Prospects of LNG Markets in the Eastern Partner Countries

Final Report

January 2020

Stantec

This document has been prepared under the terms of the European Union funded project PI/2019/406-588/1.

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Luxembourg: Publications Office of the European Union, 2020

PDF ISBN 978-92-76-17892-7 doi: 10.2833/985888 MJ-02-20-245-EN-N

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BASIC PROJECT DATA

Project Title	Technical expertise to assess the prospects of LNG markets in the Eastern Partner countries	
Project ref.no	PI/2019/406-588/1	
Service contract no	2019/406588	Contracting Authority: European Commission (FPI) Contact persons: Marion Schiller-Probst/ Ewelina Hartstein DG ENER A.3.E-mail: marion.schiller-probst@ec.europa.eu Ewelina.HARTSTEIN@ec.europa.eu Swati Sain Gupta FPI.4 E-mail: Swati-Sain.Gupta@ec.europa.eu
Date of contract signature	15.05.2019	Contractor's name and address: Stantec SA/NV Address: Nysdam Office Park, Avenue Reine Astrid 92, B-1310 La Hulpe, Belgium
Contract Duration	8 Months	Contact person: Ozlem Duyan Telephone number: +32 2 655 22 72 E-mail: Ozlem.Duyan@stantec.com
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Annexes

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LIST OF ACRONYMS

ACB	Ananiev-Cernăuți-Bogorodcianî Pipeline
ACER	Agency of the Cooperation of Energy Regulators
ACG	Azeri-Chirag-Gunashili Pipeline
ADR	Accord européen relatif au transport international des marchandises Dangereuses par Route
AERA	Azerbaijan Energy Regulatory Agency
AGRI	Azerbaijan-Georgia-Romania Interconnector
ANRE	National Energy Regulatory Agency
ATI	Ananiev-Tiraspol-Ismail Pipeline
Bcm	Billion Cubic Meters
BELAZ	Belarusian Automobile Plant
BP	British Petroleum
CAPEX	Capital expenditure
CBA	Cost Benefit Analysis
ChNG	Chornomornaftogaz
CHP	Combined heat and Power
CNG	Compressed Natural Gas
DESFA	Hellenic Gas Transmission System Operator S.A.
DG	Directorate-General
DSO	Distribution System Operator
EC	European Commission
EIA	Energy International Agency
ENPV	Economic Net Present Value
ENTSOG	European Network of Transmission System Operators for Gas
ERR	Economic Rate of Return
EU	European Union
EUD	European Union Delegation
FSRU	Floating Storage Regasification Unit
FWC	Framework Contract
FID	Final Investment Decision
GCV	Gross Calorific Value
GDP	Gross Domestic product
GEOSTAT	National Statistics Office of Georgia
GGTC	Georgian Gas Transportation Company

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GHG	Green House Gas
GIPL	Gas Interconnection Poland–Lithuania
GNERC	Georgian National Energy and Water Supply Regulatory
GOGC	Georgian Oil and Gas Corporation
HFO	Heavy Fuel Oil
HH	Households
IMO	International Maritime Organization
IP	Interconnection Point
JRC	Joint Research Centre
JSC	Joint-Stock Company
KE	Key Expert
L-CNG	Liquified-to-Compressed Natural Gas
LFO	Light Fuel Oil
LLC	Limited Liability Company
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
MAZ	Minsk Automobile Plant
Mcm	Million Cubic Meters
MGO	Marine Gas Oil
NEURC	National Energy and Utilities Regulatory Commission
NGVA	Natural & bio Gas Vehicle Association
NPP	Nuclear Power Plant
OCh	Odesa-Chișinău Pipeline
OPEX	Operation expenditure
PECI	Project of Energy Community Interest
PSO	Public Service Obligation
PSRC	Public Services Regulatory Commission
RI	Razdelinaia-Ismail Pipeline
SCP	South Caucasus Pipeline
SCPX	South Caucasus Pipeline Extension
ȘDKRI	Șebelinca-Dnepropetrovsk-Krivoi Rog-Ismail Pipeline
SOCAR	State Oil Company of Azerbaijan Republic
SoS	Security of Supply
SSLF	Small Scale Liquefaction Facility
SSO	Storage System Operator
TL	Team Leader
TPA	Third Part Access

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TPAO	Turkish Petroleum Corporation
TPP	Thermal Power Plant
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
UGS	Underground Gas Storage
UGS	Underground Gas Storage
UGV	Ukrgasvydobuvannya
UN	United Nations
UTG	Ukrtransgaz
VAT	Value Added Tax
VoLL	Value of Lost Load

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Executive Summary

Introduction

In May 2019, DG Energy commissioned Stantec to carry out a Study to assess the prospects of developing LNG markets in Eastern Partner countries, so as to enhance the cooperation and further the energy market integration between the Eastern Partner and the EU. The Study was specified in the Concept Note for the Eastern Partnership LNG Network Group that was established with the aim to assess the economic and political opportunities for LNG in the Eastern Partner countries. The specific objectives of the Study include the formulation of recommendations for development of LNG markets country-by-country and for the region as a whole, and the identification of actions that improve market functioning, competition, new infrastructures, and foster cooperation within the Eastern Partnership region. This is the summary of the Final report of the Study that was completed in January 2020.

LNG Market Development Options

The Study involved the Consultants in identifying potentially applicable options for LNG market development for each Eastern Partner country, based on characteristics and market conditions relevant to each country. Not all gas-to-other fuels competition options are applicable to all Eastern Partner countries.

Applicable LNG options are grouped under two broad categories, those enabling gas-to-gas competition and those enabling gas-to-other fuels competition. Gas-to-gas competition occurs when (regasified) LNG competes against natural (piped) gas for customers that are connected to the gas transmission system. In gas-to-other fuels competition, LNG competes with other fuels (diesel, MGO, HFO etc.) for customers that do not currently use gas and are not connected to the gas network. Depending on the end-use, LNG may be used by customers in liquid form (e.g. as fuel for trucks) or regasified and used in gaseous form (e.g. by off-grid consumers).

There are several options with which LNG may be introduced to a country in the case of gas-to-gas competition; one option is for LNG to be sourced from a third-country terminal, and transported to the Eastern Partner country in regasified form through pipes for final consumption by target customers. Another option is for an LNG receiving terminal to be built in an Eastern Partner country with sea access to supply regasified LNG to customers connected to the gas network. Alternatively, LNG either from the in-country or outside country terminal can be transported via trucks or rail to grid connected customers, as 'virtual' gas pipelines. Swaps are also a possibility for introducing LNG, in case it is feasible to do so contractually and economically. For example, for an Eastern Partner country with no sea access to purchase LNG for physical delivery to a terminal in another country, and another party to off-take this LNG in exchange for piped gas that is physically delivered to the Eastern Partner country concerned.

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In the case of gas-to-other fuels competition, LNG is used directly as a fuel by trucks, or by ships or by agricultural and mining customers who can use LNG as fuel for processes (e.g. drying etc.) or heavy equipment (tractors, graders etc.). One common feature in these end-uses is the need for 'virtual' gas pipelines delivering LNG to filling stations or to the customer's storage facility. Alternatively, regasified LNG can be used by different types of off-grid customers (industrial, commercial, remote towns etc.) for various needs that were traditionally fulfilled by alternative fuels e.g. heating, drying, turbines, furnaces etc.). In these cases, customers are required to have regasification facilities.

Approach

The work involved research into Eastern Partner countries, and particularly their gas and energy markets, and identification of potentially applicable LNG market development options. Field visits were undertaken to all Eastern Partner countries from June to September 2019. The objective was to discuss with key stakeholders in each country the current situation and prospects for developing markets for LNG, their policies and interests, and barriers and prerequisites for LNG market development, to reach a consensus on the LNG options deemed potentially applicable for each Eastern Partner Country and merit further analysis. During the field visits the Consultants presented information to enhance gas stakeholders' awareness on EU LNG strategy, market development, demand, supply, prices and key infrastructure, operational modalities of LNG terminals and 'virtual' gas pipelines involving LNG.

The applicable LNG options that were identified following the field visits for further analysis are shown in the following Table. The options were presented to and confirmed with Eastern Partner countries representatives during the third Eastern Partnership LNG Gas Network Workshop in Kiev, in September 2019.

		Armenia	Azerbaijan	Belarus	Georgia	Moldova	Ukraine
Gas-to-Gas Competition	1. Supply of regasified LNG with pipelines					✓	✓
	2. LNG receiving terminal				✓		✓
	3. LNG supply via trucks (or trains)						✓
	5. Swaps				✓		
Gas-to-Other Fuels Competition	1. LNG-fuelled trucks	✓	✓	✓	✓		✓
	2. LNG-fuelled ships		✓	✓			✓
	3. Off-grid consumets (e.g. agriculture, mining)						✓
	4. Off-grid distribution systems		✓		✓		
	5. Replacement of old distribution pipes with LNG supply						✓
	6. Exploitation of remote gas fields						✓
	7. Peak shaving LNG storage					✓	
	8. LNG-fuelled locomotives						✓

The Consultants proceeded to analyse the price competitiveness of the applicable LNG market development options for each country, using Netback Analysis, with the objective of identifying the options that are deemed economically viable. The Netback Analyses carried out are high-level, using proxies of actual costs and based on international benchmarks and assumptions. In cases where market demand data were not available and netback analysis could not be reasonably performed, the analysis focused on identifying the 'breakeven' demand in the Eastern Partner country that could render the option viable under assumed price and cost conditions throughout the supply chain.

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The results of the Netback Analysis, as well as the underlying assumptions were included in the November 2019 Interim report of the Study that was shared with Easter Partner countries for views and comments. Feedback and additional information provided by the Eastern Partner countries, as well as during the fourth Eastern Partnership LNG Gas Network Workshop in Świnoujście in December 2019 were taken into account in the Final Report. The Study includes a high-level Cost Benefit analysis for selected LNG options, to assess additional benefits accruing to economy and society. This CBA was carried out for all potentially applicable gas-to-gas competition LNG market development options in each Eastern Partner country, and for those gas-to-other fuels competition options deemed to be economically viable in each Eastern Partner country. Furthermore, the Consultants analyzed and highlighted all key prerequisites and success factors for the implementation of viable LNG options, and formulated proposals for the prioritization of economically viable options in each country and for the actions that need to be taken by policy makers in each country to foster development of the selected options. Regional perspectives for LNG market development are also included in the Final Report, together with relevant regional and sub-regional policy initiatives and joint EU-Eastern Partners countries actions that could be undertaken.

Findings

Armenia

The use of LNG as engine fuel for trucks is the only applicable option identified for Armenia. Supply of LNG in Armenia is possible through the development of an in-country mini liquefaction facility, or in case, an LNG receiving terminal with truck loading facilities is developed in Georgia.

The analysis performed shows that the LNG option using an in-country mini liquefaction facility, which requires significant infrastructure investments, is potentially viable for Armenia in case at least 340 LNG-fuelled trucks refuel in the country (corresponding to approx. 15,300 m^3 LNG/yr). Supplies from a potential LNG receiving terminal in Georgia lower the supply chain costs, and thus a smaller minimum market size of at least 135 LNG-fuelled trucks (approx. 6,000 m^3 LNG/yr) is necessary for the option to be attractive. However, establishment of a supply chain based on the terminal is beyond Armenia's control, as the infrastructure is subject to a decision by Georgian stakeholders, and dependent on a number of factors controlled by external parties.

Regardless of the source of LNG, the interest of sufficient truck owners to switch to LNG, and the attraction of investments to develop filling stations are critical to initiate a market for the use of LNG as engine fuel for trucks.

Development of an LNG supply chain using a mini liquefaction facility could be done in a short-term horizon, as it only involves decisions by local actors. In contrast, supplies of LNG from a receiving terminal in Georgia are assessed to be longer-term, due to uncertainties surrounding the terminal investments.

Considering that Armenia has a sizable fleet of trucks involved in local, regional and international transport, the minimum number of trucks required for viability of the option appears feasible at first sight and therefore this option merits further investigation, to assess its feasibility in detail.

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The policies and actions to facilitate development of the market, could encompass the formulation of a national policy framework for the use of LNG in trucks, ensuring that the legal and regulatory framework conducive to the development of an LNG supply chain, and consideration of incentives to promote the use of LNG.

Azerbaijan

The use of LNG as engine fuel for trucks, with LNG supplied from an in-country mini liquefaction facility, is an applicable option identified for Azerbaijan. However, the very low, subsidised, diesel price is an obstacle for LNG competitiveness, and costs for developing an LNG supply chain cannot be recovered.

The use of LNG as engine fuel for ships operating in the Caspian Sea, by developing LNG bunkering infrastructure in the Baku port, is another potentially applicable option. The attractiveness of switching to LNG should be examined on a case-by-case basis, for each individual case of ship, as it depends on a number of vessel-specific factors (size and type, age, service area, fuel used, refuelling pattern, prices of competing fuels, etc.). Such a detailed analysis should be undertaken in the future, in case the Government of Azerbaijan decides to pursue this option.

Although Azerbaijan has 95% coverage of population through its current network, the Government of Azerbaijan is interested in the option of establishing LNG virtual pipelines to supply gas to off-grid remote areas, within the frame of its target of 100% gasification of the country. This option was not analyzed in this Study, as no data was made available on the fuel consumption and demand characteristics of remote areas.

In case the Government decides to move ahead with the development of LNG options for environmental reasons, it should examine in detail the options, and formulate appropriate policies and actions to promote LNG. Such policies and actions should, at a minimum, establish a framework making LNG more attractive (e.g. subsidizing LNG prices or lifting prices for diesel), perform the legislative and regulatory changes necessary to allow development of an LNG supply chain, and undertake initiatives to promote the use of LNG.

Belarus

The use of LNG as engine fuel for trucks is an option that could be potentially viable for Belarus, in case LNG is sourced from the reloading station in Klaipeda (the closest facility to the country) and price differential of LNG and diesel remains at current levels. In this case, over 200 LNG-fuelled trucks would need to refuel in the country (corresponding to approx. 9,300 m^3 LNG/yr) for the LNG market to develop. Considering that Belarus has a sizeable fleet of local and imported international long haulage trucks, and local manufacturing of LNG-fueled trucks could lower switching costs, the minimum market size appears to attainable at first sight and therefore merits more detailed examination.

The LNG option could be developed over a short-term horizon, provided that truck owners are interested to switch to LNG, and investments in filling stations are implemented. To promote the

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establishment of the LNG market, the Government could formulate a national policy framework for the use of LNG in transport, and undertake actions, aiming to establish a legal and regulatory framework conducive to the development of an LNG supply chain and to providing incentives for the use of LNG.

Another potentially applicable option is the use of LNG as engine fuel for vessels operating in the Belarusian waterways, by developing LNG bunkering infrastructure in inland ports of Belarus. The applicability of the option appears to be limited, due to the small size and limited utilization of vessels vis-à-vis investment requirements. Nevertheless, in case the Government's policy priorities for the shipping sector promote LNG, it should undertake contextualized analysis, to identify whether there are any types of vessels for which switching to LNG may be attractive.

Georgia

The swap of regasified LNG landing at a terminal in Turkey, Greece or Italy with piped gas delivered to Georgia through its offtake of the SCP is a potential option that could provide Georgia with indirect access to LNG. This option is conditional upon the interest by the involved parties to conclude a swap deal, the availability of LNG at prices that are conducive to the viability of the exchange, and the lack of any contractual barriers that would obstruct access to the SCP. In case these conditions are met, negotiations for swaps with relevant stakeholders could be quickly initiated, as the option does not require development of new infrastructures.

Development of an LNG receiving terminal in Georgia, is a potentially viable option only in case the price differential between LNG and piped gas imports is at least 35 EUR/1000 m^3 (for high utilization of the terminal) or at least 85 EUR/1000 m^3 (for low utilization of the terminal). These conditions cannot be met under the current market situation, but could be triggered in case of price hikes in the new supply contracts with Azerbaijan, which are due to renewal after 2026. A critical/on-off prerequisite for the implementation of the terminal is the absence of any constraints for LNG vessels to pass through the Bosporus Straits, while key prerequisites for establishment and viability are the commitment of sufficient market players to use the terminal (so as to achieve high capacity utilization), and the availability of financing. On account of these conditionalities, the terminal is a long-term option, the final condition for which would require conclusion of negotiations with Turkey for the passage of LNG vessels through the Straits, and a successful binding market test securing market interest.

Development of a liquefaction and export terminal in Georgia, receiving gas from Azerbaijan and potentially Central Asia, is an option for LNG supplies to other Eastern Partners, particularly Ukraine and Moldova, provided that a receiving terminal is developed in Ukraine. Critical/on-off prerequisites for developing this infrastructure are the availability of sufficient long-term supply of Caspian gas to the terminal and long-term sales contracts of the produced LNG to customers. As all Azeri gas production from developed fields has already been contracted and there is no access to supplies of gas from Central Asia, the liquefaction terminal could only be considered in a long-term horizon. Furthermore, the high-level analysis performed has shown that for the supply of LNG to be viable in Ukraine, the price of Caspian gas at the liquefaction terminal would have to

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be under 115 EUR/1000 m^3, i.e. 85 EUR/1000 m^3 lower than the current import price of Azeri gas in Georgia.

The use of LNG as engine fuel for trucks is a potentially viable option for Georgia. In case a receiving terminal is developed, the option could develop with a market of only a60 LNG-fuelled trucks (corresponding to approx. 2,800 m^3 LNG/yr), while a minimum of 100 trucks would be required in case LNG is sourced from a liquefaction and export terminal (approx. 4,600 m^3 LNG/yr). Due to the uncertainties linked to the development of both the aforementioned terminals and the long term maturity of such investments, the LNG market could be established within a shorter-term horizon, in case a mini liquefaction facility is developed; however, in this case a large number of trucks is required for viability of the option (280 trucks, corresponding to approx. 12,600 LNG/yr), due to the higher costs of the supply chain. Similar to other countries, the interest of sufficient truck owners to switch to LNG, and the attraction of investments to develop filling stations are critical to initiate the LNG option. Considering that Georgia is a regional trade and transit hub, though its ports, the minimum number of trucks required appears feasible at first sight and therefore this option merits further investigation, to assess in detail its feasibility. The Government could consider formulating appropriate policies and actions to promote LNG in transport, including a national policy framework for the use of LNG in road transport, legal and regulatory changes to allow development of an LNG supply chain, and provision of incentives to promote switching to LNG.

Another applicable option identified for Georgia is the supply of LNG to off-grid remote areas targeted for gasification. This option is considered non-viable, as due to the low price of firewood (the main competing fuel in these regions), switching to natural gas is not competitive.

Moldova

The supply of regasified LNG from neighbouring EU LNG terminals is an applicable option identified for Moldova. Although the option is not viable, due to the low gas price in the Moldovan market, that renders LNG non-competitive, the supply of regasified LNG, even at small volumes, offers a new source that can have a significant impact in the country's security of supply. The option could be implemented over a short-term horizon, as it does not require development of a new infrastructure, and could merit further examination from the Moldovan stakeholders, from a security of supply perspective.

LNG imports through a Ukrainian receiving terminal (with LNG either coming through the Bosporus Straits or liquefied at a terminal in Georgia) could also enhance Moldova's security of supply. However, this option is heavily dependent upon the significant uncertainties of the Ukrainian terminal development.

Another applicable option identified for Moldova is the use of LNG for peak shaving at the country's CHP stations as a back-up supply source. This option, albeit not being viable, as it does not provide a competitive source to piped gas, can potentially enhance security of energy supply. In this respect, the economic costs and benefits for developing this option should be considered (such an analysis was not carried out within the frame of this Study, due to lack of relevant data).

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Ukraine

The supply of regasified LNG from neighbouring EU LNG terminals is an applicable option identified for Ukraine. Viability of the option requires the spread between LNG price at the terminals and prices of imported supplies from existing sources to be at least of the order of 40 – 50 EUR/1000 m^3 (depending on the route). It is marginally viable in case the LNG price is around 200 EUR/1000 m^3, and import prices in Ukraine are close to historic winter prices. However, in case the spread between LNG and import prices is wide enough, the market may procure LNG on an opportunistic basis.

Development of an LNG receiving terminal in Ukraine is only viable in case there is a price differential of at least 30 EUR/1000 m^3 between LNG supplies arriving at the terminal and imports from EU, and a high terminal utilization (over 50%) is secured. A critical/on-off prerequisite for the implementation of the terminal is the absence of any constraints for LNG vessels to pass through the Bosporus Straits, while key prerequisites for establishment and viability are the commitment of sufficient market players to use `the terminal (so as to achieve high capacity utilization), and the availability of financing. On account of these conditionalities, the terminal is a medium to long-term option, the final condition for which would require conclusion of negotiations with Turkey for the passage of LNG vessels through the Straits, and a successful binding market test securing market interest.

Another option examined, aiming at gas-to-gas competition, is the supply of LNG via trucks to consumers currently connected to the transmission system. Analysis has shown that this option is not viable, as the costs associated with this LNG supply chain render a regasified LNG price which is not competitive compared to piped gas.

The use of LNG as engine fuel for trucks, with LNG sourced from the neighbouring terminals is a potentially viable option for Ukraine, requiring a market of at least 60 LNG-fuelled trucks refuelling in the country (corresponding to approx. 2,700 m^3 LNG/yr). As Ukraine appears to have a sizable international long-haul traffic (export/imports and transit) the minimum market size seems to attainable at first sight and therefore merits more detailed examination. The LNG option could be developed over a short-term horizon, provided that truck owners are interested to switch to LNG, and investments in filling stations are implemented. To promote the establishment of the LNG market, the Government could formulate a national policy framework for the use of LNG in transport, and undertake actions, aiming to complete the legal and regulatory framework conducive to the development of an LNG supply chain and to providing incentives for the use of LNG.

The use of LNG as engine fuel for ships operating in the Black Sea and Ukrainian waterways is another potentially applicable option for Ukraine. This option would nevertheless require stakeholders to undertake contextualized analysis, as LNG use is not appropriate for all ships and would depend on technical considerations, utilization and fuel economics and environmental requirements. This option could be developed over a medium-term horizon, as it would require involvement and large investments from ship owners for a diverse number of vessels.

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Supply of LNG to individual off-grid consumers in Ukraine (such as small to medium agriculture, construction or mining sites) can be viable under conditions, and should be assessed on a case-by-case basis, as viability depends on the number, size and characteristics of these consumers. Switching to LNG is primarily the consumer's decision, and can be implemented over a short-term horizon, as LNG can be sourced from existing terminals. To facilitate the development of LNG supply chains, the Government policy should aim to completing the legal and regulatory framework conducive to LNG.

The use of LNG virtual pipelines as an alternative to replacement of old medium pressure pipelines in the Ukrainian distribution systems was identified as an applicable option. However, the large costs associated with developing the LNG infrastructure render this option as not viable and less attractive compared to installing a new pipeline.

Another applicable option identified for Ukraine is the use of LNG virtual pipelines to develop remote gas fields. Analysis of this option was not carried out within the frame of this Study, due to the lack of data on Ukraine's remote fields.

Regional Perspectives and Actions

Some of the identified potentially viable options for LNG market development are of interest to two or more Eastern Partner countries. An LNG receiving terminal in Ukraine can supply LNG to Moldova, and opens the way for a smaller LNG terminal in Georgia (that could also be established independently). Potential development of a liquefaction and export terminal in Georgia would allow exports of Caspian gas though the Black Sea and foster development of an alternative corridor for LNG supplies to Eastern Partner countries, notably Ukraine and Moldova. There are also opportunities for cooperation between Eastern Partner countries on smaller-scale infrastructure, such as the development of a regional network of LNG filling stations, to enhance accessibility of LNG to long-haul trucks operating in the region and provide incentives to truck owners to switch to LNG, an option which is of interest to most Eastern Partner countries (Armenia, Azerbaijan, Belarus, Georgia, Ukraine). Furthermore, the development of an LNG receiving or liquefaction and export terminal in Georgia would also allow Armenia access to LNG supplies, facilitating the development of an LNG market.

On a regional level, a number of actions can be considered to foster development of the above options, including the creation of sub-committees under the Eastern Partnership LNG Network, to facilitate dialogue, coordination and initiatives on key LNG issues (technical & standards, regulatory, market, etc.). Harmonization of rules, regulations and standards, for LNG-fuelled trucks, and for trucks transporting LNG, can also for benefit from regional coordination and cooperation, as well as the preparation of regional development plan for the establishment of LNG filling stations in the Eastern Partner countries. On a sub-regional level, Georgia and Ukraine can consider undertake joint initiatives for resolving the Bosporus Straits' constraints, whereas Armenia, Azerbaijan and Georgia can jointly consider the potential for co-development of a small-scale liquefaction facility to supply LNG to trucks in the Caucasus.

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EU and Eastern Partners Joint Actions

Eastern Partner countries would benefit from the experience, practices and lessons learned of EU LNG markets and stakeholders, and several joint actions could be considered to catalyse market development in Eastern Partner countries. These joint actions include the creation of sub-committees under the Eastern Partnership LNG Network, to facilitate dialogue, coordination and initiatives on key LNG issues (technical & standards, regulatory, market, etc.). Other actions involve the organised transfer of knowledge from EU counterparts to Eastern Partners, on LNG technologies, on the appropriate legislative and regulatory framework, technical rules and standards for all LNG related infrastructure and equipment etc. Such a transfer can be facilitated by another joint action, namely the development of a common IT platform for knowledge sharing of materials relevant to LNG markets. The experience the EU gained through the Blue Corridor initiative could also from a model case for developing a similar initiative for the use of LNG in the transport sectors of Eastern Partners. Finally, the EU can consider the possibilities to provide co-financing for selected projects of common interest through the European Network Instrument, or other financing mechanisms.

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1 Introduction and Purpose of the Study

The overall objective of the Study is to further develop the co-operation and integration between the Eastern Partner Countries and the EU in assessing and developing the potential of LNG in the gas markets of the region. Specific objectives of the Study are to:

- Assess current situation in Eastern Partners' gas markets and identify barriers for LNG;
- Formulate recommendations for development of LNG markets country-by-country and for the region as a whole;
- Strengthening awareness of gas stakeholders in Eastern Partner countries on technical, market, and regulatory aspects of LNG, and particularly the use of LNG in the EU;
- Identify specific actions to enhance trading, promote new infrastructure, improve market functioning and competition, fostering cooperation within the Eastern Partnership region;
- Further EU's Energy Dialogue with the Eastern Partner countries in the area of LNG.

During the Study, the Consultants identified potentially applicable options for LNG market development in each Eastern Partner country. Field visits were undertaken to all Eastern Partner countries, in the period of June to September 2019. The objectives of these visits were twofold:

- to enhance gas stakeholders' awareness on EU LNG strategy, market development, demand, supply, prices and key infrastructure, operational modalities of LNG terminals and 'virtual' gas pipelines involving LNG, and
- to discuss with stakeholders in each country the current situation and prospects for developing markets for LNG, the barriers and prerequisites for LNG market development, and to reach a consensus on the LNG market development options deemed potentially applicable for the country that merit further analysis.

Netback analysis was then carried out on all potentially applicable options in each country, so as to shortlist the options that are considered to be 'price competitive', and hence economically viable. Netback analysis determines what should the LNG price be at the source (LNG import terminal, small/mini liquefaction plan etc.) so that when all the costs of transporting and transforming the LNG to reach the target end consumer are added, the price of LNG to the customer is competitive compared to the price the customer pays now for alternative competing fuels.

It is noted that the netback analyses carried out in the study are high-level, using proxies of actual costs and based on international benchmarks and assumptions. All calculations have been made using latest available data concerning market prices, consumption levels and LNG supply costs. Sensitivity analysis has been used to assess the robustness of the results in fluctuations of key parameters. Dynamic supply-demand conditions were not examined, and contextualization of infrastructure costs and other parameters was limited by the available data. In cases where market demand data were not available and netback analysis could not be reasonably performed,

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the analysis focused on identifying the 'breakeven' demand in the Eastern Partner country that could render the option viable under assumed price and cost conditions throughout the supply chain. The Study analysis is thus considered preliminary, and the results and conclusions are not meant to be definitive but to highlight the LNG market development options that merit further consideration and detailed analysis by the Eastern Partner countries to assess in full their viability and to formulate their policies accordingly.

A high-level Cost Benefit analysis was carried out for selected LNG options, to assess the benefits accruing to economy and society. CBA was carried out for all potentially applicable gas-to-gas competition LNG market development options in each Eastern Partner country, and for those gas-to-other fuels competition options deemed to be economically viable in each Eastern Partner country. Key prerequisites and success factors for viable options are highlighted, and a proposed prioritization of the economically viable options and the actions that need to be taken, in terms of timing and ease of implementation, is provided for each Eastern partner country. Regional perspectives for LNG market development are considered, and relevant policy initiatives and joint actions are also proposed.

Finally, we would like to note that the LNG industry is undergoing significant challenges related to methane emissions. Although natural gas is considered to be a 'cleaner' fuel in terms of CO2 emissions compared to oil and coal, methane emissions throughout the gas supply chain caused by leakages, releases of gas and flaring of gas, are considerable. Methane is a more potent greenhouse gas than CO2, as one tonne of methane absorbs 84 to 87 times more energy than one tonne of CO2, for the first 20 years after being emitted to the atmosphere. IEA[1] estimates 2017 methane emissions from the oil and gas sector to be close to 80 Mt (or 2.4 billion tonnes of CO2 equivalent), and considers that 45% of the methane emissions could be avoided with measures that would have no net cost. There is a high degree of uncertainty concerning the level of methane emissions from the LNG supply chain, due to lack of data. Methane emissions from the LNG supply chain could be higher than natural gas, in case there are inefficiencies of treatment of 'boil-off gas' during the LNG liquefaction, transport and storage processes. Additionally, emissions of unburnt methane (known as the 'methane slip') occur during LNG end-use as fuel (LNG powered ships and trucks). The challenges faced by the LNG industry to reduce methane emissions, and the relevant dilemmas facing policy makers regarding the environmental standing of LNG vis-à-vis other fuels, are outside the scope of this study.

[1] IEA, Tracking Fuel Supply, Methane Emissions from Oil and Gas, November 2019

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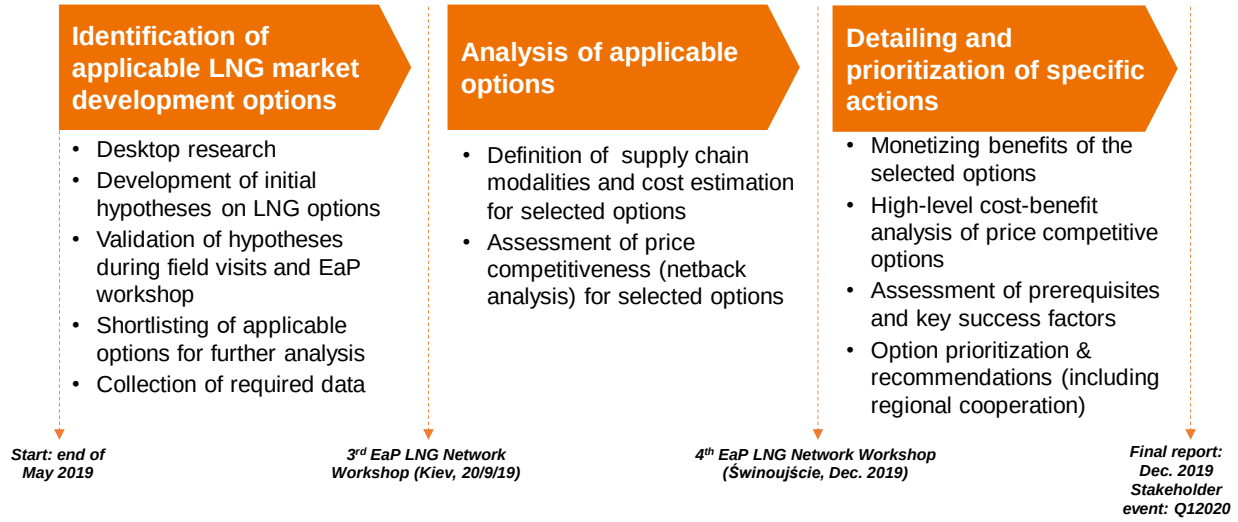
2 Methodological Approach

In this Section, we discuss our methodological approach to implementing the Study. More detailed elements concerning the Netback Analysis are provided in Annexes 2 and 3.

The overview of the approach is shown in Figure 1 below. The main methodological steps and their sequence are described next.

Figure 1 Overview of methodological approach



2.1 Identification of applicable options for LNG market development per country

Hypotheses on potential options for LNG market development were formulated for each Eastern Partner country on the basis of desktop countries analysis. These hypotheses were discussed and 'tested' with stakeholders in Eastern Partner countries during the field visits, as well as during the September Eastern Partnership LNG Network Group Workshop in Kyiv. Taking into account feedback received from stakeholders, the LNG market development options in each Eastern Partner country, considered as potentially applicable, were shortlisted for further analysis.

LNG market development options for each country are grouped under two different categories. The first category concerns gas-to-gas competition, i.e. cases where LNG could compete against natural (piped) gas for customers that are connected to the gas transmission system. In this category, LNG constitutes an additional supply source or supply route of gas for the country. Gas-to-gas competition requires LNG to be regasified before it is used by final customers.

The second category involves LNG in competition with other fuels, for customers that currently do not use gas and are not connected to the gas network. Depending on the use, LNG may be directly used by customers in its liquid form (e.g. use in transport as fuel for trucks) or regasified and used in gaseous form (e.g. by off-grid consumers). In gas-to-other fuels competition, LNG would have environmental benefits (reduction of GHG emissions) in case LNG is used in the place

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of more polluting fuels (e.g. diesel, heating oil, LFO/HFO etc.). For Gas-to-other fuels competition options to be potentially applicable in any Eastern Partner country, LNG (or gas derived from LNG) has to be competitive against prices of competing fuels.

Table 1 lists the main LNG development options under each of the two cases[2].

Table 1: LNG Market Development Options under Gas-to-Gas and Gas-to-Other Fuels Competition

Competition Case	Options for introducing LNG to the market	Main Uses of LNG	LNG Benefits
Gas-to-gas competition	• Pipelines (receiving gas of LNG origin) • LNG receiving Terminal with regasification facility • LNG trucks and trains supplying LNG to existing natural gas grid-connected customers) • Swaps (pipeline gas for LNG)	• LNG is regasified and transported for final consumption	• Gas price reduction • Security of supply benefits (mitigating impact of disruption as a result of supplier/route diversification)
Gas-to-other fuels competition	• LNG receiving Terminal with bunkering and lorry loading facilities • LNG trucks and trains (supplying LNG to new off-grid customers) • Small Scale Liquefaction Facilities (liquification of piped gas and supply to customers via LNG trucks	• Trucks that use LNG as fuel • Ships that use LNG as fuel • Agriculture and Mining customers that use LNG to generate power for processes (lighting, drying, sorting etc.) and for moving equipment (tractors, harvesters, graders etc.) • Off-grid industrial customers, large commercial customers, sizeable gas distribution systems that can use LNG to feed their systems (regasification of LNG is required) • Old distribution systems ('virtual' gas pipeline using LNG instead of investing in replacement gas pipelines) • Remote gas production fields not connected to the gas network • Peak shaving LNG plant (combining liquefaction, storage and regasification)	• Energy cost reduction (substitution of other fuels by less costly LNG) • Environmental benefits (differential in greenhouse gas emissions by using gas as opposed to other fuels)

In the case of **gas-to-gas competition**, there are several options with which LNG may be introduced to a country. The common feature of all options is that regasified LNG is eventually supplied to grid-connected customers. One option is that LNG sourced from a terminal situated

[2] The list of LNG market development options included in the Table is not exhaustive. Other options, such as the use of LNG as engine fuel for municipal vehicles, were not identified during field visits, and thus were not analysed further in this Study.

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in another country is regasified and transported via pipeline for final consumption to the Eastern Partner country concerned. Another option is for an LNG receiving terminal to be built in the Eastern Partner country, and regasified LNG from this terminal to supply customers connected to the gas network. Alternatively, LNG from in-country or outside country terminal can be transported via trucks or rail to grid connected customers (LNG needs to be regasified at the consumption end). Finally, there is also the possibility of having swaps (pipeline gas for LNG), in case it is feasible (contractually, economically) for an Eastern Partner country with no sea access to purchase LNG for physical delivery to a terminal in another country, and another party to off-take this LNG in exchange for piped gas that is physically delivered to the Eastern Partner country concerned.

Under Gas-to-gas competition, LNG derived gas should be competitive in price against piped natural gas to induce end-users to purchase. However, even in case regasified LNG is not price competitive against natural gas, LNG could be viable in case there are security of supply benefits for the society and economy, arising from the diversification of supply source/route potential provided by LNG supplies. Such benefits are particular to each Eastern Partner country. Cost-benefit analysis is undertaken to monetise such benefits and assess whether they outweigh costs, for those Eastern Partner countries where gas-to-gas competition options are shown to be applicable.

In the case of **gas-to-other fuels competition**, the LNG development options are dependent on the uses of LNG. For the purpose of this study, we do not review exhaustively all potential uses of LNG (direct fuel) but focus on a number of key LNG uses. LNG can be used directly as a fuel by trucks, or by ships or by agricultural and mining customers who can use LNG as fuel for processes (e.g. drying etc.) or heavy equipment (tractors, graders etc.). The common feature in these uses is the need to deliver LNG to the filling stations or to the customer's storage facility. Alternatively, regasified LNG can be used by different types of off-grid customers (industrial, commercial, remote towns etc.). These customers could potentially use LNG for various needs (heating, turbines, furnaces etc) and for supplying their customers (distribution systems). The distinguishing feature for these uses is that LNG is not used directly as fuel but is regasified and the derived gas is used in internal installations. In these cases, customers are required to have regasification facilities. Additionally, gas from remote gas production fields not connected to the gas network can be liquefied and LNG can be transported to end-customers by trucks e.g. to filling stations.

Not all gas-to-other fuels competition options are applicable to all Eastern Partner countries. The use of LNG to fuel long haul trucks or ships would necessitate the country to be a hub for regional transport or to have sea access or developed waterways; supply of LNG by trucks to customers not connected to the gas network, would require the existence of sizeable off-grid customers in adequate numbers and a transport infrastructure that allows trucks to reach customers. Supply options for LNG also differ between countries. For example, establishing an LNG terminal will not be possible for countries that lack sea access. Not all countries have rail networks that can allow transportation of LNG. In some cases, there could be virtually no possibilities for receiving LNG via pipelines that are outside the control of involved stakeholders.

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Price competitiveness of LNG against other compering fuels is a key precondition for the viability of Gas-to-other fuels competition options. Another precondition is that the size of the market for the end-use should be sufficiently large to justify the investments needed in the chain of supplying LNG to the target end-users (e.g. investments in trucks, filling stations, regasification plants etc.).

The benefits of substituting current fuels with LNG to economy and society are the energy cost reduction and the environmental emission reductions associated with substitution by LNG of more polluting fuels[3]. The above benefits are particular to each use and each country and can be monetized.

2.2 Analysis of applicable options for LNG market development per country

2.2.1 Analysis of supply modalities

The designated supply chain within each Eastern Partner country and for each of the applicable LNG market development options within that country, are defined. Routes and infrastructures (existing and planned) are identified.

2.2.2 Estimation of costs involved in the supply options

For each of the applicable LNG market development options, the costs involved in the supply route are estimated. In case of established modalities (e.g. cross-border charges, transit charges, transportation of LNG by existing fleets of trucks or by existing rail-block trains etc.) relevant unit costs are assessed. In case of new infrastructures (e.g. building of a new LNG terminal, a liquefaction facility, a regasification facility, a storage facility etc), capex, opex (which together with assumptions on depreciation, rates of return and throughout volumes, determine the relevant unit costs) are estimated. For options that involve retrofitting of engines (e.g. for the use of LNG as fuel for trucks), relevant costs are assessed.

The cost assumptions used in the analysis are based on international benchmarks for similar (to the extent possible) infrastructure, and/or assumptions based on the Consultant's estimates. These costs can be taken as a proxy to actual costs, to perform a high-level assessment of the potential viability of the options, and would need to be verified or changed following detailed studies and quotes from manufacturers/suppliers.

2.2.3 Assessment of price competitiveness of supply options

This is an important part of the analysis, involving the assessment of the expected price competitiveness of LNG vis-a-vis natural gas (for the options under the gas-to-gas competition category), and vis-à-vis for other competing fuels (under the gas-to-other fuels competition

[3] Gas-to-other fuels competition has limited impact on security of energy supply, as competing fuels are either indigenous (e.g. firewood) or may supplied from large number of suppliers in competitive markets (e.g. oil products)

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category). This analysis shows which options are **economically viable**, and which are not. The assessment of price competitiveness of each supply option was done using **'Netback Analysis'.**

Netback analysis provides an answer to the question: What should the LNG price be at the source (terminal) so that, when all the costs of transporting and transforming the LNG to reach the target end consumer are added, the price of LNG to the final customer is competitive compared to the price paid for existing fuels? Netback analysis starts from the price that the end-customer pays for a fuel, and goes backward subtracting all costs involved in the LNG supply option under examination up to the source of LNG, in order to determine what should be the price of LNG at the source in order for the particular option to be competitive. In case the price that LNG should have at the source is lower than the 'market' price of LNG at the source (the current regional spot price), then the option is not economically viable, and vice versa. The LNG price at the source, which is derived from the netback analysis, is effectively the maximum price that can be paid for LNG, so that when all costs to reach the end-customer are added, the final price for LNG can be competitive against fuel prices at the end-customer level. This analysis differs for each Eastern Partner country, even for the same type of option, as competing fuels have different prices at the end-customer level and supply costs are often different for each country.

Under gas-to-gas competition, netback analysis shows the price that LNG should have at the source so that the regasified LNG can compete at the end-customer level with current natural gas. Under gas-to-other fuels competition, netback analysis shows the price that LNG should have at the source so that LNG can compete at the end-customer level with other fuels (e.g. diesel, heating oil, LFO/HFO etc.), thus leading to substitution of such fuels by LNG.

The netback analysis has been carried out on a high-level, i.e. using proxy of actual costs based on international benchmarks and assumptions. All calculations have been made using current data concentring market prices, consumption levels and LNG supply costs. Sensitivity analysis has been used to assess the robustness of the results in fluctuations of key parameters.

The detailed approaches to conducting Netback Analysis, relating to each applicable LNG Market development option in each Eastern Partner country, are provided in Annexes 2 and 3.

2.3 Detailing and prioritization of specific actions

2.3.1 Cost-Benefit Analysis (CBA)

2.3.1.1 Methodology

CBA indicates whether an LNG market development option has benefits to economy and society that outweigh its costs. The methodology that we followed for CBA is in accordance with the EC CBA Guide for infrastructure investments[4].

[4] DG Regio (2015) EC CBA Guide for infrastructure investments, available at: https://ec.europa.eu/regional_policy/sources/docgener/studies/pdf/cba_guide.pdf

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2.3.1.2 Benefits under Gas-to-gas competition

CBA is carried out for all applicable gas-to-gas competition LNG market development options in each Eastern Partner country. LNG market development options under gas-to-gas competition can have both gas reduction costs benefits to the country's economy (in case LNG is shown to be price competitive to existing gas supplies) and security of supply benefits (through diversification of supply source or route). Therefore, although the analysis under the Section 2.2 may show that an option is not viable, a CBA is undertaken to assess whether its assessed economic benefits outweigh the costs associated with introducing the option in the country and the price increase of using more expensive LNG in a country's economy.

2.3.1.3 Benefits under Gas-to-other fuels competition

CBA was carried out for those applicable gas-to-other fuels competition LNG options in each Eastern Partner country that are assessed to be viable. Only in case of a viable option, LNG can displace more expensive fuels and result in benefits from a reduction in the energy bill of the economy. Moreover, the substitution of fuels that are associated with higher greenhouse gas emissions, by gas, can bring about additional environmental benefits.

2.3.1.4 Monetisation of economic benefits linked to price competitiveness

Monetisation of the economic benefits linked to price competitiveness under each applicable option, requires an assessment of the market size for LNG that could be developed under the particular option. The assessed market size, combined with the estimated incremental decrease in the unit cost of gas under gas-to-gas competition, (or the decrease in the unit cost of energy under gas-to-other fuels competition) estimated on the basis of netback analysis, provides the monetised estimate of the price competitiveness benefits.

2.3.1.5 Market sizing for LNG development options

The approach to assess potential LNG market size for options being appraised is qualitative and differs by LNG option. The approach involves, inter alia, assessing volumes of gas that could be open to competition, any capacity limitations on interconnections, loading capacity for trucks at the source LNG terminal, and other considerations, for each Eastern Partner country. Particularly when assessing the impact of LNG receiving terminals, and given that no gas market simulation was carried out within the frame of this Study, the impact of combinations of LNG supply prices and terminal utilization were examined, to provide a range of potential results.

2.3.1.6 Monetising Security of supply benefits

Monetising security of supply benefits entails an assessment of how the introduction of an additional source (LNG) in the Eastern Partner country mitigates the impact of an exogenous gas disruption to the Eastern Partner country (e.g. a cut-off in gas supplies from an existing gas supply source). Estimating the security of supply would require calculating four key elements: the probability of such a disruption taking place, the days of disruption, the incremental gas consumption that can be covered by LNG in the case of a disruption, and the value of disrupted gas to the Eastern Partner country's economy.

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2.3.1.7 Monetising Environmental benefits

Monetising the environmental impact of an option that involves substitution of other fuels by LNG, involves an estimation of the decrease in greenhouse gas emissions that LNG/gas produces compared to the other fuels that it displaces. This is based on the following steps:

1. Estimating the GHG emissions factors (tonnes of CO_2 per unit) for LNG/natural gas and for each of the fuels substituted
2. Estimating the GHG emissions saved (tonnes of CO_2) for the volumes of fuels that were substituted by LNG (according to the previously discussed market size)
3. Monetising the GHG emissions saved in accordance with a shadow price (long term opportunity cost) of GHG emissions (based on the assumptions of ENTSOG in the 2018 TYNDP Scenario Report)

It is noted that for the purpose of the high-level analysis performed in this Study, the GHG emissions saving is based on a benchmark aggregate value of GHG emissions for LNG and diesel[5]. The actual impact of the competing fuels depends on factors such as the type and age of the trucks (e.g. a fleet of old trucks with Euro-4 engines would have a different carbon footprint than a renewed fleet Euro-6 engines), and their service modality (distance travelled in urban and rural areas/motorways)[6]. To ascertain the actual impact of switching to LNG in each country, the conditions in the country's transport sector (type and age of truck engines, service modalities, regulatory limitations) would have to be further analysed.

2.3.1.8 Quantitative indicators

In addition to the monetised CBA, we have included an assessment of the expected impact of LNG supplies to the market, using capacity-based indicators in line with ENTSOG, to the extent permissible (e.g. N-1 Indicator, Import Route Diversification, Demand Curtailment).

2.3.2 Assessment of prerequisites and key success factors

For each option that is deemed to be viable, we identify prerequisites and key success factors for its implementation. Prerequisites include the necessary agreements in place to enable an option to be realised, for example, the Turkey-Ukraine agreement for passing of LNG ships through the Bosporus Straits, or availability of Caspian gas for the supply of gas to be liquefied and exported to other countries. Prerequisites also include the legal and regulatory framework that enables each viable LNG market development option to be implemented, and the development of upstream or downstream infrastructure. For example, the existence of technical standards for construction and operation of filling stations, or the existence of road safety standards for trucks, or the existence of small-scale liquefaction facilities. Other prerequisites relate to the removal of obstacles to cost reflectiveness, e.g. subsidisation of diesel or other fuels that causes difficulties

[5] Source: I. Smajla et al. (Energies Journal)," Fuel Switch to LNG in Heavy Truck Traffic", 2019

[6] See for example the results of LNG to diesel comparison of TNO, Emissions testing of a Euro VI LNG-diesel dual fuel truck in the Netherlands, April 2019, for specific types of engines and routes.

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or even impossible for LNG to compete, and the establishment of a level plain field regarding inter-fuel competition. Prerequisites can also be of a regional nature, requiring inter-country cooperation e.g. availability of a network of filling stations across several countries, so that LNG-fuelled trucks can operate across major international transport routes.

Key success factors relate to factors that could be conducive to, incentivise and accelerate LNG market development, for the options deemed to be viable, in the Eastern Partner countries concerned. These success factors include financial incentives (grants, subsidies, tax breaks) for investors and users in the viable LNG market options.

2.3.3 Priorities and policy directions

For Eastern Partner countries with more than one potentially viable options, a time prioritization is proposed (short-term, medium-term, longer-term), on the basis of qualitative assessment of factors that include the number and controllability of prerequisites for implementation of the option and the complexity and time involved for its development. Policy directions are also proposed for the development of the options, taking into account, where relevant, policy directions as expressed by stakeholders during country missions and workshops.

2.3.4 Proposed actions

Proposals on specific actions to be undertaken by the Eastern Partner countries, to evaluate and prepare for the commencement of the LNG market development options, are formulated for each Eastern Partner country. Regional cooperation actions, where applicable, are included in the recommendations. The potential timing of the actions is identified, as immediate (can start without constraints), short-term (1-3 years), medium-term (3-5 years) and long-term (over 5 years).

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3 LNG Market Prospects in Armenia

3.1 Identification of applicable LNG market development options

An overview of the Armenian gas sector is provided in Annex 1.1. Following the analysis of the gas market information, and discussions with stakeholders during the field visit to the country, the key findings related to the development of LNG markets in Armenia are as follows:

- Gas-to-gas competition from LNG seems to be a non-applicable, or at best a very weak case, for Armenia. This is due to lack of proximity to LNG sources, from which LNG can be transported to the country at reasonable cost.
- Also, Gazprom Armenia is the owner of the transmission system (operated by its subsidiary Transgaz LLC) and has a monopoly on gas imports for wholesale and retail supply (2 bcm/yr supplies from Gazprom Russia). An additional 0.5 bcm/yr of gas is imported from Iran, but this is a special tolling agreement that involves the gas used to produce electricity, which is then exported back to Iran.
- LNG could be considered for security of supply purposes (i.e. import LNG, regasify and store it for emergency use) but this is an expensive option compared to others e.g. storing natural gas in existing UGS facilities at Abovyan.
- On the other hand, Armenia appears to have potential for use of LNG as road transport fuel. Armenia has a sizable fleet of trucks involved in local, regional and international transport (over 65,500 trucks), the majority of which (65%) are fuelled by petrol and secondarily by diesel (34%). This fleet includes a number of long haul trucks that are involved in the transport of goods regionally or internationally (e.g. from Armenia to Georgia, Russia and Europe) over distances exceeding 1,500 kms per journey, and provided a sufficient number of these trucks can be induced to switch to LNG, there could be a potential market.
- Notably, Armenia has one of the largest networks in the region of CNG filling stations. There are 380 CNG filling stations in the country, with CNG sales amounting to 0.6 bcm annually. 85% of passenger vehicles are fuelled by CNG, the rest by diesel. Most CNG filling stations are quite old and need of modernization, and could be converted to use LNG as well (L-CNG).
- The familiarity of consumers with using CNG, the existence of filling stations and the availability of technology for their conversion to use LNG, provide advantages to developing a market for LNG for trucks, provided LNG is competitive in price to diesel.
- LNG can be supplied by establishing a small scale liquefaction facility to convert piped gas into LNG; Gazprom Armenia is interested in invest in such a facility, provided there is a potential market for LNG for use in transport, and private investment takes place in required supporting infrastructure (transporting LNG to filling stations, filling stations, storage etc.). An alternative option is to source LNG through Georgia (e.g. Black Sea LNG receiving terminal or liquefaction terminal with truck loading facility, provided that

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such infrastructure is developed in Georgia) which is then transported by truck/rail to Armenia, or to source LNG by trucks from Russia.

- Use of LNG virtual pipelines to supply off-grid consumers or distribution systems is not an applicable option for Armenia, as around 95% of the country is already gasified.

Based on the above analysis, the only applicable LNG market development option for Armenia is the use of LNG as engine fuel for long-haul trucks. LNG can be sourced either from an in-country mini liquefaction facility connected to the transmission system, or from Georgia, in case LNG facilities (receiving or liquefaction terminal) are developed there. It is noted that development of an LNG receiving terminal in Georgia can only be possible in case with agreement with Turkey is concluded for the passing of LNG vessels through the Bosporus Straits.

3.2 Assessment of viability of applicable LNG market options

3.2.1 Use of LNG as engine fuel for trucks

This LNG market development option can be considered as potentially viable for Armenia in case the LNG price at the filling station is competitive to that of diesel, taking into consideration the efficiency gains of LNG engines, as well as all costs associated with the LNG supply chain.

The available information on Armenia's traffic of long-haul trucks (local and transit) is not sufficiently detailed to allow reasonable assumptions to estimate the market size of LNG as fuel for trucks. For this reason, instead of performing netback analysis to estimate the maximum price of LNG to be competitive to diesel, we estimate the LNG market size (number of LNG-fuelled trucks and annual LNG volumes consumed) required for prices of LNG and diesel to be on par, under different scenarios of LNG/natural gas prices at the beginning of the supply chain.

The potential LNG supply sources examined for Armenia include an LNG receiving terminal and a liquefaction terminal in Georgia and an in-country mini liquefaction facility. For each source, a base price and positive/negative sensitivities, as displayed in Table 2, have been assessed.

Table 2: Examined prices of LNG/natural gas at the source for Armenia

Terminal	Assumed price at terminal (EUR/1000m^3)				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Georgia LNG receiving terminal[7]	220	275	330	187	165
Georgia liquefaction terminal[8]	222	277	333	189	166
In-country mini liquefaction facility[9]	183	229	275	155	137

The analysis has been carried out for long-haul trucks retrofitted to use LNG, traveling 91,000 km per annum. The costs for development of a new filling station for LNG is considered (development of a new L-CNG station or upgrade of an existing CNG station would result in lower costs). The

[7] The price for LNG in Black Sea is assumed to be the price at the Greek Revythoussa terminal (210 EUR/1000m^3, source: DG Energy, "Gas Market Report Q2 2019"), with an uplift of 5% to reflect additional transportation cost and crossing through the Bosporus straits.

[8] Equal to the gas price in the Georgian market (Source: GEOSTAT)

[9] Gas price for large end users, including transmission cost (PSRC, "Tariffs for natural gas supply to consumers")

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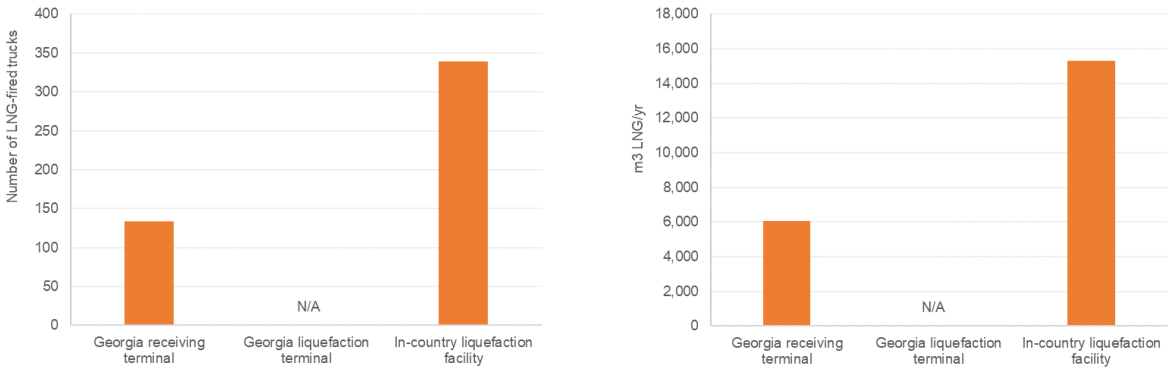
competing price of diesel has been assumed to be at the current market level, of 0.64 EUR/lt[10]. The detailed approach and calculations are presented in Annex 3.1. It is noted that cases in which the minimum LNG market size is estimated to require over 1,000 LNG-fuelled trucks are not further analysed, as a high penetration of LNG trucks, not corresponding to the EU experience[11], would be required.

Figure 2 presents the minimum number of LNG-fired trucks that have to operate in Armenia, and the minimum LNG volumes to be supplied annually, for the market to be developed, in case the base price applies at the LNG source.

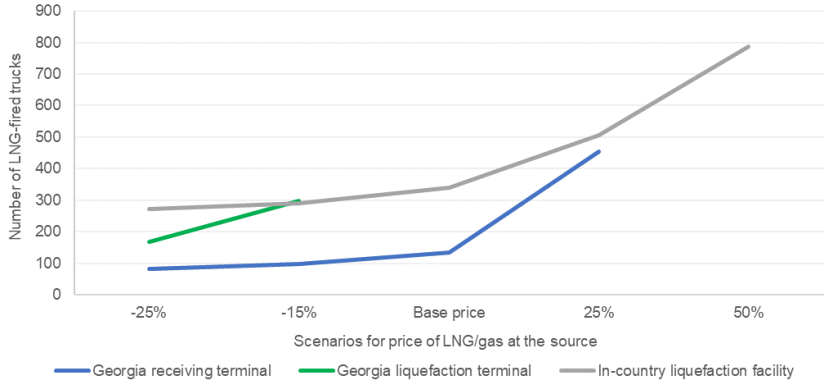
Figure 2: Minimum number of LNG-fired trucks for market development in Armenia and corresponding annual LNG market size, under base price[12]



(a) Minimum number of LNG-fired trucks *(b) Minimum LNG market size*

The minimum number of LNG-fired trucks in the case of Armenia, for all price scenarios and LNG supply variants are presented in Figure 3.

Figure 3: Minimum number of LNG-fired trucks in Armenia for all price sensitivities[13]



[10] Source: Maxoil website (accessed 1/11/2019)

[11] Current EU fleet of 6,000 LNG-fired trucks (NGVA, "NGVA Europe marks the 200th European LNG fuelling station with a revamp of its stations map", May 2019) amounts to less than 1% of the total fleet of 6.5 million heavy duty trucks (Source: LNG Blue Corridor, "Feasibility study about the SoNor Corridor", May 2018)

[12] N/A denotes market size requiring over 1,000 LNG-fuelled trucks

[13] Values exceeding 1,000 LNG-fired trucks are not presented.

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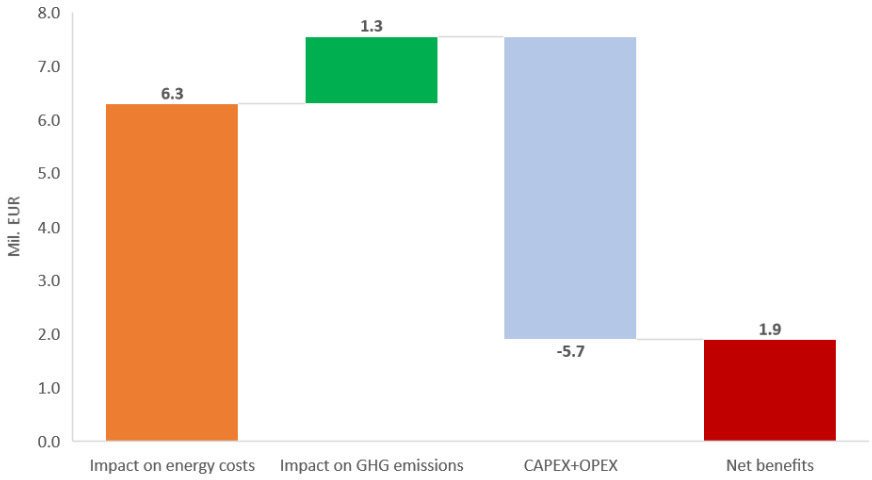
The results of the analysis show that, in case LNG is sourced from a receiving terminal in Georgia at the base price, LNG can be competitive to diesel provided at least around 130 LNG trucks operate in the Armenian market; this number of trucks can be lower provided the source price is below the assumed base price. However, for this supply modality to be applied, an agreement with Turkey for the passing of LNG vessels through the Bosporus Straits must be concluded, as a prerequisite for the potential development of an LNG terminal in Georgia. Supply from a mini liquefaction terminal, which is the most expensive solution, would require around 340 LNG-fuelled trucks to be competitive.

Considering that Armenia has a sizable fleet of trucks involved in local, regional and international transport, it appears that a market for LNG in road transport could potentially develop, in case the LNG prices remain at the assumed base price or less. Consequently, use of LNG as engine fuel for trucks can be considered as a potentially viable option for Armenia. The sourcing of LNG from a possible LNG receiving terminal in Georgia (assuming first the securing of agreement with Turkey for the Bosporus Straits and secondly the financial/economic viability of such a terminal), would render enhanced possibilities for developing an LNG engine fuel market in Armenia, as the minimum required number of trucks to render the option viable is 140, as opposed to more than double the number of trucks in case in-country liquefaction is applied. It is noted that in order to better size the size of the market, and its attractiveness, analysis of detailed data on the operation of long-haul trucks (such as number of local and transit trucks, destinations and distances covered) in Armenia would be required.

Economic analysis was performed for the identified minimum required LNG market, to estimate the extent to which economic benefits for using LNG as engine fuel (energy cost reduction for end consumers, impact on GHG emissions) outweigh the costs for developing the option. The analysis shows that the reduction of GHG emissions has a positive impact (Figure 4).

Figure 4: Present value of economic costs and benefits for use of LNG as engine fuel for trucks in Armenia



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3.3 Prerequisites and key success factors for potentially viable LNG market options

3.3.1 Use of LNG as engine fuel for trucks

Table 3 below describes the key prerequisites for effective implementation of the option of using LNG as engine fuel for trucks in Armenia. The prerequisites concern the appropriate price differential between LNG and diesel to ensure viability, as well as the necessary changes in the legal and regulatory framework, or introduction of new legislation and regulations, including permits and licenses. The legal and regulatory prerequisites relate not only to import and operation of trucks, but extend to the supply chain for LNG concerning trucks: filling stations, truck loading facilities at LNG terminal in Georgia, in case this option is implemented in the neighbouring country and LNG is sourced from there, in-country liquefaction plants and truck loading facilities at these plants, in case LNG is sourced from piped gas in the country. The interest of sufficient truck owners to switch to LNG, and the attraction of investments to develop the necessary infrastructure (filling stations, liquefaction facilities) is also critical for the development of the market.

It is noted that the prerequisites related to the import of LNG and the development of relevant import facilities in Georgia are listed separately in Section 6.3.1.

Table 3: Prerequisites for development of LNG as engine fuel for trucks

	Prerequisite	Rationale	Involved country(ies) or parties	Difficulty of implementation
Market				
1	Sufficient price differential between LNG and diesel (as discussed in Section 3.2.1)	Critical – on/off condition, as switching to LNG requires an attractive price of LNG vis-à-vis diesel at the end use	Armenia is responsible for avoiding subsidies that distort price differential. LNG and diesel source prices are determined in accordance with international demand and supply conditions (except in the case where LNG is sourced from an in-country liquefaction facility, in which the price is determined by gas import contracts)	Uncertain
2	Interest of a critical mass of truck owners to switch to LNG	Viability of the option is dependent on having a minimum market size to justify investments. This size is smaller	Decision of truck owners	Medium

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		(and more attainable) in case a supply chain from a prospective LNG receiving terminal in Georgia is established.		
Legal & Regulatory				
1	Regulations and standards for the design, manufacturing and installation of the LNG fueled trucks and different components (e.g. pressure control regulator, LNG filling receptacle etc.) for approval of LNG vehicles import and operation[14, 15]	Need to ensure safety, efficiency, quality and environmental protection. There are various European and international standards that could be incorporated in national legislation as the basis for granting approval.	Under the sole control of Armenia	Low
2	Road regulations for circulation of LNG fuelled vehicles	Need to ensure safety, by stipulating any restrictions in movement e.g. in cases of heavy traffic, adverse weather conditions affecting visibility and road conditions etc.	Under the sole control of Armenia	Low
3	LNG and L-CNG filling stations permits and licences, notably building license, operation license, and business license[16]	Need to ensure the eligibility of the selected site for the station, compliance with operational obligations (e.g. opening hours, station throughput, safety obligations, and business registration of the entity. The licenses require testing and acceptance processes and mechanisms at state/municipal level, before licences are granted and after (inspection/checks for compliance)	Under the sole control of Armenia	Low

[14] DG MOVE, LNG Blue Corridors, Vehicle Regulations - State of the Art, December 2013
[15] DG MOVE, LNG Blue Corridors, LNG stations Regulations -State of the art, December 2013
[16] DG MOVE, LNG Blue Corridors, Guidelines for set up & operation of stations, May 2015

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4	LNG and L-CNG filling stations regulatory guidelines[16] in relation to set-up and construction (e.g. distance, tank levels etc.), operation (e.g. guarantee sufficient product), and maintenance (planned maintenance work in a programmed schedule) of the station.	Need to ensure safety and efficiency of the station. The regulations require testing and acceptance processes and mechanisms at state/municipal level, before licences are granted and after (inspection/checks for compliance)	Under the sole control of Armenia	Low
5	Road safety regulations for trucks carrying LNG to the filling stations.	LNG transportation carries some potential hazards, linked to flammability as well as the impact of cryogenic fuel exposure or leakage. There are standards that could be adopted (3 years ago, LNG and CNG were included in the ADR[17]).	Under the control of Armenia (for Armenian road network) and Georgia (for Georgian road network)	Low
6	Regulations governing TPA of LNG carrying trucks at LNG terminal in Georgia (in case this supply variant is used)	Need to ensure transparent and non-discriminatory access of truck operators to the truck loading facilities	Under the sole control of Georgia	Low
7	Regulations governing loading of LNG to trucks at LNG terminal in Georgia (in case this supply variant is used)	Need to establish rules and procedures for how truck operators will use the truck loading facilities, including LNG truck approval procedure, LNG specifications, procedures for determining the LNG mass loaded etc.	Under the sole control of Georgia	Low
8	Regulations governing pricing of LNG terminal truck loading facilities in Georgia (in case this supply variant is used, and there is price regulation for third party	Need to have published tariffs for truck loading facility services at the terminal, that are non-discriminatory for users, and regulations	Under the sole control of Georgia	Low

[17] Acronym for "Accord européen relatif au transport international des marchandises Dangereuses par Route" i.e. the European Agreement concerning the International Carriage of Dangerous Goods by Road

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	access to such facilities)	for the allowed costs in such tariffs		
9	Permits and licenses, including technical specifications, for truck loading facilities at LNG terminal in Georgia (in case this supply variant is used)	Need to have permits and regulations specifying layout requirements and operational aspects, to address safety issues including fire protection.	Under the sole control of Georgia	Low
10	Permits and licences, including technical specifications, for liquefaction facilities (in case LNG is sourced from the gas network and loaded on to trucks)	Need to have permits and regulations for site requirements, health and safety considerations, transportation infrastructure, availability of key utilities, air emissions and wastewater treatment.	Under the sole control of Armenia	Low
11	Permitting process, including technical specifications, for truck loading at liquefaction facility (in case there is a liquefaction facility)	Need to have permits and regulations specifying layout requirements and operational aspects, to address safety issues including fire protection.	Under the sole control of Armenia	Low
12	(Amendment to) law to specify whether/which type of liquefaction facilities are regulated (TPA and pricing)		Under the sole control of Armenia	Low
13	Regulations governing TPA of LNG trucks at liquefaction facility (in case there is a regulated liquefaction facility)	Need to establish rules and procedures for how truck operators will use the truck loading facilities, including LNG truck approval procedure, LNG specifications, procedures for determining the LNG mass loaded etc.	Under the sole control of Armenia	Low
14	Regulations governing pricing of liquefaction facility (in case there is a regulated liquefaction facility)	Need to have published tariffs for use of the liquefaction plant services, that are non-discriminatory for users, and regulations for the allowed costs in such tariffs	Under the sole control of Armenia	Low

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Infrastructure				
1	Interest of investors to implement necessary infrastructure (filling stations, in-country liquefaction facility)	The required infrastructure must be developed in time for the LNG-fuelled trucks to be able to operate	Decision of investors	Medium

Table 4 outlines the key success factors for the implementation of the option of using LNG as engine fuel for trucks. These factors influence the speed of market development. Some of the key success factors relate to the State providing support to catalyze investments in LNG trucks and filling stations, including retrofitting of CNG stations to L-CNG, which are widespread in the country. Others relate to having a regulatory framework that favors 'cleaner' LNG use in trucking and punishes more 'dirty fuels'. State can also regulate the level of subsidies in other fuels, to make LNG more competitive. Other factors relate to the role of State and State organizations to foster changes and to support investors (one-stop-shop). Finally, the role of information campaigns for consumers, users and investors, is important to overcome resistance to change and to boost interest.

Table 4: Key success factors for development of LNG as engine fuel for trucks

	Key success factors	Rationale
1	An LNG receiving terminal, with truck loading facilities, is established by Georgia	This would significantly lower the costs involved in the LNG supply chain, and thus make the critical mass of trucks required for the option to be viable more attainable
2	Conducive fiscal framework (low taxes, low import duties, availability of state grants and rebates) for the purchase of LNG fuelled trucks or the retrofitting of existing trucks to LNG.	
3	Setting and enforcing circulation restrictions for trucks that use older generation engines with higher emissions detrimental to the environment (e.g. Euro 4 fuels)	
4	Reduction of subsidies and favourite tax treatment of fuels competing with LNG, to make LNG more competitive and incentivise its use.	
5	Conducive fiscal framework (specific concession regimes, tax holidays, state grants[18]) conducive to investment in construction of new LNG filling stations, or for retrofitting petrol stations to include LNG, or for retrofitting CNG stations to offer also LNG (L-CNG). Also, state co-funding of LNG R&D activities	Having sufficient network of LNG stations is a major success factor. Incentivising private investment is one way to develop the market.
6	Awareness and promotion campaigns for LNG.	Consumers should be educated as to the potential features and benefits of LNG in transport. Investors should be informed on the opportunities available. Such campaigns can counter resistance to change and speed up interest.

[18] 'Connecting Europe Facility', for example, provides grant to co-finance investment in LNG filling stations in the EU

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7	Having a 'National champion' e.g. the Ministry of Territorial Administration and Infrastructure and/or a State Committee that includes gas company and other key stakeholders. The role of the National champion would be to coordinate the set-up of the required legal and regulatory framework, develop and implement policy and incentives, to remove obstacles in for LNG market development and to act as one-stop-shop for investors. Its role would also include planning the number and location of LNG filling stations and facilities (possibly introducing limited concessions for infrastructure) so as to avoid stranded investments.	Many initiatives are slowed down by regulatory gaps or unclear legislation, lack of implementing administrative mechanisms and bureaucracy and lack of action. Such problems are exacerbated due to lack of awareness and resistance to change or inertia. For example, customs may not be familiar with rules and regulations for the new LNG vehicles and delay their clearance.

3.4 Priorities and policy directions

The single potentially viable option for LNG market development identified for Armenia is the use of LNG as engine fuel for trucks.

This option could be viable using an in-country mini liquefaction facility, but the high investment costs in required infrastructure necessitate a large number of LNG fueled trucks for viability. On the other hand, supplies from a potential LNG terminal in Georgia, in case implemented, could considerably reduce costs, but this infrastructure is subject to an external decision (by Georgia) and dependent on a number of factors controlled by third, external, parties.

Decision for and implementation of an in-country LNG supply chain using a mini liquefaction facility could be done in short-term horizon, as it only involves local actors. In contrast, supplies of LNG from a receiving terminal in Georgia would involve a longer-term horizon due to the nature of the investment, and the uncertainties surrounding the decisions of the involved external parties.

Given the benefits of reducing energy costs and GHG emissions, this option merits further investigation, to assess in detail its feasibility, and decide on the potential policies to be adopted, favoring the use of LNG. These policies could encompass, at the minimum, having a legal and regulatory framework conducive to the development of an LNG supply chain, and could expand to cover incentives for the use of LNG.

3.5 Proposed preparatory actions

The Table below describes the actions that are deemed important in order to evaluate and prepare the option of using LNG as engine fuel for trucks.

Table 5: Proposed preparatory actions for the option of LNG-fueled trucks in Armenia

	Proposed Actions	Timing
Initial / Preparatory Actions		
1	Perform a feasibility study for use of LNG as engine fuel in Armenia (covering not only greenfield projects, but also retrofitting of existing CNG stations to L-CNG)	Immediate

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2	Develop a national policy framework for the use of LNG in trucks, deciding on the role that the State wishes to undertake	Short-term / After the study is concluded (in case it is positive and Armenia decides to pursue)
Implementation Actions		
3	Prepare the regulatory and legal framework (legal amendments, regulations, standards, permits and licenses, etc.) necessary for the development of the LNG supply chain	Short-term (based on national policy framework)
4	In case the State undertakes a proactive role in developing infrastructure, prepare the incentive mechanisms to attract investments	Short-term (based on national policy framework)
5	Conduct awareness raising campaigns to attract end-users and investors' interest	Short-term (based on national policy framework)

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4 LNG Market Prospects in Azerbaijan

4.1 Identification of applicable LNG market development options

An overview of the Azeri gas sector is provided in Annex 1.2. Following the analysis of the gas market information, and discussions with stakeholders during the field visit to the country, the key findings related to the development of LNG markets in Azerbaijan are as follows:

- Gas-to-gas competition from LNG is not applicable in Azerbaijan. This is due to the country being a major gas producer and exporter, but also due to lack of proximity to LNG sources from which LNG can be transported to the country at reasonable cost. There are discussions for establishing an LNG terminal in the Azeri part of the Black Sea to receive LNG from Kazahkstan, but this will basically involve Azerbaijan as a transit country as Kazakh LNG will be regasified and exported to other markets.
- Another potential option, that could involve LNG in gas-to-gas competition but in other countries, is the export of Azeri gas to a liquefaction terminal in Georgia, and the resulting LNG shipped to markets such as Ukraine, Moldova and Romania where it competes against piped gas supplies. Currently, all gas production in Azerbaijan available for export has already been contracted. However, new fields under development could potentially supply an export route to a liquefaction terminal in Georgia over the mid-term. The liquefaction terminal in Georgia could also be supplied with gas from Kazakhstan and Turkmenistan, in case an LNG receiving terminal is built at the Azeri Caspian Sea coast.
- Gas-to-other fuels competition from LNG is an applicable option in Azerbaijan for supply of off-grid areas. Although around 95% of the Azeri territory is already gasified, Government roadmap targets 100% gasification. Development of LNG virtual pipelines is one of the options being assessed as a means for supplying off-grid areas that currently consume other fuels.
- Gas-to-other fuels competition from LNG in the transport sector could also be an applicable option in Azerbaijan. Although transport fuels (e.g. diesel) are subsidised and development of a supply chain to supply LNG as fuel for trucks would not be economically viable, given the environmental benefits of LNG use in transport, the Government is willing to consider supporting use of LNG in this respect. Azerbaijan has also the largest fleet active in the Caspian Sea, a new port in Baku is operational, and a new shipyard has been developed by SOCAR. Development of LNG as fuel for ships is of interest to Government, especially for environmental reasons.
- No prospects seem to exist for the use of LNG in agriculture or mining, as demand is limited, and potential consumers are already connected to the transmission system.

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Based on the above analysis, the applicable LNG market development options for Azerbaijan, all of which concern gas-to-other fuels competition, are presented in Table 6. The only potential source of LNG supply is an in-country mini liquefaction facility connected to the Azeri transmission system.

Table 6: Applicable options for LNG market development in Azerbaijan

Options for LNG market development		Sources of supply
Gas-to-Other Fuels Competition	LNG as engine fuel for long-haul trucks	In-country mini liquefaction facility
	LNG as engine fuel for ships operating in the Caspian Sea	
	LNG supplies to the remaining off-grid areas in Azerbaijan, to increase gasification	

4.2 Assessment of viability of applicable LNG market options

4.2.1 Use of LNG as engine fuel for trucks

This LNG market development option can be considered as potentially viable for Azerbaijan in case the LNG price at the filling station is competitive to that of diesel, taking into consideration the efficiency gains of LNG engines, as well as all costs associated with the LNG supply chain.

However, due to the very low current diesel price in Azerbaijan (0.26 EUR/lt[19]), LNG cannot be competitive. The results of the calculations show that the required LNG price at the filling station (285.4 EUR/1000 m^3), after having taken into consideration fuel efficiency gains, is lower than the required switching costs (296 EUR/1000 m^3), which include recovery of retrofitting costs and a small price reduction as incentive to the truck owner. The detailed approach and calculations are presented in Annex 3.1.

Consequently, use of LNG as engine fuel for trucks does not seem to be a viable option for Azerbaijan. Nevertheless, the Azeri Government have indicated that it intends to explore this option further for environmental reasons and potentially provide support.

4.2.2 Use of LNG as engine fuel for ships

The use of LNG by the existing fleet of ships operating in the Caspian Sea, in case emission control rules are applied by Azerbaijan (such as reduction of sulphur emissions) would have to compete with other options, such as the use of scrubbers or low sulphur fuel oil. Internationally, for ships currently operating in the sea areas outside Emission Control Areas (ECAs), the switching to LNG has not been the preferred option, as the retrofitting cost has been considered higher than that of alternative solutions[20]. The use of LNG can be more attractive in the case of new builds, provided that the price differential between LNG and the existing bunkering fuels is

[19] Source: Azpetrol website (accessed 1/11/2019)

[20] See analysis in Oxford Institute for Energy Studies, "LNG Supply Chains and the Development of LNG as a Shipping Fuel in Northern Europe", 2019

sufficient to cover the additional cost of an LNG-fuelled ship, and that bunkering of LNG is possible at least in the Baku port.

The attractiveness of this LNG option differs for each individual case of ship, as it depends on a number of factors, including the vessel's size and type, age, service area, fuel used, refuelling pattern, prices of competing fuels, etc. For this reason, a case-by-case analysis would be required, to examine for which ships use of LNG would be competitive.

Data on the Azerbaijan shipping sector, required to perform a contextualized analysis of this option, were not available. To facilitate further analysis of this option, in this Study we provide an indicative example, concerning a new build 50,000 MT PANAMAX type vessel operating in the Black Sea, with LNG and MGO as competing fuels and bunkering at an LNG terminal in Ukraine. The detailed approach and calculations are described in Annex 3.4. The rationale and approach followed in this example could be used as a basis to assess the use of LNG as engine fuel in Azerbaijan.

4.2.3 Supply of LNG to off-grid distribution systems

This LNG market development option can be considered as potentially viable for Azerbaijan in case the natural gas price supplied to the end customers at the targeted areas for gasification is competitive to that of the competing fuels, taking into consideration the efficiency gains of natural gas, as all costs associated with the LNG/natural gas supply chain.

Data on the areas of Azerbaijan to be gasified, required to perform a contextualized analysis of this option, were not available. The rationale and approach followed in the case study analysing this LNG market development option for Georgia (Annex 3.2) can be used as a basis to assess the financial viability of supplying LNG to ungasified regions of Azerbaijan.

4.3 Prerequisites and key success factors for potentially viable LNG market options

4.3.1 Use of LNG as engine fuel for trucks

Table 7 describes the key prerequisites for effective implementation of the option of using LNG as engine fuel for trucks in Azerbaijan. The prerequisites concern the appropriate price differential between LNG and diesel to ensure viability, as well as the necessary changes in the legal and regulatory framework, or introduction of new legislation and regulations, including permits and licenses. The prerequisites relate not only to import and operation of trucks but extend to the supply chain for LNG concerning trucks: filling stations, liquefaction plants and truck loading facilities at these plants. The interest of sufficient truck owners to switch to LNG, and the attraction of investments to develop the necessary infrastructure (filling stations, liquefaction facilities) is also critical for the development of the market.

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Table 7: Prerequisites for development of LNG as engine fuel for trucks

	Prerequisite	Rationale	Involved country(ies) or parties	Difficulty of implementation
Market				
1	LNG end use price should be subsidized, to compete against diesel or subsidies on diesel lifted (current price differential does not allow development of this option, as discussed in Section 4.2.1)	Critical – on/off condition, as switching to LNG requires an attractive price of LNG vis-à-vis diesel at the end use	Under the sole control of Azerbaijan	Low
2	Interest of a critical mass of truck owners to switch to LNG	Viability of the option is dependent on having a minimum market size to justify investments	Decision of truck owners	Medium
Legal & Regulatory				
1	Regulations and standards for the design, manufacturing and installation of the LNG fueled trucks and different components (e.g. pressure control regulator, LNG filling receptacle etc.) for approval of LNG vehicles import and operation[21, 22]	Need to ensure safety, efficiency, quality and environmental protection. There are various European and international standards that could be incorporated in national legislation as the basis for granting approval.	Under the sole control of Azerbaijan	Low
2	Road regulations for circulation of LNG fuelled vehicles	Need to ensure safety, by stipulating any restrictions in movement e.g. in cases of heavy traffic, adverse weather conditions affecting visibility and road conditions etc.	Under the sole control of Azerbaijan	Low
3	LNG and L-CNG filling stations permits and licences, notably building license, operation license, and business license[23]	Need to ensure the eligibility of the selected site for the station, compliance with operational obligations (e.g. opening hours,	Under the sole control of Azerbaijan	Low

[21] DG MOVE, LNG Blue Corridors, Vehicle Regulations - State of the Art, December 2013

[22] DG MOVE, LNG Blue Corridors, LNG stations Regulations -State of the art, December 2013

[23] DG MOVE, LNG Blue Corridors, Guidelines for set up & operation of stations, May 2015

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		station throughput, safety obligations, and business registration of the entity. The licenses require testing and acceptance processes and mechanisms at state/municipal level, before licences are granted and after (inspection/checks for compliance)		
4	LNG and L-CNG filling stations regulatory guidelines[23] in relation to set-up and construction (e.g. distance, tank levels etc.), operation (e.g. guarantee sufficient product), and maintenance (planned maintenance work in a programmed schedule) of the station.	Need to ensure safety and efficiency of the station. The regulations require testing and acceptance processes and mechanisms at state/municipal level, before licences are granted and after (inspection/checks for compliance)	Under the sole control of Azerbaijan	Low
5	Road safety regulations for trucks carrying LNG to the filling stations.	LNG transportation carries some potential hazards, linked to flammability as well as the impact of cryogenic fuel exposure or leakage. There are standards that could be adopted (3 years ago, LNG and CNG were included in the ADR.	Under the sole control of Azerbaijan	Low
6	Permits and licences, including technical specifications, for liquefaction facilities	Need to have permits and regulations for site requirements, health and safety considerations, transportation infrastructure, availability of key utilities, air emissions and wastewater treatment.	Under the sole control of Azerbaijan	Low
7	Permitting process, including technical specifications, for truck	Need to have permits and regulations specifying layout	Under the sole control of Azerbaijan	Low

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	loading at liquefaction facility	requirements and operational aspects, to address safety issues including fire protection.		
8	(Amendment to) law to specify whether/which type of liquefaction facilities are regulated (TPA and pricing)		Under the sole control of Azerbaijan	Low
9	Regulations governing TPA of LNG trucks at liquefaction facility	Need to establish rules and procedures for how truck operators will use the truck loading facilities, including LNG truck approval procedure, LNG specifications, procedures for determining the LNG mass loaded etc.	Under the sole control of Azerbaijan	Low
10	Regulations governing pricing of liquefaction facility	Need to have published tariffs for use of the liquefaction plant services, that are non-discriminatory for users, and regulations for the allowed costs in such tariffs	Under the sole control of Azerbaijan	Low
Infrastructure				
1	Interest of investors to implement necessary infrastructure (filling stations, in-country liquefaction facility)	The required infrastructure must be developed in time for the LNG-fuelled trucks to be able to operate	Decision of investors	Medium

Table 8 outlines the key success factors for the implementation of the option of using LNG as engine fuel for trucks. These factors influence the speed of market development. Some of the key success factors relate to the State providing support to catalyze investments in LNG trucks and filling stations. Others relate to having a regulatory framework that favors 'cleaner' LNG use in trucking and punishes more 'dirty fuels'. State can also regulate the level of subsidies in other fuels, to make LNG more competitive. Other factors relate to the role of State and State organizations to foster changes and to support investors (one-stop-shop). Finally, the role of information campaigns for consumers, users and investors is important to overcome resistance to change and to boost interest.

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Table 8: Key success factors for development of LNG as engine fuel for trucks

	Key success factors	Rationale
1	Conducive fiscal framework (low taxes, low import duties, availability of state grants and rebates) for the purchase of LNG fuelled trucks or the retrofitting of existing trucks to LNG.	
2	Setting and enforcing circulation restrictions for trucks that use older generation engines with higher emissions detrimental to the environment (e.g. Euro 4 fuels)	
3	Conducive fiscal framework (specific concession regimes, tax holidays, state grants[24]) conducive to investment in construction of new LNG filling stations, or for retrofitting petrol stations to include LNG, or for retrofitting CNG stations to offer also LNG (L-CNG). Also, state co-funding of LNG R&D activities	Having sufficient network of LNG stations is a major success factor. Incentivising private investment is one way to develop the market.
4	Awareness and promotion campaigns for LNG.	Consumers should be educated as to the potential features and benefits of LNG in transport. Investors should be informed on the opportunities available. Such campaigns can counter resistance to change and speed up interest.
5	Having a 'National champion' e.g. the Ministry of Energy or a State Committee that includes gas company and other key stakeholders. The role of the National champion would be to coordinate the set-up of the required legal and regulatory framework, develop and implement policy and incentives, to remove obstacles in for LNG market development and to act as one-stop-shop for investors. Its role would also include planning the number and location of LNG filling stations and facilities (possibly introducing limited concessions for infrastructure) so as to avoid stranded investments.	Many initiatives are slowed down by regulatory gaps or unclear legislation, lack of implementing administrative mechanisms and bureaucracy and lack of action. Such problems are exacerbated due to lack of awareness and resistance to change or inertia. For example, customs may not be familiar with rules and regulations for the new LNG vehicles and delay their clearance.

4.3.2 Use of LNG as engine fuel for ships

Table 9 describes the key prerequisites for effective implementation of the option of using LNG as engine fuel for ships in Azerbaijan. The prerequisites concern appropriate price differential between LNG and fuel oil to ensure viability, and the introduction of necessary regulations concerning LNG ships design and operation, as well as regulations and permits concerning bunkering facilities. The choice of ship owners to use LNG as fuel and the development of required infrastructure in the Baku port is also critical for the development of the market.

[24] 'Connecting Europe Facility', for example, provides grant to co-finance investment in LNG filling stations in the EU

Table 9: Prerequisites for development of LNG as engine fuel for ships[25]

	Prerequisites	Rationale	Involved country(ies) or parties	Difficulty of implementation
Market				
1	Sufficient price differential between LNG and fuel oil (as discussed in Section 4.2.2), for the vessels that are targeted for fuel switching	Viability of the option is dependent on LNG being competitive to fuel oil for use in shipping, so that investments in fuel conversion for the particular vessels can be recovered	Under the sole control of Azerbaijan (fuels produced and marketed locally)	Low
2	Interest of ship owners to retrofit or build new LNG-fueled vessels, based on technical feasibility and financial attractiveness	There are alternative options to be applied by ship owners to reduce costs and emissions	Decision of ship owners	Medium to high
Legal & Regulatory				
1	Codes and Regulations for the design of LNG ships, based on guidelines set by organisations such as the International Maritime Organisation (IMO), the Society of International Gas Tankers and Terminal Operators (SIGTTO), the Oil Companies International Marine Forum (OCIMF) and other ISO, European (EN) and National Fire Protection Association (NFPA) standards	Need to ensure safety, efficiency, quality and environmental protection.	Under the sole control of Azerbaijan	Low
2	Codes and Regulations for the design and operation of LNG bunkering facilities, based on ISO guidelines (for systems and installations for supply of LNG as fuel to ships) as well as other international guidelines	Need to ensure safety, efficiency, quality and environmental protection.	Under the sole control of Azerbaijan	Low

[25] In case of LNG supplied from liquefaction facilities to ports via trucks, the relevant points of Table 8 also apply.

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3	LNG bunkering facilities permits and licences	Need to ensure the suitability of the selected site for the facility, compliance with operational obligations (e.g. opening hours, station throughput, safety obligations) etc. The licenses require testing and acceptance processes and mechanisms at state/municipal level, before licences are granted and after (inspection/checks for compliance)	Under the sole control of Azerbaijan	Low
Infrastructure				
1	Implementation of necessary infrastructure (LNG bunkering infrastructure at Baku port)	The required infrastructure must be developed in time for the LNG-fuelled vessels to be able to operate	Decision of State and/or private investors	Medium

Table 10 outlines the key success factors for the implementation of the option of using LNG as engine fuel for ships. These factors influence the speed of market development. Some of the key success factors concern IMO regulations that influence the choice of LNG driven ships, especially new builds, vis-à-vis ships using other low emission fuels. Other prerequisites relate to having a legal framework conducive to investments and access to finance for the large investments needed. Another prerequisite for LNG fueled ships is the availability of adequate bunkering infrastructure.

Table 10: Key success factors for development of LNG as engine fuel for ships

	Key success factors	Rationale
1.	Reliability, operating costs advantages (driving from low LNG price and fuel efficiency) and environmental advantages of LNG fuelled ships are maintained over the long term, so as to justify large investment in LNG ships	
2.	Stricter IMO regulations on carbon emissions, and government enforcement, favouring the use of LNG in ships	
3.	IMO regulations not to include greenhouse gas emissions (methane) where LNG is seen to be at a disadvantage compared to other fuels	
4.	Availability of finance (loans, grants etc.) for investment in LNG ships.	Access to finance is key. Investment costs for new ships are significant for shipping companies, whereas retrofits are also costly, as larger fuel tanks are required to be placed in ship.

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5.	Availability of adequate bunkering infrastructure	
6.	National legislation conducive to investments in ships and/or bunkering infrastructure	

4.4 Priorities and policy directions

Given that the option of using LNG as truck fuels is not viable on account of lack of competitiveness of LNG vis-à-vis diesel, but it does have environmental benefits, the Government should assess whether it should place priority on developing this option on the basis of environmental policy. In doing so, the Government should undertake initiatives to improve LNG relative price competitiveness vis-à-vis competing fuels.

LNG use for supplying gas to off-grid remote areas, is an option that the Government could potentially apply to implement its national gasification strategy. In this case, the LNG supply chain costs would have to be compared against alternatives (CNG, piped gas) on a case-by-case basis.

The option of LNG use for ships could be explored further on the basis of the Government's environmental policy. In this respect, a case-by-case analysis of LNG application in different ship types operating in the Caspian Sea needs to be undertaken to ascertain feasibility, benefits and the ensuing priorities.

In case the Government decides to move ahead with the development of LNG options for environmental reasons, it should decide on the timing for each option. The option of using LNG for supplying gas to off-grid areas could be considered as a priority, on the basis of the ease and speed of implementation, as the supply chain can be developed by the State, without third parties involved. The development of LNG as engine fuel for trucks is a second priority, as it involved decision by truck owners to retrofit as well as development of LNG filling stations. The option of introducing LNG in the shipping sector could be developed over a longer-term horizon, as it would require involvement and large investments from ship owners for a diverse number of vessels.

4.5 Proposed actions

The Table below describes the actions that are deemed important in order to evaluate and prepare the identified applicable LNG market development options.

Table 11: Proposed preparatory actions for developing the identified LNG options in Azerbaijan

	Proposed Actions	Timing
Initial / Preparatory Actions		
1	Perform feasibility studies for the use of LNG as engine fuel for trucks and ships, and for supply of off-grid areas. The studies should examine scenarios for either subsidizing LNG use or removal of cross-subsidies of other fuels, and relevant affordability studies.	Immediate
2	Develop a national policy framework for the use of LNG in road and water transport, deciding on the role that the State wishes to undertake	Short-term / After the studies for the transport sector are concluded (in case Azerbaijan decides to pursue)

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3	Develop a programme for gasification of remote areas using LNG supplies	Short-term / After the relevant study is concluded (in case Azerbaijan decides to pursue)
Implementation Actions		
4	Prepare the regulatory and legal framework (legal amendments, regulations, standards, permits and licenses, etc.) necessary for the development of the LNG supply chain	Short-term / based on national policy framework and gasification programme
5	In case the State undertakes a proactive role in developing infrastructure, prepare the incentive mechanisms to attract investments	Short-term / based on national policy framework and gasification programme
6	Conduct awareness raising campaigns to attract end-users and investors' interest	Short-term / based on national policy framework and gasification programme
7	Undertake initiatives to catalyze interest and seek joint commitments of stakeholders (Socar, Baku port, ship owners) to develop the use of LNG in shipping	Short to medium-term / based on national policy framework

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5 LNG Market Prospects in Belarus

5.1 Identification of applicable LNG market development options

An overview of the Belarusian gas sector is provided in Annex 1.3. Following the analysis of the gas market information, and discussions with stakeholders during the field visit to the country, the key findings related to the development of LNG markets in Belarus are as follows:

- Gas-to-gas competition from LNG is not applicable in Belarus. Imports of gasified LNG through pipeline from Klaipeda and/or Świnoujście LNG terminals is an option that can only be applicable in case Belarus considers technical reverse flow of existing interconnections (Poland, Lithuania) and/or new interconnections. According to the stakeholders, no new interconnections are currently planned, and it is not feasible to make technical changes to the system to introduce reverse flow from Lithuania and/or Poland. Moreover, several gas interconnections between Belarus and Ukraine are either decommissioned and/or unutilized. Importing LNG from EU, using trucks and/or trains and regasifying it to supply existing gas network customers, is technically feasible but there is no apparent demand. According to Beltopgaz, all major gas consumers are connected to either the distribution or the transmission system and these are not considered as potential customers for LNG, in competition with piped gas.
- Gas-to-other fuels competition from LNG could be applicable in Belarus for road and waterways transport. Belarus Government policy is to favour electricity use, given that they expect cheap electricity to be produced from their Nuclear Power Plant planned to be commissioned soon, and concurrently the use of electricity in transport (road, rail and water) is of priority for the country, compared to development of other alternatives, such as LNG. On the other hand, Belarus is home to manufacturers of trucks and heavy work vehicles (MAZ, BELAZ), which have already launched pilot projects for LNG fuelled vehicles. The country has a sizeable fleet of local and imported international long haulage trucks (over 12,000 in 2013), as well as diesel heavy tractors, that could be potentially converted to use LNG as fuel. Gazprom Transgas Belarus is considering a small-scale liquefaction facility primarily for supplying LNG to filling stations.
- LNG as fuel for ships operating in Belarusian waterways could also be an applicable option, as the country has a number of waterways where passenger and cargo ships operate. The Belarus Ministry of Transport and Communications is interested to assess this option. It is noted that the use of LNG in vessels would compete with other technologies, such as the use of electric propulsion systems and electric powered ships for Belorussian waterways, which is being examined by the Ministry of Transport and Communications (a relevant study was initiated in 2018).

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- No significant prospects seem to exist in gas-to-other fuels competition for the supply of remote/off-grid customers. Gasification is high across the country; almost all consumers are gasified apart from households. CNG is extensively used in agricultural sector, where 50% of users are connected to the grid, and the national strategy is to promote biomass and peat for energy use.

Based on the above analysis, the applicable LNG market development options for Belarus concern the use of LNG as engine fuel in trucks, and potentially in waterways (Table 12). Potential sources of LNG supply can either be the EU LNG terminals close to Belarus (Świnoujście, Klaipeda) or development of an in-country mini liquefaction facility connected to the Belarusian transmission system.

Table 12: Applicable options for LNG market development in Belarus

Options for LNG market development		Sources of supply
Gas-to-Other Fuels Competition	LNG as engine fuel for long-haul trucks	• Truck loading in Świnoujście and/or Klaipeda terminals • In-country mini liquefaction facility
	LNG as engine fuel for vessels in Belarusian waterways	

5.2 Assessment of viability of applicable LNG market options

5.2.1 Use of LNG as engine fuel for trucks

This LNG market development option can be considered as potentially viable for Belarus in case the LNG price at the filling station is competitive to that of diesel, taking into consideration the efficiency gains of LNG engines, as well as all costs associated with the LNG supply chain.

The available information on the traffic of long-haul trucks (local and transit) in Belarus is not sufficiently detailed to allow reasonable assumptions to estimate the market size of LNG as fuel for trucks. For this reason, instead of performing a netback analysis to estimate the maximum price of LNG to be competitive to diesel, we estimate the LNG market size (number of LNG-fuelled trucks and annual LNG volumes consumed) required for prices of LNG and diesel to be on par, under different scenarios of LNG/natural gas prices at the beginning of the supply chain.

The potential LNG supply sources examined for Belarus include the LNG terminals in Świnoujście and Klaipeda, and an in-country mini liquefaction facility. For each source, a base price and positive/negative sensitivities, as displayed in Table 13, have been assessed.

Table 13: Examined prices of LNG/natural gas at the source for Belarus

Terminal	Assumed price at terminal (EUR/1000m^3)				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Świnoujście LNG terminal[26]	200	250	300	170	150
Klaipeda LNG terminal[27]	200	250	300	170	150

[26] As information is not available, the same price as Klaipeda is used

[27] Source: DG Energy, "Gas Market Report Q2 2019"

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In-country mini liquefaction facility[28]	234	293	351	200	175

The analysis has been carried out for long-haul trucks retrofitted to use LNG, traveling 91,000 km per annum. The costs for development of a new filling station for LNG is considered (development of a new L-CNG station or upgrade of an existing CNG station would result in lower costs). The competing price of diesel has been assumed to be at the current market level, of 0.59 EUR/lt[29]. The detailed approach and calculations are presented in Annex 3.1. It is noted that cases in which the minimum LNG market size is estimated to require over 1,000 LNG-fuelled trucks are not further analysed.

Figure 5 presents the minimum number of LNG-fired trucks that have to operate in Belarus, and the minimum LNG volumes to be supplied annually, for the market to be developed, in case the base price applies at the LNG source.

Figure 5: Minimum number of LNG-fired trucks for market development in Belarus and corresponding annual LNG market size, under base price[30]

(a) Minimum number of LNG-fired trucks *(b) Minimum LNG market size*

The minimum number of LNG-fired trucks for the Belarusian case, for all price scenarios and LNG supply variants are presented in Figure 6.

[28] Gas price for large end users, including transmission cost (Source: input provided from the Ministry of Energy of Belarus)

[29] Source: Input provided from the Ministry of Energy of Belarus

[30] N/A denotes market size requiring over 1,000 LNG-fuelled trucks

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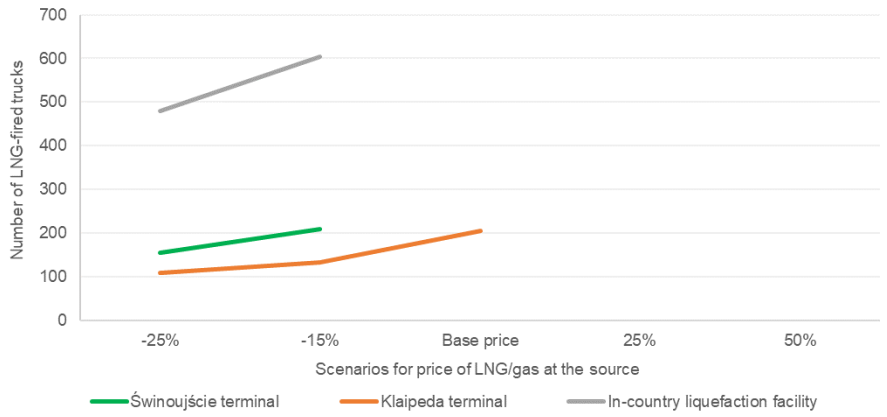
Figure 6: Minimum number of LNG-fired trucks in Belarus for all price sensitivities[31]



The results of the analysis show that for supply prices higher that the current ones, the use of LNG in road transport, under the examined assumptions, are non-viable. At the base price, LNG supplies from Klaipeda terminal (the closest one to Belarus) can be competitive to diesel, in case more than 200 LNG-fuelled trucks refuel in Belarus, while with a market of similar size supplies from the Świnoujście terminal could also be attractive in case LNG prices decrease. Use of a mini liquefaction terminal would require a considerably larger market, together with a decrease of LNG prices.

Considering that Belarus has a sizeable fleet of local and imported international long haulage trucks (over 12,000 in 2013), and local manufacturing of LNG-fueled trucks could lower switching costs, it seems that market for LNG in road transport could potentially develop, in case the LNG prices remain at the assumed base price or less. Consequently, using LNG as engine fuel for trucks can be considered as a potentially viable option for Belarus. It is noted that in order to better size the size of the market, and its attractiveness, analysis of detailed data on the operation of long-haul trucks (such as number of local and transit trucks, destinations and distances covered) in Belarus would be required.

Economic analysis was performed for the identified minimum required LNG market, to estimate the extent to which economic benefits for using LNG as engine fuel (energy cost reduction for end consumers, impact on GHG emissions) outweigh the costs for developing the option. The analysis shows that the reduction of GHG emissions has a positive impact (Figure 7).

[31] Values exceeding 1,000 LNG-fired trucks are not presented.

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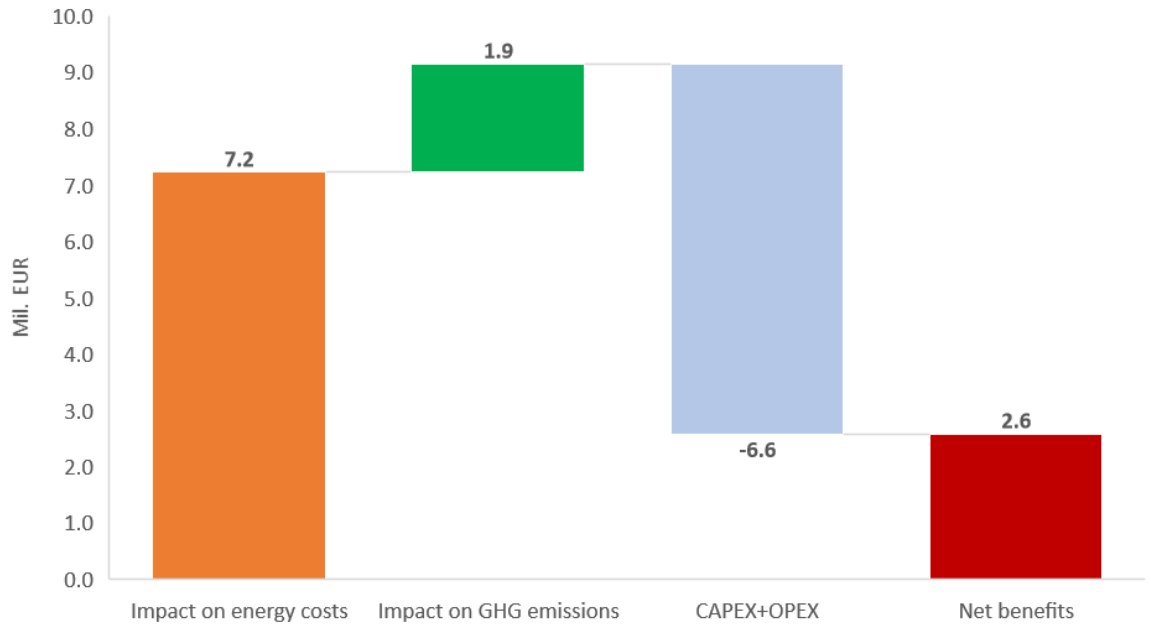
Figure 7: Present value of economic costs and benefits for use of LNG as engine fuel for trucks in Belarus



5.2.2 Use of LNG as engine fuel for ships

The Belarusian inland fleet comprises small vessels (one self-propelled barge, 147 pushed barges with an average capacity of 769 metric tons and 72 push and tow boats[32]).

The use of LNG as fuel for such small vessels is challenging, even in case LNG price can be lower than the existing bunkering fuels, as the large LNG fuel tanks take up storage capacity, affecting the ship's productivity and freight earnings. Thus, the application potential for smaller newbuilds running on LNG is limited, while retrofit of vessels in operation is not suitable for all types of small vessels, and its cost can be higher than that of a newbuild[33].

Push boats and barges that are predominant in Belarus cannot be adapted to LNG, because they do not have room to place an LNG tank. The use of LNG in newbuilds for the Belarusian waterways, or potentially retrofitting of existing vessels should be examined on a case-by-case basis, as it depends on financial (cost for retrofitting, LNG price) and technical factors (tank space, safety issues). It is also noted that LNG would compete with other potential new options, such as the use of electric propulsion systems and electric powered ships for Belorussian waterways, (a relevant study was initiated by the Ministry of Transport and Communications in 2018).

[32] Source: Draft of the White Paper on efficient and sustainable inland water transport in Europe, revised – 10 October 2009 - Working Party on Inland Water Transport - Working Party on the Standardization of Technical and Safety Requirements in Inland Navigation (SC.3/WP.3)

[33] Source: L. Simmer et Al (Journal of Clean Energy Technologies), "Liquefied Natural Gas as a Fuel in Inland Navigation: Barriers to Be Overcome on Rhine-Main-Danube", July 2016

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5.3 Prerequisites and key success factors for potentially viable LNG market options

5.3.1 Use of LNG as engine fuel for trucks

Table 14 describes the key prerequisites for effective implementation of the option of using LNG as engine fuel for trucks in Belarus. The prerequisites concern the appropriate price differential between LNG and diesel to ensure viability, as well as the necessary changes in the legal and regulatory framework, or introduction of new legislation and regulations, including permits and licenses. The prerequisites relate not only to import and operation of trucks. For example (under prerequisite #5 below), there is already a Belarusian Regulation on Safety Transportation of Dangerous Cargos by Road Transport (No 61 of 2010). LNG is included in this regulation and classified in accordance with UN codes. Other prerequisites relate to the supply chain for LNG concerning trucks: filling stations, liquefaction plants and truck loading facilities at these plants. The interest of sufficient truck owners to switch to LNG, and the attraction of investments to develop the necessary infrastructure (filling stations, liquefaction facilities) is also critical for the development of the market.

Table 14: Prerequisites for development of LNG as engine fuel for trucks

	Prerequisite	Rationale	Involved country(ies) or parties	Difficulty of implementation
Market				
1	Sufficient price differential between LNG and diesel (as discussed in Section 5.2.1)	Critical – on/off condition, as switching to LNG requires an attractive price of LNG vis-à-vis diesel at the end use	Belarus is responsible for avoiding subsidies that distort price differential. LNG and diesel source prices are determined in accordance with international demand and supply conditions (except in the case where LNG is sourced from an in-country liquefaction facility, in which the price is determined by gas import contracts)	Uncertain
2	Interest of a critical mass of truck owners to switch to LNG	Viability of the option is dependent on having a minimum market size to justify investments	Decision of truck owners	Medium
Legal & Regulatory				
1	Regulations and standards for the design, manufacturing and	Need to ensure safety, efficiency, quality and	Under the sole control of Belarus	Low

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	installation of the LNG fueled trucks and different components (e.g. pressure control regulator, LNG filling receptacle etc.) for approval of LNG vehicles import and operation[34, 35]	environmental protection. There are various European and international standards that could be incorporated in national legislation as the basis for granting approval.		
2	Road regulations for circulation of LNG fuelled vehicles	Need to ensure safety, by stipulating any restrictions in movement e.g. in cases of heavy traffic, adverse weather conditions affecting visibility and road conditions etc.	Under the sole control of Belarus	Low
3	LNG and L-CNG filling stations permits and licences, notably building license, operation license, and business license[36]	Need to ensure the eligibility of the selected site for the station, compliance with operational obligations (e.g. opening hours, station throughput, safety obligations, and business registration of the entity. The licenses require testing and acceptance processes and mechanisms at state/municipal level, before licences are granted and after (inspection/checks for compliance)	Under the sole control of Belarus	Low
4	LNG and L-CNG filling stations regulatory guidelines[36] in relation to set-up and construction (e.g. distance, tank levels etc.), operation (e.g. guarantee sufficient product), and maintenance (planned maintenance work in a	Need to ensure safety and efficiency of the station. The regulations require testing and acceptance processes and mechanisms at state/municipal level, before licences are	Under the sole control of Belarus	Low

[34] DG MOVE, LNG Blue Corridors, Vehicle Regulations - State of the Art, December 2013
[35] DG MOVE, LNG Blue Corridors, LNG stations Regulations -State of the art, December 2013
[36] DG MOVE, LNG Blue Corridors, Guidelines for set up & operation of stations, May 2015

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	programmed schedule) of the station.	granted and after (inspection/checks for compliance)		
5	Road safety regulations for trucks carrying LNG to the filling stations.	LNG transportation carries some potential hazards, linked to flammability as well as the impact of cryogenic fuel exposure or leakage. There are standards that could be adopted (3 years ago, LNG and CNG were included in the ADR.	Under the sole control of Belarus	Low
6	Permits and licences, including technical specifications, for liquefaction facilities (in case LNG is sourced from the gas network and loaded on to trucks)	Need to have permits and regulations for site requirements, health and safety considerations, transportation infrastructure, availability of key utilities, air emissions and wastewater treatment.	Under the sole control of Belarus	Low
7	Permitting process, including technical specifications, for truck loading at liquefaction facility (in case there is a liquefaction facility)	Need to have permits and regulations specifying layout requirements and operational aspects, to address safety issues including fire protection.	Under the sole control of Belarus	Low
8	(Amendment to) law to specify whether/which type of liquefaction facilities are regulated (TPA and pricing)		Under the sole control of Belarus	Low
9	Regulations governing TPA of LNG trucks at liquefaction facility (in case there is a regulated liquefaction facility with TPA)	Need to establish rules and procedures for how truck operators will use the truck loading facilities, including LNG truck approval procedure, LNG specifications, procedures for determining the LNG mass loaded etc.	Under the sole control of Belarus	Low
10	Regulations governing pricing of liquefaction	Non-discriminatory and published tariffs	Under the sole control of Belarus	Low

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	facility (in case there is a regulated liquefaction facility with regulated pricing)	for use of the liquefaction plant services are required, in case of TPA to the facility. Such tariffs ought to be accompanied by regulations for the costs allowed to enter the tariff		
Infrastructure				
1	Interest of investors to implement necessary infrastructure (filling stations, in-country liquefaction facility)	The required infrastructure must be developed in time for the LNG-fuelled trucks to be able to operate	Decision of investors	Medium

Table 15 outlines the key success factors for the implementation of the option of using LNG as engine fuel for trucks. These factors influence the speed of market development. Some of the key success factors relate to the State providing support to catalyze investments in LNG trucks and filling stations. Others relate to having a regulatory framework that favors 'cleaner' LNG use in trucking and punishes more 'dirty fuels'. State can also regulate the level of subsidies in other fuels, to make LNG more competitive. Other prerequisites relate to the role of State and State organizations to foster changes and to support investors (one-stop-shop). Finally, the role of information campaigns for consumers, users and investors is important to overcome resistance to change and to boost interest.

Table 15: Key success factors for development of LNG as engine fuel for trucks

	Key success factors	Rationale
1	Conducive fiscal framework (low taxes, low import duties, availability of state grants and rebates) for the purchase of LNG fuelled trucks or the retrofitting of existing trucks to LNG.	
2	Setting and enforcing circulation restrictions for trucks that use older generation engines with higher emissions detrimental to the environment (e.g. Euro 4 fuels)	
3	Reduction of subsidies and favourite tax treatment of fuels competing with LNG, to make LNG more competitive and incentivise its use.	
4	Conducive fiscal framework (specific concession regimes, tax holidays, state grants[37]) conducive to investment in construction of new LNG filling stations, or for retrofitting petrol stations to include LNG, or for retrofitting CNG stations to offer also LNG (L-CNG). Also, state co-funding of LNG R&D activities	Having sufficient network of LNG stations is a major success factor. Incentivising private investment is one way to develop the market.

[37] 'Connecting Europe Facility', for example, provides grant to co-finance investment in LNG filling stations in the EU

5	Awareness and promotion campaigns for LNG.	Consumers should be educated as to the potential features and benefits of LNG in transport. Investors should be informed on the opportunities available. Such campaigns can counter resistance to change and speed up interest.
6	Having a 'National champion' e.g. the Ministry of Energy or a State Committee that includes gas company and other key stakeholders. The role of the National champion would be to coordinate the set-up of the required legal and regulatory framework, develop and implement policy and incentives, to remove obstacles in for LNG market development and to act as one-stop-shop for investors. Its role would also include planning the number and location of LNG filling stations and facilities (possibly introducing limited concessions for infrastructure) so as to avoid stranded investments.	Many initiatives are slowed down by regulatory gaps or unclear legislation, lack of implementing administrative mechanisms and bureaucracy and lack of action. Such problems are exacerbated due to lack of awareness and resistance to change or inertia. For example, customs may not be familiar with rules and regulations for the new LNG vehicles and delay their clearance.

5.3.2 Use of LNG as engine fuel for ships

Table 16 describes the key prerequisites for effective implementation of the option of using LNG as engine fuel for inland waterway vessels. The prerequisites concern appropriate price differential between LNG and fuel oil to ensure viability, and the introduction of necessary regulations concerning LNG vessels' design and operation, as well as regulations and permits concerning bunkering facilities. The choice of ship owners to use LNG as fuel and the development of required infrastructure along the waterways is also critical for the development of the market.

Table 16: Prerequisites for development of LNG as engine fuel for ships[38]

	Prerequisites	Rationale	Involved country(ies) or parties	Difficulty of implementation
Market				
1	Sufficient price differential between LNG and fuel oil (as discussed in Section 5.2.2), to justify fuel switching for the type of vessels operating in Belarusian waterways	Viability of the option is dependent on LNG being competitive to fuel oil for use in shipping, so that investments in fuel conversion for the particular vessels can be recovered	LNG and fuel oil source prices are determined in accordance with international demand and supply conditions (except in the case where LNG is sourced from an in-country liquefaction facility, in which the price is determined by gas import contracts)	Uncertain

[38] In case of LNG supplied from liquefaction facilities to inland ports via trucks, the relevant points of Table 14 also apply.

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2	Interest of ship owners to retrofit or build new LNG-fueled vessels, based on technical feasibility and financial attractiveness	There are alternative options to be applied by ship owners to reduce costs and emissions	Decision of ship owners	Medium to high
Legal & Regulatory				
1	Codes and Regulations for the design of LNG ships, based on the Environmental and Emissions legal framework related to European inland waterways, including UNECE Resolutions No 21 and 61, Regulation (EU) 2016/1628, European Standard laying down Technical Requirements for Inland Navigation vessels (ESTRIN)	Need to ensure safety, efficiency, quality and environmental protection.	Under the sole control of Belarus	Low
2	Codes and Regulations for the design and operation of LNG bunkering facilities, based on ISO guidelines (for systems and installations for supply of LNG as fuel to ships) as well as other international guidelines	Need to ensure safety, efficiency, quality and environmental protection.	Under the sole control of Belarus	Low
3	LNG bunkering facilities permits and licences	Need to ensure the suitability of the selected site for the facility, compliance with operational obligations (e.g. opening hours, station throughput, safety obligations) etc. The licenses require testing and acceptance processes and mechanisms at state/municipal level, before licences are granted and after (inspection/checks for compliance)	Under the sole control of Belarus	Low
Infrastructure				

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1	Implementation of necessary infrastructure (LNG bunkering infrastructure at inland ports)	The required infrastructure must be developed in time for the LNG-fuelled vessels to be able to operate	Decision of State and/or private investors	Medium

Table 17 outlines the key success factors for the implementation of the option of using LNG as engine fuel for vessels. These factors influence the speed of market development. Some of the key success factors concern the implementation of environmental and emission requirements for inland waterways that can influence the choice of LNG driven ships, especially newbuilds, vis-à-vis ships using other low emission fuels. Other key success factors relate to having a legal framework conducive to investments and access to finance for the large investments needed. Another factor for LNG fueled ships is the availability of adequate bunkering infrastructure.

Table 17: Key success factors for development of LNG as engine fuel for ships

	Key success factors	Rationale
1	Technical constraints (tank sizes), reliability, operating costs advantages (driving from low LNG price and fuel efficiency) and environmental advantages of LNG fuelled ships are maintained over the long term, so as to justify large investment in LNG ships	
2	Compliance of Belarus with environmental/ emissions requirements for inland waterways	Incentive for the use of cleaner fuels, such as LNG
3	Availability of finance (loans, grants etc.) for investment in LNG ships.	Access to finance is key. Investment costs for new ships are significant for shipping companies, whereas retrofits are also costly as larger fuel tanks are required.
4	Availability of adequate bunkering infrastructure	
5	National legislation conducive to investments in ships and/or bunkering infrastructure	

5.4 Priorities and policy directions

The use of LNG as fuel for trucks was the only option analyzed showing, under conditions, to be viable. Availability of LNG in neighboring terminals facilitates the development of the required supply chain over a short-term horizon.

The Government could assess feasibility in detail further and take relevant policy actions. These policies could encompass, at the minimum, having a legal and regulatory framework conducive to the development of an LNG supply chain, and could expand to cover incentives for the use of LNG.

The applicability of LNG use as fuel for the ships operating in Belarus' waterways appears to be limited, due to the small size and limited utilization of vessels vis-à-vis investment requirements. Nevertheless, in case the Government decides that this option is of interest, it should undertake contextualized analysis, to identify whether there are any types of vessels for which switching to LNG may be attractive, assessing also competitiveness against other technologies being examined by the Belarusian State (e.g. electric propulsion).

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5.5 Proposed actions

The Table below describes the actions that are deemed important in order to evaluate and prepare the identified applicable LNG market development options.

Table 18: Proposed preparatory actions for developing the identified LNG options in Belarus

	Proposed Actions	Timing
Initial / Preparatory Actions		
1	Perform feasibility study for the use of LNG as engine fuel for trucks	Immediate
2	Develop a national policy framework for the use of LNG in road transport, deciding on the role that the State wishes to undertake	Short-term / After the study for road transport is concluded (in case the study is positive and Belarus decides to pursue)
3	Perform feasibility study for the use of LNG as engine fuel for ships	Short-term / In case Belarus decides to pursue
4	Inclusion of the use of LNG as engine fuel for ships in the national policy framework	Short-term / After the study for water transport is concluded (in case the study is positive)
Implementation Actions		
5	Prepare the regulatory and legal framework (legal amendments, regulations, standards, permits and licenses, etc.) necessary for the development of the LNG supply chain	Short-term / based on national policy framework
6	In case the State undertakes a proactive role in developing infrastructure, prepare the incentive mechanisms to attract investments	Short-term / based on national policy framework
7	Conduct awareness raising campaigns to attract end-users and investors' interest	Short-term / based on national policy framework

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6 LNG Market Prospects in Georgia

6.1 Identification of applicable LNG market development options

An overview of the Georgian gas sector is provided in Annex 1.4. Following the analysis of the gas market information, and discussions with stakeholders during the field visit to the country, the key findings related to the development of LNG markets in Georgia are as follows:

- Gas-to-gas competition from LNG could be applicable in Georgia. Currently there is no possibility for Georgia to receive regasified LNG through its gas pipeline interconnections with Russia, Turkey, Armenia and Azerbaijan; only in case Georgia develops its own LNG receiving terminal (smaller size than the one in Ukraine), which the stakeholders consider as interesting to explore. This option is nevertheless heavily dependent upon Turkey agreement to allow LNG vessels' passage through the Bosporus Straits.
- Georgia can facilitate gas-to-gas competition from LNG in other countries. Georgia is interested to establish an LNG liquefaction port terminal for exporting LNG to Ukraine, Moldova (via Ukraine) and further to EU markets (Romania, Hungary). This option is nevertheless subject to availability of gas to be liquefied from Azerbaijan. Azeri supplies could be possible only over the mid-term, given that all current Azeri supplies have been already contracted and new fields would have to be developed for this purpose. Kazakhstan and Turkmenistan could also be a potential supplier for this project over the long term, in case Caspian gas is transited to Azerbaijan (through pipe or through an LNG receiving terminal in the Caspian Sea).
- Swaps of piped gas for LNG landing in Turkish terminals, or terminals in SE Europe (Greece and Italy) is a potential option for gas-to-gas competition, under certain conditions. This option is dependent on Turkish LNG terminals are accessible to such deals, BOTAS agreeing to have such a swap with GOGC, and also that contractual arrangements between SOCAR and BOTAS allow Georgia to off-take gas from the SCP.
- Gas-to-other fuels competition from LNG could be applicable in Georgia for road transport. According to stakeholders, Georgia appears to have a sizable international long-haul traffic (export/imports and transit) that could merit the use of LNG as truck fuel.
- Gas-to-other fuels competition could be also applicable to remote/off-grid customers. Although over 80% of gas customers are connected to the grid, LNG supply could still be an option to supply selected off-grid consumers and areas (mainly mountainous towns and resort areas etc.), within the frame of the Government's aim to increase even further the country's gasification. GOGC may be interested to establish a small-scale liquefaction facility, to supply LNG filling stations and off-grid remote consumers.
- Gas-to-other fuels competition does not seem applicable to sea transport, at least over the short to mid-term. Given that the Black Sea is not an Emission Control Area for the

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IMO, the requirement to reduce sulphur emissions from the current 3.5% to 0.5% sulphur, as of 1/1/2020, can be addressed with other means (scrubbers, MGO with reduced sulphur etc.) instead of using LNG in ships. Additionally, stakeholders informed us that large ships refuel in Turkish ports, as opposed to Georgian ports.

Based on the above analysis, the applicable LNG market development options for Georgia, for gas-to-gas and gas-to-other fuels competition, are presented in Table 19. LNG for gas-to-other fuels competition can be sourced from an in-country receiving terminal, liquefaction terminal or mini liquefaction facility, depending on the development of the market. It is noted that development of an LNG receiving terminal in Georgia can only be possible in case an agreement with Turkey is concluded for the passing of LNG vessels through the Bosporus Straits.

It should be noted that gas-to-other fuels options cannot be considered as drivers for the development of an in-country receiving or liquefaction terminal but can benefit in case such infrastructure goes ahead.

Table 19: Applicable options for LNG market development in Georgia

Options for LNG market development		Sources of supply
Gas-to-Gas Competition	Regasified LNG through the development of an in-country LNG receiving terminal in the Black Sea	Potential in-country receiving terminal
	Swap of regasified LNG landing at LNG terminals in Turkey or SE Europe with piped gas supplied to Georgia through the SCP offtake	LNG receiving terminals in Turkey (Marmara Ereglisi), Greece (Revythoussa, planned Alexadroupolis FSRU), Italy (Panigaglia)
Gas-to-Other Fuels Competition	LNG as engine fuel for long-haul trucks	• In-country receiving terminal • In-country liquefaction terminal • In-country mini liquefaction facility
	LNG supplies to the remaining off-grid towns and consumers in Georgia, located in mountainous areas, to increase gasification	

The potential development of a liquefaction terminal in Georgia, for Caspian gas, is considered in the analysis as an additional source of LNG supplies in other Eastern Partners, particularly Ukraine and Moldova (through Ukraine).

6.2 Assessment of viability of applicable LNG market options

6.2.1 Supply of regasified LNG from in-country terminal

This LNG market development option can be considered as potentially viable for Georgia in case regasified LNG can arrive at a Georgian receiving terminal at a price competitive to that of the existing gas supply sources for the market, taking into consideration all relevant transportation costs. Agreement with Turkey for passing of LNG vessels through the Bosporus Straits in an on/off precondition for this option to be developed.

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The Georgian terminal is assumed to be located in the Black Sea, near Poti. The development of a terminal with send-out capacity of 1 bcm/yr is assumed[39], taking into consideration the size of the Georgian gas market.

To estimate the competitiveness of LNG, netback analysis was performed, starting from the gas price in Georgia, up to the terminal, taking into consideration in-country transportation costs and charges for the use of the terminal. The detailed approach and calculations are described in Annex 2.2.

The calculations are carried out using 3 scenarios of import gas prices in Georgia, so as to assess different cases of import price evolution. The current price of imported Azeri gas, for the commercial part of the market, amounts to 200 EUR/ 1000 m^3, and has ranged from 165 – 245 EUR/ 1000 m^3 in the recent years[40]. However, an emerging supply gap is observed in the coming years, due to the expected growth of demand and the expiry of the existing contracts for the optional and additional gas, after 2025. In this context, the price scenarios examined correspond to the current level of import price plus transmission tariff (206 EUR/1000 m^3), a moderate (25%) price increase (256 EUR/1000 m^3) and a high (50%) price increase (306 EUR/1000 m^3). As the terminal charges depend on its utilization rate, we examine cases of low (30%), medium (50%) and high (70%) utilization.

Figure 8 presents the results of the netback analysis for all examined price scenarios and utilization rates.

Figure 8: Netback analysis results for supplies of regasified LNG from in-country terminal in Georgia, all examined import prices and utilization rates

LNG price in the Black Sea can be expected to be higher than that of the Mediterranean, due to the additional transport costs and fees for crossing through the Bosporus Straits. With LNG import price at the Greek Revythoussa terminal at 210 EUR/1000m^3 in Q2 2019[41], it is assumed that the corresponding price in the Black Sea will be at least 5% higher.

[39] For a small-scale LNG receiving facility such as this, detailed analysis is required to determine which technological option (on-shore terminal, FRSU or FSU) is the optimum one.

[40] Source: Department of Strategic Planning and Projects of GOGC

[41] Source: DG Energy, "Gas Market Report Q2 2019"

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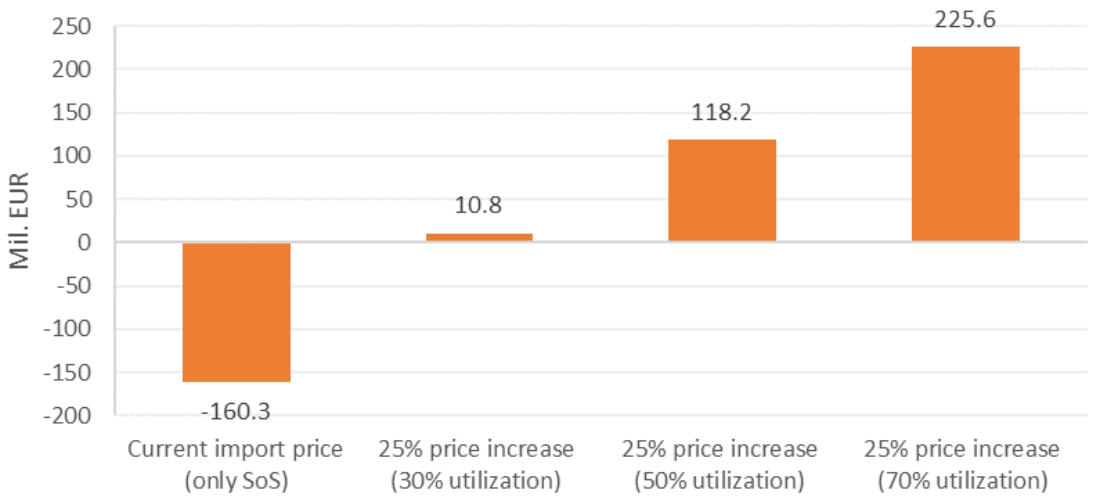
The results of the netback analysis show that the financial attractiveness for development of a receiving terminal in Georgia depends on the level of gas import prices. Under the examined assumptions and market conditions LNG can be competitive for Azeri supplies at a price over 50% of the current levels (i.e. to have an import price differential of at least 70-80 EUR/1000 m^3 between LNG and piped gas). This is of particular importance after 2025, as the expiry of the existing contracts for supply of optional and additional gas from the SCP can lead to an increase in gas supply prices.

Economic analysis for this LNG option was conducted, to assess whether the benefits of developing an LNG terminal to the economy and society can outweigh its costs, even in case the price of Azeri gas does not increase at appropriate levels to allow the infrastructure to be viable. The analysis covers the scenarios of the import prices remaining at current levels or facing a moderate increase. The detailed approach and calculations are described in Annex 4.1.

Figure 9 presents the calculated economic net present value for each of the examined price scenarios and corresponding utilization rates.

Figure 9: ENPV results for supplies of regasified LNG from in-country terminal in Georgia, all examined import prices and utilization rates



The economic analysis results show that development of an LNG terminal in Georgia is viable in case LNG can be available at prices lower than those of Azeri gas, which result in both enhancing security of supply and reducing gas prices in the market. The use of the terminal only for security of supply purposes (in case LNG price exceeds that of piped gas) does not lead to positive results, as the examined LNG terminal with 1 bcm/yr capacity can only partially cover the demand curtailment that would occur in case of a supply disruption to the market (Figure 10).

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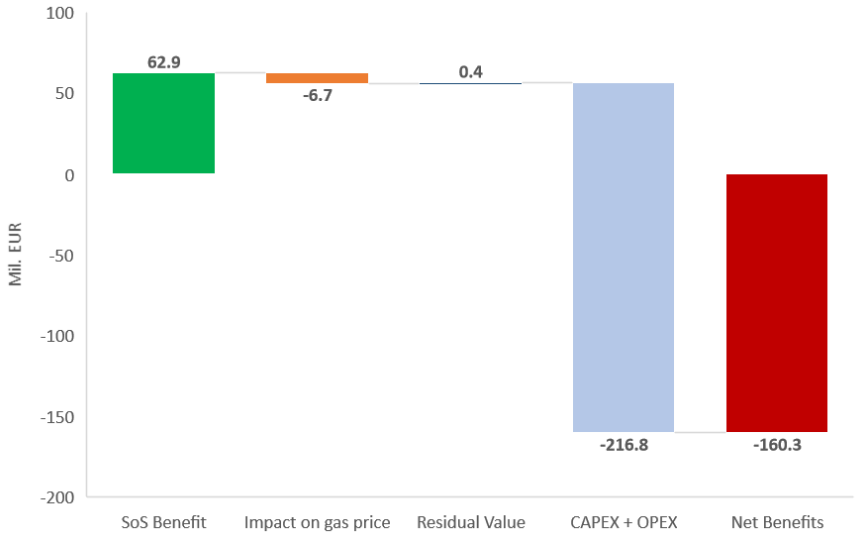
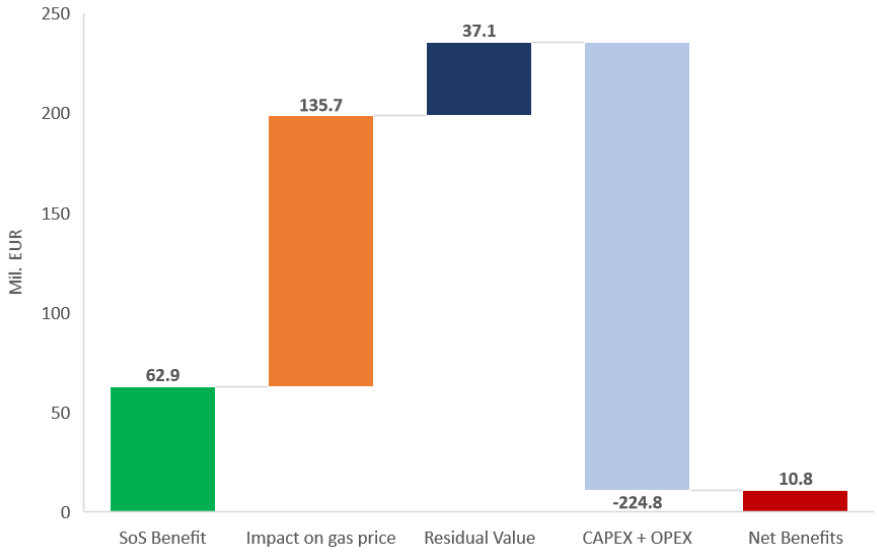
Figure 10: Present value of economic costs and benefits of in-country terminal in Georgia



(a) Current import price (only SoS)



(b) 25% price increase (30% utilization)

The impact of the LNG terminal in Georgia on the market is also highlighted by the quantitative indicators, presented in Table 20. The access to LNG increases the market players' ability to diversify routes, sources and counterparts of supply, that are currently limited to Azeri and Russian gas. Furthermore, the terminal can mitigate a potential disruption of infrastructure or supplies but cannot fully address it. The detailed approach and calculations of the indicators is provided in Annex 4.4.

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Table 20: Quantitative indicators for in-country terminal in Georgia

	W/o terminal	With terminal	Impact
N-1 indicator	61.5%	78.5%	Increase of system resilience to a large infrastructure disruption
Import route diversification	6,236	4,867	Increase of diversification of routes, sources and counterparts
Demand curtailment	72%	55%	Reduction of curtailed demand in case of disruption

Based on the above analysis, the development of an in-country LNG receiving terminal in Georgia can be considered as a potentially viable LNG option, in case the prices in the Georgian market are conducive to LNG supplies. It is noted, however, that this LNG market development option can only be realized in case an agreement is concluded with Turkey for the passage of LNG vessels through the Bosporus Straits.

6.2.2 Swaps of piped gas with regasified LNG in Turkish or EU terminals

The swap of regasified LNG landing at a terminal in Turkey, Greece or Italy with piped gas delivered to Georgia through its offtake of the SCP would require an agreement between the involved parties, to allow this virtual gas exchange. For the supply of LNG at a Turkish terminal, GOGC should reach an agreement with BOTAS, for the swap of gas and delivery at the SCP offtake. For the supply of LNG at the Greek or Italian terminals, a trilateral agreement would be required, between GOGC, a supplier active in the SE European markets holding sufficient volumes to perform the swap, and BOTAS, for the delivery of piped gas at the SCP offtake.

Development of this option is conditional upon the following:

- Price of LNG supplied at the selected terminal (including costs for use of terminal and entry at the transmission system) is lower than the price of gas contracted by BOTAS in SCP. In case the price of LNG is higher, the price differential would have to be covered by GOGC.
- Import prices of Azeri gas in the Georgian market are higher than the agreed price for the swap (inclusive of the cost of LNG, any price differential to be paid by GOGC, and service fee to be paid to the counterpart supplier).
- The contractual arrangements between SOCAR and BOTAS for the supply of gas through SCP allow BOTAS to deliver gas at the Georgian gas offtake.

Following the recent completion of the SCP expansion (SCPx), there is sufficient capacity to supply the Georgian market. To perform the swaps, GOGC should book the corresponding physical capacity at the targeted terminal. In this case, and since the exchange is virtual, there are no requirements for booking physical capacity along the path from the terminal to the Georgian market.

The financial viability of this option cannot be assessed using benchmarks, as it depends on the negotiated price between GOGC and the supplier.

The implementation of swaps would benefit the Georgian market, as it would allow access to an additional source of gas, without the need for developing additional infrastructure.

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The potential for swaps should be further explored, in particular to ensure that there are no contractual constraints for the swap, and that the price differential would create a "win-win" case for all involved parties.

6.2.3 Use of LNG as engine fuel for trucks

This LNG market development option can be considered as potentially viable for Georgia in case the LNG price at the filling station is competitive to that of diesel, taking into consideration the efficiency gains of LNG engines, as well as all costs associated with the LNG supply chain.

The available information on the traffic of long-haul trucks (local and transit) in Georgia is not sufficiently detailed to allow reasonable assumptions to estimate the market size of LNG as fuel for trucks. For this reason, instead of performing a netback analysis to estimate the maximum price of LNG to be competitive to diesel, we estimate the LNG market size (number of LNG-fuelled trucks and annual LNG volumes consumed) required for prices of LNG and diesel to be on par, under different scenarios of LNG/natural gas prices at the beginning of the supply chain.

The potential LNG supply sources examined for Georgia include an in-country LNG receiving terminal or liquefaction terminal and mini liquefaction facility. For each source, a base price and positive/negative sensitivities, as displayed in Table 21, have been assessed.

Table 21: Examined prices of LNG/natural gas at the source for Georgia[42]

Terminal	Assumed price at terminal (EUR/1000m^3)				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Georgia LNG receiving terminal[43]	220	275	330	187	165
Georgia liquefaction terminal[44]	222	277	333	189	166
In-country mini liquefaction facility[44]	222	277	333	189	166

The analysis has been carried out for long-haul trucks retrofitted to use LNG, traveling 91,000 km per annum. The costs for development of a new filling station for LNG is considered (development of a new L-CNG station or upgrade of an existing CNG station would result in lower costs). The competing price of diesel has been assumed to be at the current market level, of 0.71 EUR/lt[45]. The detailed approach and calculations are presented in Annex 3.1. It is noted that cases in which the minimum LNG market size is estimated to require over 1,000 LNG-fuelled trucks are not further analysed.

[42] LNG could potentially be sourced from the Revythoussa terminal in Greece, once truck loading facilities are developed. However, due to the large distance to Georgia (over 5,000 km round-trip), only circumstantial supplies could be considered, and therefore not analysed further

[43] The price for LNG in Black Sea is assumed to be the price at the Greek Revythoussa terminal (210 EUR/1000m^3, source: DG Energy, "Gas Market Report Q2 2019"), with an uplift of 5% to reflect additional transportation cost and crossing through the Bosporus straits.

[44] Equal to the gas price in the Georgian market (Source: GEOSTAT)

[45] Source: SOCAR Georgia website (accessed 1/11/2019)

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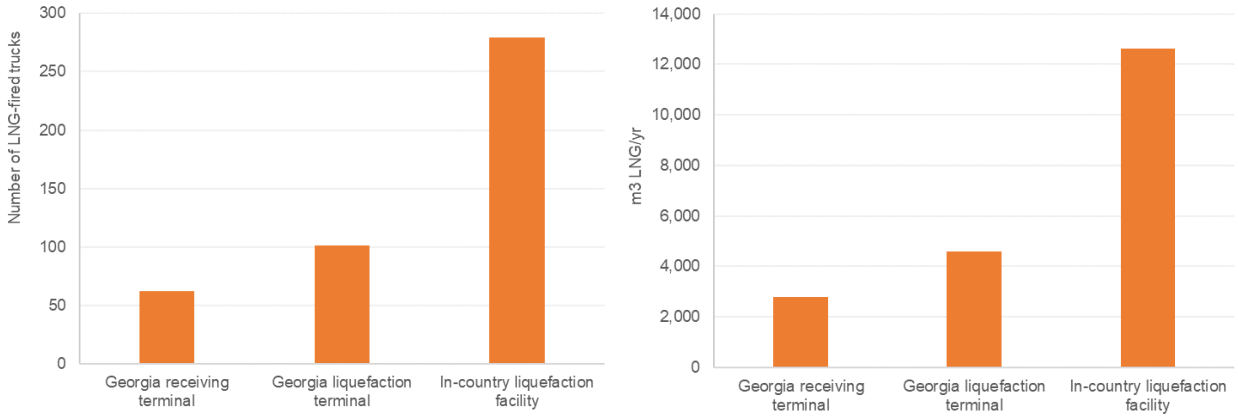
Figure 11 presents the minimum number of LNG-fired trucks that have to operate in Georgia, and the minimum LNG volumes to be supplied annually, for the market to be developed, in case the base price applies at the LNG source.

Figure 11: Minimum number of LNG-fired trucks for market development in Georgia and corresponding annual LNG market size, under base price

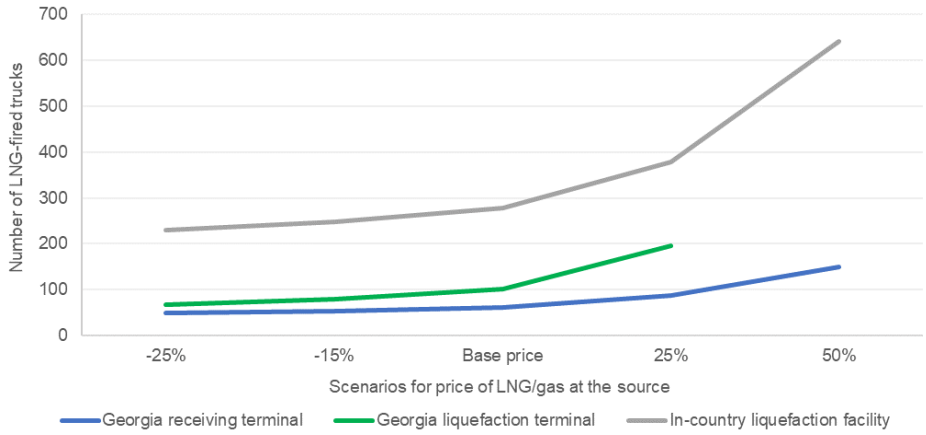


(a) Minimum number of LNG-fired trucks

(b) Minimum LNG market size

The minimum number of LNG-fired trucks for the Georgian case, for all price scenarios and LNG supply variants are presented in Figure 12.

Figure 12: Minimum number of LNG-fired trucks in Georgia for all price sensitivities[46]



The results of the analysis show that at the base prices, use of LNG in road transport under the examined assumptions can be competitive to diesel with a market of 60 or 100 LNG-fired trucks, for supplies from an in-country receiving or liquefaction terminal, in case the preconditions for the establishment of such terminals are secured. Supplies from a mini liquefaction facility would require a considerably larger market, at least around 280 trucks. Even in case LNG prices

[46] Values exceeding 1,000 LNG-fired trucks are not presented.

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increase, supplies from a regasification or liquefaction terminal can remain competitive to diesel with a market of at least 200 trucks.

Considering that Georgia is a transit country for trade in the region, though its ports, it seems that a market for LNG in road transport could potentially develop, especially if the supply prices remain at the assumed base price or less. Consequently, use of LNG as engine fuel for trucks can be considered as a potentially viable option for Georgia. The sourcing of LNG from a possible LNG receiving terminal (assuming first the securing of agreement with Turkey for the Bosporus Straits and secondly the financial/economic viability of such a terminal) or a liquefaction terminal that also serves the Georgian market, would render enhanced possibilities for developing an LNG engine fuel market in Georgia, as the minimum required number of trucks to render the option viable is 60 and 100 respectively. The other sourcing option (mini liquefaction facility), would require fourfold number of trucks, in comparison. It is noted that in order to better size the size of the market, and its attractiveness, analysis of detailed data on the operation of long-haul trucks (such as number of local and transit trucks, destinations and distances covered) in Georgia would be required.

Economic analysis was performed for the identified minimum required LNG market, to estimate the extent to which economic benefits for using LNG as engine fuel (energy cost reduction for end consumers, impact on GHG emissions) outweigh the costs for developing the option. The analysis shows that the reduction of GHG emissions has a positive impact (Figure 13).

Figure 13: Present value of economic costs and benefits for use of LNG as engine fuel for trucks in Georgia

6.2.4 Supply of LNG to off-grid distribution systems

This LNG market development option can be considered as potentially viable for Georgia in case the natural gas price at the end customers at the areas targeted for gasification is competitive to that of firewood (the dominant fuel in urban areas outside big cities in Georgia), taking into consideration the efficiency gains of natural gas, and all costs associated with the LNG/natural gas supply chain.

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Annex 3.2 presents a case study for the largest off-grid town targeted for gasification. Due to the low price for firewood, the costs for switching from firewood to gas (including gas installation costs and a 20% price differential incentive) are higher (329 EUR/1000m^3) than the required price of gas to be competitive to firewood (280 EUR/1000m^3), considering fuel efficiency gains. Under these conditions, developing this option, to supply off-grid towns in Georgia with LNG is not considered viable.

6.3 Prerequisites and key success factors for potentially viable LNG market options

6.3.1 Supply of regasified LNG from in-country terminal

Table 22 describes the key prerequisites for effective implementation of the option of establishing an in-country LNG import terminal in Georgia. Critical/on-off prerequisites are the uninterrupted supply of LNG to the terminal i.e. the absence of any constraints for LNG vessels to pass through the Bosporus straits, and the existence of sufficient interest by potential users, as evidenced by market tests. Another important prerequisite relates to the availability of financing for the terminal, from State or private funds. The necessary changes in the legal and regulatory framework, including permits and licenses, are also detailed.

Table 22: Prerequisites for development of in-country LNG terminal

	Prerequisites	Rationale	Involved country(ies) or parties	Difficulty of implementation
Political				
1	Absence of any maritime or other constraints for LNG vessels to reach and supply the terminal	Critical - on/off condition, to ensure uninterrupted, prompt and adequate LNG supplies to the terminal	Under the control of Turkey. Negotiations need to be initiated by Ukraine and Georgia	High
Market				
1	Binding market tests confirming interest of suppliers to use terminal services before FID for the terminal is taken	Critical - on/off condition, to ensure there is secure and sufficient demand for the terminal's services to make it viable. A successful market test requires suppliers to take a view on the competitiveness of LNG price vis-à-vis the gas import price that will emerge following new supply contracts with Azerbaijan, post 2026 (as discussed in Section 6.2.1)	Decision of suppliers	Uncertain

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Legal & Regulatory				
1	(Amendment to) energy law to allow establishing of LNG terminal, including ownership, regulation, TPA provisions and pricing regulation	To add the right to establish terminal and the applicable framework in the law	Under the sole control of Georgia	Low
2	Permits and licenses for LNG terminal, including prerequisite technical studies, environmental and social impact assessment study	To ensure that all authorisations and preconditions are secured	Under the sole control of Georgia	Low
3	Regulations and standards for the siting, design, construction and installation of LNG terminal, including infrastructures (jetty and connections to transmission system)	Legislators and policy makers need to set the rules so as to ensure safety, efficiency, quality and environmental protection	Under the sole control of Georgia	Low
4	Regulations for the operation of LNG terminal	Legislators and policy makers need to set the rules so as to ensure safe, efficient and environmentally conducive terminal operation	Under the sole control of Georgia	Low
5	Regulatory license and process for accreditation of the terminal	Legislators and regulators need to set the rules (in accordance with EC Acquis), and terminal to comply	Under the sole control of Georgia	Low
Financing				
1	Securing adequate financing for the investment in the terminal	To ensure that the terminal can go ahead (FID)	Decision of State and/or investors	High
Infrastructure				
1	Connection of terminal to the transmission network and agreement between terminal operator and TSO	For the terminal to be able to send regasified LNG to the system, in accordance with pre-defined rules	Under the sole control of Georgia	Low

Table 23 outlines the key success factors for the implementation of the option of establishing an in-country LNG import terminal. These factors influence the speed of market development. Some of the key success factors relate to the strength of the project promoter (access to finance etc.) and the existence of investment partners and experienced operator. Other success factors relate to having a clear and effective strategy or the development of the terminal to avoid risks of delays

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and cost-overruns and having a contractual strategy/model that allocates fairly risks between contractors and developer. A conducive legal framework in the country as well as State support to the venture is important. For the terminal sustainability as a business, it is important to secure adequate customers, especially large off-takers, and to offer good service levels at a competitive price. Finally, flexibility both in terms of terminal infrastructure and in terms of services, to changes in market conditions, enhances sustainability.

Table 23: Key success factors for development of in-country LNG terminal

	Key success factors	Rationale
1	Strength (financial and otherwise) of the project promoter	Assurance for project completion and sustainability
2	Bring-in strategic investment partners that can bring expertise to the venture and mitigate risks	To ensure sustainability and mitigate business risks
3	Bring-in experienced operator/management team	To ensure sustainability and mitigate business risks
4	Establishing an effective project delivery strategy for the terminal (for project teams, partners, contractors, consultants, stakeholder engagement, safety, financing, technical solutions, risk management, project control and monitoring etc.)	To ensure prompt and effective construction
5	Use contractual models that balance and align interests of terminal developers/operator (locking-in key suppliers and reducing supply chain costs) and contractors/suppliers (having flexibility to deal with volatile commodity and service prices)	To ensure sustainability and mitigate business risks
6	Host country has predictable and conducive legal, contractual and regulatory framework	To avoid risks
7	Competitive prices for the terminal's services and good service levels	To ensure sustainability
8	Government is supportive in general for the venture, and specifically ensures timely issuance of terminal permits and authorizations	To avoid delays and risks
9	Existence of a market for LNG (regasified and in liquid form) that can sustain the terminal's operations.	To ensure sustainability
10	Dependence on one major off-taker or several off-takers.	One major off-taker is preferable to lenders, but also increases dependence compared to situation of a portfolio of off-takers
11	Terminal operation flexibility to adjust in case market conditions change (e.g. developing new services, pricing for unbundled services as opposed to bundled, flexibility to add new infrastructures such as jetty, tanks, truck loading facilities etc.)	To ensure adaptability and sustainability

Regasified LNG is a new source and route of gas supply that has the potential to enhance competition in the Georgian gas market, especially when the following factors apply:

- Development of an organized day-ahead and within-day gas market to take advantage of the flexibility and liquidity of LNG.

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- Completing the implementation of the obligations stemming from the Energy Community related to market operation and gas network codes that will enhance non-discriminatory and transparent access of regasified LNG to the Georgian network and market.

6.3.2 Swaps of piped gas with regasified LNG in Turkish or EU terminals

Table 24 describes the key prerequisites for performing swaps of regasified LNG in Turkey or SE Europe with piped gas delivered to Georgia. The prerequisites concern the interest by the involved parties to conclude a swap deal, the availability of LNG at prices that are conducive to the viability of the swap, and lack of any contractual barriers that would obstruct access to the SCP.

Table 24: Prerequisites for swaps of piped gas with regasified LNG

	Prerequisites	Rationale	Involved country(ies) or parties	Difficulty of implementation
Market				
1	Interest by all involved parties (BOTAS, potentially EU suppliers) to perform the swap. Agreement with BOTAS is necessary to allow swaps regardless of the terminal where LNG is delivered (Turkey or EU)	BOTAS currently is sole offtaker of Azeri gas through SCP, that can be swapped with LNG	Negotiations of GOGC with BOTAS, and EU suppliers, if necessary	Low to medium
2	The following two price preconditions should apply for a swap to be viable for both GOGC and BOTAS: • Price of LNG delivered at SCP is lower than the price of gas contracted by BOTAS in SCP. In case LNG price is higher, GOGC has to compensate BOTAS for the difference • Import prices of Azeri gas in the Georgian market are higher than the agreed price for the swap	The price of swapped LNG has to be beneficial for all parties involved	GOGC, BOTAS, and potentially EU suppliers	Uncertain
Contractual				
1	Terms & conditions of Azerbaijan – Turkey supply contract allow the delivery of gas by	As there is no third-party access to SCP, if BOTAS cannot have access to the Georgian offtake, the	Under the control of BOTAS and SOCAR	Uncertain

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	BOTAS at the Georgian offtake of SCP	swap concept cannot be realized		

Other than experience in developing swaps and procuring LNG, which could influence the efficiency of this option, there are no other notable success factors.

6.3.3 Use of LNG as engine fuel for trucks

Table 25 describes the key prerequisites for effective implementation of the option of using LNG as engine fuel for trucks in Georgia. The prerequisites concern the appropriate price differential between LNG and diesel to ensure viability, as well as the necessary changes in the legal and regulatory framework, or introduction of new legislation and regulations, including permits and licenses. The prerequisites relate not only to import and operation of trucks, but extend to the supply chain for LNG concerning trucks: filling stations, truck loading facilities at an in-country LNG terminal, in case this option is implemented and LNG is sourced from there, liquefaction plants and truck loading facilities at these plants, in case LNG is sourced from piped gas in the country. The interest of sufficient truck owners to switch to LNG, and the attraction of investments to develop the necessary infrastructure (filling stations, liquefaction facilities) is also critical for the development of the market.

It is noted that the prerequisites related to the import of LNG and the development of relevant import facilities in Georgia are listed separately in Section 6.3.1, and the perquisites to the development of a liquefaction and export terminal are listed in Section 6.3.4.

Table 25: Prerequisites for development of LNG as engine fuel for trucks

	Prerequisites	Rationale	Involved country(ies) or parties	Difficulty of implementation
Market				
1	Sufficient price differential between LNG and diesel (as discussed in Section 6.2.3)	Critical – on/off condition, as switching to LNG requires an attractive price of LNG vis-à-vis diesel at the end use	LNG and diesel source prices are determined in accordance with international demand and supply conditions (except in the case where LNG is sourced from an in-country liquefaction facility, in which the price is determined by gas import contracts)	Uncertain
2	Interest of a critical mass of truck owners to switch to LNG	Viability of the option is dependent on having a minimum market size to justify investments	Decision of truck owners	Medium
Legal & Regulatory				
1	Regulations and standards for the design,	Need to ensure safety, efficiency,	Under the sole control of Georgia	Low

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	manufacturing and installation of the LNG fueled trucks and different components (e.g. pressure control regulator, LNG filling receptacle etc.) for approval of LNG vehicles import and operation[47, 48]	quality and environmental protection. There are various European and international standards that could be incorporated in national legislation as the basis for granting approval.		
2	Road regulations for circulation of LNG fuelled vehicles	Need to ensure safety, by stipulating any restrictions in movement e.g. in cases of heavy traffic, adverse weather conditions affecting visibility and road conditions etc.	Under the sole control of Georgia	Low
3	LNG and L-CNG filling stations permits and licences, notably building license, operation license, and business license[49]	Need to ensure the eligibility of the selected site for the station, compliance with operational obligations (e.g. opening hours, station throughput, safety obligations, and business registration of the entity. The licenses require testing and acceptance processes and mechanisms at state/municipal level, before licences are granted and after (inspection/checks for compliance)	Under the sole control of Georgia	Low
4	LNG and L-CNG filling stations regulatory guidelines[49] in relation to set-up and construction (e.g. distance, tank levels etc.), operation (e.g. guarantee sufficient product), and maintenance (planned	Need to ensure safety and efficiency of the station. The regulations require testing and acceptance processes and mechanisms at state/municipal level,	Under the sole control of Georgia	Low

[47] DG MOVE, LNG Blue Corridors, Vehicle Regulations - State of the Art, December 2013

[48] DG MOVE, LNG Blue Corridors, LNG stations Regulations -State of the art, December 2013

[49] DG MOVE, LNG Blue Corridors, Guidelines for set up & operation of stations, May 2015

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	maintenance work in a programmed schedule) of the station.	before licences are granted and after (inspection/checks for compliance)		
5	Road safety regulations for trucks carrying LNG to the filling stations.	LNG transportation carries some potential hazards, linked to flammability as well as the impact of cryogenic fuel exposure or Leakage. There are standards that could be adopted (3 years ago, LNG and CNG were included in the ADR.	Under the sole control of Georgia	Low
6	Regulations governing TPA of LNG carrying trucks at LNG terminal (in case an in-country LNG terminal with truck loading facilities is developed)	Need to ensure transparent and non-discriminatory access of truck operators to the truck loading facilities	Under the sole control of Georgia	Low
7	Regulations governing loading of LNG to trucks at LNG terminal facilities (in case an in-country LNG terminal with truck loading facilities is developed)	Need to establish rules and procedures for how truck operators will use the truck loading facilities, including LNG truck approval procedure, LNG specifications, procedures for determining the LNG mass loaded etc.	Under the sole control of Georgia	Low
8	Regulations governing pricing of LNG terminal truck loading facilities (in case there is an LNG terminal with truck loading facilities, and there is price regulation for third party access to such facilities)	Need to have published tariffs for truck loading facility services at the terminal, that are non-discriminatory for users, and regulations for the allowed costs in such tariffs	Under the sole control of Georgia	Low
9	Permits and licenses, including technical specifications, for truck loading facilities at LNG terminal (in case an in-country LNG terminal with truck loading facilities is developed)	Need to have permits and regulations specifying layout requirements and operational aspects, to address safety issues including fire protection.	Under the sole control of Georgia	Low

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10	Permits and licences, including technical specifications, for liquefaction facilities (in case LNG is sourced from the gas network and loaded on to trucks)	Need to have permits and regulations for site requirements, health and safety considerations, transportation infrastructure, availability of key utilities, air emissions and wastewater treatment.	Under the sole control of Georgia	Low
11	Permitting process, including technical specifications, for truck loading at liquefaction facility (in case there is a liquefaction facility)	Need to have permits and regulations specifying layout requirements and operational aspects, to address safety issues including fire protection.	Under the sole control of Georgia	Low
12	(Amendment to) law to specify whether/which type of liquefaction facilities are regulated (TPA and pricing)		Under the sole control of Georgia	Low
13	Regulations governing TPA of LNG trucks at liquefaction facility (in case there is a regulated liquefaction facility)	Need to establish rules and procedures for how truck operators will use the truck loading facilities, including LNG truck approval procedure, LNG specifications, procedures for determining the LNG mass loaded etc.	Under the sole control of Georgia	Low
14	Regulations governing pricing of liquefaction facility (in case there is a regulated liquefaction facility)	Need to have published tariffs for use of the liquefaction plant services, that are non-discriminatory for users, and regulations for the allowed costs in such tariffs	Under the sole control of Georgia	Low
Infrastructure				
1	Interest of investors to implement necessary infrastructure (filling stations, in-country liquefaction facility)	The required infrastructure must be developed in time for the LNG-fuelled trucks to be able to operate	Decision of investors	Medium

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Table 26 outlines the key success factors for the implementation of the option of using LNG as engine fuel for trucks. These factors influence the speed of market development. Some of the key success factors relate to the State providing support to catalyze investments in LNG trucks and filling stations. Others relate to having a regulatory framework that favors 'cleaner' LNG use in trucking and punishes more 'dirty fuels'. State can also regulate the level of subsidies in other fuels, to make LNG more competitive. Other factors relate to the role of State and State organizations to foster changes and to support investors (one-stop-shop). Finally, the role of information campaigns for consumers, users and investors is important to overcome resistance to change and to boost interest.

Table 26: Key success factors for development of LNG as engine fuel for trucks

	Key success factors	Rationale
1	Conducive fiscal framework (low taxes, low import duties, availability of state grants and rebates) for the purchase of LNG fuelled trucks or the retrofitting of existing trucks to LNG.	
2	Setting and enforcing circulation restrictions for trucks that use older generation engines with higher emissions detrimental to the environment (e.g. Euro 4 fuels)	
3	Reduction of subsidies and favourite tax treatment of fuels competing with LNG, to make LNG more competitive and incentivise its use.	
4	Conducive fiscal framework (specific concession regimes, tax holidays, state grants[50]) conducive to investment in construction of new LNG filling stations, or for retrofitting petrol stations to include LNG, or for retrofitting CNG stations to offer also LNG (L-CNG). Also, state co-funding of LNG R&D activities	Having sufficient network of LNG stations is a major success factor. Incentivising private investment is one way to develop the market.
5	Awareness and promotion campaigns for LNG.	Consumers should be educated as to the potential features and benefits of LNG in transport. Investors should be informed on the opportunities available. Such campaigns can counter resistance to change and speed up interest.
6	Having a 'National champion' e.g. the Ministry of Economy or a State Committee that includes gas company and other key stakeholders. The role of the National champion would be to coordinate the set-up of the required legal and regulatory framework, develop and implement policy and incentives, to remove obstacles in for LNG market development and to act as one-stop-shop for investors. Its role would also include planning the number and location of LNG filling stations and facilities (possibly introducing limited concessions for infrastructure) so as to avoid stranded investments.	Many initiatives are slowed down by regulatory gaps or unclear legislation, lack of implementing administrative mechanisms and bureaucracy and lack of action. Such problems are exacerbated due to lack of awareness and resistance to change or inertia. For example, customs may not be familiar with rules and regulations for the new LNG vehicles and delay their clearance.

[50] 'Connecting Europe Facility', for example, provides grant to co-finance investment in LNG filling stations in the EU

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6.3.4 Development of liquefaction and export terminal

Table 27 describes the key prerequisites for effective implementation of the option of establishing an in-country liquefaction and LNG export terminal in Georgia. Critical/on-off prerequisites relate to the existence of sufficient long-term and appropriately priced contracts for the supply of gas to the liquefaction plant, and for ensuring long-term sales contracts of the produced LNG to customers. Another important prerequisite relates to the availability of funding for the very large investments for the plant and terminal. The necessary changes in the legal and regulatory framework, including permits and licenses, are also detailed, as well as the infrastructure needs of the plant.

Table 27: Prerequisites for development of liquefaction and export terminal

	Prerequisites	Rationale	Involved country(ies) or parties	Difficulty of implementation
Market				
1	Existence of long-term supply contracts of gas to the liquefaction plant, at prices that make LNG produced competitive at the target markets	Critical - on/off condition, to ensure viability of the liquefaction plant (as discussed in Sections 7.2.3 and 8.2.3). Currently no gas is available, and supplies can be possible only in case new fields are developed in Azerbaijan and/or supplies from Central Asia are forthcoming	Under control of Azerbaijan, and potentially Central Asia countries that may supply gas to the plant	Uncertain
2	Securing sufficient long-term sales of LNG that provide assurance for the plant and terminal revenues	Critical – on/off condition, to ensure there is sufficient demand for the terminal's services	Decision of suppliers at the target markets	Uncertain
Legal & Regulatory				
1	(Amendment to) energy law to allow establishing of liquefaction plant and export terminal, including ownership, regulation, TPA provisions and pricing regulation	To add the right to establish plant and export terminal, and the applicable framework, in the law	Under the sole control of Georgia	Low
2	Permits and licenses for the plant and LNG export terminal, including prerequisite technical studies, environmental and	To ensure that all authorisations and preconditions are secured	Under the sole control of Georgia	Low

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	social impact assessment study			
3	Regulations and standards for the siting, design, construction and installation of the liquefaction plant and export terminal, including infrastructures (jetty and connections to transmission system)	Legislators and policy makers need to set the rules so as to ensure safety, efficiency, quality and environmental protection	Under the sole control of Georgia	Low
4	Regulations for the operation of LNG terminal	Legislators and policy makers need to set the rules so as to ensure safe, efficient and environmentally conducive terminal operation	Under the sole control of Georgia	Low
5	Regulatory license and process for accreditation of the plant and terminal	Legislators and regulators need to set the rules (in accordance with EC Acquis), and operator to comply	Under the sole control of Georgia	Low
Financing				
1	Securing adequate financing for the investment in the liquefaction plant and export terminal	To ensure that the terminal can go ahead (FID)	Decision of investors and State	High
Infrastructure				
1	Connection of the liquefaction plant to the transmission network and agreement between plant operator and TSO	For the terminal to be able to send regasified LNG to the system, in accordance with pre-defined rules	Under the sole control of Georgia	Low
2	Absence of any maritime or other constraints for empty LNG vessels to enter the Black Sea, and load at the liquefaction plant	To ensure LNG can be uninterruptedly, promptly and adequately offtaken from the terminal	Under control of Turkey	Low

Table 28 outlines the key success factors for the implementation of the option of establishing an in-country liquefaction plant and LNG export terminal. These factors influence the speed of development of the option. Some of the key success factors relate to the strength of the project promoter (access to finance etc.) and the existence of investment partners and experienced operator. Other success factors relate to having a clear and effective strategy or the development of the terminal to avoid risks of delays and cost-overruns and having a contractual strategy/model that allocates fairly risks between contractors and developer. A conducive legal framework in the country as well as State support to the venture is important. For the export terminal sustainability

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as a business it is important to secure adequate customers, especially large off-takers, and to offer good service levels at a competitive price. Finally, flexibility of the export terminal's infrastructure to changes in market conditions enhances sustainability.

Table 28: Key success factors for development of liquefaction and export terminal

	Key success factors	Rationale
1	Strength and experience (financial and otherwise) of the project promoter	Assurance for project completion and sustainability
2	Bring-in strategic investment partners (especially off-takers/buyers of LNG)	To ensure sustainability and mitigate business risks
3	Establishing an effective project delivery strategy for the plant and export terminal (for project teams, partners, contractors, consultants, stakeholder engagement, safety, financing, technical solutions, risk management, project control and monitoring etc.)	To ensure prompt and effective construction
4	Use contractual models that balance and align interests of export terminal developers/operator (locking-in key suppliers and reducing supply chain costs) and buyers (having flexibility to deal with volatile commodity and service prices)	To ensure sustainability and mitigate business risks
5	Host country has predictable and conducive legal, contractual and regulatory framework	To avoid risks
6	Government support for timely issuance of terminal permits and authorizations	To avoid delays and risks
7	Competitive prices for the terminal's services and good service levels	To ensure sustainability
8	High proportion of long-term sales contracts with buyers	To provide more secured revenues and ensure sustainability
9	Terminal operation flexibility to adjust in case market conditions change (e.g. flexibility to add new infrastructures such as jetty, tanks)	To ensure adaptability and sustainability

6.4 Priorities and policy directions

LNG for gas swaps could be a priority option, as it does not require development of new infrastructures and can be implemented in a short time provided the underlying economics of the swap of LNG for gas appeal to the concerned parties.

The LNG receiving terminal is a long-term option, on account of having to fulfil several prerequisites, some of which are critical/on-off, that affect the readiness to implement this option, notably the uninterrupted passage of LNG vessels through the Bosporus Straits and securing of a sufficient market for regasified LNG. A final decision on implementing the terminal should be made only in case of potential price hikes when existing Georgian contracts with Azerbaijan are renewed, post 2026, to ensure the viability of the terminal.

The establishment of a large liquefaction plant and export terminal is also a long-term option, subject to securing adequate gas supplies from Azerbaijan and/or Central Asia for LNG conversion, and long-term sales to LNG buyers in target markets.

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The option of LNG as fuel for trucks could be viable using an in-country mini liquefaction facility, and could be done in a short-term horizon, as it involves decisions only of local actors, but the high investment costs in required infrastructure necessitate a large number of LNG fueled trucks for viability. On the other hand, LNG as fuel for trucks with LNG supplied from an in-country receiving terminal, in case such terminal was established, would require a smaller number of trucks, to be viable, but is a longer term option, as the relevant infrastructure is dependent on a number of factors controlled by third, external, parties. The Government could assess feasibility of this option in detail further and take relevant policy actions. These policies could encompass, at the minimum, having a legal and regulatory framework conducive to the development of an LNG supply chain, and could expand to cover incentives for the use of LNG.

6.5 Proposed actions

The Table below describes the actions that are deemed important in order to evaluate and prepare the identified applicable LNG market development options.

Table 29: Proposed preparatory actions for developing the identified LNG options in Georgia

	Proposed Actions	Timing
Initial / Preparatory Actions		
1	Assess existence of any contractual barriers for implementing swaps through SCP	Immediate
2	Initiate dialogue with Turkish authorities regarding passage of LNG vessels through the Bosporus Straits	Immediate
3	Perform feasibility study for the development of LNG receiving terminal	Short-term / dependent on the progress of negotiations with Turkey
4	Perform feasibility study for the development of liquefaction and export terminal, including assessment of when (and if) sufficient gas supplies from the Caspian Region will become available to allow consideration of the liquefaction terminal	Medium-term / dependent on the availability of Caspian gas supplies
5	Perform feasibility study for the use of LNG as fuel for trucks	Immediate
6	Develop a national policy framework for the use of LNG in road transport, deciding on the role that the State wishes to undertake	Short-term / After the study is concluded (in case it is positive and Georgia decides to pursue)
Implementation Actions concerning swaps		
7	Initiate negotiations and establish MoU with relevant stakeholders for swap framework	Short-term / based on possibility to perform swaps
8	Enhance awareness on global LNG market, trading and trends, so as to be ready to secure LNG volumes for the swap when the opportunity arises	Short-term / based on possibility to perform swaps
Implementation Actions concerning large LNG infrastructures (receiving terminal, liquefaction and export terminal)		
9	Gauge and secure the market's interest to use the LNG receiving terminal (e.g. binding market test)	Medium-term
10	Explore investors' interests in the LNG receiving terminal	Medium to long-term
11	Gauge and secure the interest of gas producers to use the liquefaction terminal and suppliers in the region to procure LNG	Medium to long-term
12	Explore investors' interests in the liquefaction and export terminal	Long-term
Implementation Actions aiming at developing use of LNG in road transport		

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13	Prepare the regulatory and legal framework (legal amendments, regulations, standards, permits and licenses, etc.) necessary for the development of the LNG supply chain	Short-term / based on national policy framework
14	If the State undertakes a proactive role in developing infrastructure, prepare the incentive mechanisms to attract investments	Short-term / based on national policy framework
15	Conduct awareness raising campaigns to attract end-users and investors' interest	Short-term / based on national policy framework

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7 LNG Market Prospects in Moldova

7.1 Identification of applicable LNG market development options

An overview of the Moldovan gas sector is provided in Annex 1.5. Following the analysis of the gas market information, and discussions with stakeholders during the field visit to the country, the key findings related to the development of LNG markets in Moldova are as follows:

- Gas-to-gas competition from LNG could be applicable in Moldova. Currently import prices of Russian gas (only supplier of the market) are lower than LNG. However, regasified LNG supplies could be sourced for diversification of supply purposes. There are multiple potential import routes: from Polish Świnoujście LNG terminal and Lithuanian Klaipeda LNG terminal (once GIPL is completed) through Poland and Ukraine; from the Greek Revythoussa LNG terminal, through Bulgaria – Romania, after completion of the reverse flow of Trans-Balkan pipeline and of the Iasi – Ungheni – Chisinau pipeline; from Croatian Krk LNG terminal, through Hungary and Ukraine, provided that bottlenecks in the Hungarian system are resolved. In case an LNG receiving terminal in Ukraine is built, in the Odessa area, this could also be a source for regasified LNG supplies to Moldova, due to existing interconnections and proximity of the Moldovan system to Odessa. In case a liquefaction terminal is developed in Georgia, in combination with a Ukrainian receiving terminal, regasified LNG of Caspian origin could be supplied to the Moldovan market through Ukraine.
- Gas-to-other fuels competition could be applicable in Moldova through LNG use for peak shaving. Moldova has no gas storage and gas flows fluctuate significantly. Use of small-scale LNG storage for peak shaving at the Chisinau and Belts District CHP stations, can reduce dependence on other fuels (e.g. oil during winter) and enhance security of energy supply
- Gas-to-other fuels competition is not applicable to remote/off-grid customers. All towns are gasified and reportedly off-grid consumers are not interested to use gas
- Gas-to-other fuels competition does not seem applicable to road and water transport. International long-haul traffic through Moldova is very small. There is also very limited vessel traffic in Moldovan waterways. Therefore, it seems that there is no potential for LNG to be used in transport sector

Based on the above analysis, the applicable LNG market development options for Moldova, for gas-to-gas and gas-to-other fuels competition, are presented in Table 30. Regasified LNG can be sourced from neighbouring EU terminals (Świnoujście, Klaipeda, Revythoussa, Krk), or a potential LNG receiving terminal in Ukraine. Development of the latter is subject to either Ukraine agreeing with Turkey for the passage of LNG through the Bosporus Straits, or, in the long-term, LNG of Caspian origin being available to be produced and exported from a liquefaction terminal in Georgia (as currently there are no available supplies of Caspian gas to feed such a potential infrastructure).

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LNG for gas-to-other fuels competition can be sourced either from the Ukrainian LNG terminal or an in-country mini liquefaction facility connected to the Moldovan transmission system.

Table 30: Applicable options for LNG market development in Moldova

Options for LNG market development		Sources of supply
Gas-to-Gas Competition	Regasified LNG sourced from neighbouring EU terminals	Świnoujście, Klaipeda, Revythoussa, Krk receiving terminals[51]
	Regasified LNG sourced from a potential LNG terminal in Ukraine	Potential receiving terminal in Ukraine
	Regasified LNG sourced from a potential liquefaction terminal in Georgia, through a receiving terminal in Ukraine	Potential liquefaction terminal in Georgia
Gas-to-Other Fuels Competition	LNG storage for peak shaving at the Moldovan CHP stations	• LNG truck loading in Świnoujście and/or Klaipeda terminals • Potential receiving terminal in Ukraine • In-country mini liquefaction facility

7.2 Assessment of viability of applicable LNG market options

7.2.1 Supply of regasified LNG from neighbouring EU terminals

This LNG market development option can be considered as potentially viable for Moldova in case regasified LNG can arrive to the Moldovan market from the neighbouring EU LNG terminals at a price competitive to that of the existing gas supply sources, taking into consideration all relevant transportation costs.

To estimate the competitiveness of LNG, netback analysis was performed, starting from the wholesale gas price in Moldova, up to each examined receiving terminal, taking into consideration in-country transportation costs, pancaking of the in-between cross-border tariffs and charges for the use of the receiving terminal. The detailed approach and calculations are described in Annex 2.1.

The market price applied in the calculations is the regulated price for entry in the Moldovan transmission system[52] (151.5 EUR/1000 m^3). The netback analysis performed for each examined route is presented in Figure 14 to Figure 17.

Figure 14: Netback analysis at maximum price for route Poland->Ukraine->Moldova

[51] Other potential supply options include the Marmara Ereglisi terminal in Turkey and the planned Alexandroupolis FSRU in Greece and Gdansk FSRU in Poland. The netback analysis of these options would wield similar results with the examined terminals

[52] Source: Moldovan National Agency for Energy Regulation Decision No 88/2018

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Figure 15: Netback analysis at maximum price for route Lithuania->Poland->Ukraine->Moldova

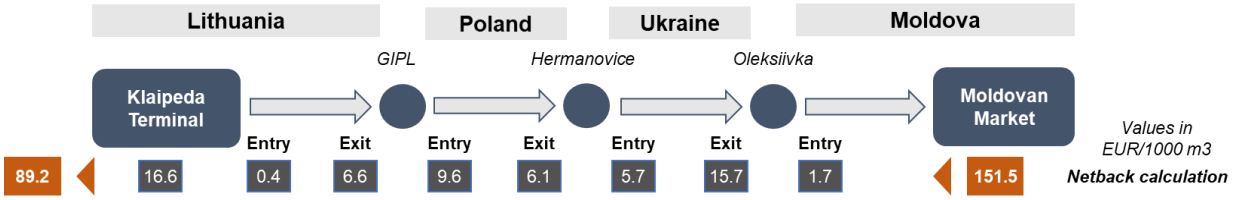


Figure 16: Netback analysis at maximum price for route Greece->Bulgaria->Romania->Moldova

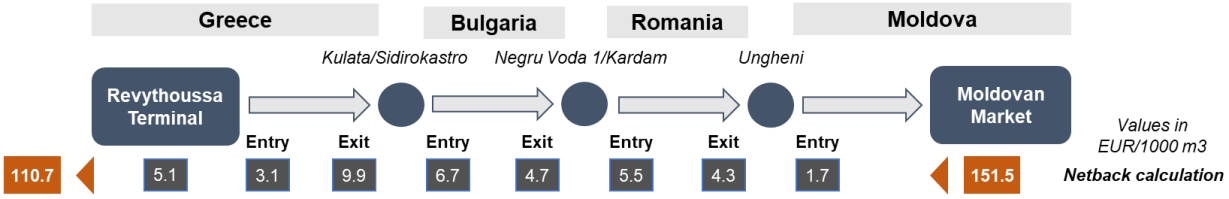


Figure 17: Netback analysis at maximum price for route Croatia->Hungary->Ukraine->Moldova

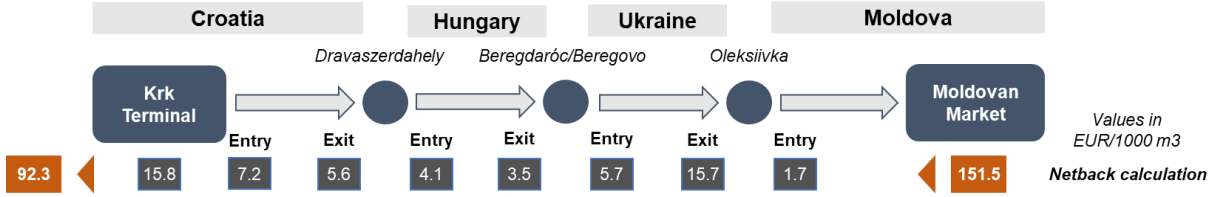
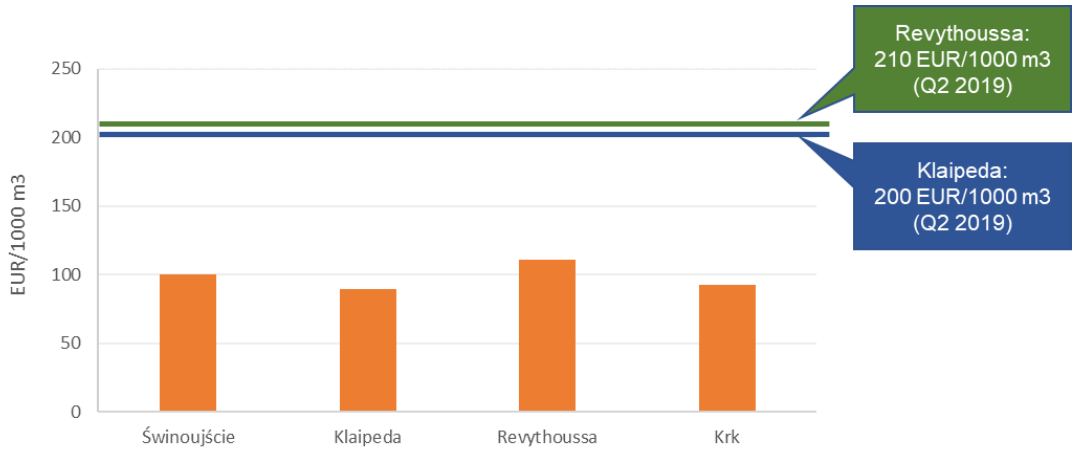


Figure 18 presents the results of the netback analysis for all assumed wholesale prices, and all examined routes to Moldova.

Figure 18: Netback analysis results for routes of regasified LNG from EU terminals to Moldova



The results of the analysis show that due to the low gas prices in Moldova, supply of regasified LNG cannot be competitive under the examined assumptions and market conditions.

Nevertheless, supplies of LNG could be considered as a way to enhance Moldova's security of supply. Economic analysis for this LNG option was conducted, to assess whether the security of supply benefits can outweigh the premium that would have to be paid for the supplied LNG. The detailed approach and calculations are described in Annex 4.1.

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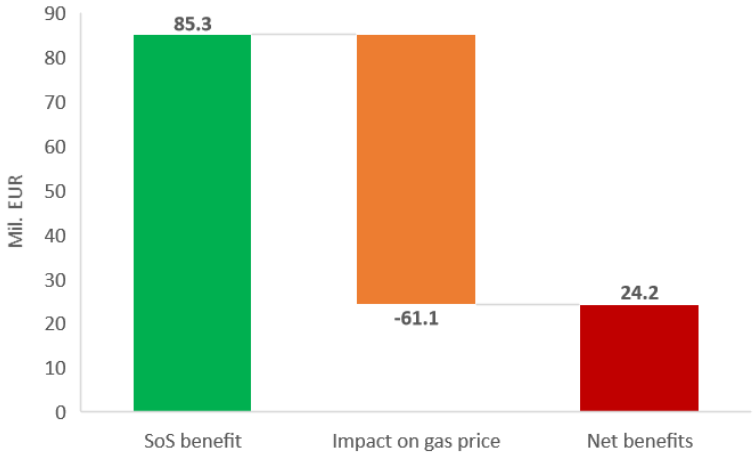
The economic analysis results show that the use of supplies of LNG for security of supply purposes appears to be beneficial for the Moldovan market, as it would eliminate potential demand curtailment, in case of a disruption in Russian gas supplies (Figure 19).

Figure 19: Present value of economic costs and benefits for supply of regasified LNG from EU terminals to Moldova



The impact of LNG supplies is also highlighted though the demand curtailment indicator (Annex 4.4), that is reduced to zero in case regasified LNG is used in case of a disruption of Russian imports.

Based on the above analysis, the supplies of regasified LNG from neighbouring terminals to Moldova can be considered as a potentially viable LNG option.

7.2.2 Supply of regasified LNG from Ukrainian terminal

This LNG market development option can be considered as potentially viable for Moldova in case LNG can arrive at a Ukrainian receiving terminal at a price competitive to that of the existing gas supply sources for the Moldovan market, taking into consideration all relevant transportation costs. Agreement with Turkey for passing of LNG vessels through the Bosporus Straits in an on/off precondition for this option to be developed.

The Ukrainian terminal is planned to be located near Odessa. The development of an FSRU with send-out capacity of 5 bcm/yr is assumed.

Netback analysis was performed, starting from the gas price in Moldova, up to the terminal, taking into consideration in-country transportation costs in Moldova, cross-border tariffs at the interconnection with Ukraine and charges for the use of the terminal. The detailed approach and calculations are described in Annex 2.2.

As the charges of the Ukrainian terminal depend on its utilization rate, we examine 3 scenarios of low (30%), medium (50%) and high (70%) utilization.

Figure 20 presents the results of the netback analysis.

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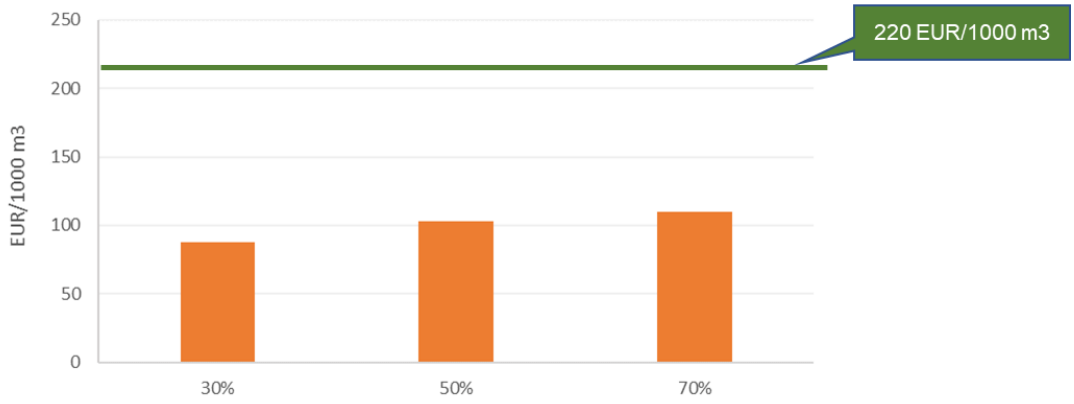
Figure 20: Netback analysis results for supplies of regasified LNG to Moldova from a terminal in Ukraine, all examined utilization rates



LNG price in the Black Sea can be expected to be higher than that of the Mediterranean, due to the additional transport costs and fees for crossing through the Bosporus Straits. With LNG import price at the Greek Revythoussa terminal 210 EUR/1000m^3 in Q2 2019[53], it is assumed that the corresponding price in the Black Sea will be at least 5% higher.

The results of the analysis show that, as in the case of supplies from EU terminals, due to the low gas prices in Moldova, supply of regasified LNG through a Ukrainian terminal cannot be competitive under the examined assumptions and market conditions.

The economic analysis of the Ukrainian LNG terminal (see Annex 4.1) shows that, in case the infrastructure is implemented, Moldova would have access to an additional supply route, through which to address a potential disruption of Russian gas supplies. It should be stressed, however, that Moldova could also enhance its security of supply by considering other options, such as the supply of regasified LNG from existing LNG terminals in the region, analysed in the previous Section.

7.2.3 Supply of regasified LNG from Georgian liquefaction terminal

This LNG market development option can be considered as potentially viable for Moldova in case regasified LNG can arrive though a Ukrainian receiving terminal from a liquefaction terminal in Georgia, at a price competitive to that of the existing gas supply sources for the Moldovan market, taking into consideration all relevant transportation costs. This option can only be developed in the long-term, provided sufficient gas supplies of Caspian origin are secured for the Georgian terminal, for liquefaction and export.

The liquefaction terminal in Georgia is assumed to have an LNG production capacity of 2 bcm/yr, and a utilization rate of 90% (with LNG supplied to Eastern Partners and EU countries). For the Ukrainian receiving terminal, the assumptions described in Section 7.2.2 above, concerning the terminal and market wholesale prices are applied.

[53] Source: DG Energy, “Gas Market Report Q2 2019”

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Netback analysis was performed, starting from the gas price in Moldova, up to the Georgian gas market, taking into consideration in-country transportation costs, cross-border tariffs at the interconnection with Ukraine and charges for the use of the receiving terminal in Ukraine and the liquefaction terminal in Georgia. The detailed approach and calculations are described in Annex 2.3.

The results are negative (i.e. costs are not recovered), due to the low gas price in Moldova. Therefore, gas liquefied in the Black Sea cannot be commercially viable for Moldova under the examined assumptions and market conditions.

Supply of LNG through Ukraine would provide Moldova with access an additional source of gas (Annex 4.3); however, as shown in Section 7.2.1, the option of supplies of regasified LNG from existing LNG terminals in the region can diversify the market's supply sources on a shorter-term and without the need for additional infrastructure.

7.2.4 Use of LNG for peak shaving at CHP stations

In this option, regasified LNG is used at the Moldovan CHP stations as a back-up supply source, to ensure continuity of electricity generation in case the regular supply of piped gas is distorted (for example due to fluctuations in gas flows through the system, or a disruption in imported gas).

The data for the CHP stations required to analyse this option further were not available, consequently netback and economic analysis was not conducted within the frame of this Study.

Implementation of the option would require development of an LNG storage and regasification facility at the CHP sites that can be supplied with LNG either from neighbouring terminals, or from a mini liquefaction facility. As the main purpose of this option is to enhance security of supply, and not to provide a competitive supply source to piped gas, it can be expected that the development of the required infrastructure would not be viable. Economic analysis should be carried out, to examine whether the resulting security of supply benefits can outweigh the costs for developing the LNG supply chain.

7.3 Prerequisites and key success factors for potentially viable LNG market options

7.3.1 Supply of regasified LNG from neighbouring EU terminals

The supply of regasified LNG to Moldova from neighboring EU terminals can be carried out without major market preconditions, as it concerns specific quantities for security of supply purposes.

Signing of an Interconnection Agreement between Moldovatransgaz and Ukrtransgaz, establishing business rules in line with the Interoperability Network Code (Regulation (EU) 2015/703), currently under negotiation by the two parties, is important to facilitate flows of regasified LNG through Ukraine to Moldova. Additionally, there should be sufficient available capacity at the interconnection points, to allow supply of regasified LNG.

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7.3.2 Use of LNG for peak shaving at CHP stations

Table 31 describes the key prerequisites for effective implementation of the option of using LNG for peak shaving at CHP stations in Moldova. The prerequisites concern the existence of rules and regulations allowing the development of LNG storage and regasification, the transportation of LNG via trucks (in case this option of supply is selected) and the development of a liquefaction facility (in case such a facility is developed at the CHP station).

Table 31: Prerequisites for use of LNG for peak shaving at CHP stations

	Prerequisites	Rationale	Involved country(ies) or parties	Difficulty of implementation
Legal & Regulatory				
1	Regulations and standards for the siting, design, construction and installation of LNG storage and regasification installations at the CHP	Need to ensure safety, efficiency, quality and environmental protection by having standards concerning LNG storage and vaporisers, including mobile LNG tanks and vaporizers	Under the sole control of Moldova	Low
2	Road safety regulations for trucks carrying LNG to the CHP stations.	LNG transportation carries some potential hazards, linked to flammability as well as the impact of cryogenic fuel exposure or leakage. There are standards that could be adopted (3 years ago, LNG and CNG were included in the ADR.	Under the sole control of Moldova	Low
3	Permits and licences, including technical specifications, for liquefaction facilities (in case gas will be liquefied at the CHP station)	Need to have permits and regulations for site requirements, health and safety considerations, transportation infrastructure, availability of key utilities, air emissions and wastewater treatment.	Under the sole control of Moldova	Low

As the development of a peak shaving facility is purely for security of supply reasons, and not for commercial purposes, there are no key factors conducive to its implementation.

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7.4 Priorities and policy directions

The supply of regasified LNG from neighbouring LNG terminals to the Moldovan market is not a viable option, on account of lack of price competitiveness of LNG to imported low priced gas. However, in view of the security of supply benefits, which even small LNG volumes could provide, as indicated in the CBA carried out, this option could merit further examination by the relevant stakeholders (Government, Moldovagas). This option can go ahead over a short-term horizon, as it is not impeded by infrastructure constraints.

Additionally, the option of using LNG for peak shaving of CHP plants could also be an important option realized over the short-term to enhance security of energy supply in the country. As such, it needs to be assessed from a cost benefit perspective to determine its priority.

The options of Moldova being supplied with LNG from Ukraine and/or Georgia are highly dependent on the development of LNG receiving terminals in these countries, with significant uncertainties in view of the on/off requirements and prerequisites, that affect the maturity/readiness to implement these options.

7.5 Proposed actions

The Table below describes the actions that are deemed important in order to evaluate and prepare the identified applicable LNG market development options.

Table 32: Proposed preparatory actions for developing the identified LNG options in Moldova

Proposed Actions		Timing
Initial / Preparatory Actions		
1	Enhance awareness on global LNG market, trading and trends, so as to be ready to secure LNG volumes for security of supply reasons, when the opportunity arises	Immediate
2	Perform detailed market options' analysis for the supply of regasified LNG to Moldova, and analyze the options for Moldovagas to recover the costs (increase of prices, PSO, grant, etc.)	Immediate
3	Conclude interconnection agreement with the Ukrainian TSO	Immediate
4	Perform feasibility study for the development of peak shaving facility at the CHP stations and analyse the financing options and the recovery of the investment costs increase of prices, PSO, grant, etc.)	Immediate
Implementation Actions		
5	Conclude agreement for procuring LNG for security of supply	Short-term (in case Moldova decides to pursue this option)
6	Prepare the regulatory and legal framework (legal amendments, regulations, standards, permits and licenses, etc.) necessary for the development of the peak shaving facility at the CHP stations	Short-term (in case Moldova decides to pursue this option)

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8 LNG Market Prospects in Ukraine

8.1 Identification of applicable LNG market development options

An overview of the Ukrainian gas sector is provided in Annex 1.6. Following the analysis of the gas market information, and discussions with stakeholders during the field visit to the country, the key findings related to the development of LNG markets in Ukraine are as follows:

- Gas-to-gas competition from LNG could be applicable in Ukraine. There are multiple pipeline routes through which regasified LNG can be imported, now or in the future. LNG can come via Poland (from Świnoujście LNG terminal), and from Klaipeda LNG terminal (once GIPL is completed) through the existing interconnection or the planned new Poland – Ukraine interconnection[54]. LNG can also come via Slovakia and Hungary (e.g. Krk or Italian LNG terminals). Moreover, LNG can be sourced via Hungary (e.g. Krk or Italian LNG terminals), provided that bottlenecks in the Hungarian system are resolved, as well as through Romania (Greek and Turkish LNG terminals), after reverse flow of the Trans-Balkan pipeline. It is noted that LNG import does not involve route diversification, as it will be transported through the routes used for piped gas supplies, and therefore price competitiveness is the key driver. Furthermore, an issue to consider would be the expected impact of discontinuation or decrease in Russian transit volumes on reduced Ukraine import capacities with Slovakia, Poland and Hungary.
- Ukraine is interested to establish its own LNG import terminal in the Black Sea, near Odessa. An LNG terminal could provide regasified LNG to customers through connection with Ukrainian transmission grid. Additionally, given adequate terminal infrastructure (storage and truck loading facilities), LNG could be supplied directly to off-grid customers and for new gas uses (filling stations for trucks and ships etc.). The option of establishing an LNG receiving terminal is nevertheless contingent upon Turkey's agreement to allow LNG vessels' passage through the Bosporus Straits. Another LNG project being examined is a small scale LNG receiving terminal in Reni, aiming to be used for bunkering and covering local gas needs.
- Ukraine can also import LNG by trucks and/or trains. Ukraine has road and rail connections to Poland (and on to Lithuania) that could be used to transport LNG with trucks from the Świnoujście and Klaipeda terminals, and via rail once the rail loading facility is developed at the Świnoujście terminal.
- Gas-to-other fuels competition from LNG could be applicable in Ukraine for road transport. According to stakeholders, Ukraine appears to have a sizable international long-haul traffic (export/imports and transit) that could merit the use of LNG as truck fuel.

[54] It is noted that according to UTG the planned Poland – Ukraine pipeline is not included in the 2020 – 2029 TYNDP of Ukraine.

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- Gas-to-other fuels competition could also have some applicability in sea transport in Ukraine. A large number of passenger and cargo ships regularly operate in Ukrainian waterways, especially Dnieper and Black Sea ports. Switching fuel to LNG would nevertheless involve significant costs, and therefore compliance with international treaties regarding emissions, such as IMO regulations, would be important in influencing whether vessels convert to LNG as a cleaner fuel. Given that the Black Sea is not an Emission Control Area for the IMO, the requirement to reduce sulphur emissions from the current 3.5% to 0.5% sulphur, as of 1/1/2020, can be addressed by shipowners through other means (scrubbers, MGO with reduced sulphur etc.) instead of converting ships to use LNG (or order new ones running on LNG). Potential LNG demand could therefore arise in case of newer vessels that operate international routes and not limited to Black Sea transport, as well as smaller vessels operating in inland waterways, especially the Dnipro and Dunay rivers.
- LNG virtual pipelines could also be an applicable option for supplying gas distribution customers in Ukraine, instead of expensive replacements of old gas distribution pipelines. The Ukrainian gas network is well developed, and most towns are gasified. There are nevertheless cases of very old gas distribution sections that can be replaced by LNG virtual pipelines, instead of heavily investing in rehabilitation.
- LNG virtual pipelines could also have some applicability in supplying remote/off-grid customers in Ukraine. Most consumers in agriculture and mining are already connected to the gas network, but LNG could have some potential as backup fuel or for fuelling heavy work tractors' in mining. Ukraine also has some remote gas fields currently not connected to the network, and whose connection would involve significant difficulties and/or costly investments.
- Liquefaction facilities can be used to develop remote gas fields. Virtual LNG pipelines, with the use of mini liquefaction facilities to transform natural gas into LNG and the transport it to end customers e.g. filling stations etc. can be used to develop such gas fields. According to JSC Ukrgasvydobuvannya (main gas production facilities of Naftogas Group), studies have been launched to assess such potential.
- Use of LNG as locomotive fuel could also be applicable. The Ukrainian Railway Company (Ukrzaliznytsa) is currently using diesel as main locomotive fuel (327.1 mil. tonnes in 2018[55]), that could potentially be substituted by LNG.

Based on the above analysis, the applicable LNG market development options for Ukraine, for gas-to-gas and gas-to-other fuels competition, are presented in Table 33. Regasified LNG can be sourced from neighbouring EU terminals (Świnoujście, Klaipeda, Revythoussa, Krk) and potentially the development of an in-country LNG receiving terminal, constructed near Odessa. Development of the latter is subject to either Ukraine agreeing with Turkey for the passage of LNG through the Bosporus Straits, or, in the long-term, LNG of Caspian origin being available to

[55] Source: Ukrainian Ministry of Infrastructure

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be produced and exported from a liquefaction terminal in Georgia (as currently there are no available supplies of Caspian gas to feed such a potential infrastructure).

LNG for gas-to-other fuels competition can be sourced from the nearby EU terminals (Świnoujście, Klaipeda), the in-country LNG terminal or a mini liquefaction facility connected to the Ukrainian transmission system. It should be noted that gas-to-other fuels options cannot be considered as drivers for the development of the Ukrainian LNG terminal, but can benefit in case such infrastructure goes ahead.

Table 33: Applicable options for LNG market development in Ukraine

Options for LNG market development		Sources of supply
Gas-to-Gas Competition	Regasified LNG sourced from neighbouring EU terminals	Świnoujście, Klaipeda, Revythoussa, Krk receiving terminals[56]
	Regasified LNG sourced from an in-country LNG receiving terminal in the Black Sea	Potential in-country receiving terminal
	Regasified LNG sourced from a potential liquefaction terminal in Georgia and an in-country receiving terminal	Potential liquefaction terminal in Georgia
Gas-to-Other Fuels Competition	LNG as engine fuel for long-haul trucks	• LNG truck loading in Świnoujście and/or Klaipeda terminals • In-country receiving terminal • In-country mini liquefaction facility
	LNG as engine fuel for ships operating in the Black Sea and Ukrainian waterways	
	LNG supplies to off-grid customers, especially in agriculture, construction, and mining	
	LNG virtual pipelines in distribution systems instead of large rehabilitation investments in distribution systems	
	LNG virtual pipelines to connect remote gas fields with off-grid customers	
	LNG as engine fuel for locomotives	

8.2 Assessment of viability of applicable LNG market options

8.2.1 Supply of regasified LNG from neighbouring EU terminals

This LNG market development option can be considered as potentially viable for Ukraine in case LNG can arrive to the Ukrainian market from the neighbouring EU LNG terminals at a price competitive to that of the existing gas supply sources, taking into consideration all relevant transportation costs.

To estimate the competitiveness of LNG, netback analysis was performed, starting from the wholesale gas price in Ukraine, up to each examined receiving terminal, taking into consideration in-country transportation costs, pancaking of the in-between cross-border tariffs and charges for

[56] Other potential supply options include the Marmara Ereglisi terminal in Turkey and the planned Alexandroupolis FSRU in Greece and Gdansk FSRU in Poland. The netback analysis of these options would wield similar results with the examined terminals.

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the use of the receiving terminal. The detailed approach and calculations are described in Annex 2.1.

The average price of gas import from EU, including the entry tariff to enter the Ukrainian market, is used as the starting point. As import prices are fluctuating considerably, we examine 3 scenarios for the average level of import prices in Ukraine, corresponding to the average (241 EUR/1000 m^3), average for winter season (257 EUR/1000 m^3) and minimum (198 EUR/1000 m^3) price for the period Q1 2017 – Q2 2019[57].

The netback analysis performed at the winter average price, for each examined route, is presented in the Figures below.

Figure 21: Netback analysis at winter average price for route Poland->Ukraine

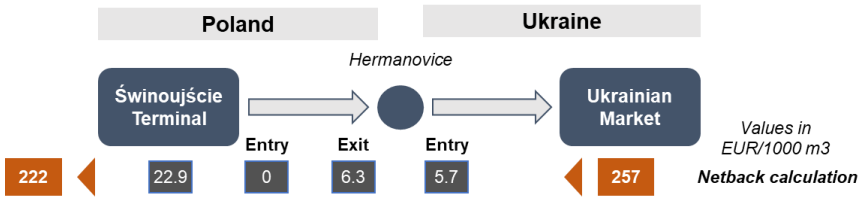

Figure 22: Netback analysis at winter average price for route Lithuania->Poland->Ukraine

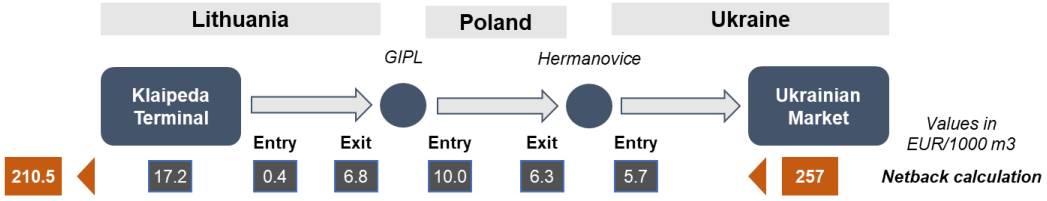

Figure 23: Netback analysis at winter average price for route Greece->Bulgaria->Romania->Ukraine

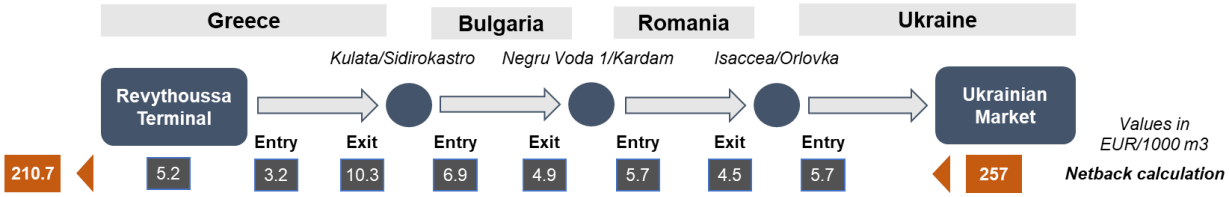

Figure 24: Netback analysis at winter average price for route Croatia->Hungary->Ukraine

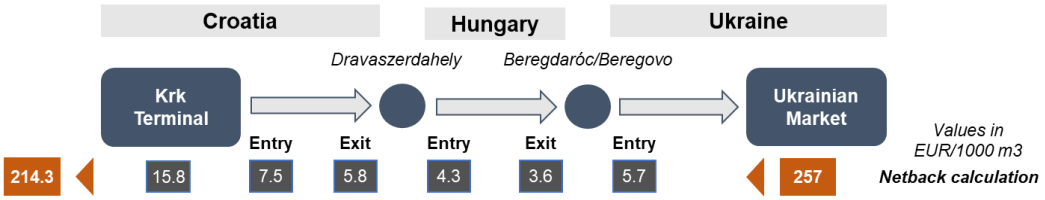

Figure 25 presents the results of the netback analysis for all assumed wholesale prices, and all examined routes to Ukraine.

[57] Source: NEURC, "Monitoring results for functioning of the gas market", Q2 2019

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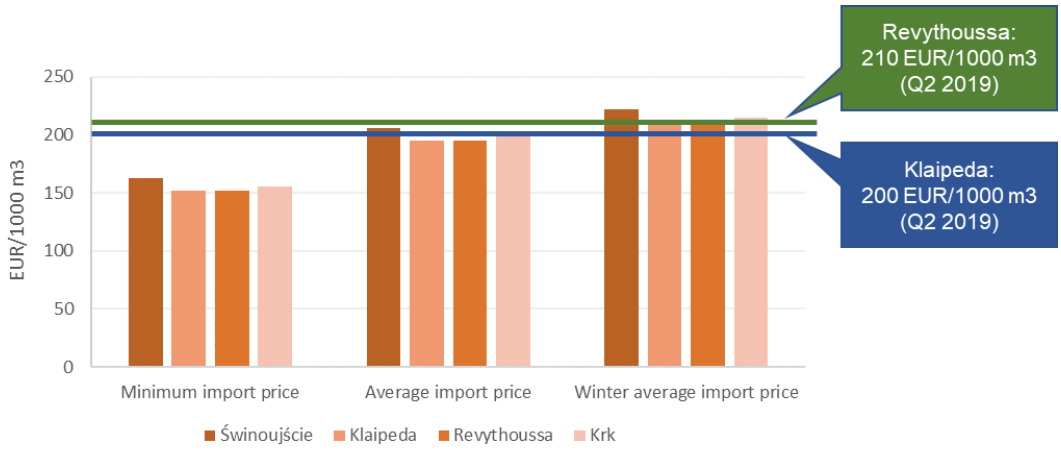
Figure 25: Netback analysis results for routes of regasified LNG from EU terminals to Ukraine, all examined wholesale prices



The results of the analysis show that under the examined assumptions and market conditions, regasified LNG sourced from EU terminals seems to be marginally competitive in the Ukrainian market in case the prices of EU imported gas exceed the winter average of the past years. Consequently, this LNG market development option could be considered as potentially viable, provided that the spread between LNG price at the terminals and prices of imported supplies from current sources is at least in the order of 40 – 50 EUR/1000 m^3 (depending on the route).

This option does not provide additional benefits of route diversification, as the supply of regasified LNG from the terminals in the region would not open up new supply routes.

8.2.2 Supply of regasified LNG from in-country terminal

This LNG market development option can be considered as potentially viable for Ukraine in case LNG can arrive at a Ukrainian receiving terminal through the Bosporus Straits at a price competitive to that of the existing gas supply sources for the Ukrainian market, taking into consideration all relevant transportation costs. Agreement with Turkey for passing of LNG vessels through the Bosporus Straits in an on/off precondition for this option to be developed.

The Ukrainian terminal is planned to be located near Odessa. As there are no up-to-date studies concerning the LNG terminal in Ukraine[58], assumptions are made concerning the size of the terminals. In Ukraine, the analysis within the frame of this Study is carried out assuming the development of an FSRU with maximum send-out capacity of 5 bcm/yr.

Netback analysis was performed, starting from the gas price of imported gas in Ukraine, up to the terminal, taking into consideration in-country transportation costs and charges for the use of the terminal. The detailed approach and calculations are described in Annex 2.2.

[58] Studies for the development of an LNG terminal near Odessa (Phase 1 FSRU with 5 bcm/yr capacity and Phase 2 on-shore terminal with 10 bcm/yr capacity) were prepared in 2013, with very different supply & demand conditions in the Ukrainian market than the existing ones.

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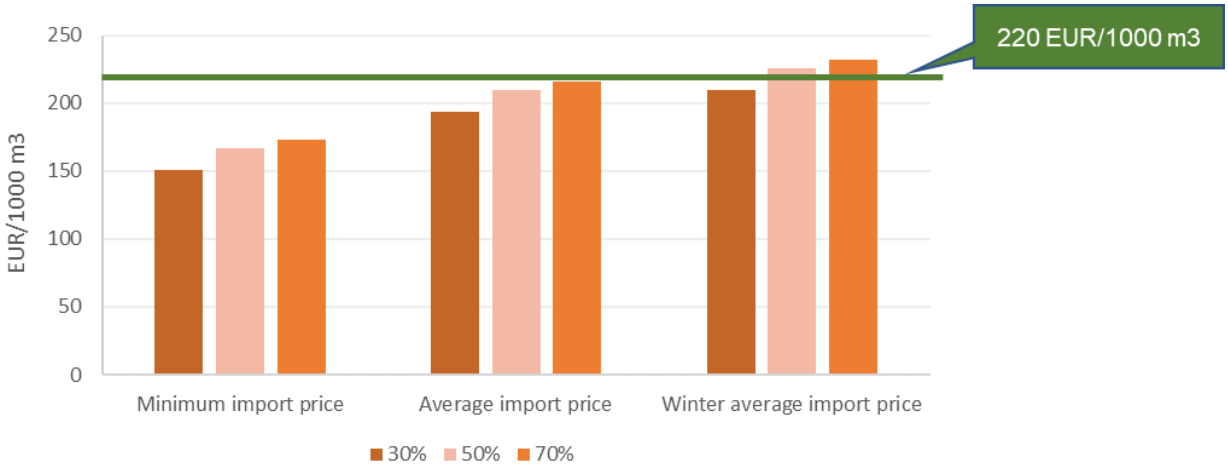
The same price scenarios as in Section 8.2.1 are examined. As the terminal charges depend on its utilization rate, we examine 3 scenarios of low (30%), medium (50%) and high (70%) utilization.

Figure 26 presents the results of the netback analysis for all assumed prices and utilization rates.

Figure 26: Netback analysis results for supplies of regasified LNG from in-country terminal in Ukraine, all examined import prices and utilization rates



LNG price in the Black Sea can be expected to be higher than that of the Mediterranean, due to the additional transport costs and fees for crossing through the Bosporus Straits. With LNG import price at the Greek Revythoussa terminal 210 EUR/1000m^3 in Q2 2019[59], it is assumed that the corresponding price in the Black Sea will be at least 5% higher.

The results of the netback analysis show that, under the examined assumptions and market conditions, an LNG receiving terminal in Ukraine can be economically viable only in case there is a price differential of at least 25 – 30 EUR/1000 m^3 between LNG supplies and imports from EU, together with a high utilization of the terminal. Taking into consideration that EU import prices are driven by the prices at the European gas hubs, which in turn are affected by the global LNG price trends, attractive prices of LNG for the terminal could be ensured through long-term contracts that also secure a significant utilization of the infrastructure.

Economic analysis for this LNG option was conducted, to assess whether the benefits of developing an LNG terminal to the economy and society can outweigh its costs, even if the price of imported gas from the EU does not have a significant price differential from LNG. The analysis covers the scenarios of importing piped gas at the minimum and average prices of the past two years. The detailed approach and calculations are described in Annex 4.1.

Figure 27 presents the calculated economic net present value for each the examined price scenarios and corresponding utilization rates.

[59] Source: DG Energy, "Gas Market Report Q2 2019"

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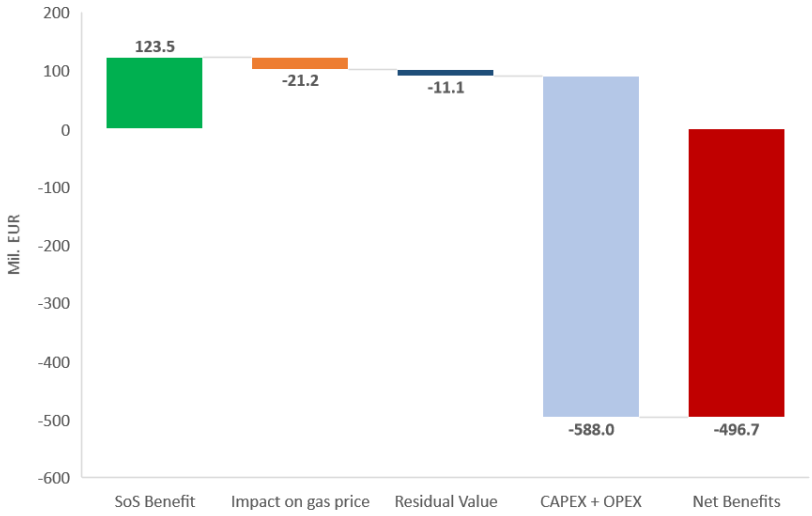
Figure 27: ENPV results for supplies of regasified LNG from in-country terminal in Ukraine, all examined import prices and utilization rates

The economic analysis results show that development of an LNG terminal in Ukraine is economically viable in case LNG can be available at prices lower than those of gas imported from EU suppliers, which result in both enhancing security of supply in Ukraine and Moldova, and reducing gas prices in the market. The use of the terminal only for security of supply purposes (in case piped gas prices remain at low levels) does not lead to positive results, as the impact of a potential short-term disruption of Russian transit can be mitigated with indigenous production and storage, and may lead to only a small part of demand to be curtailed (Figure 28).

Figure 28: Present value of economic costs and benefits of in-country terminal in Ukraine



(a) Minimum import price (only SoS)

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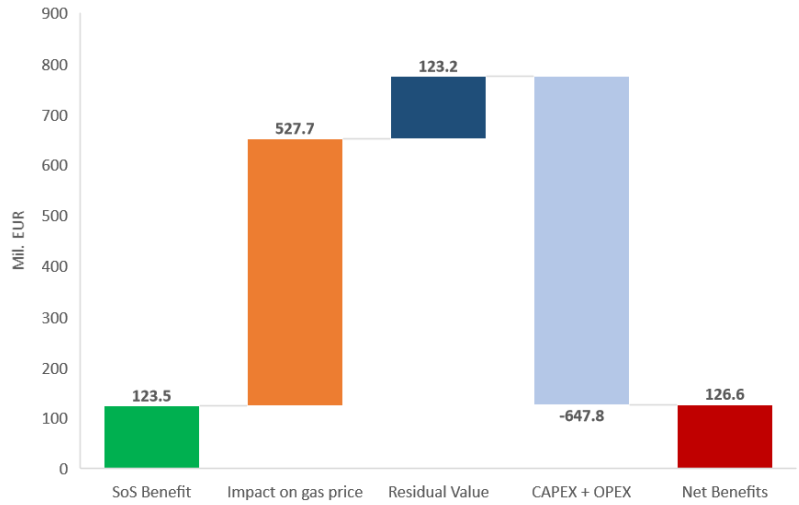

(b) Average import price (30% utilization)

The impact of the LNG terminal in Ukraine has also been examined using the quantitative indicators, presented in Table 34. Development of the terminal can eliminate the potential impact of a large infrastructure disruption. Diversification of routes is also enhanced, although Ukraine already is well connected with neighbouring countries and receives gas supplies from various counterparts. The detailed approach and calculations of the indicators is provided in Annex 4.4.

Table 34: Quantitative indicators for in-country terminal in Ukraine

	W/o terminal	With terminal	Impact
N-1 indicator	97.3%	104.%	Increase of system resilience to a large infrastructure disruption
Import route diversification	4,229	3,247	Further increase of diversification of routes
Demand curtailment	-	-	No curtailed demand

Based on the above analysis, the development of an in-country LNG receiving terminal in Ukraine can be considered as a potentially viable LNG option, in case LNG can be supplied at lower prices than existing sources, and high (over 50%) utilization of the terminal can be ensured, e.g. through long-term terminal use agreements. It is noted that this LNG market development option can only be realized in case Ukraine and Turkey conclude an agreement for the passage of LNG vessels through the Bosporus Straits.

8.2.3 Supply of regasified LNG from Georgian liquefaction terminal

This LNG market development option can be considered as potentially viable for Ukraine in case LNG can arrive at a Ukrainian receiving terminal from a liquefaction and LNG export terminal in Georgia, at a price competitive to that of the existing gas supply sources for the Ukrainian market, taking into consideration all relevant transportation costs. This option can only be developed in the long-term, provided sufficient gas supplies of Caspian origin are secured for the Georgian terminal, for liquefaction and export.

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The liquefaction terminal in Georgia is assumed to have an LNG production capacity of 2 bcm/yr, and a utilization rate of 90% (with LNG supplied to Eastern Partners and EU countries). For the Ukrainian receiving terminal, the assumptions described in Section 8.2.2 above, concerning the terminal and market wholesale prices are applied.

Netback analysis was performed, starting from the gas price of imported gas in Ukraine, up to the Georgian gas market, taking into consideration in-country transportation costs, charges for the use of the receiving terminal in Ukraine, costs for transportation of LNG and liquefaction in Georgia. The detailed approach and calculations are described in Annex 2.3.

Figure 29 presents the results of the netback analysis for the assumed import prices in Ukraine and terminal utilization rates.

Figure 29: Netback analysis results for supply of Ukrainian LNG terminal from Georgian liquefaction terminal, all examined import prices and utilization rates

The investment cost for the 2 bcm/yr configuration of the AGRI Pipeline[60] is applied as a basis. However, as the costs associated with the development of the facility are a key cost element in the analysis, and these may have changed, due to the introduction of new technologies (e.g. FLNG terminal), sensitivity analysis was performed, assessing also 80% and 60% of the investment costs. Figure 30 presents the results of the sensitivity analysis for the scenario of winter average import price in Ukraine, and 70% utilization of the Ukrainian receiving terminal.

[60] GNERC, "Case Study: Georgia's Growing Gas Market", 2018

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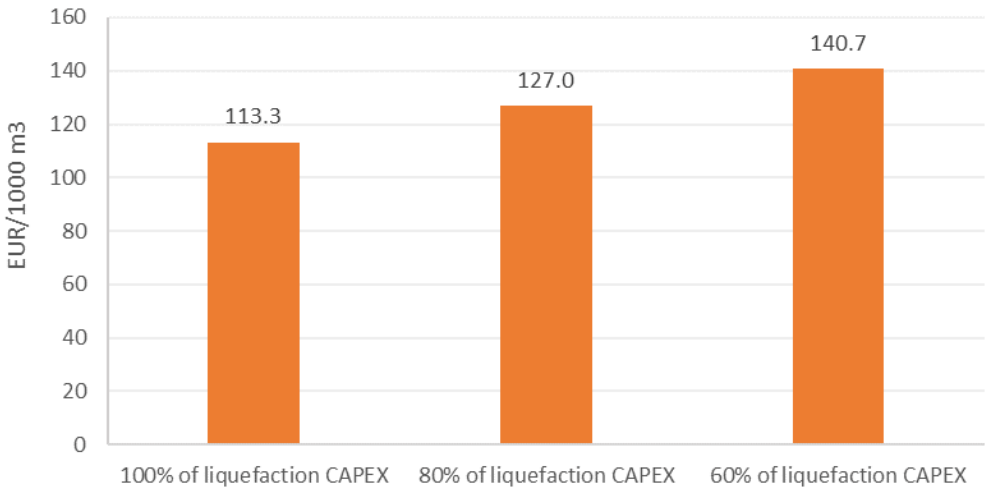
Figure 30: Netback analysis results for supply of Ukrainian LNG terminal from Georgian liquefaction terminal, sensitivity analysis on liquefaction terminal investment cost



The results of the analysis show that in all the examined scenarios, the supply of LNG at a Ukrainian receiving terminal from a liquefaction terminal in Georgia can be competitive to existing imports only in case the price of Caspian gas supplied to the liquefaction terminal is significantly lower than current import prices of Azeri gas in Georgia.

Economic analysis for this LNG option was conducted, to assess whether the benefits of developing an LNG terminal to the economy and society can outweigh its costs. The analysis covers the case having the highest netback price (winter average price), examining two scenarios of Caspian gas export prices (current level of Azeri gas supply to Georgia and low export price). Sensitivity analysis on the investment costs of the liquefaction is also applied. The detailed approach and calculations are described in Annex 4.3.

The economic analysis results show that the main benefit of the LNG option is the reduction of energy costs. Under the examined scenarios, the option is viable in case LNG can be delivered in the Ukrainian terminal at a low price, and a high utilization rate is secured at the terminal. The use of the terminal only for enhancing security of supply in Ukraine and Moldova does not lead to positive results, as the impact of a potential short-term disruption of Russian transit can be mitigated with indigenous production and storage, and may lead to only a small part of demand to be curtailed (Figure 31).

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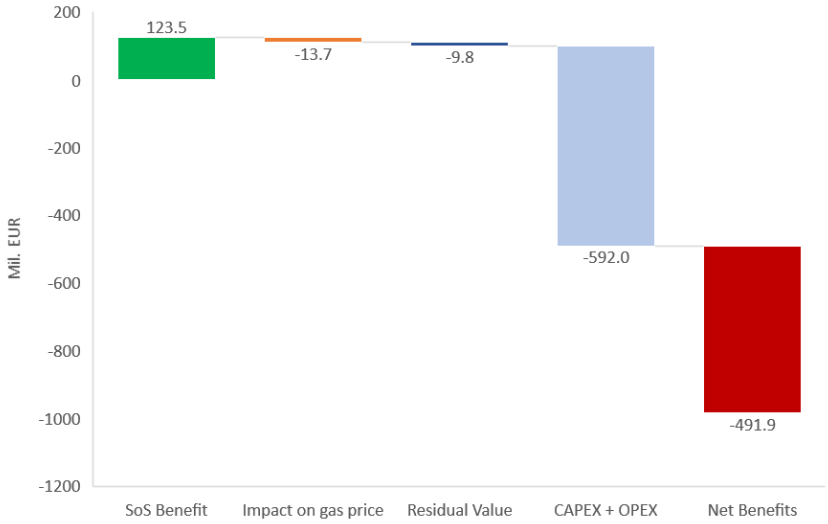
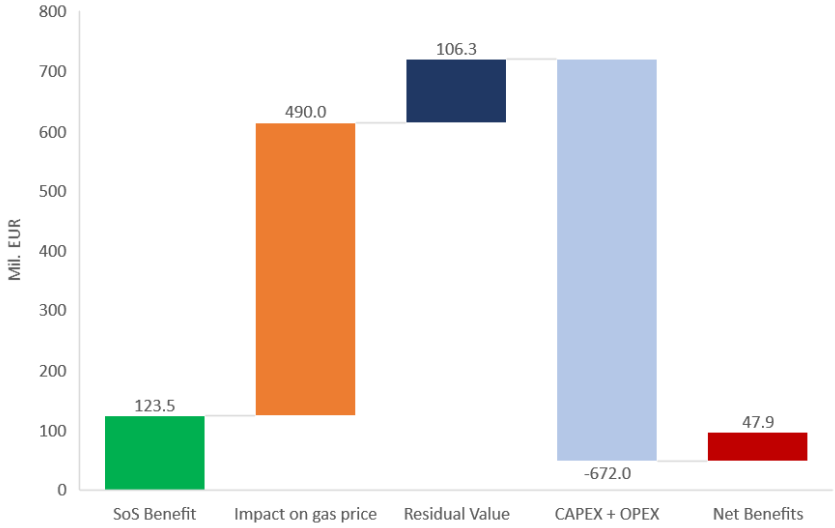
Figure 31: Present value of economic costs and benefits of in-country terminal in Ukraine



(a) Low export price of Caspian gas (100% of liquefaction costs)



(b) Low export price of Caspian gas (60% of liquefaction costs)

Based on the above analysis, the development of a liquefaction and LNG export terminal in Georgia, supplying an LNG receiving terminal in Ukraine can only be considered as a potentially viable LNG option, in case supply prices of Caspian gas are low, and a high (over 50%) utilization of the Ukrainian receiving terminal can be ensured, e.g. through long-term terminal use agreements. As the results are sensitive on the costs of liquefaction, further analysis of this option requires detailed examination of the investment needs for the liquefaction terminal, taking into consideration current liquefaction technologies and infrastructure.

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8.2.4 Supply of LNG via trucks to consumers connected to the transmission system

This LNG market development option can be considered as potentially viable for Ukraine in case the price of regasified LNG injected to the Ukrainian transmission system through a central LNG receiving terminal, which is supplied with LNG trucks from the Świnoujście and Klaipeda terminals, can be competitive to that of the existing gas supply sources, taking into consideration all relevant transportation costs.

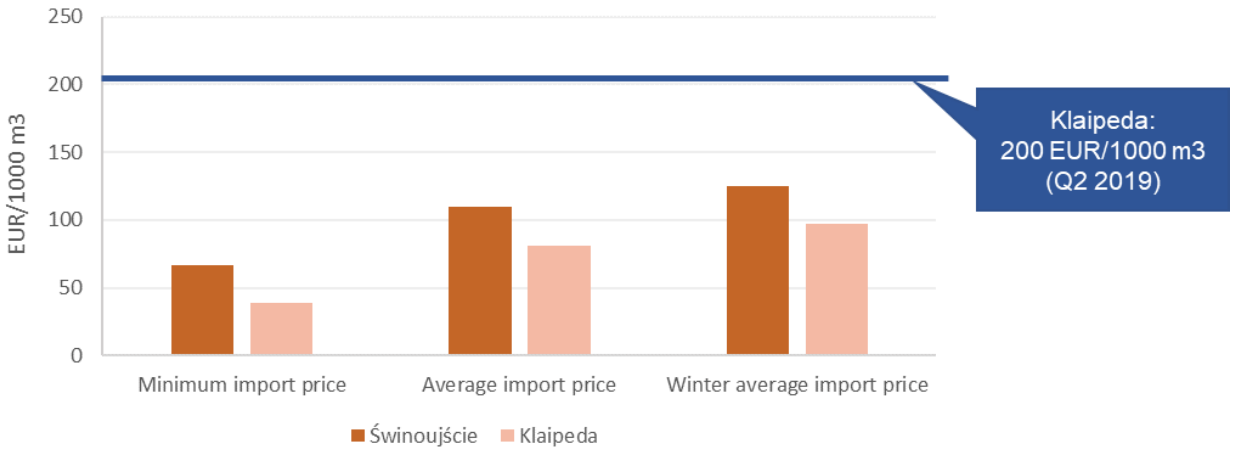
For the purpose of the analysis, we assume that the size of the regasification terminal and the number of LNG trucks used will cover annual demand of 500 mcm in Ukraine that is close to the maximum nominal capacity of the Klaipeda reloading station (100 m^3 LNG/h).

Netback analysis was performed, starting from the import gas price in Ukraine, up to each examined receiving terminal, taking into consideration in-country transportation costs, charges for the use of the LNG receiving terminal, costs of transporting LNG with trucks, and truck loading at the neighbouring terminals. The detailed approach and calculations are described in Annex 2.4.

The same price scenarios as in Section 8.2.1 are examined.

Figure 32 presents the results of the netback analysis for supply of LNG from the two examined terminals, and all assumed import prices.

Figure 32: Netback analysis results for supplies of LNG to Ukraine via trucks to transmission consumers, all examined import prices



The results of the analysis show that, under the examined assumptions and market conditions, the use of LNG trucks as a means to supply LNG to the Ukrainian market, in competition to piped gas for consumers connected to the transmission system, is not commercially viable.

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It is noted that the potential use of block trains as an LNG transportation modality could yield different results, as much larger volumes can be transported per shipment[61], and therefore transportation costs can be lower. However, this option cannot be analysed in detail, as it has not been widely applied, and unit cost benchmarks are not available. Once the planned train loading facility in the Świnoujście terminal becomes operational, the relevant costs can be assessed.

8.2.5 Use of LNG as engine fuel for trucks

This LNG market development option can be considered as potentially viable for Ukraine in case the LNG price at the filling station is competitive to that of diesel, taking into consideration the efficiency gains of LNG engines, as well as all costs associated with the LNG supply chain.

The available information on the traffic of long-haul trucks (local and transit) in Ukraine is not sufficiently detailed to allow reasonable assumptions to estimate the market size of LNG as fuel for trucks. For this reason, instead of performing a netback analysis to estimate the maximum price of LNG to be competitive to diesel, we estimate the LNG market size (number of LNG-fuelled trucks and annual LNG volumes consumed) required for prices of LNG and diesel to be on par, under different scenarios of LNG/natural gas prices at the beginning of the supply chain.

The potential LNG supply sources examined for Ukraine include the LNG terminals in Świnoujście and Klaipeda, an in-country LNG receiving terminal and a mini liquefaction facility. For each source, a base price and positive/negative sensitivities, as displayed in Table 35, have been assessed.

Table 35: Examined prices of LNG/natural gas at the source for Ukraine

Terminal	Assumed price at terminal (EUR/1000m^3)				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Świnoujście LNG terminal[26]	200	250	300	170	150
Klaipeda LNG terminal[27]	200	250	300	170	150
Ukraine LNG terminal[7]	220	275	330	187	165
In-country mini liquefaction facility[62]	254	318	381	216	190

The analysis has been carried out for long-haul trucks retrofitted to use LNG, traveling 91,000 km per annum. The costs for development of a new filling station for LNG is considered (development of a new L-CNG station or upgrade of an existing CNG station would result in lower costs). The competing price of diesel has been assumed to be at the current market level, of 0.76 EUR/lt[63]. The detailed approach and calculations are presented in Annex 3.1.

Figure 33 presents the minimum number of LNG-fired trucks that have to operate in Ukraine, and the minimum LNG volumes to be supplied annually, for the market to be developed, in case the base price applies at the LNG source.

[61] A block train of 20 tank wagons can transport 2,220 m^3 of LNG (source: VTG, "Innovation for the track: Breaking new ground in LNG supply", 2017)

[62] Average wholesale price for September 2018 – September 2019 (Source: Ukrainian Energy Exchange), plus transportation tariff (Source: UTG)

[63] Source: https://index.minfin.com.ua/ua/markets/fuel/dt/ (accessed 1/11/2019)

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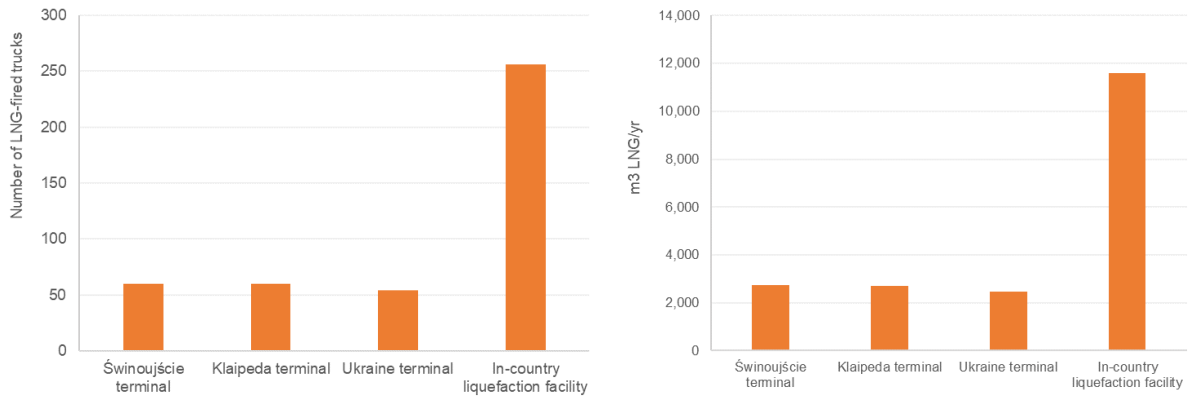
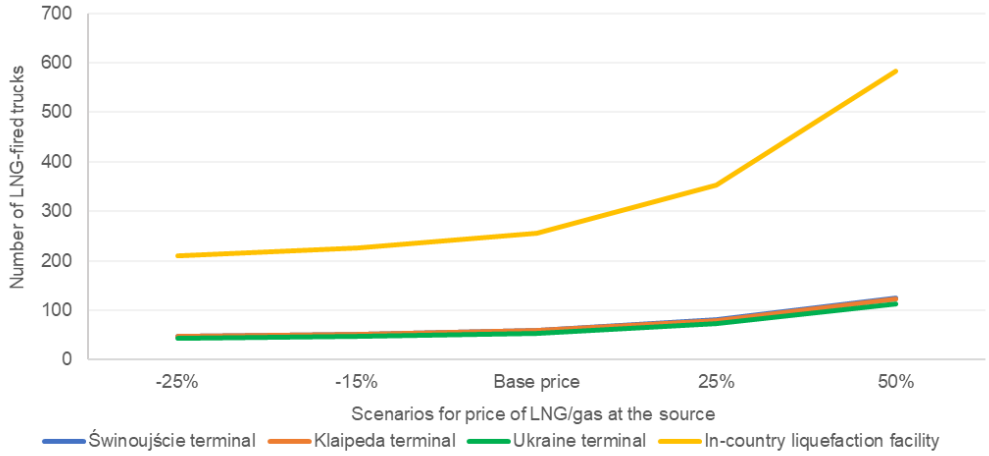
Figure 33: Minimum number of LNG-fired trucks for market development in Ukraine and corresponding annual LNG market size, under base price



(a) Minimum number of LNG-fired trucks *(b) Minimum LNG market size*

The minimum number of LNG-fired trucks for the Ukrainian case, for all price scenarios and LNG supply variants are presented in Figure 34.

Figure 34: Minimum number of LNG-fired trucks in Ukraine for all price sensitivities



The results of the analysis show that use of LNG in Ukrainian road transport, under the examined assumptions, can be competitive to diesel with a market of less than 100 LNG-fired trucks, even in case LNG import prices increase, for supplies from the neighbouring terminals in Poland and Lithuania. The sourcing of LNG from an in-country receiving terminal could also be an option, provided that an agreement with Turkey for the Bosporus Straits is secured, and the terminal is developed. Supplies from a mini liquefaction facility would require a considerably larger market, at least around 250 trucks for the base price scenario.

As Ukraine appears to have a sizable international long-haul traffic (export/imports and transit), a market for LNG in road transport of 100 or more trucks could potentially develop. Consequently, use of LNG as engine fuel for trucks can be considered as a potentially viable option for Ukraine. It is noted that in order to better size the size of the market, and its attractiveness, analysis of

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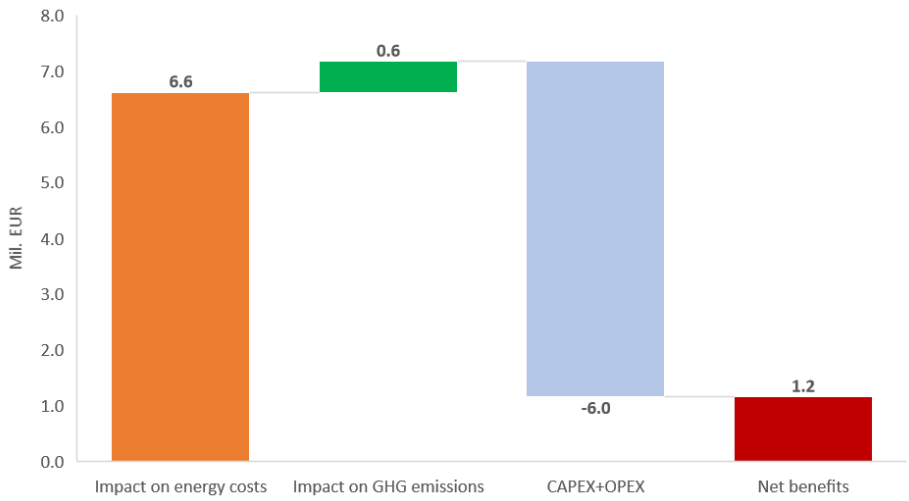
detailed data on the operation of long-haul trucks (such as number of local and transit trucks, destinations and distances covered) in Ukraine would be required.

Economic analysis was performed for the identified minimum required LNG market, to estimate the extent to which economic benefits for using LNG as engine fuel (energy cost reduction for end consumers, impact on GHG emissions) outweigh the costs for developing the option. The analysis shows that the reduction of GHG emissions has a positive impact (Figure 35).

Figure 35: Present value of economic costs and benefits for use of LNG as engine fuel for trucks in Ukraine



8.2.6 Use of LNG as engine fuel for ships

Implementation of IMO rules setting the limit the ships' sulphur emissions from 3.5% to 0.5% as of 1/1/2020 in the Black Sea leads ship owners to take measures to meet this obligation. Internationally, for ships currently operating in the sea areas outside Emission Control Areas (ECAs), the use of scrubbers or low sulphur fuel oil seems to be the preferred solution compared to switching to LNG, as the retrofitting cost has been considered higher than that of alternative solutions[64]. The use of LNG can be more attractive in the case of newbuilds, provided that the price differential between LNG and the existing bunkering fuels is sufficient to cover the additional cost of an LNG-fuelled ship, and that bunkering of LNG is possible at ports or an LNG terminal in Ukraine.

The attractiveness of this LNG option differs for each individual case of ship, as it depends on a number of factors, including the vessel's size and type, age, service area, fuel used, refuelling pattern, prices of competing fuels, etc. For this reason, a case-by-case analysis would be required, to examine for which ships use of LNG would be competitive. In this Study we provide an indicative example, concerning a newbuild 50,000 MT PANAMAX type vessel operating in the Black Sea, with LNG and MGO as competing fuels and bunkering at an LNG terminal in Ukraine.

[64] See analysis in Oxford Institute for Energy Studies, "LNG Supply Chains and the Development of LNG as a Shipping Fuel in Northern Europe", 2019

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The detailed approach and calculations are described in Annex 3.4. The results of the analysis show that for this case study the maximum supply price of LNG at the terminal is 325 EUR/1000 m^3. Under the examined assumptions, LNG can be considered as competitive, in case LNG supply prices remain at the existing levels.

Consequently, the use of LNG for ships is a market development option that merits further investigation, analysing the financial viability and potential LNG penetration specifically with the specific characteristics of the ships operating in Ukrainian ports.

8.2.7 Supply of LNG to off-grid consumers

This LNG market development option can be considered as potentially viable for Ukraine in case the natural gas price at the end consumer is competitive to that of the current fuel (e.g. diesel or LPG), any fuel efficiency gains, as well as taking into consideration all costs associated with the LNG supply chain.

Although in Ukraine the transmission system is well expanded, and most consumers with significant energy demand are already connected, there are some individual cases of consumers (mainly small to medium agriculture, construction or mining sites) that are off-grid. Details on the number, size and characteristics of these consumers were not made available to the Consultant. For this reason, we examined an indicative case study for an agriculture site in the southern part of Ukraine that cannot be connected to the transmission system, due to the lack of gas pressure reduction station capacity (the case study is based on actual information provided by an agriculture company).

The potential LNG supply sources examined for Ukraine include the LNG terminals in Świnoujście and Klaipeda, an in-country LNG receiving terminal and a mini liquefaction facility.

To estimate the competitiveness of LNG, netback analysis was performed, starting from the price of competing fuel at the consumer (LPG), up to each examined receiving terminal, taking into consideration gas efficiency compared to LPG, regasification costs, LNG transportation and truck loading costs. The detailed approach and calculations are described in Annex 3.3.

Figure 36 presents the results of the netback analysis for each of the LNG sources examined.

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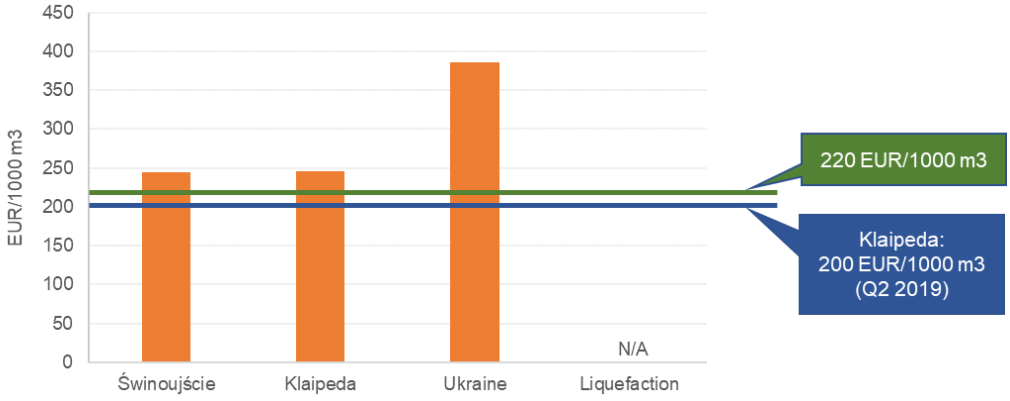
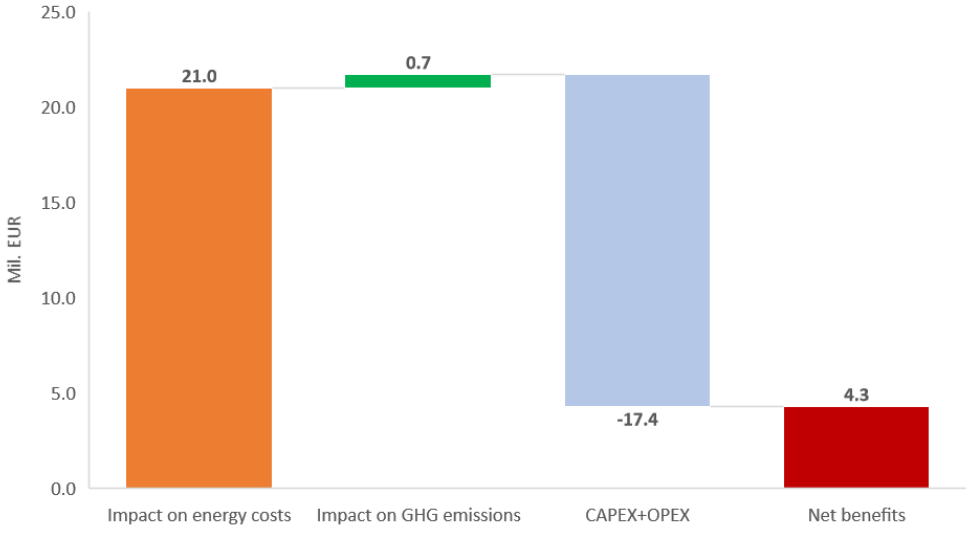
Figure 36: Netback analysis results for supplies of LNG to off-grid consumers in Ukraine[65]



Under the assumptions of the examined case study, supplies of LNG from receiving terminals can be competitive to LPG. Consequently, this LNG market development option is considered as potentially viable, at least for some of the off-grid consumers in Ukraine. Nevertheless, each particular off-grid consumer should be examined individually, as the parameters affecting the analysis (e.g. distance from the terminal, consumption profile, type of fuel, size of required regasification terminal).

Figure 37: Present value of economic costs and benefits for the supply of LNG to off-grid consumers in Ukraine



An economic analysis was also performed for the supply of LNG to the examined off-grid agriculture site, to estimate the extent to which economic benefits (energy cost reduction for end consumers, impact on GHG emissions) outweigh the costs for developing this option. The analysis, for the particular case examined, shows that the largest benefit is the reduction of energy costs, while GHG emissions also have had a slight positive impact (Figure 37).

[65] Values for LNG supplies from a mini liquefaction facility are negative, and therefore not depicted

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8.2.8 Use of LNG Virtual Pipelines in old distribution systems

In several distribution systems of Ukraine, there are very old medium pressure pipeline sections, which are in need of replacement, supplying areas with very limited number of consumers. Indicative cases include a 9.5 km pipeline serving demand of 41,000 m^3/yr or a 4 km pipeline supplying 53,500 m^3/yr. Replacement of such infrastructure would result in increases of the distribution tariff.

The development of LNG virtual pipelines to supply such areas, instead of proceeding to pipeline replacement was examined as an alternative. However, taking into consideration that the cost of pipeline replacement amounts to around 22,000 EUR/km, the costs for the LNG supply would be much higher, as demand would remain the same. For example, replacing a pipeline of 10 km would cost around 220,000 EUR, while the cost of just a liquefaction facility would exceed 7 mil. EUR.

Therefore, this option is considered as non-viable.

8.2.9 Use of LNG Virtual Pipelines to develop remote gas fields

This LNG market development option can be considered as potentially viable for Ukraine in case the liquefaction of gas produced at remote gas field, and transportation of LNG to off-grid areas can be price competitive to the existing fuels used by the targeted consumers.

Data on Ukraine's remote gas fields, required to analyse this option further were not available, consequently netback and economic analysis was not conducted within the frame of this Study.

Key factors that have to be taken into consideration to assess the financial viability of the LNG option include the size field's reserves and production capacity, that would enable sizing of the liquefaction facility, cost of gas production, proximity to potential consumers and size of targeted consumption. The cost of LNG delivered to the consumers should be competitive to the equivalent price of the dominant competing fuel, taking into consideration any additional costs and efficiency gains incurred due to the use of natural gas.

The examination of each remote gas field should be carried out separately, as the characteristics and location of each field are unique.

8.2.10 Use of LNG as engine fuel for locomotives of Ukrzaliznytsa

This LNG market development option can be considered as potentially viable for Ukraine in case the LNG price is competitive to that of diesel, taking into consideration the costs for retrofitting the locomotives, and building the necessary infrastructure for LNG supply.

An indicative cost for retrofitting a locomotive amounts to around 1.3 mil. EUR (550,000 EUR for the engine, and an additional cost of 750,000 EUR for a fuel tender that carries the LNG tank[66])

[66] Source: Natural Resources Canada (NRCAN), "Economic and Environmental Benefits of Natural Gas for the Rail Sector", March 2017

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for a dual fuel (LNG/diesel) engine. Additional investments are required to install at selected rail depots, facilities for LNG unloading, storage and locomotive refuelling. Depending on the location of the depot, LNG could be supplied either via trucks (from LNG terminals) or via using a small-scale liquefaction facility within the depot (in case a transmission pipeline is in its proximity). Benchmark costs for small scale LNG and liquefaction facilities are presented in Annex 6.

The significant consumption of diesel in the Ukrainian rail sector (around 330 mil. tonnes in 2018) could create the conditions for switching to LNG. To assess the viability of the option, a detailed analysis should be carried out, identifying the number of locomotives to be retrofitted or replaced, the optimal locations for developing LNG refuelling facilities, and assessing whether all costs for developing the LNG supply chain can be covered from the LNG-diesel price differential.

8.3 Prerequisites and key success factors for potentially viable LNG market options

8.3.1 Supply of regasified LNG

The potentially viable options for supplying regasified LNG to the Ukrainian market are either via pipelines from existing EU terminals or by developing a new in-country terminal in Ukraine. The prerequisites and key success factors for each of the two options are described separately in the following Sections 8.3.1.1 and 8.3.1.2.

Regardless of the options through which regasified LNG arrives to Ukraine, there are a number of factors that relate to the impact of LNG in enhancing competition in the Ukrainian gas market. These are described in Section 8.3.1.3.

8.3.1.1 Supply of regasified LNG from neighbouring EU terminals

Table 36 describes the key prerequisites for effective implementation of the option of supplying regasified LNG to Ukraine from the existing EU terminals. A critical/on-off prerequisite is the price competitiveness of regasified LNG at the Ukrainian border. There are also prerequisites related to the absence of regulatory or technical constraints for the supply of regasified LNG from the source terminal up to the Ukrainian market.

Table 36: Prerequisites for supplying LNG from EU terminals

	Prerequisites	Rationale	Involved country(ies) or parties	Difficulty of implementation
Market				
1	Price of regasified LNG at Ukrainian border competitive to the existing gas supply sources of the Ukrainian market (as discussed in Section 8.2.1)	Critical – on/off criterion for the viability of the option	LNG source prices are determined in accordance with international demand and supply conditions. Gas import prices in Ukraine are market based. It is the suppliers' decision	Uncertain

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			whether to import LNG	
Legal & Regulatory				
1	Absence of regulatory barriers for access to transportation infrastructure for the regasified LNG		Under the control of Ukraine as well as all other countries along the routes	Low
Infrastructure				
1	Absence of capacity constraints to import regasified LNG		Under the control of Ukraine as well as all other countries along the routes	Low

Factors that could be conducive to the development of this option include:

- Securing long-term supplies of LNG at a stable price, to avoid spot price fluctuations. This nevertheless has risks in case spot prices move lower than the contracted price. Additionally, this would require contracting large quantities.
- Lifting barriers for LNG suppliers to utilize Ukrainian storage. Access to storage would enable suppliers to take advantage of any low-priced LNG spot supply opportunities.

8.3.1.2 Supply of regasified LNG from in-country terminal

Table 37 describes the key prerequisites for effective implementation of the option of establishing an in-country LNG import terminal. Critical/on-off prerequisites are the uninterrupted supply of LNG to the terminal i.e. the absence of any constraints for LNG vessels to pass through the Bosporus straits, and the existence of sufficient interest by potential users, as evidenced by market tests. Another important prerequisite relates to the availability of financing for the terminal, from State or private funds. The necessary changes in the legal and regulatory framework, including permits and licenses, are also detailed, as well as the need to connect to the gas transmission network.

Table 37: Prerequisites for development of in-country LNG terminal

	Prerequisites	Rationale	Involved country(ies) or parties	Difficulty of implementation
Political				
1	Absence of any maritime or other constraints for LNG vessels to reach and supply the terminal	Critical - on/off condition, to ensure uninterrupted, prompt and adequate LNG supplies to the terminal	Under the control of Turkey. Negotiations need to be initiated by Ukraine	High
Market				
1	Binding market tests confirming interest of suppliers to use terminal services before FID for the terminal is taken	Critical - on/off condition, to ensure there is secure and sufficient demand for the terminal's services to make it viable. A	Decision of suppliers	Uncertain

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		successful market test requires suppliers to take a view on the competitiveness of LNG price vis-à-vis the Ukrainian gas import prices (as discussed in Section 8.2.2)		
Legal & Regulatory				
1	(Amendment to) energy law to allow establishing of LNG terminal, including ownership, regulation, TPA provisions and pricing regulation	To add the right to establish terminal and the applicable framework in the law	Under the sole control of Ukraine	Low
2	Permits and licenses for LNG terminal, including prerequisite technical studies, environmental and social impact assessment study	To ensure that all authorisations and preconditions are secured	Under the sole control of Ukraine	Low
3	Regulations and standards for the siting, design, construction and installation of LNG terminal, including infrastructures (jetty and connections to transmission system)	Legislators and policy makers need to set the rules so as to ensure safety, efficiency, quality and environmental protection	Under the sole control of Ukraine	Low
4	Regulations for the operation of LNG terminal	Legislators and policy makers need to set the rules so as to ensure safe, efficient and environmentally conducive terminal operation	Under the sole control of Ukraine	Low
5	Regulatory license and process for accreditation of the terminal	Legislators and regulators need to set the rules (in accordance with EC Acquis), and terminal to comply	Under the sole control of Ukraine	Low
Financing				
1	Securing adequate financing for the investment in the terminal	To ensure that the terminal can go ahead (FID)	Decision of State and/or investors	High
Infrastructure				
1	Connection of terminal to the transmission network and agreement between terminal operator and TSO	For the terminal to be able to send regasified LNG to the system, in accordance with pre-defined rules	Under the sole control of Ukraine	Low

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Table 38 outlines the key success factors for the implementation of the option of establishing an in-country LNG import terminal. These factors influence the speed of market development. Some of the key success factors relate to the strength of the project promoter (access to finance etc.) and the existence of investment partners and experienced operator. Other success factors relate to having a clear and effective strategy or the development of the terminal to avoid risks of delays and cost-overruns and having a contractual strategy/model that allocates fairly risks between contractors and developer. A conducive legal framework in the country as well as State support to the venture is important. For the terminal sustainability as a business it is important to secure adequate customers, especially large off-takers, and to offer good service levels at a competitive price. Finally, flexibility both in terms of terminal infrastructure and in terms of services, to changes in market conditions, enhances sustainability.

Table 38: Key success factors for development of in-country LNG terminal

	Key success factors	Rationale
1	Strength (financial and otherwise) of the project promoter	Assurance for project completion and sustainability
2	Bring-in strategic investment partners that can bring expertise to the venture and mitigate risks	To ensure sustainability and mitigate business risks
3	Bring-in experienced operator/management team	To ensure sustainability and mitigate business risks
4	Establishing an effective project delivery strategy for the terminal (for project teams, partners, contractors, consultants, stakeholder engagement, safety, financing, technical solutions, risk management, project control and monitoring etc.)	To ensure prompt and effective construction
5	Use contractual models that balance and align interests of terminal developers/operator (locking-in key suppliers and reducing supply chain costs) and contractors/suppliers (having flexibility to deal with volatile commodity and service prices)	To ensure sustainability and mitigate business risks
6	Host country has predictable and conducive legal, contractual and regulatory framework	To avoid risks
7	Competitive prices for the terminal's services and good service levels	To ensure sustainability
8	Government is supportive in general for the venture, and specifically ensures timely issuance of terminal permits and authorizations	To avoid delays and risks
9	Existence of a market for LNG (regasifed and in liquid form) that can sustain the terminal's operations.	To ensure sustainability
10	Dependence on one major off-taker or several off-takers.	One major off-taker is preferable to lenders, but also increases dependence compared to situation of a portfolio of off-takers
11	Terminal operation flexibility to adjust in case market conditions change (e.g. developing new services, pricing for unbundled services as opposed to bundled, flexibility to add new infrastructures such as jetty, tanks, truck loading facilities etc.)	To ensure adaptability and sustainability

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8.3.1.3 Factors impacting competition in the Ukrainian gas market

Regasified LNG is a new source of gas supply, as well as a new route, in the case of an in-country import terminal. It has the potential to enhance competition in the Ukrainian gas market, especially when the following factors apply:

- Completing the implementation of the obligations stemming from the Energy Community related to market operation and gas network codes that will enhance non-discriminatory and transparent access of regasified LNG to the Ukrainian network and market.
- Completing the liberalisation of gas market (e.g. reassessing extent and duration of current PSOs to non-regulated customers, unbundling of gas distribution etc.), to open up competition to a larger share of the market.

8.3.2 Use of LNG as engine fuel for trucks

Table 39 describes the key prerequisites for effective implementation of the option of using LNG as engine fuel for trucks in Ukraine. The prerequisites concern the appropriate price differential between LNG and diesel to ensure viability, as well as the necessary changes in the legal and regulatory framework, or introduction of new legislation and regulations, including permits and licenses. For example, Ukraine has a Law on Dangerous Cargo Transportation and secondary regulations issued by the Ministry of Internal Affairs, and LNG is included. The prerequisites relate not only to import and operation of trucks, but extend to the supply chain for LNG concerning trucks: filling stations, truck loading facilities at an in-country LNG terminal, in case this option is implemented and LNG is sourced from there, liquefaction plants and truck loading facilities at these plants, in case LNG is sourced from piped gas in the country. The interest of sufficient truck owners to switch to LNG, and the attraction of investments to develop the necessary infrastructure (filling stations, liquefaction facilities) is also critical for the development of the market.

It is noted that the prerequisites related to the import of LNG through an in-country terminal and the development of relevant import facilities in Ukraine are listed separately in Section 8.3.1.

Table 39: Prerequisites for development of LNG as engine fuel for trucks

	Prerequisites	Rationale	Involved country(ies) or parties	Difficulty of implementation
Market				
1	Sufficient price differential between LNG and diesel (as discussed in Section 8.2.5)	Critical – on/off condition, as switching to LNG requires an attractive price of LNG vis-à-vis diesel at the end use	LNG and diesel source prices are determined in accordance with international demand and supply conditions (except in the case where LNG is sourced from an in-country liquefaction	Uncertain

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			facility, in which the price is determined by gas import contracts)	
2	Interest of a critical mass of truck owners to switch to LNG	Viability of the option is dependent on having a minimum market size to justify investments	Decision of truck owners	Medium
Legal & Regulatory				
1	Regulations and standards for the design, manufacturing and installation of the LNG fueled trucks and different components (e.g. pressure control regulator, LNG filling receptacle etc.) for approval of LNG vehicles import and operation[67, 68]	Need to ensure safety, efficiency, quality and environmental protection. There are various European and international standards that could be incorporated in national legislation as the basis for granting approval.	Under the sole control of Ukraine	Low
2	Road regulations for circulation of LNG fuelled vehicles	Need to ensure safety, by stipulating any restrictions in movement e.g. in cases of heavy traffic, adverse weather conditions affecting visibility and road conditions etc.	Under the sole control of Ukraine	Low
3	LNG and L-CNG filling stations permits and licences, notably building license, operation license, and business license[69]	Need to ensure the eligibility of the selected site for the station, compliance with operational obligations (e.g. opening hours, station throughput, safety obligations, and business registration of the entity. The licenses require testing and acceptance processes and mechanisms at state/municipal level, before licences are	Under the sole control of Ukraine	Low

[67] DG MOVE, LNG Blue Corridors, Vehicle Regulations - State of the Art, December 2013

[68] DG MOVE, LNG Blue Corridors, LNG stations Regulations -State of the art, December 2013

[69] DG MOVE, LNG Blue Corridors, Guidelines for set up & operation of stations, May 2015

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		granted and after (inspection/checks for compliance)		
4	LNG and L-CNG filling stations regulatory guidelines[69] in relation to set-up and construction (e.g. distance, tank levels etc.), operation (e.g. guarantee sufficient product), and maintenance (planned maintenance work in a programmed schedule) of the station.	Need to ensure safety and efficiency of the station. The regulations require testing and acceptance processes and mechanisms at state/municipal level, before licences are granted and after (inspection/checks for compliance)	Under the sole control of Ukraine	Low
5	Road safety regulations for trucks carrying LNG to the filling stations.	LNG transportation carries some potential hazards, linked to flammability as well as the impact of cryogenic fuel exposure or leakage. There are standards that could be adopted (3 years ago, LNG and CNG were included in the ADR.	Under the sole control of Ukraine	Low
6	Regulations governing TPA of LNG carrying trucks at LNG terminal (in case an in-country LNG terminal with truck loading facilities is developed)	Need to ensure transparent and non-discriminatory access of truck operators to the truck loading facilities	Under the sole control of Ukraine	Low
7	Regulations governing loading of LNG to trucks at LNG terminal facilities (in case an in-country LNG terminal with truck loading facilities is developed)	Need to establish rules and procedures for how truck operators will use the truck loading facilities, including LNG truck approval procedure, LNG specifications, procedures for determining the LNG mass loaded etc.	Under the sole control of Ukraine	Low
8	Regulations governing pricing of LNG terminal truck loading facilities (in case there is an LNG terminal with truck loading facilities, and	Need to have published tariffs for truck loading facility services at the terminal, that are non-discriminatory for	Under the sole control of Ukraine	Low

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	there is price regulation for third party access to such facilities)	users, and regulations for the allowed costs in such tariffs		
9	Permits and licenses, including technical specifications, for truck loading facilities at LNG terminal (in case an in-country LNG terminal with truck loading facilities is developed)	Need to have permits and regulations specifying layout requirements and operational aspects, to address safety issues including fire protection.	Under the sole control of Ukraine	Low
10	Permits and licences, including technical specifications, for liquefaction facilities (in case LNG is sourced from the gas network and loaded on to trucks)	Need to have permits and regulations for site requirements, health and safety considerations, transportation infrastructure, availability of key utilities, air emissions and wastewater treatment.	Under the sole control of Ukraine	Low
11	Permitting process, including technical specifications, for truck loading at liquefaction facility (in case there is a liquefaction facility)	Need to have permits and regulations specifying layout requirements and operational aspects, to address safety issues including fire protection.	Under the sole control of Ukraine	Low
12	(Amendment to) law to specify whether/which type of liquefaction facilities are regulated (TPA and pricing)		Under the sole control of Ukraine	Low
13	Regulations governing TPA of LNG trucks at liquefaction facility (in case there is a regulated liquefaction facility)	Need to establish rules and procedures for how truck operators will use the truck loading facilities, including LNG truck approval procedure, LNG specifications, procedures for determining the LNG mass loaded etc.	Under the sole control of Ukraine	Low
14	Regulations governing pricing of liquefaction facility (in case there is a regulated liquefaction facility)	Need to have published tariffs for use of the liquefaction plant services, that are non-discriminatory for	Under the sole control of Ukraine	Low

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		users, and regulations for the allowed costs in such tariffs		
Infrastructure				
1	Interest of investors to implement necessary infrastructure (filling stations, in-country liquefaction facility)	The required infrastructure must be developed in time for the LNG-fuelled trucks to be able to operate	Decision of investors	Medium

Table 40 outlines the key success factors for the implementation of the option of using LNG as engine fuel for trucks. These factors influence the speed of market development. Some of the key success factors relate to the State providing support to catalyze investments in LNG trucks and filling stations. Others relate to having a regulatory framework that favors 'cleaner' LNG use in trucking and punishes more 'dirty fuels'. State can also regulate the level of subsidies in other fuels, to make LNG more competitive. Other prerequisites relate to the role of State and State organizations to foster changes and to support investors (one-stop-shop). Finally, the role of information campaigns for consumers, users and investors is important to overcome resistance to change and to boost interest.

Table 40: Key success factors for development of LNG as engine fuel for trucks

	Key success factors	Rationale
1	Conducive fiscal framework (low taxes, low import duties, availability of state grants and rebates) for the purchase of LNG fuelled trucks or the retrofitting of existing trucks to LNG.	
2	Setting and enforcing circulation restrictions for trucks that use older generation engines with higher emissions detrimental to the environment (e.g. Euro 4 fuels)	
3	Reduction of subsidies and favourite tax treatment of fuels competing with LNG, to make LNG more competitive and incentivise its use.	
4	Conducive fiscal framework (specific concession regimes, tax holidays, state grants[70]) conducive to investment in construction of new LNG filling stations, or for retrofitting petrol stations to include LNG, or for retrofitting CNG stations to offer also LNG (L-CNG). Also, state co-funding of LNG R&D activities	Having sufficient network of LNG stations is a major success factor. Incentivising private investment is one way to develop the market.
5	Awareness and promotion campaigns for LNG.	Consumers should be educated as to the potential features and benefits of LNG in transport. Investors should be informed on the opportunities available. Such campaigns

[70] 'Connecting Europe Facility', for example, provides grant to co-finance investment in LNG filling stations in the EU

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		can counter resistance to change and speed up interest.
6	Having a 'National champion' e.g. the Ministry of Energy or a State Committee that includes gas company and other key stakeholders. The role of the National champion would be to coordinate the set-up of the required legal and regulatory framework, develop and implement policy and incentives, to remove obstacles in for LNG market development and to act as one-stop-shop for investors. Its role would also include planning the number and location of LNG filling stations and facilities (possibly introducing limited concessions for infrastructure) so as to avoid stranded investments.	Many initiatives are slowed down by regulatory gaps or unclear legislation, lack of implementing administrative mechanisms and bureaucracy and lack of action. Such problems are exacerbated due to lack of awareness and resistance to change or inertia. For example, customs may not be familiar with rules and regulations for the new LNG vehicles and delay their clearance.

8.3.3 Use of LNG as engine fuel for ships

Table 41 describes the key prerequisites for effective implementation of the option of using LNG as engine fuel for ships. The prerequisites concern appropriate price differential between LNG and fuel oil to ensure viability, and the introduction of necessary regulations concerning LNG ships design and operation, as well as regulations and permits concerning bunkering facilities. The choice of ship owners to use LNG as fuel and the development of required infrastructure at ports is also critical for the development of the market.

Table 41: Prerequisites for development of LNG as engine fuel for ships[71]

	Prerequisites	Rationale	Involved country(ies) or parties	Difficulty of implementation
Market				
1	Sufficient price differential between LNG and fuel oil (as discussed in Section 8.2.6), for the vessels that are targeted for fuel switching	Viability of the option is dependent on LNG being competitive to fuel oil for use in shipping, so that investments in fuel conversion for the particular vessels can be recovered	LNG and fuel oil source prices are determined in accordance with international demand and supply conditions (except in the case where LNG is sourced from an in-country liquefaction facility, in which the price is determined by gas import contracts)	Uncertain
2	Interest of ship owners to retrofit or build new LNG-fueled vessels, based on technical	There are alternative options to be applied by ship owners to reduce costs and emissions	Decision of ship owners	Medium to high

[71] In case of LNG supplied from liquefaction facilities to ports via trucks, the relevant points of Table 39 also apply.

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	feasibility and financial attractiveness			
Legal & Regulatory				
1	Codes and Regulations for the design of LNG ships, based on guidelines set by organisations such as the International Maritime Organisation (IMO), the Society of International Gas Tankers and Terminal Operators (SIGTTO), the Oil Companies International Marine Forum (OCIMF) and other ISO, European (EN) and National Fire Protection Association (NFPA) standards	Need to ensure safety, efficiency, quality and environmental protection.	Under the sole control of Ukraine	Low
2	Codes and Regulations for the design and operation of LNG bunkering facilities, based on ISO guidelines (for systems and installations for supply of LNG as fuel to ships) as well as other international guidelines	Need to ensure safety, efficiency, quality and environmental protection.	Under the sole control of Ukraine	Low
3	LNG bunkering facilities permits and licences	Need to ensure the suitability of the selected site for the facility, compliance with operational obligations (e.g. opening hours, station throughput, safety obligations) etc. The licenses require testing and acceptance processes and mechanisms at state/municipal level, before licences are granted and after (inspection/checks for compliance)	Under the sole control of Ukraine	Low

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Infrastructure				
1	Implementation of necessary infrastructure (LNG bunkering infrastructure at ports and/or waterways)	The required infrastructure must be developed in time for the LNG-fuelled vessels to be able to operate	Decision of State and/or private investors	Medium

Table 42 outlines the key success factors for the implementation of the option of using LNG as engine fuel for ships. These factors influence the speed of market development. Some of the key success factors concern IMO regulations that influence the choice of LNG driven ships, especially newbuilds, vis-à-vis ships using other low emission fuels. Other prerequisites relate to having a legal framework conducive to investments and access to finance for the large investments needed. Another prerequisite for LNG fuelled ships is the availability of adequate bunkering infrastructure.

Table 42: Key success factors for development of LNG as engine fuel for ships

	Key success factors	Rationale
1.	Reliability, operating costs advantages (driving from low LNG price and fuel efficiency) and environmental advantages of LNG fuelled ships are maintained over the long term, so as to justify large investment in LNG ships	
2.	Stricter IMO regulations on carbon emissions, and government enforcement, favouring the use of LNG in ships	
3.	IMO regulations not to include greenhouse gas emissions (methane) where LNG is seen to be at a disadvantage compared to other fuels	
4.	Availability of finance (loans, grants etc.) for investment in LNG ships.	Access to finance is key. Investment costs for new ships are significant for shipping companies, whereas retrofits are also costly as larger fuel tanks are required to be placed in ship.
5.	Availability of adequate bunkering infrastructure	
6.	National legislation conducive to investments in ships and/or bunkering infrastructure	

8.3.4 Supply of LNG to off-grid consumers

Table 43 describes the key prerequisites for effective implementation of the option of using LNG to supply off-grid customers in Ukraine. A key prerequisite concerns the appropriate price differential between LNG and currently used fuels to ensure viability. Another prerequisite concerns the introduction of necessary regulations concerning LNG storage and regasification installations at the sites of end-users (agriculture, mining, etc.).

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Table 43: Prerequisites for supply of LNG to off-grid consumers[72]

	Prerequisites	Rationale	Involved country(ies) or parties	Difficulty of implementation
Market				
1	Sufficient price differential between LNG and the alternative fuel (as discussed in Section 8.2.7)	Critical – on/off condition, as switching to LNG requires an attractive price of LNG vis-à-vis the alternative fuel at the end use	LNG and fuel prices are determined in accordance with international demand and supply conditions (except in the case where LNG is sourced from an in-country liquefaction facility, in which the price is determined by gas import contracts)	Uncertain
Legal & Regulatory				
1	Regulations and standards for the siting, design, construction and installation of LNG storage and regasification installations at the sites of end-users (agriculture, mining, etc.)	Need to ensure safety, efficiency, quality and environmental protection by having standards concerning LNG storage and vaporisers, including mobile LNG tanks and vaporizers, and (if necessary) converting heavy equipment to use LNG as fuel.	Under the sole control of Ukraine	Low

Table 44 outlines the key success factors for the implementation of the option of using LNG to supply off-grid customers. These factors influence the speed of market development. These relate to a fiscal framework conducive to investments, reduction of subsidies and other favourable tax regimes for fuels competing with LNG, as well as awareness and promotional campaigns for LNG.

Table 44: Key success factors for supply of LNG to off-grid consumers

	Key success factors	Rationale
1	Reduction of subsidies and favourite tax treatment of fuels competing with LNG, to make LNG more competitive and incentivise its use.	
2	Conducive fiscal framework (tax holidays, state grants) conducive to investment in LNG installations in farms	
3	Awareness and promotion campaigns for LNG.	End consumers (e.g. farmers) should be educated as to the potential features and benefits of LNG in their respective fields.

[72] Points 5 – 14 of Table 39 also apply.

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8.4 Priorities and policy directions

On the basis of the viability assessment analysis performed, the option of LNG as fuel for trucks is viable, and could be implemented in a short-term horizon, as it involves decisions only of local actors and LNG can be sourced from the existing neighboring terminals. The Government could assess feasibility in detail further and take relevant policy actions. These policies could encompass, at the minimum, having a legal and regulatory framework conducive to the development of an LNG supply chain, and expand to cover incentives for the use of LNG.

The option of supplying LNG to off-grid consumers could be viable on a case-by-case basis. Switching to LNG is primarily the consumer's decision, and can be implemented over a short-term horizon, as LNG can be sourced from existing terminals. To enable relevant investments, the Government policy should target the removal of any constraints in the legal and regulatory framework, promote the use of LNG and gauge off-grid consumers' interest.

Concerning the potential for LNG use as fuel for the ships operating in the Black Sea and Ukraine's waterways, this option would require the Government to undertake contextualized analysis, as LNG use is not appropriate for all ships and would depend on technical considerations, utilization and fuel economics and environmental requirements. This option could be developed over a medium-term horizon, as it would require involvement and large investments from ship owners for a diverse number of vessels.

Regasified LNG sourced from neighbouring EU LNG terminals, aiming at gas-to-gas competition, is marginally viable at current market/LNG price conditions, and does not enhance security of supply. Consequently, this option is not a priority from a policy perspective, but it can be implemented in case relative LNG pricing is conducive for market players to take advantage of any potential opportunities.

Development of a Ukrainian LNG terminal is viable only under conditions of LNG prices dropping considerably below current levels and ensuring very high utilisation of the terminal (over 50%). More importantly, there are several prerequisites for the LNG receiving terminal to be realized, that affect the timing of its implementation, notably the uninterrupted passage of LNG vessels through the Bosporus Straits and securing of a sufficient market for regasified LNG. These render this option as medium to long-term.

8.5 Proposed actions

The Table below describes the actions that are deemed important in order to evaluate and prepare the identified applicable LNG market development options.

Table 45: Proposed preparatory actions for developing the identified LNG options in Ukraine

	Proposed Actions	Timing
Initial / Preparatory Actions		
1	Initiate dialogue with Turkish authorities regarding passage of LNG vessels through the Bosporus Straits	Immediate

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2	Perform update of the feasibility study for the development of LNG receiving terminal, including assessment of the prospects for selling LNG in the Ukrainian market	Short-term / dependent on the progress of negotiations with Turkey
3	Perform feasibility studies for the use of LNG as fuel for trucks and ships	Immediate
4	Develop a national policy framework for the use of LNG in road and water transport, deciding on the role that the State wishes to undertake	Short-term / After the study is concluded (in case it is positive and Ukraine decides to pursue)
Implementation Actions concerning LNG receiving terminal		
5	Gauge and secure the market's interest to use the LNG receiving terminal (e.g. binding market test)	Medium-term
6	Explore investors' interests in the LNG receiving terminal	Medium to long-term
Implementation Actions aiming at developing use of LNG in transport sector		
7	Prepare the regulatory and legal framework (legal amendments, regulations, standards, permits and licenses, etc.) necessary for the development of the LNG supply chain	Short-term / based on national policy framework
8	If the State undertakes a proactive role in developing infrastructure, prepare the incentive mechanisms to attract investments	Short-term / based on national policy framework
9	Conduct awareness raising campaigns to attract end-users and investors' interest	Short-term / based on national policy framework
10	Undertake initiatives to catalyze interest and seek joint commitments of stakeholders (suppliers, ports, ship owners) to develop the use of LNG in shipping	Short to medium-term / based on national policy framework

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9 Regional Perspectives for LNG Market Development

Some of the identified potentially viable options for LNG market development are of interest to two or more Eastern Partner countries.

The potential development of the LNG receiving terminal in Ukraine (subject to an agreement between Ukraine and Turkey for the crossing of LNG carriers through the Bosporus Straits) can facilitate supplies of LNG to other Eastern Partner countries (Figure 38):

- Regasified gas can be supplied to Moldova through the Ukrainian system. This option seems not to be commercially viable and therefore would not be used by Moldova under normal market conditions, but potentially in case of a supply disruption (see Section 7.2.2).
- Opening the Bosporus Straits to LNG vessels could drive the development of a small LNG receiving terminal in Georgia that can be supplied from Ukraine (transhipment) or with dedicated LNG shipments.

Figure 38: Regional perspective of LNG terminal in Ukraine

Potential development of a liquefaction terminal in Georgia, allowing exports of Caspian gas though the Black Sea (subject to the development of additional export potential in Azerbaijan and/or the commencement of gas supplies gas from Kazakhstan and Turkmenistan through the Caspian Sea), can develop an alternative corridor for LNG supplies to Eastern Partner countries

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(Figure 39). This corridor that is not subject to an agreement with Turkey on crossing of LNG carriers through the Bosporus Straits, can allow:

- Supply of LNG shipments to the LNG terminal in Ukraine. This option would provide Ukraine with access to Caspian gas resources, allowing to further diversifying its sources and routes.
- Supply of regasified gas to Moldova through the Ukrainian terminal and system. This option seems not to be commercially viable and therefore would not be used by Moldova under normal market conditions, but potentially in case of a supply disruption (see Section 7.2.3).

Figure 39: Regional perspective of liquefaction terminal in Georgia

Initiatives for cooperation between Eastern Partners on smaller-scale infrastructure can also be explored. In particular, the interest of most Eastern Partner countries (Armenia, Azerbaijan, Belarus, Georgia, Ukraine) to develop a use of LNG in road transport could lead to the establishment of a regional network of LNG filling stations, that can facilitate accessibility of LNG to long-haul trucks operating in the region, and this provide incentives to truck owners to switch to LNG.

Furthermore, the development of an LNG receiving or liquefaction and export terminal in Georgia would allow Armenia to have access to LNG supplies, facilitating the development of an LNG market.

To foster development of LNG markets in the region, a number of actions could be considered for regional (or sub-regional) coordination and cooperation, presented in the Table below.

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Table 46: Proposed actions for regional coordination and cooperation

	Actions	Involved parties	Timing
1	Creation of sub-committees under the Eastern Partnership LNG working group, to facilitate dialogue, coordination and initiatives on key LNG issues (technical & standards, regulatory, market, etc.)	Regional level (All interested Eastern Partner countries)	Immediate
2	Joint Georgia – Ukraine initiatives for addressing the Bosporus Straits' constraints	Sub-regional level (Georgia and Ukraine)	Immediate
3	Harmonization of rules, regulations and standards, for LNG-fuelled trucks, and for trucks transporting LNG, for ease of transit through the Eastern Partner and EU countries	Regional level (All interested Eastern Partner countries)	Short-term
4	Assess the potential for joint developing a small-scale liquefaction facility to supply LNG for trucks in the Caucasus region	Sub-regional level (Armenia, Azerbaijan and Georgia)	Short-term
5	Coordination, and potentially preparation of regional development plan for the establishment of LNG filling stations in the Eastern Partner countries	Regional level (All interested Eastern Partner countries)	Short-term

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10 Recommendations for EU and Eastern Partners' joint actions

The analysis carried out in this Study shows that there is interest by the Eastern Partner countries and potential for LNG market development, both for gas-to-gas and gas-to-other fuels competition. However, this potential can only be gradually realised, given the investments requirements and the current market conditions.

In catalysing this development, the Eastern Partner countries would benefit from the experience, practices and lessons learned of EU LNG markets' stakeholders. Joint actions that could be considered with the objective of fostering cooperation and market development include:

- Creation of sub-committees under the Eastern Partnership LNG working group, to facilitate dialogue, coordination and initiatives on key LNG issues (technical & standards, regulatory, market, etc.);
- Knowledge transfer from EU counterparts (from the whole LNG industry) to Eastern Partners, on LNG technologies and benchmark costs, focusing on infrastructure development, especially small-scale applications (regasification, liquefaction, filling stations etc.);
- Sharing of the experience gained through the Blue Corridor initiative, as a model case to develop the use of LNG in the transport sectors of Eastern Partners, by facilitating assessment and planning for the whole LNG supply chain;
- Provision of know-how and technical assistance for the development of the legislative and regulatory framework, technical rules and standards for all LNG related infrastructure and equipment;
- Development of a common IT platform for knowledge sharing of materials relevant to LNG markets;
- Possibility to provide co-financing for selected projects of common interest through the European Network Instrument, or other financing mechanisms.

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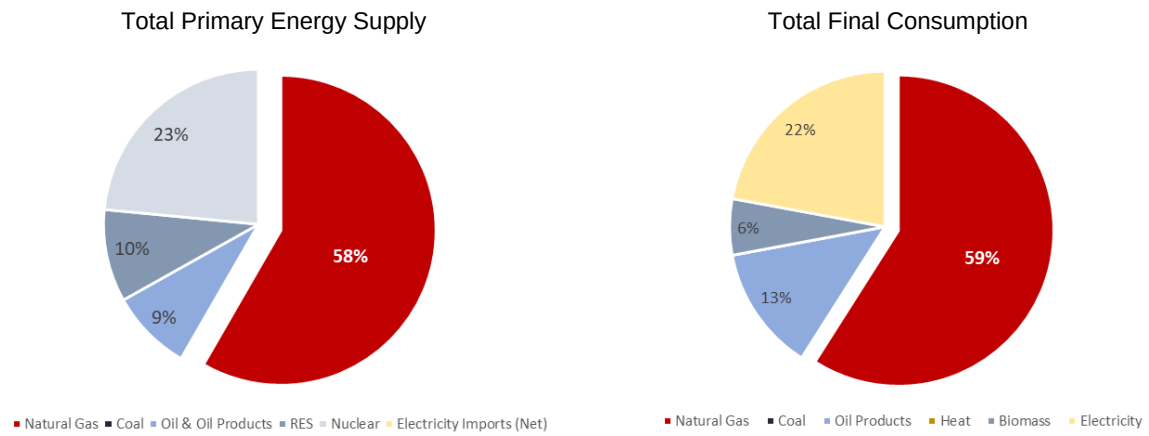
Annex 1: Overview of Eastern Partners' gas markets

A1.1. Armenia

A1.1.1. Role of natural gas in the energy mix

Natural gas is the dominant fuel in the energy mix of Armenia (Figure A. 1), in 2017 amounting to 58% of the country's total primary energy supply, and 48% of total final consumption. In the past, gas maintained similar shares in the energy mix.

Figure A. 1: Natural gas in the energy mix of Armenia (2017)



Source: Ministry of Energy Infrastructures and Natural Resources of the Republic of Armenia, Energy Balance 2017

A1.1.2. Natural gas supply & demand

Without indigenous gas production, all gas demand is covered with imports. Most gas supplies are sourced from Russia (approx. 85%), the rest being imported from Iran. Annual demand has remained relatively constant in the past few years, ranging from 2.2 to 2.4 bcm (Figure A. 2).

Gas imports from Russia are carried out in accordance with a gas supply contract signed between Gazprom Armenia, the vertically integrated gas supplier in Armenia, and Gazprom Export. The contract, valid until the end of 2019, foresees supply of up to 2.5 bcm/yr to Armenia. Import price for 2019 is set at 150 €/1000 m^3, increased from 136 €/1000 m^3 in 2018[73]. Armenia and Russia are negotiating a new gas contract, with the Armenian side seeking to sign a five-year agreement on the price of gas, instead of the current annual readjustment[74].

[73] https://ria.ru/20181231/1548952211.htmlhttps://ria.ru/20181231/1548952211.html

[74] http://tass.com/economy/1052207

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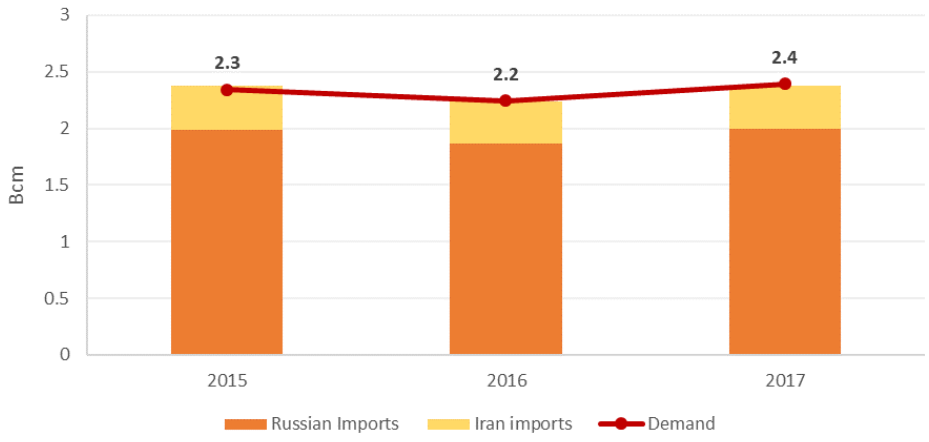
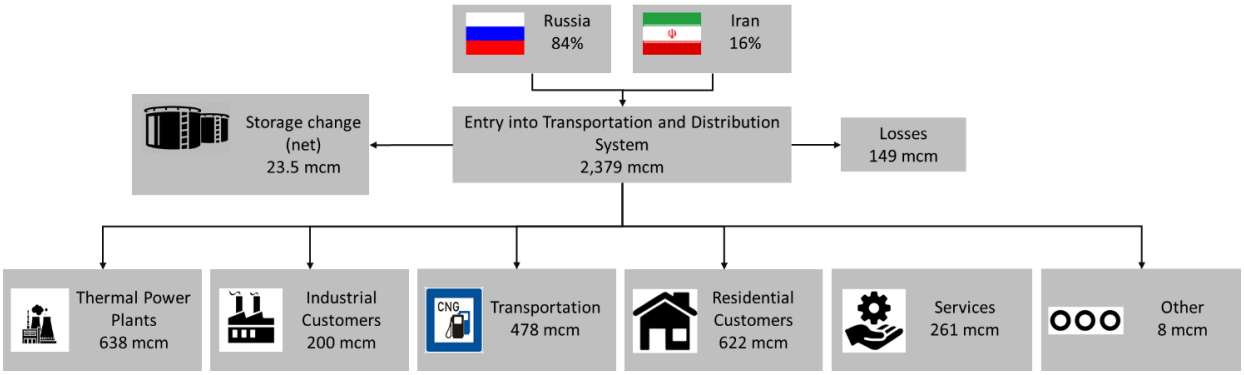
Figure A. 2: Evolution of natural gas supply and demand in Armenia[75]



Source: Ministry of Energy Infrastructures and Natural Resources of the Republic of Armenia, Energy Balance 2017

Imports from Iran are being carried out under a swap scheme that foresees supply of up to 0.5 bcm/yr of Iranian gas to Armenia, and export of Armenian electricity to Iran (3.2 kilowatt-hours of electricity are exported in exchange for 1 cubic meter of gas)[76]. The 20-year swap contract entered into force in 2009.

Figure A. 3: Natural gas balance in Armenia (2017)



Source: Ministry of Energy Infrastructures and Natural Resources of the Republic of Armenia, Energy Balance 2017

Figure A. 3 presents the 2017 balance of the natural gas sector in Armenia. The largest part of gas consumption is for electricity generation (the only fossil fuel used in thermal power plants) and for heating at households (only biomass is used as an alternative fuel). Use of natural gas in

[75] Demand includes net stock changes in UGS, and losses of distribution and transmission systems.

[76] https://financialtribune.com/articles/energy/76842/iran-gas-export-to-armenia-at-250-mcm-in-8-months

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the transport sector, as CNG, is very high. In 2017, 373 CNG filling stations are in operation in the country, and according to Gazprom Armenia, around 77% of the vehicles operate with CNG[77].

A1.1.3. Natural gas prices

End-user prices for all gas consumers are regulated, set by the Public Services Regulatory Commission (PSRC). Customer categories have been established, for which different prices are set. The Table below presents the current end-user prices applied in the market.

Table A. 1: Regulated end-user prices in Armenia

Customer Category	Regulated price (excluding VAT) in €/1000 m^3
Vulnerable household– annual consumption up to 600 m^3	154
Vulnerable household– annual consumption over 600 m^3	214
Agriculture (depending on season and consumption)	160 – 214
Other consumers – consumption up to 10,000 m^3	214
Other consumers – consumption over 10,000 m^3	183

Source: PSRC, Tariffs

A1.1.4. Natural gas infrastructure

The gas transmission system of Armenia spreads throughout the country. The total length of the main pipelines and their branches is 1682 km. According to the Ministry of Energy Infrastructures and Natural Resources, around 95% of Armenia is gasified[77].

Armenia is interconnected with Georgia and Iran (Figure A. 4). The North-South Pipeline, with a capacity of 3.65 bcm/yr, transits Russian gas to Armenia (Koghb) through Georgia. The Iran-Armenia pipeline is 142 km long, connecting Tabriz (Iran) with Meghri (Armenia) with a delivery capacity of 2.3 bcm/yr[78].

[77] Ministry of Energy Infrastructures and Natural Resources of the Republic of Armenia, Explanation on the development of Armenia's Energy Balance 2015, 2016, 2017, Available at: http://www.minenergy.am/en/page/554,

[78] World Bank,Armenia Power Sector Policy Note, 2014, Available at: http://documents.worldbank.org/curated/en/488891467998515807/pdf/94187-REVISED-WP-P133834-PUBLIC-Box391432B-Armenia-Power-Policy-Note-full-version-very-final-ENGLISH.pdf

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Figure A. 4: Armenian gas transmission system

Source: Gazprom, World Bank

The transmission system is connected to the Abovyan UGS, with capacity of 135 mcm, used to cover the seasonal and peak demand of the gas. In 2017, 58 mcm were withdrawn from the storage, and 43 mcm injected[77].

Iran, Georgia and Armenia are currently discussing the potential of transiting Iranian gas to Georgia, without however any concrete agreement signed yet.

A1.1.5. Market structure

Armenia's gas market has a monopolistic structure. All gas activities are concentrated within the vertically integrated holding structure of Gazprom Armenia (owned 100% by Gazprom). The company operates as a single gas distributor and supplier; its subsidiary TransGas operates transmission system and storage in the country (Figure A. 5). Erevan thermal power station holds a license for gas imports, as it is receiving the gas supplies from Iran.

PSRC is the country's energy regulator, responsible for issuing licenses, establishes market rules and contractual terms of gas supply contracts, sets regulated tariffs for end-users.

Figure A. 5: Key stakeholders in Armenia's gas supply chain

A1.1.6. Regulatory framework

The gas sector is governed by the "Energy Law of the Republic of Armenia", adopted in March of 2001. The Law does not provide for opening of the gas market. While non-discriminatory access to the transmission system is foreseen, no further relevant regulation has been established. The

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market rules in force, issued by PSRC ("Rules for Natural Gas Supply and Use", of September 2005), focus on the obligations of supplier and end-users, and connection rules, without any provisions related to the operation of the gas market.

Table A. 2 below, provides an outline of the key regulatory framework provisions related to the overall market operation, transmission system and off-grid supplies of LNG.

Table A. 2: Overview of regulatory framework in Armenia (✓: covered, ✓: partly covered, ➲: ongoing procedure, ✘: not covered)

Overall market operation		
Law governing the gas sector	Energy Law of the Republic of Armenia (2001)	
Licensing of gas stakeholders	✓	Entities undertaking activities in the gas sector, including import/export, transportation, distribution. Distribution licensee is entitled to supply end-users (no separate supply license)
Eligibility of final consumers to choose supplier	✘	Not foreseen in the national legislation. Suppliers entitled to sell gas must hold a distribution license
Transparent and non-discriminatory third-party access on the transmission system	✘	Non-discriminatory access to the system is foreseen, but without further requirements of supporting regulations
Rules for access to storage	✘	No rules in place
Unbundling of system operators	✘	Not foreseen in the national legislation (Transgaz fully dependent on Gazprom Armenia)
Transmission system operation		
Establishment of capacity allocation mechanisms	✘	No such provisions have been established
Establishment of congestion management procedures	✘	No such provisions have been established
Existence of transparent interconnection agreements with neighbouring TSOs	✘	No such provisions have been established
Definition of tariffs at cross-border entry/exit points	✘	No such provisions have been established
Publication of gas technical specifications	✘	No publication requirement
Transparent procedures for operation of the system (nomination, allocation, balancing)	✘	No such provisions have been established

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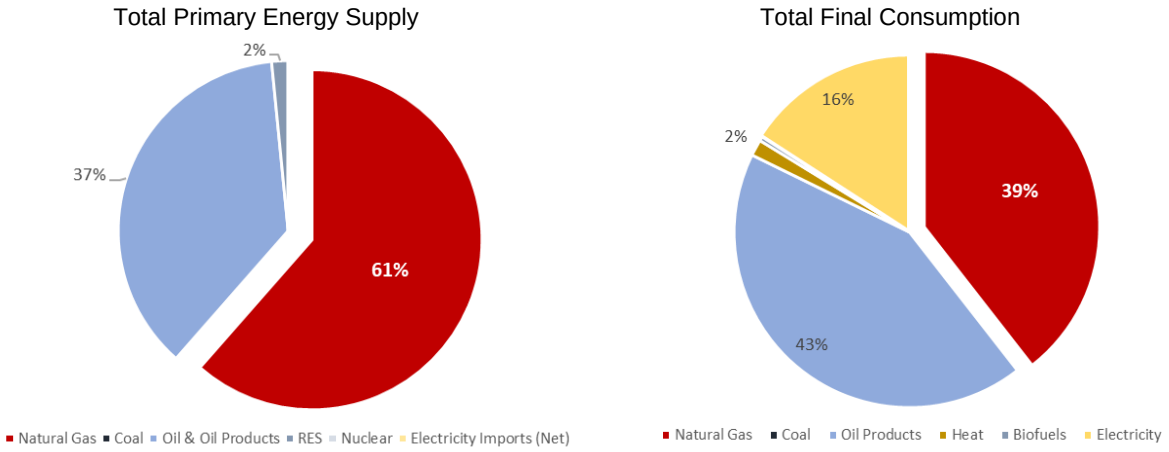
A1.2. Azerbaijan

A1.2.1. Role of natural gas in the energy mix

With Azerbaijan being a producer and net exporter of oil & gas, hydrocarbons cover almost fully the primary energy supply of the country, with natural gas having a share of 61% (Figure A. 6). Although the majority of produced gas is exported, the fuel also plays an important role in the country's total final consumption (total share of 39%) being the dominant fuel for electricity generation, industries, and households.

Figure A. 6: Natural gas in the energy mix of Azerbaijan (2017)



Source: State Statistical Committee of the Republic of Azerbaijan, Energy Balance 2017

A1.2.2. Natural gas supply & demand

Azerbaijan is a net gas exporter. In the period 2013 – 2017, gas production ranged from 18 to 19 bcm/yr, while annual consumption did not exceed 4.6 bcm/yr (Figure A. 7). In 2016 and 2017, Azerbaijan imported volumes of gas from Iran and Russia[79].

Gas imports from Russia restarted in 2017. According to EIA, gas is stored in the Garadagh and Galmaz UGSs and used for increasing oil production and potentially for gas to Iran in the winter months[80]. Azerbaijan and Iran hold a swap agreement, according to which Azerbaijan exports small quantities of gas to Iran through the Hajiqabul-Astara pipeline and receives gas at the Nakhchivan region. According to the Ministry of Energy, additional gas volumes are being imported from Iran to Azerbaijan through the Astara-Gazi pipeline.

[79] Ministry of Energy of the Republic of Azerbaijan (2017). 2017 Report on the work carried out in fuel and energy sector. Available online at: http://www.minenergy.gov.az/docs/Illik_Hesabat_2017.pdf

[80] https://www.eia.gov/beta/international/analysis_includes/countries_long/Azerbaijan/azerbaijan_bkgd.pdf

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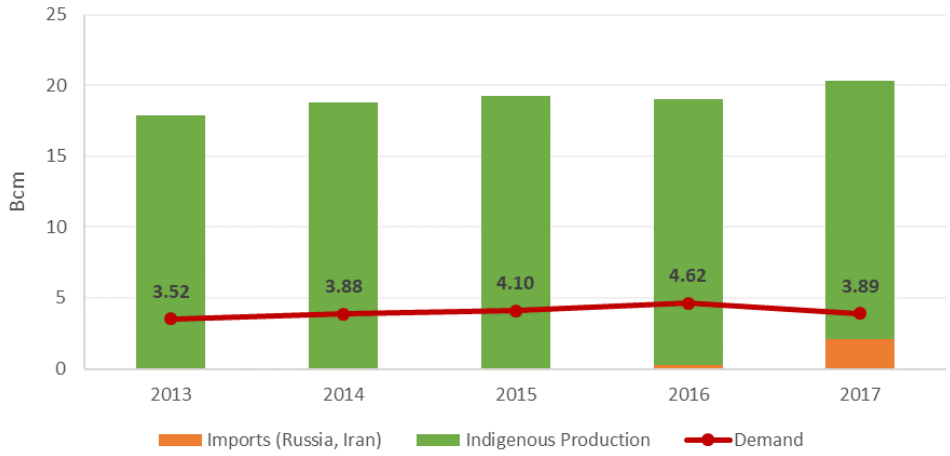
Figure A. 7: Evolution of natural gas supply and demand in Azerbaijan

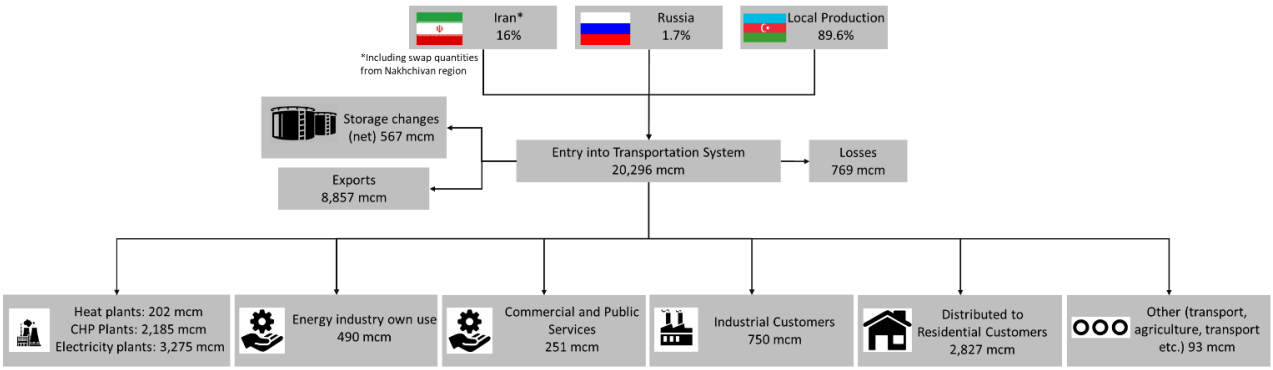


Source: State Statistical Committee of the Republic of Azerbaijan, Energy Balance 2017

Almost 80% of Azerbaijan's gas is produced from the Shah Deniz and Azeri-Chirag-Gunashili (ACG) off-shore fields, that are being operated by international consortia, with participation of SOCAR. The remaining gas production comes from small on-shore and off-shore fields operated by SOCAR. According to EIA, the country's proved reserves in January 2018 amounted to around 990 bcm, most of which in Shah Deniz. The second phase of the field's development (Shah Deniz 2) came online in 2018 and its output, once production reaches a plateau, is expected at 16 bcm/yr[81].

The majority of current gas exports are shipped through the SCP to Turkey (6.3 bcm in 2017), and the rest to Georgia (0.8 bcm through SCP and 1.4 bcm through the Magomed-Gazakh pipeline in 2017)[79]. According to EIA, all gas outputs from Shah Deniz 2 have already been contracted, for exports to Turkey and Europe[80].

Figure A. 8: Natural gas balance in Azerbaijan (2017)



Source: State Statistical Committee of the Republic of Azerbaijan, Energy Balance 2017

81 http://www.socar.com.tr/en/corporate-communication/news/2018-news/2018/07/02/shah-deniz-2-begins-gas-deliveries-to-turkey-with-tanap-project

Figure A. 8 presents the 2017 balance of the natural gas sector in Azerbaijan. More than half of gas (54%) is consumed in TPPs and CHPs, while households consume another 28%.

A1.2.3. Natural gas prices

The transportation, wholesale and end-user prices of gas in Azerbaijan are regulated, defined by the Tariff Council of Azerbaijan Republic. The transportation tariff is distance based, set at 1 €/1000 m^3 per 100km, and the wholesale price is 39 €/1000 m^3. End-user prices depend on the customer category (Table A. 3).

Table A. 3: Regulated end-user prices in Azerbaijan

Customer Category	Regulated price (including VAT) in €/1000 m^3
Residential – annual consumption up to 2200 m^3	52
Residential – annual consumption over 2200 m^3	104
Non-residential	104
Power generation – consumption over 10 mcm per month	62

Source: Tariff Council of Azerbaijan Republic, Tariffs

A1.2.4. Natural gas infrastructure

Figure A. 9 presents the transmission system of Azerbaijan, and the pipelines with neighbouring countries. The import and export pipelines include[80, 82]:

- South Caucasus Pipeline (SCP): Transports gas from the Shah Deniz field to Turkey, having also a small offtake in Georgia. SCP is owned by an international consortium (BP – operator (28.8%), TPAO (19%), Petronas (15.5%), LUKoil (10%), NICO (10%), AzSCP (10%), SNG Midstream (6.7%)). Its total length is 691km, running 443 km in Azerbaijan and 248 km in Georgia, and its initial capacity is 7.4 bcm/yr. In mid-2018 the South Caucasus Pipeline Extension (SCPX) was completed, increasing capacity to 23.4 bcm/yr[83], once Shad Deniz 2 production reaches a plateau.
- Gazi-Magomed-Mozdok Pipeline: Connects the Azeri and Russian transmission systems, and is currently used for imports of Russian gas to Azerbaijan (in the past it was also used on the opposite flow, exporting Azeri gas to Russia). Its total length is 740 km and its capacity 5 bcm/yr.
- Gazi-Magomed-Astara Pipeline: Connects Azerbaijan with Iran, and is used for gas swaps, and exports to Iran. Its total length is 274 km and maximum capacity 1.8 bcm/yr.
- Azerbaijan – Georgia Pipeline: The main export route of Azeri gas to Georgia. Its capacity is 1.8 bcm/yr.

[82] BP, South Caucasus pipeline, Available At: https://www.bp.com/en_az/caspian/operationsprojects/pipelines/SCP.html

[83] South Caucasus Pipeline Consortium https://www.sgc.az/en/project/scp

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Figure A. 9: Azeri gas transmission system

Source: U.S. Energy Information Administration (EIA), Azerbaijan Country Profile

Azerbaijan has two UGSs, in Garadagh and Galmaz, with aggregate working volume of 5 bcm. The storages are used to cover winter demand peaks[80].

There are plans for developing an additional export route of Azeri gas to Europe, through the Azerbaijan-Georgia-Romania Interconnector (AGRI) project, that foresees development of a liquefaction terminal in Georgia and export of LNG to Romania through the Black Sea, where it will be regasified and supplied to Romania, Hungary and other EU markets. Capacity of the project can be modular, ranging from 2 to 8 bcm/yr[84]. Development of the project depends on the availability of gas in Azerbaijan, and its timeline of implementation has been set after 2024-26[85].

A1.2.5. Market structure

SOCAR is the vertically integrated gas company of Azerbaijan (100% state owned), with all gas transportation, distribution, storage and supply activities within the country carried out by its subsidiaries (Figure A. 10). Azerigaz Production Union is responsible for the transmission, distribution and sale of gas in Azerbaijan, as well as for the transportation of SOCAR gas to Iran, Georgia and Russia. The Gas Export Department of SOCAR is responsible for the exports and imports of gas in the country (including swaps with Iran). Azneft Production Union is the operator of Azerbaijan's UGSs.

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[84] AGRI LNG Project Description, Available at: http://www.agrilng.com/agrilng/Home/DescriereProiect

[85] https://www.azernews.az/oil_and_gas/146939.html

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The mandate of the Azerbaijan Energy Regulatory Agency (AERA) is to regulate gas supply. However, AERA still has not issued any relevant regulations. The Tariff Council of Azerbaijan Republic is responsible for approving regulated tariffs for the gas sector, following proposals by SOCAR.

Figure A. 10: Key stakeholders in Azerbaijan's gas supply chain[86]

A1.2.6. Regulatory framework

The gas sector is governed by the "The Law of the Republic of Azerbaijan on Gas Supply", of 1998, amended in 2011. The Law does not include any provisions related to market opening, access to the systems, or even licensing of gas stakeholders.

Table A. 4 below, provides an outline of the key regulatory framework provisions related to the overall market operation, transmission system and off-grid supplies of LNG.

Table A. 4: Overview of regulatory framework in Azerbaijan (✓: covered, ✓: partly covered, ➲: ongoing procedure, ✘: not covered)

Overall market operation		
Law governing the gas sector	The Law of the Republic of Azerbaijan on Gas Supply (2011)	
Licensing of gas stakeholders	✘	No licensing rules foreseen in the national legislation
Eligibility of final consumers to choose supplier	✘	Not foreseen in the national legislation.
Transparent and non-discriminatory third-party access on the transmission system	✘	Not foreseen in the national legislation.
Rules for access to storage	✘	Not foreseen in the national legislation.
Unbundling of system operators	✘	Not foreseen in the national legislation.
Transmission system operation		
Establishment of capacity allocation mechanisms	✘	No such provisions have been established. Capacity managed only by the owners of the systems

[86] The graph presents only the stakeholders active in the internal Azeri gas market. International consortia operating gas fields (Shah Deniz, ACG) and international pipelines (SCP are not included).

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Establishment of congestion management procedures	✘	No such provisions have been established
Existence of transparent interconnection agreements with neighbouring TSOs	✘	No such provisions have been established
Definition of tariffs at cross-border entry/exit points	✘	No such provisions have been established
Publication of gas technical specifications	✘	No publication requirement
Transparent procedures for operation of the system (nomination, allocation, balancing)	✘	No such provisions have been established

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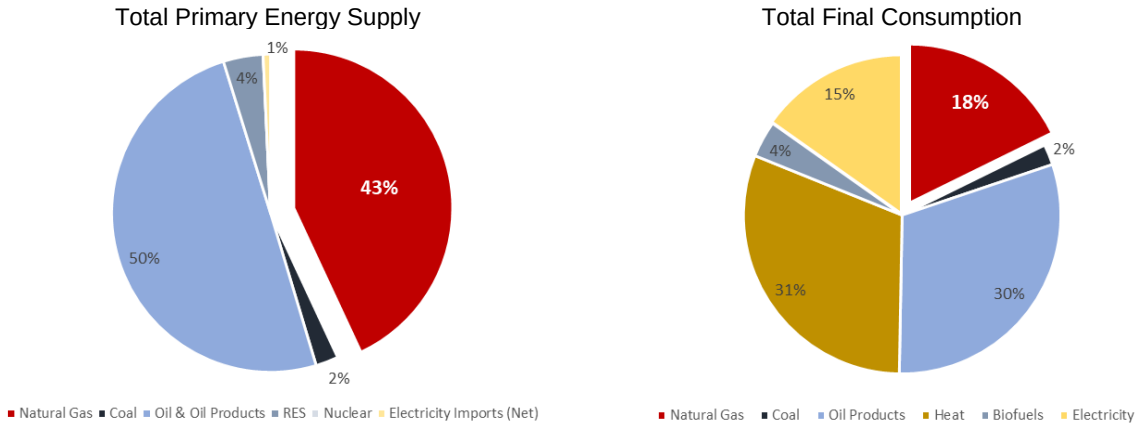
A1.3. Belarus

A1.3.1. Role of natural gas in the energy mix

Natural gas is the second largest fuel supplied in Belarus, after crude oil, with a 2017 share of 43% in the total primary energy supply of the country. It is the dominant fuel for power plants and district heating (over 90% of total fuel consumption). Most gas supplies are transformed to heat and electricity; as a result, gas has just 18% share in total final consumption.

Figure A. 11: Natural gas in the energy mix of Belarus (2017)

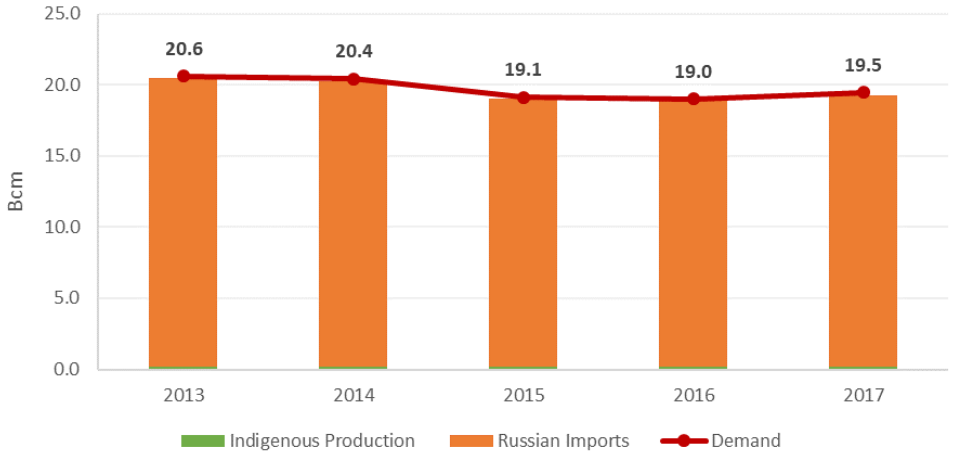


Source: National Statistical Committee of the Republic of Belarus (Belstat), Energy Balance 2017

A1.3.2. Natural gas supply & demand

The gas market is dependent on imports of Russian gas. Annual demand over the past 5 years has been within the range of 19 to 20.5 bcm (Figure A. 12).

Figure A. 12: Evolution of natural gas supply and demand in Belarus



Source: National Statistical Committee of the Republic of Belarus (Belstat), Energy Balance 2017

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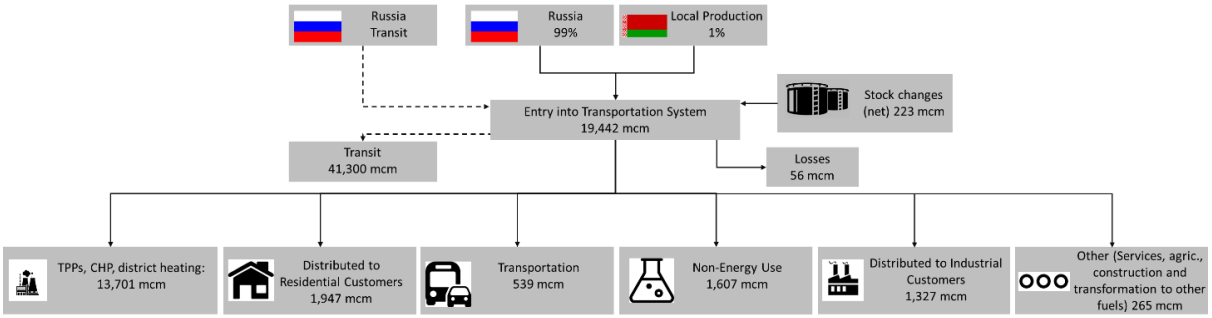
Imports of Russian gas to Belarus are carried out in accordance with the gas supply and transit contract signed in December 2014 that was extended in 2018 for supplies up to 2020. Gas delivery (border) prices are set at 130 €/1000 m^3 in 2017, 117 €/1000 m^3 in 2018 and 115 €/1000 m^3 in 2019[87].

Figure A. 13 presents the 2017 balance of the natural gas sector in Belarus. Over 70% of gas is being used for electricity and heat generation, while the rest is mainly consumed in households and industries.

Figure A. 13: Natural gas balance in Belarus (2017)



Source: National Statistical Committee of the Republic of Belarus (Belstat), Energy Balance 2017

Gas transit volume via Belarus to Ukraine, Poland, Lithuania and Kaliningrad region of Russian Federation reached 42.5 bcm in 2018, increased from 41.3 bcm in 2017[88].

To reduce dependence of electricity and heat generation from imported gas supplies, Belarus will introduce nuclear energy in its energy mix. A nuclear power plant is being build (commissioning work began in April 2019), with installed capacity of 2.4 MW[89]. As a result of the NPP operation, gas demand is expected to decrease in the next years (Figure A. 14).

87 https://neftegaz.ru/news/transport-and-storage/193568-obem-tranzita-gaza-cherez-belarus-v-2018-g-uvelichilsya-na-3/

88 https://neftegaz.ru/news/transport-and-storage/193568-obem-tranzita-gaza-cherez-belarus-v-2018-g-uvelichilsya-na-3/

89 World Nuclear Association (April 2019): http://www.world-nuclear.org/information-library/country-profiles/countries-a-f/belarus.aspx

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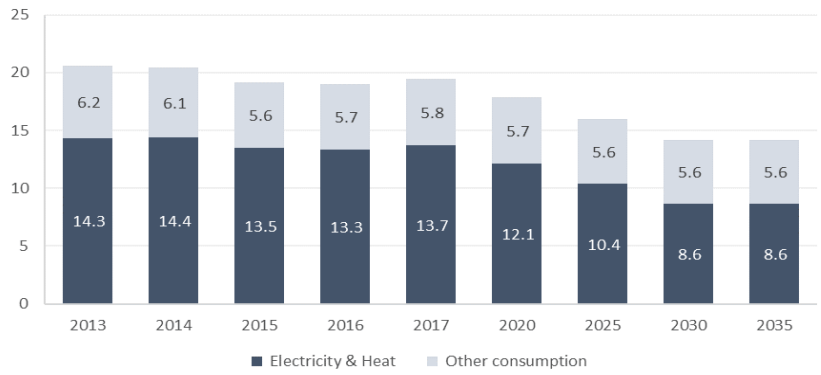
Figure A. 14: Forecasted gas demand in Belarus



Source: National Statistical Committee of the Republic of Belarus (Belstat); Energy Security Conception of Republic of Belarus (Resolution No 1084 dated 23/12/2015)

A1.3.3. Natural gas prices

End-user prices for all gas consumers are regulated, set by the Ministry of Energy of Belarus. Different prices are defined for household and non-household consumers, varying on gas use and seasonality (Table A. 5).

Prices include the Gazprom Transgaz Belarus tariff for gas transportation (in 2017 15.5 €/1000 m^3, excluding VAT) and Beltopgaz tariff for distribution (in 2017 5.8 €/1000 m^3)[90].

Table A. 5: Regulated end-user prices in Belarus

Customer Category[91]	Regulated price (VAT excluded) in €/1000 m^3
Residential (for heating) - winter period	50 – 52
Residential (for heating) - summer period	179.5
Residential (other uses)	179.5
Services - up to 600 mcm/yr	223.0
Heat plants - up to 600 mcm/yr	143.0
Agriculture (depending on season) - up to 600 mcm/yr	145 - 196
Manufacturing (depending on products) - up to 600 mcm/yr	95 - 219
Fertilizing industry - up to 600 mcm/yr	136
Other types of non-residential consumers - up to 600 mcm/yr	224
Non-residential consumers - up to 600 mcm/yr	341

Source: Ministry of Energy of Belarus

[90] https://www.sb.by/articles/skolko-stoit-prirodnyy-gaz-v-belarusi-.html; http://pravo.by/document/?guid=3871&p0=W21631316

[91] Households without installed meters have different regulated prices, on the basis of number of habitants (for cooking/hot water) and dwelling size (for heating)

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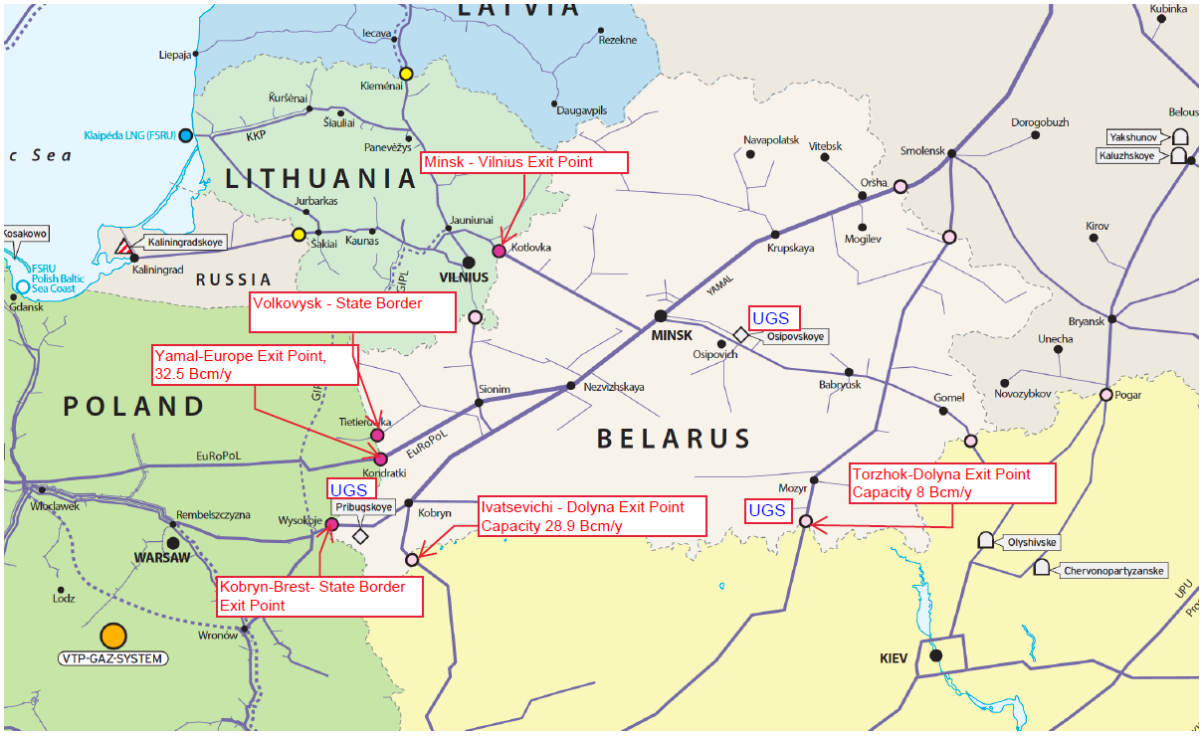
A1.3.4. Natural gas infrastructure

The total length of the transmission system in Belarus is over 7,900 km, covering most regions of the country. Part of this system (around 2,500 km) is used for transit of Russian gas to the EU. Additionally, the dedicated transit pipeline Yamal-Europe, with technical capacity of 32.9 bcm/yr, runs 575 km through Belarus[92] (Figure A. 15).

Figure A. 15: Gas transmission system in Belarus



Source: ENTSOG, Gazprom, Ukrtransgaz

There are 3 underground storages connected to the transmission system of Belarus. Osipovichsky UGS, with working volume of 0.3 bcm, Pribugskoye UGS, with working volume of 0.4 – 0.6 bcm, and Mozyr UGS, with peak daily capacity of 8 mcm/d. There are plans for extending the maximum working volume of the Mozyr UGS to 1 bcm, by 2020[92].

In July 2018, Gazprom Transgaz Belarus announced their plans for developing an LNG supply chain development, by carrying out engineering works of the first small-scale LNG production plant in Belarus. Its aim is to use gas in transit transport via Belarus and in farming machinery[93].

[92] Gazprom Transgaz Belarus, http://belarus-tr.gazprom.ru/about/activities/ ; Gazprom, http://www.gazprom.com/projects/yamal-europe/

[93] https://www.belta.by/interview/view/gazprom-transgaz-belarus-v-2018-godu-investiruet-v-obnovlenie-gazotransportnoj-sistemy-br169-mln-6360/

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A1.3.5. Market structure

The gas market of Belarus is monopolistic. Gazprom Transgaz Belarus (100% subsidiary of Gazprom) is the owner and operator of the Belarusian transmission and storage infrastructure, as well as responsible for the operation of the Yamal-Europe Pipeline, owned by Gazprom. Gazprom Transgaz Belarus also holds the import contracts with Gazprom and sells gas to the state-owned company Beltopgaz that is responsible for the supply and distribution of gas in the market. Retail sales are carried out through the regional subsidiaries of Beltopgaz.

There is no independent energy regulator in Belarus. The Ministry of Antimonopoly Regulation and Trade is responsible for setting the regulated end-user prices in the gas sector, while the Ministry of Energy is responsible for monitoring the market operation.

Figure A. 16: Key stakeholders in Belarus gas supply chain

A1.3.6. Regulatory framework

The gas sector is governed by the Natural Monopolies Law No 162-3/911 of December 2002 (amended in 2006, 2009, 2014 and 2019) and the Law of the Republic of Belarus on Gas Supply No 176-3 of January 2003 (amended in 2006, 2008, 2009 and 2011). The legislative framework does not include any provisions related to market opening, access to the systems, or even licensing of gas stakeholders.

Table A. 6 below, provides an outline of the key regulatory framework provisions related to the overall market operation, transmission system and off-grid supplies of LNG.

Table A. 6: Overview of regulatory framework in Belarus (✓: covered, ✓: partly covered, ➲: ongoing procedure, ✘: not covered)

Overall market operation		
Law governing the gas sector	Natural Monopoly Law (2014), Law on Gas Supply (2011)	
Licensing of gas stakeholders	✘	No licensing rules foreseen in the national legislation
Eligibility of final consumers to choose supplier	✘	Not foreseen in the national legislation.
Transparent and non-discriminatory third-party access on the transmission system	✘	Not foreseen in the national legislation.
Rules for access to storage	✘	Not foreseen in the national legislation.
Unbundling of system operators	✘	Not foreseen in the national legislation.

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Transmission system operation		
Establishment of capacity allocation mechanisms	✘	No such provisions have been established
Establishment of congestion management procedures	✘	No such provisions have been established
Existence of transparent interconnection agreements with neighbouring TSOs	✘	No such provisions have been established
Definition of tariffs at cross-border points	✘	No such provisions have been established
Publication of gas technical specifications	✘	No such provisions have been established
Transparent procedures for operation of the system (nomination, allocation, balancing)	✘	No such provisions have been established

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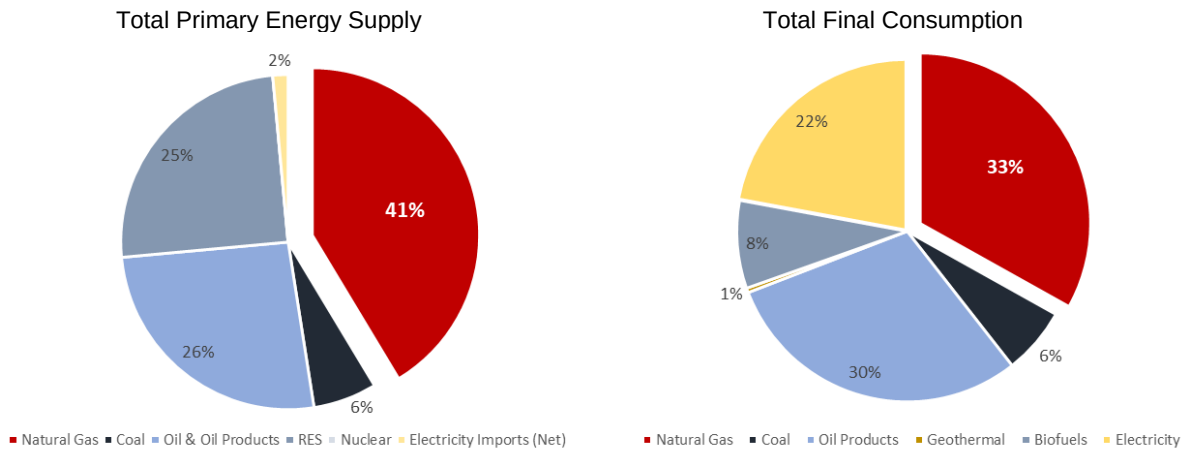
A1.4. Georgia

A1.4.1. Role of natural gas in the energy mix

Natural gas has the largest share in Georgia's total primary energy supply. The total final consumption is quite diversified, with natural gas, oil products and electricity being mostly used (Figure A. 17).

Figure A. 17: Natural gas in the energy mix of Georgia (2017)

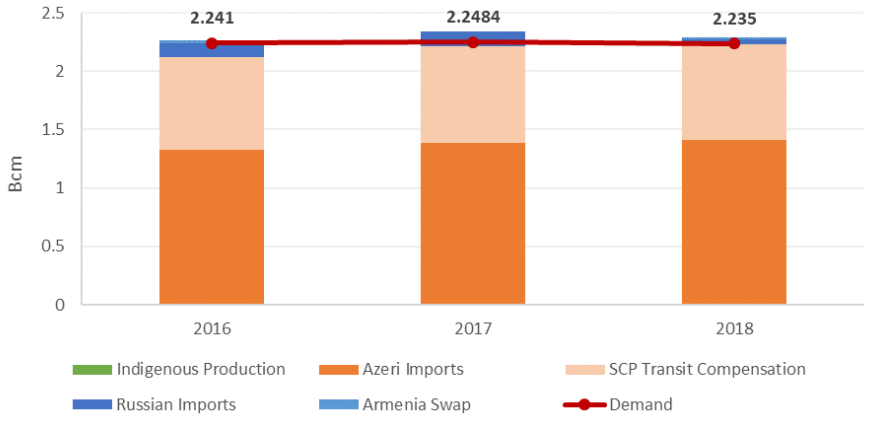


Source: National Statistics Office of Georgia, Energy Balance 2017

A1.4.2. Natural gas supply & demand

Annual gas demand in Georgia is within the range of 2.2 to 2.5 bcm/yr. The market is almost fully dependent on imports, as indigenous production accounts to less than 1% of consumed gas. Azerbaijan is the main supplier of Georgia, while additional volumes are received through the SCP, as compensation for the transit of Azeri gas to Turkey (in lieu of transit fee). Some small volumes of Russian gas are being supplied, in cases where Azeri gas is not sufficient to cover high peak demand. Finally, very small gas volumes from the gas transited to Armenia are being swapped (Figure A. 18).

Figure A. 18: Evolution of natural gas supply and demand in Georgia



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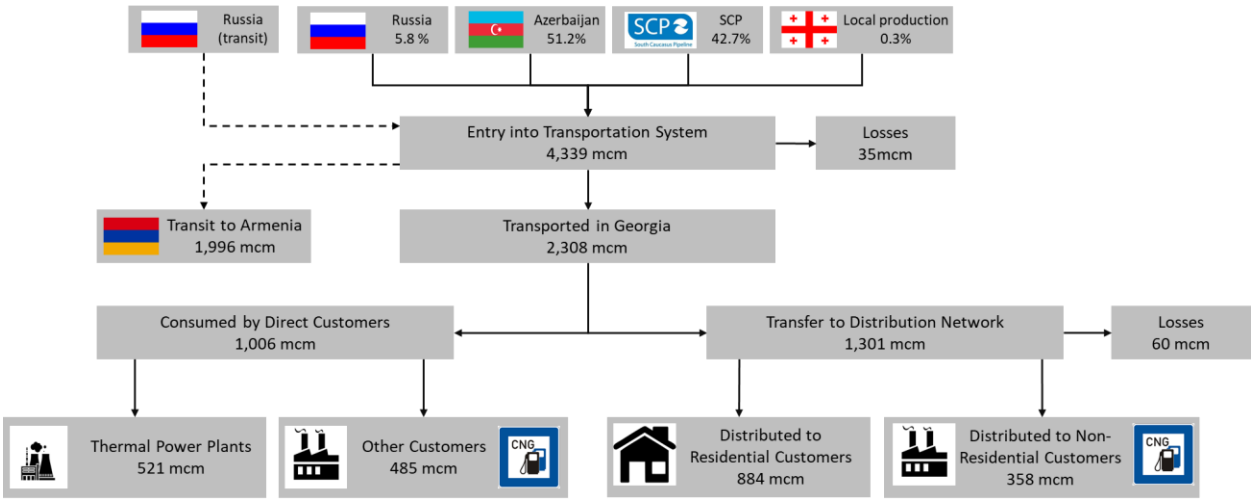
Source: Georgian National Energy and Water Supply Regulatory Commission, Annual Report 2018

Georgia and the Shah Deniz consortium hold two sale-purchase contracts, one allowing Georgia to procure up to 5% of the gas flows transited through SCP (referred to as optional gas)[94], which expires in 2026, and one that allows Georgia to purchase up to 500 mcm/yr from the Shah Deniz consortium (referred to as additional gas), at discounted prices, which ends in 2025[95].

Georgia also has a transit agreement with Gazprom Export, for the transit of gas to Armenia. Until 2016, Georgia received gas as compensation for transit, 10% of annual gas flows to Armenia. However, starting 2017, monetary compensation for the transit gas is being provided.

Figure A. 19: Natural gas balance in Georgia (2017)



Source: Georgian National Energy and Water Supply Regulatory Commission, Annual Report 2017

Figure A. 19 presents the 2017 balance of the natural gas sector in Georgia. The largest gas consumer is the residential sector (39% in 2017), followed by electricity generation (34%), and industry (17%). Use of CNG for road transport is also substantial, accounting for 11% of total gas demand.

Gas consumption is characterized by high seasonality. This is a result of the large use of gas for heating in residential and small non-residential consumers, and at thermal power plants[96].

Gas demand is foreseen to grow over the next decade (Figure A. 20). The main drivers for this increase are the recovery of the commercial and industrial sector, further gasification of the country and penetration of gas in households, and use of gas-fired power plants as back-up for developing renewables generation.

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[94] For Phase 1 of Shah Deniz development the optional gas volumes were up to a maximum of 330 mcm/yr (5% of the 6.6 bcm/yr transited to Turkey). Phase 2 of Shah Deniz development and transit volumes via SCP of up to 22 bcm/yr, results in a proportional increase in the maximum volumes of optional gas.

[95] Partnership for Social Initiatives (2017), https://www.naturalgasworld.com/pdfs/Georgias%20Gas%20Market%202.pdf

[96] GNERC, 2017 Annual Report

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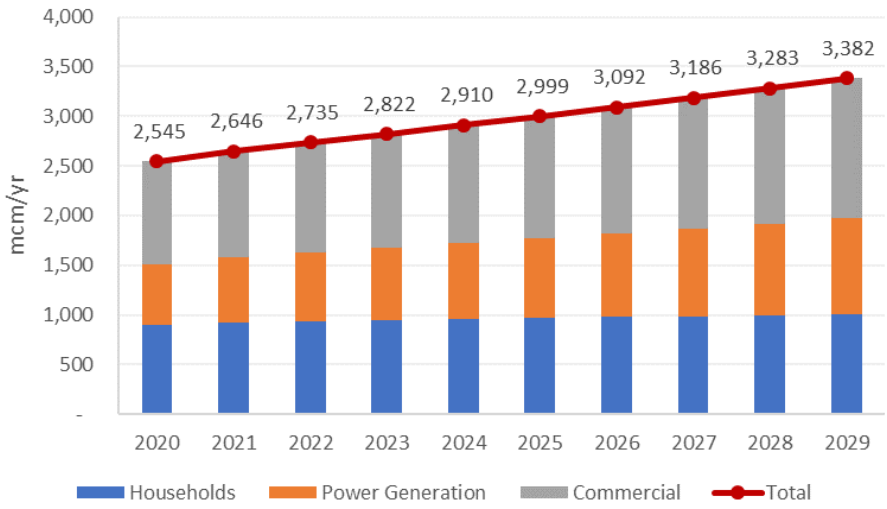
Figure A. 20: Demand forecasts for Georgian gas market



Source: Department of Strategic Planning and Projects of GOGC

A1.4.3. Natural gas prices

The end-user prices for households and thermal power plants are regulated, and based on the optional and additional gas received as tariff compensation and procured at discounted import prices through the SCP (social gas). The regulated tariffs are set by GNERC. For the rest of the consumers, prices are deregulated (commercial gas).

The gas transmission tariff is common for all regulated and deregulated consumers; it is proposed by the TSO (GGTC) and approved by GNERC. It is defined using postage-stamp approach, while currently GNERC is in the process of developing entry-exit tariffs. For the period up to December 2018, the transmission tariff was set at 6.1 €/1000 m^3, excluding VAT.

The end-user prices, apart from the transmission fee, also includes a distribution tariff (different for each distribution system) and a supply price (common for all systems, based on the transit compensation).

Table A. 7: Indicative regulated end-user prices in Georgia (2017)

DSO	Regulated price in €/1000 m^3 (excluding VAT)
KazTransGas Tbilisi LLC	126
Socar Georgia Gas LLC	155
SakOrgGaz JSC	155
Arzu-Gaz LLC	151

Source: Georgian National Energy and Water Supply Regulatory Commission, Annual Report 2017

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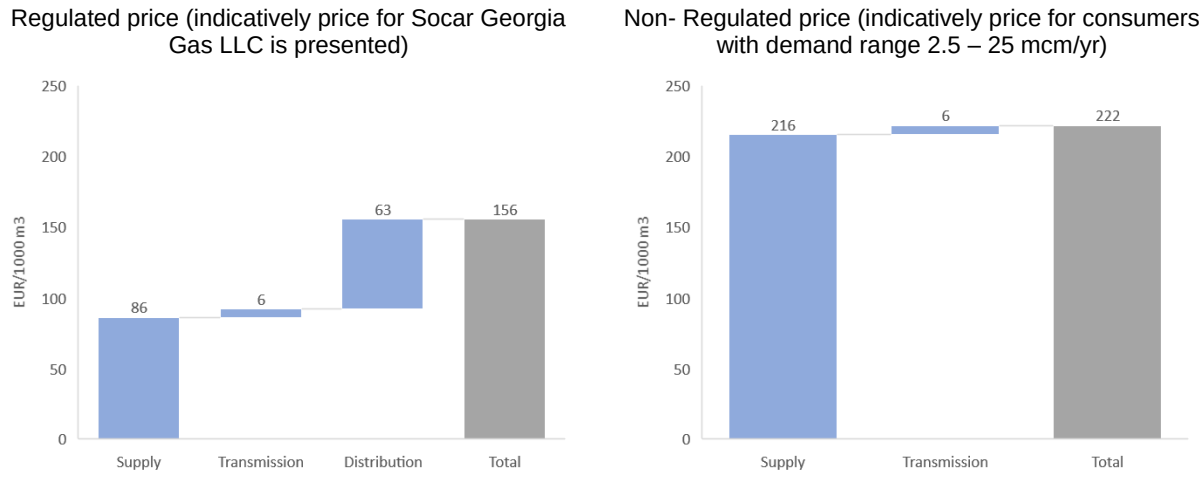
Prices for social gas are considerably lower than that of commercial gas. As a result, there are significant price differences between household customers, and consumers directly connected to the transmission system (Figure A. 21).

Figure A. 21: Prices for distribution and transmission consumers in Georgia (2017)



Sources: National Statistics Office of Georgia, Georgian National Energy and Water Supply Regulatory Commission

A1.4.4. Natural gas infrastructure

The Georgian gas transmission system is around 2,000 km long. The largest part of the country has access to gas, as a wide gasification plan is being implemented.

There are no gas compression stations or UGSs in Georgia, and to maintain appropriate transmission pressure, the transmission operator relies on neighbouring systems, particularly that of Azerbaijan and Russia. As a result of low pressure levels at the Azerbaijan – Georgia pipeline during winter period, gas flows are not sufficient to fully cover peak demand, creating issues with security of supply[97].

[97] GNERC Presentation on Investments in Storage/Transmission, available at: https://www.energy-community.org/dam/jcr:8796f176-2963-4a91-86ca-cf052df56fed/GF092018_GNERC.pdf

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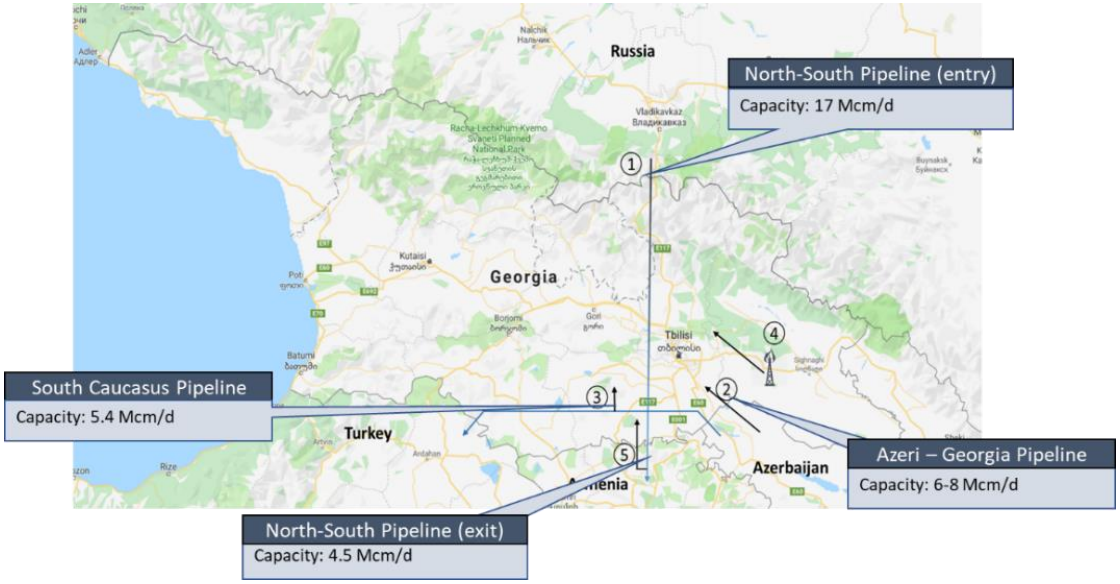
Figure A. 22: Gas transmission system in Georgia



Source: GOGC Department of Strategic Planning and Projects

There are two transit pipelines in place in Georgia. The South Caucasus Pipeline, transiting gas from Azerbaijan to Turkey, has a small offtake linked to the Georgian national transmission system. The North-South Pipeline, transiting gas from Russia to Armenia, is also connected to the transmission system. At the exit to Armenia, a small loop (after the metering station) allows transportation of gas to some small consumers in South Georgia.

Due to the low pressure of the transmission system, there are over 400 exit points, mainly to direct consumers, a very high number considering the length of the system.

To enhance security of supply, the Georgian Oil and Gas Corporation (GOGC) is planning to construct an underground storage at the Samgori South Dome field, with working volume of around 210 mcm, maximum injection rate of 2.5 mcm/d and maximum withdrawal of 5-6 mcm/d. The cost of the project is estimated at 220-250 mil. EUR, and its commissioning foreseen by 2024[98].

A1.4.5. Market structure

The Georgian gas market is divided in two segments: the social segment, that includes the households and TPPs receiving “social gas” at regulated low prices, and the commercial segment that includes all other consumers.

For the social segment, GOGC (state-owned), that has the role of state supplier imports optional and additional gas of SCP through SOCAR Gas Export-Import LLC, and supplies it to the corresponding retail suppliers and to TPPs.

[98] GOGC Department of Strategic Planning and Projects

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For the commercial segment, private entities (SOCAR subsidiaries) are active to import gas and sell it on a wholesale level. In 2017, 9 suppliers provided trade of natural gas on the wholesale level, and supplied consumers directly connected at the transmission system, and retail suppliers selling gas to non-households. On retail level, there are 26 distribution licensees, most of which offer bundled distribution and supply services (in 2017 only 4 distribution licensees did not carry out supply activities). As third-party access is possible on distribution, more than one retail suppliers are active on 5 distribution systems, selling gas to large non-household consumers.

The state-owned Georgian Gas Transportation Company (GGTC) is the transmission system operator of the national system. GGTC leases the system from GOGC, and is responsible for its operation and maintenance (development is responsibility of GOGC).

GNERC has the mandate to issue licenses for gas transmission and distribution, control license conditions, and set and regulate tariffs.

Figure A. 23: Key stakeholders in Georgian gas supply chain

A1.4.6. Regulatory framework

Georgia, as Contracting Party of the Energy Community Treaty, is obliged to conform with the 3rd Energy Package requirements. However, as the country borders only with non-Energy Community and non-EU countries, it is not obligatory to implement the 3rd Energy Package provisions at the cross-border interconnections.

The gas sector is currently governed by the "Law of Georgia on Electricity and Natural Gas", (No 15(22) of April 1999). A new Energy Law is being drafted, to comply with the 3rd Energy Package provisions for electricity and gas. To facilitate market competition, market rules and transmission and distribution grid codes were launched in 2018, with GNERC Decree No 22 of 31/8/2018. These will be updated and enhanced once the new Energy Law enters into force.

Table A. 8 below, provides an outline of the key regulatory framework provisions related to the overall market operation, transmission system and off-grid supplies of LNG.

Table A. 8: Overview of regulatory framework in Georgia (✓: covered, ✓: partly covered, ➲: ongoing procedure, ✘: not covered)

Overall market operation		
Law governing the gas sector	Law of Georgia on Electricity and Natural Gas (1999) – new Energy Law is being drafted	
Licensing of gas stakeholders	✓	Licenses are only issued for transmission and distribution activities. Suppliers are not required

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		to have a license (but must be registered with the TSO to use the transmission system)
Eligibility of final consumers to choose supplier	✓	Consumers are able to switch supplier. It is noted that households and TPPs always receive social gas
Transparent and non-discriminatory third-party access on the transmission system	✓	Grid code has been released, and model contracts for network users are public. Publication of information to be addressed with the new legislation
Rules for access to storage	➲	To be drafted once the new legislation enters into force
Unbundling of system operators	➲	Requirement set in the new legislation
Transmission system operation		
Establishment of capacity allocation mechanisms	➲	To be developed in a revision of the grid code, applying the new legislation
Establishment of congestion management procedures	➲	To be developed in a revision of the grid code, applying the new legislation
Existence of transparent interconnection agreements with neighbouring TSOs	✗	Agreements focus on technical issues and are confidential
Definition of tariffs at cross-border entry/exit points	✗	No specific tariffs for entry/exit interconnection points are set
Publication of gas technical specifications	✓	Published in the GGTC website
Transparent procedures for operation of the system (nomination, allocation, balancing)	➲	To be developed in a revision of the grid code, applying the new legislation

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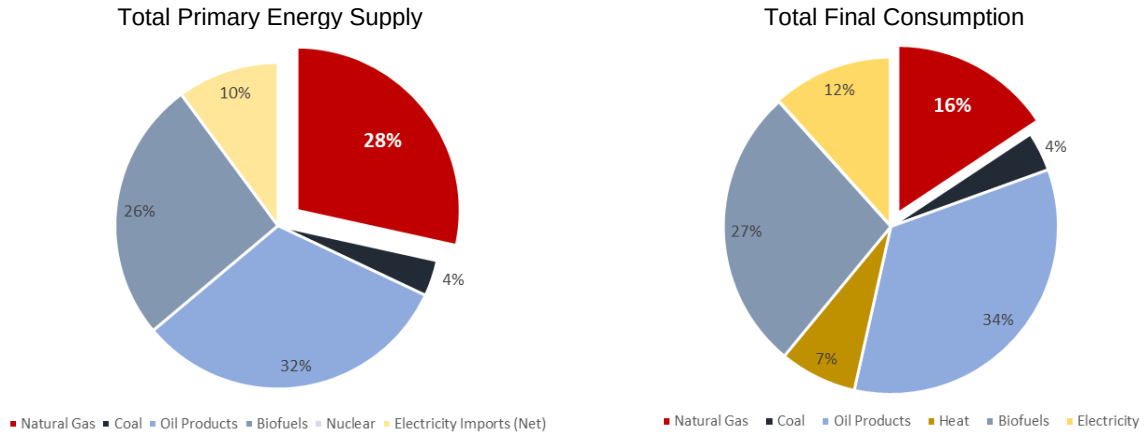
A1.5. Moldova

A1.5.1. Role of natural gas in the energy mix

Natural gas and oil products are the two main sources in the energy supply mix of Moldova. A large part of gas supplies is used for electricity and heat generation; as a result, gas has just 16% share in total final consumption. It is worth noting that biofuels are a main source in the energy mix, used for heating of households (Figure A. 24).

Figure A. 24: Natural gas in the energy mix of Moldova (2017)[99]



Source: National Bureau of Statistics of the Republic of Moldova, Energy Balance 2017

A1.5.2. Natural gas supply & demand

Indigenous gas production in Moldova is negligible, and consequently the country relies only on imports to cover demand. 99.9% of imported volumes come from Russia, transited through Ukraine (Figure A. 25). Since 2015, when operation began at a small pipeline connecting the Romanian transmission system (Iasi) with the Ungheni region in Moldova, small volumes are being imported from Romania. However, as this pipeline does not reach the Moldovan transmission system, imports from Romania to the whole market are not possible.

Annual consumption in the right bank of Dniester River is around 1 bcm/yr. In the Transnistria region 1.7 bcm/yr are consumed (60% used for electricity generation in the Cuciurgani TPP), all covered with imports of Russian gas[100].

[99] Reported data from the Bureau of Statistics does not include Transnistria

[100] Current situation and future perspective of LNG in Moldova, 2018. The 2nd meeting of the Eastern Partnership Energy Panel. Available online at: https://ec.europa.eu/energy/sites/ener/files/documents/moldova_-_lng_situation.pdf

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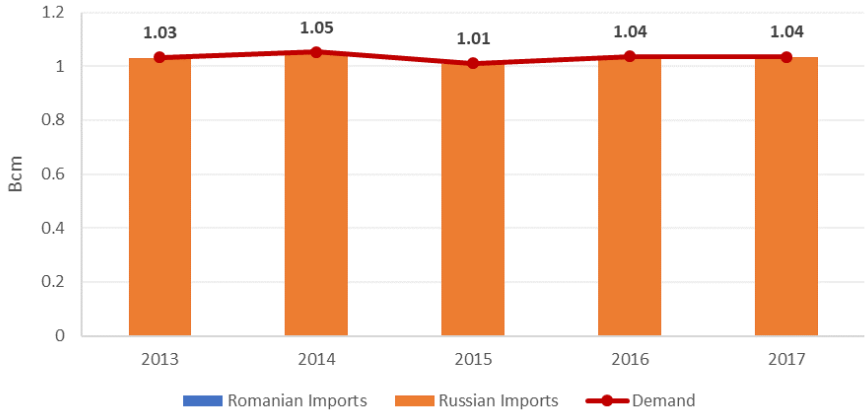
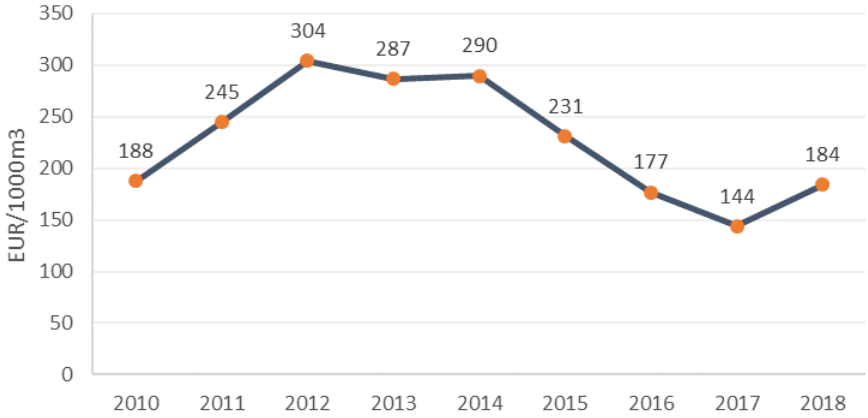
Figure A. 25: Evolution of natural gas supply and demand in Moldova (without Transnistria)



Source: Eurostat Statistics Database

The existing contract with Russia expires in December 2019[100]. Figure A. 26 presents the border prices of imported gas, for the period of 2010 – 2018.

Figure A. 26: Evolution of average import prices in Moldova



Source: National Agency for Energy Regulation (2018). Report on Activities 2018.

In its Energy Strategy to 2030, prepared in 2012, the Government of Moldova set LNG imports and development of gas storage as an alternative for enhancing security of supply. However, no concrete targets were set in this regard (the AGRI project is mentioned as a potential source that should be monitored)[101].

Figure A. 27 presents the 2017 balance of the natural gas sector in Moldova. Gas is primarily used for the generation of electricity and heat, at CHP and district heating plants. To a lesser extent, it is used for residential heating.

[101] Energy Strategy of the Republic of Moldova to the year 2030 (2012), available at: http://komorasns.cz/assets/attachments/EnStrategy-MOLD-draft310512.pdf

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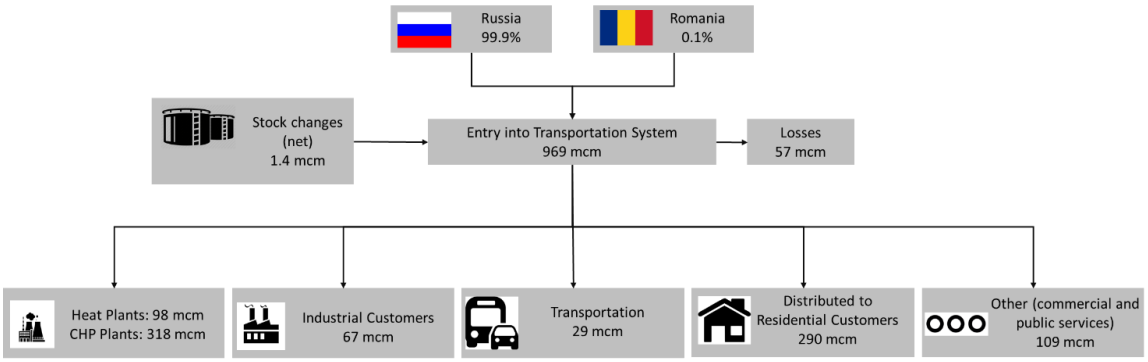
Figure A. 27: Natural gas balance in Moldova (2017) (without Transnistria)



Source: National Bureau of Statistics of the Republic of Moldova, Energy Balance 2017[102]

Due to the large use of gas for heat generation, and for heating of households, gas demand in Moldova is highly seasonal.

A1.5.3. Natural gas prices

End-user gas prices are regulated in Moldova, set by the National Agency for Energy Regulation (ANRE). ANRE has defined separate tariffs for the use of the transmission and distribution systems, and end-user prices for different categories of consumers (Table A. 9).

Both transmission and distribution tariffs are defined using a postage-stamp approach. The current tariffs for transmission is set at 1.62 €/1000 m^3, and for distribution 142[103] €/1000 m3 (split 10 €/1000 m^3 for use of high pressure pipelines, 26 €/1000 m^3 for use of medium pressure pipelines, and 106 €/1000 m^3 for use of low pressure pipelines)[104].

Table A. 9: Indicative regulated end-user prices in Moldova (2017)

Category	Regulated price in €/1000 m^3 (excluding VAT)
Residential (for heating) – consumption up to 30 m^3 per month	236
Residential (for heating) – consumption over 30 m^3 per month	245
Local heating plants and CNG stations – connected to transmission	160
Local heating plants and CNG stations – connected to medium pressure distribution	225
CHP and district heating plants	201

Source: National Agency for Energy Regulation Decision No 88/2018

[102] Converted to mcm using a GCV of 10.0474 kWh/m3 (https://www.moldovatransgaz.md/en/clients/quality)

[103] Average tariff that varies for different distribution systems

[104] ANRE Decision No 88/2018, available at: http://anre.md/files/Gaze_naturale/caculov/29112018/Hot%C4%83r%C3%A2rea%20ANRE%20nr.88%20din%2018.03.%202018.pdf

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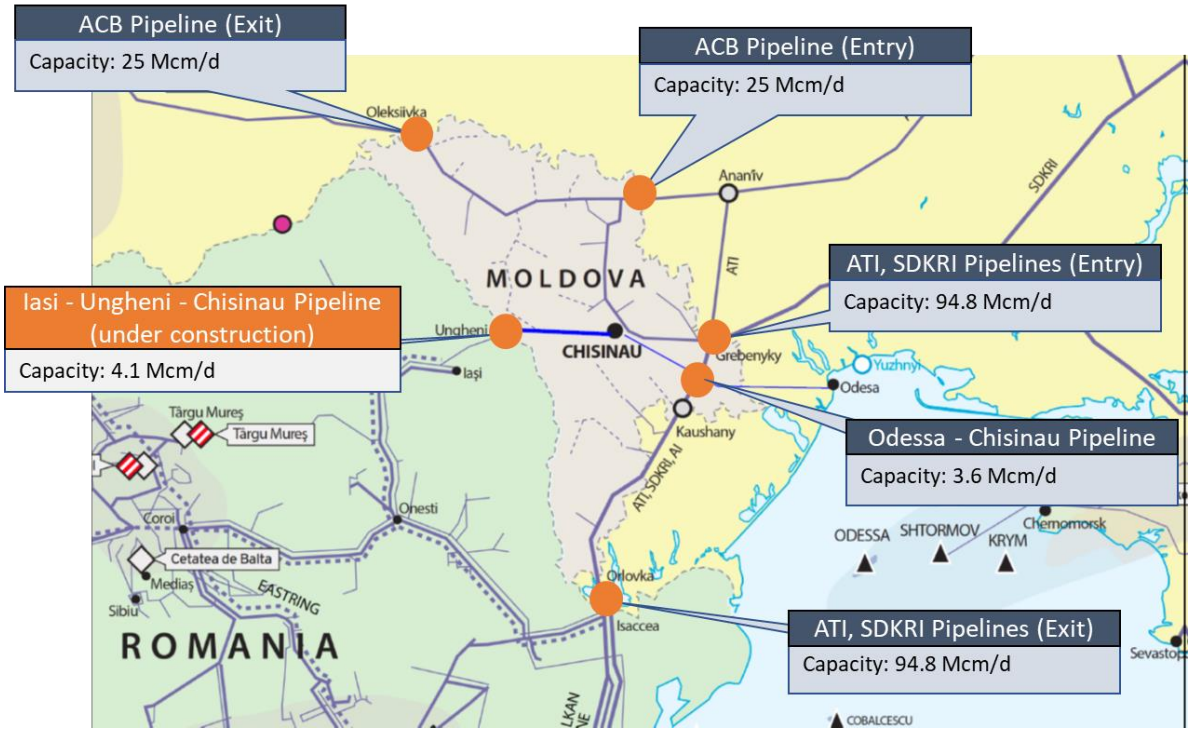
A1.5.4. Natural gas infrastructure

The length of the main sections of the Moldovan gas transmission system is 656 km. The system includes connections with Ukraine and Romania, to supply the local gas market, as well as to transit gas through the country (Figure A. 28).

The main connections of the transmission system with Ukraine include[105]:

- Ananiev-Cernăuți-Bogorodcianî (ACB) pipeline, with 185 km length and 9.1 bcm/yr capacity that crosses the northern part of Moldova to re-enter Ukraine
- 3 pipelines sections that connect Ukraine – Moldova – Romania with aggregate capacity of 34.6 bcm/yr, namely:
    - Ananiev-Tiraspol-Ismail (ATI) pipeline, with 63 km length and 20 bcm/yr capacity
    - Șebelinca-Dnepropetrovsk-Krivoi Rog-Ismail (ȘDKRI), with 92 km length and 7.9 bcm/yr capacity
    - Razdelinaia-Ismail (RI), with 92 km length and 7.9 bcm/yr capacity
- Odesa-Chișinău (OCh) pipeline, with 44 km length and 1.3 bcm/yr capacity

Figure A. 28: Gas transmission system in Moldova



Sources: ENTSOG, Moldovatransgaz

[105] Infrastructure of transmission system of Moldovatransgaz. Available online at: https://www.moldovatransgaz.md/en/activities/transmission/map

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Romania and Moldova are currently connected with a 43 km long pipeline connecting Iasi (Romania) with Ungheni (Moldova). In February 2019, construction works started for extending the pipeline up to Chisinau, with total length 120 km and capacity of 1.5 bcm/yr.

A1.5.5. Market structure

The gas market of Moldova is practice monopolistic. The vertically integrated company Moldovagaz [106] (50% Gazprom, 36.6% state-owned, 13.4% authorities in Transnistria), undertakes the imports of Russian gas, wholesale supply, the majority of retail sales, and is responsible for gas transmission and distribution, through its subsidiaries. The small volumes supplied to the region of Ungheni are being imported through a separate entity, the state-owned Energocom[107].

Moldovatransgaz (100% subsidiary of Moldovagaz) is the operator of the national transmission system. Tiraspoltransgaz operates the system in Transnistria. Eurotransgaz[108] (subsidiary of the Romanian TSO Transgaz) is the operator of the Iasi - Ungheni pipeline.

On a retail level, there are overall 25 distribution license holders, 12 of which Moldovagaz subsidiaries, that hold around 70% of the distribution networks.

ANRE is regulating the gas sector, responsible approving regulations, monitoring market operation, setting tariffs and issuing licenses.

Figure A. 29: Key stakeholders in Moldovan gas supply chain

A1.5.6. Regulatory framework

The gas sector in Moldova is governed by the Gas Law, no. 108/2016, entered into force in July 2016. The Law transposes the vast majority of the 3rd Energy Package.

In 2016, ANRE approved the Regulation on Access to the Natural Gas Transmission Network and Congestion Management (Decision no. 321/2016 of 13rd December 2016). Additional secondary legislation, to implement the 3rd Energy Package and EC Network Codes on Gas are under development.

[106] Moldova has received derogation from TSO unbundling, in compliance with Directive 2009/73/EC, until January 1st 2020

[107] Ministry of Infrastructure: Moldova starts gas imports from Romania (2015). Available at: https://mei.gov.md/en/content/moldova-starts-gas-imports-romania

[108] Formerly state-owned Vestmoldtransgaz, that was bought by Transgaz in 2018

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Table A. 10 below, provides an outline of the key regulatory framework provisions related to the overall market operation, transmission system and off-grid supplies of LNG.

Table A. 10: Overview of regulatory framework in Moldova (✓: covered, ✓: partly covered, ➲: ongoing procedure, ✗: not covered)

Overall market operation		
Law governing the gas sector	Law of the Republic of Moldova about Natural Gas (2016)	
Licensing of gas stakeholders	✓	Procedures foreseen in the Gas Law. Licensees are issued by ANRE
Eligibility of final consumers to choose supplier	✓	All consumers are allowed to switch suppliers (not in practice as supply and transmission are still bundled)
Transparent and non-discriminatory third-party access on the transmission system	✓	Rules for access to transmission have been approved by ANRE. However, model contracts are not published by the TSO
Rules for access to storage		N/A
Unbundling of system operators	➲	Derogation until 1/1/2020
Transmission system operation		
Establishment of capacity allocation mechanisms	✓	Capacity at IPs is offered on pro-rata basis. Only annual (up to 5 years) and monthly capacity is offered
Establishment of congestion management procedures	✓	Capacity surrender and secondary market is foreseen
Existence of transparent interconnection agreements with neighbouring TSOs	✗	Transgaz Romania and Vestmoldtransgaz have reportedly signed an interconnection agreement (commercial provisions not published) Interconnection agreement between Moldova and Ukraine is under negotiation
Definition of tariffs at cross-border entry/exit points	✗	No specific tariffs for entry/exit interconnection points are set
Publication of gas technical specifications	✓	Published by Moldovatransgaz in its website
Transparent procedures for operation of the system (nomination, allocation, balancing)	➲	Required by the Gas Law, but no balancing rules implemented yet. Nominations and allocation are only on monthly basis

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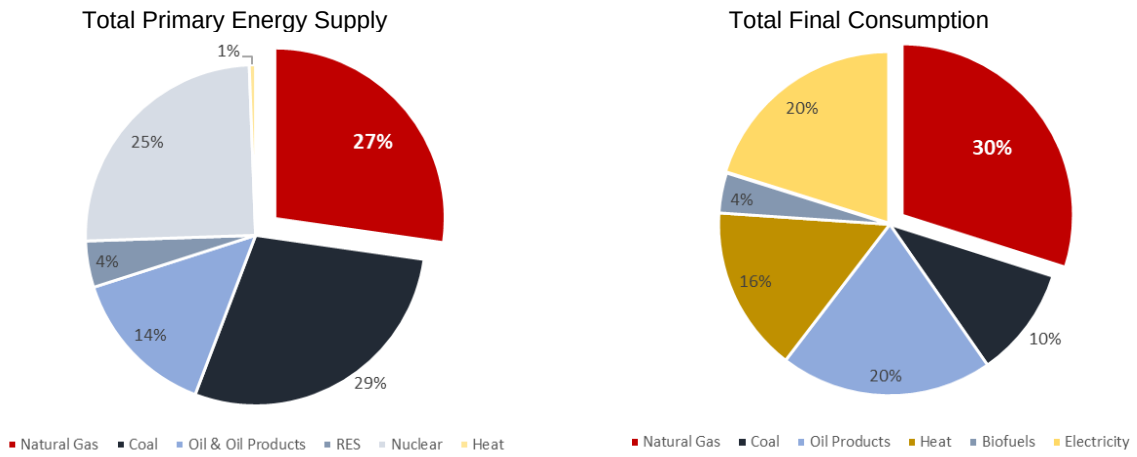
A1.6. Ukraine

A1.6.1. Role of natural gas in the energy mix

Natural gas is a key fuel in the energy mix of Ukraine (Figure A. 30). With a share of 27%, it is the second largest source in the country's total primary energy supply. In total final consumption, gas is the dominant fuel, as it is the main source of heating in the residential sector.

Figure A. 30: Natural gas in the energy mix of Ukraine (2017)



Source: State Statistics Service of Ukraine, Energy Balance 2017

A1.6.2. Natural gas supply & demand

Natural gas demand in Ukraine is currently at the level of 32-33 bcm/yr[109] (Figure A. 31). Indigenous production of gas in Ukraine is high, and has remained stable during the last three decades, at a plateau of around 20 bcm/yr. Gas is imported to cover remaining demand. In the past, all gas imports in Ukraine were sourced from Russia, until in 2013 imports from EU markets began. In November 2015, imports from Russia ceased, and Ukraine has been importing gas only from European suppliers.

Imports from the EU are mainly carried out though Slovakia, the rest coming through Poland and Hungary (Figure A. 32). With the existing transmission system infrastructure, import capacity depends partially on flow of Russian gas transits. According to Naftogaz, in case there is a disruption to transit of Russian gas, not all the capacities at the western border of the country can be used to import gas from Europe[110].

[109] The reported figures do not include gas supply and demand for Crimea and part of Donbass region

[110] https://en.interfax.com.ua/news/economic/584272.html

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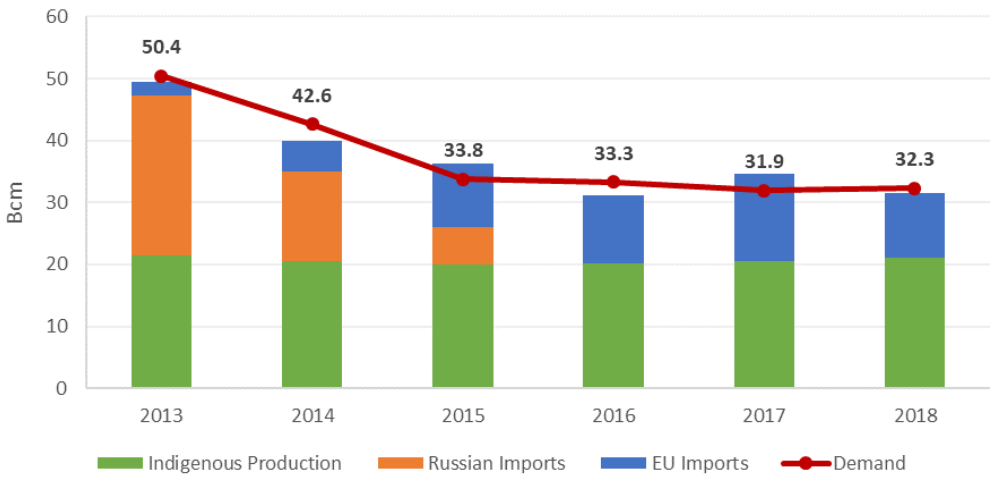
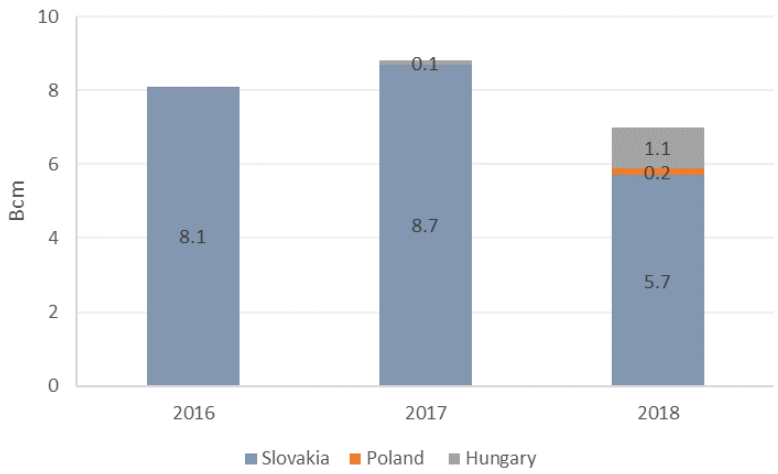
Figure A. 31: Evolution of natural gas supply and demand in Ukraine



Source: Naftogaz website, Facts & Figures

Figure A. 32: EU gas imports to Ukraine by entry point



Source: Naftogaz website, Facts & Figures

Gas production is carried out mainly by subsidiaries of Naftogaz, Ukrgasvydobuvannya (UGV), Ukrnafta and Chornomornaftogaz (ChNG) (79% in 2018), with the remaining volumes extracted by private producers.

Gas imports are mainly carried out by Naftogaz (over 66% in 2018), that is buying gas from several exporters (RWE, Axpo Trading, DufEnergy, ENGIE, Uniper Global and others). Private traders have also been engaged in gas imports, such as ERU Trading, Promenergo Resource, Socar Ukraine, Trafigura Ukraine.

Figure A. 33 presents the 2018 balance of the natural gas sector in Ukraine. Natural gas is mainly used in households, and at district heating and cogeneration plants.

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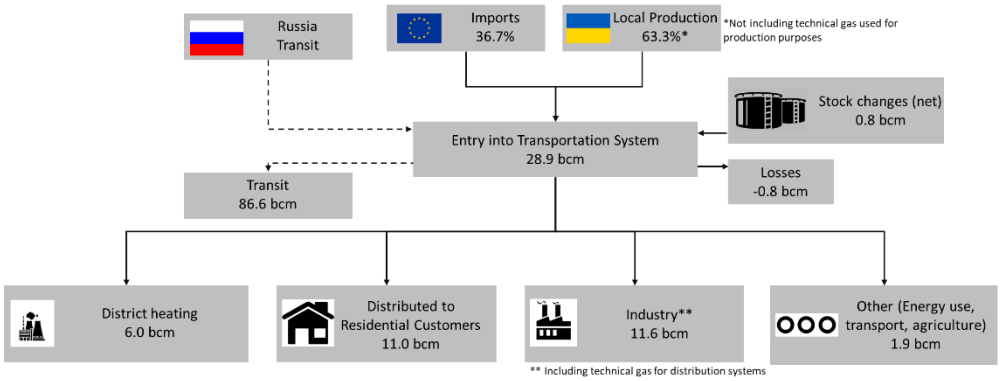
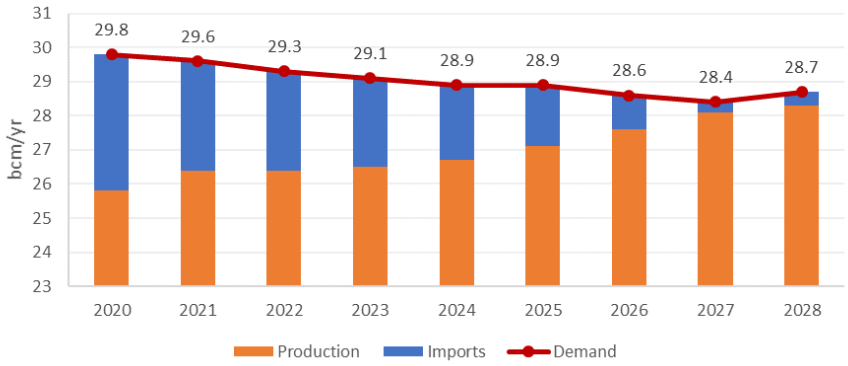
Figure A. 33: Natural gas balance in Ukraine (2018)



Source: UTG

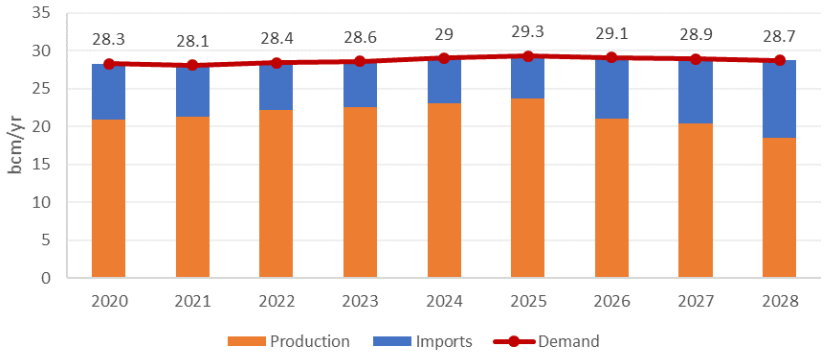
The demand projections included in the ten-year development plans of UTG (Figure A. 34) and the SSO (Figure A. 35) show similar decrease in the future consumption of gas in the Ukrainian market. However, there is a different outlook concerning the forecasts of indigenous production. According to UTG, production will cover almost 100% of demand after 2027, while SSO projections are more conservative.

Figure A. 34: Demand & Supply forecasts for Ukrainian gas market – UTG



Source: UTG, TYNDP 2019 – 2028

Figure A. 35: Demand & Supply forecasts for Ukrainian gas market – SSO



Source: SSO, Development Plan 2020 – 2029

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A1.6.3. Natural gas prices

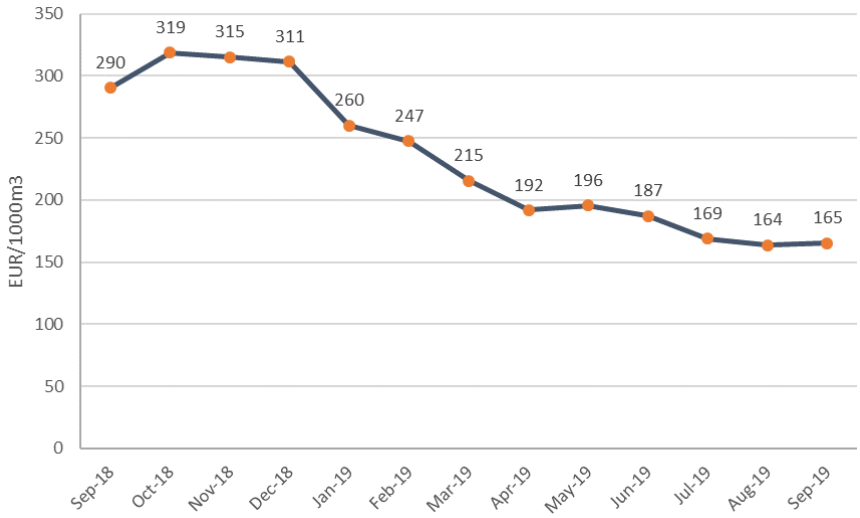
End-user prices for households, religious organizations (very small consumption), district heating and cogeneration plants, and state organizations are regulated. The regulated prices are set by the Cabinet of Ministers. The prices include four components: Naftogaz selling price, transmission price, distribution price (for retail consumers) and delivery price. The regulated price for households is provided in Figure A. 36 below.

Figure A. 36: Final retail price for households (November 2018 – April 2019)

Source: Naftogaz, Prices for natural gas

All other consumers source gas in the market at unregulated prices. On wholesale level, gas is traded at the Ukrainian Energy Exchange. Traded priced at the Exchange have decreased considerably the past months (Figure A. 37).

Figure A. 37: Average monthly natural gas prices at Ukrainian Energy Exchange



Source: Ukrainian Energy Exchange

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For the use of the transmission system, the tariffs are set by the National Energy and Utilities regulatory Commission, following proposal by the TSO. Depending on the type of entry/exit points of the system, different tariffs are set[111]:

- For the cross-border entry/exit points, entry and exit tariffs were introduced as of 1/1/2019. The entry tariff is common at all points, 5.6 €/1000 m^3, while the exit tariff ranges from 10 €/1000 m^3 to 15.5 €/1000 m^3.
- For exits to consumers directly connected to the transmission system, a tariff of 20.9 €/1000 m^3 is set.
- For exit to distribution systems, the tariff depends on the territory which is supplied, and may range from very low tariffs (0.07 €/1000 m^3, for exit to the DSO PJSC "Mykolaivgaz") up to high ones (19.8 €/1000 m^3, for exit to the DSO LLC "Spektrgaz").

A1.6.4. Natural gas infrastructure

The main transmission pipelines of the Ukrainian system exceed 35,000 km. The system was designed as an integral part of the former Soviet Union unified gas supply system, the specification to provide reliable gas delivery both to internal consumers and transit to the European gas market.

Ukrtransgaz operates one of Europe's leading networks of underground gas storage (UGS) facilities. Today, the company operates 12 underground storage facilities (including 1 in the occupied territory) with total design working volume of up to 31 bcm[112]. It should be noted that the actual technical characteristics of the storages have changed and should be verified.

The transmission system and the distribution systems are very developed and cover all Ukrainian regions. However, in 2014 there were 35 towns, 111 townships and 2,698 villages non-connected to natural gas grid as well as without LPG supply, creating potential interest for off-grid supplies of LNG.

Table A. 11: Gasification Coverage in Ukraine (2014)

	Number	Natural Gas exclusively	%	Natural gas and LPG	%	LPG exclusively	%	Without supply	%
Towns	442	117	26.5	271	61.3	19	4.3	35	7.9
Townships	828	164	19.8	398	48.1	155	18.7	111	13.4
Rural Villages	27412	4127	15.1	10606	38.7	9981	36.4	2698	9.8

Source: State Statistical Service, Statistical Bulletin on Gas Distribution, 2014

Apart from the entry points in the eastern part of the country, and the corresponding exit points to Poland, Slovakia, Hungary, Romania and Moldova, which are being used for transit of

[111] Ukrtransgaz, Tariffs & Prices, Available at: http://utg.ua/en/utg/business-info/tariffs.html

[112] Naftogas, Facts & Figures, Available at: http://naftogaz-europe.com/factsandfigures/en/factsandfigures

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Russian gas, the Ukrainian system also has entry capacity from Poland, Slovakia and Hungary, used to import gas from the EU.

Figure A. 38: Entry Interconnection Points from EU to Ukraine

Sources: ENTSOG, Ukrtransgaz

Following the adoption of the amendments to the Customs Code, Ukraine is now able to run backhaul operations; that is, replace gas on a certain pipeline with no need to receive it on specific cross-border points. Such operations, called a "virtual reverse flow", are possible under commercial supply contracts and interconnection agreements of TSOs[113].

New projects are being developed, aiming to increase the potential of Ukraine for diversified gas supplies. Ukrtransgaz and Transgaz of Romania have agreed on the reconstruction of gas metering station Isaccea-1, at the Transit-1 pipeline section of the Trans-Balkan Pipeline allowing to increase the accuracy of gas metering and bidirectional flow in the interconnection point. Ukrtransgaz conducted in March – April 2018 a non-binding market demand assessment among the participants of Ukrainian and EU market for the firm capacity of Transit-1 pipeline in direction RO-UA. 5 bcm/yr of annual capacity was offered to market participants, with the results showing much higher interest. As the next step, Ukrtransgaz plans to conduct a binding open season procedure, making available capacities to market participants starting from the beginning of 2020[114].

[113] Ukraine's Gas Sector Reform: A Future Win-Win for Ukraine and Europe, Dixi Group, 2017

[114] Ukrtransgaz announcement (2018), http://utg.ua/en/utg/media/news/2018/successfully-conducted-market-demand-assessment-for-entry-capacities-to-ukraine-from-romania.html

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The Ukrainian Government has also explored the possibility of constructing an LNG terminal in the Black Sea, located at the Yuzhny Port near Odessa. Although discussions for such an infrastructure began in 1993, the most recent effort for developing the LNG Terminal was launched by the Ukrainian leadership in late 2010, undertaken by the state-owned 'National Project LNG Terminal'. The prefeasibility and technoeconomic studies implemented, concluded to a phased development of the terminal, with initial installation of an FSRU (capacity 5 bcm/yr), and subsequent construction of an on-shore LNG terminal (capacity 10 bcm/yr). The project ceased in 2014, because the 'National Project LNG Terminal' reached a negative bottom line, and the State Agency for Investment and National Projects of Ukraine collapsed. The main challenge that the project faced was that the Turkish authorities did not agree for passage of LNG vessels through the Bosporus Straits.

Furthermore, there have been plans for the interconnector Drozdovichi – Bilche Volytsia between Poland and Ukraine aiming to import of gas primarily from the Polish LNG terminal in Świnoujście. The Ukrainian part was designed with pipeline length of 99.3 km, capacity of 8 Bcm/y (23.8 mmscm/d) at the direction Poland to Ukraine, and capacity 7 Bcm/y (20.8 mmscm/d) at the reverse direction[115]. It is noted that according to UTG the pipeline is not included in the 2020 – 2029 TYNDP of Ukraine.

A1.6.5. Market structure

The Ukrainian gas market is structured into two segments: a regulated segment, that includes gas supply to households, district heating plants, CHP, religious organizations and state organizations, and a non-regulated segment that includes all other types of consumers.

The wholesale part of gas market functions in accordance with the Public Service Obligations (PSO) stipulated in the Law on Natural Gas Market, and the Resolution of the Cabinet of Ministers No 867 of October 19, 2018 that oblige:

- State gas producers (Naftogaz subsidiaries) Ukrgasvydobuvannya (UGV) and Chornomornaftogaz (ChNG) to sell gas to Naftogaz (and for the latter to buy it) for residential market needs at a regulated price (upstream sector);
- Naftogaz to sell gas directly to district heating companies (and for the latter to buy it) for all needs at a regulated price (wholesale sector);
- Naftogaz to sell gas to retail suppliers under PSO (and for the latter to buy it) for residential market needs at a regulated price (retail sector).

Figure A. 39 below presents the structure of the regulated segment of the market.

[115] Ukrtransgaz announcement (2016), http://utg.ua/utg/media/news/2016/06/polskij-ta-ukranskij-operatori-gts-planuyut-rozpochati-proektn-roboti-po-nterkonektoru-ua-pl.html

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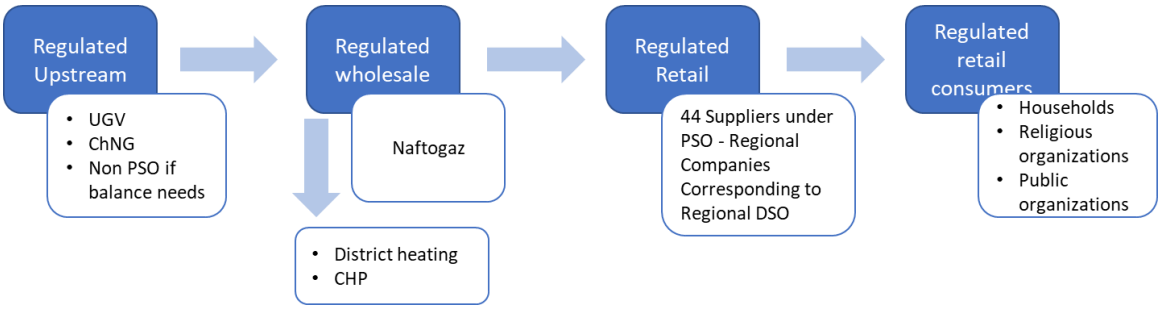
Figure A. 39: Structure of Ukrainian Gas Market Regulated Segment

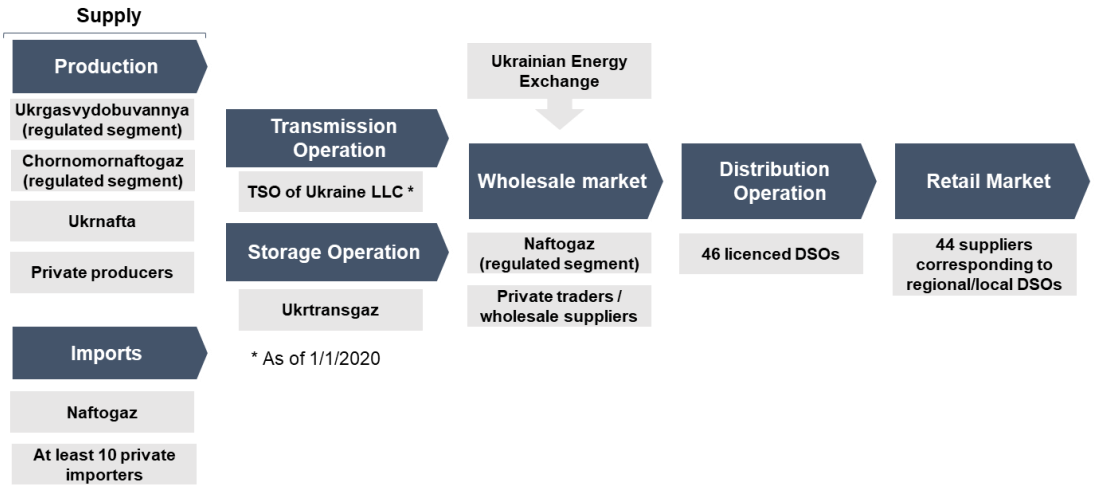


The non-regulated segment of the market is competitive. Private producers are free to sell gas at the Ukrainian Energy Exchange, and wholesale suppliers (traders) import gas from the EU and trade gas at the Exchange or sign bilateral contracts for supply. There are 548 supply licensees registered with NEURC. On distribution level, there are 46 DSOs, 44 of which are also holding a supplier licence.

Operation of the underground storage facilities is currently carried out by Ukrtransgaz (Naftogaz subsidiary). As of 1/1/2020, operation of the transmission system is carried out by a new independent operator, “TSO of Ukraine” LLC.

NEURC is regulating the gas sector, responsible approving regulations, monitoring market operation, setting transmission and distribution tariffs and issuing licenses. Regulated end-user prices are set by the Cabinet of Ministers

Figure A. 40: Key stakeholders in Ukrainian gas supply chain



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A1.6.6. Regulatory framework

The Law of Ukraine on the Natural Gas Market of 2015 (No 102/2015, 23.09.2015) is the primary legislation governing the Ukrainian gas sector. The Law transposes the most provisions of the 3rd Energy Package[116].

Key secondary legislation was developed in 2015, with adoption of the grid codes for transmission (NEURC Res. No 2494, 30.09.2015), distribution (NEURC Resolution No 2493, 30.09.2015) and storage (NEURC Resolution No 2495, 30.09.2015) by NEURC, that have been revised several times until today. The latest revisions of the transmission grid code (NEURC Resolutions No 1437 in 2017, and No 1916 in 2018) established the requirements for developing a daily balancing regime in the transmission and distribution systems.

Table A. 12: Overview of regulatory framework in Ukraine (✓: covered, ✓: partly covered, ➲: ongoing procedure, ✗: not covered)

Overall market operation		
Law governing the gas sector	Law of Ukraine on the Natural Gas Market (2015)	
Licensing of gas stakeholders	✓	Procedures foreseen in the Gas Law. Licensees are issued by NEURC
Eligibility of final consumers to choose supplier	✓	Consumers are eligible to choose supplier. All suppliers in the regulated segment must sell gas at the regulated prices
Transparent and non-discriminatory third-party access on the transmission system	✓	Rules for access to transmission have been approved by NEURC. Model contracts have been published by the TSO and transparent information is provided
Rules for access to storage	✓	Rules for access approved by NEURC
Unbundling of system operators	➲	Unbundling procedure is in progress
Transmission system operation		
Establishment of capacity allocation mechanisms	✓	Auctions are being applied on the Ukrainian side of interconnection points (not in a booking platform)
Establishment of congestion management procedures	✓	Long-term use-it-or-lose-it mechanism is foreseen. A secondary capacity market is in operation
Existence of transparent interconnection agreements with neighbouring TSOs	✓	The TSO has signed Interconnection Agreements with HU, PL, RO, SK (not on all trans-border points), but they are not published. Negotiations are ongoing for a new agreement with RO and with MD
Definition of tariffs at cross-border entry/exit points	✓	The TSO has defined entry/exit tariffs at interconnection points

[116] Energy Community, Ukraine Secondary legislation status: Gas, Available at: https://www.energy-community.org/implementation/Ukraine/secondary.html

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Publication of gas quality specifications	✓	Published by UTG in its website
Transparent procedures for operation of the system (nomination, allocation, balancing)	✓	Procedures for nomination, allocation and balancing have been established. The balancing platform began operation

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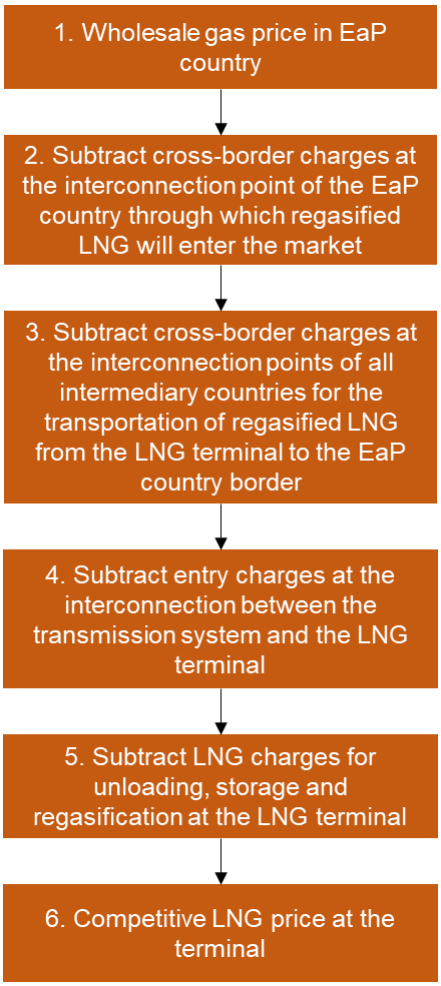
Annex 2: Netback Analysis – Gas-to-Gas Competition

A2.1. Netback analysis in case of regasified LNG supplied via pipeline from neighbouring EU LNG Terminals

A2.1.1. Analysis approach

Figure A. 41 outlines the netback analysis for deriving the competitive LNG price, in the case of regasified LNG, sourced from neighbouring EU terminals and supplied to the Eastern Partner countries via pipelines.

Figure A. 41: Netback analysis to estimate competitive LNG price at the source (LNG Terminal), for regasified LNG delivered to the Eastern Partner country by pipeline



The starting point (Step 1) for the analysis is the wholesale gas price in the Eastern Partner country in question. In the countries where prices for all consumers are regulated, the price for large consumers, excluding transmission costs, is applied. From this price, all costs to arrive from the LNG source (terminal) are sequentially estimated and subtracted: costs for entry in the transmission system of the Eastern Partner country (Step 2), cross-border charges for the gasified

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LNG to get to the Eastern Partner country border (Step 3), the charges at the interconnection between LNG terminal and transmission system (Step 4), the LNG terminal charges for unloading, storage and regasification (Step 5).

The resulting LNG price from the netback analysis is the price that needs to be compared to the regional price of spot LNG deliveries to the terminal to ascertain whether LNG is competitive to prices of existing gas sources in the Eastern Partner country.

A2.1.2. Application in Eastern Partner countries

Based on the Consultant's analysis and the consultations with the countries' stakeholders, the supply of regasified LNG from neighbouring LNG terminals is an applicable option for Moldova and Ukraine. In particular[117]:

- For Moldova, supplies of regasified gas from the Świnoujście (Poland), Klaipeda (Lithuania), Revythoussa (Greece) and Krk (Croatia) LNG terminals are examined.
- For Ukraine, supplies of regasified gas from the Świnoujście (Poland), Klaipeda (Lithuania), Revythoussa (Greece) and Krk (Croatia) LNG terminals are examined.

The capacity availability at the examined terminals is as follows[118]:

- At the Revythoussa terminal, technical regasification capacity is 17.1 mcm/d, while available capacity for Gas Year 2019 (01/10/2018 – 30/09/2019) was 44% (7.5 mcm/d), and for the current Gas Year 2020 (01/10/2018 – 30/09/2019) it is 48% (8.2 mcm/d).
- At the Klaipeda terminal, technical regasification capacity is 10.5 mcm/d, while available capacity for Gas Year 2019 was 52% (5.5 mcm/d), and for the current Gas Year 2020 it is 80% (8.4 mcm/d).
- At the Świnoujście terminal, technical regasification capacity is 13.4 mcm/d, while all capacity has been booked by PGNiG until 2034. With the upcoming capacity expansion, technical capacity will increase to 20.5 mcm/d.

Access to the terminal also depends on the availability of slots for unloading that are defined through monthly and annual nomination procedures.

The calculations for the netback analysis steps are described in the sections below.

A2.1.3. Step 1: Definition of wholesale gas prices in Eastern Partner countries

The wholesale gas prices used as a starting point in the analysis are based on the current prices in each Eastern Partner country.

[117] Other potential supply options include the Marmara Ereglisi terminal in Turkey and the planned Alexandroupolis FSRU in Greece and Gdansk FSRU in Poland. The netback analysis of these options would wield similar results with the examined terminals.

[118] Source: Websites of DESFA (Revythoussa), Polskie LNG (Świnoujście), Klaipedos Nafta (Klaipeda)

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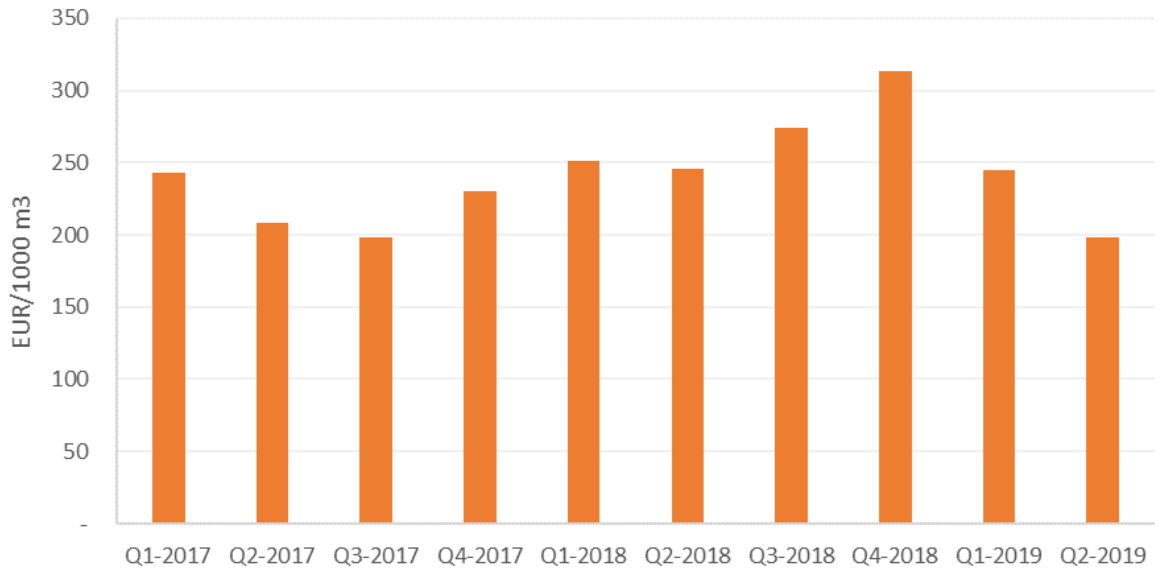
In Moldova, the regulated price set by ANRE, for entry into the gas transmission system is used[119], i.e. 151.5 EUR/1000 m^3.

In Ukraine, the price of the wholesale market is a mix of the import price of EU supplies and the price of indigenously produced gas. As Ukrainian gas is on average cheaper than the imports, it is expected that supplies of regasified LNG will compete with supplies from EU. For this reason, in our netback analysis we use the average price of imported gas, including the entry tariff to enter the Ukrainian market. As import prices are fluctuating considerably (Figure A. 42), we examine 3 scenarios for the average level of import prices in Ukraine, corresponding to the average (241 EUR/1000 m^3), average for winter season (257 EUR/1000 m^3) and minimum (198 EUR/1000 m^3) price for the period Q1 2017 – Q2 2019.

Figure A. 42: Average quarterly import price in Ukraine (including entry tariff)[120]



Source: NEURC Monitoring Report, Q2 2019

A2.1.4. Steps 2-3: Calculation of cross-border charges

The routes used to transport regasified LNG from the neighbouring terminals to Ukraine and Moldova involve, in some cases, the same interconnection points.

[119] Source: Moldovan National Agency for Energy Regulation Decision No 88/2018

[120] Conversion from UAH to EUR using the average exchange rate of the corresponding quarter

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Table A. 13 below presents the tariffs of the interconnection points covering all the routes from each LNG terminal up to the Eastern Partners' markets. Where necessary, conversion from energy units to volumetric units was carried out using the GCV presented in Annex 7. For projects under development (GIPL pipeline, Ungheni – Chisinau Pipeline, upgrade of IP Dravaszerdahely linked with development of Krk LNG terminal) assumptions based on public information have been made.

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Table A. 13: Tariffs at interconnection points relevant to the regasified LNG routes

Interconnection Point		Tariff	Unit	Capacity
IP Hermanovice	Entry Ukraine[121]	5.7	EUR/1000 m³	6.4 mcm/d (interruptible)
	Exit Poland[122] (Interruptible)	1,847.6	EUR/1000 m³/d/yr	
GIPL Pipeline	Entry Poland[123]	2,929.5	EUR/1000 m³/d/yr	5.2 mcm/d
	Exit Lithuania[124]	1,993.2	EUR/1000 m³/d/yr	
IP Isaccea (Romania) - Orlovka (Ukraine)	Entry Ukraine[121]	5.7	EUR/1000 m³	4.1 mcm/d (interruptible)
	Exit Romania[125]	1,299.8	EUR/1000 m³/d/yr	
IP Negru Voda I (Romania) / Kardam (Bulgaria)	Entry Romania[125]	1,668.1	EUR/1000 m³/d/yr	6.9 mcm/d (interruptible)
	Exit Bulgaria (Capacity charge)[126]	1,086.4	EUR/1000 m³/d/yr	
	Exit Bulgaria (Commodity charge)[126]	1.1	EUR/1000 m³	
IP Kulata (Bulgaria)/ Sidirokastron(Greece)	Entry Bulgaria (Capacity charge) [126]	1,680.2	EUR/1000 m³/d/yr	4 mcm/d
	Entry Bulgaria (Commodity charge) [126]	1.1	EUR/1000 m³	
	Exit Greece[127]	2,997.6	EUR/1000 m³/d/yr	
IP Beregdaróc (Hungary) / Beregovo (Ukraine)	Entry Ukraine[121]	5.7	EUR/1000 m³	19.5 mcm/d (interruptible)
	Exit Hungary (Interruptible)[128]	1,053.0	EUR/1000 m³/d/yr	
IP Dravaszerdahely	Entry Hungary[128]	1,260.4	EUR/1000 m³/d/yr	6.6 mcm/d (interruptible)
	Exit Croatia[129]	1,697.9	EUR/1000 m³/d/yr	
IP Oleksiivka	Entry Moldova[130]	1.7	EUR/1000 m³	24.9 mcm/d
	Exit Ukraine[121]	15.7	EUR/1000 m³	
IP Ungheni[131]	Entry Moldova	1.7	EUR/1000 m³	4.1 mcm/d
	Exit Romania	1,299.8	EUR/1000 m³/d/yr	

[121] Source: Ukrtransgaz Price List

[122] Source: Gaz System Price List

[123] The existing exit tariff in Poland has been assumed (Gaz System tariff methodology https://en.gaz-system.pl/fileadmin/centrum_prasowe/Aktualnosci/2019/20190905_Taryfa/The_Tariff_for_Gas_Transmission_Services_No._13_-_searchable_version_.pdf)

[124] The exit tariff at Kiemenai has been assumed, increased by 11% (based on GIPL promoter estimate in its Investment Request: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Individual%20Decision%2001-2014%20on%20GIPL.pdf)

[125] Source: Transgaz Price List

[126] Source: Bulgartransgaz Price List

[127] Source: DESFA Price List

[128] Source: FGSZ Price List

[129] The tariff published in Croatia LNG Open Season has been used (http://www.plinacro.hr/default.aspx?id=855)

[130] Source: Moldovan National Agency for Energy Regulation Decision No 88/2018

[131] The current tariffs on the Romanian and Moldovan systems have been assumed

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It is noted that the calculation of cross-border charges is based on the current entry/exit tariffs of each TSO. Upcoming revisions of the tariffs or changes due to the increase of gas volumes transported, are not taken into consideration.

To apply the tariffs that include a capacity charge, we assume a peak daily requirement for regasified LNG[132]:

- For Ukraine, it is assumed that the annually transported volumes will be 1 bcm/yr. As winter daily demand of non-household consumers in Ukraine is 25% higher than the average, the peak daily requirement for regasified LNG is estimated at 3.4 mcm/d.
- For Moldova, it is assumed that the annually transported volumes will be 0.5 bcm/yr. It is assumed that winter daily demand is 20% higher than the average, and therefore the peak daily requirement for regasified LNG is estimated at 1.64 mcm/d.

Table A. 14 presents the unit cross-border charges for each route to Ukraine (in EUR/1000 m^3), corresponding to the peak daily gas requirement of 6.85 mcm/d.

Table A. 14: Unit cross-border charges for regasified LNG routes of Ukraine

Interconnection Point		Tariff (EUR/1000 m^3)
Route: Poland -> Ukraine		
IP Hermanovice	Exit Poland	6.3
	Entry Ukraine	5.7
	Aggregate for route:	**12.0**
Route: Lithuania -> Poland -> Ukraine		
GIPL Pipeline	Exit Lithuania	6.8
	Entry Poland	10.0
IP Hermanovice	Exit Poland	6.3
	Entry Ukraine	5.7
	Aggregate for route:	**28.9**
Route: Greece -> Bulgaria -> Romania -> Ukraine		
IP Kulata (Bulgaria)/ Sidirokastron(Greece)	Exit Greece	10.3
	Entry Bulgaria	6.9
IP Negru Voda I (Romania) / Kardam (Bulgaria)	Exit Bulgaria	4.9
	Entry Romania	5.7
IP Isaccea (Romania) - Orlovka (Ukraine)	Exit Romania	4.5
	Entry Ukraine	5.7
	Aggregate for route:	**37.9**
Route: Croatia -> Hungary -> Ukraine		
IP Dravaszerdahely	Exit Croatia	5.8
	Entry Hungary	4.3

[132] It is noted that for the purposes of the netback analysis, the assumed volumes are only used to estimate the difference between average and peak daily demand, to apply capacity charges. As unit costs are examined, the actual availability of capacity along the route is not examined.

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IP Beregdaróc (Hungary) / Beregovo (Ukraine)	Exit Hungary	3.6
	Entry Ukraine	5.7
	Aggregate for route:	**19.4**

Table A. 15 presents the unit cross-border charges for each route to Moldova (in EUR/1000 m^3), corresponding to the peak daily gas requirement of 1.64 mcm/d.

Table A. 15: Unit cross-border charges for regasified LNG routes of Moldova

Interconnection Point		Tariff (EUR/1000 m^3)
Route: Poland -> Ukraine -> Moldova		
IP Hermanovice	Exit Poland	6.1
	Entry Ukraine	5.7
IP Oleksiivka	Exit Ukraine	15.7
	Entry Moldova	1.7
	Aggregate for route:	**29.2**
Route: Lithuania -> Poland -> Ukraine -> Moldova		
GIPL Pipeline	Exit Lithuania	6.6
	Entry Poland	9.6
IP Hermanovice	Exit Poland	6.1
	Entry Ukraine	5.7
IP Oleksiivka	Exit Ukraine	15.7
	Entry Moldova	1.7
	Aggregate for route:	**45.4**
Route: Greece -> Bulgaria -> Romania -> Ukraine -> Moldova		
IP Kulata (Bulgaria)/ Sidirokastron(Greece)	Exit Greece	9.9
	Entry Bulgaria	6.7
IP Negru Voda I (Romania) / Kardam (Bulgaria)	Exit Bulgaria	4.7
	Entry Romania	5.5
IP Ungheni	Exit Romania	4.3
	Entry Moldova	1.7
	Aggregate for route:	**32.7**
Route: Croatia -> Hungary -> Ukraine -> Moldova		
IP Dravaszerdahely	Exit Croatia	5.6
	Entry Hungary	4.1
IP Beregdaróc (Hungary) / Beregovo (Ukraine)	Exit Hungary	3.5
	Entry Ukraine	5.7
IP Oleksiivka	Exit Ukraine	15.7
	Entry Moldova	1.7
	Aggregate for route:	**36.3**

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A2.1.5. Step 4: Definition of entry charges from LNG terminal

Table A. 16 below presents the tariffs of the entry points connecting the LNG terminals to the transmission systems. Where necessary, conversion from energy units to volumetric units was carried out using the GCV presented in Annex 7. For the LNG terminals in operation (Świnoujście, Klaipeda, Revythoussa), the current tariffs applied by the TSOs are used. For the planned terminal in Krk, and the potential terminals in Ukraine and Georgia, assumptions have been made, based on public information.

Table A. 16: Tariffs for entry from LNG terminal to transmission

LNG terminal	Entry Tariff to transmission	Unit
Świnoujście (entry to Polish system)[122]	**0**	EUR/1000 m^3/d/yr
Klaipeda (entry to Lithuanian system)[133]	**112.2**	EUR/1000 m^3/d/yr
Revythoussa (entry to Greek system)[127]	**929.8**	EUR/1000 m^3/d/yr
Krk (entry to Croatian system)[129]	**2,176.5**	EUR/1000 m^3/d/yr
Ukrainian terminal (entry to Ukrainian system)[134]	**5.7**	EUR/1000 m^3
Georgian terminal (entry to Georgian system)[135]	**6.1**	EUR/1000 m^3

As in the case of cross-border interconnection points, to apply the tariffs that include a capacity charge, we use the assumed peak daily requirement. The calculated charges for Ukraine and Moldova are presented in Table A. 17 and Table A. 18 respectively.

Table A. 17: Unit charges for entry from LNG terminal to transmission for routes of Ukraine

LNG terminal	Tariff (EUR/1000 m^3)
Świnoujście (entry to Polish system)	0
Klaipeda (entry to Lithuanian system)	0.4
Revythoussa (entry to Greek system)	3.2
Krk (entry to Croatian system)	7.5

Table A. 18: Unit charges for entry from LNG terminal to transmission for routes of Moldova

LNG terminal	Tariff (EUR/1000 m^3)
Świnoujście (entry to Polish system)	0
Klaipeda (entry to Lithuanian system)	0.4
Revythoussa (entry to Greek system)	3.1
Krk (entry to Croatian system)	7.2

[133] Source: Amber Grid Price List

[134] The same entry tariff as interconnection points is assumed

[135] The transmission tariff is assumed

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A2.1.6. Step 5: Definition of charges at EU LNG terminals

Table A. 19 below presents the tariffs applied at the EU LNG terminals for unloading, storage and regasification. Where necessary, conversion from energy units to volumetric units was carried out using the GCV presented in Annex 7. For the LNG terminals in operation (Świnoujście, Klaipeda, Revythoussa), the current tariffs applied are used. For the planned terminal in Krk, assumptions have been made, based on public information.

Table A. 19: Tariffs for the use (unloading, storage, regasification) of LNG terminals

LNG terminal		Tariff	Unit	Send-out capacity
Świnoujście[136]	Fixed component	6,253.0	EUR/1000 m³/d/yr	13.4 mcm/d (to be increased to 20.5 mcm/d with expansion programme)
	Variable component	1.5	EUR/1000 m³	
Klaipeda[137]	Fixed component	4,583.5	EUR/1000 m³/d/yr	10.2 mcm/d
	Variable component	1.5	EUR/1000 m³	
Revythoussa[127]	Fixed component	1,105.8	EUR/1000 m³/d/yr	17.1 mcm/d
	Variable component	1.4	EUR/1000 m³	
Krk[129]	Variable component	15.8	EUR/1000 m³	7.1 mcm/d

As in the case of cross-border interconnection points, to apply the fixed component of the tariffs, we use the assumed peak daily requirement. The calculated unit tariffs for Ukraine and Moldova are presented in Table A. 20 and Table A. 21 respectively.

Table A. 20: LNG terminal tariffs for the routes of Ukraine

LNG terminal	Tariff (EUR/1000 m³)
Świnoujście	22.9
Klaipeda	17.2
Revythoussa	5.2
Krk	15.8

Table A. 21: LNG terminal tariffs for the routes of Moldova

LNG terminal	Tariff (EUR/1000 m³)
Świnoujście	22.1
Klaipeda	16.6
Revythoussa	5.1
Krk	15.8

[136] Source: Polskie LNG

[137] Source: Klaipedos Nafta Price List

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A2.1.7. Results of analysis

Ukraine

The results of the netback analysis for Ukraine, concerning the maximum supply price of LNG at each of the examined EU receiving terminals, covering the 3 wholesale price scenarios (average, minimum, maximum) are presented in Table A. 22, Table A. 23 and Table A. 24 respectively.

Table A. 22: Calculated maximum competitive LNG price at the source per receiving terminal, for average import price in Ukraine

Item	Source of regasified LNG			
	Świnoujście	*Klaipeda*	*Revythoussa*	*Krk*
Wholesale gas price in Ukraine (EUR/1000 m^3)	241			
Aggregate cross-border charges (EUR/1000 m^3)	*-12.0*	*-28.9*	*-37.9*	*-19.4*
Entry charges from LNG terminal to transmission (EUR/1000 m^3)	*-0*	*-0.4*	*-3.2*	*-7.5*
Charges at LNG terminal (EUR/1000 m^3)	*-22.9*	*-17.2*	*-5.2*	*-15.8*
Maximum LNG price at the terminal (EUR/1000 m^3)	**206.0**	**194.5**	**194.7**	**198.3**

Table A. 23: Calculated maximum competitive LNG price at the source per receiving terminal, for minimum import price in Ukraine

Item	Source of regasified LNG			
	Świnoujście	*Klaipeda*	*Revythoussa*	*Krk*
Wholesale gas price in Ukraine (EUR/1000 m^3)	198			
Aggregate cross-border charges (EUR/1000 m^3)	*-12.0*	*-28.9*	*-37.9*	*-19.4*
Entry charges from LNG terminal to transmission (EUR/1000 m^3)	*-0*	*-0.4*	*-3.2*	*-7.5*
Charges at LNG terminal (EUR/1000 m^3)	*-22.9*	*-17.2*	*-5.2*	*-15.8*
Maximum LNG price at the terminal (EUR/1000 m^3)	**163.0**	**151.5**	**151.7**	**155.3**

Table A. 24: Calculated maximum competitive LNG price at the source per receiving terminal, for maximum Ukrainian wholesale price

Item	Source of regasified LNG			
	Świnoujście	*Klaipeda*	*Revythoussa*	*Krk*
Wholesale gas price in Ukraine (EUR/1000 m^3)	257			
Aggregate cross-border charges (EUR/1000 m^3)	*-12.0*	*-28.9*	*-37.9*	*-19.4*
Entry charges from LNG terminal to transmission (EUR/1000 m^3)	*-0*	*-0.4*	*-3.2*	*-7.5*
Charges at LNG terminal (EUR/1000 m^3)	*-22.9*	*-17.2*	*-5.2*	*-15.8*
Maximum LNG price at the terminal (EUR/1000 m^3)	**222.0**	**210.5**	**210.7**	**214.3**

Moldova

The results of the netback analysis for Moldova, concerning the maximum supply price of LNG at each of the examined EU receiving terminals, are presented in Table A. 25 below.

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Table A. 25: Calculated maximum competitive LNG at the source per receiving terminal, for Moldova

Item	Source of regasified LNG			
	Świnoujście	*Klaipeda*	*Revythoussa*	*Krk*
Wholesale gas price in Moldova (EUR/1000 m^3)	151.4			
Aggregate cross-border charges (EUR/1000 m^3)	*-29.2*	*-45.4*	*-32.7*	*-36.3*
Entry charges from LNG terminal to transmission (EUR/1000 m^3)	*0*	*-0.4*	*-3.1*	*-7.2*
Charges at LNG terminal (EUR/1000 m^3)	*-22.1*	*-16.6*	*-5.1*	*-15.8*
Maximum LNG price at the terminal (EUR/1000 m^3)	**100.2**	**89.2**	**110.7**	**92.3**

A2.2. Netback analysis in case of LNG receiving terminal in Eastern Partner country

A2.2.1. Analysis approach

The netback analysis approach outlined in Figure A. 41 of Section A2.1 is applied, but in this case for regasified LNG sourced from an LNG terminal developed in an Eastern Partner country.

A2.2.2. Application in Eastern Partner countries

Based on the Consultant's analysis and the consultations with the countries' stakeholders, there is interest for the development of LNG receiving terminals in Georgia and Ukraine. The case of supplies of regasified LNG sourced from the Ukrainian terminal to the Moldovan market is also examined.

As there are no up-to-date studies concerning the development of LNG infrastructure in either Georgia or Ukraine[138], assumptions are made concerning the size of the terminals. In Ukraine, the analysis was carried out assuming the development of an FSRU with maximum send-out capacity of 5 bcm/yr. In Georgia, a terminal with send-out capacity of 1 bcm/yr is assumed. For a facility of this size, detailed analysis is required to determine whether an on-shore terminal, FRSU or FSU solution should be selected, as availability of small-scale FSRUs in the market is very limited.

In the absence of market analysis for the use of LNG in these markets, and taking into consideration that the unit costs of an LNG terminal are sensitive on its assumed utilization rate, in order to conduct this high-level analysis we examine 3 scenarios for each terminal, of low (30%), medium (50%) and high (70%) utilization.

Based on this context, the calculations for the netback analysis steps are described in the sections below. It is noted that when examining the in-country terminals is Georgia and Ukraine, Steps 2 and 3 of Figure A. 41, concerning cross-border charges, are omitted.

[138] Studies for the development of an LNG terminal near Odessa were prepared in 2013, with very different supply & demand conditions in the Ukrainian market than the existing ones.

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A2.2.3. Step 1: Definition of wholesale gas prices in Eastern Partner countries

For Moldova and Ukraine, the gas prices defined in Section A2.1.3, for the case of supplies from the EU terminals, are applied.

In the case of Georgia, the price of imported Azeri gas, for the commercial part of the market, amounts to 200 EUR/ 1000 m^3, and has ranged from 165 – 245 EUR/ 1000 m^3 in the recent years[139]. As discussed in Section A1.4, gas demand in the coming years is expected to grow, while the existing contracts with SOCAR for the optional and additional gas are expiring after 2025. The emerging supply gap should be covered by additional contracted gas volumes, that are likely to be more expensive that current supplies. To assess different cases gas price evolution, we examine 3 scenarios for the wholesale gas price in Georgia, corresponding to the current level of import price plus transmission tariff (206 EUR/1000 m^3), a moderate (25%) price increase (256 EUR/1000 m^3) and a high (50%) price increase (306 EUR/1000 m^3).

A2.2.4. Steps 2-3: Calculation of cross-border charges

The only case for which Steps 2 and 3 apply is the supply of Moldova from the Ukrainian terminal. As defined in Sector A2.1.4, at the Oleksiivka interconnection point between the two countries, the exit tariff for Ukraine is 15.7 EUR/1000 m^3 and the entry tariff for Moldova 1.7 EUR/1000 m^3.

A2.2.5. Step 4: Definition of entry charges from LNG terminal

Estimates for the tariffs of the entry points connecting the LNG terminals to the transmission systems are made, based on the existing tariffs applied by the TSOs. In the case of Ukraine, we assume an entry tariff of 5.7 EUR/1000 m^3, equal to the entry tariffs from interconnection points. In the case of Georgia, all potential costs required for the connection of the LNG receiving terminal to the transmission system (to allow reverse of the existing gas flow) are included in the terminal's investment costs (Section A2.2.6), and therefore in the charge for use of the terminal. As an entry charge to the transmission system, we apply the existing transmission tariff of 6.1 EUR/1000 m^3.

A2.2.6. Step 5: Calculation of charges for Eastern Partners' LNG terminals

The charges for the use of the potential LNG terminals in Ukraine and Georgia are calculated using benchmark investment costs and operation expenses. The cost for using the terminal is calculated as the present value of the required annual revenues (including recovery of all the investment costs and operating expenses and a return on the assets) per volume of regasified LNG, for the full duration of the terminal's life cycle. The approach applied to calculate the charges is presented in Figure A. 43.

[139] Source: Department of Strategic Planning and Projects of GOGC

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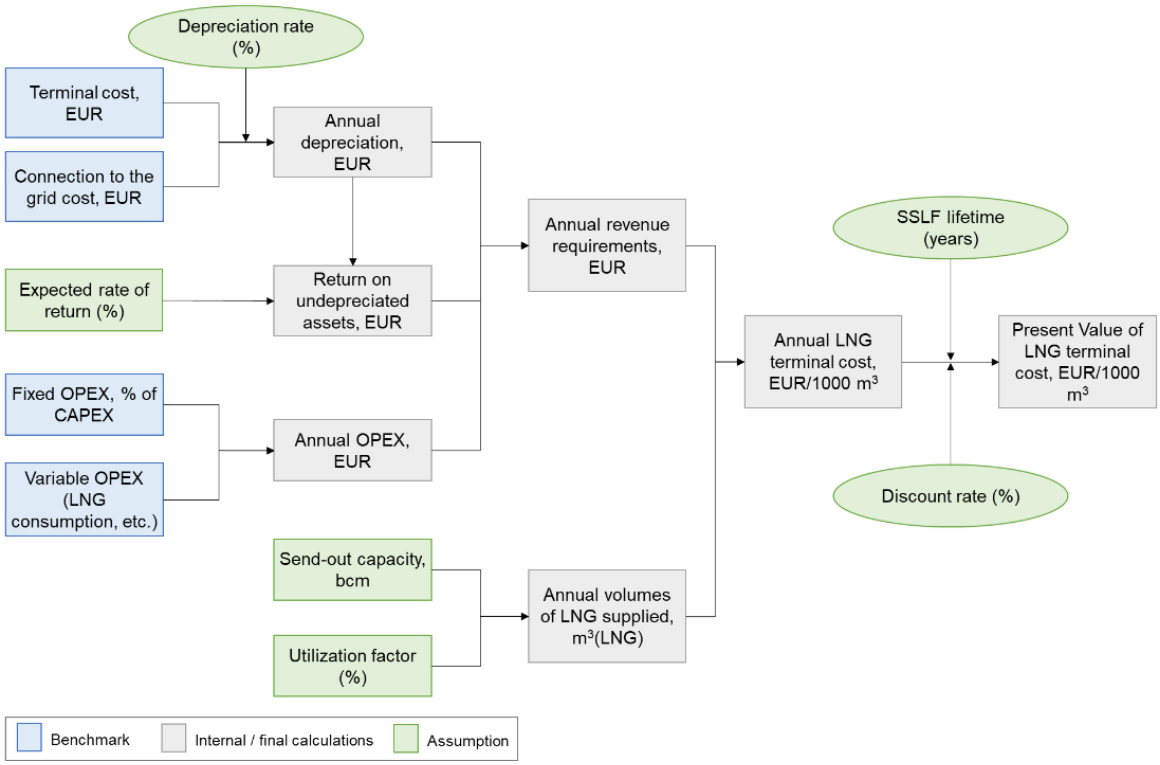
Figure A. 43: Calculation of charges at Eastern Partners' LNG terminal



The assumptions and benchmarks applied for calculating the LNG terminal charge in the case of Georgia are presented in Table A. 26. An approximation of the costs for a small on-shore terminal are used. These costs the required interventions to transmission the system, which would need to reverse of the current flows.

Table A. 26: Values applied to calculate LNG terminal charge in Georgia

Item	Value		
Annual send-out capacity (bcm/yr)	1		
Cost for terminal (EUR)	170,000,000[140]		
Life cycle of terminal (years)	30 (depreciation rate 3%)		
Expected rate of return on investment / discount rate	10%		
Fixed operating expenses	2.5% of CAPEX[140]		
Variable operating expenses	1.1% of send-out		
Assumed LNG opportunity cost (EUR/1000 m³)	220		
Terminal utilization factor	30%	50%	70%
LNG terminal charge (EUR/1000 m³)	**80.5**	**48.3**	**34.5**

The assumptions and benchmarks applied for calculating the FSRU charge in the case of Ukraine are presented in Table A. 27.

[140] Investment cost is based on a unit cost for on-shore terminals of 250 USD/tpa, source: Oxford Institute for Energy Studies, "The Outlook for Floating Storage and Regasification Units", 2017

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Table A. 27: Values applied to calculate LNG terminal charge in Ukraine

Item	Value		
Annual send-out capacity (bcm/yr)	5		
FSRU vessel cost (EUR)	260,000,000[141]		
Facilities costs (EUR)	190,000,000[142]		
Life cycle of FSRU (years)	30 (depreciation rate 3%)		
Expected rate of return on investment / discount rate	10%		
Fixed operating expenses	2.5% of CAPEX[140]		
Vessel LNG consumption (1000m3/d)	16		
Assumed LNG opportunity cost (EUR/1000 m^3)	220		
Variable operating expenses	1.1% of send-out		
Terminal utilization factor	30%	50%	70%
LNG terminal charge (EUR/1000 m^3)	**41.6**	**25.9**	**19.2**

A2.2.7. Results of analysis

Georgia

The results of the netback analysis for Georgia, concerning the maximum supply price of LNG at the Georgian terminal, for each scenario of the assumed utilization, are presented in Table A. 28.

Table A. 28: Calculated maximum competitive LNG price at the source per utilization rate, for current import price in Georgia

Item	Utilization of LNG terminal		
	30%	*50%*	*70%*
Wholesale gas price in Georgia (EUR/1000 m^3)	206.0		
Aggregate cross-border charges (EUR/1000 m^3)	*N/A*		
Entry charges from LNG terminal to transmission (EUR/1000 m^3)	*-6.1*		
Charges at LNG terminal (EUR/1000 m^3)	*-80.5*	*-48.3*	*-34.5*
Maximum LNG price at the terminal (EUR/1000 m^3)	**119.4**	**151.6**	**165.4**

Table A. 29: Calculated maximum competitive LNG price at the source per utilization rate, for 25% import price increase in Georgia

Item	Utilization of LNG terminal		
	30%	*50%*	*70%*
Wholesale gas price in Georgia (EUR/1000 m^3)	256		
Aggregate cross-border charges (EUR/1000 m^3)	*N/A*		
Entry charges from LNG terminal to transmission (EUR/1000 m^3)	*-6.1*		
Charges at LNG terminal (EUR/1000 m^3)	*-80.5*	*-48.3*	*-34.5*
Maximum LNG price at the terminal (EUR/1000 m^3)	**169.4**	**201.6**	**215.4**

[141] Average cost of FSRU vessels, source: Oxford Institute for Energy Studies, "The Outlook for Floating Storage and Regasification Units", 2017

[142] Estimate, based on benchmark jetty/piping costs and estimated connection to the Ukrainian transmission system

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Table A. 30: Calculated maximum competitive LNG price at the source per utilization rate, for 50% import price increase in Georgia

Item	Utilization of LNG terminal		
	30%	*50%*	*70%*
Wholesale gas price in Georgia (EUR/1000 m³)	306		
Aggregate cross-border charges (EUR/1000 m³)	*N/A*		
Entry charges from LNG terminal to transmission (EUR/1000 m³)	*-6.1*		
Charges at LNG terminal (EUR/1000 m³)	*-80.5*	*-48.3*	*-34.5*
Maximum LNG price at the terminal (EUR/1000 m³)	**219.4**	**251.6**	**265.4**

Ukraine

The results of the netback analysis for Ukraine, concerning the maximum supply price of LNG at the Ukrainian terminal, for each scenario of the assumed utilization, covering the 3 wholesale price scenarios (average, minimum, maximum) are presented in Table A. 31, Table A. 32 and Table A. 33 respectively.

Table A. 31: Calculated maximum competitive LNG price at the source per utilization rate, for average import price in Ukraine

Item	Utilization of LNG terminal		
	30%	*50%*	*70%*
Wholesale gas price in Ukraine (EUR/1000 m³)	241		
Aggregate cross-border charges (EUR/1000 m³)	*N/A*		
Entry charges from LNG terminal to transmission (EUR/1000 m³)	*-5.71*		
Charges at LNG terminal (EUR/1000 m³)	*-41.6*	*-25.9*	*-19.2*
Maximum LNG price at the terminal (EUR/1000 m³)	**193.7**	**209.4**	**216.1**

Table A. 32: Calculated maximum competitive LNG price at the source per utilization rate, for minimum import price in Ukraine

Item	Utilization of LNG terminal		
	30%	*50%*	*70%*
Wholesale gas price in Ukraine (EUR/1000 m³)	198		
Aggregate cross-border charges (EUR/1000 m³)	*N/A*		
Entry charges from LNG terminal to transmission (EUR/1000 m³)	*-5.71*		
Charges at LNG terminal (EUR/1000 m³)	*-41.6*	*-25.9*	*-19.2*
Maximum LNG price at the terminal (EUR/1000 m³)	**150.7**	**166.4**	**173.1**

Table A. 33: Calculated maximum competitive LNG price at the source per utilization rate, for winter average import price in Ukraine

Item	Utilization of LNG terminal		
	30%	*50%*	*70%*
Wholesale gas price in Ukraine (EUR/1000 m³)	257		
Aggregate cross-border charges (EUR/1000 m³)	*N/A*		
Entry charges from LNG terminal to transmission (EUR/1000 m³)	*-5.71*		

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Charges at LNG terminal (EUR/1000 m³)	*-41.6*	*-25.9*	*-19.2*
Maximum LNG price at the terminal (EUR/1000 m³)	**209.7**	**225.4**	**232.1**

Moldova

The results of the netback analysis for Moldova, concerning the maximum supply price of LNG at the Ukrainian terminal, for each scenario of the assumed utilization, are presented in Table A. 34.

Table A. 34: Calculated maximum competitive LNG price at the source per receiving terminal, for Moldova

Item	Utilization of LNG terminal		
	30%	*50%*	*70%*
Wholesale gas price in Ukraine (EUR/1000 m³)	151.4		
Aggregate cross-border charges (EUR/1000 m³)	*-17.0*		
Entry charges from LNG terminal to transmission (EUR/1000 m³)	*-5.71*		
Charges at LNG terminal (EUR/1000 m³)	*-41.6*	*-25.9*	*-19.2*
Maximum LNG price at the terminal (EUR/1000 m³)	**87.4**	**103**	**109.8**

A2.3. Netback analysis in case of LNG supplied from liquefaction terminal in Black Sea

A2.3.1. Analysis approach

Figure A. 44 outlines the netback analysis for deriving the competitive LNG price, in the case of regasified LNG, sourced from a liquefaction terminal located in Georgia.

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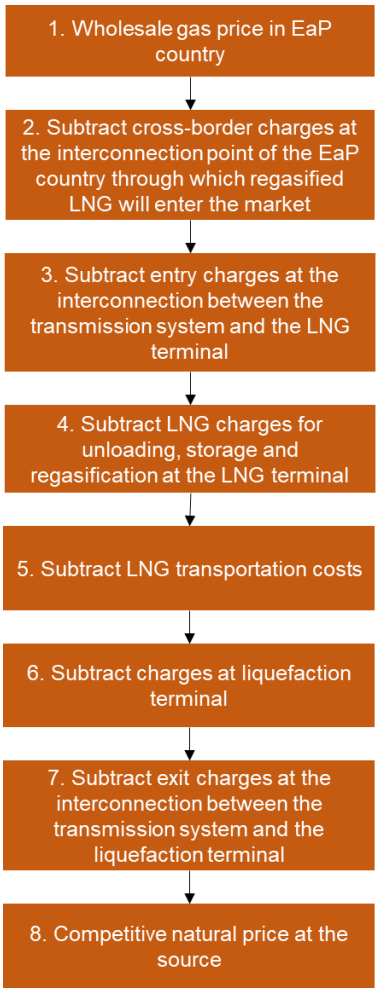
Figure A. 44: Netback analysis to estimate competitive LNG price at the source, for LNG liquefied in the Black Sea



The initial Steps of the process (Steps 1 to 4) are the same as in Sections A2.1 and A2.2. Additional costs considered are the LNG transportation costs (Step 5), charges for the liquefaction service (Step 6), and the tariff at the interconnection between the transmission system and the liquefaction terminal (Step 7).

The resulting natural gas price from the netback analysis is the price that needs to be compared to the gas price in Georgia, to ascertain whether LNG is competitive to prices of existing gas sources in the Eastern Partner country.

A2.3.2. Application in Eastern Partner countries

Potential target Eastern Partner countries for a liquefaction terminal in Georgia are Ukraine and Moldova, provided that a receiving terminal in Ukraine is also developed.

It is noted that when examining the in-country terminal in Ukraine, Step 2 is omitted.

Based on this context, the calculations for the netback analysis steps are described in the sections below.

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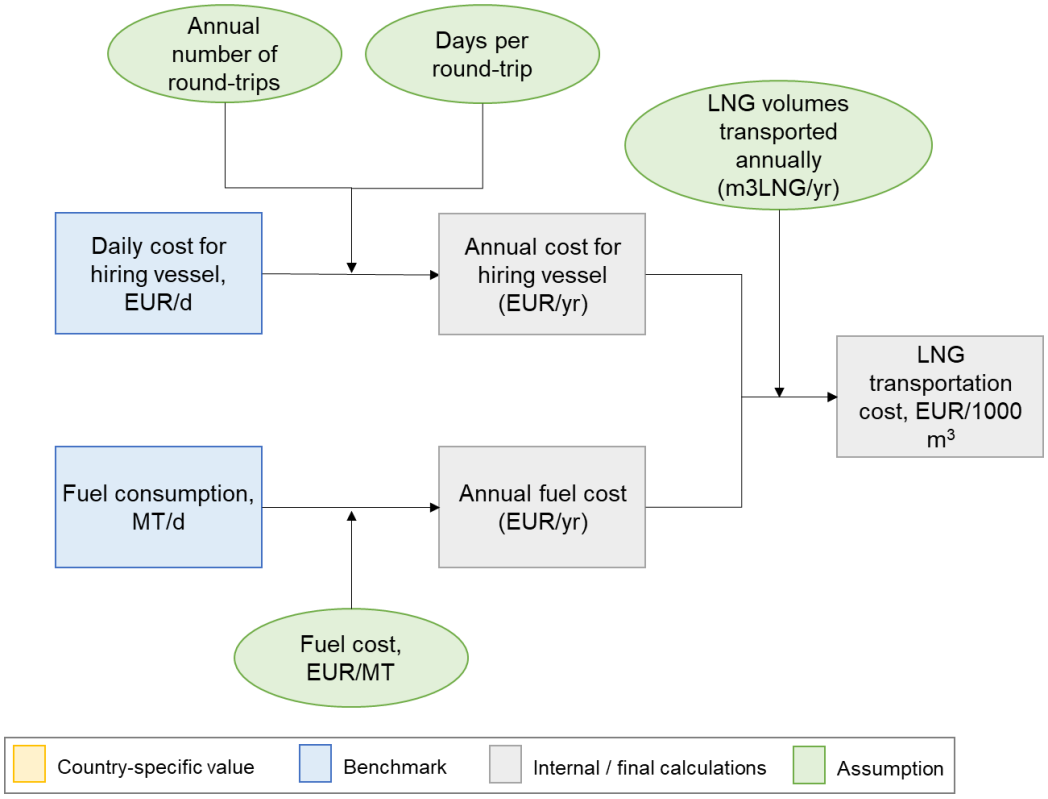
A2.3.3. Steps 1 to 4

The calculations for Steps 1 to 4 are the same with those defined in Sections A2.2.3 – A.2.2.6.

A2.3.4. Step 5: Definition of LNG transportation costs

Transportation from the liquefaction plant in Georgia to the receiving terminal in Ukraine is required. It is assumed that an LNG vessel with capacity of 74,000 m^3 will be hired to transport LNG to the target destinations (Romania, Hungary, Ukraine, Moldova). The annual cost is calculated on the basis of the cost for hiring the vessel and its fuel consumption (Figure A. 45).

Figure A. 45: Calculation of LNG transportation costs



The assumptions and benchmarks applied in the calculation are presented in Table A. 35.

Table A. 35: Values applied to calculate LNG transportation cost

Item	Value
Cost for hiring LNG vessel (EUR/d)	50,000
Transported volumes (m^3 LNG/yr)	3,000,000 (90% utilization of liquefaction facility)
Roundtrips required	50
Days per round trip	3
Fuel consumption (MT HFO/d)	50
Fuel cost (EUR/MT)	320
Transportation cost (EUR/1000 m^3)	**5.5**

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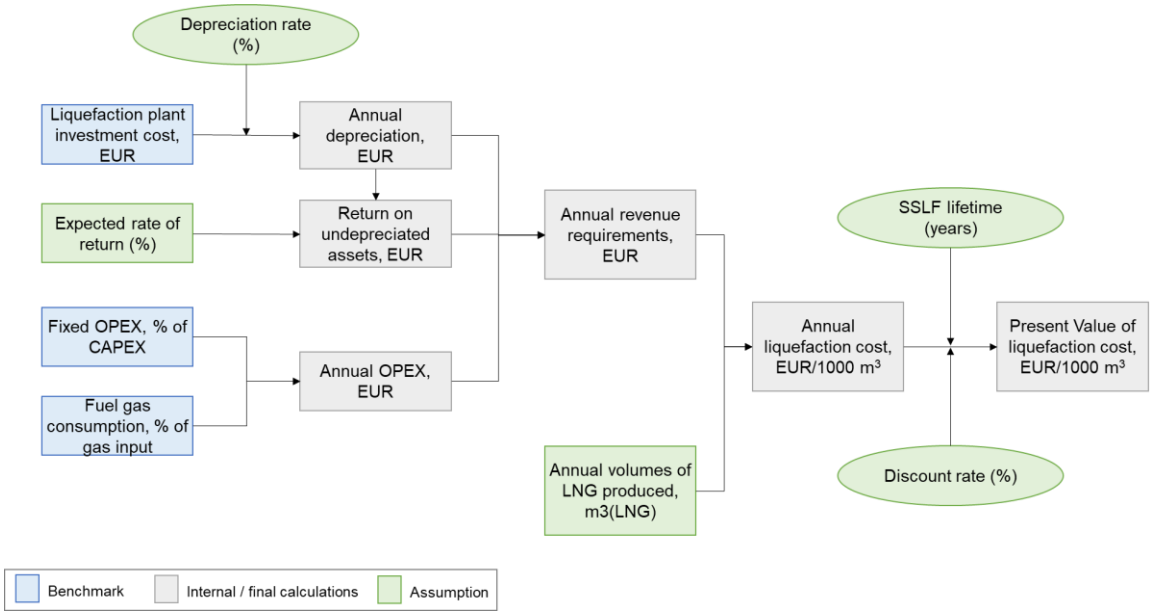
A2.3.5. Step 6: Calculation of liquefaction cost

The cost for producing LNG at the liquefaction plant is calculated as the present value of the required annual revenues (including recovery of all the investment costs and operating expenses and a return on the assets) per volume of produced LNG, for the full duration of the liquefaction plant's life cycle. The approach applied to calculate the cost of gas liquefaction is presented in Figure A. 46.

Figure A. 46: Calculation of gas liquefaction costs



The liquefaction terminal is assumed to have an output capacity of 2 bcm/yr, and a utilization rate of 90% (with potential gas supply to Eastern Partners and EU countries). The assumptions and benchmarks applied in the calculation are presented in Table A. 36. The investment cost estimated for the 2 bcm/yr configuration of the AGRI Pipeline is applied as a basis. However, as the costs associated with the development of the facility are a key cost element in the analysis, and these may have changed, due to the introduction of new technologies (e.g. FLNG terminal), sensitivity analysis was performed, assessing also 80% and 60% of the investment costs.

Table A. 36: Values applied to calculate gas liquefaction cost

Item	Cost of liquefaction terminal		
	100%	80%	60%
LNG production capacity	2 bcm/yr		
Liquefaction plant investment cost (EUR)	1,200,000,000[143]	960,000,000	720,000,000
Life cycle of plant (years)	30 (depreciation rate 3%)		
Expected rate of return on investment / discount rate	10%		

[143] Assumed equal to the investment cost of the 2 bcm/yr configuration of the AGRI Pipeline, source: GNERC, "Case Study: Georgia's Growing Gas Market", 2018

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Fixed operating expenses	2.5% of CAPEX[144]		
Fuel gas (feed gas) consumption	10% of gas input[144]		
Assumed LNG opportunity cost (EUR/1000 m³)	220		
Utilization rate	90%		
Liquefaction cost (EUR/1000 m³)	**109.6**	**93.5**	**79.8**

A2.3.6. Step 7: Definition of exit charges to liquefaction terminal

The exit tariff from the Georgian transmission system to the liquefaction terminal is assumed to be equal to the existing transmission tariff, 6.1 EUR/1000 m³.

A2.3.7. Results of analysis

Ukraine

The results of the netback analysis for Ukraine, concerning the maximum supply price of natural gas in Georgia, for each scenario of the assumed Ukrainian receiving terminal utilization, covering the 3 wholesale price scenarios (average, minimum, winter average) are presented in Table A. 37, Table A. 38 and Table A. 39 respectively. Furthermore, sensitivity analysis was performed on the liquefaction terminal investment costs, for Ukrainian winter average price and utilization 70% at the Ukrainian LNG receiving terminal (Table A. 40).

Table A. 37: Calculated maximum competitive price of gas liquefied in Georgia, for average import price in Ukraine

Item	Utilization of Ukrainian LNG terminal		
	30%	*50%*	*70%*
Wholesale gas price in Ukraine (EUR/1000 m³)	241.0		
Cross-border charges (EUR/1000 m³)	*N/A*		
Entry charges from LNG terminal to transmission (EUR/1000 m³)	*-5.71*		
Charges at LNG terminal (EUR/1000 m³)	*-41.6*	*-25.9*	*-19.2*
LNG transportation cost (EUR/1000 m³)	*-5.5*		
Liquefaction service charge (EUR/1000 m³)	*-109.6*		
Exit from Georgian system	*-6.1*		
Maximum LNG price at the terminal (EUR/1000 m³)	**74.9**	**90.6**	**97.3**

Table A. 38: Calculated maximum competitive price of gas liquefied in Georgia, for minimum import price in Ukraine

Item	Utilization of Ukrainian LNG terminal		
	30%	*50%*	*70%*
Wholesale gas price in Ukraine (EUR/1000 m³)	198.0		
Cross-border charges (EUR/1000 m³)	*N/A*		
Entry charges from LNG terminal to transmission (EUR/1000 m³)	*-5.71*		
Charges at LNG terminal (EUR/1000 m³)	*-41.6*	*-25.9*	*-19.2*

[144] Source: Oxford Institute for Energy Studies, "LNG Plant Cost Reduction", 2018

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LNG transportation cost (EUR/1000 m³)	*-5.5*		
Liquefaction service charge (EUR/1000 m³)	*-109.6*		
Exit from Georgian system	*-6.1*		
Maximum LNG price at the terminal (EUR/1000 m³)	**31.9**	**47.6**	**54.3**

Table A. 39: Calculated maximum competitive price of gas liquefied in Georgia, for winter average import price in Ukraine

Item	Utilization of Ukrainian LNG terminal		
	30%	*50%*	*70%*
Wholesale gas price in Ukraine (EUR/1000 m³)	257.0		
Cross-border charges (EUR/1000 m³)	*N/A*		
Entry charges from LNG terminal to transmission (EUR/1000 m³)	*-5.71*		
Charges at LNG terminal (EUR/1000 m³)	*-41.6*	*-25.9*	*-19.2*
LNG transportation cost (EUR/1000 m³)	*-5.5*		
Liquefaction service charge (EUR/1000 m³)	*-109.6*		
Exit from Georgian system	*-6.1*		
Maximum LNG price at the terminal (EUR/1000 m³)	**90.9**	**106.6**	**113.3**

Table A. 40: Sensitivity analysis on maximum competitive price of gas liquefied in Georgia, for winter average import price in Ukraine and 70% utilization of Ukrainian terminal

Item	Cost of liquefaction terminal		
	100%	*80%*	*60%*
Wholesale gas price in Ukraine (EUR/1000 m³)	256		
Cross-border charges (EUR/1000 m³)	*N/A*		
Entry charges from LNG terminal to transmission (EUR/1000 m³)	*-5.71*		
Charges at LNG terminal (EUR/1000 m³)	*-19.2*		
LNG transportation cost (EUR/1000 m³)	*-5.5*		
Liquefaction service charge (EUR/1000 m³)	*-109.6*	*-93.5*	*-79.8*
Exit from Georgian system	*-6.1*		
Maximum LNG price at the terminal (EUR/1000 m³)	**113.3**	**127.0**	**140.7**

Moldova

The results of the netback analysis for Moldova, concerning the maximum supply price of natural gas in Georgia, for each scenario of the assumed Ukrainian receiving terminal utilization, are presented in Table A. 41. The results of a sensitivity analysis on the liquefaction terminal costs, for utilization rate of the Ukrainian terminal of 70% is presented in Table A. 42.

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Table A. 41: Calculated maximum competitive price of gas liquefied in Georgia, for Moldova

Item	Utilization of Ukrainian LNG terminal		
	30%	*50%*	*70%*
Wholesale gas price in Moldova (EUR/1000 m^3)	151.5		
Cross-border charges (EUR/1000 m^3)	*-17.0*		
Entry charges from LNG terminal to transmission (EUR/1000 m^3)	*-5.71*		
Charges at LNG terminal (EUR/1000 m^3)	*-41.6*	*-25.9*	*-19.2*
LNG transportation cost (EUR/1000 m^3)	*-5.5*		
Liquefaction service charge (EUR/1000 m^3)	*-109.6*		
Exit from Georgian system	*-6.1*		
Maximum LNG price at the terminal (EUR/1000 m^3)	**-31.4**	**-15.7**	**-9.0**

Table A. 42: Sensitivity analysis on maximum competitive price of gas liquefied in Georgia, for Moldova and 70% utilization of Ukrainian terminal

Item	Cost of liquefaction terminal		
	100%	*80%*	*60%*
Wholesale gas price in Ukraine (EUR/1000 m^3)	151.5		
Cross-border charges (EUR/1000 m^3)	*-17.0*		
Entry charges from LNG terminal to transmission (EUR/1000 m^3)	*-5.71*		
Charges at LNG terminal (EUR/1000 m^3)	*-19.2*		
LNG transportation cost (EUR/1000 m^3)	*-5.5*		
Liquefaction service charge (EUR/1000 m^3)	*-109.6*	*-93.5*	*-79.8*
Exit from Georgian system	*-6.1*		
Maximum LNG price at the terminal (EUR/1000 m^3)	**-9.0**	**4.7**	**18.4**

A2.4. Netback analysis in case of LNG supplied via trucks to a regasification terminal connected to the transmission

A2.4.1. Analysis approach

Figure A. 47 outlines the netback analysis for deriving the competitive LNG price, in the case of LNG transported from a neighbouring EU terminal to an LNG receiving terminal connected to the to the transmission system of the examined Eastern Partner country.

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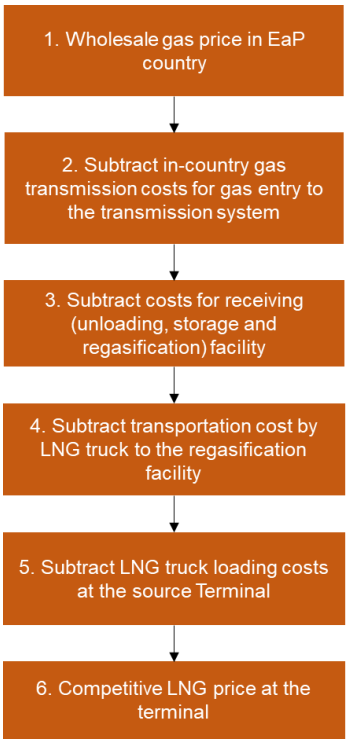
Figure A. 47: Netback analysis to estimate competitive LNG price at the source (LNG Terminal), for LNG delivered to a regasification terminal connected to the Eastern Partner country's transmission



The starting point (Step 1) for the analysis is the wholesale gas price in the Eastern Partner country in question. From this price, all costs to arrive at the competitive price of LNG at the LNG terminal are sequentially estimated and subtracted: costs for entry in the transmission system of the Eastern Partner country (Step 2), infrastructure cost for an LNG receiving facility (unloading, storage and regasification) connected to the transmission system (Step 3), transportation costs of LNG by the LNG trucks to the receiving facility (Step 4), and the cost of loading LNG to trucks at the LNG terminal (Steps 5).

A2.4.2. Application in Eastern Partner countries

Based on the Consultant's analysis and the consultations with the countries' stakeholders, the supply of LNG from neighbouring LNG terminals to a regasification facility connected to the country's transmission system is an applicable option for Ukraine.

The development of a regasification facility in the western part of Ukraine is assumed to be close to the LNG terminals in Świnoujście and Klaipeda. Other neighbouring terminals are not considered, due to their distance to Ukraine.

For the purpose of the analysis, we assume that the regasification will cover annual demand of 500 mcm, that is close to the maximum nominal capacity of the Klaipeda reloading station (100 m^3 LNG/h). The assumed demand corresponds to around 1.4 mcm/d, i.e. 2,300 m^3 LNG/d.

Based on this context, the calculations for the netback analysis steps are described in the sections below.

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A2.4.3. Step 1: Definition of wholesale gas prices in Eastern Partner countries

The import gas prices (average, minimum, winter average) defined for Ukraine in Section A2.1.3, for the case of supplies from the EU terminals, are applied.

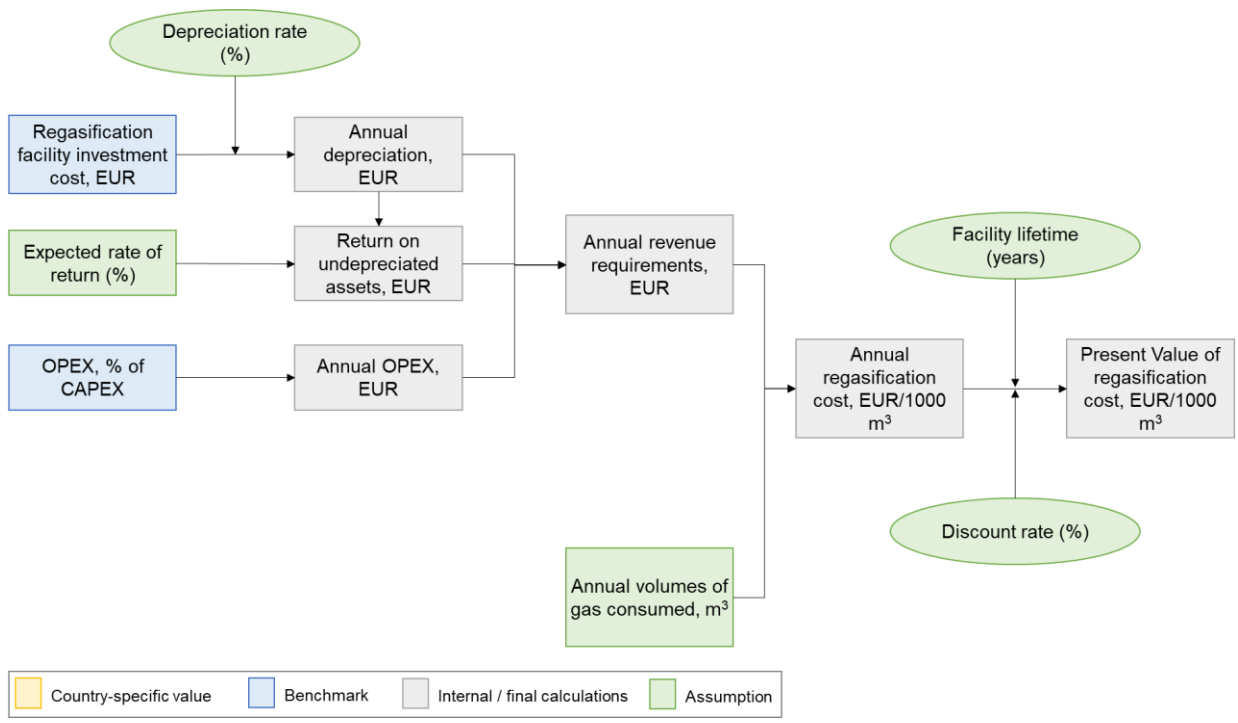
A2.4.4. Step 2: Definition of entry charges from regasification facility

An estimate for the tariff of the entry point connecting the LNG regasification facility to the transmission systems is made, based on the existing tariffs applied by Ukrtransgaz. We assume an entry tariff of 3.3 EUR/1000 m^3, equal to the tariff for gas storage withdrawal[145].

A2.4.5. Step 3: Calculation of receiving facility service fee

The service charge for the use of the LNG receiving facility (unloading, storage, regasification) is calculated as the present value of the required annual revenues (including recovery of all the facility's investment costs and operating expenses and a return on the assets) per volume of regasified gas, for the full duration of the facility's life cycle. The approach applied to calculate the service charge for the LNG receiving facility is presented in Figure A. 48.

Figure A. 48: Calculation of service charge for receiving facility



The average daily assumed send-out gas needs are 1.4 mcm/d (2,300 m^3 LNG/d). With a minimum stock requirement of 7 days, a storage of 16,100 m^3 should be installed. As a regasification facility of a significant size is required, to accommodate high pressure pumps

[145] Source: Ukrtransgaz Price List

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allowing injection in the transmission system, large boil-off gas handling system and pipings, multiple truck unloading bays, etc, benchmark unit costs of on-shore receiving terminals, adjusted for this particular case should be used. The benchmarks and assumptions used in the calculations of the service charge for the receiving facility are presented in Table A. 43.

Table A. 43: Values applied to calculate service charge for receiving facility

Item	Value
Receiving facility investment costs (EUR)	45,000,000[146]
Payback period (years)	20 (depreciation rate 5%)
Expected rate of return on investment / discount rate	10% (assuming that the infrastructure will be regulated)
Operating expenses	5% of investment costs[147]
Regasification service charge (EUR/1000 m^3)	**14.6**

A2.4.6. Step 4: Calculation of transportation cost for LNG truck

The cost for transporting the LNG volumes via truck from the receiving LNG terminal to the regasification facility is calculated as the present value of the required annual revenues (including recovery of all the LNG truck(s) investment costs and operating expenses and a return on the assets) per volume of transported LNG, for the full duration of the LNG truck's life cycle. The approach applied to calculate the transportation cost is presented in Figure A. 49.

[146] Estimation assuming unit installation cost of 150 USD/tpa, considering that unit cost of coastal terminal is around 175 USD/tpa, source: Oxford Institute for Energy Studies, "The Outlook for Floating Storage and Regasification Units", 2017

[147] Assumption based on regasification terminals

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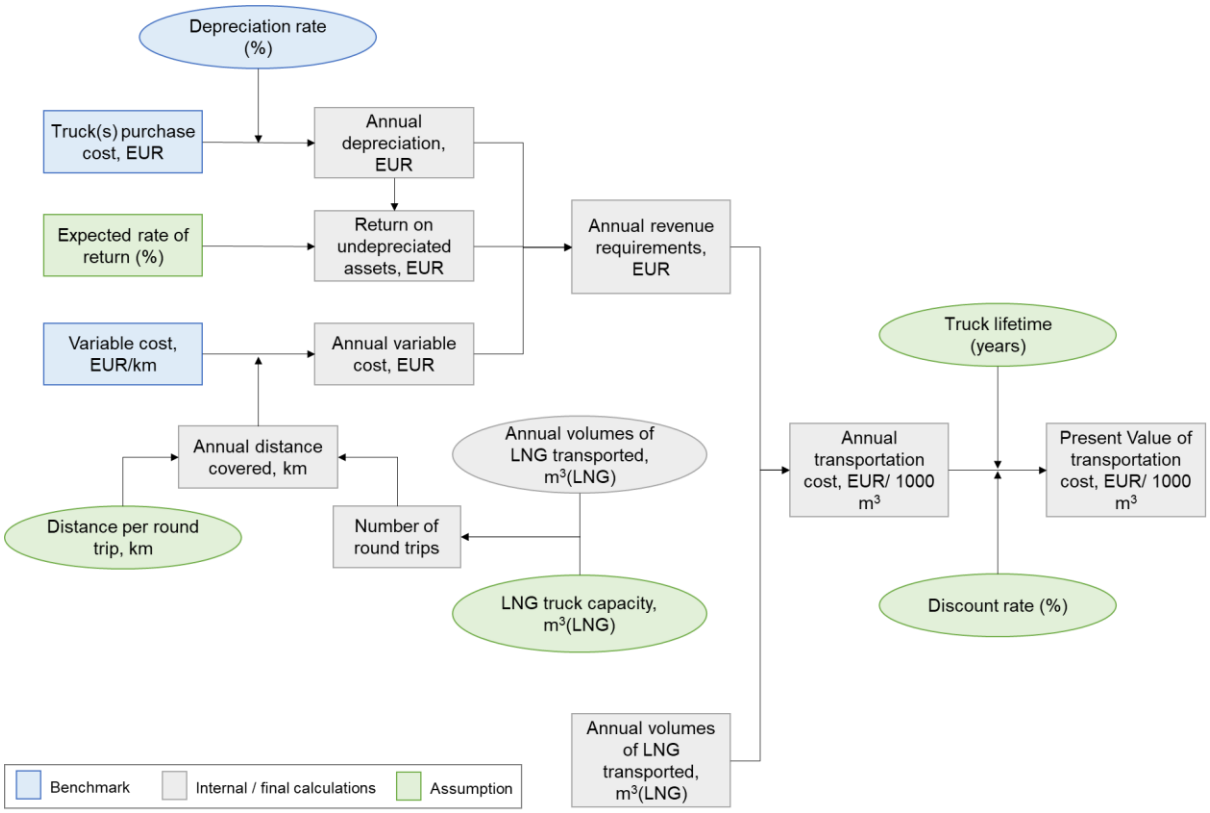
Figure A. 49: Calculation of transportation cost for LNG trucks



Based on the assumed send-out volumes of the regasification facility, on a daily basis at least 2,300 m3 of LNG have to be transported and stored. This would require a minimum of 46 LNG trucks with 50 m3 LNG capacity each operating on a year-round basis. To allow for contingencies, a fleet of 55 trucks is assumed. The distances considered are for a facility located in the western part of Ukraine. The assumptions and benchmarks applied in the calculation are presented in Table A. 44.

Table A. 44: Values applied to calculate LNG transportation cost

Item	Values per terminal	
	Świnoujście	*Klaipeda*
Number of trucks	55	
Cost per truck (EUR)	310,000[148]	
Life cycle of truck (years)	8 (depreciation rate 13%)[148]	
Expected rate of return on investment / discount rate	20%	
Variable cost (EUR/km)	1.45[148]	
LNG truck capacity (m^3(LNG))	50[148]	
Distance per round trip (km)	2,000	1,800
Annual volumes of LNG transported (thousand m^3 LNG)	833	
LNG transportation cost (EUR/1000 m^3)	**103.4**	**93.7**

[148] Source: Interview with Klaipedos Nafta

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A2.4.7. Step 5: Definition of LNG truck loading cost at neighbouring terminals

The price charged by the LNG terminals neighbouring to Eastern Partners (Świnoujście, Klaipeda reloading station) for LNG truck loading service is as follows[149]:

- In Świnoujście, the fee for truck loading service amounts to 10.4 EUR/1000m3 [150];
- In Klaipeda, the fee for truck loading service amounts to 24 EUR/1000 m^3. In this case, an additional fee is required for delivering LNG to the reloading station, from the FSRU or another source. Such a fee depends on the distance, availability of the vessels for certain delivery windows, and may range from around 24 – 70 EUR/1000 m3 [148]. For the purpose of this analysis we assume the minimum transportation cost to the LNG reloading station (24 EUR/m^3), and therefore the aggregate cost for truck loading in Klaipeda is 48 EUR/1000 m^3.

A2.4.8. Results of analysis

The results of the netback analysis for Ukraine, concerning the maximum LNG supply price at the neighbouring terminals, covering the 3 wholesale price scenarios (average, minimum, maximum) are presented in Table A. 45 Table A. 46 and Table A. 47 respectively.

Table A. 45: Calculated maximum competitive price of LNG supply to gas transmission customers, for average import price in Ukraine

Item	Values per terminal	
	Świnoujście	*Klaipeda*
Wholesale gas price in Ukraine (EUR/1000 m^3)	241	
Entry charges from regasification to transmission (EUR/1000 m^3)	*-3.3*	
Regasification cost (EUR/1000 m^3)	*-14.6*	
LNG transportation cost (EUR/1000 m^3)	*103.4*	*-93.7*
Truck loading cost (EUR/1000 m^3)	*-10.4*	*-48.0*
Maximum LNG price at the terminal (EUR/1000 m^3)	**109.3**	**81.4**

Table A. 46: Calculated maximum competitive price of LNG supply to gas transmission customers, for minimum import price in Ukraine

Item	Values per terminal	
	Świnoujście	*Klaipeda*
Wholesale gas price in Ukraine (EUR/1000 m^3)	198	
Entry charges from regasification to transmission (EUR/1000 m^3)	*-3.3*	
Regasification cost (EUR/1000 m^3)	*-14.6*	

[149] Prices in EUR/MWh have been converted to EUR/lt(LNG) using the GCV assumptions presented in Annex 7

[150] Source: Polskie LNG, "LNG Regasification Services Tariff", December 2018

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LNG transportation cost (EUR/1000 m^3)		*-93.7*
Truck loading cost (EUR/1000 m^3)	*-10.4*	*-48.0*
Maximum LNG price at the terminal (EUR/1000 m^3)	**66.3**	**38.4**

Table A. 47: Calculated maximum competitive price of LNG supply to gas transmission customers, for winter average import price in Ukraine

Item	Values per terminal	
	Świnoujście	*Klaipeda*
Wholesale gas price in Ukraine (EUR/1000 m^3)	257	
Entry charges from regasification to transmission (EUR/1000 m^3)	*-3.3*	
Regasification cost (EUR/1000 m^3)	*-14.6*	
LNG transportation cost (EUR/1000 m^3)		*-93.7*
Truck loading cost (EUR/1000 m^3)	*-10.4*	*-48.0*
Maximum LNG price at the terminal (EUR/1000 m^3)	**125.3**	**97.4**

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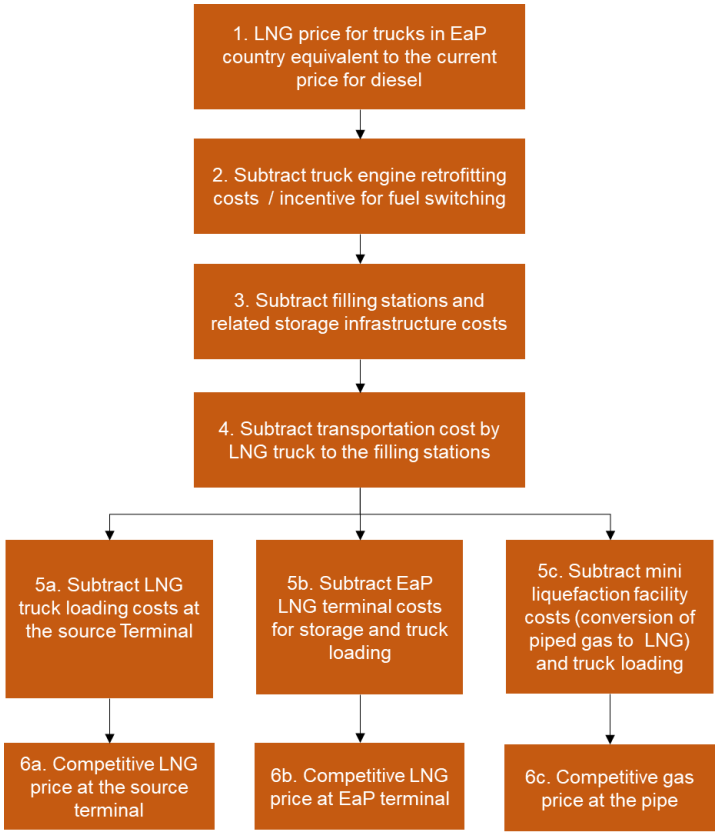
Annex 3: Netback Analysis – Gas-to-Other Fuels Competition

A3.1. Netback analysis for LNG as fuel for long-haul trucks

A3.1.1. Analysis approach

Figure A. 50 outlines the process of netback analysis for deriving the competitive LNG price in an Eastern Partner country for LNG to be used as fuel by trucks (converting long haul trucks currently running on diesel fuel to run on LNG).

Figure A. 50: Netback analysis to estimate competitive LNG price at the source, for LNG as fuel for long-haul trucks, in competition with diesel



The starting point (Step 1) for the analysis is the equivalent LNG price to the price/cost paid by trucks, for diesel, in the Eastern Partner country examined. It is noted that the equivalent LNG price takes into account the efficiency of LNG as a fuel versus diesel. From this equivalent LNG price, all costs to arrive at the competitive price of LNG at the source are sequentially estimated and subtracted: costs of retrofitting truck engines (Step 2), infrastructure costs for LNG filling stations (Step 3), the transportation costs of LNG by the LNG trucks to the filling stations (Step 4), and the cost of loading LNG to trucks at the source or the costs of liquefaction of gas from the pipeline in the case of a mini liquefaction facility (Steps 5 – 6).

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There are three potential variants for the LNG deliveries (LNG supply variants) from the source to the filling stations, each variant having different costs to be incurred under Steps 5 and 6:

a. (Steps 5a and 6a): The LNG trucks load and transport LNG from a terminal outside the Eastern Partner country.
b. (Steps 5b and 6b): The LNG trucks load and transport LNG from a terminal in the Eastern Partner country (regasification or liquefaction terminal), provided it is feasible for the country to have its own terminal.
c. (Steps 5c and 6c): A mini liquefaction facility is installed to convert pipeline gas to LNG, which is then loaded into LNG trucks for delivery to end-customers.

The resulting LNG price from the netback analysis is the price that needs to be compared to the regional price for spot LNG deliveries (in case LNG is sourced from a terminal) and/or the price of piped natural gas (in case LNG is produced using a liquefaction facility), so as to ascertain whether LNG is competitive to prices of diesel for the Eastern Partner country concerned.

It is noted that the diesel prices used in the analysis exclude VAT, but are inclusive excise taxes or any other taxes applied for the fuel. On the other hand, it is assumed that LNG used for transport will be exclusive of any taxes. Inclusion of taxes on the LNG price would decrease its competitiveness vis-à-vis diesel.

In case the information available for a country's long-haul trucks (number of local and transit trucks, destinations and distances covered) is not sufficiently detailed, it is not possible to make reasonable assumptions to estimate the market size for use of LNG in road transport. In these cases, instead of estimating the maximum LNG price for the option to be competitive, following sequentially the steps 1 – 6 of Figure A. 50, we assess the minimum LNG market size required in steps 3, 4 and 5 to achieve a competitive LNG / natural gas price at the beginning of the supply chain.

A3.1.2. Application in Eastern Partner countries

Based on the Consultant's analysis and the consultations with the countries' stakeholders, the use of LNG as fuel for long-haul trucks is an applicable option for Armenia, Azerbaijan, Belarus, Georgia and Ukraine. The LNG supply variants that are relevant to each Eastern Partner country differ (Table A. 48):

- LNG terminal outside the country: Relevant to Belarus and Ukraine for LNG supplied from the Świnoujście LNG terminal and Klaipeda FSRU and LNG reloading station[151], and to Armenia for LNG from a potential LNG terminal in Georgia.
- Eastern Partner LNG terminal: Relevant on to a receiving terminal with truck loading facilities developed in Georgia or Ukraine, which have direct access to the Black Sea, as well as a liquefaction terminal in Georgia, that could also be used to supply LNG to the region.

[151] For the Gas-to-Other fuels competition analysis, the LNG supply from the Klaipeda FSRU is examined together with the Klaipeda LNG reloading station.

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- Mini liquefaction facility: Relevant to all Eastern Partner countries, as the mini liquefaction facility will be directly connected to each country's transmission system.

Table A. 48: LNG supply variants for LNG-fueled trucks per Eastern Partner country

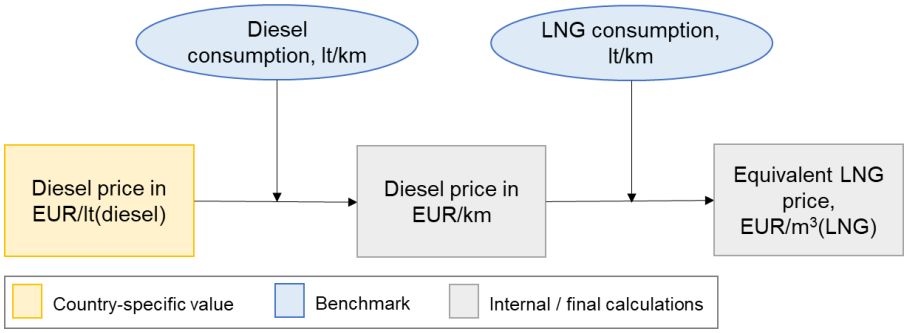
	Armenia	Azerbaijan	Belarus	Georgia	Ukraine
LNG Terminal outside country	✓		✓		✓
In-country LNG (receiving or liquefaction) terminal				✓	✓
Mini liquefaction facility	✓	✓	✓	✓	✓

Based on this context, the calculations for each of the netback analysis steps are described in the sections below.

A3.1.3. Step 1: Calculation of LNG equivalent price

The approach applied to calculate the LNG price equivalent to the diesel price at the pump is presented in Figure A. 51 below.

Figure A. 51: Calculation of LNG equivalent price



To provide contextualized estimates for each Eastern Partner country, we have applied current diesel prices per country. Table A. 49 below presents the values used to calculate the equivalent LNG price for each examined Eastern Partner country.

Table A. 49: Values applied to calculate LNG equivalent price

Item	Armenia	Azerbaijan	Belarus	Georgia	Ukraine
Diesel price (EUR/lt)	0.64[152]	0.26[153]	0.59[154]	0.71[155]	0.76[156]
Diesel consumption (lt/km)	0.326[157]				
LNG consumption (lt/km)	0.495[158]				

[152] Source: Maxoil website (accessed 1/11/2019)
[153] Source: Azpetrol website (accessed 1/11/2019)
[154] Source: Belarus Ministry of Energy
[155] Source: SOCAR Georgia website (accessed 1/11/2019)
[156] Source: https://index.minfin.com.ua/ua/markets/fuel/dt/ (accessed 1/11/2019)
[157] Source: International Council on Clean Transportation, "Fuel consumption testing of tractor trailers in the European Union and the United States", 2017
[158] Source: Volvo, "Volvo introduces new LNG truck", October 2017

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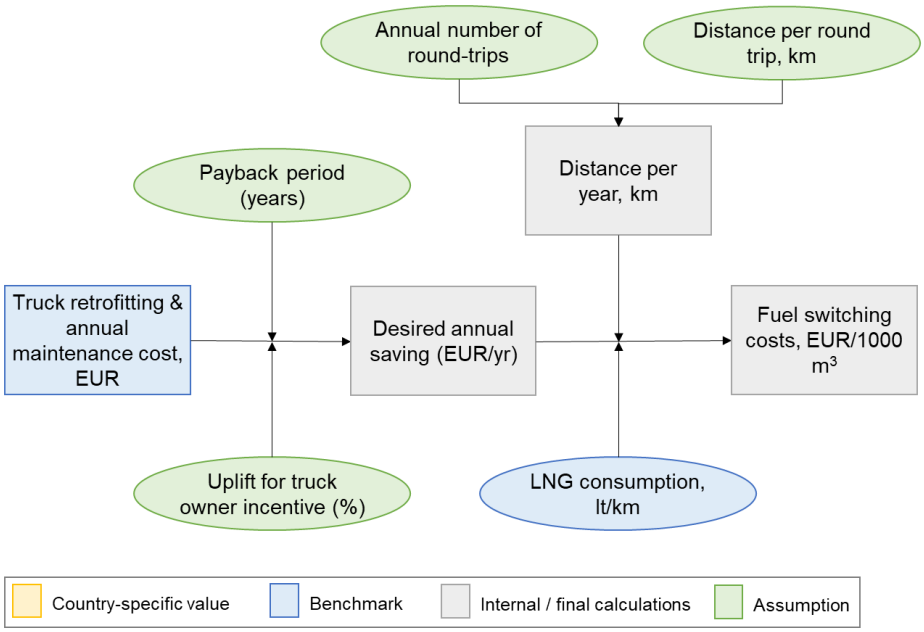
Item	Armenia	Azerbaijan	Belarus	Georgia	Ukraine
Equivalent LNG price EUR/m^3 (LNG)	**421.5**	**171.2**	**388.6**	**467.6**	**500.5**
Equivalent LNG price EUR/1000 m^3 (gas)	**702.5**	**285.4**	**647.6**	**779.3**	**834.2**

A3.1.4. Step 2: Calculation of costs for fuel switching

Fuel switching from diesel to LNG would require retrofitting of the truck engine, while the LNG price at the pump would have to be discounted compared to that of diesel, so that the truck owner can be incentivised to switch fuels.

The approach applied to calculate the costs (including incentives), for switching from diesel to LNG, is presented in Figure A. 52 below.

Figure A. 52: Calculation of costs for fuel switching



The calculations require a number of assumptions concerning the desired incentives of the truck owner (payback period of truck retrofitting costs, discounts on LNG price), as well as the use of the truck (number of round-trips per annum, distance of each round-trip). The applied assumptions and benchmarks are presented in Table A. 50. As there are no country-specific elements in the calculations the same values apply for all examined Eastern Partner countries.

Table A. 50: Values applied to calculate LNG switching costs

Item	Value per country				
	Armenia	*Azerbaijan*	*Belarus*	*Georgia*	*Ukraine*
Retrofitting costs (EUR)	22,000[159]				
Payback period requirement (years)	5				

[159] Assumption based on reported range of prices from various sources

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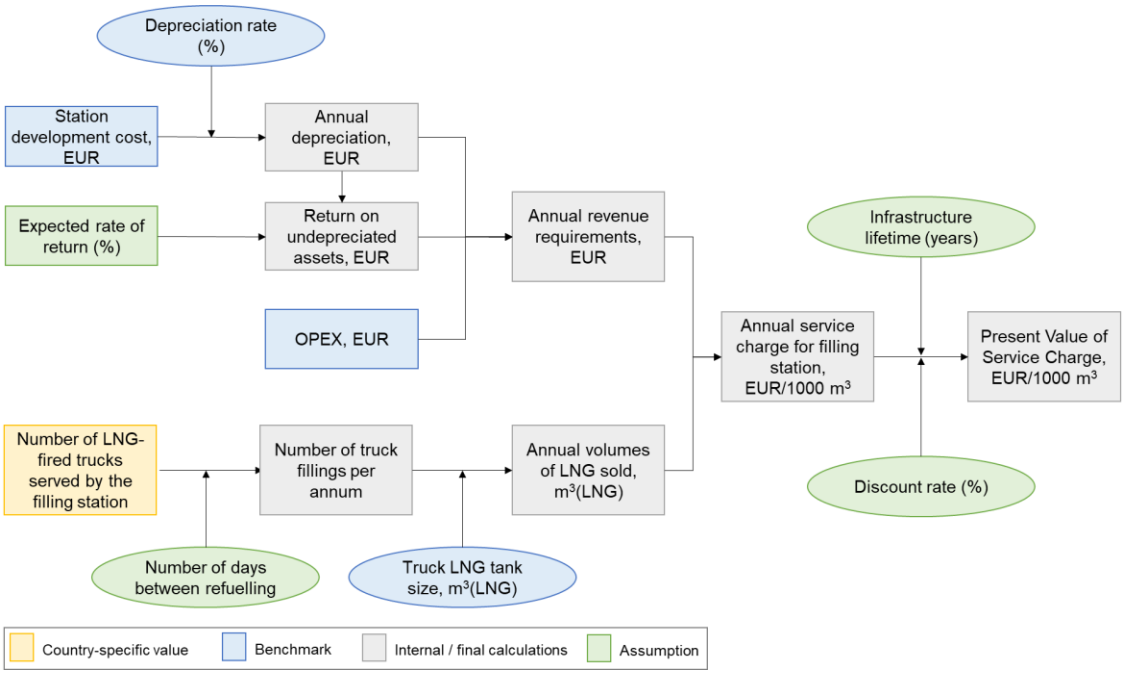
Additional maintenance cost for LNG (EUR/yr)	2,000[160]
Uplift for truck-owner incentive (%)	25%
Number of annual round-trips	91 (corresponding to 1 trip per 4 days)
Distance per round-trip (km)	1,000 (corresponding to 1 LNG tank filling)
LNG consumption (lt/km)	0.495
LNG switching costs EUR/1000 m^3	**296.00**

A3.1.5. Step 3: Calculation of service charge for LNG filling station

The service charge for the use of the LNG filling station is calculated as the present value of the required annual revenues (including recovery of all the station's investment costs and operating expenses and a return on the assets) per volume of supplied LNG, for the full duration of the filling station's life cycle. The approach applied to calculate the service charge for the LNG filling station is presented in Figure A. 53.

Figure A. 53: Calculation of service charge for filling station



Due to the lack of transport data of sufficient detail to make reasonable assumptions on the potential number of LNG-fired trucks in each Eastern Partner country, the minimum number of trucks for this LNG option to be viable are estimated as part of this netback analysis.

The assumptions and benchmarks applied in the calculation are presented in Table A. 51. It is noted that these calculations are based on the development of a new LNG filling station. The potential upgrade of an existing fuel station or development of an L-CNG station could lead to reduced costs, due to reduction in operating expenses and economies of scale in investment costs.

[160] Source: I. Smajla et al. (Energies Journal)," Fuel Switch to LNG in Heavy Truck Traffic", 2019

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Table A. 51: Values applied to calculate ser

Item	Value per country				
	Armenia	*Azerbaijan*	*Belarus*	*Georgia*	*Ukraine*
Filling station investment costs (EUR)	555,000 (including cost for filling station development 528,000 EUR[161], for filling station with 4 truck slots, and assuming cost of land of 27,000 EUR)				
Filling station operating expenses (EUR)	119,500[161] (including staff costs for 24/7 operation of the station)				
Life cycle of filling station (years)	10 (depreciation rate 10%)[161]				
Expected rate of return on investment / discount rate	20%				
Days between truck refueling	4				
Truck LNG tank size (lt(LNG))	495[158]				
Number of LNG-fired trucks	Minimum number to be calculated through netback analysis				

A3.1.6. Step 4: Calculation of transportation cost for LNG truck

The approach applied to calculate the cost for transporting LNG from its source (LNG terminal or liquefaction facility) to the receiving facility is the same with the one presented in Figure A. 49, in Section A2.4.6.

The annual volumes of LNG transported are equal to the gas volumes supplied at the filling station, defined in Step 3, and thus dependent on the number of LNG-fired trucks (the minimum number of which will is estimated as part of the netback analysis).

The distance travelled by the LNG truck depends on the LNG variant examined. For the case of LNG terminals outside the examined Eastern Partner country, separate calculations are carried out for each relevant terminal. For the case of developing a liquefaction facility in the Eastern Partner country, the facility is assumed to be close to the filling station.

The assumptions and benchmarks applied in the calculation are presented in Table A. 52.

Table A. 52: Values applied to calculate LNG transportation cost

Item	Value per country				
	Armenia	*Azerbaijan*	*Belarus*	*Georgia*	*Ukraine*
Truck cost (EUR)	310,000[148] (cost for one truck – cost for additional trucks is estimated in case more LNG transportation capacity is required)				
Life cycle of truck (years)	8 (depreciation rate 13%)[148]				
Expected rate of return on investment / discount rate	20%				
Variable cost (EUR/km)	1.45[148]				
LNG truck capacity (m^3(LNG))	50[148]				
Distance per round trip (from Świnoujście LNG terminal)	N/A	N/A	2,400	N/A	2,800
Distance per round trip (from Klaipeda LNG terminal) (km)	N/A	N/A	1,000	N/A	2,000

[161] Source: NGVA Europe, EC 7th Framework Programme, "Cost analysis of LNG refuelling stations", 2016

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Distance per round trip (from Ukraine LNG terminal) (km)	N/A	N/A	N/A	N/A	1,200
Distance per round trip (from Georgia LNG terminal) (km)	1,100	N/A	N/A	600	N/A
Distance per round trip (from in-country liquefaction facility) (km)	20	20	20	20	20
Annual volumes of LNG transported	Depends on the number of LNG-fired trucks (defined in step 3)				

A3.1.7. Steps 5a-6a: Calculation of LNG truck loading cost at neighboring terminals

The truck loading costs for Świnoujście and Klaipeda LNG terminals are applied (Table A. 53), as described in Section A2.4.7.

Table A. 53: Values used for LNG truck loading

Terminal	Truck loading cost (EUR/1000m^3)
Świnoujście LNG terminal	10.4
Klaipeda LNG terminal	48 (including transportation from terminal to reloading station and truck loading)

A3.1.8. Steps 5b-6b: Calculation of LNG truck loading cost at terminals in Eastern Partner countries

In this analysis we assume that the potential LNG receiving terminals in Ukraine and Georgia will be FSRUs, in which case on-shore LNG reloading stations will be required. The LNG truck loading costs are assumed to be similar to those defined in Step 5a for Klaipeda, i.e. 48 EUR/1000 m^3.

In case of development of an on-shore liquefaction terminal in Georgia, the LNG truck loading costs are assumed to be similar to those defined in Step 5a for Świnoujście (10.4 EUR/ 1000 m^3). In this case, a charge for liquefaction service must also be included in the calculations (corresponding to the liquefaction terminal tariff calculated in Section A2.3.5).

Table A. 54 summarizes the values used for LNG truck loading costs at each examined terminal (Steps 5a and 5b).

Table A. 54: Values used for LNG truck loading

Terminal	Truck loading cost (EUR/1000m^3)
Świnoujście LNG terminal	10.4
Klaipeda LNG terminal	48 (including transportation from terminal to reloading station and truck loading)
Ukraine LNG terminal	48 (as in Klaipeda)
Georgia LNG receiving terminal	48 (as in Klaipeda)
Georgia liquefaction terminal	117.8 (includes liquefaction tariff, and truck loading as in Świnoujście)

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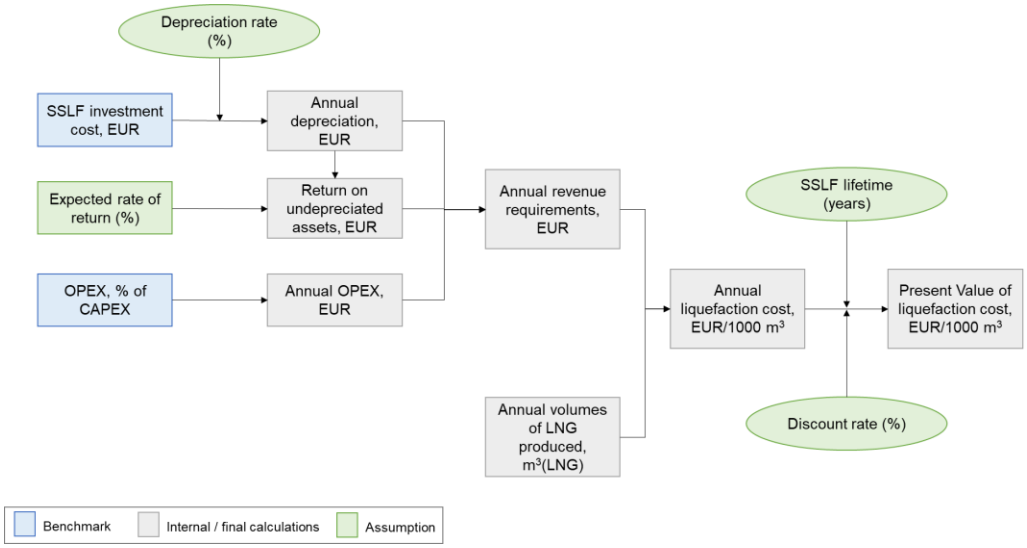
A3.1.9. Steps 5c-6c: Calculation of liquefaction cost at mini liquefaction facility

The cost for producing LNG at a liquefaction facility is calculated as the present value of the required annual revenues (including recovery of all the investment costs and operating expenses and a return on the assets) per volume of produced LNG, for the full duration of the liquefaction facility's life cycle. The approach applied to calculate the cost of gas liquefaction is presented in Figure A. 54.

Figure A. 54: Calculation of gas liquefaction costs



The annual volumes of LNG produced are equal to the gas volumes supplied at the filling station, defined in Step 3, and thus dependent on the number of LNG-fired trucks (the minimum number of which is estimated as part of the netback analysis). Furthermore, the capacity of the mini liquefaction facility (and therefore its investment requirements) depends on the estimated size of the market. It is noted that a benchmark average investment cost for liquefaction facilities[162] is applied in the calculations, not taking into consideration a specific liquefaction process. The assumptions and benchmarks applied in the calculation are presented in Table A. 55.

Table A. 55: Values applied to calculate gas liquefaction cost

Item	Value per country				
	Armenia	*Azerbaijan*	*Belarus*	*Georgia*	*Ukraine*
Liquefaction facility investment cost (EUR)	7,700,000 – 12,500,000 (for capacities ranging from 16 ton/d to 50 ton/d of LNG production)[162]				
Life cycle of truck (years)	20 (depreciation rate 5%)				
Expected rate of return on investment / discount rate	20%				
Operating expenses	2% of investment costs[163]				

[162] Source: World Bank, "Mini / Micro LNG for commercialization of small volumes of associated gas", 2015

[163] Source: Lantau Group, "Pricing of LNG from Small Scale Facilities – Some Examples from Indonesia and Thailand", 2012

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A3.1.10. Results of analysis

The available information on the Eastern Partner countries' transport sector is not of sufficient granularity to allow identification of the number of long-haul trucks operating in the country (nationally or as transit), and therefore we make reasonable assumptions on the prospective penetration of LNG-fired trucks. For this reason, the analysis carried out estimated the minimum number of LNG-fired trucks that are required in the country, in order for this LNG option to be commercially attractive, under specific assumptions of LNG and natural gas supply prices.

Five price scenarios at the beginning of the supply chain have been examined for each supply variant, covering the current LNG or natural gas price (depending on the variant) and sensitivity analysis for its potential increase (+25% and +50%) or decrease (-15% and -25%). The assumed LNG prices (Table A. 56) depend on the LNG terminal (same for all countries supplied by the terminal), while natural gas prices for liquefaction (Table A. 57) are country specific, and include the wholesale price and transmission costs for transporting the gas up to the liquefaction facility.

Table A. 56: LNG prices at LNG terminals examined

Terminal	Assumed price at terminal (EUR/1000m3)				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Świnoujście LNG terminal[164]	200	250	300	170	150
Klaipeda LNG terminal[165]	200	250	300	170	150
Ukraine LNG terminal[166]	220	275	330	187	165
Georgia LNG receiving terminal[166]	220	275	330	187	165
Georgia liquefaction terminal[167]	222	277	333	189	166

Table A. 57: Natural gas prices for liquefaction examined

Country	Assumed price at liquefaction facility (EUR/1000m3)				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Armenia[168]	183	229	275	155	137
Azerbaijan[169]	85	107	128	72	64
Belarus[170]	234	293	351	200	175
Georgia[171]	222	277	333	189	166
Ukraine[172]	254	318	381	216	190

[164] As information is not available, the same price as Klaipeda is used

[165] Source: DG Energy, "Gas Market Report Q2 2019"

[166] The price for LNG in Black Sea (Ukraine and Georgia) is assumed to be the price at the Greek Revythoussa terminal (210 EUR/1000m3, source: DG Energy, "Gas Market Report Q2 2019"), with an uplift of 5% to reflect additional transportation cost and crossing through the Bosporus straits.

[167] Equal to the gas price in the Georgian market (Source: GEOSTAT)

[168] Source: PSRC, "Tariffs for natural gas supply to consumers"

[169] Source; Azerbaijan Tariff Council, "Natural gas processing, transportation, wholesale and retail tariffs", 2019

[170] Source: Ministry of Energy

[171] Price for with demand band 2.5 – 25 mcm/yr , source: GEOSTAT, "Data on Consumer Prices of Electricity and Natural Gas, 2019"

[172] Average wholesale price for September 2018 – September 2019 (Source: Ukrainian Energy Exchange), plus transportation tariff (Source: UTG)

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The calculation results (minimum volumes of LNG and minimum number of LNG-fired trucks) per country and LNG supply variant, for the five price scenarios are presented in the Tables below. Only the supply variants relevant to each country are presented. It is noted that the cases in which the minimum LNG market size is calculated to be over 1,000 LNG-fuelled trucks are not presented in the Tables, as a high penetration of LNG in transport would be required in the relevant country compared to the EU experience (around 6,000 trucks across EU in 2019[173]).

Armenia

Table A. 58: Minimum number of LNG-fired trucks for Armenia

LNG supply variant	Minimum number of LNG-fired trucks				
	Price scenario				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Georgia LNG receiving terminal	134	454	-	97	82
Georgia liquefaction terminal	-	-	-	298	167
Mini liquefaction facility in-country	339	505	786	290	271

Table A. 59: Minimum LNG volumes supplied annually for Armenia

LNG supply variant	Minimum number LNG volumes supplied (m^3 LNG/yr)				
	Price scenario				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Georgia LNG receiving terminal	6,048	20,485	-	4,384	3,697
Georgia liquefaction terminal	-	-	-	13,482	7,534
Mini liquefaction facility in-country	15,295	22,789	35,499	13,120	12,240

Azerbaijan

The very low diesel price (0.26 EUR/lt) results in an equivalent LNG price (285.4 EUR/1000 m^3) that is lower than the required switching costs (296 EUR/1000 m^3). Consequently, introduction of LNG is not possible at a competitive price.

Belarus

Table A. 60: Minimum number of LNG-fired trucks for Belarus

LNG supply variant	Minimum number of LNG-fired trucks				
	Price scenario				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Świnoujście LNG terminal	-	-	-	210	155
Klaipeda LNG terminal	205	-	-	134	109
Mini liquefaction facility in-country	-	-	-	604	480

Table A. 61: Minimum LNG volumes supplied annually for Belarus

LNG supply variant	Minimum number LNG volumes supplied (m^3 LNG/yr)				
	Price scenario				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Świnoujście LNG terminal	N/A	-	-	9,492	6,982
Klaipeda LNG terminal	9,281	-	-	6,050	4,925
Mini liquefaction facility in-country	-	-	-	27,302	21,678

[173] Source: NGVA, "NGVA Europe marks the 200th European LNG fuelling station with a revamp of its stations map", May 2019

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Georgia

Table A. 62: Minimum number of LNG-fired trucks for Georgia

LNG supply variant	Minimum number of LNG-fired trucks				
	Price scenario				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Georgia LNG receiving terminal	62	87	149	53	50
Georgia liquefaction terminal	101	195	N/A	79	68
Mini liquefaction facility in-country	279	379	642	248	230

Table A. 63: Minimum LNG volumes supplied annually for Georgia

LNG supply variant	Minimum number LNG volumes supplied (m^3 LNG/yr)				
	Price scenario				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Georgia LNG receiving terminal	2,791	3,948	6,749	2,375	2,255
Georgia liquefaction terminal	4,573	8,807	N/A	3,554	3,072
Mini liquefaction facility in-country	12,624	17,098	28,978	11,204	10,389

Ukraine

Table A. 64: Minimum number of LNG-fired trucks for Ukraine

LNG supply variant	Minimum number of LNG-fired trucks				
	Price scenario				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Świnoujście LNG terminal	60	82	125	52	48
Klaipeda LNG terminal	60	80	123	52	47
Ukraine LNG terminal	54	73	112	47	43
Mini liquefaction facility in-country	256	353	583	227	210

Table A. 65: Minimum LNG volumes supplied annually for Ukraine

LNG supply variant	Minimum number LNG volumes supplied (m^3 LNG/yr)				
	Price scenario				
	Base price	*+25%*	*+50%*	*-15%*	*-25%*
Świnoujście LNG terminal	2,731	3,710	5,650	2,370	2,172
Klaipeda LNG terminal	2,691	3,628	5,536	2,334	2,141
Ukraine LNG terminal	2,462	3,315	5,074	2,128	1,958
Mini liquefaction facility in-country	11,584	15,943	26,324	10,232	9,465

A3.2. Netback analysis for LNG supply to off-grid distribution systems

A3.2.1. Analysis approach

Figure A. 55 outlines the process of netback analysis for deriving the competitive LNG price in an Eastern Partner country in the case LNG is used as a transportation modality of natural gas to an off-grid distribution system, the potential retail end-customers of which are currently using alternative fuels (e.g. oil products or firewood).

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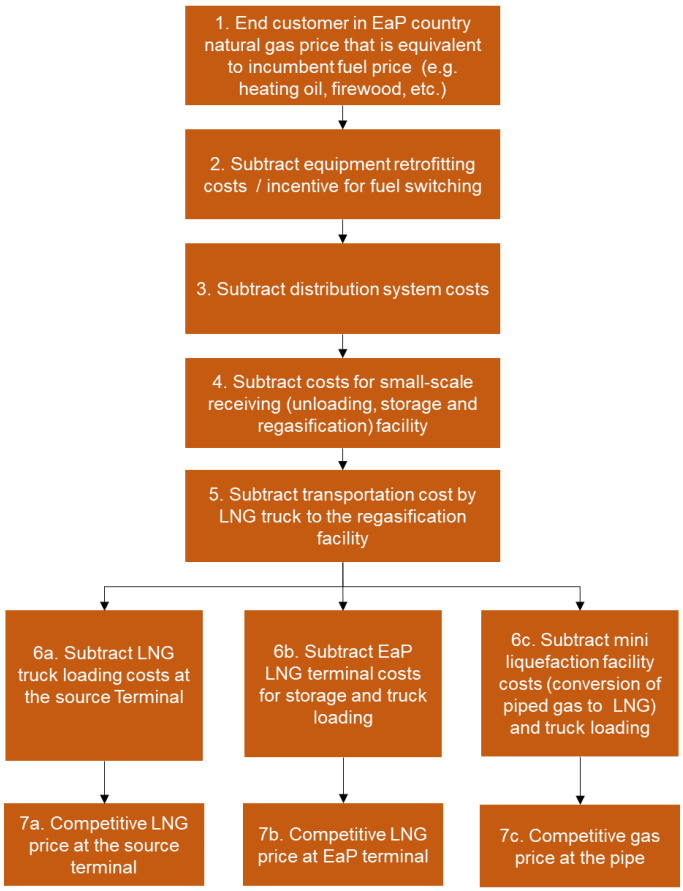
Figure A. 55: Netback analysis to estimate competitive LNG price at the source, for LNG used to supply off-grid distribution systems



The starting point (Step 1) for the analysis is the equivalent natural gas price to the price that end-customers pay, in the Eastern Partner country examined, for the alternative fuel, for the specific use. It is noted that the equivalent gas price takes into account the efficiency of natural gas versus the competing fuel. From this equivalent gas price, all costs to arrive at the competitive price of LNG at the source are sequentially estimated and subtracted: costs of retrofitting equipment to burn gas (Step 2), costs for development, operation and maintenance of the local distribution system (Step 3), infrastructure cost for a small scale unloading, storage and regasification facility connected to the distribution system (Step 4), transportation costs of LNG by the LNG trucks to the regasification facility (Step 5), and the cost of loading LNG to trucks at the source or the costs of liquefaction of gas from the pipeline in the case of a mini liquefaction facility (Steps 6 – 7).

As in the case of LNG as fuel for long-haul trucks, there are three potential LNG supply variants from the source to the regasification terminal, including:

a. (Steps 6a and 7a): The LNG trucks load and transport LNG from a terminal outside the Eastern Partner country.
b. (Steps 6b and 7b): The LNG trucks load and transport LNG from a terminal in the Eastern Partner country (regasification or liquefaction terminal), provided it is feasible for the country to have its own terminal.

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c. (Steps 6c and 7c): A mini liquefaction facility is installed to convert pipeline gas to LNG, which is then loaded into LNG trucks for delivery to end-customers.

The resulting LNG price from the netback analysis is the price that needs to be compared to the regional price for spot LNG deliveries (in case LNG is sourced from a terminal) and/or the price of piped natural gas (in case LNG is produced using a mini liquefaction facility), so as to ascertain whether LNG is competitive to prices of competing fuels for off-grid retail end-customers in the Eastern Partner country concerned.

It is noted that the prices of competing fuels used in the analysis exclude VAT, but are inclusive excise taxes or any other taxes applied. On the other hand, it is assumed that the sourced LNG used to supply the distribution system will be exclusive of any taxes. Inclusion of taxes on the LNG price would decrease its competitiveness vis-à-vis the competing fuel.

A3.2.2. Application in Eastern Partner countries

Based on the Consultant's analysis and the consultations with the countries' stakeholders, the use of LNG to supply off-grid distribution systems is an applicable option for Azerbaijan and Georgia.

For Georgia, the LNG supply variants applicable are the development of an LNG receiving or liquefaction terminal in the country, or the use of a mini liquefaction facility.

For Azerbaijan, the LNG supply variant applicable is the use of a mini liquefaction facility connected to the Azeri transmission system.

Calculations for the use of LNG to supply distribution system in ungasified towns in Georgia are provided as a case study, using inputs provided by the Ministry of Economy and Sustainable Development of Georgia. The examined towns, which have not yet been gasified as they are in mountainous regions, include Chiatura, Oni, Aspindza, Borjomi and Mestia. The analysis assumes that only households, currently using firewood (the dominant fuel in urban areas outside big cities in Georgia), will switch to gas. The netback analysis performed focuses on the unit costs for a single residential consumer in Chiatura.

Based on this context, the calculations for each of the netback analysis steps are described in the sections below.

A3.2.3. Step 1: Calculation of natural gas equivalent price

The approach applied to calculate the natural gas price equivalent to that of firewood at the end-consumer is presented in Figure A. 56 below. It is noted that the existing firewood consumption in urban areas of Georgia (3.1 m^3/yr per household[174]) is significantly lower than that of other countries (e.g. 12 m^3/yr per household in Italy[175]). This indicates that the use of firewood in Georgia is not a typical one, and consequently the heating volumes used do not correspond to

[174] Source: GEOSTAT, "Energy Consumption in Households", 2017

[175] Source: VVT, "Manual for Firewood Production, 2008, http://www.biomasstradecentre2.eu/data/upload/D5_5_Manual_firewood_production_biohousing.pdf

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other fuels. To allow comparability between firewood, we estimate the cost of firewood required to produce the same energy as natural gas being used by households in Georgia.

Figure A. 56: Calculation of natural gas equivalent price

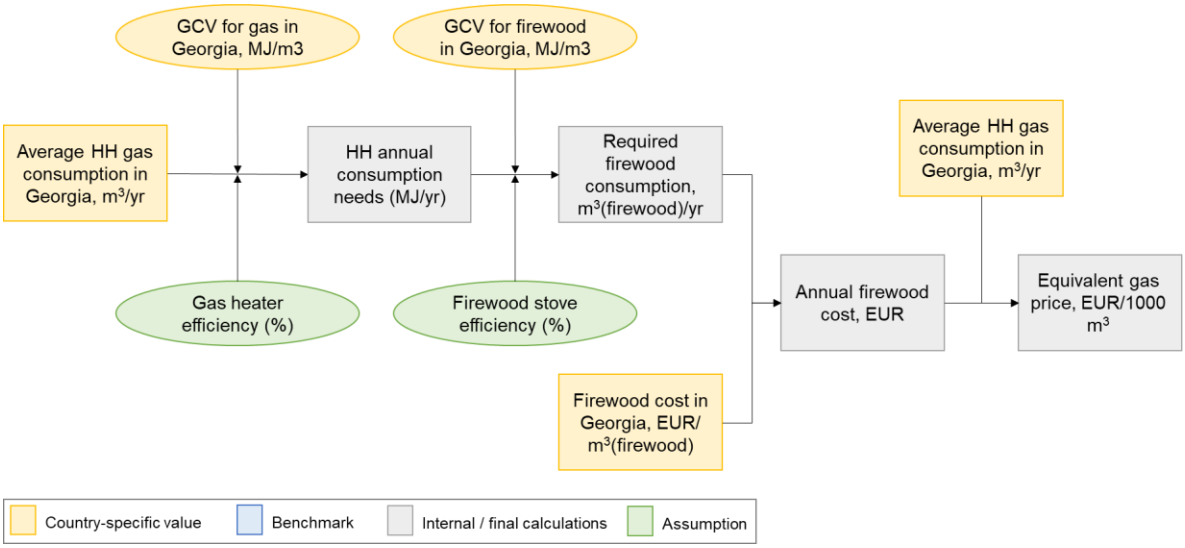

Table A. 66 below presents the values used to calculate the equivalent natural gas price.

Table A. 66: Values applied to calculate LNG equivalent price

Item	Value
Average HH natural gas consumption in Georgia (m^3)	1,100[174]
GCV for natural gas in Georgia (MJ/m^3)	35.0[176]
Gas heater efficiency	90%[177]
GCV for firewood in Georgia (MJ/m^3 firewood)	7,800[174]
Firewood stove efficiency	30%[177]
Firewood cost in Georgia (EUR/m^3 firewood)	20.8[174]
Annual cost for firewood per HH (EUR)	**308.0**
Equivalent natural gas price (EUR/1000 m^3)	**280.0**

A3.2.4. Step 2: Calculation of costs for fuel switching

Fuel switching from firewood to natural gas would require development of a gas installation at the end customer (service line and internal installation), while the gas retail price would have to be discounted compared to that of alternative fuels, so that the consumer can be incentivised to switch.

The approach applied to calculate the costs (including incentives), for switching from firewood to gas, is presented in Figure A. 57 below.

[176] Source: GEOSTAT, Energy Balance 2018

[177] Assumption based on input requirements of such equipment

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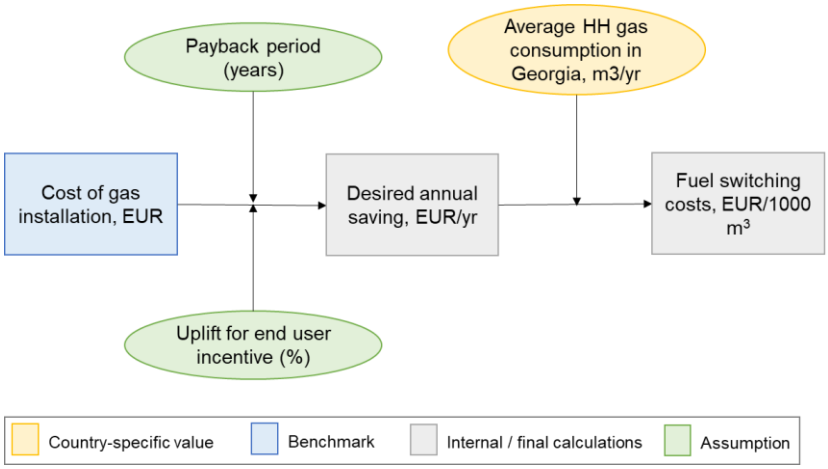
Figure A. 57: Calculation of costs for fuel switching



The calculations require assumptions concerning the desired incentives of the end user, i.e. the payback period of internal installation costs and discounts on gas price. The values used in the calculation are presented in Table A. 67.

Table A. 67: Values applied to calculate gas switching costs

Item	Value
Cost of gas installation (EUR)	3,000[178] (internal installation plus connection)
Payback period (years)	10[178]
Uplift for end consumer incentive (%)	20% (of competing fuel price) [178]
Average HH natural gas consumption in Georgia (m^3/yr)	1,100[174]
Fuel switching cost (EUR/1000 m^3)	**328.7**

A3.2.5. Step 3: Calculation of Distribution system costs

As the examined towns are not gasified, a new gas distribution system has to be developed, operated and maintained, to supply end consumers with gas.

As a benchmark for the distribution costs, we apply the 2019 approved distribution tariff of Socar Georgia Gas LLC (68.3 EUR/1000m^3)[179]. The particular DSO has been selected due to its extensive expansion plan (obligation under the distribution license) that resulted in recent gasification of new regions.

A3.2.6. Step 4: Calculation of small-scale receiving facility service fee

The service charge for the use of the small-scale LNG receiving facility (unloading, storage, regasification) is calculated as the present value of the required annual revenues (including recovery of all the facility's investment costs and operating expenses and a return on the assets)

[178] Estimates based on relevant values in distribution systems of EU countries

[179] Source: GNERC, "Report on Activities of 2018", 2019. The tariff applied is indicative, used for the high-level calculations. The actual tariff of the distribution system can be quite different, depending on the system's characteristics, size and utilization.

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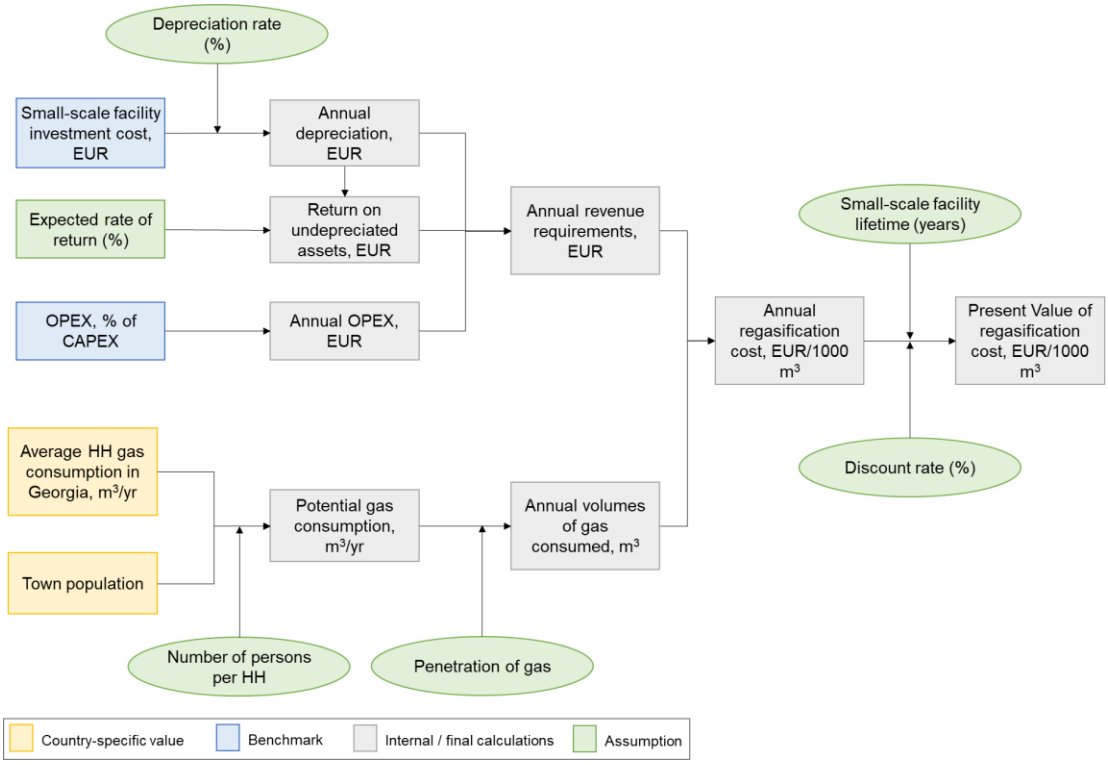
per volume of regasified gas, for the full duration of the facility's life cycle. The approach applied to calculate the service charge for the receiving facility is presented in Figure A. 58.

Figure A. 58: Calculation of service charge for receiving facility



The calculation of gas consumption for each town to be gasified (Table A. 68) is based on the population and average consumption per household. The assumed penetration of gas is based on the experience from mature gas markets, and not the current penetration in Georgia; gradual penetration from 30% to 70% in 4 years is assumed.

Table A. 68: Calculation of gas consumption per gasified town

Item	Value per Town				
	Chiatura	Oni	Aspindza	Borjomi	Mestia
Population[180]	12,803	2,656	2,793	10,546	1,973
Persons per HH	3				
Average HH natural gas consumption in Georgia (m^3/yr)	1,100[174]				
Penetration rate	Gradual penetration: Y1: 30% | Y2: 40% | Y3: 55% | Y4: 70%				
Annual gas consumption at maximum penetration (70%) (mcm)	**3.29**	**0.68**	**0.72**	**2.71**	**0.51**

A small-scale receiving facility has to be installed in each distribution system, to allow supply of the concerned end consumers. The sizing of each receiving facility depends on the gas volumes required in the town, and especially the gas storage needs, as the storage capacity is the main cost driver for the facility. Given that gas consumption in householders is highly seasonal (80%

[180] Source: GEOSTAT, "Population by regions and self-governed units", 2018

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of annual demand corresponds to the November-April period[179]), storage capacity must be designed to cover peak winter demand. In the examined town of Chiatura, considering the 80% annual demand in winter period, average daily demand in winter is estimated at 14,600 m^3/d. The receiving facility for Chiatura is assumed to have LNG storage capacity of 350 m^3, allowing sufficiency for 14 days.

The benchmarks and assumptions used in the calculations of the service charge for the small-scale receiving facility in Chiatura are presented in Table A. 69.

Table A. 69: Values applied to calculate service charge for receiving facility

Item	Value
Small-scale facility investment costs (EUR)	950,000 (for 350 m^3 storage)[181]
Payback period (years)	10 (depreciation rate 10%)
Expected rate of return on investment / discount rate	10% (assuming that the infrastructure will be regulated and operated by DSO)
Operating expenses	5% of investment costs[182]
Regasification service charge (EUR/1000 m^3)	**70.40**

A3.2.7. Step 5: Calculation of transportation cost for LNG truck

The approach applied to calculate the cost for transporting LNG from its source (LNG terminal or liquefaction facility) to the receiving facility is the same with the one presented in Figure A. 49, in Section A2.4.6.

Given that the same LNG trucks will be used to supply all gasified towns, the estimated costs should cover transportation of LNG to all regions. The number of trips to each of the towns depends on the corresponding consumption. Table A. 70 presents the LNG trucks' travel requirements (distance weighted with gas volume transported) to each town, starting from an LNG terminal in the Black Sea or a liquefaction facility located in the middle of the country.

Table A. 70: LNG truck travel requirements from LNG terminal and liquefaction facility

	LNG Terminal			Liquefaction Facility		
	Distance (one-way) (km)	Volumes transported ('000 m^3 LNG)	Weighted distance (km)	Distance (one-way) (km)	Volumes transported ('000 m^3 LNG)	Weighted distance (km)
Chiatura	170	5.5	71	73	5.5	30
Oni	220	1.1	19	100	1.1	9
Aspindza	270	1.2	25	206	1.2	19
Borjomi	225	4.5	77	130	4.5	45
Mestia	200	0.9	13	221	0.9	14
TOTAL		**13.2**	**204**		**13.2**	**116**

[181] Estimate based on storage investment cost range of 800 – 3000 USD/m^3 (IGU, "2012 – 2015 Triennium Work Report – Small Scale LNG", 2015). It is assumed that a 3,000 USD/m^3 unit cost is required to cover all facility expenses (storage tanks, piping, vaporizers, control system, operating room, etc.)

[182] Assumption based on regasification terminals

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The assumptions and benchmarks applied in the calculation of the LNG transportation costs are presented in Table A. 71.

Table A. 71: Values applied to calculate LNG transportation cost

Item	Value
Truck cost (EUR)	620,000[148] (cost for two trucks)
Life cycle of truck (years)	8 (depreciation rate 13%)[148]
Expected rate of return on investment / discount rate	20%
Variable cost (EUR/km)	1.45[148]
LNG truck capacity (m^3(LNG))	50[148]
Distance per round trip from LNG terminal (km)	408
Distance per round trip from liquefaction facility (km)	232
Annual volumes of LNG transported (thousand m^3 LNG)	13.2
LNG transportation cost from LNG terminal (EUR/1000 m^3)	**49.9**
LNG transportation cost from liquefaction (EUR/1000 m^3)	**38.8**

A3.2.8. Steps 6a-7a: Calculation of LNG truck loading cost at neighboring terminals

Not relevant in this case study.

A3.2.9. Steps 6b-7b: Calculation of LNG truck loading cost at terminals in Eastern Partner countries

As in the case of LNG as fuel for long-haul trucks the LNG truck loading costs for the LNG receiving terminal are assumed to be similar to those for Klaipeda (48 EUR/1000 m^3), and for the LNG liquefaction plant similar to those defined for Świnoujście (10.4 EUR/ 1000 m^3).

In the case of the liquefaction plant, a charge for liquefaction service must also be included in the calculations (corresponding to the liquefaction terminal tariff calculated in Section A2.3.5).

A3.2.10. Steps 6c-7c: Calculation of Liquefaction cost at mini liquefaction facility

The approach applied to calculate the liquefaction cost is the same with the one presented in Figure A. 54, for the case of LNG as fuel for long-haul trucks.

The annual volumes of LNG produced are equal to the gas volumes required for all gasified towns.

The assumptions and benchmarks applied in the calculation are presented in Table A. 72.

Table A. 72: Values applied to calculate gas liquefaction cost

Item	Value
Liquefaction facility investment cost (EUR)	7,700,000 (for capacity of 16 tons/d)[162]
Life cycle of truck (years)	20 (depreciation rate 5%)
Expected rate of return on investment / discount rate	10% (due to its importance for the market, it is assumed that a single regulated facility will be developed)
Operating expenses	2% of investment costs[163]
Liquefaction cost (EUR/1000 m^3)	**146.8**

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A3.2.11. Results of analysis

In this case study, the costs for switching from firewood to gas (including gas installation costs and a 20% price differential incentive) are higher (329 EUR/1000m^3) than the gas equivalent price for firewood (280 EUR/1000m^3). Under these conditions, use of gas for the examined towns is not considered attractive.

A3.3. Netback analysis for LNG supply to off-grid individual consumers

A3.3.1. Analysis approach

Figure A. 59 outlines the process of netback analysis for deriving the competitive LNG price in an Eastern Partner country in the case LNG is used as a transportation modality of natural gas to an off-grid final consumer, such as a farming facility or mining facility located away from the transmission system.

The starting point (Step 1) for the analysis is the equivalent natural gas price to the price that end-customers pay, in the Eastern Partner country examined, for the alternative fuel, for the specific use. It is noted that the equivalent gas price takes into account the efficiency of natural gas versus the competing fuel. From this equivalent gas price, all costs to arrive at the competitive price of LNG at the source are sequentially estimated and subtracted: costs of retrofitting equipment to burn gas (Step 2), infrastructure cost for a small scale unloading, storage and regasification facility at the site of the consumer (Step 3), transportation costs of LNG by the LNG trucks to the regasification facility (Step 4), and the cost of loading LNG to trucks at the source or the costs of liquefaction of gas from the pipeline in the case of a mini liquefaction facility (Steps 5 – 6).

As in the other LNG options, there are three potential LNG supply variants from the source to the regasification terminal, including:

a. (Steps 5a and 6a): The LNG trucks load and transport LNG from a terminal outside the Eastern Partner country.
b. (Steps 5b and 6b): The LNG trucks load and transport LNG from a terminal in the Eastern Partner country (regasification or liquefaction terminal), provided it is feasible for the country to have its own terminal.
c. (Steps 5c and 6c): A mini liquefaction facility is installed to convert pipeline gas to LNG, which is then loaded into LNG trucks for delivery to end-customers.

The resulting LNG price from the netback analysis is the price that needs to be compared to the regional price for spot LNG deliveries (in case LNG is sourced from a terminal) and/or the price of piped natural gas (in case LNG is produced using a mini liquefaction facility), so as to ascertain whether LNG is competitive to prices of competing fuels for off-grid end-customers in the Eastern Partner country concerned.

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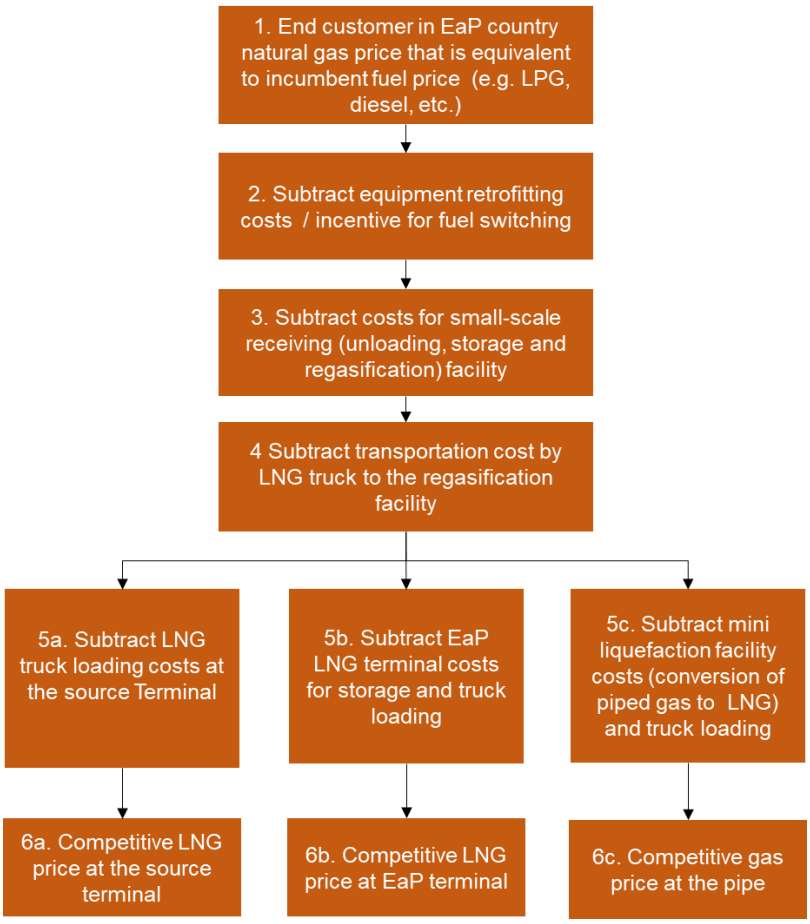
Figure A. 59: Netback analysis to estimate competitive LNG price at the source, for LNG used to supply off-grid consumers



It is noted that the prices of competing fuels used in the analysis exclude VAT, but are inclusive excise taxes or any other taxes applied. On the other hand, it is assumed that the sourced LNG used to supply the off-grid consumer will be exclusive of any taxes. Inclusion of taxes on the LNG price would decrease its competitiveness vis-à-vis the competing fuel.

A3.3.2. Application in Eastern Partner countries

Based on the Consultant's analysis and the consultations with the countries' stakeholders, the use of LNG to supply off-grid consumers is an applicable option for Ukraine.

The LNG supply variants applicable to Ukraine include supply from the Świnoujście LNG terminal and Klaipeda FSRU and LNG reloading station, an LNG receiving terminal developed in Ukraine, and a mini liquefaction facility connected to the Ukrainian transmission system.

The attractiveness of this LNG option may differ for each individual off-grid consumer, as the particular characteristics of the consumer (competing fuel used, consumption requirements and distance from the system) determine whether switching to natural gas would be viable.

In this Study we provide an indicative example, for supply of LNG to a regasification facility of an agriculture site located in the southern part of Ukraine, that cannot be connected to the

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transmission system, due to the lack of gas pressure reduction station capacity. It is assumed that the current fuel used is LPG. The agriculture site operates corn driers that require total natural gas consumption of 2,700 m^3/h. The average drying season is from September – November, i.e. 70-80 days, during which the driers would operate on a continuous basis. Consequently, the annual gas consumption of the site is estimated at 5,184,000 m^3/yr.

Based on this context, the calculations for each of the netback analysis steps are described in the sections below.

A3.3.3. Step 1: Calculation of natural gas equivalent price

The approach applied to calculate the natural gas price equivalent to that of LPG at the end-consumer is presented in Figure A. 60 below.

Figure A. 60: Calculation of natural gas equivalent price

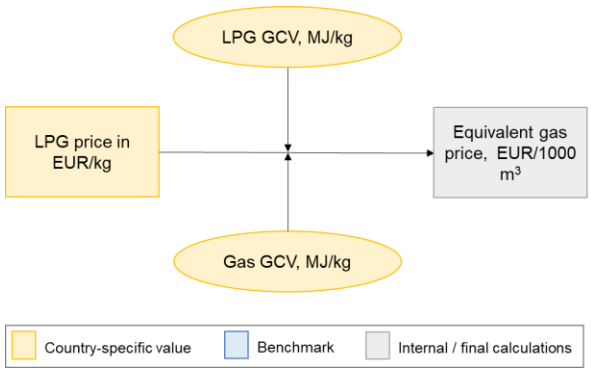

Table A. 73 below presents the values used to calculate the equivalent natural gas price.

Table A. 73: Values applied to calculate LNG equivalent price

Item	Value
LPG price (EUR/kg)[183]	0.75
GCV for LPG in Ukraine (MJ/kg)[184]	46.9
GCV for firewood in Georgia (MJ/m^3)[185]	31.8
Equivalent natural gas price (EUR/1000 m^3)	**508.5**

A3.3.4. Step 2: Calculation of costs for fuel switching

It is assumed that the existing driers used are in need for replacement, and therefore the same investment requirements are applied for new infrastructure of either LPG or natural gas (the additional costs for an LNG receiving facility required to use natural gas is examined in Step 3 of the analysis).

Furthermore, due to the significant price differential of LPG and natural gas, it is assumed that no additional price incentives are necessary for the consumer to switch to gas.

[183] Source: https://index.minfin.com.ua/ua/markets/fuel/detail/ (accessed 1/11/2019)

[184] Based on Ukrainian Standards DSTU 4047-2001

[185] Based on Ukrainian Standards GOST 5542-2014

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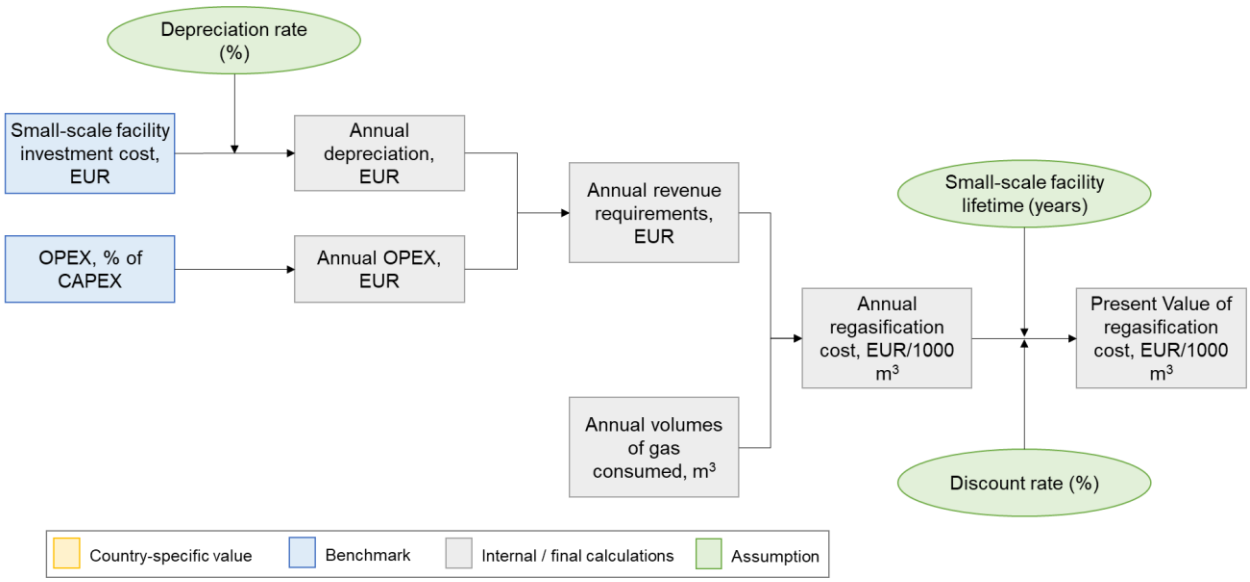
A3.3.5. Step 3: Calculation of small-scale receiving facility cost

The approach applied to calculate the cost for the small-scale LNG receiving facility (unloading, storage, regasification) is presented in Figure A. 61. As this facility will be owned and operated by the consumer, no additional return on the assets is estimated.

Figure A. 61: Calculation of cost for receiving facility



The size of the small-scale receiving facility is driven by the daily gas needs during the drying season (64,800 m^3/d). An LNG storage of 480 m^3 is assumed, allowing refilling every 4 days.

The benchmarks and assumptions used in the calculations are presented in Table A. 74.

Table A. 74: Values applied to calculate service charge for receiving facility

Item	Value
Small-scale facility investment costs (EUR)	1,300,000 (for 480 m^3 storage)[181]
Payback period (years)	10 (depreciation rate 10%)
Operating expenses	5% of investment costs[182]
Annual gas volumes (m^3/yr)	5,184,000
Regasification cost (EUR/1000 m^3)	**37.6**

A3.3.6. Step 4: Calculation of transportation cost for LNG truck

The approach applied to calculate the cost for transporting LNG from its source (LNG terminal or liquefaction facility) to the receiving facility is the same with the one presented in Figure A. 49, in Section A2.4.6.

The assumptions and benchmarks applied in the calculation of the LNG transportation costs are presented in Table A. 75. Depending on the supply variant, a different number of LNG trucks is required to cover demand needs; three trucks will be required to cover the needs of the facility for its 80 days of operation from the terminals outside the country due to the large distances to be covered, two trucks are sufficient to transport supplies from the terminal in Ukraine, an a single

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truck from a liquefaction terminal near the facility. The round-trip distance for each LNG supply variant is depicted in the Table.

Table A. 75: Values applied to calculate LNG transportation cost

Item	Values per LNG supply variant			
	Świnoujście	*Klaipeda*	*Ukraine*	*Liquefaction*
Truck cost (EUR)	930,000[148] (cost for three trucks)		620,000	310,000
Life cycle of truck (years)	8 (depreciation rate 13%)[148]			
Expected rate of return on investment / discount rate	20%			
Variable cost (EUR/km)	1.45[148]			
LNG truck capacity (m^3(LNG))	50[148]			
Distance per round trip (km)	3,600	2,800	200	50
Annual volumes of LNG transported	8,637			
LNG transportation cost (EUR/1000 m^3)	**216.6**	**177.8**	**37.9**	**16.2**

A3.3.7. Steps 5a/b-6a/b: Calculation of LNG truck loading cost

The truck loading costs for Świnoujście and Klaipeda LNG terminals are applied, as presented in Table A. 76 below.

Table A. 76: Values used for LNG truck loading

Terminal	Truck loading cost (EUR/1000m^3)
Świnoujście LNG terminal	10.4
Klaipeda LNG terminal	48 (including transportation from terminal to reloading station and truck loading)
Ukraine LNG terminal	48 (as in Klaipeda)

A3.3.8. Steps 5c-6c: Calculation of Liquefaction cost at mini liquefaction facility

The approach applied to calculate the liquefaction cost is the same with the one presented in Figure A. 54, for the case of LNG as fuel for long-haul trucks.

The size of the liquefaction facility should allow coverage of daily gas demand during the drying period (over 45 tons/d). For this reason, a liquefaction capacity of 50 tons/d is assumed.

The assumptions and benchmarks applied in the calculation are presented in Table A. 77.

Table A. 77: Values applied to calculate gas liquefaction cost

Item	Value
Liquefaction facility investment cost (EUR)	12,500,000 (for capacity of 50 tons/d)[162]
Life cycle of facility (years)	20 (depreciation rate 5%)
Expected rate of return on investment / discount rate	20%
Operating expenses	2% of investment costs[163]
Liquefaction cost (EUR/1000 m^3)	**470.2**

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A3.3.9. Results of analysis

The results of the netback analysis for this case study, concerning the maximum supply price of LNG at the receiving terminals and natural gas at the entry of the mini liquefaction facility, are presented in Table A. 78 below.

Table A. 78: Calculated maximum competitive LNG/gas price at the source per supply variant

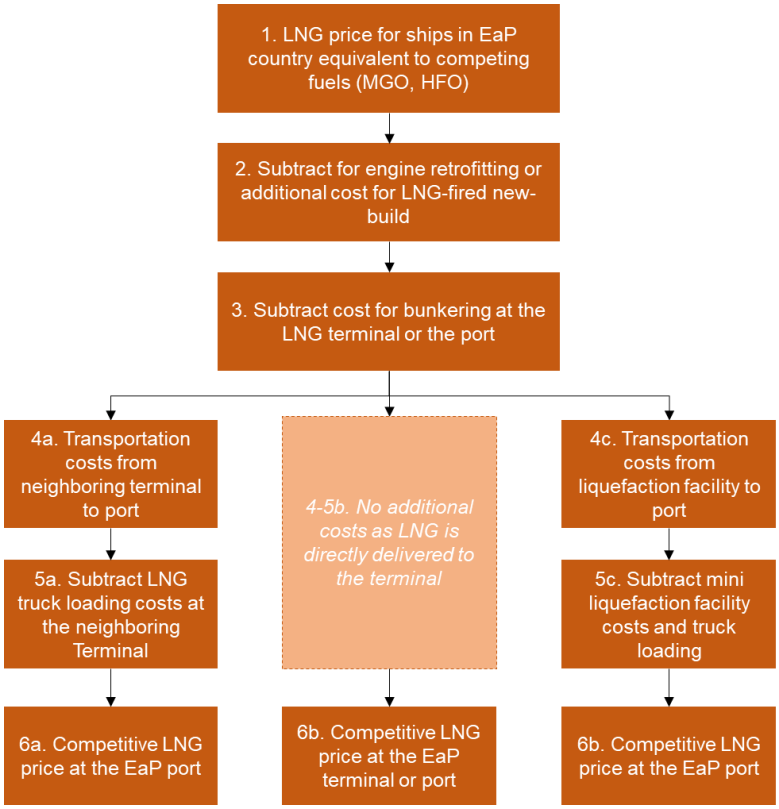
Item	LNG supply variant			
	Świnoujście	*Klaipeda*	*Ukraine*	*Liquefaction*
Equivalent natural gas price (EUR/1000 m³)	508.5			
Regasification cost (EUR/1000 m³)	*- 37.6*			
LNG transportation cost (EUR/1000 m³)	*- 216.6*	*- 177.8*	*- 37.9*	*- 16.5*
Truck loading / liquefaction cost (EUR/1000 m³)	*- 10.4*	*- 48.0*	*-48.0*	*- 470.2*
Maximum LNG/gas price at the source (EUR/1000 m³)	**243.9**	**246.1**	**386.0**	**-15.8**

A3.4. Netback analysis for LNG as fuel for ships

A3.4.1. Analysis approach

Figure A. 62 outlines the process of netback analysis for deriving the competitive LNG price in an Eastern Partner country for LNG to be used as fuel by ships (either converting ships currently running on oil products to run on LNG, or constructing newbuilds that run on LNG).

Figure A. 62: Netback analysis to estimate competitive LNG price at the source, for LNG as fuel for ships, in competition with oil products



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The starting point (Step 1) for the analysis is the equivalent LNG price to the price/cost paid by ships, for the existing fuel (MGO, HFO), in the Eastern Partner country examined. It is noted that the equivalent LNG price takes into account the efficiency of LNG as a fuel versus the existing fuel. From this equivalent LNG price, all costs to arrive at the competitive price of LNG at the source are sequentially estimated and subtracted: costs of retrofitting the ship or additional cost for a newbuild LNG-fuelled ship (Step 2), bunkering costs at the LNG terminal or port (Step 3), and, in case LNG has to be delivered to the port via LNG trucks, the cost of transporting LNG (Step 5) and of loading it to trucks at the source or the costs of liquefaction of gas from the pipeline (Steps 5 – 6).

Three supply variants can be considered, each variant having different costs to be incurred under Steps 4 and 5:

a. (Steps 4a and 5a): The LNG trucks load and transport LNG from a terminal outside the Eastern Partner country.
b. (Steps 4b and 5b): LNG for bunkering is directly delivered to an LNG terminal (or port) in the Eastern Partner country, provided it is feasible for the country to have its own terminal. This allows direct bunkering from the terminal or port, without any additional transportation costs incurred.
c. (Steps 5c and 6c): A mini liquefaction facility is installed to convert pipeline gas to LNG, which is then loaded into LNG trucks for delivery to the port.

The resulting LNG price from the netback analysis is the price that needs to be compared to the regional price for spot LNG deliveries (in case LNG is sourced from a terminal) and/or the price of piped natural gas (in case LNG is produced using a liquefaction facility), so as to ascertain whether LNG is competitive to prices of other bunkering fuel for the Eastern Partner country concerned.

It is noted that the prices of competing fuels used in the analysis exclude VAT, but are inclusive excise taxes or any other taxes applied for the fuel. On the other hand, it is assumed that LNG used for transport will be exclusive of any taxes. Inclusion of taxes on the LNG price would decrease its competitiveness vis-à-vis the competing fuel.

A3.4.2. Application in Eastern Partner countries

Based on the Consultant's analysis and the consultations with the countries' stakeholders, the use of LNG as a fuel for ships is an applicable option for Azerbaijan, Belarus and Ukraine.

The potential use of LNG as a bunkering fuel for existing ships in the region, to cover international obligations (IMO rule to the ships' sulphur emissions from 3.5% to 0.5% as of 1/1/2020) competes with alternative solutions such as the use of scrubbers or low sulphur fuel oil. So far retrofitting of ships in operation to run on LNG has not been the preferred option outside Emission Control Areas, as the retrofitting cost has been considered higher than that of alternative solutions. In this respect, and with cost being the driver to switch to LNG, the case of promoting the use of LNG in newbuilds appears to have more potential than retrofitting existing ships.

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The attractiveness of this LNG option differs for each individual case of ship, as it depends on a number of factors, including the vessel's size and type, age, service area, fuel used, refuelling pattern, prices of competing fuels, etc.

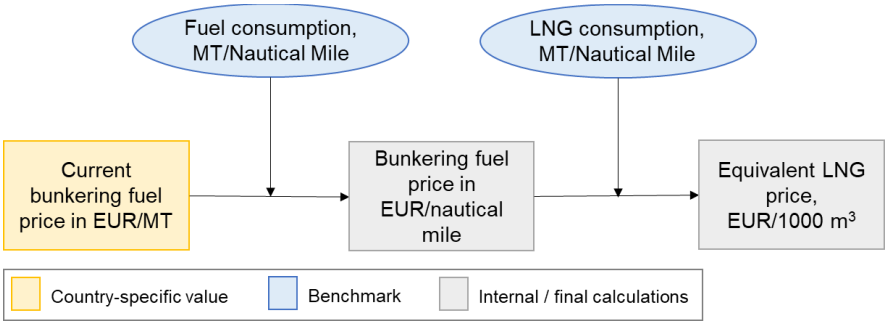
In this Study we provide an indicative example, for the use of LNG in shipping. The case of a newbuild 50,000 MT PANAMAX type vessel operating in the Black Sea, with LNG and MGO as competing fuels. It is assumed that the ship will perform 30 roundtrips per annum, covering a distance of 1,500 nautical miles per roundtrip. Bunkering is assumed to take place at an LNG terminal in Ukraine, consequently Steps 4 and 5 of the netback analysis (that concern costs for the transportation of LNG to ports via trucks) are omitted[186].

Based on this context, the calculations for each of the netback analysis steps are described in the sections below.

A3.4.3. Step 1: Calculation of LNG equivalent price

The approach applied to calculate the LNG price equivalent to that of MGO is presented in Figure A. 63 below.

Figure A. 63: Calculation of LNG equivalent price



The fuel price used to perform the case study is based on the price level of MGO at the Istanbul port, as an indicative competing price. Table A. 79 presents the values used to calculate the equivalent LNG price.

Table A. 79: Values applied to calculate LNG equivalent price

Item	Value
Bunker fuel price (EUR/MT)	600[187]
Fuel consumption (MT/Nautical Mile)	0.063[188]
LNG consumption (MT/Nautical Mile)	0.051[188]
Equivalent LNG price EUR/1000 m³	**566.9**

[186] The calculation of costs for steps 4 and 5 would follow the same approach as the one in Sections A3.1.6, A3.1.7 and A3.1.9.

[187] Assumption based on MGO price at the Istanbul port

[188] Source: Sangsoo Hwang et al. (Journal of Marine Science and Engineering), "Life Cycle Assessment of LNG Fuelled Vessel in Domestic Services", 2019. Note: Values correspond to a low service speed of 14 knots. Higher speed would lead to increase in fuel consumption.

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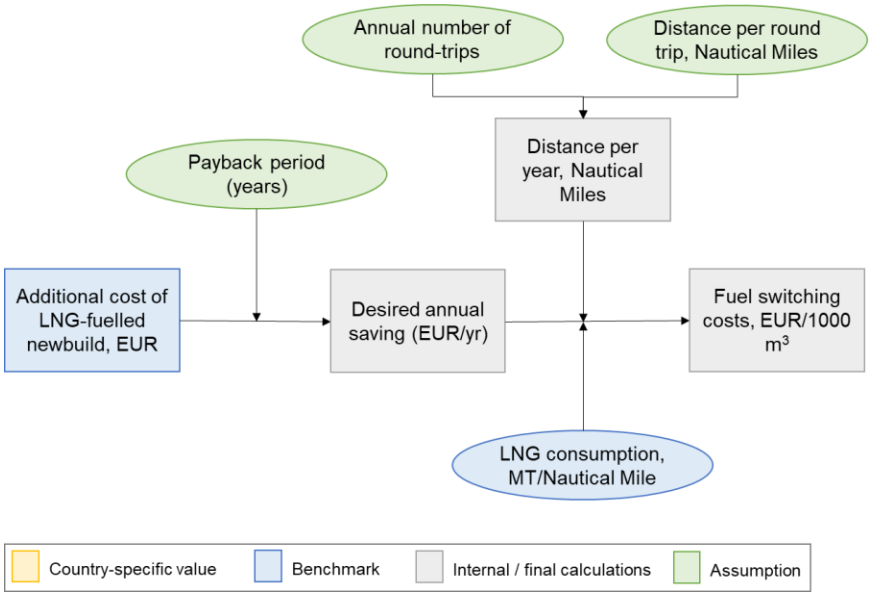
A3.4.4. Step 2: Calculation of costs for fuel switching

The cost of a newbuild running on LNG is higher than that of ships using conventional bunkering fuels. The recovery of this additional cost should be taken into consideration in the analysis of the option's financial viability. The approach applied to include this additional cost in the analysis is presented in Figure A. 64.

Figure A. 64: Calculation of costs for fuel switching



The applied assumptions and benchmarks are presented in Table A. 80.

Table A. 80: Values applied to calculate LNG switching costs

Item	Value
Additional cost for newbuild LNG ship (EUR)	9,000,000[189]
Payback period requirement (years)	15 years[189]
Number of annual round-trips	30
Distance per round-trip (Nautical Miles)	1,500
LNG consumption (MT/Nautical Mile)	0.051
LNG switching costs EUR/1000 m^3	**218.4**

A3.4.5. Step 3: Definition of bunkering costs

As a benchmark for the cost of bunkering at the LNG terminal, we use the fee charged for bunkering of vessels at the Klaipeda reloading facility, 24 EUR/1000 m^3.

Potential environmental discounts offered in the port tariffs for LNG-fuelled ships are not taken into consideration in the analysis of this case study.

[189] Based on shipping sector sources

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A3.4.6. Results of analysis

The results of the netback analysis for this case study, concerning the maximum supply price of LNG at the terminal for bunkering purposes, are presented in Table A. 81.

Table A. 81: Calculated maximum competitive price for LNG bunkering at the LNG terminal

Item	Value
Equivalent natural gas price (EUR/1000 m^3)	566.9
LNG switching costs (EUR/1000 m^3)	*-218.4*
LNG bunkering costs (EUR/1000 m^3)	*-24*
Maximum LNG price at the terminal (EUR/1000 m^3)	**324.6**

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Annex 4: Economic Analysis – Gas-to-Gas Competition

A4.1. Economic analysis for LNG receiving terminal in Eastern Partner country

A4.1.1. Analysis approach

The aim of the economic (cost-benefit) analysis to assess whether the costs for developing and operating an in-country LNG receiving terminal are outweighed by its potential benefits to the economy and society. The economic analysis is applied only for the cases that, according to the netback analysis, are not viable, and therefore additional benefits for the society should be achieved, for the LNG market option to be implemented.

The approach followed is in accordance with the EC CBA Guide for infrastructure investments[190].

The costs and monetized benefits assessed are the following:

- Costs:
  - Investment costs for the development of the terminal;
  - Annual operating costs;
  - Premium paid to import LNG to the market, in case the supply price of LNG to the market (including all transportation costs) is higher than that of piped gas, and LNG is imported only for security of supply purposes.
- Monetized benefits:
  - Enhancement of security of supply, by examining the economic impact of reducing gas demand curtailment in case of a supply disruption;
  - Reduction of energy costs for final consumers, in case the supply price of LNG to the market (including all transportation costs) is lower than that of piped gas.

The monetization of security of supply benefits covers only the cases of short-term disruptions that cannot be addressed with the existing infrastructure. In case long-term supply gaps emerge in the market, due to the lack of sufficient infrastructure, the alternative options to address them (including development of the LNG terminal) should be analysed in detail to identify the optimal and cost-effective solution for the market. Therefore, long-term gaps are not examined in terms of security of supply within the frame of this Study.

For the examined scenarios in which the assumed LNG import price at the terminal is higher than the market price, and therefore not competitive, it is assumed that the operation of the terminal will be only for security of supply purposes. In this case, the terminal annually receives LNG volumes sufficient to cover a supply disruption in the market, which are sold at a loss in case the disruption is not realised.

[190] DG Regio (2015) EC CBA Guide for infrastructure investments, available at: https://ec.europa.eu/regional_policy/sources/docgener/studies/pdf/cba_guide.pdf

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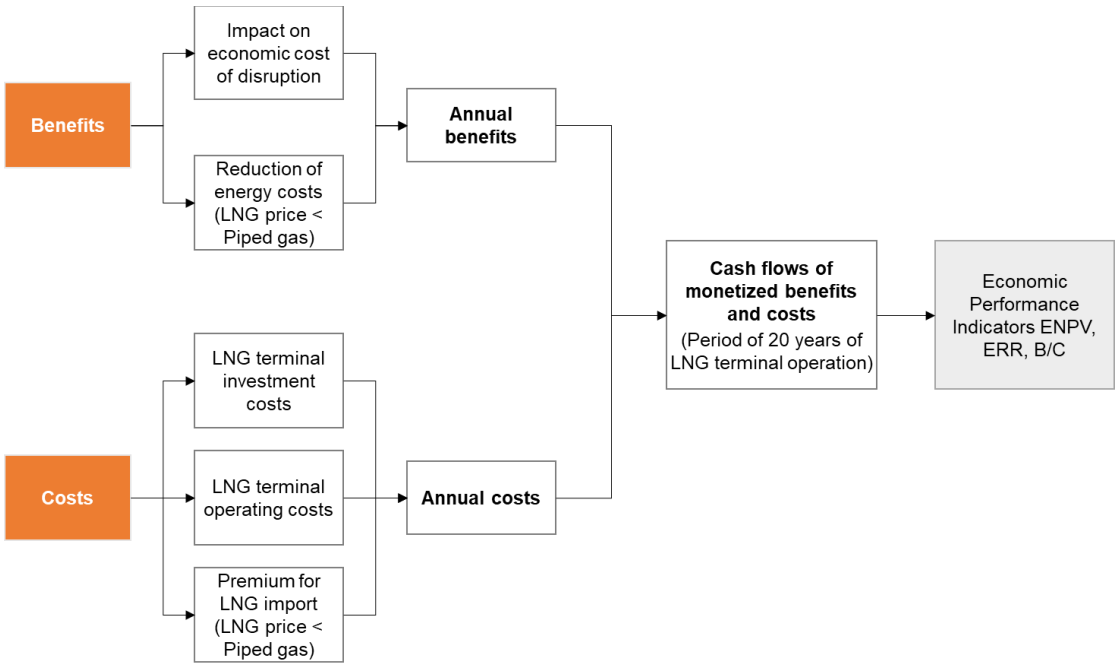
The economic analysis was carried out for a 20-year period of the LNG terminal operation. As the development of the infrastructure (FSRU and supporting infrastructure) would require at least 2-3 years, we assume that imports of LNG in the market would commence in 2023, and the full period of the analysis is 2023 – 2042.

The analysis results in the estimation of the key economic performance indicators; the Economic Net Present Value (ENPV), Economic Rate of Return (ERR), and Benefit-to-Cost ratio (B/C). A social discount rate of 4% has been applied in the calculations, in line with those used by the Energy Community in the PECI evaluation[191].

Figure A. 65: Assessment of costs and benefits



It is noted that the analysis carried out is high-level, based on assumptions on gas/LNG supply prices and market demand for LNG, without examining dynamic supply-demand curves. The results of this analysis can be used to draw preliminary conclusions, whereas for a more detailed view of the projects' economic performance modelling of the markets evolution is required.

A4.1.2. Application in Eastern Partner countries

Economic analysis was conducted for the LNG terminal in Georgia, supplying LNG for the local market, and the terminal in Ukraine, supplying LNG to both Ukraine and Moldova. For the purpose of the analysis, the price of LNG in the Black Sea is assumed to be 220 EUR/ 1000 m^3, corresponding to a 5% increase to the average price of LNG at the Greek Revythoussa terminal for Q2 2019 (210 EUR/1000m^3, source: DG Energy, "Gas Market Report Q2 2019").

[191] REKK, "Final report on Assessment of the candidate Projects of Energy Community Interest (PECI) and Projects for Mutual Interest (PMI)", 2018

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Georgian LNG terminal

The netback analysis for the Georgian LNG terminal has shown that, with the examined terminal utilization and assumed LNG price in the Black Sea, LNG is not competitive to existing supply sources, in case import prices remain at the current level or moderately increase.

The terminal's benefit for enhancing security of supply is assessed by examining a disruption of Azeri gas supplies to the market during a peak demand period.

Economic analysis was performed for the following price and terminal utilization scenarios:

- Import price of Azeri gas to Georgia (including transmission tariff) of 206 EUR/1000 m^3. As the assumed LNG price is higher, and thus not competitive, the terminal will be utilized only for security of supply purposes, to cover potential demand curtailment (supply gap) in case of disruption in the Azeri imports. The volumes used for security of supply correspond to the annual potential curtailed demand are estimated in Section A4.1.3.
- Import price of Azeri gas to Georgia (including transmission tariff) of 256 EUR/1000 m^3. As the assumed LNG price is lower, sales of LNG in the market equal to 30%, 50% and 70% of the terminal's utilization are examined.

Ukrainian LNG terminal

The netback analysis for the Ukrainian LNG terminal has shown that, with the examined terminal utilization and assumed LNG price in the Black Sea, LNG is not competitive to existing supply sources in Ukraine, in case import prices are at a low or average historic price. Furthermore, supply of LNG in the Moldovan market is not economically viable, as current price levels are low.

The terminal's benefit for enhancing security of supply is assessed by examining a disruption of Russian transit through Ukraine that would affect the import capacity of Ukraine and the supplies to Moldova.

Economic analysis was performed for the following price and terminal utilization scenarios:

- Import price of piped EU gas to Ukraine (including transmission tariff) of 198 EUR/1000 m^3. As the assumed LNG price is higher, and thus not competitive, the terminal will be utilized only for security of supply purposes in Ukraine and Moldova, to cover potential demand curtailment in case of disruption in Russian transit that affects the capacity to import gas. The volumes used for security of supply correspond to the annual potential curtailed demand are estimated in Section A4.1.3.
- Import price of piped EU gas to Ukraine (including transmission tariff) of 241 EUR/1000 m^3. As the assumed LNG price is lower, sales of LNG in the market equal to 30%, 50% and 70% of the terminal's utilization are examined.

A4.1.3. Calculation of demand curtailment in case of disruption

For each examined country (Georgia, Ukraine, Moldova) we examine a 2-week disruption scenario at peak demand. The supply gap is calculated after supplies from remaining sources, storage and indigenous production are taken into consideration.

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Georgia

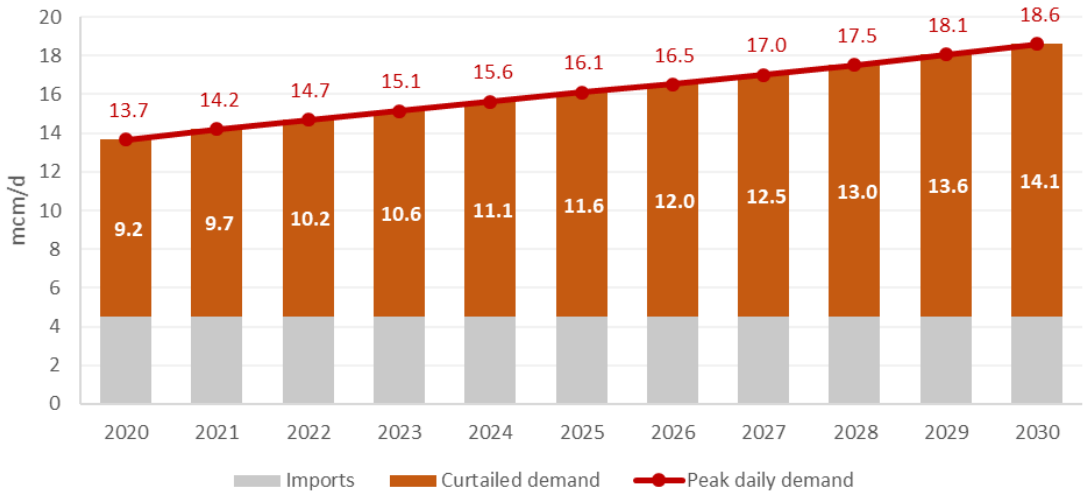
Projected peak daily gas demand in the Georgian market is 16.1 mcm/d by 2025 and 18.6 mcm/d by 2030[192], which corresponds to almost double the average daily gas consumption of those years (Table A. 82). The ratios presented in the Table below are applied on the annual gas demand forecasts (Figure A. 20) to estimate the peak daily demand for the period 2020 – 2030.

Table A. 82: Ratio of peak daily to average demand for Georgia

	2025	2030
Annual demand (mcm/yr)[192]	2,999	3,483
Average daily demand (mcm/d)	8.2	9.5
Peak daily demand (mcm/d)	16.1	18.6
Peak / average ratio	**1.96**	**1.95**

With the Azeri gas supplies disrupted, and considering that indigenous production is negligible, the only potential source for the market is Russian gas received though the Georgian off-take of the North-South Pipeline, that can amount up to 4.5 mcm/d[192]. The estimated evolution of daily peak demand and the curtailed demand, for the period 2020 – 2030 is presented in Figure A. 66. As longer-term demand projections are not available, for the remaining period of the 20-year economic analysis, 2031 – 2042, we assume the same demand curtailment as in 2030.

Figure A. 66: Estimated evolution of peak daily demand and demand curtailment for Georgia



The reduction of curtailed demand by the terminal impact for a 2-week disruption is presented in Table A. 83.

Table A. 83: Curtailed demand in Georgia for a 2-week period for 2023 – 2042

	2023	2027	2032	2037	2042
Daily demand curtailment (mcm/d)	10.6	12.5	14.1	14.1	14.1
2-week demand curtailment (mcm)	149.1	175.2	197.4	197.4	197.4

[192] Source: Department of Strategic Planning and Projects of GOGC

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Ukraine

The network development plans prepared for the transmission system (UTG[193]) and the storage facilities (SSO[194]) include only annual demand forecasts (Figure A. 34 and Figure A. 35), and not peak daily projections. To analyse the demand curtailment in Ukraine, we estimate future peak demand on the basis of historic observations (Table A. 84). The average of the ratios presented in the Table below (2.33) is applied on the annual gas demand forecasts (Figure A. 34 and Figure A. 35) to estimate the peak daily demand for the period 2020 – 2029.

Table A. 84: Ratio of peak daily to average demand for Ukraine

	2016	2017
Annual demand (mcm/yr)[195]	33,200	31,900
Average daily demand (mcm/d)	91.0	87.4
Peak daily demand (mcm/d)[196]	217.4	198.1
Peak / average ratio	**2.39**	**2.27**

In case of disruption of Russian gas transit through Ukraine, the import capacity from EU will be affected significantly, as most of the capacity is interruptible, and dependent on the Russian flows to EU[197]:

- Budince (Slovakia): 27 mcm/d firm capacity, 15.5 mcm/d interruptible capacity;
- Beregdaroc (Hungary): 19.5 mcm/d interruptible capacity;
- Hermanovice (Poland): 6.4 mcm/d interruptible capacity.

Consequently, import capacity of 27 mcm/d would remain available. It is noted that the upcoming reverse flow at IP Orlovka, allowing imports of up to 4.5 mcm/d from Romania, is expected to have interruptible capacity, while other planned projects, such as the planned interventions by FGSZ at the Beregdaroc IP to provide 16.8 mcm/d of firm capacity, or the interconnector Drozdovichi – Bilche Volytsia between Poland and Ukraine, have not received FID, and are thus not taken into consideration in the analysis.

The levels of Ukrainian gas production typically remain constant throughout the year. Therefore, in the analysis we use the average daily production, estimated on the basis of the annual production forecasts for the period 2020 – 2029 (Figure A. 34 and Figure A. 35).

According to the UGS Development Plan 2020 – 2029, the design peak withdrawal rate of the Ukrainian gas storages reaches 260 mcm/d. However, the actual maximum deliverability is significantly lower, mainly due to technical limitations (the Bilche-Volytsia UGS cannot reach its design withdrawal rate due to shortage in cushion gas), and the fact that the storages have been designed for seasonal fluctuations to support gas transit, and not for peak shaving purposes.

[193] UTG, TYNDP 2019 – 2028

[194] UTG / SSO, USG Development Plan 2020 – 2029

[195] Source: Naftogaz website, (accessed 25/11/2019)

[196] Sources: Energy Community, Reports on the results of the security monitoring of natural gas supply during 2016 and 2017

[197] Source: Input from UTG

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Taking into consideration that high deliverability rates depends on reservoir pressure and normally declines over the withdrawal season, we assume a withdrawal rate of 100 – 150 mcm/d.

The estimated evolution of daily peak demand and the curtailed demand, for the period 2020 – 2028/29 are presented in Figure A. 67 and Figure A. 68 respectively (assuming a storage withdrawal rate of 100 mcm/d). As longer-term demand projections are not available, for the remaining period of the 20-year economic analysis, 2030 – 2042, we assume the same demand curtailment as in 2029.

Figure A. 67: Estimated evolution of peak daily demand and demand curtailment for Ukraine (UTG)

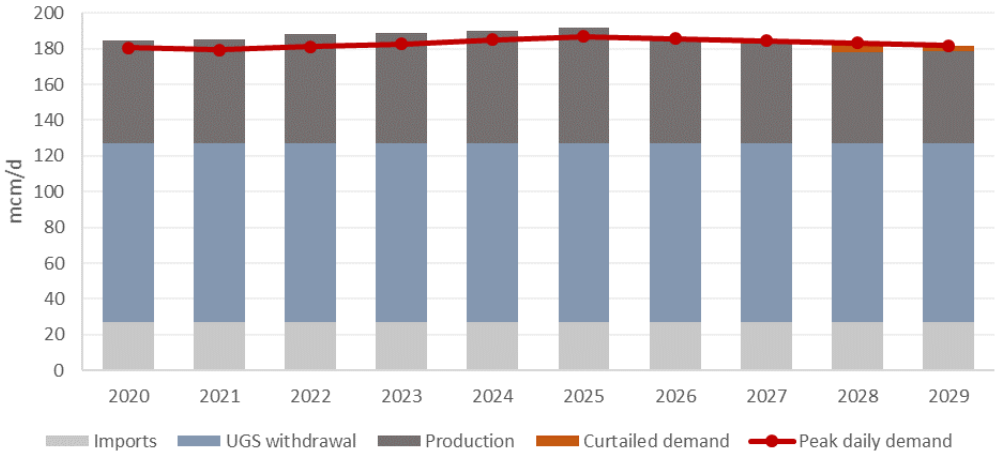
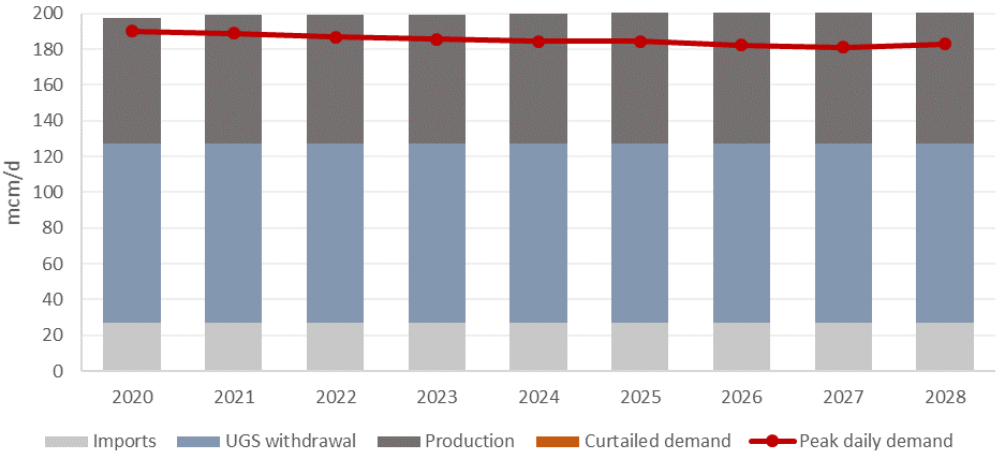


Figure A. 68: Estimated evolution of peak daily demand and demand curtailment for Ukraine (SSO)



The Figures above show that demand is curtailed only in case gas production follows a conservative evolution path, as the one indicated in the UGS Development Plan 2020 – 2029, and available maximum withdrawal rate for UGS is low. Given that this is the only case in which the LNG terminal would have an impact in security of supply, the corresponding curtailed volumes are further used in the economic analysis (Table A. 85).

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Table A. 85: Curtailed demand in Ukraine for a 2-week period for 2023 – 2042

	2023	2027	2032	2037	2042
Daily demand curtailment (mcm/d)	-	1.5	3.3	3.3	3.3
2-week demand curtailment (mcm)	-	20.5	46.2	46.2	46.2

Moldova

To estimate the peak daily demand in the Moldovan market, we use the gas demand projections that were applied for the evaluation of the 2018 PECI list. In the absence of publicly available daily demand data for Moldova, we apply the ratio of peak to average demand of Ukraine (2.33). The calculation results are presented in Table A. 86.

Table A. 86: Calculation of peak daily demand for Moldova

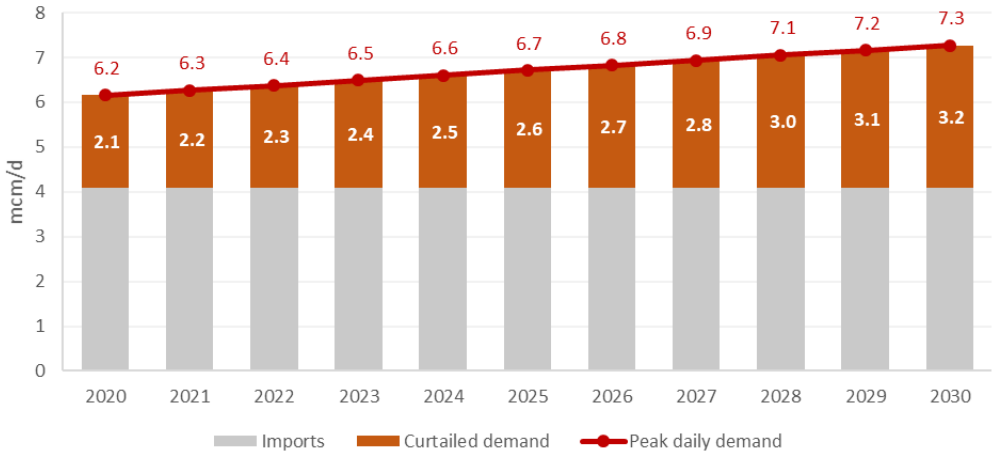
	2020	2025	2030
Annual demand (mcm/yr)[198]	965	1,053	1,140
Average daily demand (mcm/d)	2.6	2.9	3.1
Peak / average ratio		2.33	
Peak daily demand (mcm/d)	6.2	6.7	7.3

Peak demand for the intermediary years is estimated by applying linear interpolation. As longer-term demand projections are not available, for the remaining period of the 20-year economic analysis, 2031 – 2042, we assume the same demand curtailment as in 2030.

In case Russian gas supplies are disrupted, Moldova can continue receiving up to 4.1 mcm/d through the extension of the Iasi (Romania) – Ungheni (Moldova) pipeline to Chisinau, which is currently under construction.

The estimated evolution of daily peak demand and the curtailed demand, for the period 2020 – 2030 is presented in Figure A. 69. The gas demand curtailment used to assess the terminal's impact for a 2-week disruption are presented in Table A. 87.

Figure A. 69: Estimated evolution of peak daily demand and demand curtailment for Moldova



[198] REKK, "Final report on Assessment of the candidate Projects of Energy Community Interest (PECI) and Projects for Mutual Interest (PMI)", 2018. The GCV used to convert to mcm is presented in Annex 7.

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Table A. 87: Curtailed demand in Moldova for a 2-week period for 2023 – 2042

	2023	2027	2032	2037	2042
Daily demand curtailment (mcm/d)	2.4	2.8	3.2	3.2	3.2
2-week demand curtailment (mcm)	33.5	39.7	44.4	44.4	44.4

A4.1.4. Definition of investment and operational costs

The CAPEX and OPEX values used are the same with those used for the netback analysis of each terminal, presented in Table A. 26 for the Georgian terminal and in Table A. 27 for the Ukrainian terminal.

A 3-year period of terminal development is assumed in 2020 – 2022, with 20% of CAPEX used in the 1st year, 40% in the 2nd and 40% in the 3rd.

A4.1.5. Monetization of impact on the cost of gas supplies

Depending on the examined scenario for the price of imported gas, LNG may be:

- More expensive than piped gas, in which case LNG is supplied only to cover the potential curtailed demand for each year. In these scenarios the cost of gas supplies in the market would increase, to enhance security of supply.
- Cheaper than piped gas, in which case LNG can substitute piped gas, and reduce the cost of gas supplies.

The benefit/cost of LNG supplies is determined by the annual volumes of LNG landing at the terminal and the positive/negative price differential of LNG and imported piped gas.

Georgian LNG terminal

In the scenario that import price of Azeri gas remains at current levels (206 EUR/1000 m^3), LNG at the assumed price for the Black Sea (220 EUR/1000 m^3) would be 14 EUR/1000 m^3 more expensive. The LNG terminal in Georgia has been assumed to have a send-out capacity of 1 bcm/yr, corresponding to 2.7 mcm/d. Consequently, only part of the curtailed demand can be covered by the terminal, 38.4 mcm for the duration of the 2-week disruption. The annual premium to be paid in the market to have LNG for security of supply is presented in Table A. 88.

Table A. 88: Gas price increase in Georgia for current import price (supplies for security of supply)

	2023	2027	2032	2037	2042
Security of supply needs (2-week demand curtailment) (mcm)	38.4	38.4	38.4	38.4	38.4
Gas price increase (mil. EUR)	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**

In the scenario, that import price of Azeri gas moderately increases (256 EUR/1000 m^3), LNG would be 36 EUR/1000 m^3 cheaper. Table A. 89 below presents the assumed LNG volumes for each case of terminal utilization, and the corresponding benefit on gas prices.

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Table A. 89: Gas price decrease in Georgia for 25% import price increase, per utilization rate

	30%	50%	70%
Annual LNG volumes (mcm)	300	500	700
Gas price decrease (mil. EUR)	**10.8**	**18.0**	**25.2**

Ukrainian LNG terminal

In the scenario of minimum import price (198 EUR/1000 m^3), LNG at the assumed price for the Black Sea (220 EUR/1000 m^3) would be 22 EUR/1000 m^3 more expensive. The LNG volumes supplied to avoid curtailment are estimated as the aggregate for Ukraine and Moldova. The annual premium to be paid in the market to have LNG for security of supply is presented in Table A. 90.

Table A. 90: Gas price increase in Ukraine for minimum import price (supplies for security of supply)

	2023	2027	2032	2037	2042
Security of supply needs in Ukraine (2-week demand curtailment) (mcm)	-	20.5	46.2	46.2	46.2
Security of supply needs in Moldova (2-week demand curtailment) (mcm)	33.5	39.7	44.4	44.4	44.4
Gas price increase (mil. EUR)	**0.7**	**1.3**	**1.9**	**1.9**	**1.9**

In the scenario of average import price (241 EUR/1000 m^3), LNG would be 21 EUR/1000 m^3 cheaper. Table A. 91 below presents the assumed LNG volumes for each case of terminal utilization, and the corresponding benefit on gas prices.

Table A. 91: Gas price decrease in Ukraine for average import price, per utilization rate

	30%	50%	70%
Annual LNG volumes (mcm)	2,000	2,500	3,500
Gas price decrease (mil. EUR)	**10.8**	**18.0**	**25.2**

A4.1.6. Monetization of security of supply benefits

The security of supply benefits of the LNG terminal corresponds to the elimination of the impact of a supply disruption. To monetize the impact of demand curtailment, we use the Value of Lost Load for the market. VoLL is calculated as the ratio of the country's GDP to the value of final energy consumption required to produce it[199].

The VoLL applied to each country is presented in Table A. 92 below.

[199] A typical simplified approach to estimate VoLL, instead of resorting to economy-wide surveys to assess the consumers' willingness to pay.

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Table A. 92: VoLL calculated for each examined country

	Georgia	Ukraine	Moldova
GDP in 2017 (bil. EUR)	13.1[200]	101.4[201]	8.6[202]
Total Final Energy Consumption in 2017 (TWh)	50.7	582.5	31.6
VoLL (EUR/MWh)	**257.3**	**174.2**	**271.6**
VoLL (EUR/1000 m^3)	**2,609**	**1,944**	**3,096**

A probability for the occurrence of the disruption event has to be used to assess the risk of demand curtailment. For this analysis, we apply a 5% probability (corresponding to a 1-in-20 years event), which is the probability used by ENTSOG in the Union-wide TYNDP and security of supply simulations.

The benefits of security of supply are the same for all examined price scenarios and utilization rates of each terminal.

Georgian LNG terminal

The LNG terminal in Georgia has been assumed to have a send-out capacity of 1 bcm/yr, corresponding to 2.7 mcm/d. Consequently, only part of the curtailed demand can be covered by the terminal, 38.4 mcm for the duration of the 2-week disruption. The calculation of the monetized security of supply benefit is presented in Table A. 93.

Table A. 93: Security of supply benefit of Georgian LNG terminal

	2023	2027	2032	2037	2042
Security of supply needs (2-week demand curtailment) (mcm)	38.4	38.4	38.4	38.4	38.4
VoLL (EUR/1000 m^3)	2,609				
Probability of disruption	5%				
SoS benefit (mil. EUR)	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**

Ukrainian LNG terminal

The LNG terminal in Georgia has been assumed to have a send-out capacity of 1 bcm/yr, corresponding to 13.7 mcm/d. Consequently, the capacity is sufficient to fully address the curtailed demand. The calculation of the monetized security of supply benefit is presented in Table A. 94.

Table A. 94: Security of supply benefit of Ukrainian LNG terminal

	2023	2027	2032	2037	2042
Security of supply needs in Ukraine (2-week demand curtailment) (mcm)	-	20.5	46.2	46.2	46.2
VoLL in Ukraine (EUR/1000 m^3)	1,944				
Probability of disruption	5%				
SoS benefit for Ukraine (mil. EUR)	**-**	**2.0**	**4.5**	**4.5**	**4.5**
Security of supply needs in Moldova (2-week demand curtailment) (mcm)	33.5	39.7	44.4	44.4	44.4

[200] Source: National Statistics Office of Georgia

[201] Source: State Statistics Service of Ukraine

[202] Source: National Bureau of Statistics of the Republic of Moldova

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VoLL in Moldova (EUR/1000 m^3)	3,096				
Probability of disruption	5%				
SoS benefit for Moldova (mil. EUR)	**5.2**	**6.1**	**6.9**	**6.9**	**6.9**
Total SoS benefit (mil. EUR)	**5.2**	**8.1**	**11.4**	**11.4**	**11.4**

A4.1.7. Calculation of remaining net benefits (residual value)

The period for which the economic analysis is conducted (20 years) is not in sync with the lifetime of the terminal (30 years). For this reason, a residual value has to be estimated for the remaining years of the terminal's operation, until its decommissioning or replacement. To estimate the residual value, we assume that the annual net benefits of the terminal for years 21 – 30 are equal to those of the 20th year.

A4.1.8. Results of analysis

Georgian LNG Terminal

Figure A. 70 to Figure A. 73 below present the evolution of economic costs and benefits of the Georgian LNG terminal, for each price scenario and utilization rate.

Figure A. 70: Evolution of economic costs / benefits for Georgian receiving LNG terminal, for current import price

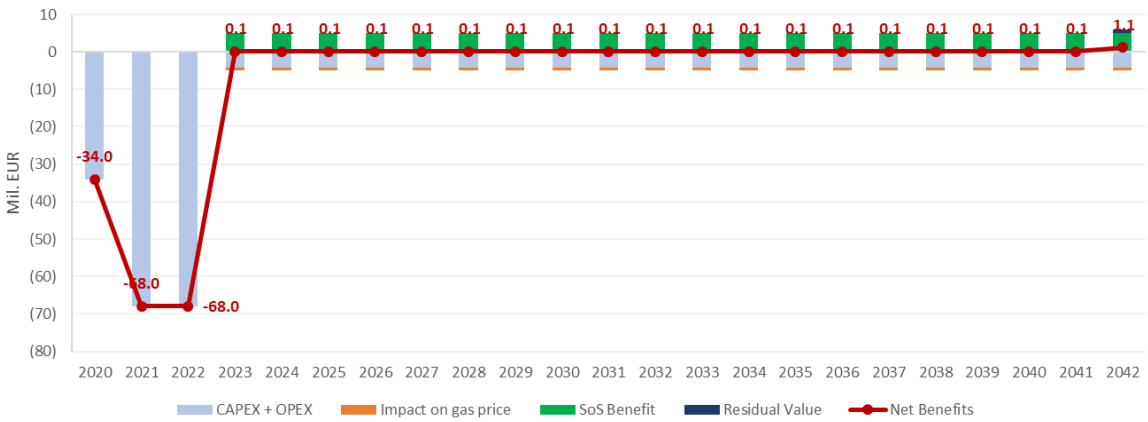

Figure A. 71: Evolution of economic costs / benefits for Georgian receiving LNG terminal, for 25% import price increase, 30% utilization rate

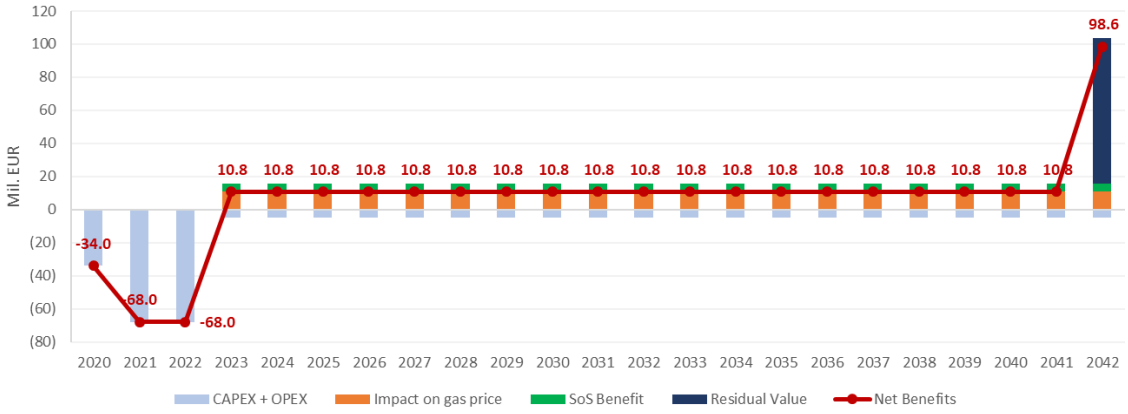

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Figure A. 72: Evolution of economic costs / benefits for Georgian LNG terminal, for 25% import price increase, 50% utilization rate

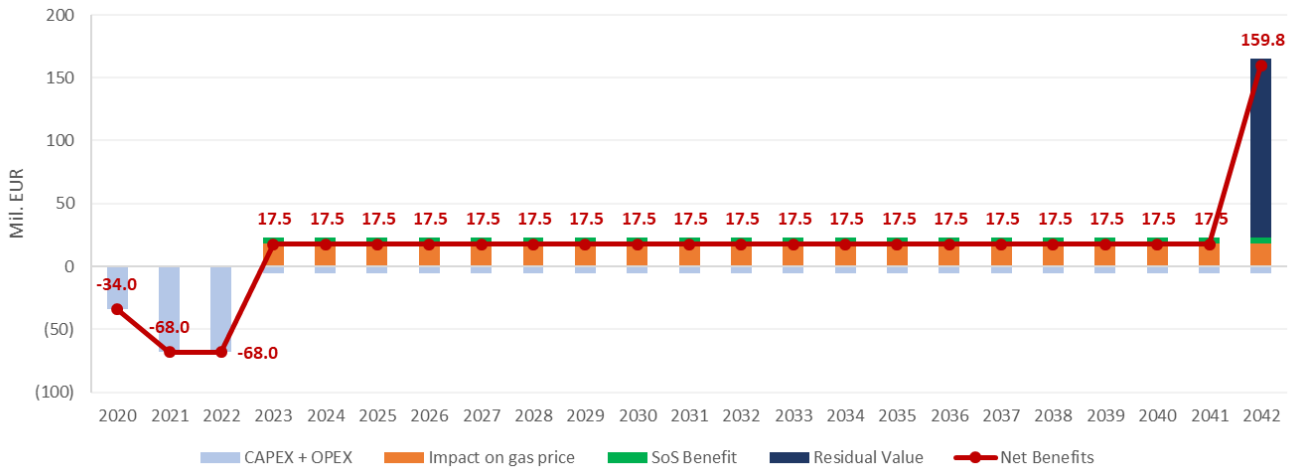

Figure A. 73: Evolution of economic costs / benefits for Georgian LNG terminal, for 25% import price increase, 70% utilization rate

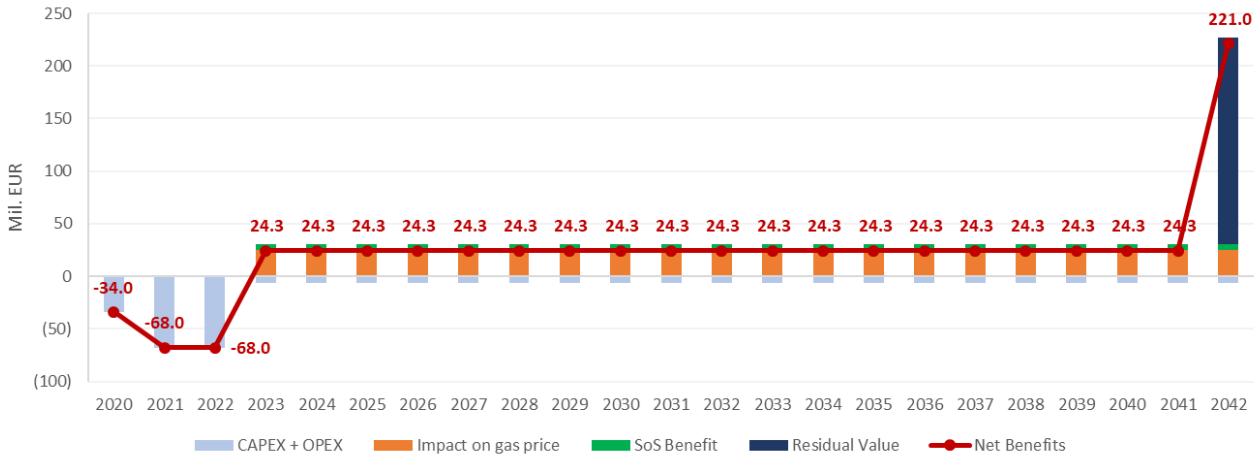

Table A. 95 presents the present values of the calculated economic costs and benefits for the Georgian LNG terminal.

Table A. 95: Present value of economic costs and benefits for Georgian LNG terminal per examined scenario

	Current import price	25% import price increase		
Examined utilization rate	Only SoS	30%	50%	70%
CAPEX + OPEX (Mil. EUR)	*-216.8*	*-224.8*	*-230.9*	*-236.9*
Impact on gas price (Mil. EUR)	*-6.7*	135.7	226.2	316.6
SoS benefit (Mil. EUR)	62.9	62.9	62.9	62.9
Residual value (Mil. EUR)	0.4	37.1	60.0	83.0
Net benefits (Mil. EUR)	**-160.3**	**10.8**	**118.2**	**225.6**

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Table A. 96 presents the economic indicators for the Georgian LNG terminal.

Table A. 96: Economic indicators for Georgian LNG terminal per examined scenario

	Current import price	25% import price increase		
Examined utilization rate	Only SoS	30%	50%	70%
ENPV (Mil. EUR)	-160.3	10.8	118.2	225.6
ERR	N/A	4.6%	9.2%	12.9%
B/C Ratio	0.26	1.05	1.5	1.95

Ukraine LNG Terminal

Figure A. 74 to Figure A. 77 below present the evolution of economic costs and benefits of the Ukrainian LNG terminal, for each price scenario and utilization rate.

Figure A. 74: Evolution of economic costs / benefits for Ukrainian LNG terminal, for minimum import price

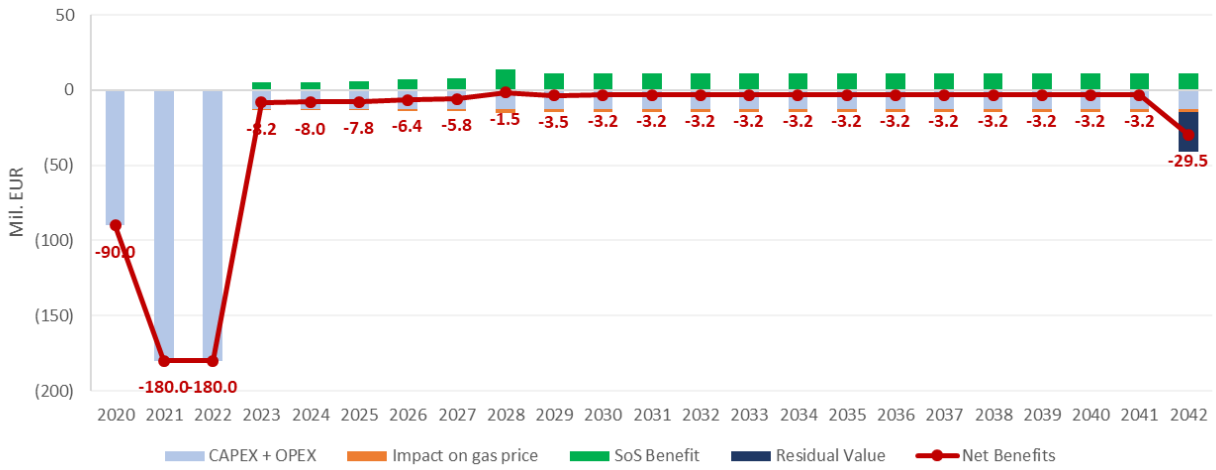

Figure A. 75: Evolution of economic costs / benefits for Ukrainian LNG terminal, for average import price, 30% utilization rate

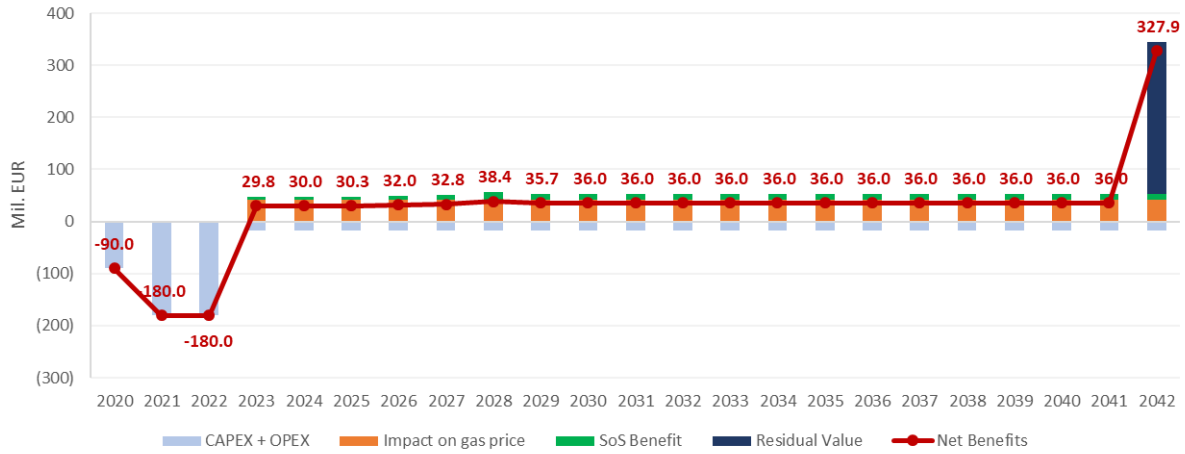

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Figure A. 76: Evolution of economic costs / benefits for Ukrainian LNG terminal, for average import price, 50% utilization rate

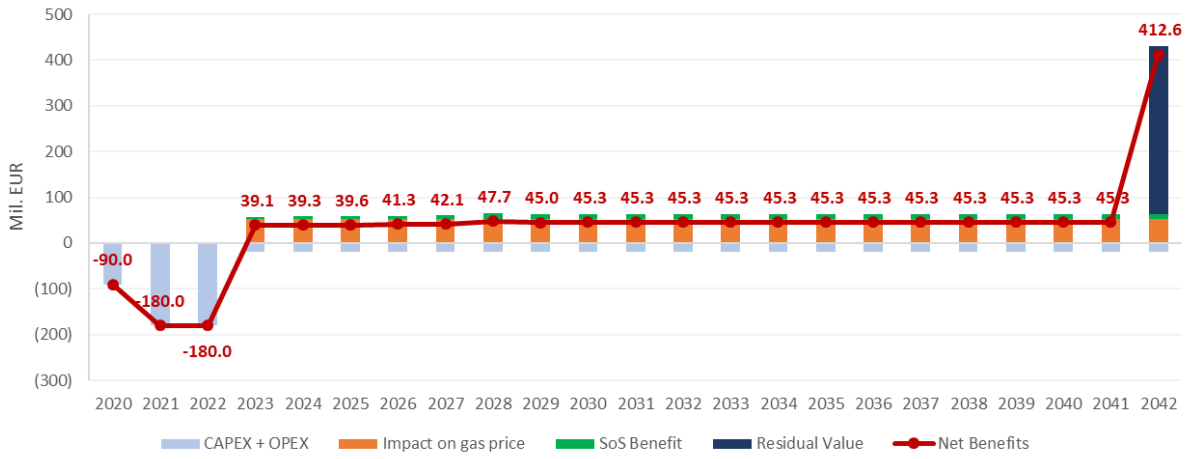

Figure A. 77: Evolution of economic costs / benefits for Ukrainian LNG terminal, for average import price, 70% utilization rate

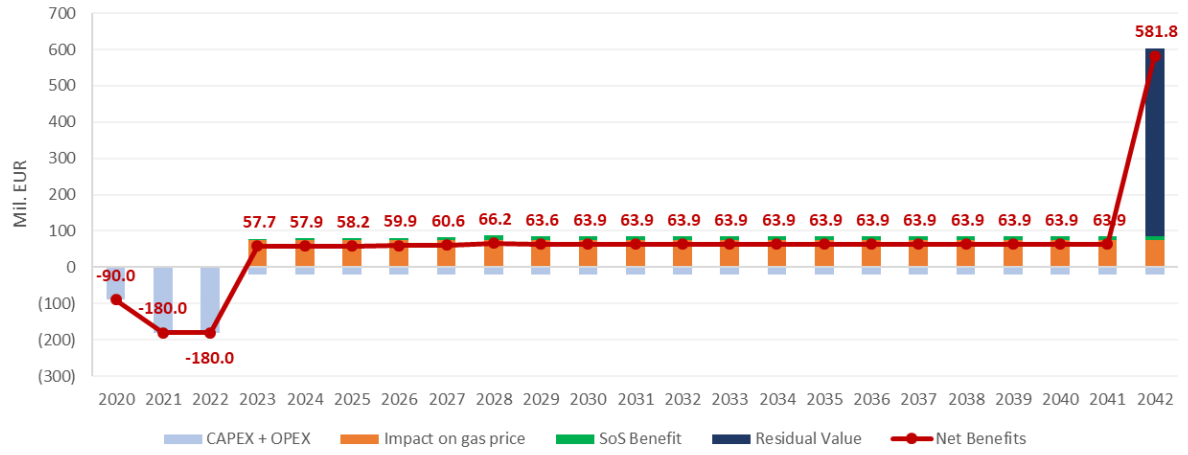

Table A. 97 presents the present values of the calculated economic costs and benefits for the Ukrainian LNG terminal.

Table A. 97: Present value of economic costs and benefits for Ukrainian LNG terminal per examined scenario

	Minimum import price	Average import price		
Examined utilization rate	Only SoS	30%	50%	70%
CAPEX + OPEX (Mil. EUR)	*-588.0*	*-647.8*	*-663.0*	*-693.4*
Impact on gas price (Mil. EUR)	*-21.2*	527.7	659.7	923.5
SoS benefit (Mil. EUR)	123.5	123.5	123.5	123.5
Residual value (Mil. EUR)	-11.1	123.2	155.0	218.6
Net benefits (Mil. EUR)	**-496.7**	**126.6**	**275.2**	**572.2**

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Table A. 98 presents the economic indicators for the Ukrainian LNG terminal.

Table A. 98: Economic indicators for Ukrainian LNG terminal per examined scenario

	Minimum import price	Average import price		
Examined utilization rate	Only SoS	30%	50%	70%
ENPV (Mil. EUR)	-496.7	126.7	257.2	572.2
ERR	N/A	6.2%	8.5%	12.4%
B/C Ratio	0.16	1.2	1.4	1.8

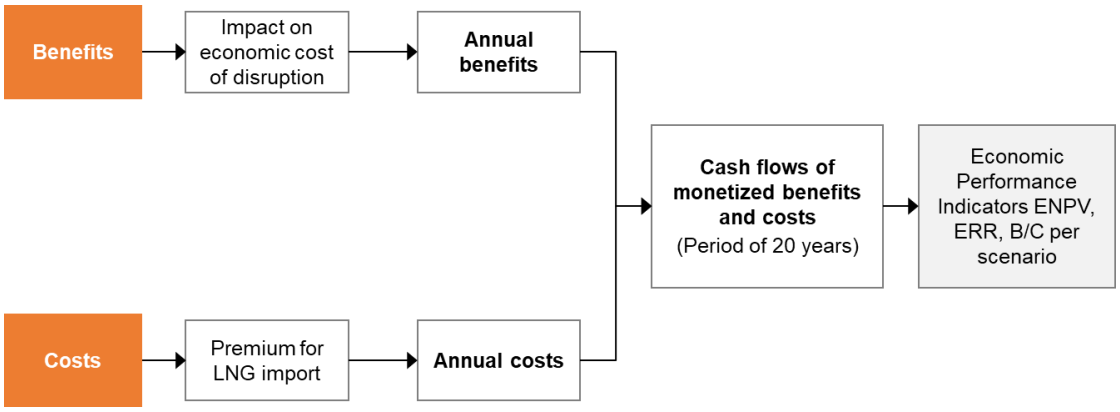
A4.2. Economic analysis for regasified LNG supplied via pipeline from neighbouring EU LNG Terminals

A4.2.1. Analysis approach

The aim of the economic (cost-benefit) analysis to assess whether the economic costs for importing regasified LNG from neighbouring terminals to an Eastern Partner country are outweighed by its potential benefits to the economy and society.

The overall approach is the same with the one described in Section A4.1.1. However, in this case no new investment is required, only imports of regasified LNG through the existing routes, at a price higher than the existing market price, for security of supply purposes. The only costs examined concern the premium paid to import LNG to the market, whereas the benefit is the enhancement of security of supply.

Figure A. 78: Assessment of costs and benefits



The economic analysis was carried out for a 20-year period, assuming commencement of imports of regasified LNG in 2020. As in the case of Section A4.1, a social discount rate of 4% has been applied in the calculations.

It is noted that the analysis carried out is high-level, based on assumptions on gas/LNG supply prices and market evolution, without examining dynamic supply-demand curves. The results of this analysis can be used to draw preliminary conclusions, whereas for a more detailed view of

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the LNG market development option's economic performance, modelling of the markets evolution is required.

A4.2.2. Application in Eastern Partner countries

Economic analysis was conducted only for the case of Moldova, for which supplies of regasified LNG is not viable, but could have impact on the country's security of supply.

The benefit for enhancing security of supply is assessed by examining a disruption of Russian supplies to Moldova.

Regasified LNG can be supplied from the neighbouring terminals of Świnoujście, Klaipeda and the planned terminal in Krk, and through the Ukrainian system. Additional supplies from Revythoussa could not reach the market, in case of a supply disruption, as the interconnection point with Romania would already be used as much as possible.

Since the transportation costs from the terminals up to Moldova do not vary considerably (Section A2.1.7), and the economic analysis would lead to similar results, we examine only the case of Klaipeda.

A4.2.3. Calculation of demand curtailment in case of disruption

The daily peak demand and curtailed demand for Moldova is the same with the one estimated in Section A4.1.3 (Figure A. 69). The gas demand curtailment used to assess the LNG option's impact for a 2-week disruption is presented in Table A. 99.

Table A. 99: Curtailed demand in Moldova for a 2-week period for 2020 – 2039

	2020	2024	2029	2034	2039
Daily demand curtailment (mcm/d)	2.1	2.5	3.1	3.2	3.2
2-week demand curtailment (mcm)	28.8	35.0	42.9	44.4	44.4

A4.2.4. Monetization of increase of the cost of gas supplies

The LNG import price is assumed to be the current level of average price at the Klaipeda terminal (200 EUR/1000 m^3)[203]. The gas supply price in Moldova is set at the regulated price set by ANRE, for entry into the gas transmission system (151.5 EUR/1000 m^3)[204].

The transportation costs of regasified LNG up to the Moldovan borders are calculated using the tariffs presented in

[203] Source: DG Energy, "Gas Market Report Q2 2019"

[204] Source: Moldovan National Agency for Energy Regulation Decision No 88/2018

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Table A. 13. It is assumed that the same capacity booking profile as the one presented in Section A2.1.4, resulting in a cross-border transportation cost of 45.4 EUR/1000 m^3, and a cost of LNG terminal use and entry to the Lithuanian transmission system of 17.0 EUR/1000 m^3 (Table A. 25).

With the assumed import price of LNG and transportation costs, LNG at the Moldovan market would be 111.14 EUR/1000 m^3 more expensive. The annual premium to be paid in the market to have LNG for security of supply is presented in Table A. 100.

Table A. 100: Gas price increase in Moldova for current import price (supplies for security of supply)

	2020	2024	2029	2034	2039
Security of supply needs (2-week demand curtailment) (mcm)	28.8	35.0	42.9	44.4	44.4
Gas price increase (mil. EUR)	**3.2**	**3.9**	**4.8**	**4.9**	**4.9**

A4.2.5. Monetization of security of supply benefits

The approach to determine the monetised benefit of addressing demand curtailment for Moldova is the same with that presented in Section A4.1.6. The calculation is presented in Table A. 101.

Table A. 101: Security of supply benefit for supplies of regasified LNG to Moldova

	2020	2024	2029	2034	2039
Security of supply needs in Moldova (2-week demand curtailment) (mcm)	28.8	35.0	42.9	44.4	44.4
VoLL in Moldova (EUR/1000 m3)	3,096				
Probability of disruption	5%				
SoS benefit for Moldova (mil. EUR)	**4.5**	**5.4**	**6.6**	**6.9**	**6.9**

A4.2.6. Results of analysis

Figure A. 79 presents the evolution of economic costs and benefits of the LNG option of supplying regasified LNG from neighbouring terminals to Moldova.

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Figure A. 79: Evolution of economic costs / benefits for supply of regasified LNG from Klaipeda to Moldova

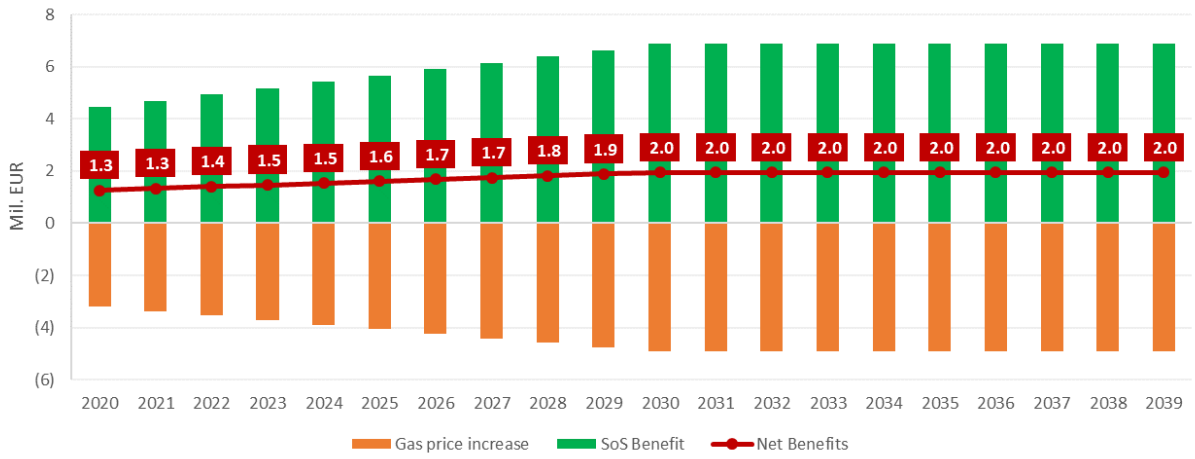

Table A. 102 presents the present values of the calculated economic costs and benefits for the examined LNG option.

Table A. 102: Present value of economic costs and benefits for supply of regasified LNG from Klaipeda to Moldova

	Present Value
Impact on gas price (Mil. EUR)	*-61.1*
SoS benefit (Mil. EUR)	85.3
Net benefits (Mil. EUR)	**24.2**

Table A. 103 presents the economic indicators for the examined LNG option.

Table A. 103: Economic indicators for supply of regasified LNG from Klaipeda to Moldova

	Indicator
ENPV (Mil. EUR)	24.2
ERR	N/A
B/C Ratio	1.4

A4.3. Economic analysis for in case of LNG supplied from liquefaction terminal in Black Sea

A4.3.1. Analysis approach

The aim of the economic (cost-benefit) analysis to assess whether the economic costs for developing and operating a liquefaction and export terminal in Georgia, together with an in-country LNG receiving terminal in Ukraine are outweighed by its potential benefits to the economy and society.

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The approach followed, and the examined costs and benefits are the same as in Section A4.1. In this case, however, the LNG supply costs also include the costs for liquefaction at the Georgian terminal and transportation with an LNG vessel to the Ukrainian terminal.

A4.3.2. Application in Eastern Partner countries

An economic analysis was conducted for the development of a liquefaction and export terminal in Georgia, together with a receiving terminal in Ukraine that allows supply of regasified LNG to the Ukrainian and Moldovan markets.

The netback analysis for this option shows that in all the examined scenarios of Ukrainian import price and utilization, the estimated maximum competitive prices at the liquefaction terminal are below the import prices of Azeri gas currently applied in the Georgian market, 200 EUR/1000 m3[205]. The economic analysis was performed for the case having the highest netback price (winter average price, 257 EUR/1000 m^3), examining two scenarios of Caspian gas export prices (current level of Azeri gas supply to Georgia and low export price). Sensitivity analysis on the investment costs of the liquefaction is also applied (Section A2.3.6). A matrix of scenarios/sensitivities and corresponding prices is presented in Table A. 104.

Table A. 104: Price scenarios and sensitivities examined

Price scenario	Item	Cost of liquefaction terminal		
		100%	*80%*	*60%*
Current Azeri supply price to Georgia	Export price of Caspian gas (EUR/1000 m^3)	200		
	Exit from Georgian system	6.1		
	LNG transportation cost (EUR/1000 m^3)	5.5		
	Liquefaction service charge (EUR/1000 m^3)	109.6	93.5	79.8
	LNG Price at Ukrainian terminal (EUR/1000 m^3)	**321.2**	**305.1**	**291.4**
Low export price of Caspian gas	Export price of Caspian gas (EUR/1000 m^3)	150		
	Exit from Georgian system	6.1		
	LNG transportation cost (EUR/1000 m^3)	5.5		
	Liquefaction service charge (EUR/1000 m^3)	109.6	93.5	79.8
	LNG Price at Ukrainian terminal (EUR/1000 m^3)	**271.2**	**255.1**	**241.4**

For the scenarios that price of LNG arriving at the Ukrainian terminal is higher than the winter average price in Ukraine, the terminal will be utilized only for security of supply purposes in Ukraine and Moldova, to cover potential demand curtailment in case of disruption in Russian transit that affects the capacity to import gas. The volumes used for security of supply correspond to the annual potential curtailed demand estimated in Section A4.1.3.

For the scenarios that price of LNG arriving at the Ukrainian terminal is lower than the winter average price in Ukraine, terminal utilization of 50% is examined.

[205] Source: Department of Strategic Planning and Projects of GOGC

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A4.3.3. Definition of investment and operational costs

The CAPEX and OPEX values defined in Section A4.1.4 are applied. Costs for the liquefaction terminal and transportation are included in the price of LNG at the Ukrainian terminal (examined as part of the impact on energy costs).

A4.3.4. Monetization of impact on the costs of gas supplies

The approach described in Section A4.1.5 is followed. In the scenarios that the LNG supply price at Ukraine are higher than that of piped gas, the premium for the import of LNG for security of supply is estimated (Table A. 105). In the scenarios that the LNG supply price at Ukraine are lower than that of piped gas, the cost saving is estimated (Table A. 106).

Table A. 105: Annual gas price increase in Ukraine in case LNG is used for security of supply

		Year[206]				
		1	*5*	*10*	*15*	*20*
Security of supply needs in Ukraine (2-week demand curtailment) (mcm)		-	20.5	46.2	46.2	46.2
Security of supply needs in Moldova (2-week demand curtailment) (mcm)		33.5	39.7	44.4	44.4	44.4
Gas price increase (mil. EUR)						
Current Azeri price scenario	*321.2 EUR/1000 m³*	**2.1**	**3.9**	**5.8**	**5.8**	**5.8**
	305.1 EUR/1000 m³	**1.6**	**2.9**	**4.4**	**4.4**	**4.4**
	291.4 EUR/1000 m³	**1.2**	**2.1**	**3.1**	**3.1**	**3.1**
Low export price of Caspian gas scenario	*271.2 EUR/1000 m³*	**0.5**	**0.9**	**1.3**	**1.3**	**1.3**

Table A. 106: Annual gas price decrease in Ukraine for 50% utilization rate

		50%
Annual LNG volumes (mcm)		2,500
Gas price decrease (mil. EUR)		
Low export price of Caspian gas scenario	*255.1 EUR/1000 m³*	**4.7**
	241.4 EUR/1000 m³	**39.0**

A4.3.5. Monetization of security of supply benefits

The monetized benefits for security of supply used are those presented in Table A. 94.

A4.3.6. Calculation of remaining benefits (residual value)

The approach described in Section A4.1.7 is followed.

A4.3.7. Results of analysis

Table A. 107 presents the present values of the calculated economic costs and benefits for the development of a liquefaction export terminal in Georgia, together with a receiving terminal in Ukraine.

[206] This LNG option can be developed in the medium term, in case additional gas from the Caspian region becomes available. It is assumed that the same demand curtailment trend, as the one estimated in Section A4.1.3 will be followed.

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Table A. 107: Present value of economic costs and benefits for supply of Ukrainian LNG terminal from Georgian liquefaction terminal, per examined scenario

	Current Azeri price			Low export price of Caspian gas		
Investment cost sensitivity	*100%*	*80%*	*60%*	*100%*	*80%*	*60%*
CAPEX + OPEX (Mil. EUR)	*-595.9*	*-594.7*	*-593.6*	*-592.0*	*-677.7*	*-672.0*
Impact on gas price (Mil. EUR)	*-61.7*	*-46.3*	*-33.1*	*-13.7*	59.7	490.0
SoS benefit (Mil. EUR)	123.5	123.5	123.5	123.5	123.5	123.5
Residual value (Mil. EUR)	*-26.3*	*-21.0*	*-16.5*	*-9.8*	*-12.5*	106.3
Net benefits (Mil. EUR)	**-560.4**	**-538.4**	**-519.6**	**-491.9**	**-506.9**	**47.9**

Table A. 108 presents the economic indicators for the liquefaction export terminal in Georgia, together with a receiving terminal in Ukraine.

Table A. 108: Economic indicators for supply of Ukrainian LNG terminal from Georgian liquefaction terminal, per examined scenario

	Current Azeri price			Low export price of Caspian gas		
Investment cost sensitivity	*100%*	*80%*	*60%*	*100%*	*80%*	*60%*
ENPV (Mil. EUR)	-560.4	-538.4	-519.6	-491.9	-506.9	44.9
ERR	N/A	N/A	N/A	N/A	N/A	4.9%
B/C Ratio	0.06	0.09	0.12	0.17	0.25	1.07

Figure A. 80 and Figure A. 81 below present the evolution of economic costs and benefits of the examined LNG option, for the case of low Caspian export price, and sensitivities of liquefaction terminal investment costs.

Figure A. 80: Evolution of economic costs / benefits for supply of Ukrainian LNG terminal from Georgian liquefaction terminal, for low Caspian export price, 80% investment cost

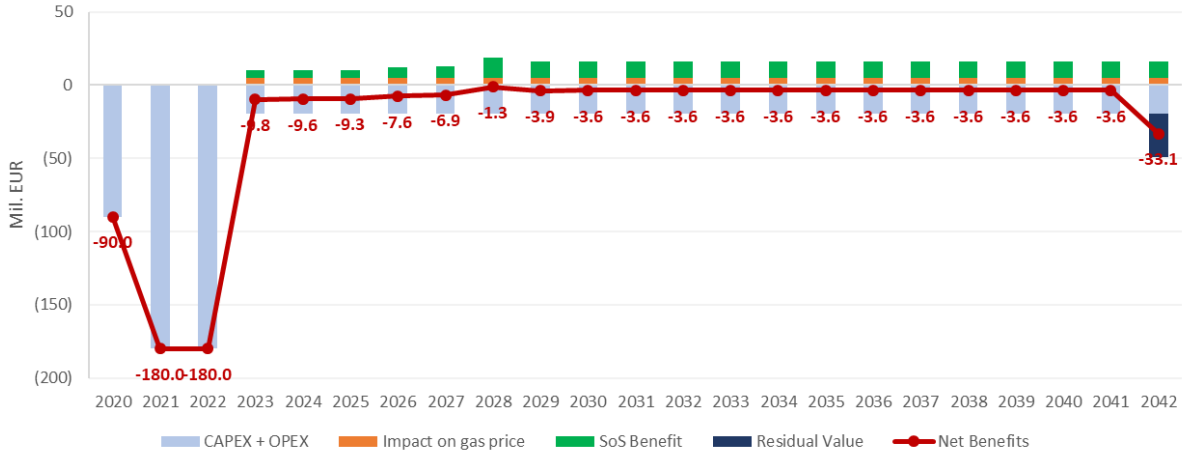

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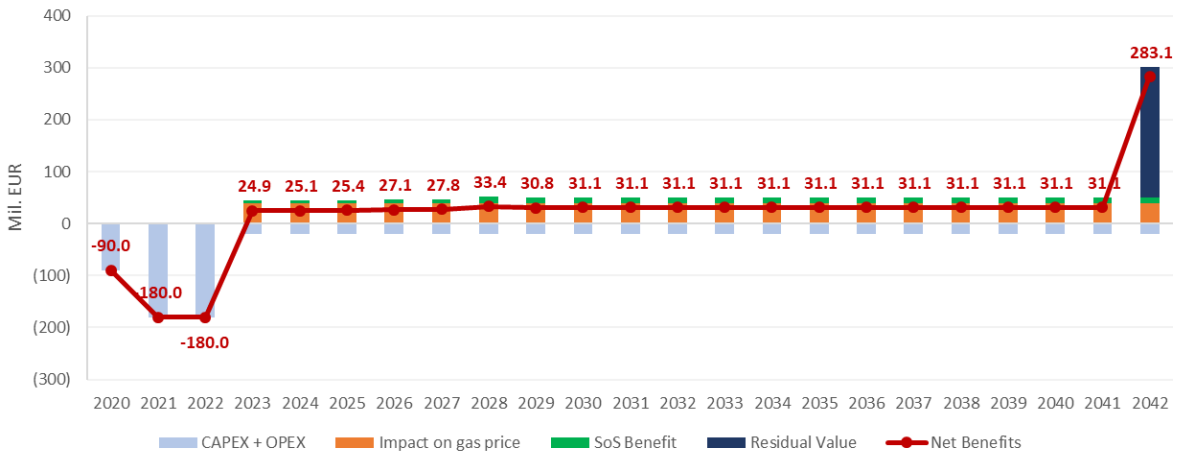
Figure A. 81: Evolution of economic costs / benefits for supply of Ukrainian LNG terminal from Georgian liquefaction terminal, for low Caspian export price, 60% investment cost



A4.4. Quantitative indicators for gas-to-gas competition LNG market development options' assessment

A4.4.1. Indicators applied

The economic indicators calculated for the LNG market development options under the gas-to-gas competition are supplemented by the assessment of quantitative indicators that allow further analysis of the options' impact to the market.

The indicators applied are mainly capacity-based, as the high-level analysis performed under this Study does not include market simulations, and thus modelling-based indicators cannot be used. The quantitative indicators examined include:

- N-1 indicator: The indicator examines whether peak demand in the market can be satisfied in case its single largest infrastructure is disrupted.
- Import route diversification: The indicator examines the extent to which there is potential for the market to diversify its routes of supply and associated counterparts.
- Demand curtailment: The indicator examines the extent to which the market is impacted by a disruption in external supplies.

The impact of the LNG option is assessed by examining the indicators with and without the development of the option. The analysis was conducted for 2025.

A4.4.2. N-1 Indicator

The calculation of the N-1 indicator is based on the N-1 formula included in the EC Security of Gas Supply Regulation (EU) 2017/1938:

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$$N-1=\frac{EP+P+S+LNG-I}{D_{max}}*100$$

where:

- EP: Aggregate firm technical capacity of all cross-border entry points (mcm/d);
- P: Maximum national production capability (mcm/d);
- S: Aggregate maximum technical daily withdrawal capacity (mcm/d) of all storage facilities;
- LNG: Aggregate LNG regasification capacity (mcm/d) of all LNG terminals;
- I: Firm technical capacity of the single largest infrastructure (mcm/d);
- D_{max}: peak daily demand in the market (mcm/d).

To meet the Regulation (EU) 2017/1938 requirements, the N-1 indicator must exceed 100%.

As this indicator is capacity-based, it is relevant for Georgia and Ukraine, in which the entry capacities will change with the development of LNG terminals.

Georgia

The calculation of the N-1 indicator for the Georgian market, with and without the development of an LNG terminal with send-out capacity of 1 bcm/yr (2.75 mcm/d) is presented in Table A. 109. Disruption of the Azeri-Georgia Pipeline, that has the largest capacity, is examined.

Table A. 109: Calculation of N-1 indicator for Georgia

	W/o terminal	With terminal
Entry Points (EP) (mcm/d)[207]	17.9	17.9
North-South Pipeline (mcm/d)	*4.5*	*4.5*
SCP (mcm/d)	*5.4*	*5.4*
Azeri-Georgia Pipeline (mcm/d)	*8*	*8*
Production (P) (mcm/d)	~0	~0
USG (S) (mcm/d)[208]	N/A	N/A
LNG (mcm/d)	N/A	2.75
Largest Infrastructure (I) (mcm/d)	8	8
Peak daily demand in 2025 (D_{max}) (mcm/d)	16.1	16.1
N-1 indicator	61.5%	78.5%
LNG terminal impact (percentage points)	17.0	
LNG terminal impact (% change)	28%	

Ukraine

The calculation of the N-1 indicator for the Ukrainian market, with and without the development of an FSRU with send-out capacity of 5 bcm/yr (13.7 mcm/d) is presented in Table A. 110.

[207] Source: Department of Strategic Planning and Projects of GOGC

[208] The planned UGS, not included in the calculations as it has not received an FID yet, will increase the N-1 indicator.

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For peak demand and production, the forecasts included in the UGS Development Plan 2020 – 2029 are used as a basis. For the interconnection points, only firm entry capacity is included in the calculations. The UGS withdrawal capacity used is not the maximum design withdrawal rate but takes into consideration the limitations discussed in Section A4.1.3. Disruption of the Bilche-Volytsia UGS, that has the largest entry capacity to the Ukrainian transmission system, is examined.

Table A. 110: Calculation of N-1 indicator for Ukraine

	W/o terminal	With terminal
Entry Points (EP) (mcm/d)[209]	27.0	27.0
Budince (Slovakia) (mcm/d)	*27.0*	*27.0*
Beregdaroc (Hungary) (mcm/d)	*0*	*0*
Hermanovice (Poland) (mcm/d)	*0*	*0*
Production in 2025 (P) (mcm/d)	64.9	64.9
USG (S) (mcm/d)	150.0	150.0
LNG (mcm/d)	N/A	13.7
Largest Infrastructure (I) (mcm/d)	-60	-60
Peak daily demand in 2025 (D_{max}) (mcm/d)	186.9	186.9
N-1 indicator	97.3%	104.7%
LNG terminal impact (percentage points)	7.3	
LNG terminal impact (% change)	8%	

A4.4.3. Import Route Diversification

The Import Route Diversification (IRD) indicator is calculated using the Herfindahl - Hirschman Index (HHI), to assess the share of each gas import point:

$$IRD = \sum_{i=1}^{n} \left(\frac{EC_i}{\sum_n EC} * 100\right)^2$$

where:

- EC: Capacity of each entry point to the market (mcm/d), including interconnection points with neighbouring markets and LNG terminals. All interconnection points between two markets are aggregated, regardless of their geographical position.
- n: Total number of entry points.

The lower the value of IRD, the higher is the market's potential to diversify its routes and counterparts. The maximum value is 10,000, corresponding to a market with a single import point.

As this indicator is capacity-based, it is relevant for Georgia and Ukraine, in which the entry capacities will change with the development of LNG terminals.

Georgia

[209] Source: Input from UTG

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The calculation of the IRD indicator for the Georgian market, with and without the development of an LNG terminal with send-out capacity of 1 bcm/yr (2.74 mcm/d) is presented in Table A. 111. The entry points from SCP and the Azeri – Georgia Pipeline are examined jointly as they concern gas of the same source.

Table A. 111: Calculation of IRD indicator for Georgia

	HHI w/o terminal	HHI with terminal
North-South Pipeline	632	475
Azeri entries	5,604	4,215
LNG terminal	N/A	176
Total	6,236	4,867
LNG terminal impact	1,370	
LNG terminal impact (% change)	22%	

Ukraine

The calculation of the IRD indicator for the Ukrainian market, with and without the development of an FSRU with send-out capacity of 5 bcm/yr (13.7 mcm/d) is presented in Table A. 112. Both firm and interruptible capacity is included in the analysis, given that under normal market operation supplies from all routes arrive to Ukraine.

Table A. 112: Calculation of IRD indicator for Ukraine

	HHI w/o terminal	HHI with terminal
Budince (Slovakia)	3,399	2,408
Beregdaroc (Hungary)	716	507
Hermanovice (Poland)	77	55
Orlovka (Romania)	38	27
LNG terminal	N/A	250
Total	4,229	3,247
LNG terminal impact	982	
LNG terminal impact (% change)	23%	

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A4.4.4. Demand Curtailment

The demand curtailment is examined using a Disruption Rate (DR) indicator:

$$DR = \frac{DD}{D_{max}}$$

Where:

- DD: Curtailed demand on peak day (mcm/d);
- D_{max}: peak daily demand in the market (mcm/d).

This indicator is estimated for Georgia with disruption of Azeri gas supplies, Ukraine with disruption of Russian gas transit and for Moldova with disruption of Russian gas supplies. The curtailed demand for each country has been calculated in Section A4.1.3.

Georgia

The calculation of the DR indicator for the Georgian market, with and without the development of an LNG terminal with send-out capacity of 1 bcm/yr (2.74 mcm/d) is presented in Table A. 113.

Table A. 113: Calculation of DR indicator for Georgia

	W/o terminal	With terminal
Peak daily demand in 2025 (mcm/d)	16.1	16.1
Curtailed demand in 2025 (mcm/d) in case of Azeri gas disruption	11.6	8.9
DR	72%	55%
LNG terminal impact (percentage points)	17	
LNG terminal impact (% change)	24%	

Ukraine

The calculation of the DR indicator for the Ukrainian market, with and without the development of an LNG terminal with send-out capacity of 5 bcm/yr (13.7 mcm/d) is presented in Table A. 114.

Table A. 114: Calculation of DR indicator for Ukraine

	W/o terminal	With terminal
Peak daily demand in 2025 (mcm/d)	186.9	186.9
Curtailed demand in 2025 (mcm/d) in case of Russian transit disruption	0	0
DR	0	0
LNG terminal impact (percentage points)	-	
LNG terminal impact (% change)	-	

Moldova

The calculation of the DR indicator for the Moldovan market, with and without the development of an LNG terminal in Ukraine with send-out capacity of 5 bcm/yr (13.7 mcm/d) is presented in Table A. 115.

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Table A. 115: Calculation of DR indicator for Moldova

	W/o terminal	With terminal
Peak daily demand in 2025 (mcm/d)	6.7	6.7
Curtailed demand in 2025 (mcm/d) in case of Russian gas disruption	2.5	0
DR	37%	0%
LNG terminal impact (percentage points)	37	

The imports of regasified LNG from neighboring terminals to Moldova, in case of a disruption of Russian gas supplies, would have the same impact.

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Annex 5: Economic Analysis – Gas-to-Other Fuels Competition

A5.1. Economic analysis for LNG as fuel for long-haul trucks

A5.1.1. Analysis approach

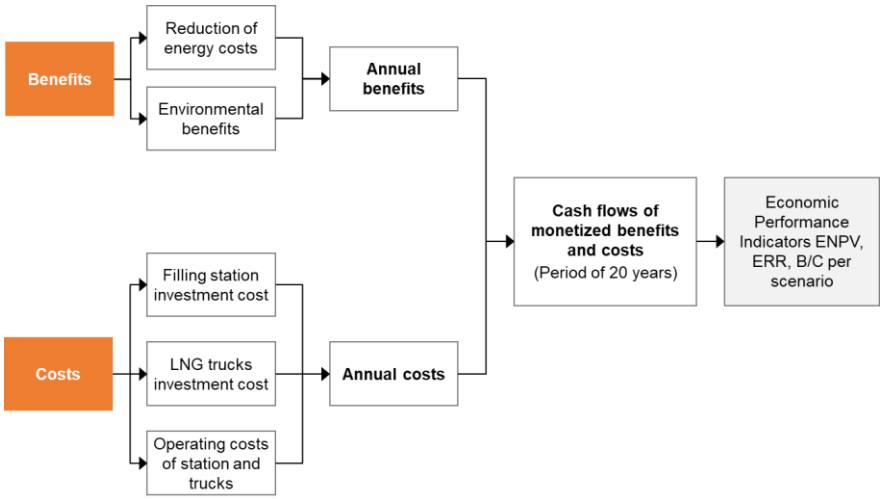
The aim of the economic (cost-benefit) analysis to assess whether the costs for developing and operating the infrastructure necessary for the use of LNG as engine fuel in long-haul trucks (filling stations and LNG trucks for the supply of LNG) are outweighed by its potential benefits to the economy and society. The economic analysis was carried out for the minimum size of the LNG market in each Eastern Partner country, for which LNG is competitive to diesel (calculated in Section A3.1.10).

The approach followed is in accordance with the EC CBA Guide for infrastructure investments[210].

The costs and monetized benefits assessed are the following (Figure A. 82):

- Costs:
  - Investment costs for the development of an LNG filling station in the country;
  - Cost for purchase of LNG trucks to transport LNG to the filling station;
  - Annual operating costs for the filling station and trucks.
- Monetized benefits:
  - Reduction of energy costs for final consumers;
  - Environmental benefits from reduction of GHGs.

Figure A. 82: Assessment of costs and benefits



[210] DG Regio (2015) EC CBA Guide for infrastructure investments, available at: https://ec.europa.eu/regional_policy/sources/docgener/studies/pdf/cba_guide.pdf

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The economic analysis was carried out for a 20-year period, assuming development of the required infrastructure in 2020 and commencement of LNG supplies in 2021. As in the case of Annex 4, a social discount rate of 4% has been applied in the calculations.

The analysis results in the estimation of the key economic performance indicators; the Economic Net Present Value (ENPV), Economic Rate of Return (ERR), and Benefit-to-Cost ratio (B/C).

A5.1.2. Application in Eastern Partner countries

An economic analysis was carried out for the Eastern Partner countries for which the required minimum number of LNG-fueled trucks can potentially be considered as attainable. Armenia, Belarus, Georgia and Ukraine were examined (Table A. 116).

Table A. 116: LNG market examined for each Eastern Partner country

	Armenia	Belarus	Georgia	Ukraine
Number of LNG-fuelled trucks	134	205	62	60
Size of LNG market (mcm)	3.63	5.56	1.68	1.63

For each country, the examined source of LNG supply is the following:

- For Armenia, supply from a potential LNG terminal in Georgia;
- For Belarus, supply from the Klaipeda LNG reloading station;
- For Georgia, supply from a potential in-country receiving terminal;
- For Ukraine, supply from the Świnoujście LNG terminal.

It is noted that the minimum market size used for the analysis of each country is defined according to the characteristics of the country, and not using uniform assumptions across all Eastern Partners. For this reason, the results of the economic analysis provide an indication of the economic impact of the LNG option on the specific country but are not comparable on a regional level.

A5.1.3. Definition of investment and operational costs

The CAPEX and OPEX values used for the filling station and LNG trucks are the same with those used for the netback analysis, presented in Table A. 51 and Table A. 52 respectively.

As the life cycle of an LNG filling station is assumed to be 10 years, and that of an LNG truck 8 years, additional investments need to be taken into consideration in the 20-year economic analysis. It is assumed that, to continue the supply of LNG, a new investment for the filling station (equal to the initial investment) will be carried out in the 10th year, and new LNG trucks will be procured in the 8th and 16th year.

A5.1.4. Monetization of reduction of energy costs

The price differential between LNG and diesel will result in a reduction in the consumers' energy costs. The competing fuel price assessed at the filling station includes the equivalent LNG price of diesel, net of the fuel switching costs (calculated in Section A3.1.3 and Section A3.1.4). The LNG import price and truck loading costs assumed for each country depends on its supply source (Table A. 117).

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Table A. 117: LNG price differential estimated for each Eastern Partner country

	Armenia	Belarus	Georgia	Ukraine
LNG equivalent price (EUR/1000 m^3)	702.5	647.6	779.3	834.2
Fuel switching cost (EUR/1000 m^3)	296.0			
Competing price "at the pump" (EUR/1000 m^3)	406.5	351.6	483.3	538.2
LNG import price (EUR/1000 m^3)	220	200	220	200
Truck loading cost (EUR/1000 m^3)	46.8	46.8	46.8	10.4
Unit price reduction (EUR/1000 m^3)	**139.7**	**104.8**	**216.5**	**327.8**

For each market, it is assumed that there will be a gradual increase of the number of LNG-fuelled trucks, corresponding to 25% of the total number in the 1st year, 50% in the 2nd year and reaching 100% from the 3rd year onwards. Table A. 118 presents the annual energy cost saving for each country.

Table A. 118: Annual energy cost saving for each Partner Country

	Armenia	Belarus	Georgia	Ukraine
Unit price reduction (EUR/1000 m^3)	139.7	104.8	216.5	327.8
LNG sales (mcm)	3.63	5.56	1.68	1.63
Annual energy cost saving (mil. EUR)	**0.51**	**0.58**	**0.36**	**0.53**

As the analysis was performed on the basis of the minimum market size required for the LNG option to be economically viable, the price differential of LNG and diesel will be sufficient to cover costs for development and operation of the filling station, and the transportation of LNG with trucks from the terminal to the filling station.

A5.1.5. Monetization of environmental benefits

The monetization of the environmental benefits for switching from the current use of diesel to LNG is based on estimating the difference in GHG emissions for the two fuels, and shadow prices of GHG, which reflect the future cost of emissions.

The impact of the competing fuels on GHG emissions depends on factors such as the type and age of the trucks (e.g. a fleet of old trucks with Euro-4 engines would have a different carbon footprint than a renewed fleet Euro-6 engines), and their service modality (distance travelled in urban and rural areas/motorways). For example, a recent TNO study[211] concluded that, for specific engines and routes, LNG CO_2 and CH_4 tank-to-wheel emissions are lower than those of diesel, whereas LNG NOx emissions, specifically in urban areas, are higher while in motorways they are equal or lower than diesel.

For the purpose of the high-level analysis performed in this Study, we apply a benchmark aggregate value of GHG emissions for each fuel[212]. To ascertain the actual impact of switching to LNG in each country, the conditions in the country's transport sector (type and age of truck engines, service modalities, regulatory limitations) would have to be further analysed.

[211] TNO, Emissions testing of a Euro VI LNG-diesel dual fuel truck in the Netherlands, April 2019

[212] Source: I. Smajla et al. (Energies Journal)," Fuel Switch to LNG in Heavy Truck Traffic", 2019

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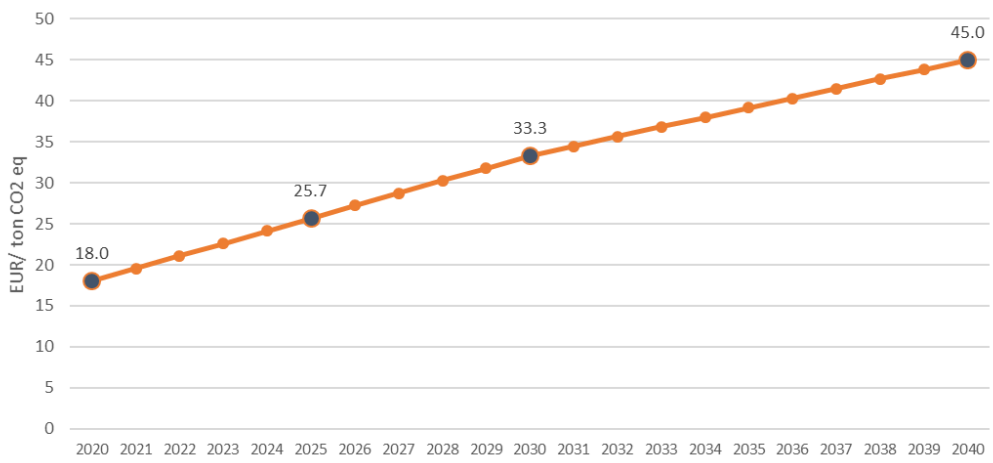
To estimate the economic benefit of emissions reduction, we apply the shadow price of CO_2 used by ENTSOs in the TYNDP 2018 scenarios[213]. The scenario path examined is the 2020-Expected Progress, 2025 Coal-Before-Gas, 2030-2040 Sustainable-Transition, which is the most conservative path of CO_2 prices' increase. The CO_2 prices for the intermediary years are calculated by applying linear interpolation (Figure A. 83).

Figure A. 83: Assumed growth of CO_2 prices



Source: ENTSOs TYNDP Scenario Report, Scenarios Fuel & CO2 Prices

As an example of the estimation of annual monetized benefit from GHG emissions' reduction, Table A. 119 presents the calculations for 2025, for each country.

Table A. 119: Annual energy cost saving for each Partner Country for 2025

	Armenia	Belarus	Georgia	Ukraine
GHG emission for diesel (kg CO_2eq/km)	2.83[212]			
GHG emission for LNG (kg CO_2eq/km)	2.57[212]			
Total emissions for diesel (kg CO_2eq/km)	34,504	52,786	15,965	15,450
Total emissions for LNG (kg CO_2eq/km)	31,365	47,984	14,512	14,044
CO2 price (EUR/ton CO_2eq)	25.7			
Annual energy cost saving (mil. EUR)	**0.08**	**0.12**	**0.04**	**0.04**

A5.1.6. Results of analysis

Armenia

Figure A. 84 presents the evolution of economic costs and benefits of the use of LNG as fuel for long-haul trucks in Armenia.

[213] ENTSOs TYNDP Scenario Report, Scenarios Fuel & CO2 Prices

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Figure A. 84: Evolution of economic costs / benefits for LNG as fuel for long-haul trucks in Armenia

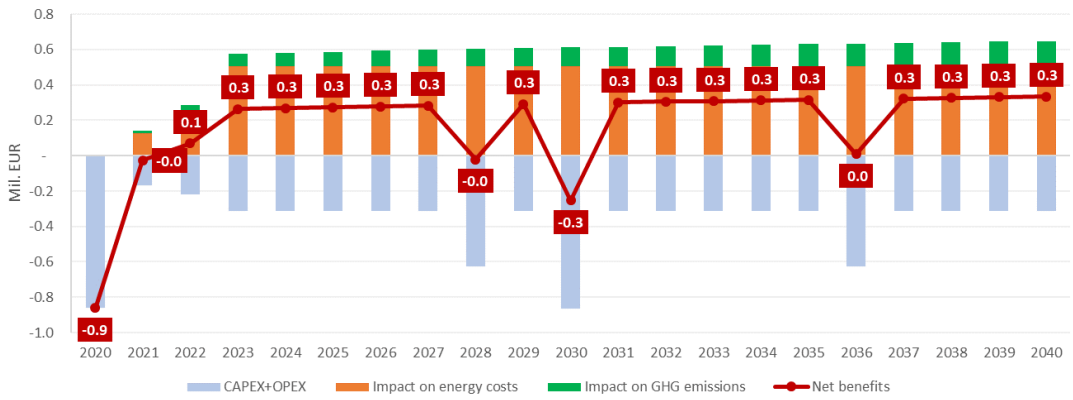

Table A. 120 presents the present values of the calculated economic costs and benefits for the examined LNG option.

Table A. 120: Present value of economic costs and benefits for LNG as fuel for long-haul trucks in Armenia

	Present Value
CAPEX + OPEX (Mil. EUR)	*-5.7*
Impact on gas price (Mil. EUR)	6.3
SoS benefit (Mil. EUR)	1.3
Net benefits (Mil. EUR)	**1.9**

Table A. 121 presents the economic indicators for the examined LNG option.

Table A. 121: Economic indicators for LNG as fuel for long-haul trucks in Armenia

	Indicator
ENPV (Mil. EUR)	1.89
B/C Ratio	1.33

Belarus

Figure A. 85 presents the evolution of economic costs and benefits of the use of LNG as fuel for long-haul trucks in Belarus.

Figure A. 85: Evolution of economic costs / benefits for LNG as fuel for long-haul trucks in Belarus

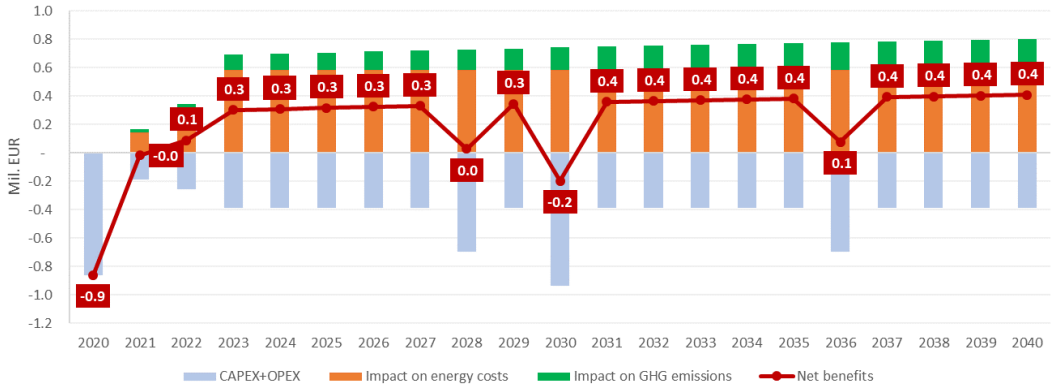

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Table A. 122 presents the present values of the calculated economic costs and benefits for the examined LNG option.

Table A. 122: Present value of economic costs and benefits for LNG as fuel for long-haul trucks in Belarus

	Present Value
CAPEX + OPEX (Mil. EUR)	*-6.6*
Impact on gas price (Mil. EUR)	7.2
SoS benefit (Mil. EUR)	1.9
Net benefits (Mil. EUR)	**2.6**

Table A. 123 presents the economic indicators for the examined LNG option.

Table A. 123: Economic indicators for LNG as fuel for long-haul trucks in Belarus

	Indicator
ENPV (Mil. EUR)	2.56
B/C Ratio	1.39

Georgia

Figure A. 86 presents the evolution of economic costs and benefits of the use of LNG as fuel for long-haul trucks in Georgia.

Figure A. 86: Evolution of economic costs / benefits for LNG as fuel for long-haul trucks in Georgia

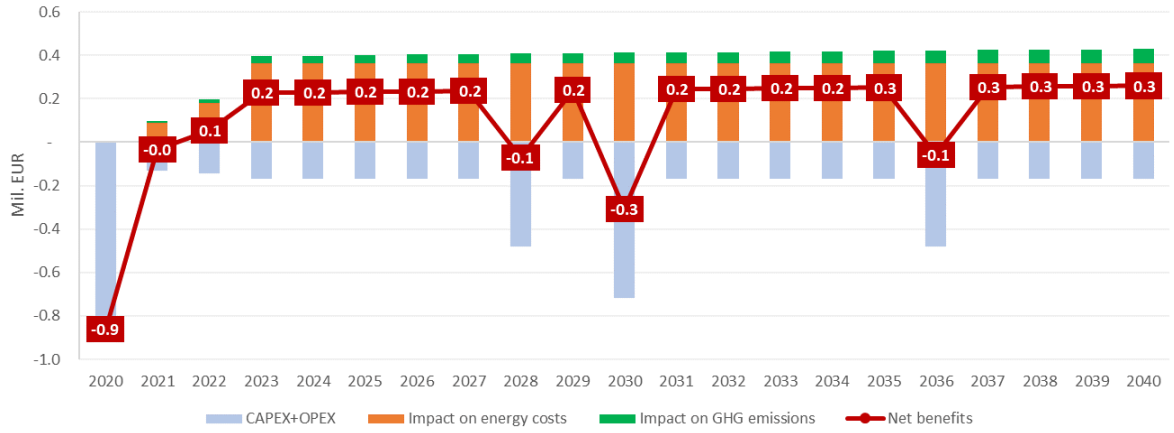

Table A. 124 presents the present values of the calculated economic costs and benefits for the examined LNG option.

Table A. 124: Present value of economic costs and benefits for LNG as fuel for long-haul trucks in Georgia

	Present Value
CAPEX + OPEX (Mil. EUR)	*-3.9*
Impact on gas price (Mil. EUR)	4.5
SoS benefit (Mil. EUR)	0.6
Net benefits (Mil. EUR)	**1.2**

Table A. 125 presents the economic indicators for the examined LNG option.

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Table A. 125: Economic indicators for LNG as fuel for long-haul trucks in Georgia

	Indicator
ENPV (Mil. EUR)	1.23
B/C Ratio	1.32

Ukraine

Figure A. 87 presents the evolution of economic costs and benefits of the use of LNG as fuel for long-haul trucks in Ukraine.

Figure A. 87: Evolution of economic costs / benefits for LNG as fuel for long-haul trucks in Ukraine

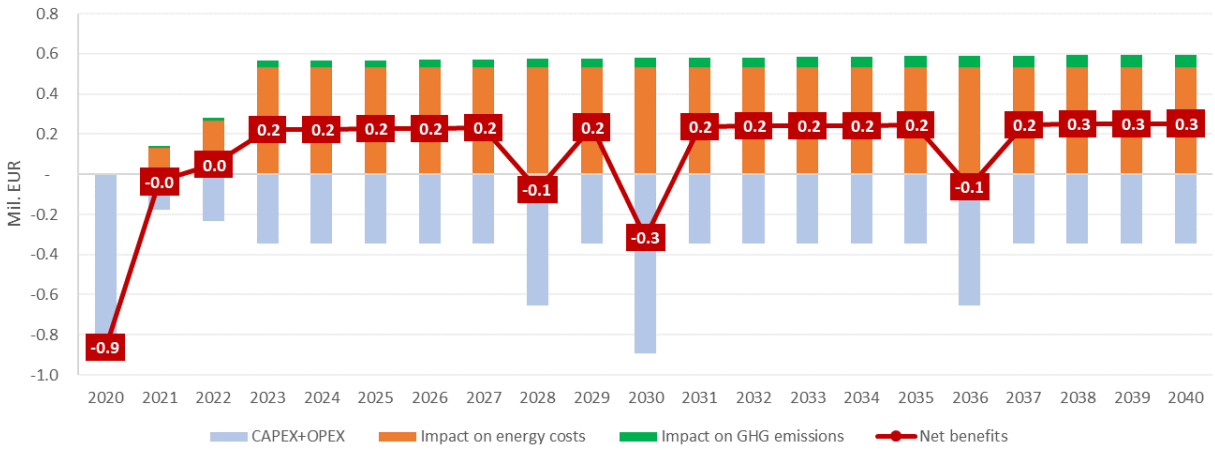

Table A. 126 presents the present values of the calculated economic costs and benefits for the examined LNG option.

Table A. 126: Present value of economic costs and benefits for LNG as fuel for long-haul trucks in Ukraine

	Present Value
CAPEX + OPEX (Mil. EUR)	*-6.0*
Impact on gas price (Mil. EUR)	6.6
SoS benefit (Mil. EUR)	0.6
Net benefits (Mil. EUR)	**1.2**

Table A. 127 presents the economic indicators for the examined LNG option.

Table A. 127: Economic indicators for LNG as fuel for long-haul trucks in Ukraine

	Indicator
ENPV (Mil. EUR)	1.16
B/C Ratio	1.19

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A5.2. Economic analysis for LNG supply to off-grid consumers

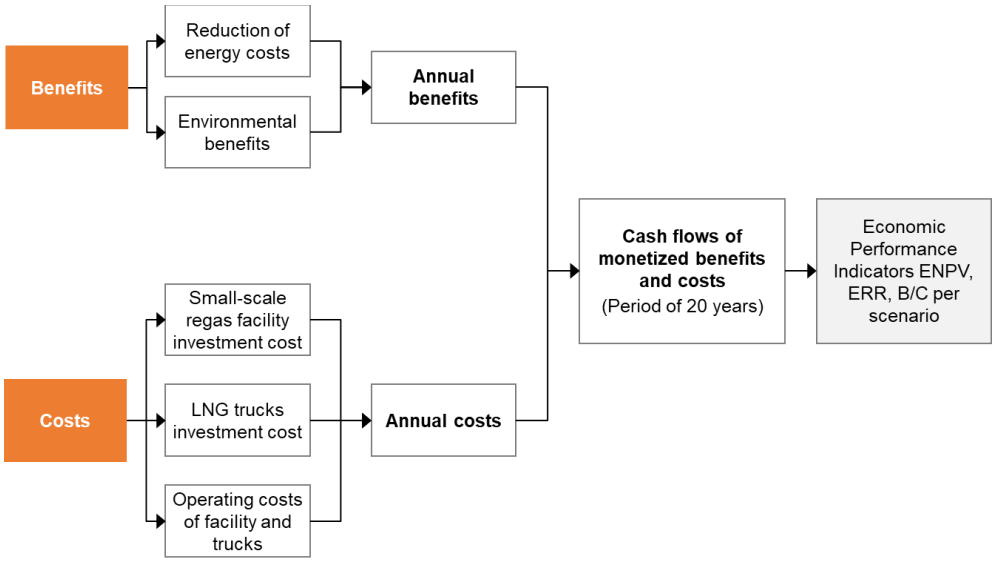
A5.2.1. Analysis approach

The aim of the economic (cost-benefit) analysis to assess whether the costs for supplying an off-grid consumer (investment and operating expenses for a small-scale regasification facility at the consumer, and for using LNG trucks to supply the facility) are outweighed by its potential economic benefits for cost reduction and reduction of GHG emissions.

The overall approach is the same with the one described in Section A4.1.1. In this case, the costs and monetized benefits assessed are the following (Figure A. 88):

- Costs:
  - Investment costs for the development of a small-scale LNG storage and regasification facility at the consumer's site;
  - Cost for purchase of LNG trucks to transport LNG to the regasification facility;
  - Annual operating costs for the facility and trucks.
- Monetized benefits:
  - Reduction of energy costs for the examined final consumer;
  - Environmental benefits from reduction of GHGs.

Figure A. 88: Assessment of costs and benefits



The economic analysis was carried out for a 20-year period, assuming development of the required infrastructure in 2020 and commencement of LNG supplies in 2021. As in the case of Annex 4, a social discount rate of 4% has been applied in the calculations.

The analysis results in the estimation of the key economic performance indicators; the Economic Net Present Value (ENPV), Economic Rate of Return (ERR), and Benefit-to-Cost ratio (B/C).

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A5.2.2. Application in Eastern Partner countries

Economic analysis was carried out for the case study of an off-grid agriculture site in Ukraine that is examined in Section A3.3 with annual gas demand of 5.2 mcm. The supply from the Świnoujście LNG terminal is analysed.

A5.2.3. Definition of investment and operational expenses

The CAPEX and OPEX values used for the regasification and LNG trucks are the same with those used for the netback analysis, presented in Table A. 74 and Table A. 75 respectively.

As the life cycle of a regasification facility is assumed to be 10 years, and that of an LNG truck 8 years, additional investments need to be taken into consideration in the 20-year economic analysis. It is assumed that, to continue the supply of LNG, a new investment for the regasification facility (equal to the initial investment) will be carried out in the 10th year, and new LNG trucks will be procured in the 8th and 16th year.

A5.2.4. Monetization of reduction of energy costs

The price differential between LNG and LPG will result in a reduction in the energy costs of the agriculture site. The competing fuel price assessed at the end consumer includes the equivalent LNG price of LPG (calculated in Section A3.3.3). The estimation of the price differential, for supply of LNG from the Świnoujście LNG terminal is presented in Table A. 128.

Table A. 128: LNG price differential for the supply of LNG to the agriculture site

	Ukraine
LNG equivalent price (EUR/1000 m^3)	508.5
LNG import price (EUR/1000 m^3)	200
Truck loading cost (EUR/1000 m^3)	10.4
Unit price reduction (EUR/1000 m^3)	**298.1**

Table A. 129 presents the annual energy cost saving for the end consumer. As the consumption of gas is assumed to remain constant, the savings are the same for all years of the analysis.

Table A. 129: Annual energy cost saving for the supply of LNG to the agriculture site

	2021	2025	2030	2035	2040
Unit price reduction (EUR/1000 m^3)	298.1	298.1	298.1	298.1	298.1
Gas consumption (mcm)	5.2	5.2	5.2	5.2	5.2
Annual energy cost saving (mil. EUR)	**1.55**	**1.55**	**1.55**	**1.55**	**1.55**

A5.2.5. Monetization of environmental benefits

The monetization of the environmental benefits for the agriculture site switching from LPG to natural gas is based on estimating the difference in GHG emissions for the two fuels, and shadow prices of GHG, which reflect the future cost of emissions.

The values applied for GHG emissions used for natural gas and LPG are those applied by ENTSOG in the TYNDP 2017. The CO_2 prices used are those define in Section A5.1.5.

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Table A. 130: Annual energy cost saving for the supply of LNG to the agriculture site

	2021	2025	2030	2035	2040
GHG emission for diesel (kg CO_2eq/kWh)	0.23[214]				
GHG emission for natural gas (kg CO_2eq/kWh)	0.20[214]				
Total emissions for diesel (kg CO_2eq/km)	13,235	13,235	13,235	13,235	13,235
Total emissions for LNG (kg CO_2eq/km)	1,508	11,508	11,508	11,508	11,508
CO2 price (EUR/ton CO_2eq)	19.5	21.1	25.7	33.3	45.0
Annual energy cost saving (mil. EUR)	**0.03**	**0.04**	**0.04**	**0.06**	**0.08**

A5.2.6. Results of analysis

Figure A. 89 presents the evolution of economic costs and benefits of the use of LNG as a means to supply gas to off-grid consumers in Ukraine.

Figure A. 89: Evolution of economic costs / benefits for LNG supply to off-grid consumers in Ukraine

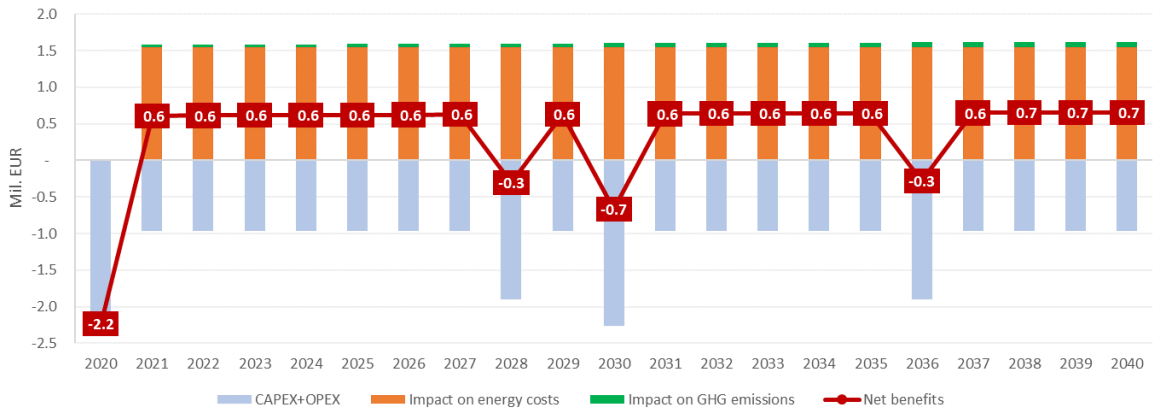

Table A. 131 presents the present values of the calculated economic costs and benefits for the examined LNG option.

Table A. 131: Present value of economic costs and benefits for LNG supply to off-grid consumers in Ukraine

	Present Value
CAPEX + OPEX (Mil. EUR)	*-17.4*
Impact on gas price (Mil. EUR)	21.0
SoS benefit (Mil. EUR)	0.7
Net benefits (Mil. EUR)	**4.3**

Table A. 132 presents the economic indicators for the examined LNG option.

Table A. 132: Economic indicators for LNG supply to off-grid consumers in Ukraine

	Indicator
ENPV (Mil. EUR)	4.3
B/C Ratio	1.25

[214] ENTSOG TYNDP 2017

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Annex 6: Key LNG infrastructure cost benchmarks

The Table below summarizes the investment cost benchmarks for LNG infrastructure that have been used in the analysis of this Study.

Item	Investment cost benchmark
On-shore LNG terminal	250 USD/tpa[215]
FSRU vessel	260 mil. EUR/vessel[215]
LNG truck	310,000 EUR/truck[216]
Retrofitting costs for LNG-fueled truck	22,000 EUR/truck[217]
LNG filling station	528,000 EUR/station[218]
Small-scale liquefaction facility	7.7 – 12.5 mil. EUR (for capacities ranging from 16 ton/d to 50 ton/d of LNG production) [219]
Small scale LNG storage	800 – 3,000 USD/m^3 [220]

[215] Source: Oxford Institute for Energy Studies, "The Outlook for Floating Storage and Regasification Units", 2017
[216] Source: Interview with Klaipedos Nafta
[217] Assumption based on reported range of prices from various sources
[218] Source: NGVA Europe, EC 7th Framework Programme, "Cost analysis of LNG refuelling stations", 2016
[219] Source: World Bank, "Mini / Micro LNG for commercialization of small volumes of associated gas", 2015
[220] Source: IGU, "2012 – 2015 Triennium Work Report – Small Scale LNG", 2015

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Annex 7: Currency / Unit Conversions

Exchange rates:

1 USD = 0.91 EUR

1 BYR = 0.44 EUR

1 GEL = 0.32 EUR

1 UAH = 0.034 EUR

1 AMD = 0.0019 EUR

1 AZN = 0.52 EUR

1 PLN = 0.23 EUR

1 MLD = 0.051 EUR

1 LEI = 0.21 EUR

1 BGN = 0.51 EUR

Gross Calorific Values:

Polish Transmission System: 11.56 kWh/m^3

Klaipeda LNG terminal: 11.70 kWh/m^3

Bulgarian Transmission System: 11.42 kWh/m^3

Romanian / Moldovan Interconnection: 11.13 kWh/m^3

Romanian / Ukrainian Interconnection: 11.41 kWh/m^3

Croatian Transmission System: 11.33 kWh/m^3

Ukrainian Transmission System: 11.1 kWh/m^3

Moldovan Transmission System: 11.4 kWh/m^3

Hungarian Transmission System: 11.41 kWh/m^3

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