and power generation. As the local consumption is expected to grow significantly in the future and validity of some supply contracts will expire, it will be much more difficult to balance the demand and supply disparity. For instance, after the supply of supplemental gas from SCP is discontinued after 2026, the country will have to regularly obtain the additional gas supply to meet the demand of the social sector in the winter season.

Based on projections, annual demand of Georgia is planned to increase up to 3,5-3,6 bcm (instead of the current 2,4-2,5 bcm/y) by 2030 with peak demand up to 18,6 Mm^3/d, while allowable maximum capacity of Georgian imports currently (2020) equals to ≈15 Mm^3/d and will remain the same without taking additional measures.

As the analysis shows, during the forecasted peak load and/or in case of unscheduled interruption (or significant decrease) of supply, sharp deficit in natural gas is to be created and provision of protected consumers with fuel is at risk and probable gas deficit cannot be compensated with the country's own resources [106]. Therefore, taking costly and urgent measures prove to be necessary in order to avoid serious complications with regard to supplying the consumers with the gas and electricity. During the crisis, Georgia fails to meet the obligations envisaged by the transit contract.

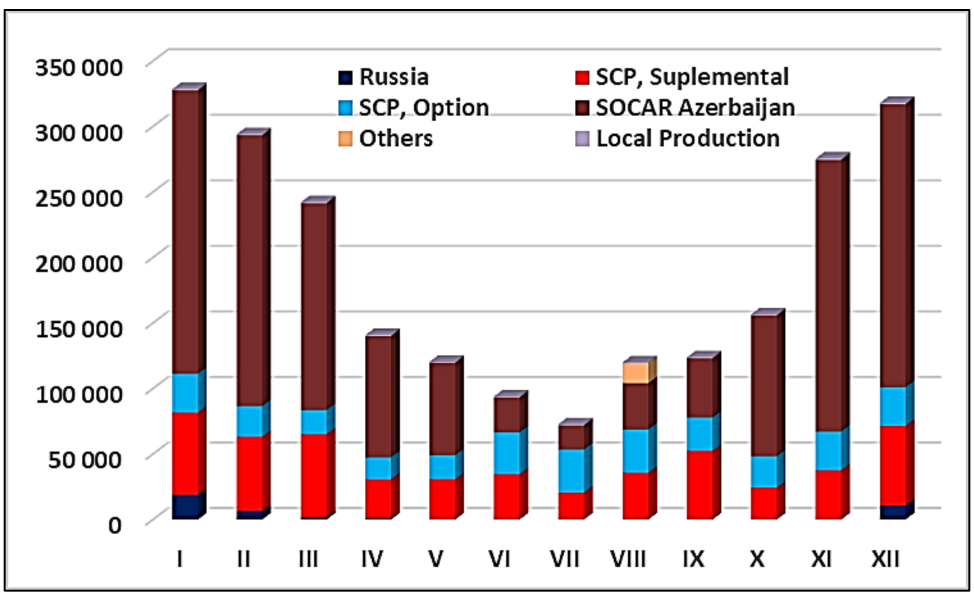

Figure 3.25. Supply sources, 2018 data, 1000 m^3/month

3.6.3. POTENTIAL RISKS AND HAZARDS

Analysis of results of assessment of potential risks and hazards affecting the operational security of the Georgian natural gas sector shows that development of the most critical situation in the natural gas sector may be related to supply deficit, network failure and absence of strategic reserves that results in a practical inability of the system to ensure effective operation in times of peak consumption or incidental interruption of supply.

Results of qualitative assessment of the Georgian system gas supply security by vulnerability criteria are presented below[53]. The potential risks and threats affecting energy vulnerability of Georgia's gas supply system and results of rough assessment of possible risks (based on the conventional five-score qualitative assessment method) are shown in the tables 3.9 and 3.10.

Table 3.9. General classification of risks and threats of gas supply system [107]

	Risks	Threats
Short-term	SR1. Technological breakdowns, accidents and natural disasters	ST1. Termination of supply (by supplier or transit country)
	SR2. Insufficient storage/stored reserves	ST2. Blockade/ban (by a rival or hostile countries)
	SR3. Sharp change of prices due to imbalance between supply and consumption	ST3. Sabotage/attack on a critical infrastructure facility
Long-term	LR1. Insufficient investment in production or transport activities	LT1. Transfer of strategic energy assets to a foreign country
	LR2. Unstable demand in the importer and/or exporter country	LT2. Risky consent (agreements) with foreign partners
	LR3. Insufficient supply in the exporter country at the global scale	LT3. Inadequacy of energy policy

[53] Energy vulnerability is the level of negative impact of possible exogenous harmful factors affecting the country's energy supply system and negativelly impacting on welfare of the population and/or territorial integrity of the state or normal functioning of public institutions (source: Christie, E. "Energy vulnerability and EU-Russia energy relations", Journal of Contemporary European Research, Vol. 5, No. 2, August 2009, pp. 274-292)

Table 3.10. Risks and threats predetermining energy vulnerability of Georgian gas supply system

Risk/ Threat	Insignificant (1)	Low (2)	Average (3)	High (4)	Critical (5)
SR1					
SR2					
SR3					
ST1					
ST2					
ST3					
LR1					
LR2					
LR3					
LT1					
LT2					
LT3					

As it seems, occurrence of the most critical situation in the gas sector may be related to the shortage of strategic reserves (e.g. during peak consumption and unplanned failure of part of supply infrastructure), which has been predetermined by particularly low level of the system flexibility, while the country is almost entirely dependent on imported fuel, supplied through the highly fragile transborder and internal transmission infrastructure.

The likelihood of critical situation is rather high due to risky consents (e.g. long term agreements with the inadequate conditions of supply) with foreign partners, also due to natural disasters or insufficient reserves of gas in the main supplier country, resulting in shortage of supplies.

In turn, a critical increase in peak consumption is related to a sharp change in climate conditions, while interruptions in supply may be caused by accidents prompted by natural disasters, acts of political sabotage, or technological failure, which arise from specific features of Georgian landscape and climate, political instability in the region, low technical reliability and insufficient capacity of part of old trunk pipelines and related equipment, also relatively limited export potential of Azerbaijan.

In recent years, Georgia has seen a few cases of unscheduled interruption in gas supply, as a result of which the supply of gas to the country from different sources failed from 1 to 3 weeks or dropped by at least 33% of total supply.

Significant accidents of Georgian gas pipelines are related to natural disasters or damage caused by the corrosion of old pipelines (undeliberate threats). Also, there is recorded that Georgia has seen a few deliberate threats - interruptions in gas supply due to political sabotage or even for an operational necessity. During the armed conflict with Russia in 2008 and thereafter, there have been real threats of cyber-attacks on the critical infrastructure of the country also[54].

Physical (kinetic) or cyber-attacks damaging electricity grid and/or gas transmission system may cause cascading impact on the operation of energy sector countrywide. In January 2006, during the simultaneous terrorist attack on gas pipeline and high voltage transmission line supplying Russian gas and electricity to Georgia, the country faced major social problems and an economic crisis, as Russia was the only exporter at the time. As a result, supply of the Russian gas and transit to Armenia were interrupted in the most critical time of the winter. It was only two weeks after the accident that the gas supply from Russia was fully restored. Consequently, gas supply to the main part of consumers was limited in the time of the crisis. Consumption in the month dropped about three times compared to the average consumption statistics for January and more than five times compared to peak consumption. In parallel, gas transit to Armenia was fully interrupted.

From time to time there have been interruptions of gas supply due to technological failures occurring in the Azeri offshore fields or the necessary maintenance works and tests on pipelines or metering units.

Expenses caused by emergency termination of operation of the gas transportation system exceed hundreds of millions of GEL. Statistical materials, as well as results of the analysis of surveys conducted for 26 EU countries were used for calculation of expenses [108].

[54] Many hundreds of energy companies in USA have had their systems penetrated, their data stolen and remote software installed in recent years. Source: Dan Nussbaum, Framing the Operational Energy. Presentation at Regional Energy Security Symposium, April, 2019, Tbilisi, Georgia

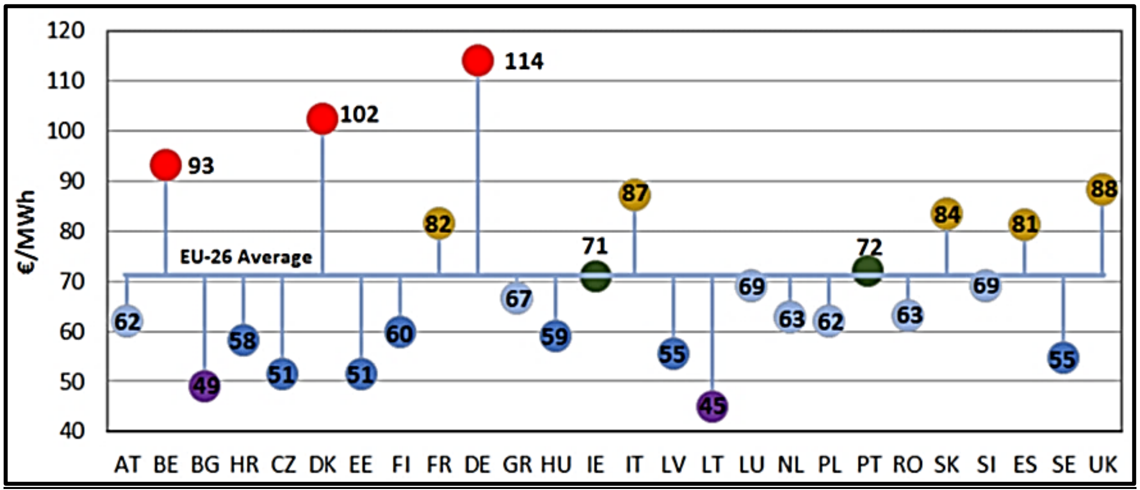

Figure 3.26. Cost of disrupted gas supply calculated through their UCM proxies in EU, €/MWh

Table 3.11. Major interruptions of Georgian trunk pipelines

Pipeline Data and Place of accident	Nature of accident	Result of accident
Russian transit pipeline, 224,5 km point	Rupture caused by landslide	5,8 mln m³ gas emission, discontinuation of supply and transit
Russian transit pipeline, 132,0 km point	Rupture caused by landslide	4,5 mln m³ gas emission, discontinuation of supply and transit
Azeri-Georgia import pipeline, 61,0 km point	Fire caused by leakage	2,8 mln m³ gas emission, discontinuation of supply and transit
Russian transit pipeline, 122,0 km point	Rupture caused by landslide	4,7 mln m³ gas emission, discontinuation of supply and transit
Russian transit pipeline, 78,0 km point	Rupture caused by landslide	3,5 mln m³ gas emission, discontinuation of supply
Azeri-Georgia import pipeline, 55,0 km point	Rupture caused by pipeline corrosion	3,6 mln m³ gas emission, discontinuation of supply and transit
Russo-Georgian border - Russian transit pipelines, 55,0 km point	Simultaneous explosion of two pipelines resulted	Full discontinuation of supply and transit from Russia for 2 weeks

	disruption of supply	
Russian transit pipeline, 233,0 km point	Rupture caused by landslide	2,4 mln m^3 gas emission, discontinuation of transit
Russian transit pipeline, 66,0 km point	Failure of pipeline caused by snow avalanches	Due to destroy of 350 m section, functioning of 700 mm pipeline was blocked
Russian transit pipelines, 143,1 km point and 55,5 km point	Rupture caused by mudslide	0,5 mln. m^3 gas emission, discontinuation of transit for 5 days

3.6.4. CRITICAL INFRASTUCTURE

To meet increasing demand on energy resources, it is importatant to ensure guaranteed supply of imported natural gas, related to significant challenges due to instable political situation in the region, critical dependence of the country's energy sector on climate conditions, high risk of natural disasters, insufficient throughput capacity and unacceptable technical reliability of some sections of outdated transportation infrastructure. Apart from the above, natural gas losses in the process of transportation are still high, main reason for which is the technical malfunctioning due to corrosion of ageing pipelines. Therefore, rehabilitation/development of network is crucial for reliability of functioning of systems.

Rehabilitation-modernization works of the key sections and branches of the main gas pipeline system are aimed at promoting secure exploitation and operational flexibility of the Georgian trunk pipeline system that will enable uninterrupted and effective delivery of natural gas to final consumers across the whole territory of Georgia. In this regard, first of all, it is significant to ensure proper operation of the most critical energy infrastructure in the normal operation mode, considering the gas consumption growth trend, as well as its quick restoration possibility (resilience) during each significant deviation from the normal operation mode.

Critical infrastructure of systems and networks are such that their continued operation is required to ensure security of a given region or entire nation, its economy, and the public's health and safety. Critical infrastructure includes assets, systems, facilities, networks, and other elements that society relies upon to maintain national security, economic vitality, and public health and safety.

The government in every country has a responsibility to protect critical infrastructure against natural disasters, terrorist activities and also cyber threats - actions to reduce risk for providing vitality of critical function is a crucial element of maintaining security of the region affected, or the entire country.

Resilience, on the other hand, is the ability (of system, network etc.) to be prepared for and adapted to changing conditions. This means being able to withstand and recover rapidly from disruptions, deliberate attacks, accidents, or naturally occurring threats or incidents.

Since not all infrastructure is critical to a country or region, it is necessary to identify which infrastructure is the most critical to maintain continued services or functions and vulnerable to some type of threat or hazard. Preliminary identification of threats and hazards that pose the highest risks to critical infrastructure, allows for more effective and efficient planning and resource allocation.

An example of the immediate need for instant recovery operations is damage of gas transmission system due to a natural disaster. Until the infrastructure system is restored, natural gas cannot flow to provide heat to households, fuel to industry and power generation, causing inoperability of telecommunications systems once backup power sources begin to fail. To get natural gas and power back up to all customers within hours or days, including emergency services, hospitals and other life-sustaining critical infrastructure is a crucial challenge for every nation.

It is highly important to prioritize vulnerability reduction efforts and perform physical or operational means that guarantee effective avoidance of negative consequences of probable failure of critical infrastructure, including mitigation of potential consequences of incidents proactively, or preparation to mitigate them effectively if they do occur.

Multi-decade experience of gas infrastructure operation allows to point out the main threats and hazards specific to the Georgian gas transmission system. These are:

- Technological and Industrial Accidents and Unscheduled Disruptions caused by aging infrastructure, equipment malfunction, termination of offshore field production;
- Natural disasters: earthquakes and landslides, floods, extreme temperatures, drought, wildfires;
- Terrorist Attacks of Supply Chain and Criminal Incidents causing system failure (kinetic attacks during military conflict or sabotage, vandalism, theft, property damage, etc.);

- Cyber Incidents (related to the growing integration of information and communications technologies with energy infrastructure and its potential cyber vulnerabilities although not recorded in the Georgian practice yet) [109];
- Untrusted Investment to potentially give foreign powers undue influence over the critical infrastructure.

Ageing is the major reason of damages of corroded pipelines, although, external interference and ground movement (damages caused by natural disasters or third-party uncontrolled impact) are the main reasons of failure of pipeline systems. Failures caused by subjective reasons (including construction defects of pipes, material failures or hot taps performed without compliance with respective standards) are minimal in the Georgian reality. Figure 3.27 shows correlation between failures and operational reliability of natural gas transmission pipelines and their age.

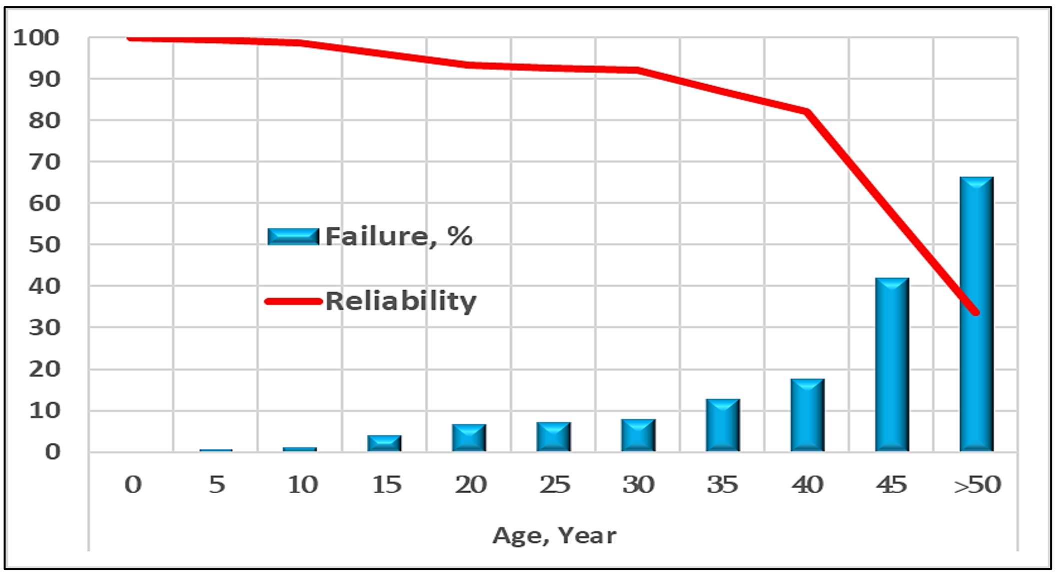

Figure 3.27. Correlation between Failures/Operational Reliability vs Aging of Pipelines [110]

The analysis shows that reliability of pipelines during the initial 10-15 years of operation is practically unchanged and failures are assumingly related to subjective factors, such as personnel's errors in construction or hot taps performed and material off-spec. Failures of pipelines aged 20-25 are comparatively intense and equal to approx. 7% of total failures.

Intense failures are observed in trunk pipelines from the age of 30: in case of pipelines aged 30-40, their share exceeds 25% and in case of pipelines aged 50 and more their share exceeds 66%.

Approx. 6% of main gas pipelines of Georgia were built 50 years ago (see Figure 3.28)[55]. In general, out of the currently operated pipelines, approx. 64% are aged 30 and more (see Figure 3.29) and belong to a potentially high risk sections considering the corrosion factor. Therefore, their reliability or replacement by new sections is an urgent task of increasing the transport system reliability.

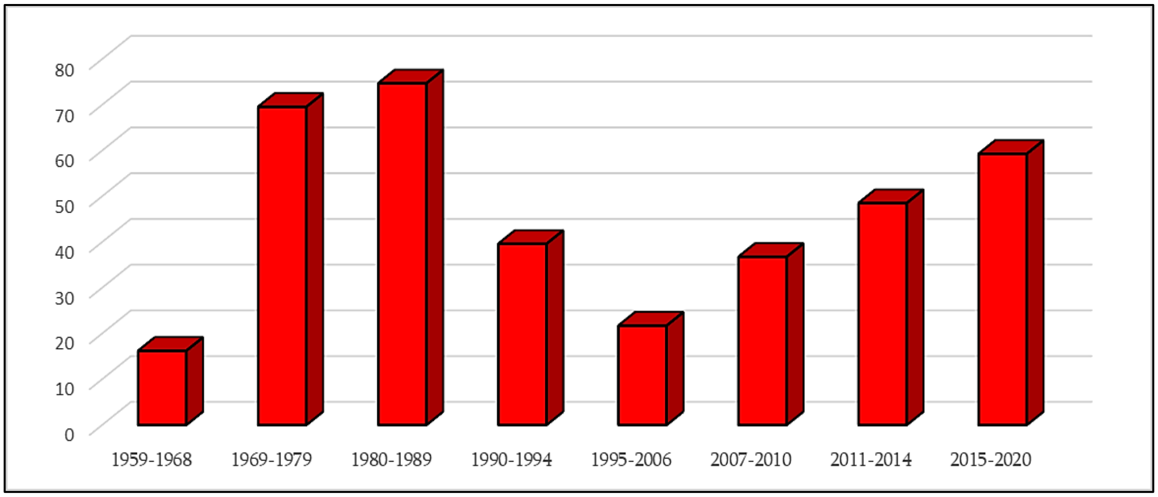

Figure 3.28. Construction History of Gas Transmission Pipelines[56], km

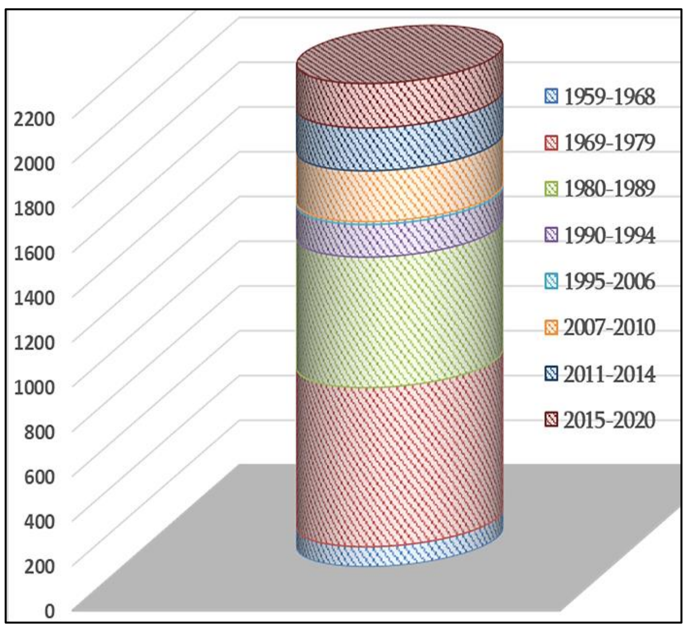

Figure 3.29. Aging of Pipelines currently under operation [57]

55 Approximately half of them are operated again today

56 According to the operator company, part of these pipelines are used today, with total length of 1983 km, and part of pipelines, including mainly looping, are moved to the reserve

57 Includes data of pipelines owned by GOGC only

Results of analysis of statistical data of failures of the Georgian main gas pipelines during the last 25 years are shown on Figures 3.30 and 3.31.

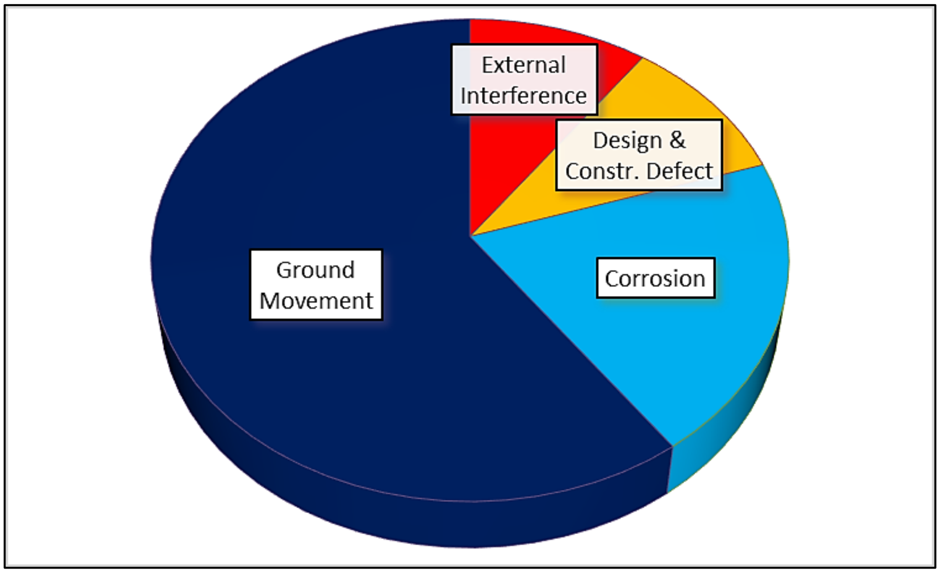

Figure 3.30. Frequency of failures caused by various reasons

High frequency of failures due to ground movement (approximately 60% of total number of failures) is connected with the complexities of construction and operation of pipelines on the mountainous terrain of the country. For comparison, the international experience shows that ground movement caused failures of main gas pipeline in approx. 15% of cases (according to the analysis of 2004-2013 statistical data – see Figure) [110].

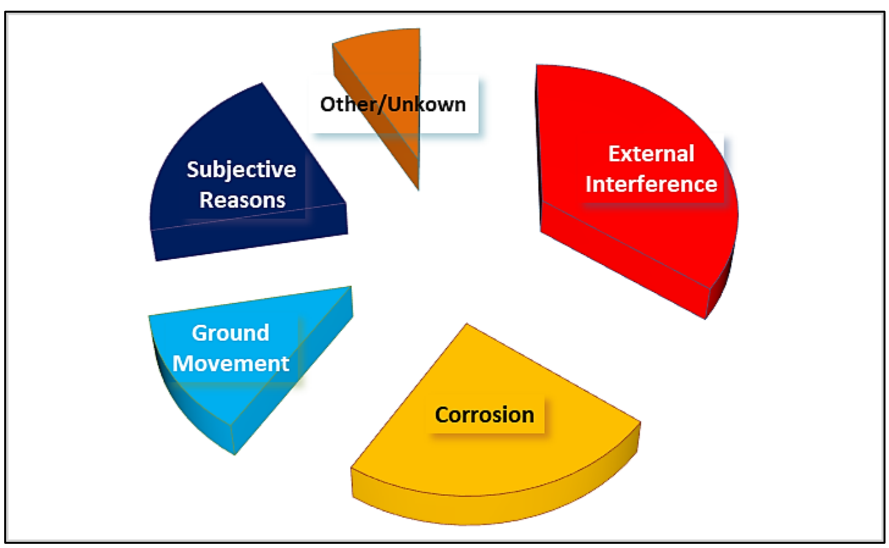

Figure 3.31. Incident distributions per cause over the 10-year observation

The share of emergencies bringing significant negative outcomes observed as a result of the pipeline corrosion equals to approx. 20% (see Figure 3.32). Though corrosion is a time dependent phenomenon of deterioration of pipes, the corroded pipe failure frequency significantly decreases for pipelines with increased wall thickness – the process of deterioration of walls due to corrosion develops independently from the wall thickness, but early constructed pipelines with thinner walls fail sooner in comparison with the pipelines constructed after 2000 with the enhanced material characteristics and increased wall thickness.

It must be mentioned that due to the opportunity of forecasting the possible influence of the corrosion factor, by preliminary implementation of preventive measures (such as: cathodic protection, pipeline coating, in line inspection, replacement of some segments of pipelines etc.) many cases of emergency damage of pipelines are actually avoided, while many small-scale damages whose liquidation expenses are minimal, are not envisaged here.

In terms of scale of the negative impact, incidents caused by external uncontrolled influence appeared to be particularly detrimental for Georgia, due to significant financial losses, as well as total or partial hindering of supply of gas to the internal market and transit.

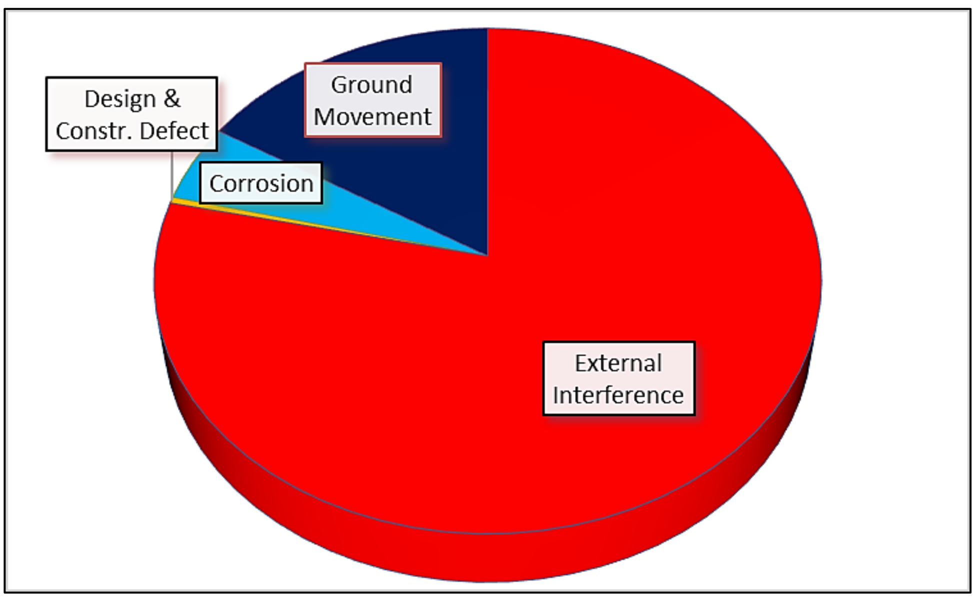

Figure 3.32. Percentage of loss caused as a result of emergency damage of main pipelines according to the failure nature

Incidents caused by external interference or ground movement are characterized by potentially higher negative consequences. The loss occurring as a result of emergencies in the gas transportation system caused by unauthorized external interference or sabotage, exceed 75% of the total loss accumulated during 25 years. The higher depth of cover (≥0,8 m) and higher wall thickness (≥10-12 mm) of large diameter pipelines constructed in the last 15-20 years are less vulnerable to the external interference.

The Table provides characterization and technical parameters of those sections of the Georgian gas transportation network whose condition for the current period is highly likely to become the main cause of the system failures. Figure 3.33 shows the existing critical infrastructure (critical sections of main gas pipelines), as well as the planned infrastructure the construction whereof is considered as a priority.

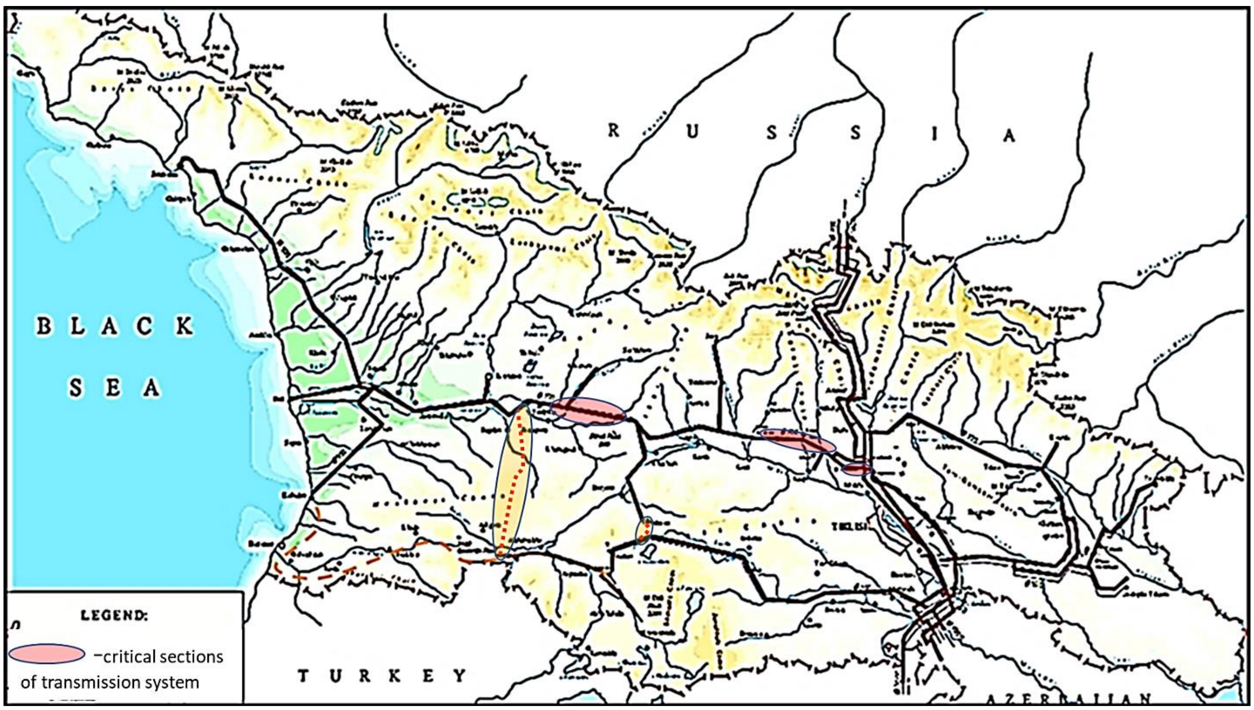

Figure 3.33. Critical Infrastructure

Generally, rehabilitation-development plan of the Georgian Main Gas Pipeline System, as well as arrangement of its loops and interconnectors, will lay foundation for replacement of the Georgian dead-end gas supply system with highly secure ring-type system, which in critical situations will redirect gas flows in order to provide consumers with safe and secure supply of gas, resulting in significant increase of the technological reliability of the entire transportation system.

Table 3.12. Characteristics of critical sections of transmission pipelines

Pipeline Section	General specification and technical parameters	Probable negative impact in case of failure
Aerial crossing of Aragvi river	D=500 mm, P_d=55 bar, L=2,6 km, T=53 years. Single line which may be damaged during the flooding of river	Gas supply to 7 regions of Georgia (from total 10) will be interrupted
Natakhtari-Gori section of EWGP	D=500/700 mm, P_d=55 bar, L=38,8 km, T=30 years 700 mm sections and T=4 5years 500 mm section. Single line with capacity not adequate to the planned consumption in 2030	Gas supply to 6 regions of Georgia will be interrupted
Khashuri-Zestaponi section of EWGP	D=700 mm, P_d=55 bar, L=71 km, T=42-45 years. Single line of aged pipes, in case of failure of which rehabilitation activities can't be performed immediately due to location of some part of the section in high mountainous terrain and harsh climatic conditions	Gas supply to all 5 regions of western Georgia will be interrupted
Bakuriani branch of pipelines	D=300/500 mm, P_d=25 bar, L=52,8 km, T=45 years 500mm section and T=31 years 300 mm sections. Single line of aged pipes, in case of failure of which rehabilitation activities can't be performed immediately due to location of some part of section in high mountainous terrain and harsh climatic conditions	Gas supply to Borjomi-Bakuriani recreation zone and international centers sports and tourism will be interrupted
Kazakhi-Saguramo	D=1000 mm, P_d=55 bar, L=4,0 km, T=40 years. Aged, highly corroded pipelines	Transit to Armenia will be terminated
Tsiteli Khidi-Kogbi (Armenia) section	D=1000 mm, P_d=55 bar, L=11,5 km, T=28 years. Pipeline without adequate maintenance and high risk of external interference	Transit to Armenia will be terminated

For the purpose of defining the planned capacity of the infrastructure development plan, consumption forecasts in Georgia (adjusted to the data of the previous years) and future transit volumes through the Georgian pipelines are considered (see Table 3.5). For the domestic gas supply system, actual demand trend and projected peak consumption for separate directions and the main branches of the pipeline are also used.

A different approach is used to determine the trans-border pipeline calculation parameters. Namely:

a) Maximum loading capacity of the interconnector connecting to SCP is taken from the pressure reduction and metering stations located at the gas receiving point (Area 72), taking into consideration the planned reconstruction project. Its peak loading capacity after reconstruction equals to 5.4 Mm^3/d;

b) For the gas delivered from Azerbaijan, a newly constructed pipeline Azerbaijani border-Gardabani-Navtlughi-Saguramo with a design capacity of 16 Mm^3/d is considered to be used, however, it cannot be loaded fully because of its limited pressure 22-24 bar, which allows receiving gas not exceeding 7-8 Mm^3/d in ordinary conditions (with the possibility to ensure capacity up to 8,4 Mm^3/d for a short time period as happened in January 2020[58]). By 2030, when it will be required to transport up to 1,5 bcm/y of gas from Azerbaijan (if additional gas is supplied by SOCAR), and the peak daily load will increase up to 18,6 Mm^3/d (see Table 3.14), it will become necessary to take special additional measures.

c) Possibility to receive gas from the North-South pipeline is limited by capacity of pressure regulating and metering unit connecting to the Georgian internal gas supply system which equals to about 4,2 Mm^3/d. In addition, the actual capacity of the main pipeline is lower than the design capacity of Georgian sections of pipeline (maximum operational pressure does not exceed 34 bar at the 1200 mm section adjacent to the Russian border and does not exceed 25 bar in the 1000 mm pipeline). In case of rehabilitation of 1200 mm Gveleti-Saguramo and 1000 mm Saguramo-Tsiteli Khidi sections are performed, loading capacity of the system will increase by 60-70%.

[58] In January 2020 there was fixed daily peak consumption amounted to 15,5 Mm3. The main reason for such a jump in the consumption is related to the drastic increase in the use of gas by power generation (up to 6 Mm^3/d), caused by the abnormally increased demand for electricity

Table 3.13. Forecasts of peak demand[59]

Power Generation				
Consumption	2017	2020	2025	2030
ΣQ, Mcm/y	515	na	805	987
QAve, Mcm/d	1,41	na	2,21	2,70
QPeak, Mcm/d	4,11	5,90	6,89	7,87
Hosehold Sector				
ΣQ, Mcm/y	942	na	969	1 019
QAve, Mcm/d	2,58	na	2,65	2,79
QPeak, Mcm/d	5,48	5,90	5,92	5,93
Commercial Sector				
ΣQ, Mcm/y	982	na	1 225	1 461
QAve, Mcm/d	2,69	na	3,36	4,00
QPeak, Mcm/d	3,23	3,70	4,25	4,80
ΣQPeak, Mcm	**12,82**	**15,50**	**17,05**	**18,60**

Statistics and forecast result data analysis [111] shows that in order to meet the forecasted demand by 2030:

- Transmission capacity of Kazakhi-Saguramo 1000 mm section of the North-South Transit System is insufficient for transit of projected gas volumes to Armenia due to the pressure limitation in the pipeline considering its unsatisfactory condition[60]. For guaranteed delivery of the required transit volumes to Armenia, Saguramo crossing point of transit system should receive gas at about 30 bar pressure. This requires rehabilitation of hardly corroded sections of the pipelines including 53,4-57,4 kmp sections. Besides, reconstruction of 11,5 km branch of the pipeline connecting to Armenia is also recommended.
- Azerbaijan border-Saguramo new 700-mm pipeline's nominal capacity equals to about 7-8 Mm^3/d (2.5 bcm per year), provided that the loading distribution percentages across the pipeline length remains unchanged during peak load [111]. After completion of the planned restoration and reconstruction program of Saguramo-Western Georgia route of system, which envisages arrangement of the route entirely with the 700 mm diameter pipes and maintaining the minimum pressure required for industrial enterprises in free industrial zones - 12 bar, the required pressure at Azerbaijan border by the year 2030 peak load, will reach 29,2 bar, while Azerbaijan supplies gas with maximum pressure of 24 bar. The shortage of the loading capacity becomes more critical, if additional gas is supplied from Azerbaijan.

[59] Gas demand forecast data and actual consumption inequality (see above) are used for calculation of the table data
[60] In case if Georgia gets additional gas from Russia

Based on the analysis of data for short and medium-term periods, rehabilitation of critical sections of the East-West Main Gas Pipeline is considered to be of high priority. Specifically, construction of aerial crossing on river Aragvi, 500 mm sub-section of the Natakhtari-Gori section and Khashuri-Zestaponi mountainous pass section of the East-West Main Gas Pipeline is the first priority for rehabilitation (construction) of the Georgian gas transmission system.

In the long-term perspective, some of the next priority projects include construction of interconnectors of different branches and directions of the gas pipelines, in particular, looping of the sections that are located in mountaneous regions difficult to access in adverse weather conditions, therefore in case of failure, commencement of their urgent rehabilitation is very difficult. Out of these sections, Akhaldaba-Bakuriani section of Bakuriani branch is considered to be the most critical.

The main purpose of ***Tabatskuri-Bakuriani connector*** linking the southern branch of the gas mains to the western and central regions of the country is to provide guaranteed gas supply to Borjomi-Bakuriani urbanized tourist-recreation zone by means of a circular gas supply system. Besides, the project implementation makes it possible to supply gas to the central (or southern) regions of Georgia in a critical emergency using the temporary emergency scheme via the southern branch gas supply system of Tsiteli Khidi-Tsalka-Akhaltsikhe pipeline 160 km-point (or 2nd SCP off-take) to the gas mains of the central regions of the country, or vice versa. The design pressure of the pipeline is 55 bars, diameter - 300 mm, length - about 18 km. The new Bakuriani-Tabatskuri gas pipeline together with the existing Akhaltsikhe-Vale (Arali) Connector makes it possible to considerably improve gas supply to Borjomi-Bakuriani recreation zone.

Also, construction of Vale-Vani interconnector is under consideration in case of rapid development of economy in Poti and Kutaisi Free Industrial Zones and/or entire Western Georgia. Vale-Vani interconnector and the 2nd gas off-take point on the SCP pipeline nearby from Turkey border will connect pipeline systems of Western and Southern Georgia, currently supplied via deadlocked system, and establish a circular system with a significantly higher level of gas supply security. This allows to redirect gas flows in critical situations from any suppliers to any large customers and distribution companies.

The 2nd off-take to SCP will be set up near Akhaltsikhe before the pipeline crosses the Georgian-Turkish border and will allow adding a virtually new gas supply source to the country's gas supply system. The subsequent development of the new source would guarantee a circular gas supply of the entire system and substantially enhance its operational reliability. Also, appropriateness of arrangement of the 2nd off-take near SCP is connected to AGRI and WS projects implementation.

The project implementation would also facilitate a rational redistribution of gas flows through the Georgian gas mains when gas flows via the territory of Georgia and gas volumes purchased under the transit-related contracts increase sharply following the completion of the 2nd phase of Shah-Deniz field full-scale development. According to the existing forecast, gas volumes will gradually reach 1,3-1,6 bcm/y. Receiving such volume of gas through the area 72 off-take into the internal gas mains located in the adjacent area, which are also used to import SOCAR's gas from Azerbaijan, seems irrational and may result in serious technical problems in supplying gas to consumers in the central and western regions of the country.

In case of need of additional 8 bcm or more of transit capacity of the Georgian trunk pipelines (excluding SCP)[61], which may be required in case of supply of large volumes of exported gas from Turkmenistan, a ***new Rustavi-Poti pipeline*** can be built on the territory of Georgia (and Azerbaijan). Technical parameters and estimated investment cost of such pipeline are defined [112]. The pipeline would start at the Azerbaijan-Georgian border, pass through Georgia along the parallel EWGP route and end at the Black Sea Coast. The length of the pipeline on the territory of Georgia is about 370 km, diameter – 36" or 42", design pressure of the pipeline is 95 bars and operating pressure – 90 bars. As the results of hydraulic modelling show, for D=36" pipeline, with 2 interim compressors with approx. 23 MW combined capacity, the system can supply at least 8.5-10 bcm. The transmission capacity of D=42" pipeline of the same configuration would reach about 14.5-15 bcm (combined capacity of compressor stations to be approx. 33-35 MW).

The transmission infrastructure projects developed on a priority basis in the short- term period include rehabilitation and construction of critical sections of the main pipelines. Realization of these projects gives opportunity to significantly increase technological reliability of the entire Georgian gas supply system. Besides, the updated system creates the possibility of providing uninterrupted supply of demanded gas during peak loading periods in the future until year 2030.

It is also considered to perform gas infrastructure rehabilitation works on the temporarily occupied territories of Georgia, after the conflict resolution. Implementation of such projects would facilitate resolution of important social and commercial problems and reintegration of regions into the economic system of Georgia. Besides, rehabilitation of (Zugdidi-) Sukhumi branch of gas pipelines enables to provide the region with the low cost and easy to use heating resources before political settlement of the conflict, in order to partially replace electricity produced by Enguri HPP.

[61] Presumably after year 2027 (see: Chapter 3, Regional market)

3.6.5. POTENTIAL SOLUTIONS TO MAINTAIN SECURITY OD SUPPLY

The analysis, based on the Network Standard and Supply Standard defined by the EU regulation concerning measures to safeguard security of natural gas supply and incorporated in the Law of Georgia On Energy and Water Supply, shows that the strategic reserves of about 100 Mcm gas must be stored to provide guaranteed gas supply to the so-called ‘protected’ consumers (the population and thermal power plants) across the country in critical situations.

The analysis shows that challenges arise from inability to rationally manage and seasonally balance gas flows with own resources when there are consumption asymmetry and relatively stable supply of imported gas. Moreover, if there is any unscheduled interruption of supply during periods of peak consumption, harsh gas deficit may arise, posing risk to protected consumers and the country is unable to handle the crisis independently. In these periods, Georgia is no longer able to perform its obligations under the transit contract too. In such situations, it is necessary to take urgent measures to supply consumers with gas (and electricity) in order to avoid significant complications. Consequently, it is necessary to arrange provision of gas reserves by means of construction of LNG receiving terminal[62] or underground storage or increase of capacity of trans-border pipelines (see Figure – Key NG infrastructure, existing and projections).

Figure 3.34. Key natural gas infrastructure of Georgia

Below is presented the assessment of potential alternative solutions for providing Georgia’s supply security. Comparison of potential options to meet the natural gas supply security needs are weighted in term of seasonal flexibility, peak load, security of supply and commercial flexibility.

[62] Due to impossibility of implementation of LNP project at the current stage , this option is not considered in the analysis

Analyses are based on a simplified gas balance of Georgia (2019): total supply 2,45 bcm/y, total imports 2,44 bcm/y, local production 9 Mm^3/y; current peak daily demand 13,5-15,5 Mm^3/d; projected peak daily demand 17,1 Mm^3/d by 2025 and 18,6 Mm^3/d by 2030; maximum throughput capacity of gas receiving units (due to physical or contractual limitations):[63] – Karadagh-Tbilisi pipeline (SOCAR's supply) – 8,0 Mm^3/d[64]; SCP – 4,1 Mm^3/d; NSGP - 2,2 Mm^3/d (maximum, physically achievable throughput capacities for short period of operation, are as follows: SOCAR's supply – 8,4 Mm^3/d; SCP – 5,4 Mm^3/d; NSGP - 4,2 Mm^3/d). Consequently, allowable maximum capacity of the Georgian imports equals to ≈14,3 Mm^3/d and might be increased insignificantly, while projected peak demand of the country may increase up to 17,1-18,5 Mm^3/d and more by 2025-2030.

- **Pipeline capacity**

Full utilization and/or increasing capacity of cross-border pipelines is the most cost efficient approach as pipelines connecting the Georgian trunk pipeline system to supplier countries such as Azerbaijan and Russia are delivering gas from importer countries directly without involvement of a third, i.e. transit country. This results in minimal transmission costs and natural gas price on the market is traditionally lower in comparison with European prices.

There are theoretical options to increase capacity of transborder transmission lines: a) Azerbaijan section of import pipeline adjacent to the Georgian border, including compressor station; b) provide a reliable operation of NSGP on the Georgian territory and c) increase the throughput capacity of the existing off-take (or arrange additional one) on SCP and negotiate with Shah Deniz Consortium the terms of receiving additional gas. But it has to be considered that contractual limitations for the Russian gas and SCP contracts and limited physical capacity of Azerbaijan's pipeline make it impossible to fully utilize transit pipelines to the maximum physical extent.

Contracts with SCP Consortium limit delivery of gas through the Georgian off-take to up to 4,5 Mm^3/d and it is highly difficult any amendments in the existing contract as SCP is a dedicated pipeline, (physically and contractually) for transportation of gas from the Caspian region to Turkey and EU and cannot be used as a tool of increased flow for Georgia. Additionally, Shah Deniz 2nd phase natural gas volumes have already been contracted fully.

In relation with NSGP, there are factors which would prevent guaranteed supply of additional gas from Russia any time and under unforeseen conditions, notably in the context of reliability and

[63] Peak day load data are fixed not in the same one day

[64] Peak day imports for SOCAR and SCP - historical daily maximum

security of supply from this source. Russia occupies 20% of Georgia's territory and has meaningful military presence with bases located in the breakaway regions. There are no diplomatic relations between Georgia and Russia since August 2008 war. Russia is not following the signed peaceful settlement arrangement initiated by EU mediators. Obviously, political grounds is the main obstacle to negotiation of the terms of delivery of additional gas for utilization during critical peak demand periods with Russia's state owned "Gazprom". Moreover, the existing transit contract and membership of Georgia (together with Armenia) of the International Energy Charter, oblige Georgia not to disrupt transit to the third country under any circumtances (multilateral framework agreement on energy transit). For reference, Armenia's peak demand in winter seasons is up to 12 Mm^3/day, which means that unutilized reserve in the North Caucasus-South Caucasus System for Georgia is only up to 4÷5, Mm^3/d (to Saguramo pipeline crossing point). This capacity cannot meet the local market's demand for additional gas in the critical, peak demand periods, especially after it increases to 18,6 Mm^3/d by 2030.

Connection to Azerbaijan's Kazakhi-Saguramo pipeline is currently utilized to its full capacity (in January 2020, maximum capacity of pipeline 8,4 Mcm/day was reached for short period of operation). At the same time, the option of increasing Azerbaijan's transport system is under control of a foreign country's state owned company and thereby cannot be considered as a guarantee of increased capacity and delivery of additional gas volumes in the critical, peak demand periods. Moreover, estimated investments required to increase capacity of Azerbaijan's pipelines only for Kazakhi (Azerbaijan)- Georgian border section, with the cost ca. M$90[65] , but for a full right of way from Hajigabul (Kazi-Magomed CS) to Georgian border, with the total length of approximately 411 km will be significantly higher.

- **Underground Gas Storage**

Considering that Georgia is significantly dependent on import of energy resources, underground gas storage may play a significant positive role in maintaining strategic reserves of energy resources and ensuring energy security of the country. Besides, gas storage is the easiest and convenient tool to regulate seasonal imbalance in gas supply and consumption. Under liberalized market conditions, where the demand of a certain segment of consumers is met with gas received through an organized trading platform, gas storage takes on the function of a commercial facility too and can serve as the source of considerable additional revenues, when any supplier or consumer can buy and stock up gas any time and use (or resell) it as necessary.

[65] data for investment are only indicative and not based on real conditions of all sections of transmission pipelines and compressor stations on the territory of Azerbaijan.

Also, storage facility is one of the factors contributing to formation of local, or even regional trading hubs. Experience shows that gas trade centers worldwide were mainly established on the basis of underground gas storages located at the place of intersection of main gas pipelines of various routes or vice versa, the underground gas storages perform one of the most important functions of the market center – providing required volume of gas during peak loads and absorbing excess gas volumes during low consumption periods.

Under Georgia-EU Association Agreement, implementation of EU energy acquis, in relation to network and supply standards based on the EU Regulation concerning measures to safeguard security of gas supply, transposed in the new energy law of Georgia requires development and implementation of supply security regulations for natural gas considering instruments and measures performed by natural gas undertakings, to endeavor to ensure the supply of natural gas to protected customers in the following cases at least in the event of:

1. extreme temperatures during 7-day peak period occurring with a statistical probability of once in twenty years;
2. any period of at least thirty days of exceptionally high gas demand, occurring with a statistical probability of once in twenty years; and
3. for a period of at least thirty days in case of disruption of the single largest gas infrastructure under average winter conditions.

The analysis based on these norms shows that in order to provide protected consumers of Georgia with secured gas supply in possible critical situations, it is necessary to have at least 100 mcm strategic reserves of natural gas [113]. Considering the above, nominal technological parameters for the underground gas storage have been specified (see table below).

Feasibility study for the underground gas storage has been completed [114]. The proposed UGS is located on Samgori South Dome depleted oil field, close to major consumers of Georgia – Gardabani-Rustavi-Tbilisi industrial zone. Projected capacity of the UGS is 250 (210-280) mcm of working gas, approximately 50% of which might be used for commercial purposes to generate additional revenue stream;

Average price of gas for social sector consumers is significantly lower than the market price. To handle excess volumes of gas in summer period, received per "take or pay" contracts, GOGC is transferring these volumes to SOCAR, which is acting as a virtual storage for balancing Georgian market's supply/demand imbalances, including import of deficit volumes from Russia. The company is compensated for this service (extra margin on gas price). While operating its own

UGS, Georgia will handle the local market's supply/demand misbalances with its own resources, saving the expenses and significantly increasing the country's energy security, as supply of strategic energy resources will be fully managed independently, without involvement of foreign state-owned companies (SOCAR or Gazprom).

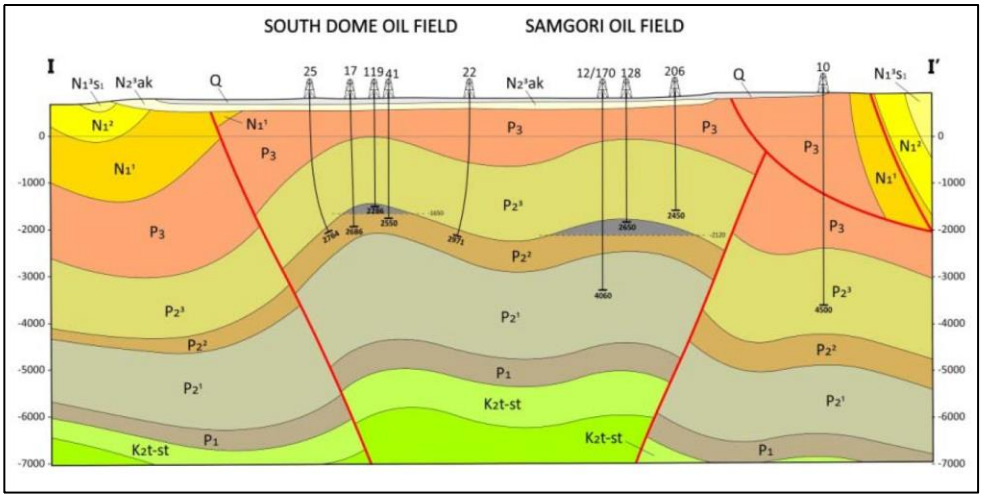

Figure 3.35. Geological cross-section of SSD and Samgori oil fields

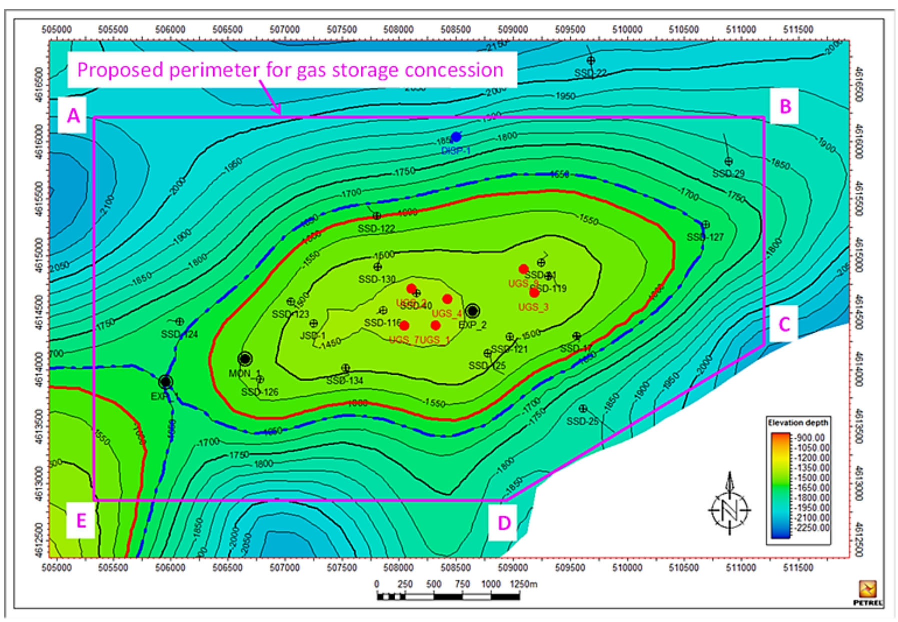

Figure 3.36. SSD top Middle Eocene structural depth map [114]

Legend: "SSD" - are existing wells; EXP-1 and EXP-2 - the planned exploration wells to be drilled ; "UGS" wells (in red) - the planned injection/withdrawal wells; DISP-1 - the planned water disposal well; MON-1 the planned monitoring well

Table 3.14. Main design parametres of the underground gas storage

Total volume of natural gas, mcm	400-500
Active gas volume, Mm^3	210-280
Buffer gas volume, Mm^3	190-290
Injection rate, Mm^3/d	1,7-2,5
Withdrawal rate, Mm^3/d	≥2-6
Average Withdrawal rate (during normal winter period)	2
Strategic deliverability (30 critical days)	3,1-3,8
Stress case deliverability (7 days)	5
Stress case deliverability (1 day)	6

Conceptual design of SSD UGS envisages construction of a Central Gas Processing station (CGPS), a Gas Metering Station (GMS), a specific Power sub-station, gas pipeline to and from the main trunklines of the country, 2 cluster pads for injection/withdrawal, 13 new wells including: 6 gas injection/withdrawal wells, 3 reservoir monitoring plus 3 upper formation monitoring, 1 water disposal (re-injection) well, and plugging and abandonment of 15 existing wells. An oil pipeline shall be also constructed from the CGPS to the railway station for oil evacuation.

Considering complex geological conditions of location of the underground gas storage, natural seismisity conditions (see Figures below) and the detrimental factor of induced seismicity, it is planned to implement the project in 2 phases.

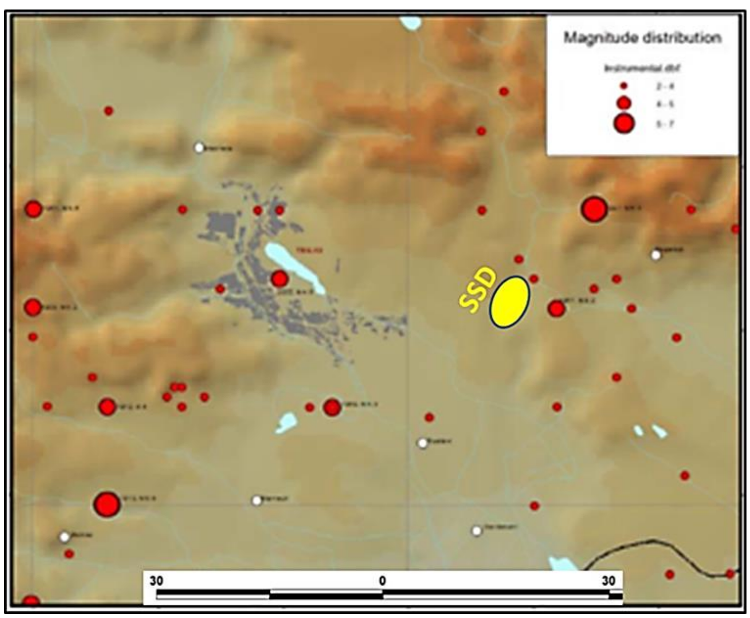

Figure 3.37. Seismicity map of the ajacent territory of the SSD field[66]

[66] Source: GOGC, SamgoriSouth Dome UGS Project, Step 2, Natural Seismisity and Acceleration Measurement by GEOSTOCK S.A.S., August, 2017

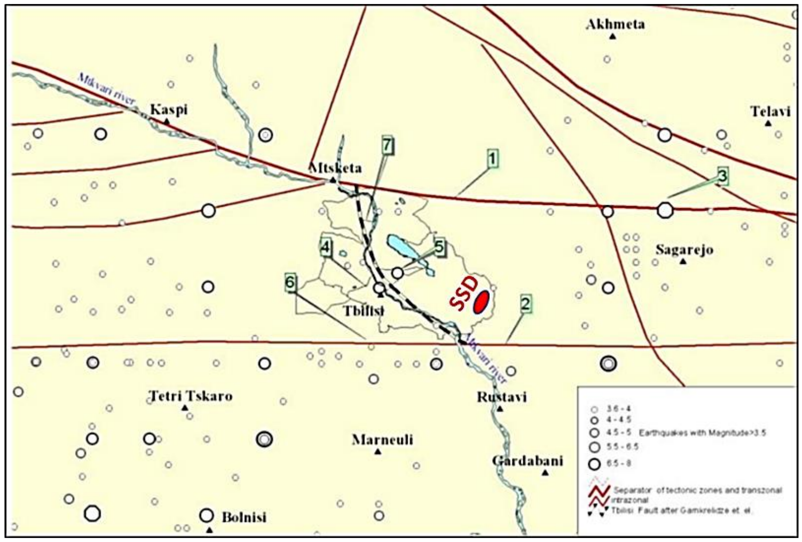

Figure 3.38. Faults and epicenters of earthquakes near the SSD field

During the first, 1-year exploration phase, on the basis of additional studies, all possible risks related to construction and operation of the gas storage and the risk mitigation opportunities will be evaluated and operation parameters will be optimized. After completion of the exploration phase, bearing in mind the evaluated level of risk and funding opportunities, the final investment decision will be made for the gas storage construction project.

- **Efficiency of power generation**

Replacement of import of electricity with locally produced power and introduction of modern, highly-efficient generation technologies for the purpose of substantial reduction of consumption of imported natural gas, represents an important tool of increasing the energy security of the country.

Presently, about 80% of electricity produced in Georgia is generated by HPPs and the remaining is generated by natural gas-fired TPPs (also, insignificant volume is generated by a wind farm) [115]. At the same time, due to significant increase of electricity consumption in the recent years, Georgia has to satisfy the demand by increasing imports. The situation is complicated by dependence on electricity produced by HPPs on climatic conditions, as well as, significant increase of share of consumers with unpredictable load (crypto-currency servers) in the total load in recent years, which becomes the ground for a significant disbalance between indigenous production and demand. In particular, consumption of electricity in the country achieves its peak during winter season, when energy generated by HPPs is relatively low due to shallowness of rivers.

The production of baseload gas-powered thermal power stations (TPPs) for balancing, ensures operating reliability of the entire electricity system, but the increased demand due to the significant increase of electricity consumption in recent years cannot be satisfied by generation of local TPPs in this period, which preconditions critical increase of import – 479 M kWh of energy were imported in 2016 and this indicator exceeded 1 600 M kWh in 2019, which is a significant challenge for energy security of the country.

There are 6 gas firing TPPs operating in Georgia, including modern, combined cycle gas turbine TPPs (Gardabani and Gardabani 2 CCGT power plants with the design capacity 235 MW of each). TPPs use relatively cheap, so called "social" gas to generate electricity.

Due to the seasonal changes in the patterns of supply and demand and the dependence of hydropower potential on climate, Georgia needs to increase the capacity of baseload TPPs and arrange to store sufficient volumes of natural gas or alternatively import more electricity during the winter period.

In order to close the gap between the seasonal patterns of generation and possible obstacles arising in case of wide utilization of local renewable energy resources, requiring back-up baseload capacity, construction of HPPs with reservoir storages and high-efficiency gas-fired TPPs should be prioritized, rather than increasing import of electricity. On the other hand, reliable exploitation of a TPP requires guaranteed supply of fuel, during the periods of peak load or unforeseen delays in the supply of imported gas that can be managed by arrangement of stocks of strategic fuel in the gas storage.

The electricity system of Georgia is interconnected with the systems of all neighboring countries. 500 kV and 220 kV transmission lines connect the Georgian and Russian electricity systems, while 400 kV and 220 kV transmission lines connect the Georgian electricity system with that of Turkey. The electricity system of Armenia is connected to the Georgian system through 220 kV transmission lines and that of Azerbaijan - through 500 kV and 330 kV lines. The total transfer capacity with neighboring power systems presently amounts to some 2.570 MW. Due to certain physical, commercial or legislative limitations, substantial problems are arising for the export-import of electricity with the requested parameters.

Under such conditions, the most rational way of eliminating the sharp increase of demand gas electricity production and the seasonal deficit is to construct gas-fired baseload thermal power plants, which will ensure development of generation independent from the climate, balancing and stable functioning of the energy system using own resources.
Generally, production growth rate should precede electricity demand growth. At the same time,

despite the future orientation at renewable energy, the basic power energy mostly produced by fossil fuel resources, represents and, according to the forecast, will remain to be the prevailing source of balancing and sustainable functioning of power energy systems worldwide and in separate countries in the transitional period[67].

Based on international experience, development of power sector founded on use of separate, even extremely attractive renewable energy resources, cannot be perceived to be a panacea at the current stage - at least, for the purpose of ensuring energy security, it requires necessary reservation by own basic generation facilities, independent from environmental conditions or imports.

In rare exceptional cases, with Norway being the most vivid example (where practically entire volume of locally produced power energy is provided by hydropower, there are several significant peculiarities, in particular:

- excessive local production of power energy for own consumption. In case of Norway, own consumption significantly exceeds local consumption which allows the country to become a net exporter of power energy;
- opportunity of unlimited exchange of power energy with neighbor countries and regions Norway is a part of the unified power energy system of Scandinavian countries, so-called "Nordic Energy Market" and it is connected to markets of the Baltic region, north Europe and other countries by the existing interconnectors with 700-1700 MW capacity;
- high level of regional integration both in terms of technologies and legislation to ensure unlimited access to imported energy and its unhindered delivery to the internal market in case of need and energy security of the country in general. The exhaustive integration of Norway into regional systems, in addition to the existence of interconnectors, is ensured by harmonization of energy legislation and identity of market regulations with the EU countries. Norway's power energy trade with the remaining Scandinavian countries and the Baltic countries is carried out through the joint trade platform of "Nord Pool").

There is the same situation in other countries of Europe rich in renewable resources which are integrated into unified energy systems of the Energy Community and their unhindered exchange of power energy with neighbor countries is ensured both at the technological and legislative level. Despite the above, sustainable functioning of power energy systems in Norway and other Hydro-power producing countries, requires an agreed management of stability conditions and economic

[67] Target for large-scale transition to renewable and environment-friendly technologies in many countries of the world by 2040-2050

requirements, which is often associated with unplanned shut-offs of hydro generation facilities and their operation with the partial load.

In Georgia, which from energy point of view is isolated from Energy Community contracting countries (having identical market structures and regulations) as well as EU member states allied with it and exchange of power energy with neighbor countries is limited also due to the market regulations envisaged by the energy legislation and technical capacities to a certain extent, in the reasonable prospective of the closest period, it is practically impossible to establish preconditions similar to Norway. Power systems of neighboring countries are functioning in the 3 different synchronized mode and all of them have different from others planning and operating philosophies.

Accordingly, a sole alternative to satisfaction of the increasing demand on power energy with own production and ensuring sustainability and energy security under conditions of Georgia, when the system often has to operate in isolated mode, is accelerated development of basic energy generation facilities based on modern, highly-efficient and environment-friendly technologies operating on comparatively available natural gas.

It is noteworthy that in 1980-1990s, total installed capacity of baseload TPPs of Georgia equaled to 1500 Mw and annual generation equaled to about 7 billion kWh, despite the fact that all main HPPs which are currently operated had already been constructed and functioned, and, while the power system of Georgia represented a part of the unified system of the southern regions of united state and carried out unhindered exchange with the systems of neighbor republics. At the same time, it should be mentioned that in this period specific consumption of energy per capita was almost equal in Georgia and European countries having a similar geographic-climatic environment, however, today it falls behind not only European indicator, but also the average indicator of the world.

Therefore, despite the fact that satisfaction of the basic demand on electricity generated by local HPPs is considered to be the dominant of the energy policy of Georgia and the top priority of average- and long-term strategy, the international experience confirms that baseload power energy generation facilities represent an irreplaceable part of energy systems of the transitional stage and the guarantors of their sustainability and energy security of the country in general.

Gas-fired, combined-cycle TPPs built in Georgia in the recent years and operating today represent energy generation facilities based on one of the most efficient, resource-saving and ecologically less detrimental, modern technologies [118]. They are equipped with modern type, F class 2 GE-Power gas and 1 steam turbine and generators. Their design efficiency is 55,6 %. GE-Power is a worldwide leader in manufacturing of facilities of this class and its products are distinguished for energy efficiency and high standard of quality. It should be mentioned that F class gas turbines successfully function in more than 100 TPPs in the world. For comparison, estimated saving of fuel for generation of approx. 1,3 billion kWh of power energy per year by a TPP in a combined cycle mode, equals to 150-160 mcm of gas compared to producing the same amount of power energy on “old” blocks of Georgia built during the Soviet period.

All other key equipment and systems of the new TPP are selected in strict compliance with ISO (International Organization for Standardization) standards, EN (Euro norms), ASME (American Society of Mechanical Engineers) standards and other international standards and norms. In environmental protection issues, restrictions implemented by CCGT projects, recommended by the World Bank and are considered together with the Georgian legislation.

Two more CCGT TPP’s, with total installed capacity approx. 500 Mw are planned to construct in the nearest years by the Government of Georgia.

Operating of new TPPs ensures a significant environment-friendly effect – in particular, during operation of TPPs, specific emission of carbon dioxide per 1 kWh of produced power energy is reduced by 70%, which means reduction of the total emission by approx. 450-500 thousand tons per year.

It is also important to increase sustainability and flexibility of the power energy system of the country, which is ensured by new TPPs. In particular:

- possible annual generation of new TPPs in the design mode allows for replacing approx. 85% of compulsorily imported electricity (including from Russia) of the current period predetermined by sharp seasonal misbalance by local production;
- a new TPPs are distinguished for operational flexibility – in case of emergency shut-off of the unified power energy system of the country, they ensure independent activation in a short period of time and prevention of a negative large-scale effect with own resources.

Operation of a gas-fired, combined-cycle TPP provides a significant fiscal effect too, because cost of imported power energy is much higher than the cost of import of gas used for production of power energy of the same amount (1 cubic meters of gas ensures replacement of imported power energy which costs at least 20 cents, while average cost of import of Shah Deniz gas is twice less). It should also be considered that local production of energy facilitates creation of additional jobs and unlike gas, one of the main suppliers of power energy is the Russian Federation.

Proactive implementation of power generation facility construction projects, in advance of growth of demand on power energy, gains a particular significance against the background of the market's current deregulation process, ensures saving significant amount of fuel (approx. 700 Mcm of imported gas) and essential reduction of greenhouse gas emissions and power energy import. Also, it contributes to using the existing potential of renewable energy on a full scale, which on its part, will be ensured by their backup by energy generated on new base-load generation facilities.

- **Safety of Infrastructure**

As analyses show, external interference of the third party to the pipeline represents the main reason for unpredictable expenses to maintain the transmission system in the planned operation mode. Therefore, for the purpose of pipeline protection, development of the adjacent territory and exercising control on the activities of a third party during the pipeline construction and further operation period, protection and safety zones are established and certain restrictions are imposed on them.

Trunk oil and gas pipelines of Georgia were constructed in various times, in the period of different political systems and formations and during different economic relations, which exerted a respective influence on establishment of design-construction and operation parameters of facilities, including establishment of safety (or protection) zones.

Norms of the former Soviet Union, as a rule, were based on the so-called prescriptive approach, when conditions and safety of pipeline operation are provided with instructions strictly defined by the Regulations. For example, clearly defined safety zones with restrictions of various levels are established according to the Soviet period norms. These norms require adherence to restrictions established by the respective land ownership rules for the pipeline project purposes in zones established by construction norms [119].

All trunk pipelines constructed on the territory of Georgia during the Soviet period and operating today (including: North-South gas pipeline, Vladikavkas-Tbilisi, Karadagh-Tbilisi, Kazakhi-Saguramo and other trunk gas pipelines, Samgori-Batumi oil pipeline which became a part of the new Baku-Supsa oil pipeline after rehabilitation and reconstruction) were designed considering these restrictions. At the same time, during implementation of projects of operation, as well as rehabilitation-development of the above pipelines in the period of independent Georgia, many deviations occurred from the initial norms, e.g. considering ASM norms, one of the bases of implementation whereof is not only a prescriptive, but also risk assessment-based approach in the issues of ensuring safety and management of pipeline integrity.

The list of already completed projects or projects being at the implementation stage which are not based (wholly or partially) on standards and norms inherited from the Soviet period any more is as follows: a) South Caucasus Pipeline and the section connecting it to the trunk gas pipeline system of Georgia; b) Rehabilitation of various sections of the North-South Gas Pipeline and East-West Gas Pipeline Systems (Gardabani-Navtlughi, Navtlughi-Saguramo, Zestaponi-Kutaisi-Abasha-Senaki-Poti and other sections of the trunk gas pipelines) built in last two decades.

On the basis of the existing experience it can be concluded that the former Soviet norms are established considering a exaggerated reserve and the recommended presently measures of ensuring safety and pipeline integrity management, if carried out in a timely and quality manner, will practically ensure guaranteed protection of population and environment and maintaining the pipeline integrity during the entire planned period of operation. However, on the other part, feasibility of taking unified measures for pipelines of various diameters and pressures envisaged by the Regulations raises significant doubts, because, they hardly consider specific conditions of pipeline operation. Accordingly, use of a prescriptive approach may be not always expedient, especially during significant change of design-construction and operation parameters of new main pipelines or design parameters of the existing pipelines on the territory of Georgia, which is a country oriented at market economy (i.e. economic expediency of any measure) unlike the Soviet Union. At the same time, unlike the Russia, Georgia is a small country with private ownership of the significant part of land fund and dense urban development, which significantly complicates and increases the cost of use of territory for the purposes of pipeline projects, including new transit projects, if pipeline operation safety zones will be defined based on the "old", Soviet regulations. In this regard, use of methodology based on risk assessment allows for saving substantial funds and time, which has already been successfully implemented while implementing of new pipeline projects, mentioned above.

It should also be mentioned that for the purpose of harmonization of the Georgian legislation and technical regulations with the European legislation, the European Community Euro-Asian Council for Standartization, Metrology and Certification (EASC) has prepared normative documents within the framework of the project:

1. EN/TS 15173:2006, Gas Supply Systems – Frame of reference regarding PIMS;
2. EN/TS 15174:2006, Gas Supply Systems – Guideline for Safety Management Systems for natural gas transmission pipelines;
3. And many others,

which are registered by the respetive standartization authority in Georgia and are recommended for application. These norms give methodological and generalized recommendations instead of specific decisions, which allows for more flexibility when defining the pipeline operation rules and safety zones.

These norms, similar to regulations adapted in many western industrial countries allow for using a methodology based on mitigation of risks in each specific case for ensuring pipeline operation safety and integrity, to establish safety (protection) zone borders.

To establish safety zones in USA, population density is considered for defining the pipeline category and the wall thickness, however, pipe diameter and pressure, possibility of monitoring are also taken into consideration and safety zone calculation formulas (or diagrams) are established. Methodology based on risk assessment is also used, mostly in cases when the created situation requires revision of distances envisaged by norms (for example, if any building or structure is located in the immediate vicinity of the pipeline or when the pipeline crosses very densely populated areas or natural obstacles and sophisticated artificial structures).

Generally, the following protection and safety zones are established for trunk pipelines:

- Internal zone (particularly high protection area) where the allowed risk level (individual risk during a year) is $\leq 10^{-5}$ (0,00001) [104]. As a rule, such zone is taken from the central line of the pipeline within 10 m, depending on properties of transported liquid (gas) and various risk factors. In the internal zone, which is 4 m according to the respective regulations applicable in Georgia [120], it is allowed to carry out only limited agricultural works;
- Middle zone (high protection), where the allowed risk level is $\leq 10^{-6}$ and construction of some facilities of urban development is prohibited, is taken within 25 m from the central line of the pipeline;
- External zone (relatively low protection), where gathering of more than 1000 persons, construction of schools, hospitals etc. is prohibited, with the allowed risk level $3 \cdot 10^{-7}$, will be generally taken within 150-500 meters from the central line of the pipeline.

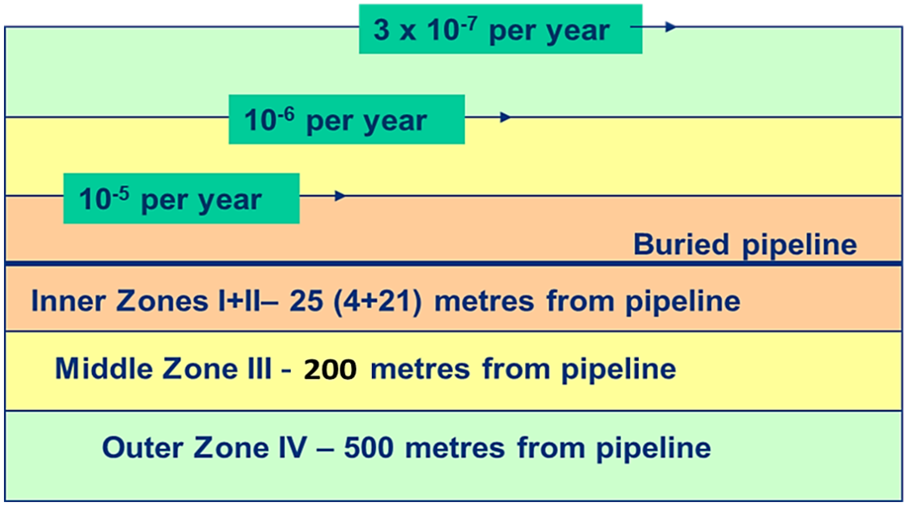

Figure 3.39. Typical pipeline protection and safety zones

Dimensions of safety and protection zones are defined at the design stage, but must be defined more precisely upon commencement of operation and will be repeated at certain intervals (in USA, at least once in 2 years and in case of need, more often) according to the pipeline diameter, flow pressure and population density (or nature of the adjacent natural environment) to which adequate restrictions apply during construction and other agricultural or other activities of a third party.

The zones selected for transit pipelines of large diameter (≥ 1000 mm and pressure 70 bar) offered by BP [121] in Georgia equal to:

- Zone 1 (internal) – 4 meters from central axes of Baku-Tbilisi-Ceyhan and South Caucasus Pipelines to both sides which is defined as the "pipeline corridor". The strictest requirements apply to this zone to avoid causing damage to the pipeline by a third part. Characteristics of the restrictive regime applicable in the zone is shown in a special table.
- Zone 2 (middle) – 4-15 meters from central axes of pipelines to both sides. The regime applicable to this zone significantly restricts entry of a third party and performance of construction, agricultural or other activities.

Protection zone 2 defined by the regulations adopted in Georgia for other pipelines extends up to 25 meters to both sides of the trunk pipeline under construction or being in operation.

Under regulations applicable in Georgia, safety zone 3 (external) extends at 25-175 meters from the central axis of the pipeline to both sides (for Baku-Tbilisi-Ceyhan and South Caucasus Pipelines, security zone extends from II zone at 370 meters to both sides, and for Baku-Supsa pipeline – at 125 meters).

Mandatory consultation of the pipeline operator is established for zone 3 for all application for construction permits and some other activities. The consultation will be given: considering the pipeline design specification which must be in compliance with ASME B31.4 (BTC pipeline) or ASME B31.8 standarts (SCP), as well as considering the methodology of quantitative risk assessment (for example, in accordance with the UK health, safety and environmental protection standards and approaches).

Consultation zone 4 extends from external border of zone 3, within 500 meters from the central axis of the trunk pipeline in all directions.

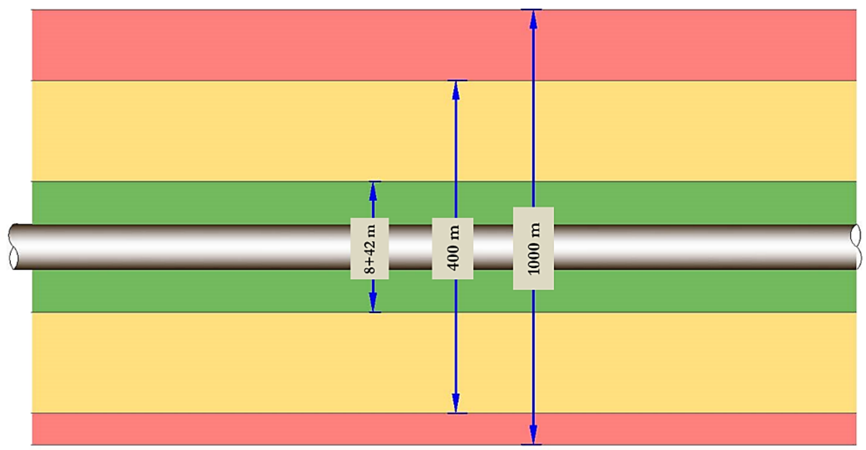

Figure 3.40. Protected, Safety and Consultation Zones of Trunk Pipelines

Establishment of protection and safety zones and respective minimum distances and imposition of restrictions in each specific case depends on the nature and purpose of the pipeline design, skills and experience of the design engineer, with mandatory compliance with the condition that "respective (safe) distances from pipelines will be provided …" [122]. Considering the above, the Regulations allow for reducing the minimum distances specified for zone 3, by decision of the trunk pipeline operator and on the basis of the respective justification. In particular: it is allowed to reduce minimum distances from the axis to buildings and structures with the condition of ensuring safe operation of structures envisaged for the trunk gas pipeline or its section by technical regulations (considering the location class assigned according to the designation of land of the adjacent territory of the route, population density and nature of industrial and settled areas).

The international experience shows that the most effective method of mitigation of pipeline damage risk is to increase the pipe wall thickness and use high quality, comparatively corrosion-resistant steel pipes, which as confirmed by statistical material. Under conditions of normal operation practically excluded unforeseen pipeline failure in case of using pipes with wall thickness of 15 mm and more [110]. Deep placement of the pipeline in soil is considered to be an effective measure for prevention of interference of a third party and therefore, ensuring safe operation of the pipeline too. For example, increase of deepening by 1 m and more reduces the likelihood of its damage by approx. 5 times compared to pipelines located at the depth of at least 0.8 meters.

Also, the most effective measure for reduction of risk predetermined by defects of materials is to use high quality, thick wall steel pipes, which together with active corrosion protection system excludes failures caused by corrosion.

Preventive measures such as training of personnel, regular monitoring of the pipeline condition and elimination of causes of expected emergencies in advance (such as bank protection, removal of the route from the landslide zone etc.) also significantly reduce the likelihood of failures. As shown by the analysis of 2006-2010 data, only 1 average statistical failure per year is observed in Europe per each 6172 km high pressure trunk gas pipeline.

Accordingly, in special cases, on the basis of quantitative assessment of risks, the pipeline operator or other stakeholder may submit to the authorized body materials on possibilities of assumed risk mitigation considering special measures, with necessary compliance with the condition that safe distances from pipelines will be ensured, request permission for constriction restricted in safety zones or other activities restricted by the Regulations. The respective services will conduct a competent expertise of the submitted materials, and in case of a positive conclusion, will agree on the possibility of performance of activities restricted by the Regulations in safety zones and shall notify the stakeholder and the competent authority thereof, together with possible additional conditions, to make a final decision.

CHAPTER IV

4. INTEGRATION INTO THE INTERNATIONAL ENERGY ORGANIZATIIONS

4.1.GENERAL ASPECTS OF INTEGRATION

Within the framework of the Association Agreement with the EU, Georgia signed the Protocol of Accession to the European Energy Community on October 14, 2016 which was ratified by the Parliament on April 21, 2017. Georgia has been a country holding a status of the full-fledged contracting party of the Energy Community since July 1, 2017.

Membership of the Energy Community forms preconditions for receiving technical and financial assistance from EU during the process of reforms and predetermines more trust of investors as well as activation of solidarity leverage under emergency conditions in the field of energy. The conditions of joining the Energy Community define the possibility of important derogations for Georgia. In particular:

- The existing conditions of transit and supply of gas through the main transit pipelines are maintained;
- The mandatory conditions of access to the transborder trade with the neighbor countries and access to the network do not apply;
- The EU competition rules will apply to Georgia to a full extent only after the local market physically connects with at least one member state of EU or the Energy Community.

Within the framework of the Association Agreement, Georgia undertook an obligation to apply the basic principles of the EU Energy Acquis to the local market gradually, which implies:

- Formation of a competitive and transparent energy market, with a non-discriminatory access of a third party to the network;
- Formation of energy resource trade platform(s);
- Formation of a stable and atractive investment environment by introduction of regulation rules free from institutional, legal and fiscal policy;
- Unbundling of naturally monopolistic and competitive activities;
- Ensuring supply security.

Under the conditions of Georgia, the above, first of all, requires activation of work for solving basic problems such as:

- Guaranteed satisfaction of demand on gas in the long run;
- Formation of a competitive market instead of a market with unacceptably high concentration by separation naturally monopolistic enterprises from competitive activities;

• Opening the market and possibility of selection of a supplier according to the choice of consumers.

According to the plan agreed with the Energy Community, it is necessary to introduce the key principles of the following directives and regulations in the oil and gas sector of Georgia:

- Directive 2009/73/EN concerning common rules for internal market in natural gas;
- Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks;
- Directive 2004/67/EC concerning measures to safeguard security of natural gas supply (which is already replaced by Regulation (EU) No 994/2010 concerning measures to safeguard security of gas supply);
- Directive 2009/119/EC 14/09-2009, imposing an obligation on Member States an obligation to maintain minimum stocks of crude oil and /or petroleum products;
- Consideration of legislative norms, which are indirectly related to operation of the oil and gas sector in Georgia and the Energy Community, including in the issues related to competition.

Generally, a liberalized market represents an effective instrument for attraction of investments required for infrastructural projects and meeting the increasing demand on gas consumption. Introduction of a clearly defined competitive market structure and a regulatory system, ensuring a non-discriminatory access to the transportation and distribution networks will facilitate successful development of the Georgian gas sector and its integration into regional systems, which is one of the significant preconditions for increasing the energy security of the country.

Development of the natural gas sector requires refinement and thorough improvement of the legislative-normative framework. Introduction of effective instruments of improvement of the legislative framework and the market monitoring, in case of ensuring direct non-interference in the regulation activities from the part of the state, will allow for achieving the ultimate goal of liberalization – full opening of the market in such manner that any consumer of natural gas can freely select a supplier and the supplier can have unhindered access to the transportation and distribution infrastructure. For this purpose, supplier change rules, effective measures of protection of consumers of various categories, the respective secondary legislation, standard contract form etc. must be developed.

For the purpose of development of the natural gas sector, including successful implementation of infrastructural projects, it is necessary to harmonize the Georgian standards and technical regulations adapted in the international practice of design and operation to international standards and ensure their practical application.

4.2. LAW OF GEORGIA ON ENERGY AND WATER SUPPLY

Key objectives of the Law and the regulatory authorities

The Energy and Water Supply Law (LEWS), adopted by Parliament of Georgia on December 20 2019, represents an adapted version of the respective legislative acts of the EU, considering peculiarities of the energy market of Georgia. Particularly law shall not apply to those relations emerged from the inter-governmental agreement between Azerbaijan and Georgia, which apply to transit of natural gas via the pipeline system of South Caucasus, its transportation and sale both on and beyond the territories of Georgia and Azerbaijan.

LEWS is based on the requirements of the following legislative acts of EU:

- EU Directive N 2009/72/EC of July 13, 2009 on common rules for the internal market of electric power with which directive N 2003/54/EC was abolished;
- EU Directive N 714/2009 (EC) of July 13, 2009 on common rules for the internal market of electric power with which regulation (EC) N 1228/89/EC was abolished;
- EU Directive N2005/89/EC of January 18, 2006 on supplying electric energy and measures of ensuring security of investments in infrastructure;
- EU Directive N2009/73/EC of July 13, 2009 on imposing common laws for the internal market of natural gas with which directive N 2003/54/EC was abolished;
- EU Directive (EC) N715/2009 of July 13, 2009 on the conditions of admitting to the natural gas transmission lines with which directive (EC) N1715/2005 was abolished;
- EU Directive N2004/67/EC of April 26, 2004 on the measures of ensuring security of supplying natural gas.

The Law envisages reformation of the system of management, organization, regulation, monitoring and supervision of the natural gas sector.

Scope and purpose of the Law in natural gas sector are as follows:

1. establish a general legal framework for the transmission, distribution, supply, storage of and trade in natural gas sector with a view to the facilitated emergence, opening, development and integration of well-functioning, transparent and competitive natural gas market.
2. governing and organization, regulation, monitoring and supervision of natural gas sector, provision of open access to natural gas market, cross-border trade of natural gas, the criteria and procedures applicable to calls for tenders and the granting of authorizations for energy activities, operation of and access to natural gas systems, public service obligations and the rights of customers and their protection.

3. establish measures to safeguard an adequate level for the security of supply so as to ensure proper functioning of natural gas sectors.
4. establish legislative framework to take into consideration in the legislation of Georgia the requirements of the corresponding legislative acts in EU and activate them.
5. apply the rules established by Law for natural gas, including LNG, shall also in a non-discriminatory way to biogas and gas from biomass or other types of gas;
6. establish the terms and conditions for the participation of natural gas producers in the natural gas market of Georgia which also include those requirements which are related with connection of natural gas production facilities to transmission or distribution networks, access to the natural gas system and sale of natural gas on the market.

The LEWS is not applying to the exploration, extraction and processing of natural gas or other hydrocarbons, as well as selling natural gas by means of petrol stations, production of gas products and any relations thereto, except for activities related to the processing of natural gas at LNG facilities.

Main objectives of the Law for natural gas sector are the following:

a) to establish a legal framework for uninterrupted supply natural gas;

b) to ensure secure, reliable and efficient operation of natural gas systems, and the provision of related services to all system users;

c) to define the rights and obligations of regulated undertakings under the terms and conditions stipulated by the Law and to set the rights and obligations of the Commission, as well as to establish a legal framework for mutual relations among regulated undertakings and their relations with the Commission and other state authorities;

d) to create conditions for a full opening of natural gas market in based on the principles of competitiveness, transparency and non-discrimination aiming at full opening of natural gas market with the view of unrestricted trade;

e) to establish common rules for the organization and functioning of natural gas market, including, its further development and, subject to future pan-European integration;

f) to set the terms and conditions for the provision of public service obligations in natural gas sector, and to ensure the protection of interests of final customers;

g) to regulate and monitor the unbundling of transmission system operators and distribution system operators, as well as to ensure their effective independence from other energy activities and related commercial interests;

h) to create adequate conditions for investments in natural gas systems, including, interconnections with neighboring systems and in other facilities enhancing the security of supply;

i) to establish a legal framework for regional and international cooperation of system and market operators, the Commission and other state authorities, as well as for mutual cooperation among competent national authorities, institutions and other public bodies of Georgia.

The Law establishes conditions of participation on the natural gas market for natural gas consumers, infrastructure owners[68] and other subjects and these conditions include requirements of connection to transmission or distribution networks of natural gas production facilities, access to the natural gas system, natural gas trade on the market and other respective requirements.

Particularly significant provisions of the Law on Energy for ensuring arrangement and effective functioning of the Georgian energy market are provided below.

The Law defines functions of the Government of Georgia, rights and obligations of the Ministry responsible for the energy sector. Under the Law, the Government makes a final decision on:

- the gas market design;
- unbundling model and action plan of enterprises responsible for monopolistic and competitive activities;
- appointment of the "last resort supplier" and "public supplier";
- announcement of emergency during the threat of formation of a critical situation in energy sector;
- approval of protection program of socially vulnerable consumers.

The Ministry responsible for the energy sector shall be authorized to:

- develop a long-term energy policy and strategy and ensure their implementation;
- ensure energy security of the country;
- approve regulations on natural gas supply security, prepare emergency action plans;
- prepare and agree the natural gas market design with the Government;
- select and agree the candidacies for "public supplier" and "last resort supplier" with the Government;

[68] According to the Law, an enterprise which lawfully, on the basis of the ownership right, owns a natural gas transportation (or another, for example, gas storage, LNG terminal) system, but it is not the operator of this system" shall be considered to be the "system owner".

- ensure identification of strategic projects and their inclusion in 10-Year Development Plans, approval of these Plans;
- hold a public tender for construction of new production (generation) facilities in agreement with the Government;
- establish the "vulnerable category" of consumers in cooperation with the respective state agencies;
- ensure development of technical rules and norms related to energy equipment and appliances, considering the EU technical safety standards and regulations.

According to the Law, competence and powers of the energy regulatory authority (GNERC) in connection with authorization of energy activities and other activities governed by law, establishment of conditions of such activities and their monitoring are significantly increased.

The competence of the regulatory authority includes the following main objectives and duties:

- promoting, competitive, secure and environmentally sustainable internal energy markets within the Energy Community, effective market opening for all customers and suppliers, ensuring appropriate conditions for the effective and reliable operation of energy networks, taking into account long-term objectives;
- eliminating restrictions on trade in energy, including developing appropriate cross-border transmission capacities to meet demand and enhancing the integration of national markets which may facilitate energy flows across the Energy Community;
- helping to achieve, in the most effective way, the development of secure, reliable and efficient non-discriminatory systems, promoting system adequacy and energy efficiency;
- facilitating access to the network for new capacities of the generation of electricity and production of gas;
- ensuring that system operators and system users are granted appropriate incentives, in both the short and long term;
- ensuring that customers benefit through the efficient functioning of energy markets, promoting effective competition and helping to ensure customer protection;
- helping to achieve high standards of public services provided in electricity and natural gas sectors, contributing to the protection of vulnerable customers and contributing to the compatibility of necessary data exchange processes for switching the supplier;
- issuance, modification and revocation of licenses under the terms and conditions stipulated in the Law of Georgia on Licenses and Permits and in the LEWS;
- certification of transmission system operators and their continual monitoring;

- establishing the terms and conditions for the provision of services by regulated undertakings;
- approving special regulatory requirements for accounting in regulated undertakings, monitoring and enforcing their proper implementation;
- establishing the terms and conditions regulating the provision of information possessed by regulated undertakings to system users and/or customers;
- monitoring the performance of regulated undertakings;
- monitoring the provision of public services and implementation of public service obligations;
- defining the rules of payment of the regulated enterprise;
- approving standard conditions of the agreement;
- etc.

The Commission is assigned to establish tarrifs and/or determine the cost for regulated activities and approve respective methodologies to ensure that:

a) tariffs and charges reflect the documented expenses of the network operation, maintenance, replacement, construction and reconstruction, which include reasonable investment proceeds, amortization and taxes, considering environmental and consumer protection;
b) tariffs and charges allow for carrying out required investments in networks and equipment to ensure their effective functioning and development;
c) long-term and short-term stimulation of transmission and distribution system operators for the purpose of facilitating of increase of efficiency, market integration and supply security and supporting related research activities.

In addition to the key regulatory powers, the Commission shall ensure that the tariff of access to the system adopted by the independent operator of the system includes remuneration of the transmission system owner too, which implies respective remuneration for the network assets and any new investments made in them provided that they are carried out cost-effectively and efficiently.

The Ministry of Economy and Sustainable Development of Georgi has prepared a list of secondary legislation related to implementation of the Law and considered to be a priority, in cooperation with donor organizations (see the Table).

Table 4.1. Secondary legislation for natural gas sector

Secondary Legislation in Natural Gas
Natural Gas Market Concept Design
Natural Gas Market Rules
Rules on the Security of Natural Gas Supply
National Natural Gas Emergency Plan included regulations on Emergency Situations on Natural Gas
Model and Action Plan for Unbundling of the Transmission System Operator for Natural Gas
Procedure for Certification of the Transmission System Operator for Natural Gas
Regulation on Imposition of Public Service Obligation(s) on Natural Gas Market Participants
Designation of the Natural Gas Supplier of Last Resort
Rules and regulations referring protection measures of vulnerable consumers
Rules on Public Consultations
Rules on the Monitoring of Energy Markets
Rules on Enforcement of Penalties Imposed
Rules on Settlement of Disputes
Rules on Mediation
Methodology for Calculation and Setting of Natural Gas Transmission and Distribution Tariffs
Methodology for Calculation and Setting of Fees for Connection to Natural Gas Transmission and Distribution Networks
Methodology for Calculation and Setting of Fees for Services Provided by the Natural Gas Market Operator
Methodology for Calculation and Setting of Prices for the Supply of Natural Gas of Last Resort
Methodology for Calculation and Setting of Natural Gas Storage Tariffs
Natural Gas Storage Code
Criteria for Determination of the Access Regime to Natural Gas Storage Facilities and Line pack
Decision on Authorization for Construction of Direct Natural Gas Pipelines
Decision on Classification of a Closed Natural Gas Distribution System
General Natural Gas Supply Conditions
Natural Gas Supplier Switching Rules
Ten-Year Natural Gas Transmission Network Development Plan
Natural Gas Distribution Network Development Plan
Rules and regulations referring protection measures of vulnerable consumers
Licensing and operation of the Storage Facility

Standard Contract on the Supply of Natural Gas to Household Customers and Small Enterprises
Operational Rules for Public Service Suppliers of Natural Gas
Operational Rules for Natural Gas Supplier of Last Resort
Standard Natural Gas Transmission Contract(s)
Contract between the Natural Gas Transmission System Operator for Natural Gas and the Compliance Officer
Contract for the Possession of Natural Gas Transmission System Assets
Compliance Programme of the Natural Gas DSO
Standard Natural Gas Storage Facility Contracts and Procedures
Rules on Unified System of Accounting
Unbundling of DSO's
The Uniform System of Accounts (USoA) for transmission and distribution network operators (TSO and DSOs)
The minimum internal operational rules and obligations on network security
Procedures for operating the natural gas system under normal network operation regime and Operation under extraordinary conditions, taking into account, emergency management and security of supply rules
Terms and conditions for dispatching, including services provided by the transmission system operator
Terms and conditions for the implementation of procedures for interruptions of natural gas deliveries through the natural gas transmission network
Generally Applicable Standards related to the gas transmission service and system for the Georgian gas transmission system

4.3. ORGANIZATION OF THE MARKET

a) Current situation on the gas market

The issues related to supply of natural gas, including: problems of mandatory public service of vulnerable and protected consumers (households, small enterprises and part of TPPs), "last resort supplier" and other significant problems are prescribed in the Law in detail. Particular attention is paid to ensuring supply security and the respective monitoring of the process by the state.

The Law establishes necessity of supply of natural gas to consumers at a non-regulated market price, except the cases defined by law. Suppliers can purchase gas by bilateral contracts or at the organized market.

Generally, the supply activities are not restricted and are only subject to informing the regulatory authority. The Law establishes the rights of suppliers and final consumers under supply agreements the typical conditions whereof are defined by the regulatory authority.

Gas supply of protected consumers of the gas sector in Georgia (households, small enterprises and part of TPPs) will be provided by a "public supplier".

"Last resort supplier" is obliged to deliver natural gas to consumers if the existing supplier has left the market for some reasons.

Law defines the general principles of the market organization and functioning, market structure and key rights and obligations of participants. The main issues of organization and operation of the market are defined by the market rules which include:

- establishment of the market design and key participants, conditions of their registration;
- procedures, principles and standards of organization and operation of the market;
- types of contracts and their respective standard forms (templates);
- list of traded products on the market;
- standards and procedures for keeping records of market transactions, creation of databases, announcement and verification of purchase, ensuring network losses and other required operations;

Natural gas market consists of retail and wholesale trade segments. Retail trade is mainly based on application of bilateral contracts between retail suppliers and consumers. Traditional OTC, forward, "day ahead" and "organized" markets are distinguished in the field of wholesale trade.

At this time, Georgia's gas market organization and regulatory framework do not coincide with the EU energy acquis and do not support to establish truly competitive market and conditions for the free trade. Gas price subsidizing for large sectors of market, raises barriers to establishment of competitive market and effective development of indigenous renewable resources. Moreover, the lack of supply diversification and dominance of state companies of foreign countries on the market hangs over Georgia's energy security and, generally, economic independence.

Considering the issues related to organization of natural gas market and guaranteed gas supply, such as: mandatory public service, supply to vulnerable and protected consumers, requirements established by the Law in respect to the "Last Resort Supplier" and the current situation in the country, it is expedient to handover to the completely formed, competitive market stage by stage, for the purpose of ensuring security of supply in the transitional period, price regulation for a certain category of customers, financial stability of the key companies acting on the market and effective monitoring of the process by the state.

The Energy and Water Supply Law **establishes the necessity of supply of natural gas to consumers at a non-regulated market price** (except the cases defined by the law), which represents the necessary final goal of the proposed market model. At the same time, in terms of energy, Georgia is isolated from other countries of the Energy Community, which is preconditioned by the geographic location of the country and yet, it cannot use the benefits enjoyed by other contracting parties of the Community (due to absence of interconnectors with the contracting parties of the Community, it is impossible for Georgia to maintain free exchange with the neighbor countries and receive possible assistance based on the solidarity principle in critical situations).

The contemporary wholesale gas market of Georgia (see Figure 3.7) represents a market, based on the bilateral contracts, where the state company of a foreign country dominates. Georgia is entirely dependent on the imported gas supplied on the basis of long-term contracts and the wholesale market has an extremely high concentration.

The market concentration indices in Georgia significantly exceed the competitive market parameters in the international practice, in particular: the respective indices of the gas market target model, recommended by the European Agency for the Cooperation of Energy Regulators (ACER) for the EU (see the Table) or the criteria established by the US Department of Justice (market with an HHI of less than 1500 is a competitive marketplace, an HHI of 1500÷2500 - a moderately concentrated marketplace and an HHI of 2500 or greater to be a highly concentrated marketplace. Also, a 4 leading company concentration ratio of over 60% indicates a highly oligopolistic market structure).

Table 4.2. Target and actual indices of the market concentration

	HHI	No of Suppliers	MCR
Threshold by ACER Gas Market Model	≤2000	≥3	≤40%
Actual Geo	≈5000	3	≈90%
Actual EU	≈1700	>>3	<40%

The analysis shows that according to the 2018-2019 data, the Georgian wholesale natural gas market concentration ratio (MCR) exceeds 90%, which is common for oligopolistic market and Herfindahl-Hirschman Index (HHI) equals to 4000-5000 (considering that Shah Deniz field is an independent source of gas supply).

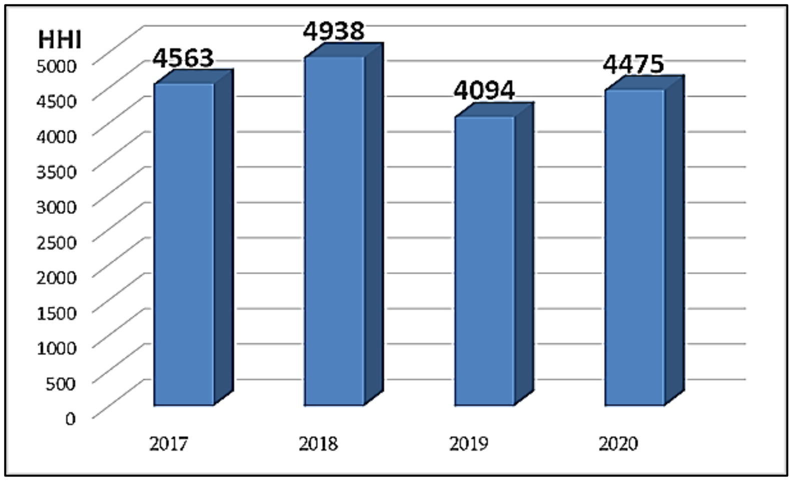

Figure 4.1. HHI of the wholesale natural gas market of Georgia

As a result, the state companies of a foreign countries control more than 95% of the wholesale gas market (as well as the entire retail market in Georgia, except Tbilisi household and commercial consumers) and as they represent the actual monopolists, have an opportunity to offer unreasonably high prices to the deregulated, commercial segment of the market, which are considerably higher compared to other countries in the region and become a heavy burden for the country's economy and more importantly, it represents a critical challenge for the energy security of the country.

b) Proposed natural gas market reform

Indeed, it is not expedient to entirely handover from the existing market structure to the competitive market without transitional steps, as it is connected with significant challenges. In particular, Georgia has only 2 potential supplier – SOCAR (Azerbaijan) and Gazprom (Russia). Today, due to the political confrontation with Russia which has occupied 20% of Georgia, uncontrolled access of the Russian state company Gazprom to the market is not expedient. Accordingly, in the case of deregulation and offering the full volumes of imported gas through an organized market, SOCAR's real monopoly will become a powerful instrument for market control.

As a result, threat will be posed to the possibility of providing public services prescribed by law by the state, by own resources and effectively carry out the guaranteed gas supply of protected and vulnerable consumers according to Article 109.1 of the Law. Thus, the social policy declared by the country will depend on foreign company's goodwill (today, avoidance of such problem is guaranteed by the SOCAR's obligation of ensuring the gas supply of the country's social sector consumers at a regulated tariff on the basis of the Memorandum signed with the Government of Georgia).

Accordingly, due to the existing situation and considering requirements of law, it seams reasonable to:

- At the initial stage of structural reforms, to instruct the local state company to be the main partner in the transactions of natural gas import. The later will ensure a guaranteed gas supply of the market's regulated segment at affordable tariffs and will trade with the remaining gas on the organized market (trade platform) in compliance with the free-trade principles. In this case state company of Georgia will be able to control the share of Gazprom in the total balance and will limit its rational level, utilizing Shah Deniz gas volumes to create competition in the deregulated (commercial) sector of the market.

  At the same time, the market operator shall become responsible for organizing auctions and functioning of a trade platform and the transmission (and/or distribution) network operator shall be obliged to ensure balancing of the market and other additional services, in accordance with the network and market rules, considering the following key requirements:

  - ➢ Balancing rules shall reflect genuine system needs, taking into account the resources available to transmission system operators and shall provide incentives for network users to balance their balancing portfolios efficiently;
  - ➢ Network users shall be responsible to balance their balancing portfolios in order to minimize the need for transmission system operators to undertake balancing actions set out under corresponding Regulation.
  - ➢ Network users shall have the possibility to enter into a legally binding agreement with a transmission system operator which enables them to submit trade notifications irrespective of whether they have contracted transport capacity or not.

- At the following, transitional stage of the reforms, together with attraction of alternative suppliers (at least, traders) to the market and growth of market liquidity, as well as considering the underground gas storage resources by the onset of the stage and using the experience gained by the market operator, the local state company will have only the obligation to provide public service and the remaining suppliers (importers, traders, producers) will trade through an organized platform.

  At this stage of reforms, long-term supply contracts by direct gas supply to qualified consumers or distribution companies at the wholesale market will not be prohibited. However, according to the European experience, gas supplier companies give preference to long-term bilateral contracts and reluctantly engage in organized trade through a trade platform. Therefore, mandatory sale of part of gas supplied at the initial stage at the organized market is introduced in several European countries. A similar regulation may be successfully used in Georgia too (see Figure 4.2).

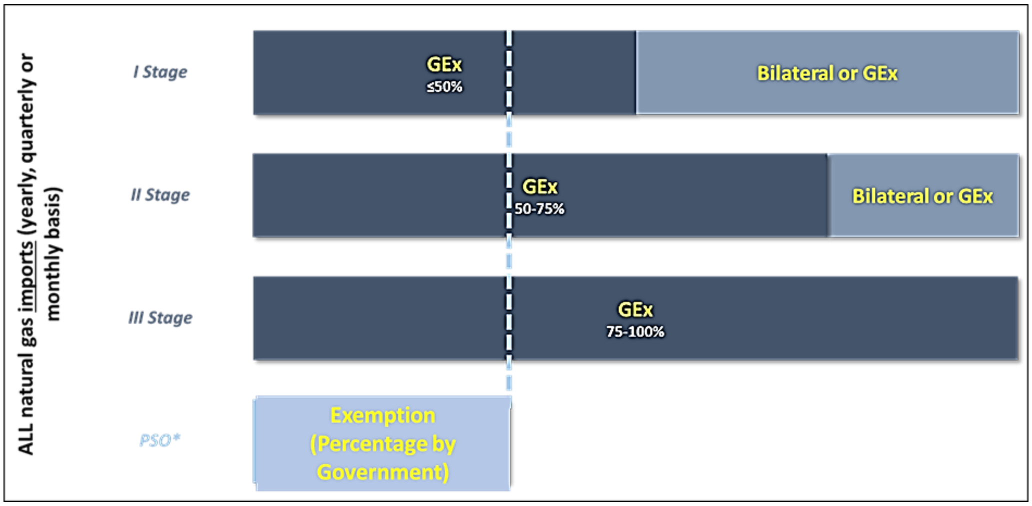

Figure 4.2. Organized market with mandatory sale of part of traded gas

The possible market structure at the initial stage of reforms is shown on the Figure 4.3.

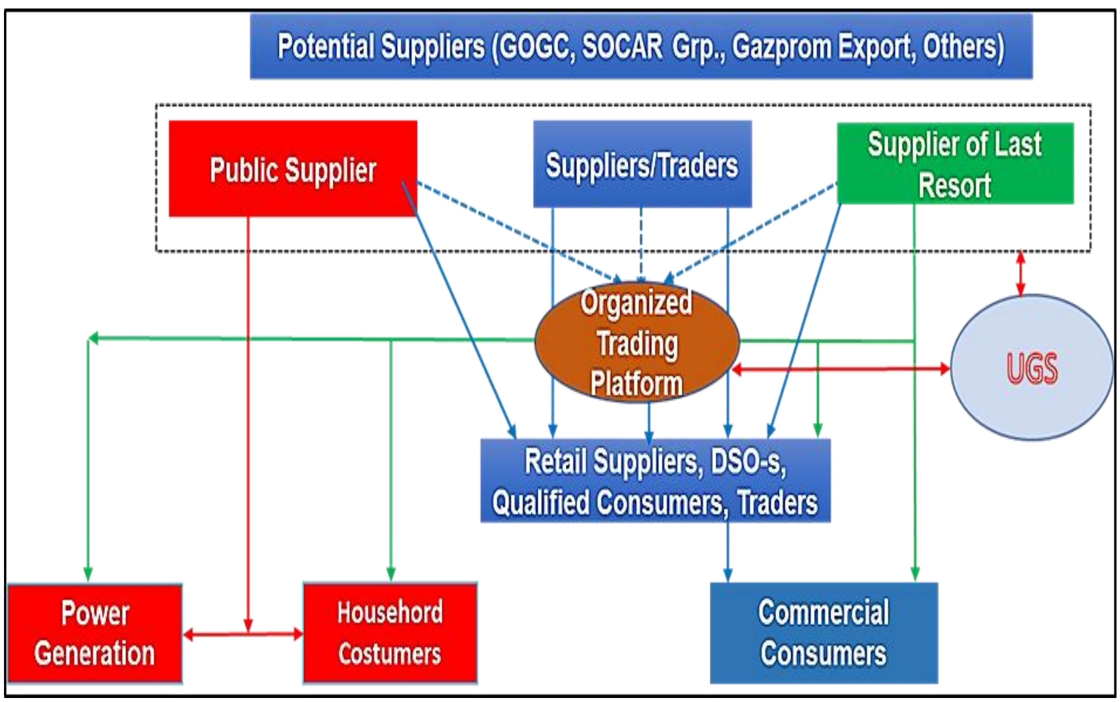

Figure 4.3. The gas market structure on the transition period

- The final structure of a competitive and transparent market envisages organization of natural gas trade mainly through a trade platform (see Figure 4.4) and the market operator shall be responsible for its functioning. At the same time, the possibility of exemption of the market subject bound with the obligation of public service from the obligation of trade at the organized market will be still admissible, if it is considered expedient. Under conditions of Georgia, this exception can be effectively used the supply of the household sector, small enterprises, and the TPPs authorized as guaranteed capacity source (Article 109.1 of Law) by relatively accessible gas from Shah Deniz field. Other consumers will be able to purchase gas under bilateral contracts (OTC), as well as by day ahead market options or other products established by the market rules in compliance with reasonable requirements of competition, transparency and confidentiality.

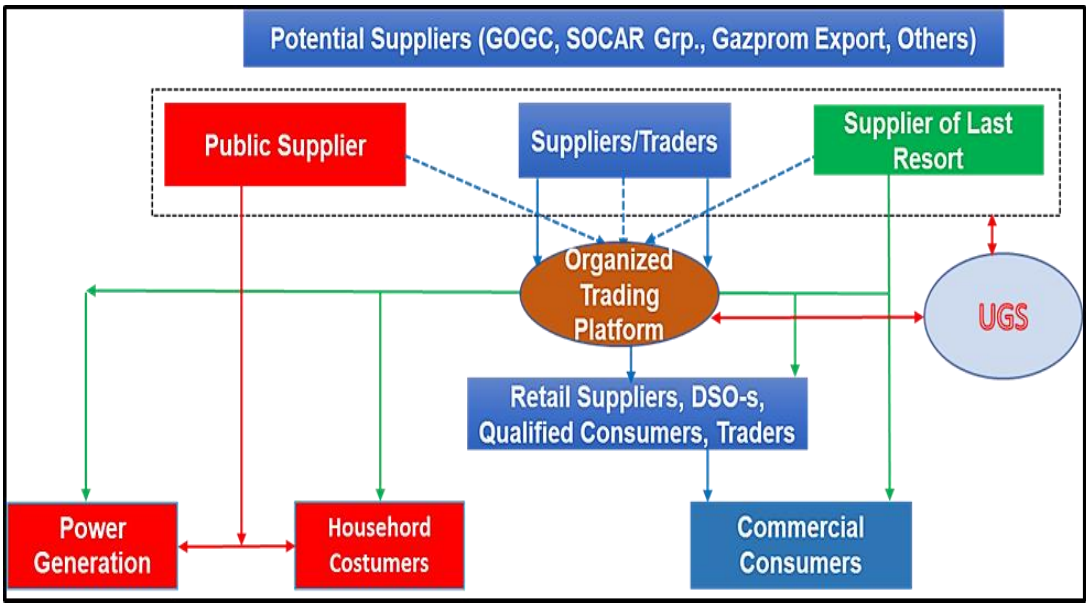

Figure 4.4. Structure of competitive natural gas market

It should be mentioned that iimplementation of reforms related to organized trade has already begun in the power sector of the country. In particular, the established “Georgian Energy Exchange” (GEE) operates with the main goals of the formation of the open and competitive electricity market, enhancement of the country’s energy security and safe delivery of resources to consumers, facilitation of energy efficiency, development of renewable energy sources and other priority directions. Founders of the GEE are JSC "Georgian State Electrosystem" and JSC "Electricity Market Operator", with the 50-50% co-participation.

The main function of the GEE is registration of bilateral contracts, formation, operation, gradual development and administration of bilateral contracts, day ahead and daily markets; formation of the unified financial payment system of various components of the electricity market, as well as maintaining a register of market participants. GEE is consulted and software support is provided by a Norwegian consulting company "Nord Pool Consulting".

Considering the international practice and local (Georgian power energy sector) experience, it is expedient to found an independent natural gas market operator (company) by the key players of sector, including: GOGC, GGTC, MOSD, etc. Alternatively, the Government of Georgia may decide that the existing energy exchange operator shall be instructed to operate the natural gas market too, but this option does not correspond to the best international practice.

Based on the above discussions, following key conclusions are offered:

- Due to energy isolation of Georgia, preconditioned by its geographic location and unacceptably high concentration of the existing market, on the one part and, the necessity of formation of a competitive market based on free trade principles, on the other part, it is expedient to carry out a gradual reform of the natural gas sector of Georgia with the assumption that no threat will be posed to the guaranteed gas supply of consumers at the transitional stage and at the same time, basis will be laid for organizing the gas trade through a trade platform;
- The organized market at the first stage of reforms will ensure:
  - prevention of participation of "Gazprom" in the local market with an undesirable dose;
  - formation of a competitive environment in the deregulated, commercial sector of the market;
  - strengthen the bargaining power of Georgia;
  - guaranteed provision of mandatory public service at affordable tariffs;
  - elimination of the actual monopoly of a foreign country's state companies at the local market;
  - increasing the capacity of the Georgia's state companies to refill the market deficit with its own resources in possible critical situations, in case of the key suppliers (Gazprom or SOCAR) do not (or cannot) ensure supply of planned volumes of gas;
  - regulation of the gas tariff based on principles of equity, under conditions of removal of "interim" players from the existing supply scheme and the market controllable by the state within reasonable margins;
  - fair distribution of revenues and profits among local and foreign importer companies.
- The structure offered at the 2nd stage of reforms will ensure:
  - application of the competitive market principles to actually all market participants;
  - mandatory but gradual transition to the fully organized trade.

- The structure offered at the final stage of reforms will ensure:
  - operation of an organized market required by law, based on the principles of competition and transparency, which will finalize harmonization of the Georgian energy legislation (in gas sector) with the EU energy acquis;

- integration with the respective Energy Community institutions in the natural gas sector and as a result, formation of an attractive environment for foreign investors;
- Regulation of gas tariffs in the competitive environment and under conditions of free trade.

4.4. UNBUNDLING OF ACTIVITIES

Unbundling implies separation of the regulated, naturally monopolistic network activities (transmission and distribution) from competitive activities, such as generation/production and supply.

Transmission is activities of public interest which include transportation of electricity or natural gas through the transmission network, its service, maintenance, development and other related activities required for safe, reliable and efficient functioning of systems.

Transmission system operator must be established as a specialized and independent energy enterprise having a status of a legal entity. Independence of the operator is achieved by separation of integrated enterprise (unbundling of competitive and natural monopoly). Effective separation of activities related to energy infrastructure from commercial interests is achieved by division of property and/or ensuring legal, functional, administrative, operational and decision-making independence.

In performance of its own duties and functions, transmission system operator must be independence from other energy activities, in particular, production, distribution, supply, trade. For this purpose, two models of unbundling (separation) of activities of natural gas transmission system operator are offered by Law:

a) The model of ownership (property) division as a norm, which implies that each enterprise which owns a transmission system must act as a transmission system operator and obtain a license for transmission activities;
b) As an exception from ownership (property) division model – model of Independent System Operator (ISO) in cases when the respective transmission system operator represented a vertically integrated enterprise on October 6, 2011 or earlier. Under conditions of the gas sector of Georgia, such restriction would not be a factor hindering formation of ISO, because the system operator – Georgian Gas Transportation Company

was a part of a vertically integrated enterprise, Georgian Oil and Gas Corporation, until September 1, 2011[69].

In case of Georgia, it should be considered expedient to establish an exception envisaged by law – Independent System Operator in accordance with the conditions defined by Articles related to separation (Articles 46 and 47 of the Law).

The Law imposes certain restrictions on each enterprise established as a result of separation. For example, a vertically integrated enterprise can participate in activities of gas production, supply and purchase and sale, it may own a transmission network which it will lease to the Operator, but exercising control on the activities of the system operator is restricted for it in any form and to any extent.

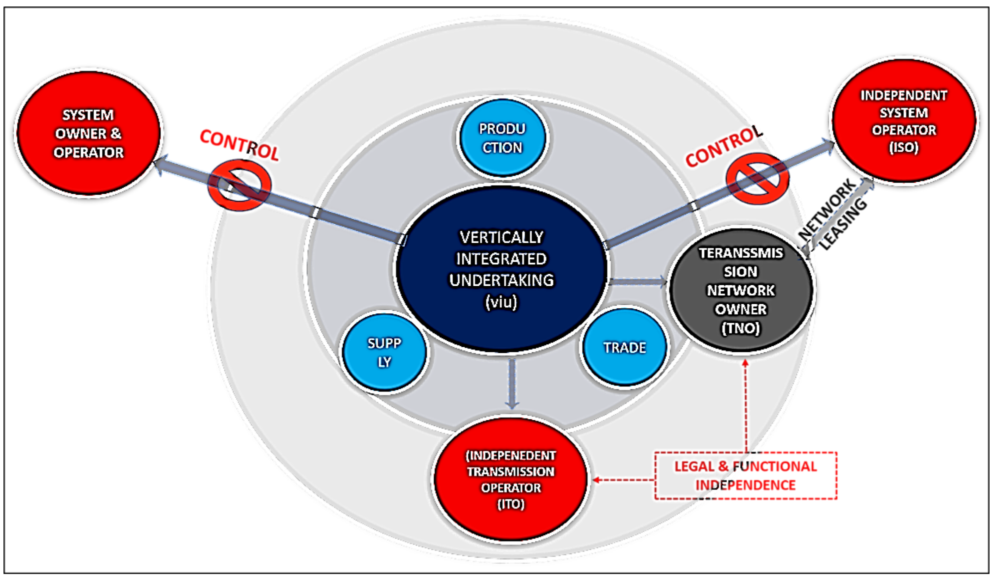

Figure 4.5. Constraints of various models of unbundling of the transmission system operator

For the purpose of ensuring independence of the transmission system operator, the same person (persons) should not be empowered to simultaneously, directly or indirectly exercise control on the enterprise carrying out production or supply activities and directly or indirectly exercise control or apply any right to the transmission system operator or transmission network.

[69] Unbundling model using an Independent Transmission Operator (ITO) status envisaged ownership of the network. It was considered expedient to use this model only for the power sector of Georgia

At the same time, it should be mentioned that if shareholders of a vertically integrated enterprise and the transmission system operator are state authorities (for example, Ministry, self-governing authority or other public institution), they must be authorities of various accountability, one of which exercises control on the transmission system operator and the other one exercises control on the enterprise which carries out production, supply or other competitive activities (see the Figure 4.6). Under the conditions of Georgia, this provision limits the possibility of control of the transmission system operator and the network owner enterprise carrying out competitive activities by the same Ministry (state organization).

Independent System Operator (ISO) is obliged to:

1. demonstrate that it possesses the required financial, technical, physical and human resources to carry out the functions and responsibilities of the transmission system operator defined by Law;

2. Prepare and fulfil the 10-Year Transmission Network Development plan and the respective investment decisions;

3. demonstrate its ability to perform its obligations under Articles 47 and 48 of the Law, which define obligations of the Independent System Operator. For this purpose, it must submit a draft lease agreement agreed with the network owner.

Independent System Operator is responsible for:

- operation, maintenance and development of the transmission ststem, as well as ensuring long-term capacity of the system and planning investments for the infrastructure development;

- granting access to and management of a third party, which includes collection of connection and congestion cost;

- other activities envisaged by law, which are related to effective functioning of the system.

The Law defines the rights and obligations of the transmission network owner. In particular, the transmission network owner (TNO) must:

1. cooperate and support the Independent System Operator in performing its functions, including delivery of all relevant information;
2. make investments which the Independent System Operator has decided to carry out in cooperation with the network owner and the commission and in agreement with the

Ministry or give consent regarding making these investments by another stakeholder, including the Independent System Operator[70];

3. ensure fulfillment of responsibilities related to network assets except those related to functions of the Independent System Operator.

At the same time, the transmission network owner which is a part of a vertically integrated enterprise, must be independent, at least in terms of legal form, organization and decision-making from any activities not related to transmission, distribution and storage. The following criteria will be used for achievement of such independent goal:

1. The persons responsible for management of the transmission network owner must not participate in the company structure of the integrated enterprise which is directly or indirectly responsible for daily activities of production, distribution and supply;
2. Adequate measures must be taken for the purpose of considering professional interests of persons responsible for management of the transmission network owner to ensure possibility of their independent action;
3. The transmission network owner may create a compliance program which establishes the measures to be taken for avoidance of a discriminatory action and ensures monitoring of their performance. The compliance program must define specific obligations of employees. The person or entity responsible for monitoring of the compliance program prepares an annual report of taken measures which will be published.

Considering consultations with experts of the Energy Community, the existing long-term contracts, ensuring supply security of the country and international commitments of key plaers of the natural gas market of Georgia, it may be considered expedient to establish the "Independent System Operator" (ISO) on the basis of the current system operator – Georgian Gas Transportation Company and transfer the main gas pipeline network into ownership of a newly established company, subsidiary of a vertically integrated enterprise, Georgian Oil and Gas Corporation, which will be independent, in terms of legal form, organization and decision-making, will not participate in activities not related to transmission, distribution and storage. In addition, it must be necessary to subordinate the transmission system operator and pipeline owner companies to various state agencies in terms of property and management.

[70] Before giving such consent, consultations will be held with the transmission network owner and other stakeholders

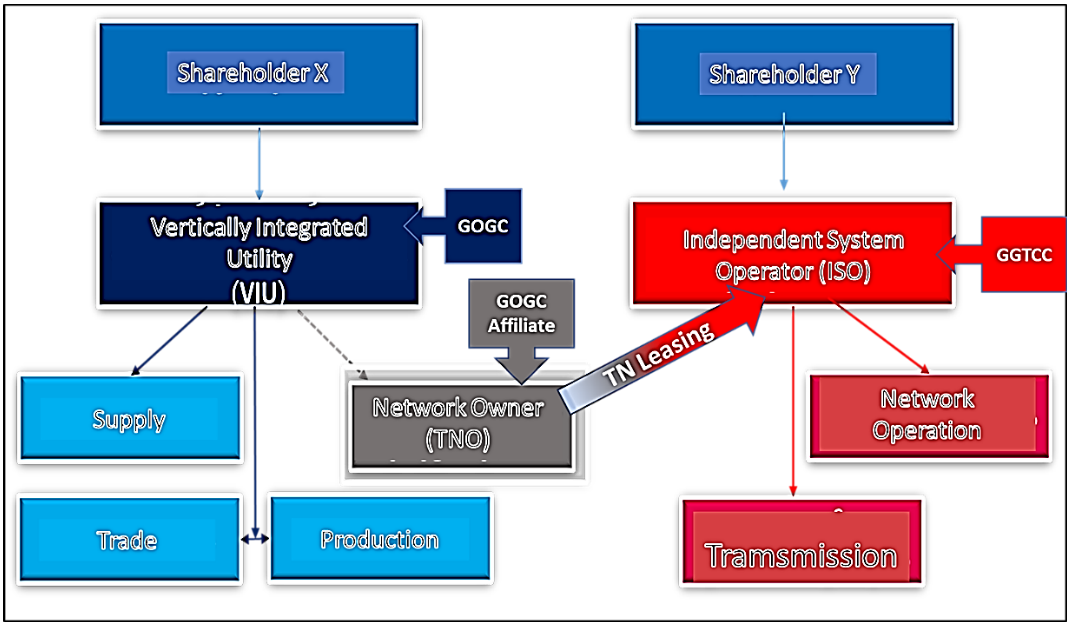

Figure 4.6. Separation by the Independent System Opetator model

According to the transitional provisions of the Law, transportation licensee must prepare and submit the unbundling plan not later than October, 2021.

In case of Distribution System Operator (DSO), division may be performed by means of legal, functional or financial report unbundling:[71]

- Legal division envisaged establishment of independent legal entities: Distribution System Operator and retail supply companies on the basis of the currently existing integrated company of distribution and retail supply;
- In case of functional division, Distribution System Operator is prohibited from participating in any activities of the integrated enterprise, such as, production and supply and its management must have a right to make effective decisions in connection with operation, protection and development of the network;
- In case of division/separation of reports, Distribution System Operator will be required to submit financial reports on distribution activities separately.

The Law defines responsibilities of the Distribution System Operator which includes ensuring effective functioning of the network and providing a non-discriminatory and unlimited access to the distribution system, elaboration of the network development and investment plans and the network rules etc.

[71] Small size DSOs which serve less than 100,000 consumers may be released from the division obligation.

4.5. OTHER IMPORTANT PROVISIONS OF THE LAW

Security of supply

The Law establishes measures for the purpose of providing such level of security of supply which ensures proper functioning of power and natural gas sectors. Law also establishes a legal framework which defines the supply security policy, commitments of market players and procedures of ensuring supply security, considering compliance with requirements of the competitive electricity and natural gas markets.

Issues of security of natural gas supply are reviewed following the requirements of Directive 2004/67/EC concerning measures to safeguard security of natural gas supply and implemented later Regulation (EU) No 994/2010 concerning measures to safeguard security of gas supply, which include:

- Measures related to security of supply;
- National emergency plan;
- Emergency situation in gas sector and conditions of restriction of gas supply;
- Monitoring of security of gas supply.

Implementation of measures of gas supply security implies: identification of protected consumers, identification of various risk groups (risk assessment), identification of risk reducing measures, including the planned measures of affecting the unscheduled termination of supply, particularly, under conditions of peak demand on gas etc.

The law governs the level of adequate liquidity of natural gas reserves, the volume of gas to be extracted from the storage and level of extraction, capacity of interconnectors connecting to the systems of neighbor countries and/or need of construction, balance between demand on and supply of gas, information about long-term import agreements etc.

Protection of consumer rights

The law defines a concept of "vulnerable consumer", which implies a category of consumers defined by a competent national authority due to the social status or state of health, who have been granted a right to use the system and/or be supplied with natural gas on special conditions. At the same time, the national regulatory authority, together with other authorized entities of state, must ensure efficiency of measures of protection of rights of vulnerable and other consumers granted by law to guarantee receipt of fair and non-discriminatory, high quality services and prevention of actions against competition.

Licensing

It is considered mandatory to obtain a license to carry out some energy activities envisaged by law. A license seeker, in addition to the requirements established by the Law of Georgia "On Licenses and Permits", together with the license application must submit to the Commission the documents confirming possession of equipment required for carrying out of specific energy activities and providing related services to market participants by the right of possession or on other legal grounds or as applicable, the documents confirming the possibility of outsourcing of such equipment and/or equipment for related operational or maintenance services. The licensed grants the respective licensee an exclusive right to carry out these activities on a definite territory.

Natural gas storage

Particular importance is attached to inclusion of issues related to operation of natural gas supply in the new Law on Energy. According to the Law, natural gas storage must be operated by the storage system operator (SSO) in accordance with the conditions defined by the Law, other respective laws and/or other legal acts, which govern the energy sector of Georgia.

Natural gas storage system operator must be independent, at least in terms of legal form, organization and decision-making from any activities not related to natural gas transmission, distribution and storage. The following minimum criteria must be used for the purpose of ensuring independence of the natural gas storage system operator.

1) the persons responsible for management of the natural gas storage system operator must not participate in the company structure of the natural gas integrated enterprise which is directly or indirectly responsible for daily activities of production and supply.
2) Adequate measures must be taken for the purpose of considering professional interests of persons responsible for management of the natural gas storage system operator to ensure possibility of their independent action.

Natural gas storage system operator, independently from an integrated natural gas enterprise, must have effective decision-making rights in connection with assets required for the purpose of operation, maintenance or development of the gas storage equipment. At the same time, existence of respective coordination mechanisms mainly related to proceeds from assets also should not be excluded for the purpose of ensuring protection of economic and managerial supervision rights of the founder company (for example, a vertically integrated company). This should allow the founder company to approve financial plans of the natural gas storage system operator and establish restrictions on the level of its indebtedness. At the same time, the founder company is not authorized to give instructions in connection with making separate decisions on daily activities or construction or improvement of natural gas storage equipment which do not go beyond the approved financial plan.

The law provides functions of the natural gas storage system operator, transparency requirements, organization of admission of a third party and service-related issues, capacity distribution and overload management procedures etc.

Considering the preliminary analysis results and peculiarities of the natural gas sector of Georgia, it is implied [93] that assumingly, the tariff of admission to the gas storage will be regulated by GNERC, and suppliers will be obliged to ensure storage of sufficient gas for protected consumers in expected critical situations and accordingly, they will have a guaranteed priority access to gas storage capacities. The remaining capacity of the gas storage will be used for commercial purposes and the right of access to this capacity will be established through an auction. Gas storage expenses will be reflected in the end consumer tariff, assumingly, as an independent (so-called safety) component.

Implementation of models of the natural gas market, unbundling of monopolistic and competitive activities, institute of suppliers and other models offered by the Law on Energy and Water Supply of Georgia ensures obtaining of the following significant advantages:

- Formation of an open and competitive gas market in the deregulated (commercial) sector;
- Market transparency and fair tariffs in the mandatory public service (social) sector with justified subsidies;
- Liquidation of critically high market concentration and restriction of actual monopoly of the dominant supplier(s);
- Fair distribution of revenues between market participants and guaranteed profitability of all energy companies in the sector;
- Facilitation of market diversification, together with restriction of possible monopolistic tendencies of new players;
- Simplification of attraction of investments;
- Economic and technological integration into European structures.

At the same time, the introduction of the new Law without corresponding secondary legislation drafted for the purpose of determination of the market structure, in compliance with the energy security of the country, creates a threat of serious risks. This is first of all connected with the possibility of uncontrolled access of an undesirable importer to the gas market, which may be used to the detriment of the security of the country. In particular, for the purpose of prevention of risks associated with security, it is expedient to limit the presence of state companies of the foreign countries on the market and the obligation of mandatory sale of part of imported gas through a trading platform, with transparent conditions and through the transactions, similar to the practice applied in the international practice.

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Professor Gochitashvili earned his Doctor of Sciences Degree at Moscow Mining Institute in 1988. He has extensive scientific, engineering and managerial experience in fields of Energy Policy, Natural Resources Management and Pipeline Transport for nearly 50 years, he is the author of more than 200 publications including scientific articles, manuals, monographs, etc.

Prof. Gochitashvili has been involved in various academic and research activities at universities and scientific institutions of Georgia and foreign countries, has managed the development of various engineering projects, including planning, design, and implementation of significant strategic projects of main transmission pipelines of Georgia, underground gas storage, thermal power plants, etc., participated in negotiations associated with the transit projects of the Caspian oil and gas through the territory of Georgia. Teimuraz Gochitashvili participated in the formulation of energy strategy and legislation in the relevant fields while working for the Georgian Parliament and Governmental Bodies as an Expert-Consultant. In 2007, Teimuraz Gochitashvili joined the Georgian Oil and Gas Corporation, holding positions of Advisor, Chairman of the Supervisory Board, Technical Director, Commercial Director, Head of Strategic Planning Department.