# CBA SOUTH KAVALA UGS

## A report for the Hellenic Republic Asset Development Fund

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Confidential

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# 1 EXECUTIVE SUMMARY

HRADF is planning to award a concession for a regulated underground gas storage (UGS) facility at South Kavala after a competitive tender. The regulation for the UGS will be developed by RAE. To inform the regulation this report contains a cost-benefit analysis of a UGS at South Kavala in line with the 2nd ENTSOG methodology. The methodology includes monetary costs, monetary benefits, and non-monetary benefits.

The monetary costs of the UGS are based on two variations of a UGS: a UGS based on a publication by Energean with total costs of €305 million, and a smaller UGS based on TYNDP with total costs of €242 million (NPV, real 2020).

The monetary benefits are assessed using a range of scenarios to capture the uncertainties regarding the future environment in which the UGS will operate. These scenarios include assumptions on demand, infrastructure, the pricing of natural gas in Greece, and allow policy makers to explore a range of benefits generated under different assumptions.

We define a reference case based on a central scenario for demand, a scenario in which only current + FID infrastructure exists, a gas price scenario in which pipeline gas is cheaper than LNG by an amount which is broadly representative of historic spreads, and disruption events related to the non-availability of LNG import infrastructure and the non-availability of gas through Turkish supply routes.

The monetary benefits for the reference case (all NPV, real 2020) are:

- The benefits of trade. These benefits are generated by injecting gas when the costs of gas are low, and withdrawing gas when it can displace more costly gas. The associated benefits are €208 million (€145 million for the smaller UGS);
- Security of supply. The UGS is an additional source of gas supply in Greece. It provides natural gas to consumers that would otherwise not be served in a number of disruption events. The choice of disruption events to value and the value placed on this is a matter for Greek policy makers. Based on the reference case events, the results suggest a benefit between €41 to €128 million (€17 to €100 million for the smaller UGS); and
- Residual value. This reflects the value of the UGS after 2050, and accounts for and €21 million (€19 million or smaller UGS).

The combination of monetised costs and benefits suggests a positive case for investment, although this outcome is dependent on the valuation of security of supply. When a higher demand scenario is considered, benefits of trade amount to €225 million. The application of the ENTSOG methodology to a very severe disruption amounts to security of supply benefits of €568 million.

A number of important non-monetised benefits supplement the monetised aspects of the CBA, including:

- Additional trading value not captured in our modelling framework, including:
  - Avoided variable costs in LNG regassification or pipeline transport;
  - Additional value as a result of real world uncertainty;

- The facilitation of enhanced competition in relevant gas markets;
- Contributions to the use of fuel with a lower emission intensity (emergency diesel, or use in a hydrogen or CO2 system); and
- Potential benefits as a result of avoided network infrastructure costs.

# 2 INTRODUCTION

## 2.1 The context for this report

The South Kavala natural gas field is a nearly depleted natural gas field located in the Thracian Sea. HRADF is the Greek agency responsible for the development of assets in Greece which are part of the privatisation programme. As part of this programme, HRADF will award the rights to develop an underground storage facility at South Kavala after a competitive tender. It is envisaged that the successful tenderer will develop and then operate a regulated UGS. The UGS will be regulated by RAE, the independent regulatory authority for energy in Greece. RAE has been tasked with setting out the relevant revenue regulation.[1]

To inform the regulation RAE requires a cost benefit analysis (CBA) setting out the relevant costs and benefits of a UGS at South Kavala. Frontier Economics has been commissioned by HRADF to provide this CBA.

## 2.2 Structure of the report

The structure of the report is as follows:

- Section 3 sets out the CBA framework;
- Section 4 sets out two different variations of the UGS;
- Section 5 sets out relevant scenarios;
- Section 6 sets out the results of the CBA given a reference case of scenarios;
- Section 7 sets out the benefits of trade under different scenarios;
- Section 8 sets out the security of supply benefits under different scenarios;
- Section 9 describes the competition benefits associated with the UGS;
- Section 10 describes the sustainability benefits associated with the UGS;
- Section 11 describes the trade and system benefits of the UGS; and
- Section 12 provides a conclusion.

1 Official gazette of the Hellenic Republic, Issue B '759 / 05.03.2019.

# 3 COST BENEFIT FRAMEWORK

## 3.1 General introduction

The general framework for this CBA is based on the 2nd ENTSOG methodology for cost-benefit analysis of gas infrastructure projects.[2] The purpose of the ENTSOG methodology is to provide guidelines to stakeholders for the evaluation the costs and benefits of gas infrastructure such that gas infrastructure projects are assessed in a consistent manner. The methodology is primarily developed for the selection of projects of common interest and ENTSOG's TYNDP process. It also provides a blueprint for CBAs outside of this context, e.g. in the context of national decision making.[3]

The CBA approach suggested by ENTSOG is based on multi-criteria analysis. This form of CBA seeks to estimate costs and benefits in three ways:

- Provide a monetary evaluation of costs and benefits when there is a suitable methodology to express the costs benefits in monetary terms;
- Provide a quantitative evaluation of benefits when there are methods that allow for a quantitative insight; and
- Provide a qualitative evaluation of benefits when no quantitative method has been developed or provides insufficient detail on the scope of the benefit.

The monetary value in the CBA is therefore only a part of the value that should be considered by stakeholders.

The benefits that are generated by the underground gas storage (UGS) are assessed based on a factual/counterfactual approach. This means the effects of the storage facility are considered by a comparison of outcomes when investment in the UGS does take place (factual) versus the outcomes when investment in the UGS does not take place (counterfactual), keeping all other factors constant. To capture the uncertainty regarding the future environment in which the UGS will operate, the factual/counterfactual analysis is carried out for a range of scenarios, reflecting different developments that might occur in the future, but which are inherently uncertain. Section 5 sets out the scenarios considered.

## 3.2 Costs and benefits considered

The ENTSOG framework sets out a number of costs and benefits to be considered:

- The capital costs and operating costs of the facility (Section 4);
- The benefits in relation to:
  - Benefits of trade (Section 7). These benefits relate to the trade of natural gas. For a UGS this mainly refers to the injection of gas at lower costs, replacing more expensive gas at times of high demand, and therefore representing a resource cost saving to society (increased social welfare). In order to capture

[2] Available at https://www.entsog.eu/sites/default/files/2019-03/1.%20ADAPTED_2nd%20CBA%20Methodology_Main%20document_EC%20APPROVED.pdf.

[3] Although the CBA design and parameters used by ENTSOG might serve as a clear reference point for stakeholders, stakeholders can chose the apply different designs and parameters in their specific contexts.

this benefit this analysis relies on a wholesale gas model to estimate the costs of gas in Europe (subject to a number of constraints and assumptions on costs of gas and availability of infrastructure) in a number of snapshot years. The model estimates the use of the UGS as well as the impact it has on prices in the Greek market. More details are provided in Section 7;

- Security of Supply (Section 8). This benefit reflects the increased availability of natural gas to serve demand at times of system stress, e.g. at times of high demand or the failure of infrastructure or supply routes;
- Competition (Section 9). This benefit reflects the impact the UGS has in promoting competitive outcomes in the market;
- Sustainability (Section 10). This benefit reflects the impact the UGS has in reducing emissions in the Greek economy; and
- Other benefits (Section 11). For gas storages, ENTSOG highlights further value in the form of trading value and system value.

The benefits of trade and security of supply are the main benefits that are monetised in this CBA, while the valuation of other benefits relies to a greater extent on qualitative and quantitative descriptions.

The monetised costs and benefits are discounted using a social discount rate, to capture the difference in value placed on costs and benefits occurring over time (e.g. a benefit arising today is worth more than the same benefit arising in ten years' time). The costs and benefits considered in this CBA are those costs and benefits expected to occur until 2050 (inclusive), and are discounted to 2020, i.e. the value that those costs and benefits have today.[4] This is referred to as the present value, and is used throughout this report to represent the total value of the monetised costs/benefits, estimated to occur up to 2050.[5] The UGS is assumed to be in operation in 2025.

The CBA analysis is designed to estimate the overall welfare improvement to society as a result of investment in the UGS. It does not allocate any of the costs or benefits to producers or consumers,[6] but rather seeks to address the question whether an investment in the UGS will lead to an overall welfare improvement for society.[7]

While the ENTSOG methodology focuses on social welfare, the value of the UGS investment to society can be disaggregated into benefits that accrue to identifiable groups of private entities (e.g. gas traders or the facility operator), and those which cannot be captured by individual or groups of entities, and therefore accrue to society as a whole. For example:

- Gas traders value the right to use the UGS based on arbitrage value between the wholesale price at which gas is injected and withdrawn. In principle this value can be extracted by the operator of the storage facility, i.e. by the collection of revenues from those that derive a direct benefit from it. These benefits are therefore considered private benefits; and
- Other benefits such as the security of supply benefit or increased competition cannot easily be extracted by the operator or other market participants such as

4 The discount rate is 4% real, as required in the ENTSOG methodology.

5 It should not be mistaken for an annual value.

6 For example, we do not assume any tariff for the UGS.

7 Society might refer to Greek or European society. This report focusses on Greek society.

traders in gas. These benefits are social benefits, which cannot be captured by individual entities or groups of entities.

If an investment is societally positive (i.e. social benefits are higher than social costs) but privately negative (i.e. private benefits are less than private costs), then in the absence of intervention, the investment would not occur. There can therefore be a strong case for intervention to ensure that a net-welfare enhancing investment takes place.

If social welfare is disaggregated into effects on consumers and producers (or importers), policy makers might also consider how an investment could lead to redistributive effects. These effects are most clear for price effects:

- The use of the UGS might lead to an increase or decrease in price which all producers and consumers face. In particular:
  - If the UGS displaces more expensive sources of supply when gas is being withdrawn, this can benefit consumers by reducing the price of gas which all face. At the same time the lower price reduces the surplus for producers or importers (i.e. there is a transfer from producers to consumers). The saving to all consumers (all gas demand) might be greater than the benefit to society (which just relates to that share of demand which is now served with gas at lower resource costs);
  - Conversely, the UGS will be an additional source of demand for gas when gas is being injected, which will increase prices to consumers and to producers or importers;

  These considerations are discussed in more detail in Section 7;
- Use of the UGS may avoid demand curtailment. This may prevent the market price rising to the cost of unserved gas demand. Equivalent to the redistributional effect in normal market conditions, this would benefit consumers but decrease producer surplus. These are likely to be greater than the social benefit, which simply relates to the lost value on the units of energy demand, which can be met thanks to the operation of the UGS.[8]

Policy makers might put different weights on consumer and producer surplus. If greater weight is placed on consumer surplus, the additional consumer surplus generated by UGS provides an upper bound to the willingness of consumers to contribute to the investment. A contribution lower than the upper bound of generated consumer surplus will make consumers better off.

The ENTSOG methodology does not consider the redistributive effects of investments. This report does consider the redistributive impacts given the context of revenue regulation and socialisation that might be introduced for the UGS. The analysis of redistributive effects should however be interpreted with due care This is because it depends on behavioural assumptions and information that are currently unavailable or subjective.

[8] This report does not explicitly address redistributional effects during extreme events such as those considered in Security of Supply analysis.

## 3.3 Scenario analysis

As set out above, the results of the quantitative aspects of the cost benefit analysis are derived by comparing the gas system with, and without a UGS in place. The results therefore depend on:

- The characteristics of the investment.
- The storage capacity and other operational characteristics of the UGS determine the extent to which it generates benefits. The UGS characteristics considered are based on two publications:
  - Analysis by Energean;
  - The 2018 ENTSOG TYNDP.

  The details are set out in Section 4.
- The definition of the factual and counterfactual scenario regarding the environment in which the UGS will operate:
  - In relation to situations in which normal operation of the market is expected, three dimensions are considered, with two or three scenarios analysed for each dimension: demand, infrastructure availability, and supply cost;
  - In relation to stress situations, three separate dimensions are considered: climatic stress, infrastructure stress (the failure of the largest piece of infrastructure) and supply route stress (disruption to supply routes).

  The details of the scenarios considered are set out in Section 5.

# 4 TWO VARIATIONS OF THE UGS

This CBA considers two variations of a UGS facility at South Kavala:

- The UGS as envisaged by Energean;[9] and
- The UGS as envisaged in the ENTSOG TYNDP.[10]

The technical characteristics and costs of these two variations are different. Two variations are considered, because the technical characteristics of the UGS that will be developed by the successful concession holder are unknown at this stage.

## 4.1 The technical characteristics of the UGS

The two variations of the UGS have technical specifications as set out in Figure 1.

**Figure 1 Key technical specifications of UGS facilities**

| | Energean | TYNDP |
|---|---|---|
| Withdrawal rate, GWh/d | 103 | 44 |
| Injection rate, GWh/d | 80 | 55 |
| Working gas volume, GWh | 6,063 | 3,861 |

*Source: Energean and ENTSOG TYNDP*

The Energean facility is the larger of the two facilities, with a withdrawal rate of 103 GWh/d and an injection rate of 80 GWh/d. The working gas volume of the facility is 6,063 GWh.

The TYNDP facility is the smaller of the two facilities, with a withdrawal rate of 44 GWh/d and an injection rate of 55 GWh/d. The working gas volume of the facility is 3,861 GWh.

## 4.2 The costs of the UGS

The cost estimates for the two variations of the UGS are presented in Figure 2.

**Figure 2 Cost estimates of UGS facilities (undiscounted)**

| € million, 2020 prices | Energean | TYNDP |
|---|---|---|
| Capex<br>(range) | 305<br>(239 – 371) | 242<br>(181 – 302) |
| Opex, annual<br>(range) | 4.6<br>(3.6 – 5.6) | 3.6<br>(2.7 – 4.5) |

*Source: Energean and ENTSOG TYNDP*

The capital expenditures presented in Figure 2 are based on the original estimates made in 2011 (Energean) and 2014 (TYNDP). To account for cost developments in the sector, these estimates have been inflated using the Upstream Capital Costs Index for the oil and gas sector as published by IHS Markit.[11] As shown in Figure 3, a

9 Available at http://www.hazliseconomist.com/uploads/speeches/CyprusEnergy2011/Rigas_Mathios.pdf.

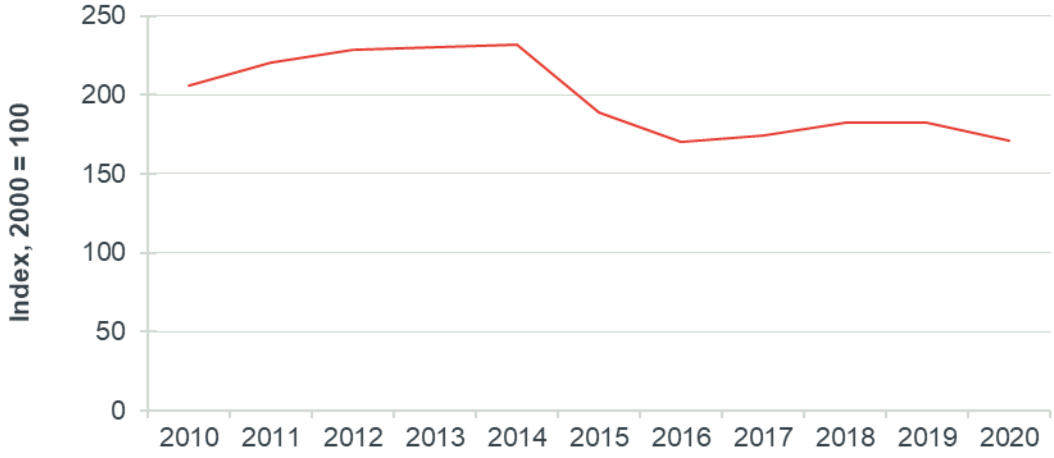
10 Available at https://www.entsog.eu/sites/default/files/2019-04/TYNDP%202018%20Project-Specific%20CBA%20Results.pdf.

11 Available at https://ihsmarkit.com/info/cera/ihsindexes/index.html.

decrease in costs can be expected relative to the costs estimates from 2001 and 2014.

The capital costs of the Energean facility are estimated to be €305 million versus €242 million for the TYNDP facility. Although the larger Energean facility has higher capital costs, the costs per unit of withdrawal rate are significantly lower.

**Figure 3 Upstream Capital Costs Index**




*Source: IHS Markit*

*Note: The latest information available for 2020 is Q2*

The capital cost estimate for the Energean facility also allows for an update to the cost of cushion gas, which is indexed with the price of gas observed on TTF[12] for the summer of 2022. A breakdown of the costs of the TYNDP facility was not available to us. Although we understand from HRADF it includes cushion gas, the exact value for this cost element is unknown.

The total capital spent for both facilities is spread equally across the 3 years before the facility becomes operational in 2025. The assumed lifetime for both facilities is 40 years.

There is limited amount of detail available on the required operational expenditure. The estimated ratio of annual operating costs to capital costs in the TYNDP is 1.5%. No estimate is available for the Energean scenario and therefore the same ratio is applied, to derive the operational expenditure of both facilities.

To capture some of the uncertainty around the actual level of costs, cost sensitivities are also considered. A positive and negative deviation to the costs of 25% is assessed, similar to the estimates presented in the TYNDP publication.[13] It is worth noting that the level of uncertainty around these estimates is higher than in typical CBAs, given the absence of recent cost estimates and the uncertainty regarding the type of facility that will be developed at South Kavala.

[12] Title Transfer Facility, the hub for natural gas in the Netherlands and the most liquid market in continental Europe.

[13] No range is available for the Energean facility, and therefore the same sensitivities are applied.

If other sources of funding are available to finance the capital investment (e.g. CEF funding), this funding can be applied proportionally to the capital costs to evaluate the economic performance.

Assuming the assumptions described above, the NPV of capital cost is shown in Figure 4.

**Figure 4 Capital cost estimates of UGS facilities**

| € million, 2020 prices | Low case | Medium case | High case |
|---|---|---|---|
| Energean | 205 | 261 | 317 |
| TYNDP | 155 | 207 | 258 |

*Source: Energean and ENTSOG TYNDP*

Assuming the assumptions described above, the NPV of operating cost is shown in Figure 5.

**Figure 5 Operating cost estimates of UGS facilities**

| € million, 2020 prices | Low case | Medium case | High case |
|---|---|---|---|
| Energean | 47 | 60 | 73 |
| TYNDP | 36 | 48 | 60 |

*Source: Energean and ENTSOG TYNDP*

# 5 SCENARIOS AND ASSUMPTIONS

We assess the UGS under scenarios related to the demand, supply and infrastructure. Our scenarios vary according to:

- The level of gas demand in Greece (Section 5.1);
- The availability of infrastructure that can compete with the UGS to satisfy demand in Greece (Section 5.2); and
- The pricing of individual supply routes over time and the difference between them (Section 5.3).

An overview of these scenarios and a reference case is presented in Section 5.5.

We also assess the UGS under scenarios related to stress conditions for our assessment of Security of Supply. These stress conditions are introduced in Section 5.4.

## 5.1 Demand scenarios

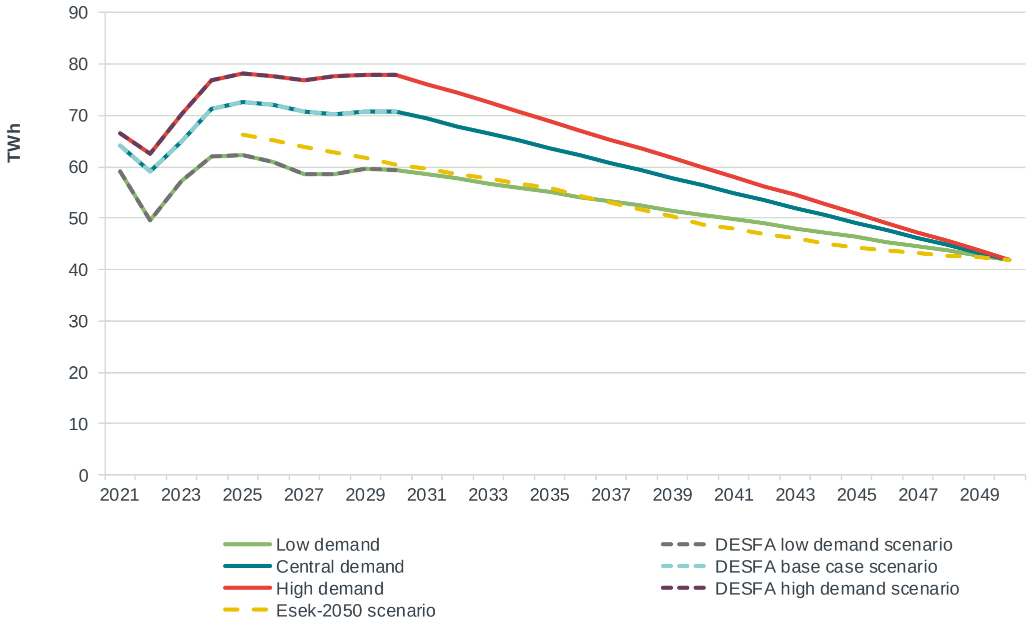
We model three different annual demand scenarios for Greece from 2020 to 2050:

- A central demand scenario, which corresponds to DESFA's base case demand estimation until 2030 and then consists of a linear extrapolation to the 2050 demand estimation of the Esek-2050 scenario;
- A low demand scenario, which corresponds to DESFA's low demand estimation until 2030 and then consists of a linear extrapolation to the 2050 demand estimation of the Esek-2050 scenario; and
- A high demand scenario, which corresponds to DESFA's high case demand estimation until 2030 and then consists of a linear extrapolation to the 2050 demand estimation of the Esek-2050 scenario.

The Esek-2050 scenario is part of the national long-term strategy scenarios considered in the National Energy and Climate Plan.[14]

[14] Available at https://ec.europa.eu/clima/sites/lts/lts_gr_el.pdf.

### Figure 6 Annual demand scenarios




*Source: DESFA Development Study 2021-2030, p7*
*Greek 2050 long-term strategy, https://ec.europa.eu/clima/sites/lts/lts_gr_el.pdf*

In the near future Greek gas demand is projected to increase due to the increased presence of gas-fired power generators in Greece, but overall demand is projected to decrease until reaching 42 TWh demand in 2050.

The gas demand of other European countries is taken from the ENTSOG TYNDP 2018 data:

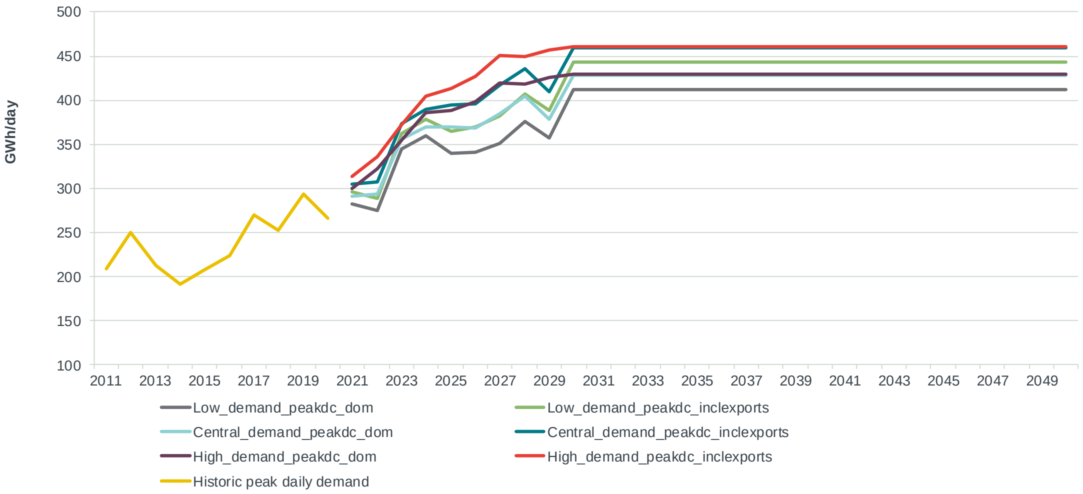
- For the year 2025, the “gas before coal demand” level is used;
- For 2030 and 2040, the demand estimates are taken from the “Sustainable Transition” scenario; and
- For 2050, gas demand levels are assumed to remain at 2040 levels.

For the purposes of the wholesale model, the annual demand is allocated across the year based on a profile of 30 representative days and projections received from DESFA. For the years 2025 and 2030 separate profiles are specified. Thereafter, the profile for gas demand remains the same as in 2030. Annex A.2 provides more detail.

For the purposes of security of supply analysis, extreme levels of demand are considered. They relate to:

- Demand expected on the peak day of an extremely cold winter with a probability of occurrence once every 20 years. This is typically referred to as the design case, 1-in-20 peak day, or extreme peak day. These values are reported by DESFA for 2025 and 2030 for each of the scenarios. No detailed information is available for the years thereafter. The levels of 1-in-20 peak day demand are therefore kept constant through 2050 for each of the demand scenarios; and

**Figure 7 1-in-20 peak day demand**




*Source: DESFA historic data and Frontier Economics*

- Demand expected during a two-week cold spell with a probability of occurrence once every 20 years. The average daily demand level during this cold spell, is based on the projected ratio of 1-in-20 peak demand, and the two-week cold spell reported to ENTSOG for winter 2019/2020.[15] DESFA has also provided the value of a two-week cold spell for the high demand level in 2030, and this ratio is presented as a sensitivity.

# 5.2 Infrastructure scenarios

A number of sizeable gas infrastructure projects are planned in the region in the near future. These include expanded pipeline and LNG terminal capacity, as well as access to new natural gas sources. To understand the impact of such new infrastructure on the benefits resulting from the development of the UGS, we consider scenarios with difference configurations of entry and exit capacity in Greece.

We have formulated the infrastructure scenarios based on project status as follows:

- Existing + FID infrastructure;
- Existing + FID + advanced infrastructure; and
- Existing + FID + less advanced infrastructure (including advanced).

We do not consider a scenario based on existing infrastructure alone, because all FID infrastructure in the Greek gas market is expected to be operational on, or before the UGS commissioning date.

The starting point for our infrastructure scenarios was the latest data available from ENTSOG (TYNDP 2018). We have refined and supplemented this with additional information from HRADF and RAE, and official information made available by infrastructure promoters. We display the entry capacities in Figure 8 and Figure 9.

[15] Available at https://www.entsog.eu/sites/default/files/2019-10/SO024-19%20Winter%20Supply%20Outlook%202019-20.pdf.

Infrastructure developments in the rest of Europe are based on data from TYNDP 2018.

**Figure 8 Infrastructure scenario entry points and maximum daily capacities, GWh/d**

| | Existing + FID | Existing + FID + advanced | Existing + FID + less advanced |
|---|---|---|---|
| Sidirokastro | 121 | 121 | 121 |
| Kipi | 48 | 48 | 48 |
| Revithoussa LNG | 241 | 241 | 241 |
| TAP | 54 | 54 | 54 |
| Alexandroupolis LNG | | 202 | 202 |
| EastMed | | | 330 |
| Dioryga LNG | | | 132 |
| **Total** | **464** | **666** | **1,128** |

*Source: Frontier Economics*

**Figure 9 Infrastructure scenario exit points and maximum daily capacities, GWh/d**

| | Existing + FID | Existing + FID + advanced | Existing + FID + less advanced |
|---|---|---|---|
| Sidirokastro | 65 | 65 | 65 |
| IGB | 90 | 90 | 90 |
| North Macedonia | | 77 | 77 |
| Cyprus | | | 30 |
| **Total** | **155** | **232** | **262** |

*Source: Frontier Economics*

## 5.3 Costs of supply scenarios

### Relative difference in the cost of supply

The relative differences in the cost of gas supply from different supply sources, and hence differences in the wholesale price of gas for different demand levels, are key drivers of potential storage benefits. These differences determine the opportunities for UGS to store cheaper gas, which can displace more expensive alternative sources and influence pricing in the Greek market.

The starting point for our assumptions on the costs of supply sources is based on two elements:

- The costs of producing the gas. For existing sources the short-run marginal costs are used (as capital costs are already sunk), while for new sources of supply the long-run marginal costs (as investment will only occur if all costs are expected to be recovered);[16] and
- The costs of transporting the gas. This relates to the cost of pipeline sources, or the costs of transport for LNG and the costs of regassification.

[16] For LNG sources this includes the costs of liquefaction.

Baseline production costs and transport costs estimates are derived from TYNDP and recent Wood McKenzie publications.[17] The costs referred to in the TYNDP refer to current costs, while projections of the cost of gas supply are available up to 2030. We assume that costs remain at this level for the remaining period of the analysis until 2050. More detail on these is provided in Annex A2.3.

### Costs of Russian gas

Russia is an important source of gas for Europe. While Russia is able to produce gas at very low costs, its gas is typically not available at a cost-reflective price because of:

- Export duties that the Russian state levies; and
- The pivotal position of Russia as a supplier of gas to Europe.

The costs and volumes at which Russian gas is available to the European market therefore need to allow for strategic behaviour. We consider two scenarios that reflect the cost of Russian gas relative to LNG:[18]

- LNG is more expensive than Russian pipeline gas: a "favourable pipeline" scenario. This scenario assumes that the strategic behaviour from Russian importers would be to maximise revenues while maintaining a large market share, and ensuring that the market share of LNG does not grow excessively. Russian gas would therefore be made available at a discount to LNG. Given the low costs of Russian supplies and the vast amount of gas available in Russia, compared to the higher costs projected for new LNG projects, this scenario is more likely to represent a long-term equilibrium; and

- Pipeline gas is more expensive than LNG: a "favourable LNG" scenario. Here, the assumption is that Russian exporters would direct Russian gas supplies to other markets, while losing market share in markets that have direct access to LNG supplies. A price of LNG below the price of pipeline gas might also be more reflective of the situation seen in the market today, which is in part driven by unforeseen shocks to gas demand and the long lead times associated with upstream LNG investments.

In our modelling, we therefore calibrate the baseline costs set out above to reflect these scenarios. While the level of price spread between pipeline gas and LNG will in reality be determined by the specifics of strategic behaviour and economic developments, historical observations provide some information as to potential spreads. This is the basis of our two price spread scenarios:

- In our "favourable pipeline" scenario, the costs of pipeline imports from Russia is allowed to fall to a €3.5/MWh discount to LNG, reflecting the observation that imports from Russia since 2015 have been cheaper than the average costs reported for LNG by around this amount; and

- In our "favourable LNG" scenario, the costs of LNG imported is allowed to fall to a €2/MWh discount to pipeline gas, reflecting the observation that since 2015,

[17] Global gas markets long-term outlook 2019: Costs, August 2019 in combination with Global gas markets long-term outlook H1 2019: LNG Supply, Global gas markets long-term outlook H1 2019: LNG Supply, September 2019.

[18] Projected costs of other pipeline supply sources to Greece are higher than LNG and Russian pipeline supplies.

imports of LNG to Italy have been cheaper than imports of Russian gas by around this amount.[19] [20]

## 5.4 Stress scenarios

The UGS can provide the gas Greek system with additional security of supply. To assess the value the security of supply that the UGS brings, a number of stress scenarios are considered and the role of the UGS during these events is evaluated.

ENTSOG's methodology is clear that security of supply should be assessed in relation to climatic stress situations, and also to infrastructure and supply route disruptions. The methodology is also clear on the infrastructure disruption scenarios to consider (non-availability of the largest piece of infrastructure), but leaves more discretion in relation to supply route disruptions. The key supply risks will clearly vary from country to country.

We have therefore considered the following stress scenarios:

- Climatic stress: the system is brought into a stressful condition as a result of high demand caused by very cold winter conditions.[21] Two durations for this high demand are considered: the 1-in-20 peak day, and the two-week cold spell. The demand levels are described above;
- Infrastructure stress: the system is brought into a stress condition as a result of a failure of the largest piece of infrastructure. For Greece the largest piece of infrastructure is the Revithoussa LNG Terminal.[22] The assessment of infrastructure stress is carried out assuming the climatic stress conditions described above; and
- Supply route stress: the system is brought into a stress condition as a result of a disruption to supply routes. In this analysis two disruptions are considered:
  - An interruption of supplies originating from Turkey (entry points Kipi and TAP/ Nea Mesimvria);
  - An interruption of supplies originating from Turkey (entry points Kipi and TAP/ Nea Mesimvria) as well as the unavailability of LNG terminals.

  The assessment of infrastructure stress is carried out assuming the climatic stress conditions described above.

Each of these events can be used to evaluate security of supply.

It is worth noting that, following ENTSOG's methodology, while we apply a probability (5%) to the climatic stress scenarios, we do not apply a probability to the occurrence of infrastructure failure or supply disruption.

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[19] The difference between the LNG prices and border prices for Russian imports between 2015 and 2020 Q1 as reported by the European Commission's Quarterly Report on European Gas Prices is €3.65/MWh for Greece and €-2.16/MWh for Italy.

[20] This might be a function of small volumes and spot trades. There is however limited information available to parametrise a scenario in which LNG is priced below pipeline gas on a consistent basis.

[21] We do not consider normal climatic conditions in this section. In normal climatic situations demand in Greece is met.

[22] We assess the loss of Revithoussa LNG Terminal as the N-1 throughout the study. Only in the less-advanced scenario the EastMed connection has a higher capacity, but given the inherent uncertainty of this development it seems more appropriate to maintain the current N-1 as the failure point. In any case, in a less-advanced scenario the N-1 standard is met.

## 5.5 Summary of scenarios and reference case

Figure 10 outlines the scenarios for normal conditions used in the analysis schematically:

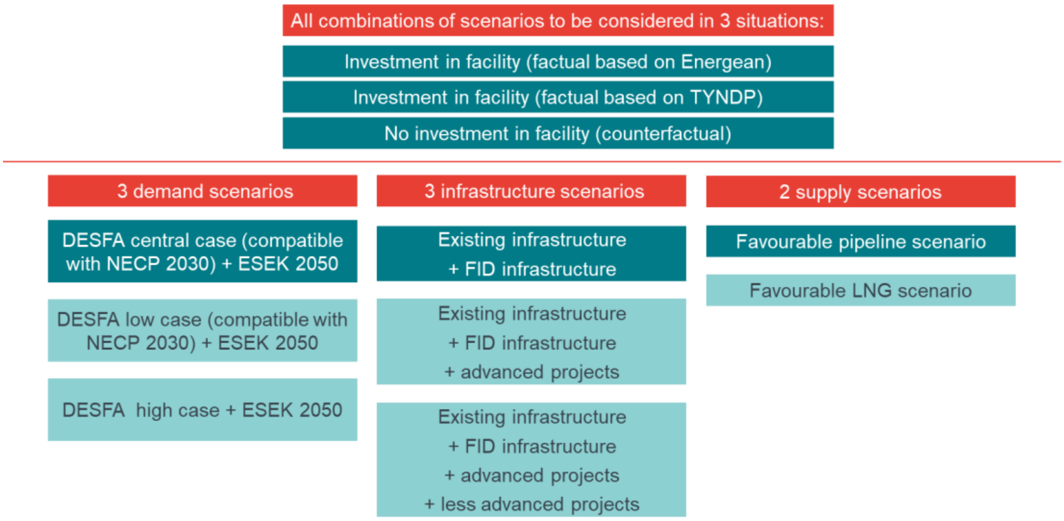
- 3 demand scenarios;
- 3 infrastructure scenarios; and
- 2 supply scenarios.

In order to guide the reader, a reference case is defined. This is the combination of scenarios that will serve as the starting point for the description of the benefits of the UGS. It is only a starting point and intended to keep the report concise. The results of other combinations can be found in later parts of the main document or the annex. The reference case is not meant to reflect a higher likelihood of this reference case versus a combination of other scenarios. The reference case consists of:

- The central demand scenario;
- The existing plus FID infrastructure scenario; and
- A favourable pipeline scenario.

The reference case is discussed for the Energean configuration in the next section, and for both facilities in the remainder of the report. The darker blue colour in Figure 10 represents the reference case.

**Figure 10 Outline of scenarios used in analysis**




*Source: Frontier Economics*

We consider two possible sets of stress situations as part of the reference case: the loss of the Revithoussa LNG Terminal during climatic stress conditions, and an interruption of supplies originating from Turkey, again during stress conditions.

# 6 OVERVIEW OF COSTS AND BENEFITS

This section provides an overview of the estimated costs and benefits, based on the ENTSOG methodology, using the reference case described above in Section 5. The remainder of the report describes each of these benefits in more detail, including an overview of these benefits under different assumptions, and provides further detail such as the extent to which societal benefits flow through to consumers.

The results below describe separately:

- Monetised value, which are set out in Section 6.1; and
- Non-monetised benefits, which are set out in Section 6.2.

## 6.1 Monetised value

Figure 11 shows the results for a combination of costs and estimated benefits for the reference case described in Section 5, with a low and high case variation for the estimated benefits. Figure 12 shows the overall reference case results.

**Figure 11 Reference case and variations, costs and benefits (in € million, real 2020)**

| Category | Breakdown | Reference case | Low case | High case |
|---|---|---|---|---|
| Costs | *Capex* | *-€ 261* | | |
| | *Opex* | *-€ 60* | | |
| | Total | -€ 321 | | |
| Benefits | *Benefit of trade (Greek welfare) (A)* | *€ 208* | *€ 113* | *€ 225* |
| | *Security of Supply (infrastructure disruption) (B)* | *€ 41* | *€ 0* | *€ 9* |
| | *Security of Supply (supply route disruption) (C)* | *€ 87* | *€ 0* | *€ 568* |
| | *Residual value (D)* | *€ 21* | *€ 21* | *€ 21* |
| | Total | € 269*(A+B+D)* to € 356 *(A+B+C+D)* | € 134 *(A+B+C+D)* | € 823 *(A+B+C+D)* |

*Source: Frontier Economics*

**Figure 12 Reference case results (in € million, real 2020)**

| Metric | Energean |
|---|---|
| Economic Net Present Value | -€ 52 to € 35 |
| Benefits to Costs Ratio | 0.84 to 1.11 |
| Economic Internal Rate of Return | 2.0% to 5.2% |

*Source: Frontier Economics*

The monetised elements of the CBA are the following:

- Central cost estimates. The Capex and Opex estimates as described in Section 4.2 are used and total costs are obtained by computing the NPV of the two cost categories;

- The benefit of trade to Greek society in the reference case. Greek welfare benefits correspond to the reduced costs of gas supply in Greece. The UGS can store low cost gas in periods of low demand, and replace more costly gas when gas demand is higher. This benefit is conservative in that it does not include potential savings from avoided regassification in Greece;
- Security of supply benefits. The range associated with this benefit represents the two stress scenarios considered as part of the reference case (the non-availability of the Revithoussa LNG Terminal and an interruption of supplies entering from Turkey). The lower end of the range reflects the non-availability of the terminal, and the upper end of the range reflects a situation of disruption of both LNG supplies and supplies from Turkey in a given year, although not both at the same time (and hence is representative of an extreme situation);
- Finally, the residual value refers to the benefits arising from having the facilities in place post 2050, which might be related to use in a decarbonised economy.

The CBA results for the reference case suggest that, in terms of monetised benefits alone, whether the project is assessed as having a positive case depends on the weight attached to the different security of supply assessments. If the Greek authorities believe it is relevant to consider the risks of both an infrastructure and a supply route disruption, then on monetised benefits alone, the UGS shows a positive social welfare benefit. This benefit would be greater if a further disruption scenario is considered in which both LNG and supplies from Turkey are not available at the same time and valued with the same standard as applied by ENTSOG.

However, the CBA results also show that while it may be economically beneficial from a societal point of view to invest in the facility, a significant part of the benefits will not be valued by individual market participants, making the private investment case negative. This implies some form of intervention would be required to support the investment in the UGS.

As noted above, the results for the reference case only provide one view on the potential benefits. Figure 11 includes two other cases to provide an indication of the impact of different scenarios:

- Relative to the reference case, in the low case the low demand scenario and the advanced infrastructure scenario are considered; and
- Relative to the reference case, in the high case the high demand scenario and the advanced infrastructure scenario are considered, while policy makers value the unavailability of LNG and supplies from Turkey at the same time, with the same standard as applied by ENTSOG, and the infrastructure disruption.

In terms of monetised benefits, the low case suggests a negative impact on social welfare, while the high case suggests a significant positive impact. Other combinations of scenarios can lead to further deviations from the result presented in the reference case. For example, the use of a lower spread will reduce the overall welfare gain, costs are uncertain, and the construction of other infrastructure would make Greece more robust against a number of disruption events. The overall outcome of the CBA therefore depends on the perceived likelihood of each of these scenarios. We have reached no conclusion on this, but the following sections set out in detail the benefits for all of the different scenarios described in Section 5.5.

## 6.2 Non-monetised benefits

The fact that particular benefits are monetised does not indicate that they are more important – just that they are more capable of quantification. The non-monetised benefits must be seen as an important part of the overall results of the CBA. In particular:

- The investment can add further competitive pressure to different parts of the gas market:
  - The market for entry capacity to Greece. This is illustrated by a decrease of the concentration index (equivalent of the HHI) from 3862 to 2916 (Energean) or 3297(TYNDP) assuming current and FID infrastructure;
  - The market for the import of gas to Greece. This effect depends mostly on weakening the pivotal position of dominant importers (which might be more relevant in some time periods than others);
  - The market for the flexibility in the Greek gas market and any knock-on effects on downstream competition;
- The UGS allows for sustainability benefits in the following situations:
  - When the UGS displaces diesel as an emergency fuel with natural gas;
  - When the UGS plays a role in a decarbonised system after the period envisaged in this CBA (which is monetised as a residual value);
- There may be additional benefits to the monetised value shown above from benefits to trade. This is because:
  - Our modelling does not identify the proportion of regassification costs which may be considered to be variable, and hence may be saved as a result of reduced LNG imports;
  - Our modelling assumes perfect foresight and does not capture fully the uncertainty which traders face in the real world. Faced with uncertainty, there should be additional option value from the UGS to traders;
- Other benefits inherent to a UGS such as:
  - The UGS may facilitate cost savings related to the operation of an investment in the natural gas network as a whole.

The monetised benefits set out above demonstrate that, in some scenarios, the UGS contributes positively to society, even before non-monetised benefits are taken into account. Any value placed on the non-monetised benefits set out above, would improve the overall assessment of the UGS from a societal perspective.

# 7 BENEFITS OF TRADE

The UGS is able to inject gas when costs are low, and withdraw this gas to replace more expensive gas when the costs of gas are higher. This lowers the costs of fulfilling gas demand, thus improving social welfare. Consumers can benefit from an improvement in social welfare when this results in lower average wholesale gas prices.

We use a wholesale gas model which simulates gas flows and prices over time, by minimising the costs of meeting gas demand (per year). The model includes in this optimisation the use of UGS facilities across Europe. An analysis of the factual where the UGS is present in Greece, versus the counterfactual where it is not, allows for an estimation of the impact of the UGS on the cost of serving demand. Any reductions in supply costs observed as a result, represent the benefits of trade.

The scenarios employed in the analysis are designed to test different possible outcomes. It is therefore important to view results in relation to other scenarios, rather than draw conclusions from individual results. Certain elements are held fixed over time, such as whether pipeline or LNG supplies are cheaper, while in reality these dynamics could change.

## 7.1 Reference case results

For the reference case, we model the Greek market (as part of a wider European market) assuming:

- In the counterfactual case, no UGS; and
- In the factual case, the Energean UGS, with a sensitivity presenting the TYNDP UGS.

The difference between the cost to supply Greek gas demand in the counterfactual and factual, indicates the size of this benefit of the UGS.

The way in which Greek demand is met by different sources of gas over time is shown in Figure 13 to Figure 15 in representative days. The wholesale model simulate each year by modelling the gas system on 30 representative days. This is done in gas years, with day 1 representing 1$^{st}$ October and day 20 representing 1$^{st}$ April. Peak demand occurs on representative day 10 as by following gas years, the winter heating season is modelled ahead of summer.

### 7.1.1 Gas flows

Figure 13 shows the reference counterfactual scenario (i.e. no UGS). We observe the following outcomes in the Greek market:

- Demand is met through a mix of Russian pipeline gas and LNG, with small levels of domestic gas production in later modelled years;[23]

[23] From 2030, small level production of domestic biomethane begins, which is fully consumed in Greece. This is in line with the spirit of domestic environmental policymaking, which envisages biomethane penetration in the Greek primary energy consumption.

- Russian pipeline gas is the first source to be imported, as it is cheaper than LNG;
  - During higher demand periods, the full supply capacity of pipeline gas through Bulgaria and Turkey is utilised (170 GWh/d from 2025);
- Demand above this level is met by more expensive LNG, up to peak daily demand in the year; and
- This means that LNG deliveries are the marginal supply source and set the market price during winter peaks, as well as summer peaks in earlier years.

Total gas demand and the size of the absolute daily peak both increase up to 2030, in line with our demand scenarios. Gas demand then begins to fall, as does the size of the peak.

These results reveal that there is an opportunity for UGS to store cheaper Russian gas, and use it to supply the market during demand peaks in winter and in summer, reducing the reliance on more expensive LNG.

Figure 14 shows the reference factual scenario with Energean UGS and Figure 15 shows the sensitivity with the TYNDP UGS.

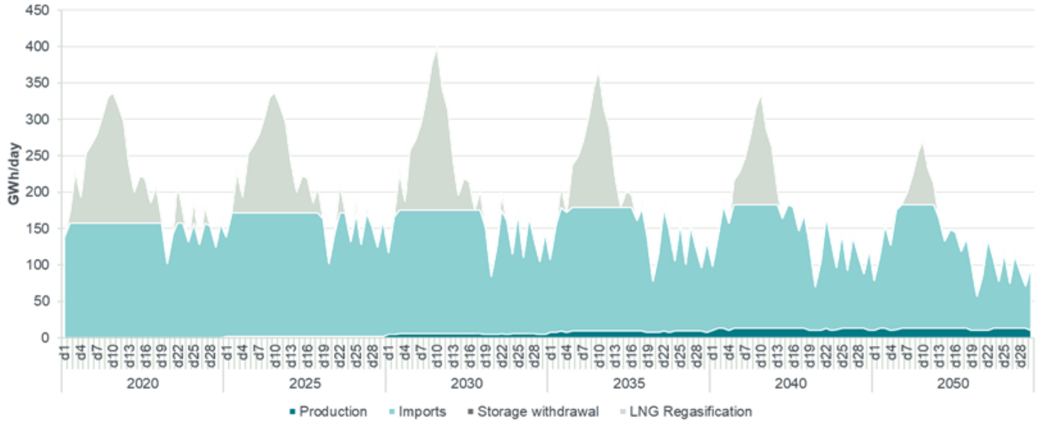
In comparison to the counterfactual results presented in Figure 13, use of some LNG over peak periods is avoided through use of the UGS, while demand for Russian gas in non-peak periods is higher.

In some years, the storage facility cycles a second time over the summer: our modelling shows it supplying gas during summer peaks in 2025 and 2030. As demand for gas falls after 2030, summer peaks can be supplied by pipeline imports alone, and storage withdrawal is only observed during the winter i.e. the facility only completes one cycle.

In the reference case, the facility has opportunity to be utilised up to its maximum withdrawal rate, as shown by the flat withdrawal rate in 2025, 2030, 2035 and 2040. Moreover, in contrast to sensitivity results with a TYNDP facility, the Energean capacity is sufficient in 2050 to avoid the need for LNG shipments.[24] In general, the Energean facility allows a greater share of peak winter demand to be served by stored gas, compared to the TYNDP sensitivity, as seen in Figure 14 and Figure 15.

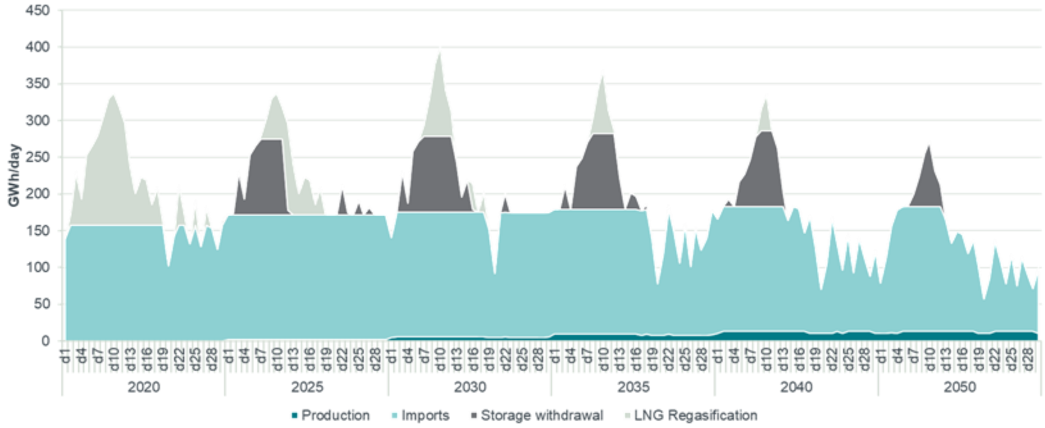
[24] This result does not indicate that LNG would not be expected to play a role in gas imports to Greece. It should be viewed in the context of comparing outcomes between scenarios, rather than putting weight on specific results.

## Figure 13 Greece modelled daily gas flows: reference case counterfactual



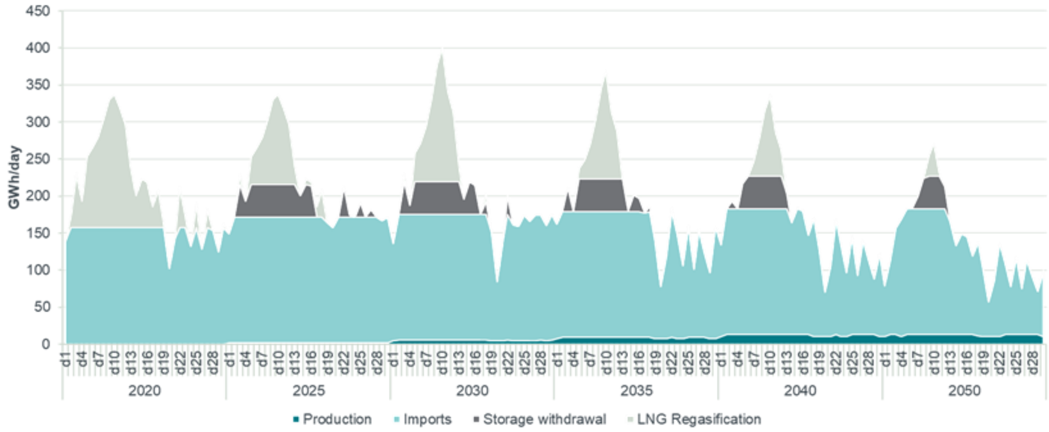

*Source: Frontier Economics*

## Figure 14 Greece modelled daily gas flows: reference case Energean UGS




*Source: Frontier Economics*

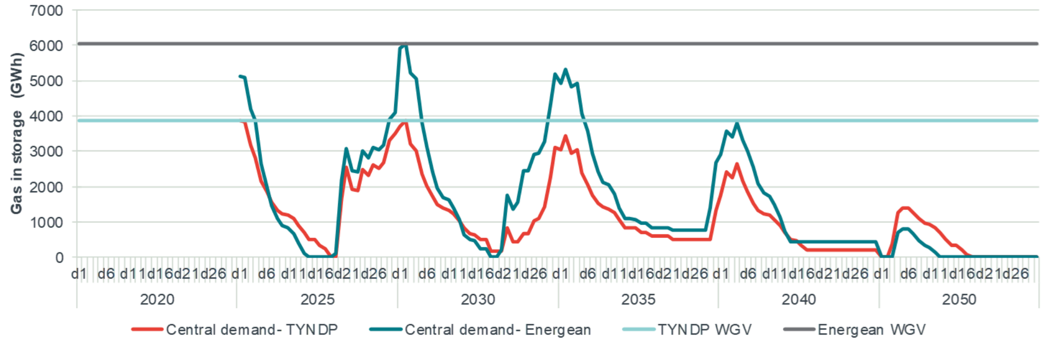
## Figure 15 Greece modelled daily gas flows: sensitivity case TYNDP UGS




*Source: Frontier Economics*

Figure 16 compares the utilisation rates of the two facilities based on our modelling in the reference case and sensitivity. The use of the Energean facility is clearly higher, implying greater monetised benefits, all else being equal. It can also be seen that in both the reference and the sensitivity cases, the facility is used fully in the first years of our modelling, but is then used less intensively over time.

**Figure 16 Storage utilisation in reference and sensitivity case**




*Source: Frontier Economics*

## 7.1.2 Welfare benefits in Greece

When the UGS is able to supply gas that is cheaper than the alternative supply route, such as LNG during winter peak demand, welfare benefits to the Greek economy are created in the form of reduced costs of gas supply to society.

We calculate welfare benefits by comparing the total wholesale costs of meeting gas demand in Greece in the counterfactual, to those when the Energean or TYNDP facilities are in place (Figure 17). As shown, the supply cost savings are higher with a larger facility up to 2040, due to its greater withdrawal rate and greater WGV.

**Figure 17 Greek welfare benefits in reference case**

| € million (real 2020) | 2025 | 2030 | 2035 | 2040 | 2050 | NPV, € million |
|---|---|---|---|---|---|---|
| Energean | 21 | 23 | 17 | 11 | 3 | 208 |
| TYNDP | 17 | 15 | 11 | 8 | 3 | 145 |

*Source: Frontier Economics*

*Note: NPV figures are discounted to 2020 and shown in 2020 prices*

Benefits fall from a peak during 2030, as gas demand falls, and so do opportunities to arbitrage between pipeline gas and LNG. By 2050, welfare benefits are very similar between both facilities, with savings of €3.3 million with Energean UGS, compared to €2.7 million with the TYNDP facility.

The welfare gains to Greek society as estimated above could be complemented by two additional welfare gains:

- First, the replacement of LNG by natural gas will lead to lower variable regassification costs at the LNG terminal (we note that the capital costs of the terminal are already sunk, and therefore the avoidance of the full regassification tariff at the LNG terminal is not a societal benefit); and

- The LNG that would have been used to serve Greece will be available to serve other European (LNG) demand, creating a benefit for the wider European economy.

### 7.1.3 Cost savings to Greek consumers

By changing the marginal supply of gas to the Greek market, the UGS may create consumer benefits through changing wholesale prices. Such a price change affects not only the volume of gas displaced, but the price paid for all gas consumed. The potential impact on consumers can therefore be substantial.

However, the mechanism for determining whether this benefit materialises, and its size, requires additional considerations:

- Wholesale prices may increase when the storage is injecting;
- Wholesale prices may reduce when gas is being withdrawn from the UGS. However, the extent of price reduction will depend on a number of factors:
  - LNG might still be needed to meet market demand and hence set the price when gas is withdrawn from the storage facility;
  - Storage users might have clear benchmarks as to the gas that would be on the margin absent storage withdrawals (mostly LNG) and therefore have an incentive to sell gas at only a small discount to this;
  - The level of this discount may be affected by the level of competition in the downstream market and between users of the storage facility; and
  - The users of the UGS will at a minimum want to recover the variable costs of using the storage facility.[25] For the purposes of the CBA no tariff is assumed to be in place.

It is also worth noting that in our modelling, prices change when the marginal source of supply changes. This may lead to "step changes" in price being modelled, whereas in reality (i.e. in a world of uncertainty and imperfect information and foresight), price changes may be more gradual.

We model the UGS as displacing LNG. In such a situation, it is likely that storage users would attempt to predict the price of LNG supplies and aim to undercut them by a small amount when selling gas withdrawn from the facility. The key question from a customer benefit perspective is therefore the size of this discount or "pass-on". Given the above considerations, it is clear that this will depend on a number of behavioural factors, which are difficult to model. However, a low level of pass-on could be feasible.

## 7.2 Results for other scenarios

This section presents the results of benefits of trade under other scenarios than the reference case. We present first the favourable pipeline scenario, and within that consider higher demand and advanced infrastructure scenarios. We then consider

[25] Which costs will be variable from the perspective of the user will depend on the tariff arrangements for the storage facility (commodity, capacity and bundled products) and the type of product (long-term contract versus opportunities to use storage facility at very short notice).

the favourable LNG scenario, and again present results for higher demand and advanced infrastructure scenarios.

### 7.2.1 Favourable pipeline supply scenario

The NPV of benefits under different scenarios is shown in Figure 18.

Under the favourable pipeline supply scenario, the size of benefits of trade does not vary with additional infrastructure. This is because benefits of trade rely on the supply potential from cheaper sources of gas, and our modelling assumes the additional planned infrastructure only adds more expensive sources of gas. The new supply sources unlocked by additional pipeline projects are more expensive than Russian imports, and do not create any further savings. Similarly, as LNG is more expensive than Russian pipeline in this scenario, the opening of the Alexandroupolis or Dioryga LNG terminals, does not offer the opportunity to land gas that is cheaper than the existing supply sources.

The results of all 3 infrastructure scenarios are therefore identical, and differences are only driven by the demand scenario and facility case.

**Figure 18 NPV of benefit measures, favourable pipeline scenario, all infrastructure scenarios**

| NPV in € million, discounted to 2020, real 2020 | Energean | TYNDP |
|---|---|---|
| **High demand scenario** | | |
| Greek welfare benefits | 225 | 163 |
| **Low demand scenario** | | |
| Greek welfare benefits | 113 | 83 |

Source: Frontier Economics

As with the reference case, the welfare gains to Greek society as estimated above could be complemented by two additional welfare gains:

- First, the replacement of LNG by natural gas will lead to lower variable regassification costs at the LNG terminal (we note that the capital costs of the terminal are already sunk, and therefore the avoidance of the full regassification tariff at the LNG terminal is not a societal benefit); and
- The LNG that would be used to serve Greece will be available to serve other European (LNG) demand, creating a benefit for the wider European economy.

### 7.2.2 Favourable LNG supply scenario

#### Existing + FID infrastructure

The NPV of benefits under different demand scenarios with existing + FID infrastructure is shown in Figure 19.

In contrast to the favourable pipeline scenario, the welfare gains are smaller, as there is less opportunity for the UGS to avoid the use of more expensive gas sources, and the difference between the assumed cost of the gas sources is smaller.

The welfare gains to Greek society could be complemented by two additional welfare gains:

- First, the replacement of natural gas by LNG will lead to lower variable pipeline transportation costs in the European pipeline system (as with regassification, we note that the capital costs for these pipelines are already sunk, and therefore the avoidance of the full transportation tariff is not a societal benefit); and
- The pipeline gas that would be used to serve Greece will be available to serve other European demand, creating a benefit for the wider European economy.

**Figure 19 NPV of benefit measures, favourable LNG scenario, Existing + FID infrastructure**

| NPV in € million, discounted to 2020, real 2020 | Energean | TYNDP |
|---|---|---|
| **High demand scenario** | | |
| Greek welfare benefits | 54 | 36 |
| **Central demand scenario** | | |
| Greek welfare benefits | 31 | 22 |
| **Low demand scenario** | | |
| Greek welfare benefits | 7 | 6 |

*Source: Frontier Economics*

### Other infrastructure scenarios

Additional infrastructure has a stark impact on benefits in the favourable LNG supply scenario. Any additional LNG infrastructure will reduce benefits, to the extent to which it can directly replace Russian gas.

In the existing + FID scenario, the Greek market's access to cheaper gas (in the form of LNG) is constrained by the regassification capacity of the Revithoussa terminal. Under these conditions, the UGS can drive benefits by storing cheaper LNG in the summer, to withdraw in the winter and displace some of the more expensive Russian pipeline supply (once LNG entry reaches maximum).

Both the advanced and less advanced scenarios contain sufficient extra LNG entry capacity to supply peak Greek demand with cheaper LNG. As a result, the whole market demand can already be met with the assumed cheapest source of supply under normal climatic conditions, without the need for a storage facility.

As a result, there are no benefits of trade from the UGS (i.e. the value of this benefit is zero).[26]

It is noteworthy that in the advanced scenario, entry capacity of Revithoussa and Alexandroupolis terminals (assumed to be 443 GWh/d) is just enough to meet the highest annual demand peaks without the need for pipeline imports. However, adding the Dioryga LNG terminal from the less advanced scenario provides an additional 132 GWh/d capacity. At this level of LNG import capacity, if LNG is assumed to be the cheapest source of gas, the conclusion of zero benefit for the UGS has a greater level of confidence attached to it.

[26] This is the case for both the Existing + FID + advanced and Existing + FID + advanced + less advanced infrastructure scenarios.

## 7.3 Stylised results cross check

The benefits outlined above are based on fundamental market modelling, which in turn is dependent on input assumptions. These results are therefore subject to the limitations outlined in Annex B. As a cross check, the two tables below abstract from the modelled results and instead assume:

- A given price spread;
- A volume of gas cycled through the facility per year relative to the WGV of the facility at the assumed price spread;
- The spread and cycled volume to remain constant from 2025 to 2050; and
- The NPV of this value in 2020 for the period considered at a 4% discount rate.

Figure 20 sets out the results of this analysis for a number of combinations. The combinations that most closely (within a 20% margin) resemble the findings in the reference case are a 75% cycle with a spread of €4/MWh, or a 100% cycle with a spread of €3/MWh. These values confirm the broad patterns and assumptions of the reference case. Although different markets, observations in other European countries for seasonal storage suggest a 75% annual cycle and a seasonal spread between €2-4/MWh.[27]

**Figure 20 Stylised Greek welfare benefit results (NPV, € million)**

| NPV | €4/MWh spread | | €3/MWh spread | |
|---|---|---|---|---|
| **Annual cycle** | **Energean** | **TYNDP** | **Energean** | **TYNDP** |
| 150% | 449 | 286 | 337 | 215 |
| 125% | 374 | 238 | 281 | 179 |
| 100% | 299 | 191 | <u>225</u> | <u>143</u> |
| 75% | <u>225</u> | <u>143</u> | <u>168</u> | 107 |
| 50% | 150 | 95 | 112 | 72 |
| | €2/MWh spread | | €1/MWh spread | |
| | **Energean** | **TYNDP** | **Energean** | **TYNDP** |
| 150% | <u>225</u> | <u>143</u> | 112 | 72 |
| 125% | <u>187</u> | <u>119</u> | 94 | 60 |
| 100% | 150 | 95 | 75 | 48 |
| 75% | 112 | 72 | 56 | 36 |
| 50% | 75 | 48 | 37 | 24 |

*Source: Frontier Economics*

*Note: NPV figures are discounted to 2020 and shown in 2020 prices. Underlined values are within 20% of the values estimated in the reference case*

[27] Available at https://ec.europa.eu/energy/sites/ener/files/quarterly_report_on_european_gas_markets_q1_2020.pdf.

# 8 SECURITY OF SUPPLY BENEFITS

The probability that gas consumers are interrupted is generally very low, but the costs to society if a major disruption to gas supplies occurs can be substantial. The UGS reduces the probability of such a disruption affecting consumers because it is an additional source of gas supply.

In the following sections we set out:

- The methodology applied to estimate security of supply benefits (Section 8.1); and
- The level of gas disruption the UGS avoids given a number of stress conditions, and the monetary value of the UGS in each case (Section 8.2). We note that the monetary value from these conditions is not necessarily additive, but allows policy makers to explore the value of the UGS to provide security of supply in a range of situations.

## 8.1 Methodology

The ability of the gas system to meet demand is assessed, assuming a number of stress conditions:

- Climatic stress: the system experiences high demand caused by very cold winter conditions.[28] Two durations for this high demand are considered: the 1-in-20 peak day, and the two-week cold spell. The assumed levels of demand for this are described in Section 5.1.
- Infrastructure stress: the system experiences the failure of the largest piece of infrastructure. For Greece the largest piece of infrastructure is the Revithoussa LNG Terminal.[29] The assessment of infrastructure stress is done assuming the climatic stress conditions described above;
- Supply route stress: the system experiences a disruption to supply routes. In this analysis two disruptions are considered:
  - An interruption of supplies originating from Turkey (entry points Kipi and TAP/ Nea Mesimvria);
  - An interruption of supplies originating from Turkey (entry points Kipi and TAP/ Nea Mesimvria) as well as the unavailability of LNG terminals.

The assessment of infrastructure failure and supply route disruption assumes demand conditions as under the climatic stress conditions described above.

The level of additional security provided by the UGS is then assessed based on following two physical metrics:

- Avoided demand curtailment: Demand curtailment is the amount of demand that can no longer be served under the stress conditions. The avoided demand

[28] We do not consider normal climatic conditions in this section. In normal climatic situations demand in Greece is met.

[29] We assess the loss of Revithoussa LNG Terminal as the N-1 throughout the study. Only in the less-advanced scenario the EastMed connection has a higher capacity, but given the inherent uncertainty of this development it seems more appropriate to maintain the current N-1 as the failure points. In any case, in a less-advanced scenario the N-1 standard is met.

curtailment is the incremental demand that can be served as a result of the UGS being in place;[30] and

- Increase in remaining flexibility: the remaining flexibility is the demand increase that could be accommodated without leading to curtailed demand. The increase in remaining flexibility as a result of the UGS is a benefit to the system caused by the introduction of the UGS. This benefit might then manifest itself as an extra margin for the management of the system, or as a competitive pressure on supply sources, even at times of system stress.

The monetised benefits in the ENTSOG methodology are then derived using the avoided demand curtailment, multiplied by two factors:

- The cost of gas disruption. ENTSOG use a European-wide value of €600/MWh that is derived by dividing the Gross Value Added of the EU-economy by the gas consumptions.[31] In the methodology, this value represents the costs that consumers would incur, would gas supply be lost. It therefore also implicitly represents the maximum willingness to pay from consumers to avoid such a disruption.
- The probability of occurrence. ENTSOG applies a 5% probability based on the 1-in-20 year occurrence of the assumed climatic stress condition. The use of this probability allows for the calculation of an expected loss/willingness to pay.

The probability of infrastructure or supply route disruption is not considered explicitly in the methodology, i.e. it implicitly expresses a policy preference from policy makers to have the guarantee that demand is not interrupted, if climatic stress and infrastructure or supply route stress occur at the same time. It can also be interpreted as a pragmatic estimation of a much wider set of variables that capture security of supply (e.g. different levels of demand in various years, different durations of interruptions and different failure conditions and probabilities). As such the various elements of ENTSOG cannot be seen as completely independent from one another.

While the ENTSOG methodology and use of disruption cases in a CBA are well-documented, the specific disruption cases used in this study were discussed and agreed with the Greek authorities. The security of benefits following this methodology therefore assume that Greek policymakers have a similar approach to determining credible supply disruption events as the policy makers using the ENTSOG framework elsewhere. Clearly the assessment of credible security of supply threats is a matter for the Greek authorities.

## 8.2 Avoided curtailed demand and derived benefit

### 8.2.1 Climatic stress

Figure 21 shows the Greek gas system's entry capacity and the 1-in-20 peak demand levels both including and excluding exports. This table only presents the domestic 1-

[30] The implicit assumption is that there is sufficient gas available in storage to store this demand. In the absence of historic storage levels in Greece, it is inherently uncertain whether sufficient gas is available in storage at times of disruption and/or high demand.

[31] This value does not consider any environmental costs, which we consider in Section 10.1.

in-20 peak demand and not the two-week cold spell one, as the former is always higher than the latter.

**Figure 21 Comparison between the Greek gas system capacity and demand under climatic stress (GWh)**

| | Existing + FID | Existing + FID + advanced | Existing + FID + less advanced |
|---|---|---|---|
| Gas entry system capacity (without a storage facility) | 464 | 666 | 1128 |
| Domestic 1-in-20 peak 2030 | 428 | 428 | 428 |
| 1-in-20 peak including exports 2030 | 459 | 459 | 459 |

Source: *Frontier Economics and DESFA Development study 2021-30*

Note: *The domestic 1-in-20 peak demand is obtained from the DESFA Development study 2021-30. The domestic 1-in-20 peak demand level is assumed to remain at the 2030 levels for following years, until 2050.*

The Greek gas system entry capacity is greater than the 1-in-20 peak demand including exports. In normal infrastructure and supply conditions, Greece should therefore be able to meet any climatic stress conditions without a storage facility. By implication, in this case there is no security of supply benefit. The UGS therefore only adds remaining flexibility to the system.

## 8.2.2 Infrastructure stress

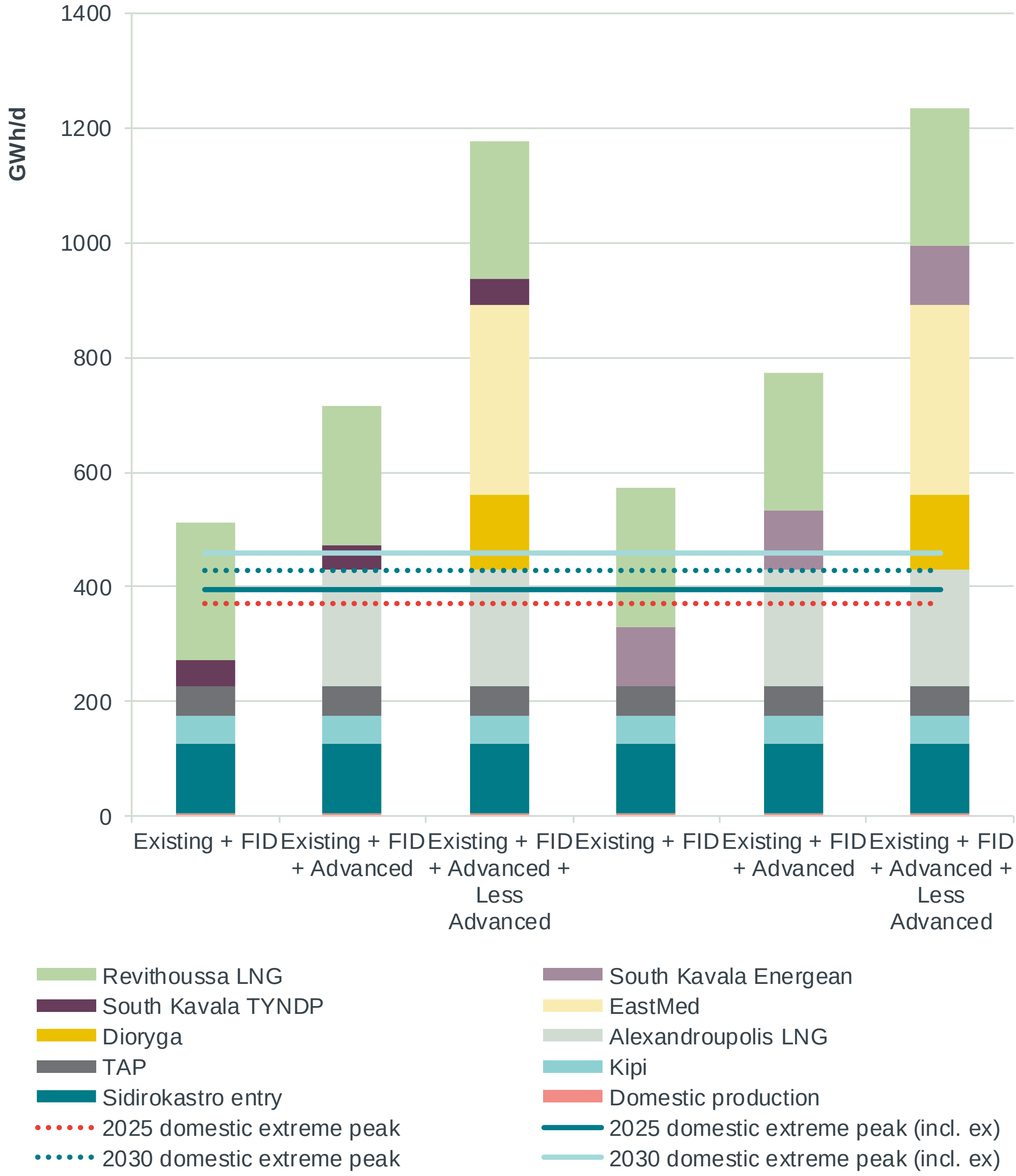
The picture changes when it is assumed that the largest piece of infrastructure fails (the largest piece of infrastructure is the Revithoussa LNG terminal).

### Avoided demand curtailment

In the absence of the Revithoussa LNG terminal, Greece's domestic demand cannot be served. The UGS will be able to serve load that would otherwise be unserved. This is illustrated in Figure 22. The horizontal lines show the demand level at extreme peaks over time. The stacked bars show the capacity of the various entry sources for each of the infrastructure scenarios. The Revithoussa LNG terminal is always shown at the top of the stack, such that maximum supply without Revithoussa can easily be compared to demand levels. The withdrawal capacity of the two storage facilities is included in the stacked bars, located just below the Revithoussa terminal.

The storage facilities provide a security of supply benefit when additional demand can be served (i.e. when horizontal lines cross or are located above the storage facilities).

**Figure 22 Impact of the storage facility in the single largest infrastructure disruption (SLID) with central demand scenario**




Source: *Frontier Economics*

Note: *The level of domestic production represented here corresponds to the projected 2030 levels.*

Figure 23 shows by year how much demand is not met in the event of the unavailability of the Revithoussa terminal, during an extreme domestic peak and under the existing + FID scenario.[32] This takes into account indigenous supply.

[32] The values under different infrastructure scenarios are presented in Annex C , as well as the unserved demand for a two-week cold spell.

**Figure 23 Unserved gas demand SLID during an extreme domestic peak in the central demand scenario**

| | 2025 | 2030 | 2035 | 2040 | 2050 |
|---|---|---|---|---|---|
| No facility | 146 | 200 | 196 | 193 | 193 |
| TYNDP | 102 | 156 | 152 | 149 | 149 |
| Energean | 43 | 97 | 93 | 90 | 90 |

*Source: Frontier Economics*

The avoided curtailed demand is of the size of the full withdrawal capacity of both facilities throughout the considered period. Hence, in the case of the single largest infrastructure disruption, both facilities would be able to serve otherwise unserved demand.

### Monetised benefit

The monetary value that can be attached to the demand served by the UGS during the stress event that would otherwise be unserved is as follows:

- the Energean facility allows 103 GWh/d of demand curtailment to be avoided, which creates a benefit of €41 million (NPV) if valued in line with the ENTSOG methodology; and
- the TYNDP facility allows 44 GWh/d of demand curtailment to be avoided, which creates a benefit of €17 million (NPV) if valued in line with the ENTSOG methodology.

For all other infrastructure scenario and demand scenarios the UGS does not serve otherwise unserved demand. The only exception to this is the existing + FID + advanced scenario with high demand for which benefits amount to €9 million (NPV) for both the Energean and the TYNDP facility. This is also presented in Figure 31 and Figure 32 in Annex C.

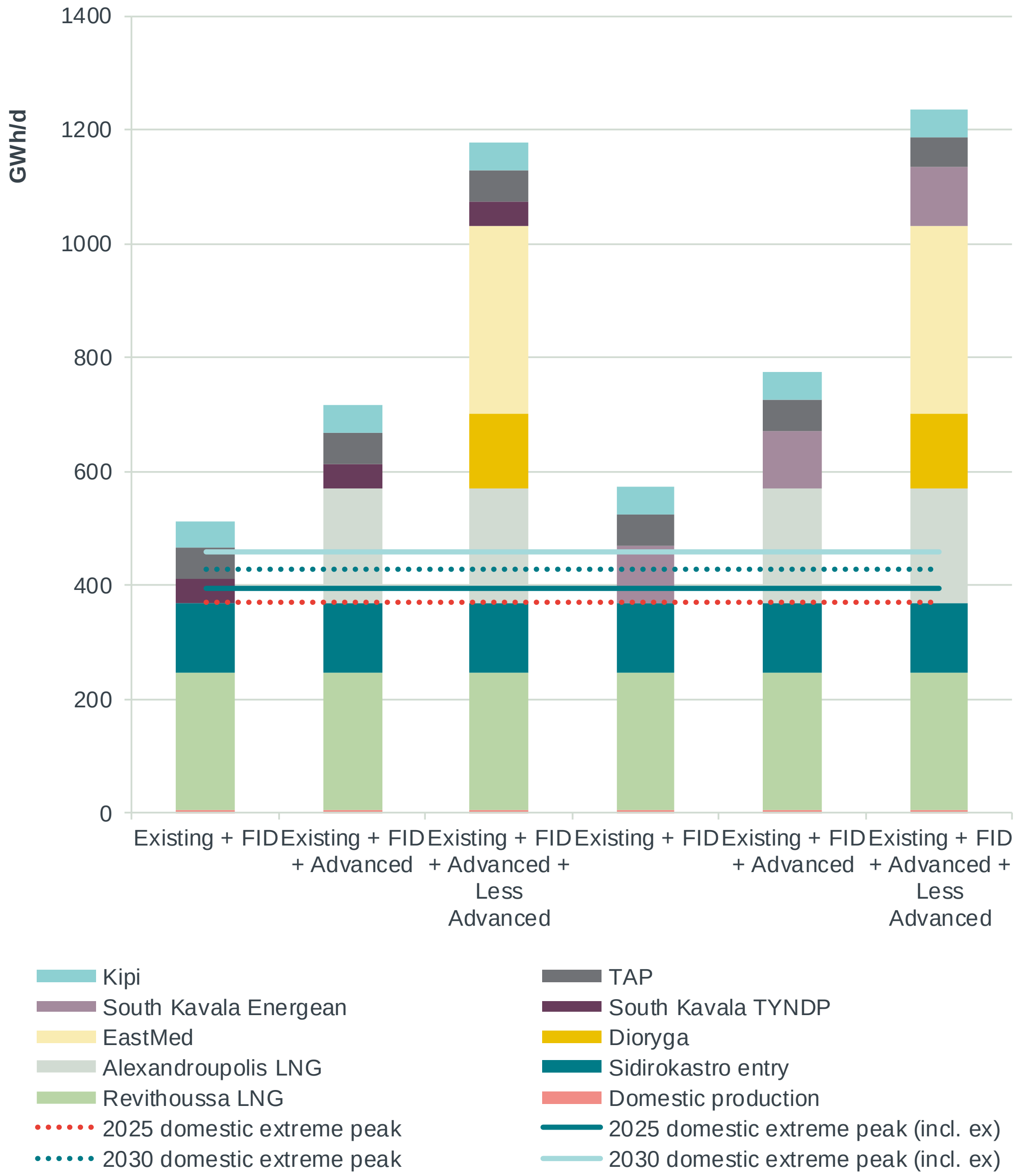
## 8.2.3 Supply disruption stress – pipeline supplies from Turkey

The UGS also creates benefits in the event of an interruption of pipeline supplies going through Turkey.

### Avoided demand curtailment – 1-in-20 peak day

Using the same format as for the loss of the Revithoussa terminal above, Figure 24 shows the entry capacities from Turkey at the top of each bar, with the UGS just below this, such that the contribution from the storage facilities to a disruption from this route is clear.

**Figure 24 Impact of the storage facility in the case of a supply disruption from Turkey in the central demand scenario**




*Source: Frontier Economics*

Figure 25 shows the unserved demand during the 1-in-20 peak demand day in the event of a disruption of entry capacity through Turkey. The Energean UGS can always ensure that all demand is met. The TYNDP UGS leaves some demand unserved in all years except 2025, when it is sufficient to ensure all demand can be met. The negative values suggest remaining flexibility for the system.

**Figure 25 Unserved gas demand in the case of a supply disruption from Turkey during an extreme domestic peak**

| | 2025 | 2030 | 2035 | 2040 | 2050 |
|---|---|---|---|---|---|
| No facility | 31 | 92 | 88 | 85 | 85 |
| Energean | -72 | -11 | -15 | -18 | -18 |
| TYNDP | -13 | 48 | 44 | 41 | 41 |

*Source: Frontier Economics*

### Monetised benefit – 1-in-20 peak day

As we note above, the supply disruption scenario has been provided by the Greek authorities. Applying a monetary value to it based on the ENTSOG methodology implicitly makes the assumption that the probability of the supply route disruption can be compared with other similar supply disruptions evaluated under the methodology. Assessing this is outside the scope of this report, and therefore here we simply report monetised results using the ENTSOG methodology for information.

The security of supply benefit of the demand that otherwise would be unserved is the following:

- The Energean creates a benefit of €19 million (NPV) if valued in line with the ENTSOG methodology; and
- The TYNDP creates a benefit of €15 million (NPV) if valued in line with the ENTSOG methodology.

The net present value for other scenarios is presented in Figure 34 and Figure 35 in Annex C.

### Avoided demand curtailment – two-week cold spell

In contrast to the approach taken in relation to the loss of the largest piece of infrastructure, ENTSOG also considers the level of unserved demand in the event of a supply disruption during a two-week cold spell.

Figure 26 presents the daily unserved demand assuming the disruption happens during a two-week cold spell. This demand level is lower than that projected for the extreme demand peak day, but does apply to 14 days.

**Figure 26 Unserved gas demand in the case of a supply disruption from Turkey during a two-week cold spell in the central demand scenario**

| | 2025 | 2030 | 2035 | 2040 | 2050 |
|---|---|---|---|---|---|
| No facility | -7 | 47 | 44 | 40 | 40 |
| Energean | -110 | -56 | -59 | -63 | -63 |
| TYNDP | -51 | 3 | 0 | -4 | -4 |

*Source: Frontier Economics*

It can be observed that after 2030, a supply disruption would cause unserved demand under a two-week cold spell. For practically all years, both configurations of the UGS can serve this demand.

### Monetised benefit – two-week cold spell

Noting the same caveats as to the valuation and likelihood of this disruption event, simply applying the ENTSOG methodology would suggest monetised values as follows:

- The Energean facility creates a benefit of €68 million (NPV) if valued in line with the ENTSOG methodology; and
- The TYNDP facility creates a benefit of €68 million (NPV) if valued in line with the ENTSOG methodology.

The net present value for other scenarios is presented from Figure 36 to Figure 39 in Annex C.

### 8.2.4 Supply disruption stress – pipeline supplies from Turkey and absence of LNG supplies

In the following section, we consider an additional supply disruption scenario, in which pipeline supplies going through Turkey are interrupted at the same time as LNG supplies to Greece. Again, this scenario was suggested by the Greek authorities, and the caveats relating to the monetised values also apply.

#### Avoided demand curtailment – 1-in-20 peak day

Figure 27 shows the unserved demand assuming the unserved demand coincides with the 1-in-20 peak demand day. It can be observed that while both Energean and TYNDP UGS specifications reduce unserved demand in all years, a high level of unserved demand will remain.

**Figure 27 Unserved gas demand in the case of a supply disruption from Turkey and LNG terminals during on 1-in-20 peak day**

| | 2025 | 2030 | 2035 | 2040 | 2050 |
|---|---|---|---|---|---|
| No facility | 247 | 301 | 298 | 295 | 295 |
| Energean | 144 | 198 | 195 | 192 | 192 |
| TYNDP | 203 | 257 | 254 | 251 | 251 |

*Source: Frontier Economics*

#### Monetised benefit – 1-in-20 peak day

Using the ENTSOG methodology, the security of supply benefit is as follows:

- The Energean creates a benefit of €41 million (NPV) if valued in line with the ENTSOG methodology; and
- The TYNDP creates a benefit of €17 million (NPV) if valued in line with the ENTSOG methodology.

The net present value for other scenarios is presented in Figure 40 and Figure 41 in Annex C.

#### Avoided demand curtailment – two-week cold spell

Figure 28 presents the level of unserved demand assuming the supply disruption happens during a two-week cold spell. This demand level is lower than that projected for the extreme demand peak day, but does apply to 14 days.

**Figure 28 Unserved gas demand in the case of a supply disruption from Turkey and LNG terminals during a two-week cold spell**

| | 2025 | 2030 | 2035 | 2040 | 2050 |
|---|---|---|---|---|---|
| No facility | 211 | 260 | 256 | 253 | 253 |
| Energean | 108 | 157 | 154 | 150 | 150 |
| TYNDP | 167 | 216 | 212 | 209 | 209 |

*Source: Frontier Economics*

Again, both facilities help to avoid unserved demand, but high levels of unserved demand remain.

### Monetised benefit – two-week cold spell

Using the ENTSOG methodology, the security of supply benefit is as follows:

- The Energean facility creates a benefit of €568 million (NPV) if valued in line with the ENTSOG methodology; and
- The TYNDP facility creates a benefit of €243 million (NPV) if valued in line with the ENTSOG methodology.

The net present value for other scenarios is presented in Figure 42 to Figure 45 in Annex C.

# 9 COMPETITION BENEFITS

The UGS will provide a new source of gas supply in Greece and thereby increases the level of competition in the market. To capture this:

- ENTSOG suggests a number of indicators, which are presented in Section 9.1;
- A broader assessment of competition is presented in Section 9.2.

## 9.1 Indicators of competition benefits

ENSTOG suggest a number of indicators to quantify the effect the UGS might have on competition.

### 9.1.1 Market Diversification

The market diversification index, as defined by ENTSOG, captures the diversification of sources through which gas can flow into Greece. We compute a measure which considers storage to be an additional source of supply and LNG to be one global source.

The index is obtained by summing the squared value of the total entry capacity share of each supply source multiplied by a hundred. The result is a Herfindahl–Hirschman index (HHI) which ranges from 0 to 10,000. A lower value indicates greater diversification.

As expected, the presence of a storage facility leads to a decrease in the HHI score: it is smaller for the Energean facility than for the TYNDP one since TYNDP has a lower withdrawal rate than Energean.

**Figure 29 Market diversification index**

| | Existing + FID | Existing + FID + advanced | Existing + FID + less advanced |
|---|---|---|---|
| No facility | 3,862 | 4,990 | 4,279 |
| Energean | 2,916 | 3,922 | 3,663 |
| TYNDP | 3,297 | 4,429 | 3,978 |

*Source: Frontier Economics*

### 9.1.2 Supply Source Dependence (SSD)

The supply source dependence helps identifying strong dependence of countries to specific supply sources. It highlights the extent to which the supply can still be served in the absence of a given supply source.

For the reference case the dependence on LNG and Russian gas is considered.

- LNG SSD: The results of our wholesale model indicate that when Russian gas is the baseload source of supply the maximum amount of LNG that is imported is 226 GWh on the peak day in 2030, the amount of LNG that is imported that year is 8.2 TWh. In the absence of the LNG facility, this cannot be compensated fully by supplies from TAP. In this situation 3.6 TWh of demand would not be served. With the UGS in place, only 0.3 TWh would be unserved (Energean facility, 1.4

TWh for TYNDP). This suggests the dependency on LNG supplies is reduced by the UGS, increasing the competitive pressure on the supply source.

- Russian gas SSD: The results of our wholesale model indicate that when LNG is the baseload source of supply, the maximum amount of Russian gas that is imported is 154 GWh on a peak day in 2030, the amount of Russian gas that is imported throughout the year 2030 is 2.2 TWh. In the absence of the Russian supply source, this cannot be compensated for by TAP and 159 GWh of demand would not be served. With the Energean UGS in place there would be no unserved demand. With the TYNDP UGS in place, there would only be 14 GWh unserved demand. This suggests the dependency on Russian supplies is reduced by the UGS, increasing the competitive pressure on the supply source.

We do not consider it meaningful to assess the impact of the UGS on a disruption of all LNG or Russian gas supplies to Europe given the size of supplies relative to the UGS. The impact of the UGS on the competitive position of these sources for the entire European market is small.

## 9.2 Broader qualitative assessment of competition benefits

The UGS provides additional entry capacity into the Greek gas network, and provides shippers with additional options to source and manage gas demand. As such, the UGS provides additional competitive pressure in a range of markets:[33]

- The market for gas import capacity into Greece. Prices for access to some supply routes (either within Greece or further upstream) may be exempted from regulation and hence determined by competition. Albeit only for limited time periods, the UGS will provide another source of entry capacity into Greece, increasing competitive pressure on these other supply routes, reducing the extent to which they can mark up prices for access. The level of substitutability between such supply routes and domestic storage, will be determine the significance of the constraint the UGS will impose. It is likely that the UGS will be more suitable to substitute for import capacity to deliver small flexible volumes of gas over specific time periods than import capacity that is used for large and sustained import flows;
- The market for gas delivery to Greece. The UGS will be another source of supply for shippers who import gas to Greece, even if only for limited volumes (dependent on the amount of gas stored) and for limited time periods. By providing a further source of competition, the UGS will reduce the extent to which producers are able to charge a premium for gas to be supplied to Greece – this may be particularly important if specific supply routes are pivotal (i.e. are required to meet demand) at particular times of the year. At these times, the UGS should reduce the extent to which producers might be able to charge above cost as a result of increased scarcity; and
- Short-term flexibility. The UGS will provide an additional source of flexibility to help balance the Greek gas market. In particular, the UGS provides flexibility in both direction (short and long). When a shortage of flexibility is a barrier to gas

[33] These markets are loosely defined as potential markets, no formal marker definition is undertaken here.

suppliers, the UGS might reduce this barrier and further lead to a greater competitive pressure in the downstream market.

For all of these markets the extent to which a competitive pressure is provided depends on at least two parameters:

- The tariff that will apply to the UGS relative to the costs of other options;
- The users of the UGS and the position the users have in the commodity markets. For example, the use of the UGS by existing gas importers with substantial market shares might not lead to an increase in competitive pressure.

In the context of the CBA, the value that is placed on the additional competitive pressure enabled by the UGS depends on the current level of competition in the market (in a market which is already competitive, the value of a marginal increase in competitive pressure is likely to be lower than in a market with weak competition).

We understand there is a growing interest to create a gas market hub in Greece. The main benefit of a hub is that it allows for price discovery, providing clear signals to market participants on the value of gas. This then aids the efficient allocation of gas. The ability of the Greek system to acts as a hub in South and Eastern Europe depends in part on:

- Bringing together a sufficient number of players that are interested in buying and selling gas. The increasing transport capacities as set out in Section 5.2 and the increasing levels of demand as set out in Section 5.1 suggest the number of parties in Greece interested in transactions could grow; and
- Being able to adjust the volume of gas to changes in supply and demand. This flexibility can come from the UGS, but can also come from production or consumption sources that have sufficient flexibility.

The UGS is not a necessary or sufficient condition for the creation of a gas hub. However, by improving competition and increasing the number of players involved, it may help any emerging hub to develop more rapidly.

# 10 SUSTAINABILITY BENEFITS

Sustainability benefits relate to the role that the UGS has in reducing emissions in Greece. In the context of natural gas, such benefits relate to the replacement of other fuels by natural gas. In normal demand situations it is not expected that the UGS is necessary to serve gas demand, and it is therefore unlikely that the UGS has a causal effect on a transition in the power sector from coal and lignite to natural gas. However, the following benefits can be classified as environmental benefits of the UGS:

- The avoided use of diesel in extreme situations (Section 10.1); and
- The alternative use of the facility after the period considered in this assessment, such as use for the storage of hydrogen or CO2 (Section 10.2).

## 10.1 Avoided diesel consumption

5 gas-fired power plants in Greece have the ability to switch from natural gas to diesel. The system operator, DESFA, will request these plants to do this if it is required to manage the Greek natural gas system (for example, in stress conditions, to reduce gas demand).

The UGS provides the system operator with access to an alternative source of supply in Greece, which might prevent the use of the dual-fuel ability. This benefit is captured as part of the Security of Supply benefits estimated in Section 8. The use of natural gas instead of diesel for the five day obligation currently in place for the power stations would lead to an estimated emission saving of 30,404 tonnes. Applying the social costs of carbon as estimated by the EBRD, this would have a value of €1.4 million.[34]

## 10.2 Alternative use in a decarbonised economy

The UGS considered in this CBA is envisaged to store natural gas, which is a gas mainly consisting of methane. Natural gas emits greenhouse gases (mainly CO2) when it is burned. For this reason the unabated use of natural gas is inconsistent with the long-term ambitions to decarbonise the economy. This creates opportunities as well as risks for the UGS.

### Opportunity

There are a range of potential gases which could substitute for fossil methane. These include biomethane, synthetic gas, and hydrogen. The EU considers hydrogen an important element in its decarbonisation strategy, as set out in its recent Hydrogen Strategy.[35] A number of scenarios setting out the transition of the Greek energy system also include a prominent role for hydrogen.

Hydrogen is currently already produced for industrial consumption using from steam-methane reformation, a process that uses natural gas and emits CO2. In the future hydrogen consumption could be expanded to sectors that currently use natural gas, and the production of hydrogen can be decarbonised (either through capture of CO2 from reformation, or through use of other carbon neutral technologies).

[34] More detail is provided in a separate analysis provided to HRADF.

[35] European Commission, A hydrogen strategy for a climate-neutral Europe, 8th July 2020.

The UGS can play a role in a hydrogen system if it allows for the storage of hydrogen or CO2. Although suitability will always be site specific, there is some evidence to suggest depleted natural gas fields can be used as seasonal storage sites for hydrogen.[36] There is no geological information available that would confirm whether or not the Kavala facility would be able to serve as a hydrogen or CO2 storage. It also is unknown whether significant additional costs would need to be incurred at the time the storage facility is converted.

### Risk

The risk the UGS faces is an inability to convert to a useful function in a decarbonised economy, or a reduction in demand for its services. Absent other interventions, this could lead to a risk of stranding, a situation in which not all costs are recovered by the investors.

### Valuation

There are a number of uncertainties that make the exact value of alternative use of the facility challenging to estimate, including:

- The uncertainty around the technical capabilities of the UGS itself;
- The uncertainty about the future hydrogen demand and that of other energy carriers; and
- The uncertainty about the most advantageous production techniques and locations leading to trade flows and resulting infrastructure needs.

All of these make an explicit valuation very uncertain. The ENTSOG CBA methodology allows for the inclusion a residual value. This value captures the potential value/benefits that might arise after 2050.[37] This value is equal to the depreciation that will occur after 2050. The residual value included in the CBA is €21 million for lager facility, and €19 million for the smaller facility.

[36] See for example Amid, Mignard & Wilkinson, Seasonal storage of hydrogen in a depleted natural gas reservoir, International Journal of Hydrogen Energy 41 (2016) p. 5549-5558.

[37] The residual value does not allocate all capital costs to the period over which the CBA is carried out, but allocated some costs to future users. These lower costs within the period considered therefore represent the benefit of being able to pass on costs to later years because there is a useful life beyond the period considered.

# 11 OTHER UGS BENEFITS

## 11.1 Trading value

In Section 7, our valuation of the UGS is based on modelling which assumes perfect foresight within a given scenario. In reality traders face unknown and volatile prices.

Modelling with perfect foresight will maximise the use of (and value from) the storage facility for a given set of market conditions. It is likely that in reality the utilisation of any storage site is less optimal than an *ex post* perfect foresight analysis would suggest. In this sense, the modelling may overstate value.

However, it may also understate value, because it does not fully reflect uncertainty and volatility.

Holding capacity in a gas storage site is equivalent to a complex option product. It gives holders the option to swap gas from one time period to another and benefit from the change in prices over time. The value of this option will, in common with all option products, depend on the underlying volatility of prices. Put another way, if there is a greater demand for flexibility in the gas market (because of underlying volatility), this will be reflected in the value of storage.

The potential volatility of future prices is not taken into account in our modelling, which looks at one given scenario for the development of demand and supply (and hence price) in a year. Therefore, the modelling may underestimate value, particularly since for various reasons there may be more volatility, including as a result of increased RES-E penetration.

## 11.2 System value

The system value reflects the potential of an underground storage facility to reduce the need for network expansion or reinforcement, for example because gas can already be transported through a bottleneck when it is not yet congested, thereby avoiding the need to reinforce the system. Similarly, the storage facility might reduce the costs of operating the network by providing additional pressure through a change of flows that reduce the overall need for compression and transportation in the network.

System value reduces costs to the system, and storage operators are unlikely to be able to monetise this value (unless there are very specific incentives on gas transportation tariffs). Instead, all network users benefit from the system value of the storage facility. System value is therefore an externality that can be compensated by network users.

We are not in a position to determine if a UGS at South Kavala would generate system value. It would require detailed flow modelling and network planning to provide an assessment of this. We do note that like any other connection point, the system value might be positive (reduce system costs), or negative (i.e. create more costs).

# 12 CONCLUSION

This report provides an overview of the costs and benefits of a UGS at South Kavala in line with the 2nd ENTSOG methodology. This methodology considers specifically defined costs and benefits and is intended to estimate the overall impact of the investment on social welfare. Some of these benefits can be captured by the users or operator of the UGS, such as the arbitrage value, while other benefits cannot be easily be captured by the operator, such as the security of supply gains that the UGS brings.

We find that:

- For a range of scenarios considered, the benefits that the operator is able to monetise do not outweigh the costs, and hence it is possible that the infrastructure would not be built without further intervention;
- However, for a range of scenarios the other benefits create a net welfare improvement for society;
- In these circumstances it would be societally beneficial to support the investment with a monetary contribution to the storage operator, at least in relation to the social benefits generated;

The level of benefit generated does vary by scenario considered. In particular:

- The benefit of trade varies with the level of spread between the different sources of gas available. The extent to which these benefits are passed on the consumers requires careful consideration;
- The benefit of security of supply varies significantly with the disruption cases considered. The value that is placed on different disruption cases requires further consideration by policy makers;

A number of other further benefits can be expected from the UGS including:

- Additional trading value not captured in our modelling framework, including:
  - Avoided variable costs in LNG regassification or pipeline transport;
  - Additional value as a result of real world uncertainty;
- The facilitation of enhanced competition in relevant gas markets;
- Contributions to the use of fuel with a lower emission intensity (emergency diesel, or use in a hydrogen or CO2 system); and
- Potential benefits as a result of avoided network infrastructure costs.

# ANNEX A DESCRIPTION WHOLESALE MARKET MODEL

## A.1 Wholesale model overview

The wholesale model is a linear optimisation model. It simulates the natural gas market in European countries by minimising the overall costs of meeting gas demand, subject to costs and constraints.

The model generates results for given snapshot years, and the results are interpolated to provide a stream of impacts, for the purpose of conducting the CBA.

## A.2 Further assumptions

### A.2.1 Demand profiles

The annual demand within the year for each scenario is then approximated by a profile of 30 representative days, which proportionally distributes annual demand over these days.

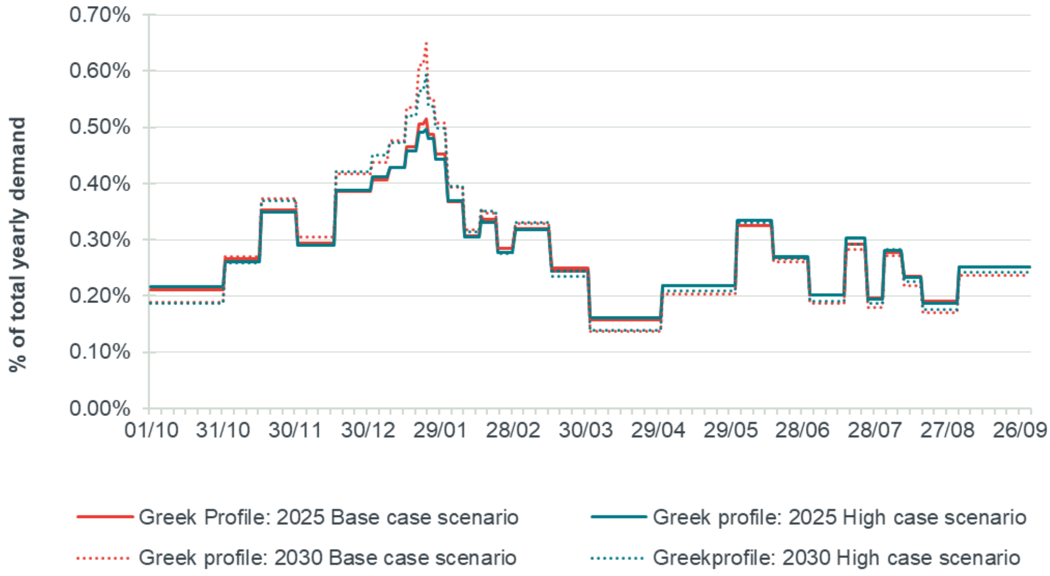
Demand profiles for European countries are based on the ENTSOG seasonal outlooks for winter 2019/20 and summer 2019,[38] which contain expected average monthly demands for each country for a reference winter.[39] Variation is then added to these monthly averages to reflect the variation observed within a month and to capture peak moments (day 10 in January is used as the peak day for all countries).

For Greece more detailed information has been received from DESFA for the years 2025 and 2030, for the normal and high scenarios. The daily values from these scenarios have been fitted to the shape of the European profile to ensure the movements in Greek demand coincide with the movements of demand in other countries within the winter and summer season, while respecting the peak and average demand levels expected. The profile derived for 2030 is also used for the following years. The figure below shows the implemented profile for Greece.

[38] The summer values for 2019 are used instead of 2020 to avoid including any estimates affected by the COVID-19 pandemic.

[39] Available at https://www.entsog.eu/outlooks-reviews#summer-outlooks-and-reviews.

**Figure 30 Representative days profiles**




*Source: DESFA daily demand profile data allocated to the representative profile for 2025 and 2030 for both the base case demand estimation and the high case demand estimation of DESFA 2021-2030 Development study.*

## A.2.2 European annual demand

Annual demand for each country in the model applies data from TYNDP 2018. For the years 2020 and 2025, demand is based on the “Best Estimate” case, using the “Gas Before Coal” case for 2025. Demand in 2030 and 2040 uses figures from the “Sustainable Transition” scenario and we assume that demand is constant towards 2050, in absence of a projected value.

## A.2.3 Supply

### Pipeline gas supply

- We adopt TYNDP 2018 data for supply potential, in the supply regions in our model;[40]
- For more recently commissioned supply regions:
  - We use current editions of TYNDP 2020 data to obtain supply figures for Azerbaijan and Turkmenistan, as they were unavailable in TYNDP 2018;[41]
  - An expected offtake volume from DEPA is used to project Cyprus supply following the planned commission of EastMed pipeline;
- We use TYNDP 2018 data on interconnections, which we group according to area zones in our model;

[40] While some data is available from the 2020 editions of the ENTSOG TYNDP analysis and reference material, at the time of writing gas materials are limited to scenario data on demand and supply. This does not include updated interconnection capacity or tariff information and we therefore use the latest full dataset, which is available from the 2018 edition. TYNDP 2018 data is available at https://www.entsog.eu/tyndp#entsog-ten-year-network-development-plan-2018

[41] Available in Scenario Datafile at https://www.entsos-tyndp2020-scenarios.eu/download-data/#download.

### Pipeline supply prices

Wood McKenzie data on gas export LRMCs provides the assumptions for gas prices from the following suppliers, which are relevant for the range of infrastructure scenarios:

- Norway;
- Romania;
- Russia;
- Cyprus;
- Azerbaijan;
- Algeria; and
- Lybia.

Some of these supply sources are of interest to the Greece market under specific infrastructure scenarios. For example, TAP provides potential for Azerbaijani Caspian sea gas to transit through Turkey, and be imported to Greece. EastMed will add supply potential from Cyprus.

However, analysis from Wood McKenzie indicates that these sources of supply may be relatively expensive. Wood McKenzie explains that “supply from Azerbaijan and the Southern Corridor into Italy will be amongst the most expensive supply options in 2022 at nearly US$6/mmbtu at SRMC but will flow under contractual agreement indexed to European hubs”.[42]

While we account for the expected volumes of smaller scale domestic gas production in Europe, we assume this gas is cheaper than imported pipeline gas and LNG. This gas production generally represents expected volumes of biomethane to be produced in line with national climate change targets. Pricing such supplies below pipeline and LNG imports ensures it is “consumed”, in line with such obligations.

### LNG supply

We use a model of global LNG supply and European LNG regassification terminals:

- We use Wood McKenzie data on LNG supply potential to set a quantity of LNG supply that is available at different costs, which produces a global LNG supply curve;
- We include all existing European LNG terminals and apply Gas LNG Europe data[43] to determine their technical parameters: peak regassification and storage capacity.

## A.2.4 Infrastructure

### Interconnectors

Interconnector capacities across the countries in the wholesale model, are defined using data provided in TYNDP 2018 according to the low infrastructure scenario. In

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[42] Wood McKenzie, 2019, Global gas markets long-term outlook 2019: Costs, p.6.

[43] Available at https://www.gie.eu/index.php/gie-publications/databases/lng-database

the Greek market, interconnector capacity of entry and exit points are refined further, with input from HRADF and RAE.

To determine capacity of the Russia to Turkey interconnection, we use Turk stream official information.[44]

### Gas storage

The technical characteristics of all storage facilities in European countries, are based on data from Gas Storage Europe.[45] These are WGV, injection and withdrawal rates and the type of storage e.g. depleted oil field.

For UGS Kavala, we use:

- Publicly available information from Energean;[46] and
- Data from TYNDP on injection and withdrawal rates, and apply information from Gas Storage Europe to set the WGV.

### Pipeline tariffs

The starting point for pipeline transport tariffs is data published by TYNDP 2018. We have made a number of alterations and updates to tariffs in the region, to improve the accuracy of our modelling:

- We have updated BG>GR tariffs by calculating them from the tariffs published by the Bulgarian and Greek TSOs respectively,[47] although this figure is very close to that published by TYNDP in 2018;
- We have used this tariff to also approximate the tariff BG>TR and TR>GR, as we assume they would converge over time, in absence of other information;
- We have assumed that the cost of transport of Russian gas into Greece is the same, whether via Ukraine or Turkey (i.e. the total tariff paid through UA>RO>BG>GR is the same as RU>TR>GR);
- We also include tariffs for transport via new sources and pipelines relevant to Greece and the region (including Italy), using transport cost data from Wood McKenzie:
  - Azerbaijan to Greece via TAP;
  - Cyprus to Greece via EastMed;
- For these sources, we assume that the tariffs for landing gas in Greece are equivalent to the tariffs applied to Italy, which is the main market for these projects. The reason for this is that the total costs of the pipeline will need to be recovered.

### LNG terminal tariffs

We apply tariffs from a regulatory framework study by the European Commission to determine tariffs at European LNG terminals.[48] For the Greek market, we calculate

44 Total capacity in both directions of 31 bcm/year, which we assume is split equally in each direction with a peak supply to Turkey of 15.75 bcm/year https://www.gazprom.com/projects/turk-stream/.

45 Available at https://www.gie.eu/index.php/gie-publications/databases/storage-database.

46 Available at http://www.hazliseconomist.com/uploads/speeches/CyprusEnergy2011/Rigas_Mathios.pdf.

47 Available at https://www.bulgartransgaz.bg/en/pages/tarifi-28.html and https://www.desfa.gr/en/regulated-services/transmission/tariffs.

48 European Commission, 2020, "Study on Gas market upgrading and modernisation – Regulatory framework for LNG terminals".

the LNG tariff for the Revithoussa LNG terminal, using the tariff formula provided by DESFA.[49] We apply the same tariff to the Alexandroupolis and Dioryga LNG terminals.

### Pipeline tariffs

Our starting point is the use of tariffs published in TYNDP 2018, which represent the latest set of ENTSOG tariff data. We adopt the entry and exit tariffs for individual zones along each pipeline route, which we verify and refine further. In particular, we use up-to-date Greek entry and exit tariffs

### LNG prices

To determine the supply costs of LNG we identity LNG supplier regions and determine their supply potential at different price levels:

- We use Wood McKenzie data on LNG supply potential to set a quantity of LNG supply that is available at different costs, which produces a global LNG supply curve; and
- We calculate the individual transport costs to each LNG terminal in our model, from the LNG supply regions.

We assume that LNG demand in the rest of the world (RoW) must be satisfied in line with the Wood McKenzie projection.

## A.2.5 Other assumptions and definitions

- Model snapshot years:
  - 2020, 2025, 2030, 2035, 2040, 2050;
- Where applicable to analysis for the Greek market, we have used a gas conversion rate of 11.439 kWh/Nm3, calculated using DESFA average gas quality indicators published for 2008-2020.[50]

[49] Available at https://www.desfa.gr/en/regulated-services/lng/tariffs.

[50] Available at https://www.desfa.gr/en/regulated-services/transmission/pliroforisimetaforas-page/historical-data/quality.

# ANNEX B LIMITATIONS

The wholesale gas market model has a number of limitations, including the following:

- Any prices derived from the model are the shadow values of demand. This means that prices reflect the underlying costs of one incremental unit of demand, similar to what can be expected in a fully competitive market. The model therefore abstracts from any consideration of market power that could increase the prices above the competitive level. It therefore also follows that all shippers and producers are price takers and cannot strategically influence wholesale prices;
- The model relies on perfect foresight and minimises the total costs given a known availability of supply sources and costs, storage options and the profile of demand. Uncertainty that market players might face in reality is therefore not captured, e.g. unavailability of supply sources or fluctuations in demand as a result of deviations in weather (demand for heat driven by temperature, demand from the power sector driven by wind and solar conditions);
- The absence of liquid forward and day-ahead markets in South-Eastern Europe limits the degree to which assumptions can be calibrated or the optimal behaviour of the UGS can be modelled as a price taker relative to historic price;
- The ENTSOG TYNDP tariffs used in the model reflect the costs of transporting gas on a baseload basis. The costs are spread equally across each unit of gas transported to derive a commodity-based tariff, rather than a capacity based tariff. The model includes a single tariff, and does not consider the short-term products and multipliers;
- The model does not capture potential sources of competition and competitive advantages between LNG terminals other than differences in network tariffs that are applied. In reality, the charges that different terminals demand are different (but largely confidential) and are a function of e.g.:
  - The prices charged to the users of the terminal, which can be driven by:
    - The regulated or exempted nature of different of the terminal;
    - The economies of scale which some terminals might be able to exploit to offer lower tariffs;
    - The services offered at the terminal;
    - The attractiveness of connecting markets;
- LNG supply is modelled as a continuous value, rather than as a discrete value representing cargos and LNG tankers;
- Long-term contracts are not considered in the model;
- The model does not capture feedback effects, such as:
  - Responses in demand as a result of higher or lower prices. Demand is assumed to be completely inelastic;
  - An increase in tariffs from cross-border capacity when capacities are not used on a baseload basis;
  - Increased (decreased) costs of transport at times of high (low) demand;
  - Sources of supply entering or exiting the market in response to pricing dynamics.

# ANNEX C RESULTS SECURITY OF SUPPLY

The tables in this annex present the results of the security of supply analysis.

## C.1.1 Infrastructure stress

Figure 31 and Figure 32 present the monetised benefits of having the facilities in place during a disruption of the largest infrastructure (the Revithoussa terminal) during a 1-in-20 peak day.

**Figure 31 NPV SoS benefit – SLID – Energean facility – 1-in-20 peak day**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 41 | 0 | 0 |
| Central demand | 41 | 0 | 0 |
| High demand | 41 | 9 | 0 |

*Source: Frontier Economics, CBA*

**Figure 32 NPV SoS benefit – SLID – TYNDP facility – 1-in-20 peak day**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 17 | 0 | 0 |
| Central demand | 17 | 0 | 0 |
| High demand | 17 | 9 | 0 |

*Source: Frontier Economics, CBA*

Figure 33 shows by year how much demand is not met in the event of the unavailability of the Revithoussa terminal, during a two-week cold spell under the existing + FID scenario. This takes into account indigenous supply.

The avoided curtailed demand is of the size of the full withdrawal capacity of both facilities throughout the considered period. Hence, in the case of the single largest infrastructure disruption, both facilities would be able to serve otherwise unserved demand.

**Figure 33 Unserved gas demand SLID during a two-week cold spell**

| | 2025 | 2030 | 2035 | 2040 | 2050 |
|---|---|---|---|---|---|
| No facility | 104 | 118 | 114 | 111 | 111 |
| Energean | 1 | 15 | 11 | 8 | 8 |
| TYNDP | 60 | 74 | 70 | 67 | 67 |

*Source: Frontier Economics*

## C.1.2 Supply disruption stress – pipeline supplies from Turkey

### Avoided demand curtailment – 1-in-20 peak

Figure 34 and Figure 35 present the monetised benefits of having the facilities in place in the case of a supply disruption from Turkish entry points occurring on the 1-in-20 peak day for all infrastructure and all demand scenarios. Benefits occur for all three demand scenarios in the Existing + FID infrastructure case, but they are zero in all other cases both for the TYNDP and the Energean facility.

**Figure 34 NPV SoS benefit – supply disruption entry points Turkey – Energean facility – 1-in-20 peak day**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 13 | 0 | 0 |
| Central demand | 19 | 0 | 0 |
| High demand | 33 | 0 | 0 |

*Source: Frontier Economics, CBA*

**Figure 35 NPV SoS benefit – supply disruption entry points Turkey – TYNDP facility – 1-in-20 peak day**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 13 | 0 | 0 |
| Central demand | 15 | 0 | 0 |
| High demand | 17 | 0 | 0 |

*Source: Frontier Economics, CBA*

### Avoided demand curtailment – two-week cold spell

Figure 36 and Figure 37 presents the monetised benefits of having the facilities in place in the case of a supply disruption from Turkish entry points during a two-week cold spell for all infrastructure and all demand scenarios.

The results are presented based on two different assumptions regarding the demand levels of the two-week cold spell.

Figure 36 and Figure 37 present the results obtained inferring the demand levels from the ENTSOG 1-in-20 to two-week cold spell ratio. Benefits occur for all three demand scenarios in the Existing + FID infrastructure case, but they are zero in all other cases both for the Energean and the TYNDP facility.

**Figure 36 NPV SoS benefit – supply disruption entry points Turkey – Energean facility – two-week cold spell based on ratio ENTSOG**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 8 | 0 | 0 |
| Central demand | 68 | 0 | 0 |
| High demand | 214 | 0 | 0 |

*Source: Frontier Economics, CBA*

**Figure 37 NPV SoS benefit – supply disruption entry points Turkey – TYNDP facility – two-week cold spell based on ratio ENTSOG**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 8 | 0 | 0 |
| Central demand | 68 | 0 | 0 |
| High demand | 206 | 0 | 0 |

*Source: Frontier Economics, CBA*

Figure 38 and Figure 39 present the results obtained inferring the demand levels from the DESFA 1-in-20 to two-week cold spell ratio. Benefits occur only for the high demand scenario in the Existing + FID infrastructure case, but they are zero in all other cases both for the Energean and the TYNDP facility.

**Figure 38 NPV SoS benefit – supply disruption entry points Turkey – Energean facility – two-week cold spell based on ratio DESFA**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 0 | 0 | 0 |
| Central demand | 0 | 0 | 0 |
| High demand | 12 | 0 | 0 |

*Source: Frontier Economics, CBA*

**Figure 39 NPV SoS benefit – supply disruption entry points Turkey – TYNDP facility – two-week cold spell based on ratio DESFA**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 0 | 0 | 0 |
| Central demand | 0 | 0 | 0 |
| High demand | 12 | 0 | 0 |

*Source: Frontier Economics, CBA*

### C.1.3 Supply disruption stress – pipeline supplies from Turkey and absence of LNG supplies

Figure 40 and Figure 41 show the monetary benefits of the avoided unserved demand for both the Energean and the TYNDP facility, assuming there is a supply disruption from both Turkish pipelines and LNG coinciding with the 1-in-20 peak day. It can be observed that while both Energean and TYNDP UGS specifications reduce unserved demand in all years, a high level of unserved demand will remain.

**Figure 40 NPV SoS benefit – supply disruption entry points Turkey and LNG terminals and LNG terminals – Energean facility – 1-in-20 peak day**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 41 | 41 | 0 |
| Central demand | 41 | 41 | 0 |
| High demand | 41 | 41 | 1 |

*Source: Frontier Economics, CBA*

**Figure 41 NPV SoS benefit – supply disruption entry points Turkey and LNG terminals and LNG terminals – TYNDP facility – 1-in-20 peak day**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 17 | 17 | 0 |
| Central demand | 17 | 17 | 0 |
| High demand | 17 | 17 | 1 |

*Source: Frontier Economics, CBA*

Figure 42 and Figure 43 presents the monetised benefits of having the facilities in place in the case of a supply disruption from both Turkish pipelines and LNG coinciding with a two-week cold spell for all infrastructure and all demand scenarios.

The results are presented based on two different assumptions regarding the demand levels of the two-week cold spell.

Figure 42 and Figure 43 present the results obtained inferring the demand levels from the ENTSOG 1-in-20 to two-week cold spell ratio. Benefits occur for all three demand scenarios in the Existing + FID infrastructure and the Existing + FID + advanced infrastructure case, but they are zero in all other cases both for the Energean and the TYNDP facility.

**Figure 42 NPV SoS benefit – supply disruption entry points Turkey – Energean facility and LNG terminals – two-week cold spell based on ratio ENTSOG**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 568 | 568 | 0 |
| Central demand | 568 | 568 | 0 |
| High demand | 568 | 568 | 0 |

*Source: Frontier Economics, CBA*

**Figure 43 NPV SoS benefit – supply disruption entry points Turkey and LNG terminals – TYNDP facility – two-week cold spell based on ratio ENTSOG**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 243 | 243 | 0 |
| Central demand | 243 | 243 | 0 |
| High demand | 243 | 243 | 0 |

*Source: Frontier Economics, CBA*

Figure 44 and Figure 45 present the results obtained inferring the demand levels from the DESFA 1-in-20 to two-week cold spell ratio. Benefits occur for all three demand scenarios in the Existing + FID infrastructure and the Existing + FID + advanced infrastructure case, but they are zero in all other cases both for the Energean and the TYNDP facility.

**Figure 44 NPV SoS benefit – supply disruption entry points Turkey – Energean facility and LNG terminals – two-week cold spell based on ratio DESFA**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 568 | 568 | 0 |
| Central demand | 568 | 568 | 0 |
| High demand | 568 | 568 | 0 |

*Source: Frontier Economics, CBA*

**Figure 45 NPV SoS benefit – supply disruption entry points Turkey – TYNDP facility and LNG terminals – two-week cold spell based on ratio DESFA**

| | Existing infrastructure+ FID | E. infra.+ FID + advanced | E. infra.+ FID + advanced + less advanced |
|---|---|---|---|
| Low demand | 243 | 243 | 0 |
| Central demand | 243 | 243 | 0 |
| High demand | 243 | 243 | 0 |

*Source: Frontier Economics, CBA*