Spillovers of underground gas storage facilities and their role in the sustainable energy markets: Assessment and policy recommendations

Abstract:

Purpose - The purpose of this study is to investigate the impact of construction and operation of underground gas storage (UGS) facilities, under the prism of the recent rise in energy prices. The focus is on developing energy markets interconnected with gas producers through pipelines and have in parallel access to liquefied natural gas (LNG) facilities.

Design/methodology/approach - Through a focal market in Europe, we estimate the economic value for both stakeholders and consumers by introducing a methodology, appropriately adjusted to the specificities of the domestic energy market. The Transmission System Operator, the Energy Market Regulator, the Energy Exchange, and Eurostat are used as main data sources for our calculations and drawing of conclusions.

Findings - We investigate the perspectives of UGS facilities, identifying financial challenges considering specific energy market conditions which are barriers for new storage facilities. Nevertheless, the energy price rocketing coupled with security of gas supply issues, that arose in autumn 2021 and were continuing in 2022 due to the Russia-Ukraine crisis, highlight that gas storage remains, at least for the midterm, at the core of European priorities.

Originality/Value - The paper emphasizes on developing markets towards green transition, proposing tangible policy recommendations regarding gas storage. A new methodological approach is proposed, appropriate to quantify the economic value of underground gas storages in such markets. Last, a mix of energy policy options are suggested which include regulatory reforms, support schemes, and new energy infrastructures that could make the gas storage investments economically viable.

Keywords: energy storage, energy and climate policy, energy economics, sustainability, hydrogen

1. Introduction

The practice of underground gas storage (UGS) is common in Europe and North America, and a substantial capacity equivalent to between 15 - 25% of total annual gas consumption is available (IGU, 2018). This type of gas storage is materialized in geological structures, dramatizing a key role in energy systems; since it is mainly used to manage seasonal demand variability (Baranes et al., 2013). In particular, UGS facilities contribute to price stabilization during the winter months when demand spikes. Gas storage remains a timely topic under the light of the unprecedented energy prices surge and the consequences to the smooth European gas supply that started in Q4 2021 and lasted during 2022, while recent EU policy interventions is expected to mitigate risks related to extreme price fluctuations. The current electricity price spike is primarily driven by the global demand for gas, as the economic recovery (after the pandemic) is picking up, coupled with Russian aggression against Ukraine. So, the gas market tightness resulted in TTF (Title Transfer Facility) unprecedented future price (month-ahead contract), that overcame 340 €/MWh (Euro/megawatt hour) in August 2022, when the respective prices were around 15 €/MWh two years ago. In this context, the European Commission acknowledges that an integrated approach could optimize the cost and benefits of gas storage across the EU territory to help cushion volatility in energy prices, since storage is not available in all EU Member States (European Commission, 2021a). The situation was further exacerbated by the conflict in Ukraine in February 2022, when energy prices skyrocketed, threatening the global economy. The current turmoil in the energy market, makes that period not the most suitable for unbiased results. This is the main reason of focusing on a five-year period before pandemic and geopolitics affect energy prices in an unpredictable manner. Consequently, high volatility in energy prices along with concerns about the smooth European market supply (due to the gas import dependency), make gas storage an issue that policy makers and market's stakeholders should reconsider.

We investigate the gas storage under the light of the aforementioned developments along with the new policy mandate in the European Union as depicted in the context of the new Green Deal strategy (European Commission, 2019). This strategy constitutes the cornerstone of the European vision and aspires to bring the continent into the era of the decarbonized economy by 2050. Moreover, fossil fuels can be replaced by electricity that is produced by renewables and other low carbon technologies, which in turn reduce CO_2 emissions, changing the fuel mix without compromising security of supply (Li et al., 2018). To this direction, even more ambitious environmental targets have been set out by REPowerEU strategy (European Commission, 2022). The latter emphasizes on the reduction of the EU's energy dependency coupled with cutting demand for gas and acceleration of clean energy transition. We point out that the perspectives of a storage facility differs when it supports the penetration of the green hydrogen since then it provides further sustainability opportunities and benefits, offering increased energy system value on a long-term basis (Elberry et al., 2021).

In this study, we focus on a candidate UGS facility in Greece (Facility code: UGS N-385), following a methodology that has been proposed about the Brazilian market (Almeida et al., 2018). However, in our case a research gap identified, since Almeida et al. (2018) correlated gas injections with low specific marginal electricity price, investigating mainly the impact on the electricity market. Thus, the power sector uses stored gas to fulfil its demand, instead of purchasing spot LNG when the electricity price exceeds a specific price. This approach has been adapted appropriately, after a careful study of the specific structure of the Greek market. As a result, we propose the pipeline "capacity threshold" which triggers withdrawals, instead of adopting the aforementioned electricity price index. This element is the added value of our methodology, which additionally focuses on the benefits or losses of consumers, avoiding the restriction in the electricity market. This approach could be replicated in similar developing markets, committed to implement an energy market liberalization program. Greece has been selected as our case study, since the country lacks long term gas storage installations, but remains an interconnected market on track to become a mature exchange-based gas market. Our motivation has strengthened even more, given that a bidding process for the allocation of storage rights to a depleted gas field is in full progress, giving substance to our research activity.

To this context, this work has two main objectives. First, we explore the economic perspectives of UGS facilities, using an evaluation methodology, appropriately adapted to the domestic market fundamental and structure, aiming at being replicated in markets with similar conditions. Energy market analysis is of utmost importance for the followed methodology and this is the reason why we considered several in depth market analyses. Second, policy recommendations are provided to assess the impacts of UGS installations from both the welfare and energy market stakeholder perspectives. The proposed recommendations are in line with the energy perspectives outlined in the Greek National Energy and Climate Plan 2020-2030, the European energy policy framework, and the funding outlook. Our suggestions focus on synergies with other energy investments and regulatory reforms, providing an optimistic perspective.

To address the above, emphasis is given to the main parameters that trigger the development of the storage market. Based on the commercial aspects, price volatility is the main factor that drives the storage market, creating investment opportunities (Hirschhausen, 2006). The lack of price fluctuation limits the positive impacts for both the investor and the consumers. We also consider the regulatory aspect since it is related to wholesale gas market liquidity. In this context, the upcoming establishment of a gas trading platform (exchange market), along with the amendment of sale-purchase agreements and the role of gas projects that are constructed, are also being analyzed.

The rest of the paper is organized as follows: Section 2 presents the economic evaluation of UGS facilities. Section 3 describes the methodology and the assumptions that are adopted for the numerical analysis. Section 4 analyzes the specificities of the Greek electricity and natural gas sector in light of the new energy and climate plan. In Section 5, we present the economic results and a sensitivity analysis that focuses on capital expenditure and the storage fee. Section 6 analyses the policy recommendations that could make such storage investments attractive and sustainable. The study summarizes the conclusions in Section 7, highlighting the added value that further investigation of hydrogen storage could have, regarding the sustainability benefits of such storage installations in the near future.

2. Background

During the last decade, several academics and practitioners have investigated underground gas storage; an energy activity that initially was related to the security of supply. Gas storage has gradually taken characteristics of a typical energy market (United Nations, 2013). Its role has been analyzed under the condition of safety and using sustainable methods for pressure management (Zhang et al., 2020). The literature reveals that an energy system with higher shares of renewables requires sufficient storage and balancing capabilities (GIE, 2019). It also highlights the importance of multiple supply routes or sources and the gas storage, as an option to compensate for supply failures and disruptions by reducing load shedding (Devlin et al., 2016). This is more intense, especially in cases of high penetration of renewables, which due to uncertainty makes energy systems vulnerable. The gas storage, along with LNG facilities, have been considered as complementary investments that guarantee security of supply and competitive prices in favor of consumers' benefit, contributing to the enhancement of energy systems' flexibility (Devine and Russo, 2019).

Regarding the procedure of UGS storage, this includes gas routing from a gas pipeline to a processing plant, for solids' removal, metering and then for injection to the underground installation, using a compressor. Withdrawal includes extraction of gas from the storage, separation from water and solids, and then routing to a cleaning and drying site. Last, the gas is delivered to end consumers, through the transmission and distribution network. A gas system which includes a storage facility is depicted in the Figure 1.

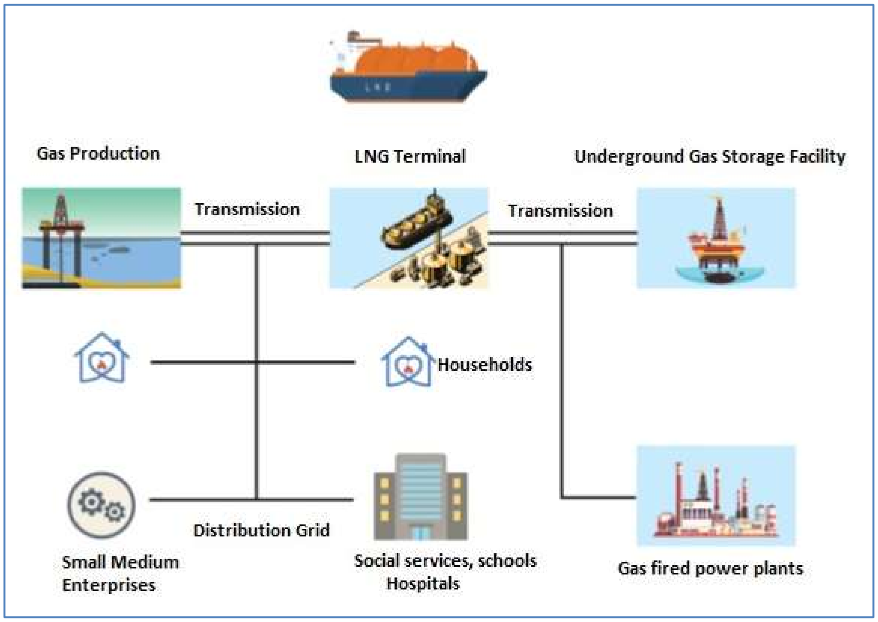

Figure 1: Underground Gas Storage as part of a gas system

2.1 Gas Storage Value

From an economic point of view, gas storage refers to a spectrum of different facilities which allow market stakeholders to inject gas from the transmission system to the storage facilities when prices are low (off-peak demand) and withdraw gas when prices are high (peak demand). This price differentiation triggers gas transactions and creates incentives for gas suppliers to invest in storage facilities (Ejarque, 2011). Therefore, storage capacity provides the suppliers an opportunity to achieve benefit (arbitrage) from seasonal price volatility and arbitrage chances in spot markets (Cavaliere et al., 2013), contributing to globally integrated and competitive natural gas markets (Neumann, 2009; Li et al., 2014). In mature markets, gas storage can be considered as a tool that ensures flexibility, also used for speculation through price arbitration, enabling the optimization of natural gas transmission and securing continuity of the service (Leahy et al., 2012). Hence, the UGS role is summarized in speculation, precaution, and mitigation of seasonal load variations (Baranes et al., 2013).

The first component of the gas storage value is the system one. Gas Infrastructure Europe (GIE), an Association representing the interests of European natural gas infrastructure operators underlines in its report (GIE, 2015) that a UGS facility located close to production allows efficient operations and provides system security; especially, in case of technical problems that undermine the smooth production process. This results in reduced costs, extended lifespan of production fields and maximized volumes extracted. The Association also notes that when a UGS facility is near to demand areas, storage contributes to lower network investment costs. The latter is achieved through the reduced dimension of the pipelines necessary to meet peak demand and the improvement of the system operations' efficiency. The penetration of renewables in the energy mix is also facilitated by a UGS since Power to Gas technology mitigates their stochastic variation, supportively contributing to the transition of a low carbon emission economy (Budny et al., 2015). It is also identified the importance of gas storage for the stability of energy systems since gas interruptions increase both system and energy costs (Deane et al., 2017). Additionally, gas storage streamlines power generation allowing smoother power system operation and reducing the generation cost (up) to 40% (Qiao et al., 2018).

The second component is the insurance value which is related to the storage's contribution to the continuity of gas supply, safeguarding suppliers from sudden price spikes. On a national and international level, having gas in store can provide a safeguard against the high impact of unexpected technical failures in production systems or pipelines, or even against geopolitical risk. Therefore, storage mitigates vulnerability and provides emergency cover when politically sensitive situations affect the energy supply (e.g., the 2009 Russia-Ukraine dispute) (European Commission, 2009). Nevertheless, storage does not constitute the only solution; so, it is crucial for Europe to take the appropriate economic, efficient measures considering the economic impact of gas supply disruptions (ACER, 2018).

The work of Zafirakis et al. (2016) deals with the arbitrage value analyzing its two main components: the intrinsic and the extrinsic value. Given a liquid forward market, traders are able to lock in a base or intrinsic value to the storage asset by agreeing on the future prices, while inherent extrinsic value can be extracted through dynamically trading in the underlying forward and options market. The first component (intrinsic value) is extensively analysed by Cyriel (2015), and it is driven by price spreads in forward markets and involves a simple hedge taking advantage of the price seasonality. In addition to the intrinsic value, a market stakeholder may extract more value from the storage products by refining the hedge. The case of the extrinsic value (second component) is approached by Cummins et al. (2018) and refers to the revenue captured from active trading and the asset's ability to operate on short term basis. This implies an increase of storage cycles to the extent that overcome the one cycle (intrinsic value) and is subject to technical and market constraints. The extrinsic value is more difficult to calculate since it constitutes a substantial part of the total revenues. An indicative example of an opportunity to harvest extrinsic value from storage is when a spread between the spot price and the month-ahead futures price develops during the winter season. This enables the storage customer to buy spot gas and, at the same time, conclude a futures contract to sell it in the months ahead. Furthermore, storage can be used by suppliers to grasp price opportunities in case of sudden price spikes, taking advantage of an excellent spread and thus, it has an "optionality" value.

In practice, the economic value of a UGS facility is calculated using the Discounted Cash Flow method (DCF) along with Net Present Value (NPV) and Internal Rate of Return (IRR) indicators as well (Almeida et al., 2018). These are the appropriate widely adopted parameters in assessing the profitability of a long-term project as a UGS facility (Anyadiegwyu et al., 2012).

2.2 Investment Outlook

Investments at gas storage have been thoroughly investigated, and several of those are driven by the price seasonality and the related demand (Hirschhausen, 2006). The revenues obtained through the induced price spread should be sufficient to pay for the capital expenditure (CAPEX) and the operational one (OPEX) and generate an expected return on capital. It is highlighted that UGS projects are characterized by a high initial investment and low fixed operating costs which refer to the procedures of gas injection and withdrawal and are only a very small fraction of capital costs (up to 3%) excluding fuel costs (Fevre, 2013).

Several concerns have been raised about the viability of UGS facilities ahead of 2021, as factors such as low summer-winter spreads and reduced-price volatility weigh negatively on investment in such energy projects. The European Commission concerns that this situation may lead to the closure of many facilities to the benefit of other flexibility tools (European Commission, 2015). Nevertheless, a relevant analysis carried out specifically for north-west Europe indicates that there is a substantial need for additional gas storage facilities, supporting project proposals for new investments in this sector (Joode and Ozdemir, 2010). The latter is primarily based on an expansion of a game-theoretic model of the European gas market (Boots et al., 2003), indicating that additional storage capacity (of 20 billion cubic meters - bcm) is needed till 2030 in north-west Europe. The new storage capacity is slightly decreased in case of increased regional gas indigenous production, new LNG, or more efficient use of the existing gas transmission capacity.

The literature reveals the positive role of market reforms in making investments in underground gas storage more attractive (Chen et al., 2018). Furthermore, social welfare can be maximized using both spot market and storage even if the storage fee is higher than the spot price (Baranes et al., 2013). Hence, the storage fee is a tool for the Regulator to arrange liquidity spot market's issues, assuming that the managing authority disposes of the appropriate market's monitoring tools. Concluding our analysis, the reader could find in the Table 1 below, the main benefits and challenges, identified in the specific Section.

Table 1: Benefits/Challenges of Underground gas storage

Benefits	Challenges
Gains stemming from seasonal price volatility	Limitations of appropriate geological structures
Security of supply	High investment cost
Gas market integration and competition	
Optimization of gas transmission network	
Renewables system penetration	

3. Methodology

3.1 Overview

The UGS evaluations presented by the European Commission (2015) are mainly based on the assumptions of a fully liberalized market that allow price variations. Since there are several markets that lack such variation, we propose a different approach to reach solid conclusions regarding economic evaluation, adapting the method that Almeida et al. (2018) has applied to Brazilian market. Our approach emphasizes on the substitution of the LNG from the stored gas, which will be used when consumption exceeds a "capacity threshold" (i.e., during peak-demand periods). This is related to technical and commercial constraints, further analyzed below. Initially, the stored gas is evaluated at the current gas pipeline prices, since injection occurs during low demand periods when the market remains stable and smoothly supplied, through long-term gas pipeline contracts. Hence, during peak-demand periods the market has access to affordable stored gas instead of purchasing less competitive LNG. The storage value for market stakeholders is related to the price margin between stored gas and LNG, which would be used otherwise. The proposed approach can be implemented in developing energy markets, such as the Greek one.

From the economic aspect, we employ the Discounted Cash Flow (DCF) method (see Appendix). In practice, the costs and benefits are discounted at an appropriate cost of capital equal to the weighted average cost of capital (WACC); in the case of Greece, this type of investment's WACC approaches approximately 10%. The latter is calculated by the Greek Energy Regulator, adding a typical WACC (7.44 - 8.23%) that usually refers to the gas infrastructure owned by DESFA, with a risk premium for new gas infrastructures. In practice, a risk premium that could provide incentive for investors and be also acceptable by the Regulator ranges between 1.5% to 2.5%.

3.2 Operation Mechanism

Our working pattern follows the assumption flow shown in Figure 2. During low demand period, from March to May and from October to November, power plants and suppliers purchase "more affordable" gas through long-term gas contracts and inject it into the UGS facilities, mainly for trading and security of supply reasons. Concerning the second reason, the Regulator plans for the establishment of a storage obligation that will be imposed on the suppliers of protected customers' and the gas-fired power producers. We suppose that both injection and withdrawal may occur during September since market fundamentals advocate this, without security of supply to be jeopardized. No withdrawal occurs when spread LNG-gas pipeline prices are negative. Even though negative prices are not common, these can be observed in some extreme cases; an indicative example was in 2019 (from April to September) when LNG was being exchanged at more competitive prices, compared to pipeline gas prices (European Commission, 2021b). In details, LNG contracting slowed down in 2019 with a total volume of 74 bcm, after a wave of strong contracting activity culminating in 2018 with 95 bcm signed (IEA, 2020). This happened since Asia LNG demand slowed down as economy's growth rate mitigated. In parallel, IEA (2019) refers that remarkable rise of shale gas has pushed down natural gas prices. As a result, the spread has been reversed. It is pointed out that we use and deeply analyze the available capacities and delivered gas amounts as they are uploaded by DESFA, in its daily gas flow reports[1] (Validated Natural Gas Deliveries/off-takes).

We assume that the withdrawal occurs when demand exceeds 70% of the nominal technical capacity of gas pipeline; so, suppliers withdraw gas during December to February and June to August, considering the particularity of September, (as mentioned above - dotted area in Figure 2). Below this "capacity threshold" (70%) trading companies supply consumers with gas pipeline, as this choice is considered "*more affordable*" and then opt for the use of the stored gas, instead of importing LNG, which primarily constitutes an expensive trading choice. The utilization rate of 70% has been calculated on historical data and seems that depict the gas producers' ability to serve the signed Sales and Purchase Agreements (SPA). It is also assumed that this threshold could not be overcome due to commercial constraints of suppliers since the latter pay any reasonable effort to serve each signed SPAs, even in peak demand periods. Last but not least, during our simulation, we follow the technical accepted injection or withdrawal rates. Figure 2 depicts the entire flow procedure.

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[1]DESFA Gas Flow reports (Last Access Date May 2021). Available online from: https://www.desfa.gr/en/regulated-services/transmission/pliroforisimetaforas-page/historical-data/deliveries-offtakes

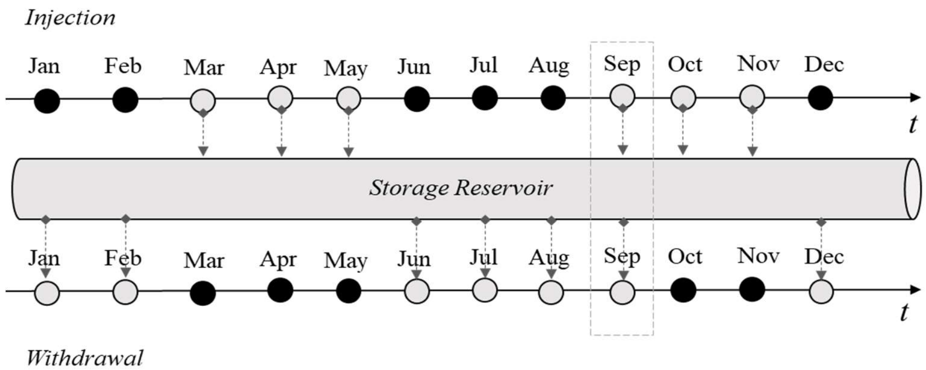

Figure 2: Schedule of injection and withdrawal monthly periods in the storage reservoir

To sum up the aforementioned procedure, we apply the following steps:

- Injection of pipeline gas in the storage installation during low demand period.
- Cost evaluation of the injected gas according to prices published by Eurostat.
- Storage cost evaluation that burdens consumers and constitutes the facility's Operator income.
- Gas withdrawal when demand exceeds 70% of the nominal technical capacity of gas pipeline.
- Profit estimation for consumers, based on the positive spread between LNG and pipeline gas, due to the use of stored gas instead of LNG that would be imported.

Our pattern is in line with the one analyzed in the case of European storage facilities that present the same cyclical filling process. According to European Commission (2015), gas inventories face a steady growth from March/April to September/October of year t (injection period). Then they start to decrease until the following March/April of *t+1* year (withdrawal period). The installation's operation is monetized, using the monthly gas pipeline and LNG prices, as announced by European Commission (2021b). These quarterly market reports allow us to calculate the profit obtained for stakeholders when they use stored gas valuated in gas pipeline prices, instead of LNG.

Regarding our assumptions, the capital expenditure (CAPEX) reaches 300 million € (ENTSOG, 2018), while the energy infrastructure operates under a Third-Party Access (TPA) regime, in line with the respective EU legal framework[2]. The latter permits the project's funding from the European or Institutional banks, although this option seems to weaken since the European Green Deal policies enter into force. Finally, concerning the storage fee, which constitutes the main income for the Storage System Operator, we adopt the approach of an independent institutional entity in Greece. This entity identifies the tariff at the level of 5 €/MWh, a price which refers to the bundled product that combines injection, storage, and withdrawal services. This figure is in line with the estimations of the Regional Policy for Energy Policy Research (REKK, 2013) which concluded that tariffs in the Danube region, are capped at the level of 5.30 €/MWh.

In parallel, we consider the available institutional long-term plans (MEE, 2019a; DESFA, 2020) to incorporate trends of the energy market fundamentals which could bring essential differentiations in our assumption. So, we calculate cash flows on a monthly basis,

[2]Directive 2009/73/EC, Directive (EU) 2019/692/EC

identifying the annual income and evaluating NPV and IRR for a period of 25 years. All the assumptions we have adopted are included in Table 2.

Table 2: Assumptions based on market fundamentals and UGS's technical characteristics

Assumption	Value	Source / Note
Parameters		
CAPEX	300 (mil. €)	Base case scenario in 2020 prices
Storage fee	5 (€/MWh)	For bundled product-service price
Energy content of 10^3 Ncm	11.53 MWh	Equivalent energy of gas in MWh for given volume
Working gas	360 mcm	Based on max 4,150,800 MWh (storage capacity)
LNG Shipping & re-gasification cost	2.50 €/MWh	Forecast estimation (internal baseline scenario)
Injection Rate	5 mNcm/d	57,650 MWh/d
Withdrawal Rate	4 mNcm/d	46,120 MWh/d
Variables		
Wholesale Gas prices	Variable per month	As announced in European Commission Quarterly reports

4. Focal Case: The Greek Energy Market

In this work, we focus on the Greek, since the country lacks installations which provide long term gas storage capabilities, although it disposes of this prospect. The reports, which we have reviewed, reveal a non-fully liberalized market, where price variations does not depict the fluctuations of the demand, as analyzed below. The Greek energy market is supervised by the Regulatory Authority of Energy (RAE) and has recently started to implement the European electricity target model (MEE, 2019a). The model refers to the wholesale Electricity Market and is applied in almost all EU countries. It is the pillar for the coupling of the individual national markets through the adoption of a common architecture. Consequently, the Greek energy market is being gradually but steadily transformed into a liberalized and well-interconnected market based on renewables and energy storage. In this context, the gas plays a transition role.

Regarding the National Natural Gas Transmission System (NNGTS), it is operated by DESFA (Transmission System Operator – TSO). The domestic gas market is characterized so far by poor interconnectivity with mature markets and non - existence of seasonality of gas prices, since they are inextricably linked to oil prices. An interesting observation is that the gas price is not correlated (Pearson correlation coefficient is 0.099) with the supply and demand (Figure 3), despite the high price volatility (the average price is 19.25 and the variance is 14.1). We observe that the gas price does not increase during periods with high demand, as is expected. However, the gas price was decreased (Nov-2015 to Feb-2016) or remained stable (Oct-2017 to Mar-2018) despite the increased demand during that period. This demonstrates that the domestic market remains immature over the corresponding period, as oil-indexed natural gas prices (as published by RAE) incorporate subsequent oil price volatility in time lag reflecting current market fundamentals.

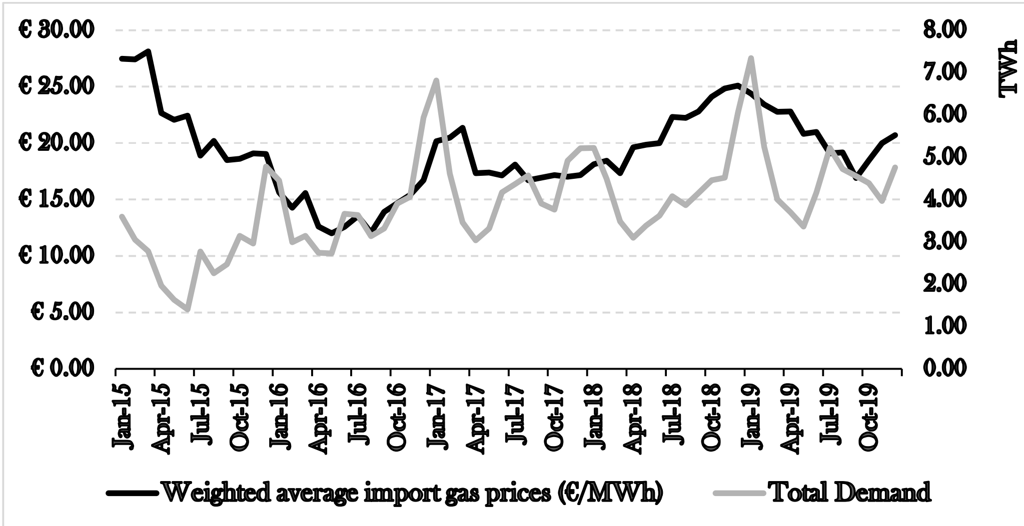

Figure 3: Evolution of price and demand (source: Regulatory Authority for Energy, https://www.rae.gr/import-prices/?lang=en)

It is highlighted that the gas is mainly consumed in the electricity sector (65%), followed by industry and distribution grids (residential and small-medium enterprises) by 15% and 20%, respectively (DESFA, 2020). Hence, demand volatility is driven by power sector, which strives to cover retail electricity demand for heating and cooling. It is noted that January and July are months of peak gas demand, while February, June, August, September, and October follow as high-demand periods (HEnEx-Hellenic Energy Exchange, 2019). The detailed overview of the system's current situation shows that the installed capacity in the interconnected network was 18.3 GW (35% renewables, 27% gas-fired plants, 21% lignite-fired plants, and 17% hydro) at the end of 2019, while the average system's marginal price (SMP) reached 63.8 €/MWh increased by 5% compared to 2018 (HEnEx, 2019). HEnEx in this report notes that the electricity is generated from a differentiated and balanced fuel mix, where the lignite participation has sharply been de-escalated, plummeting from 61% in 2014 to 20% in 2019. This happened mainly because of new shale gas amounts which entered the global market, resulting in gas prices de-escalation. Regarding electricity demand, it has been satisfied by natural gas that exceeded 32% in 2019 followed by electricity imports (23%), renewables (20%), lignite (19.4%) and hydro (5%). Therefore, the gas stabilized its share in the energy mix, playing a crucial role of the back-up fuel (i.e., substitute lignite), while hydro contributes only to periods with peak demand. The lignite-fired electricity production will be eliminated by 2028 (MEE, 2019a); so, it should be partially replaced by gas.

Until 2019, gas demand was satisfied mainly by imported amounts through Bulgaria and Turkey entry points. From then, the Revythoussa LNG terminal plays the role of the main gate of gas imports (accounting around 50%). The installation's role has extensively analyzed, particularly regarding the commercial options provided to the suppliers (Strantzali et al., 2019). At the end of 2020, a new entry point close to Thessaloniki has been added since Trans-Anatolian Pipeline (TAP) has started its commercial operation. The aforementioned gas infrastructure is depicted in Figure 4.

Figure 4: Location of the UGS N-385 (Underground Storage Facility) within the Greek gas system. Source: ENTSOG, Ten Year National Development Plan (2018), Project Specific CBA (page 243)[3]

As far as the gas security of supply is concerned, the following conclusions can be drawn by the gas supply crisis during the winter of 2016/17 (IEA, 2017). The Agency pointed out in its country's In-Depth Review that Greece remains vulnerable to the failure of its largest gas infrastructure in case of severe gas disruptions. In this specific Review, it is highlighted that the domestic market is heavily influenced both by delays in LNG deliveries and unexpected shortages of gas supply at the interconnection points. So, the Agency focuses on the problem of the non-existence of a facility for long-term gas storage. Last, IEA points out that another lesson learned is the strong interaction of the gas supply with the electricity one during a gas crisis.

4.1 New Energy and Climate Strategy

According to the National Energy and Climate Plan 2020-2030 (MEE, 2019b) and the Study for the Adequacy of Electricity Power 2020 - 2029 (ADMIE, 2019), all the lignite-fired power plants will phase out by 2023 except a newly constructed one which will remain operational till 2028. The decommissioning of lignite plants should be accelerated, given the increasing CO_2 cost, coupled with a more environmentally friendly national energy policy as outlined in the newly established energy and climate strategy for 2050 (MEE, 2019a). The installed capacity will be

[3]European Network of Transmission Systems Operators for Gas, Ten-Year Network Development Plan (2019). Available online from: https://www.entsog.eu/sites/default/files/2019-04/TYNDP%202018%20Project-Specific%20CBA%20Results.pdf

replaced by 1.7 GW new gas-fired plants (MEE, 2019b), while 7.7 GW and 0.4 GW of renewables and hydro, respectively, will be added to the power system by 2030. In addition, a new electricity 0.6 GW interconnection with Bulgaria will be commissioned within 2022.

Therefore, the period 2021 - 2024 is the most critical for the country's power adequacy since all except one lignite plants will be decommissioned without being replaced by gas-fired plants. From 2025 onwards, the adequacy of the system will become particularly vulnerable to climatic and hydrological conditions, and it remains questionable to which extent the new international interconnections will be able to mitigate the impacts of load spikes during this period. In this context, temporary measures are taken without undermining the long term climate targets. The role of energy storage is critical given the wide penetration of renewables in the energy mix, which adds an even greater parameter of variability due to their intermittent operation, thus increasing the vulnerability of the system.

Concerning the gas market, three demand scenarios have been developed according to the Development Study 2021 - 2030 by DESFA (2020). The first scenario (Low demand) coincides with the NECP estimations and the second one (Base case) considers lower gas prices (NECP adjusted). Concerning the last scenario (High demand), this one is in line with the assumptions of the Power Adequacy Study, carried out by the electricity TSO. We estimate that the high demand scenario seems to be more likely to be confirmed given the confirmed market's fundamentals, and it foresees that gas demand will vary from 5.8 bcm (67 TWh) in 2021 to 6.8 bcm (78 TWh) in 2030. The bulk of this consumption is related to electricity production, whose load spikes impact gas peak demand. These spikes constitute a worrying factor for the energy system's stability. So far, peaks were usually occurring during the winter period, but from now and then, the more often and severe heat waves trigger extensive use of air-conditioning units, which leads to a peak in energy consumption.

4.2 Underground Gas Storage

As it has been already mentioned, the only suitable underground gas storage in Greece is the South Kavala depleted gas field, which is located offshore in Northern Greece[4] (Gulf of Kavala), approximately 11 km south of the Prinos oil field, in a water depth of 58 m. During periods of low demand, the UGS will take gas at an injection rate of 5 million cubic meters per day from the national gas transmission system. A new land pipeline will deliver gas to an onshore plant (new or the existing Sigma oil and gas processing plant), where it will be metered and compressed. A new 36 km sub-sea pipeline will then transmit the gas to the existing Kappa unmanned and remotely operated platform, where it will be injected and stored in the offshore gas reservoir. During periods of high demand, the flow will be reversed at a withdrawal rate of 4 million cubic meters per day.

From a geological aspect, it is commonly accepted that depleted gas condensate reservoirs, as the one that lies in Greece, remain suitable for gas storage use (Mazarei et. al., 2018). In general, these geological structures are proper to accommodate an easy and low-cost gas storage operation, because they dispose of appropriate porosity and permeability characteristics. These reservoirs may provide the best, and the most economical accommodations for gas storage since their annual number of injections and withdrawals are normally low. Moreover, underground gas storage capacity has been extensively considered

[4]Hellenic Republic Asset Development Fund (HRADF), Available online (Last Access Date March 2022): https://hradf.com/en/south-kavala-underground-natural-gas-storage/

in the Netherlands, as this country disposes one of the largest natural gas production potential in Western Europe (Juez-Larré et al., 2016).

5. Estimation of the Economic Value

Aiming at estimating the economic value that the specific UGS facility could deliver, we opted the period 2015 - 2019 to run the process. So, we considered that gas injection in the UGS started in March 2015, at the maximum technical rate of 1,729,500 MWh/month. The same amount of gas has been injected in May, and the remaining storage capacity of 691,800 MWh has been filled in June, covering the entire UGS capacity of 4,150,800 MWh. It is calculated 20.75 million € have been paid by suppliers this period, since storage fee is assumed to 5 €/MWh. Subsequently, storage level remains unchanged since the consumption is such that no gas withdrawal is required, although summer months and September is usually a high demand period. From December 2015 to January 2016, according to monthly gas flows uploaded by TSO, amounts of 1,383,600 and 715,000 MWh have been withdrawn, respectively, since the demand exceeded 70% of gas pipelines capacity. Using stored gas, suppliers avoided purchasing LNG and saved 7.1 million €, due to the spread of 3.39 €/MWh between LNG and gas pipeline prices (European Commission, 2021b). These withdrawals resulted in a storage level of 2,052,200 MWh in January 2016. It is pointed out that 1,383,600 MWh/month is the max technical withdrawal rate. Last, the consumption in October and November could justify the withdrawal of 115,000 MWh and 30,800 MWh of gas, respectively. This did not occur since we assumed that during these months, only gas injection is permitted, for security of supply reasons.

From March to April 2016, the storage level has been totally restored after injections of 1,729,500 and 369,100 MWh respectively, which cost 10.49 million € for storage services. A small amount of 49,000 MWh gas was withdrawn in June 2016, permitting a profit of 0.28 million € for suppliers. The demand exceeded again 70% of gas pipelines capacity from October to November 2016, and consequently, a withdrawal could occur if the restrictions related to the security of supply were not existing. From December 2016 to February 2017, 3,902,650 MWh have been withdrawn that resulted in limiting the storage level at 199,150 MWh and offered a gain of 31.96 million €, four times more compared to the respective previous period and two times more than the typical annual profit that suppliers obtain using the storage installation.

Proceeding our simulation, we make similar calculations which are omitted for the convenience of the reader. Nevertheless, it is underlined that there are several cases that storage replenishment does not take place since security of supply reasons are prioritized. It is also mentioned a case (June 2019), that even if withdrawal of 554,000 MWh gas was required, the energy demand has been covered by imported LNG, since price difference (spread) between LNG and gas pipeline was negative.

Concluding this cycle of five years, storage facility created cash flows of 106 million € which have been paid by the suppliers and are depicted in the Figure 5 in annual basis, assuming a storage fee of 5 €/MWh. In parallel, suppliers gained 78.6 million € that resulted in an annual cost of 5 million €, since the incurred profit has been overcome by fees for storage services. In general, assuming that the annual revenue reaches 20 million €, the project results in a negative NPV.

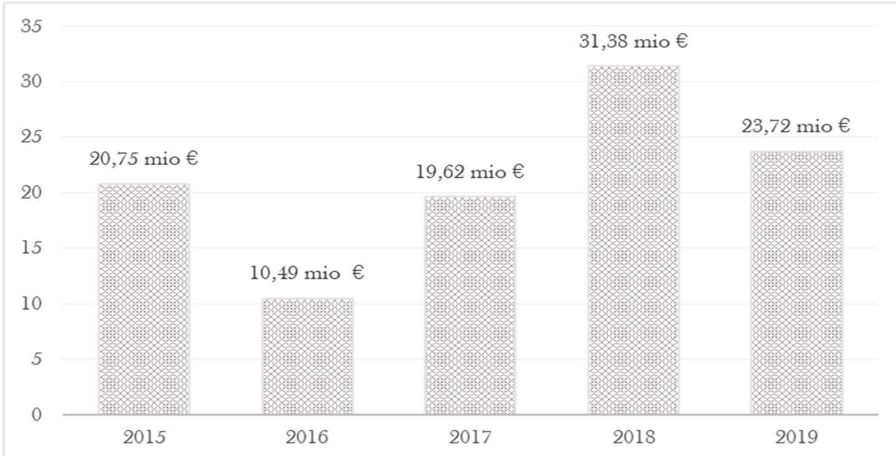

Figure 5: Calculated annual cash flows

The robustness of the economic results is confirmed by a sensitivity analysis which is carried out based on CAPEX and storage fee. Regarding CAPEX, the sensitivity is calculated for a variation of ± 20% of the initially assumed value of 300 million €. In relation to storage fee, sensitivity is estimated for a variation of ± 50% of the initially assumed value of 5 €/MWh. In both settings we have calculated the indexes of NPV and IRR. The UGS has a negative NPV in each case, as it is shown in Table 3.

Table 3: Results for CAPEX sensitivity analysis given that the storage fee is 5 €/MWh

Case	Variation	CAPEX (million €)	NPV (million €)	IRR
A	20%	360	-161.7	-4.46 %
B	0%	300	-101.7	-3.31 %
C	-20%	240	-41.7	-1.66 %
			Storage fee 5 euro/MWh	

Exploring further the CAPEX base case scenario, we carry out when a tariff sensitivity analysis. We identify the case that a positive NPV, coupled with a weak IRR prove that the project tends to be marginally viable. Finally, we observe that the project can result in a positive NPV, when CAPEX and the tariff are assumed at 240 million € and 7.5 €/MWh respectively. In parallel, this approach brings a satisfying IRR index fluctuated at 3%. This should be compared with the debt interest rate of funds granted by the country's bank system. The results are presented in the Table 4.

Table 4: Results for storage fee sensitivity analysis

Case	Variation	Storage fee	NPV	IRR	NPV	IRR
A	50%	7,5	17.27	0.54%	77.27	3.00%
B	0%	5	-101.70	-3.31%	-41,40	-1.66%
C	-50%	2,5	-190.94	-6.63%	- 130.94	-5.53%
			CAPEX 300 million €		**CAPEX 240 million €**	

We also investigate the case of the project's cost limitation at 240 million €, accompanied by simultaneous funding through a European financial tool, at the level of 30 - 35% of its CAPEX. This results in 157 million € NPV and a robust IRR at 9.08%, assuming a storage fee of 7.5 €/MWh. The latter constitutes a burden for the supplier, an issue that requires the Regulator's engagement. The storage tariff socialization, through a fee charged in the internal energy market, could be a solution, limiting the figure to 3.5 €/MWh. We calculate that a storage fee at this level could provide an incentive to suppliers to use the installation for commercial use, obtaining in parallel security of supply benefits. Assuming an average of 5 TWh for storage gas annually, the socialized value of 4 €/MWh suggests that 20 million € are allocated to a market of 60 TWh annual consumption in the upcoming years, which in its turn is translated to a burden of 0.33 €/MWh for the consumers.

6. Policy Recommendations

The discussion on the economic results highlights the importance of policy recommendations for the successful integration of this storage project in the energy market. In this section, we provide recommendations that could be used by the policy makers and the authorities. Our suggestions intend to make the investment attractive and the project sustainable and mutually beneficial for both the market stakeholders and consumers.

Consequently, it is suggested that the Regulator is required to set and regularly update the appropriate storage fee, with the aim to maximize the social welfare. The storage tariff's calculation requires a detailed Cost Benefit Analysis (CBA), which will analyze and quantify all the benefits related to market integration and security of supply. Such Analysis could assess whether and to what extent, a UGS facility provides positive externalities that could justify a tariff socialization. The latter implies that a premium will be imposed over the gas price in the internal market when the gas is sold to final consumers. It is obvious that a CBA based on scenarios adjusted to the recognized and commonly acceptable geopolitical threats, will identify benefits that will subsequently justify a broader extent of socialized tariff, since hesitant regulatory support could discourage investors. Additionally, the Regulator is also recommended to identify the compliance with the storage obligation regarding protected customers subject to the supply standard[5] and the respective licensing code. It is estimated that 40 - 50% of the capacity could satisfy storage obligation needs. Last but not least, the unprecedented high energy prices along with security of supply issues since Q3 2021 and the war in Ukraine at the beginning of 2022 confirmed the vital role of UGS facilities. Therefore, in the midterm, the European Union seems to consider again to regulatory initiatives that make gas storage a business attractive option.

Concerning the financial aspect of the South Kavala project, its grant funding eligibility from national or European institutional financial tools (Connecting Europe Facility) enhances its business perspectives. Nevertheless, the European funding is provided under strict time constraints (up to 2023) since natural gas as a fossil fuel has a specific role in the context of the European strategy for an economy of low (or zero) CO_2 emissions (European Commission, 2019). Therefore, it seems that the European funds will be channeled in gas projects, under strict prerequisites (Schittekatte et al., 2020). Consequently, national authorities should consider the perspectives of the storage facility under the light of the European Commission's green hydrogen strategy. Gas storage installations, when are transformed to hydrogen ones, are able to play a twofold role: i) improve energy comprehensive utilization rates which depict more efficient integration of renewables in the energy systems, and ii) achieve better load

[5] EU Regulation 1938/2017.

supply shortage rates (Zhou et al., 2020). Bearing all these in mind, policy makers in Greece should pre-define the ability of South Kavala UGS to store a mix of natural gas and green hydrogen, obtaining sustainability perspectives, given the pursuit of deep de-carbonization targets (Bistline et al, 2021). Nevertheless, it is not underestimated that the hydrodynamic characteristics of an underground hydrogen storage, compared to these ones of a natural gas storage, are different, since the chemical composition of these two gases is also different (Hagemann et al., 2016).

Furthermore, the weak price volatility for the investigated time period is a negative particularity of the internal Greek market, since leave limited room for sufficient profit margin for UGS investments. A gas trading platform coupled with the new or the amended SPAs and new gas investments will allow signal prices to depict better the demand's variations. In this context a new UGS facility could make the market more competitive, permitting suppliers to optimize their commercial transactions, resulting in increased social welfare. Therefore, it is proposed that the Authorities step up their efforts towards the establishment of the gas exchange market.

Finally, the national Administration should support the timely construction of gas projects that enhance the interconnectivity with the South-Eastern (Balkans) and Central Europe gas market. Doing so, projects as IGB pipeline and Alexandroupolis FSRU, in synergy with UGS will provide security of supply and flexibility solutions, in favor of the specific highly import-dependent region. These projects pave the way for the new suppliers to use the new infrastructure, enriching their portfolios with gas, stored in Greece. Moreover, policy makers should consider ways that permit market stakeholders to benefit from the recent interconnection with the Italian gas market via the TAP pipeline. The latter infrastructure gives access to a mature and competitive energy market that could benefit the advantages that South Kavala UGS offers.

7. Conclusions, limitations, and further research

This paper calculated the economic value of South Kavala UGS, considering that our approach could be replicated in similar energy markets. We have followed the appropriately adjusted methodology for the purpose of calculating suppliers' benefit, when the latter use stored gas instead of purchasing LNG, during high demand periods. The specificities of the Greek energy sector have been considered, so that good quality results to be obtained. According to our study, South Kavala UGS leads in negative NPV outcomes, while the project's commercial attractiveness seems weak. It has been concluded that there is no seasonal price volatility, since gas is negotiated over-the-counter (OTC), on the base of oil-indexed long-term contracts.

In terms of the investment's cost, CAPEX reduction at the lower possible level of 240 million € could make the project viable. The latter is ensured in case of setting the tariff price at the upper level of our estimations that is followed by a broad tariff socialization. It is pointed out that, the most expensive component of an underground gas storage facility remains the cushion gas. Minimizing its volume and understanding the reservoir well enough to define the efficient operating range can reduce the overall development cost of a storage project, as well as greatly enhance project profitability (Brown et al, 2008).

Several directions seem promising for future research. One is to examine the extent at which the proposed regulatory amendments and top priority investments could have positive impact. Further sustainability benefits related to renewable gas storage is also a demanding issue that deserves to be thoroughly investigated. The latter could emphasize on the project's contribution to the objective of reaching climate- neutrality by 2050. Finally, it remains to examine the role of capacity, coupled with an improved withdrawal/injection rate, in order a more effective project's operation to be obtained, under the restriction of the implied increased CAPEX. Other directions of interest include the effect of gas storage facilities on supply chain sustainability focusing on specific operations (Zissis et al, 2018).

We left for last the topic of security of supply that deserves to be further analyzed since the war in Ukraine highlighted its importance. The monetization of the benefits related to the avoidance of disruptions, remains a challenge. Regarding the security of supply, the storage facility provides an applicable solution in terms of the implementation of the European supply standard. In practice, gas storage is an undisputable need for an electricity system based on high renewable penetration, which suffers from instability. Nevertheless, we highlight that the security of supply obligations impact on the smooth commercial operation of the storage facility. On the other side, the LNG or the long-term pipeline contracts' flexibility seems to be more competitive compared to storage, now and for the upcoming years. However, LNG even if it provides a robust solution, parameters as the market's tightness, which definitely influences costs, should be reconsidered under the light of the recent geopolitical developments in Ukraine.

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Appendix

The Discounted cash flow (DCF) method is used to estimate the value of an investment based on its expected future cash flows. Therefore, the method contributes to determining the value of an investment based on its future cash flows. The latter constitutes the main method's limitation since the accurate estimation remains a challenge. The present value of expected future cash flows is arrived at by using a discount rate to calculate the DCF. The formula is:

$$DCF = \frac{CF_1}{(1+r)} + \frac{CF_2}{(1+r)^2} + \cdots + \frac{CF_n}{(1+r)^n},$$

where: CF is the cash flow for a given year, r is the discount rate, n is the number of years.

Energy companies typically use the weighted average cost of capital (WACC) for the discount rate, as it has been calculated by the Regulatory Authorities. The formula for WACC is:

$$WACC_{pre-t\quad,nominal} = (1-G) + \frac{ROE_{post-tax,nominal}}{(1-TX)} + G + DR,$$

where: $ROE_{post-tax,nominal} = RFR + CRP + \beta * MRP$, G is the gearing ratio, DR is the debt rate, TX is the tax rate, RFP is Risk Free Rate, CRP is the Country Risk Premium, β measures the systematic risk of a portfolio compared to the market as a whole, while MRP is the Market Risk Premium.

After discounting the expected future cash flows, then we estimate the Net Present Value (NPV), deducting the upfront cost of the investment from the investment's DCF. In case that NPV is a positive number then project is considered acceptable and profitable while in contrary, the investment is detrimental. The formula for NPV is: $NPV = DCF - I$, where I is the amount of the investment in the present.

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