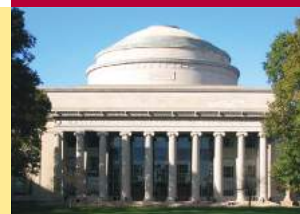
Interim Report for the Study

Natural Gas Monetization Pathways for Cyprus

Economics of Project Development Options



MITei

MIT Energy Initiative

Produced by The MIT Energy Initiative,
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In collaboration with The Cyprus Institute

Sponsored by The Cyprus Research Promotion Foundation

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This study is an interim report on the economics of natural gas project development options in Cyprus. It is a part of the overall study on natural gas monetization pathways for Cyprus. The full study is expected to be released in 2014.

The report is a joint collaboration between MIT and The Cyprus Institute.

The study authors:

Sergey Paltsev (MIT), Francis O'Sullivan (MIT), Nathan Lee (MIT), Anna Agarwal (MIT), Mingda Li (MIT), Xuejing "Michelle" Li (MIT), Nestor Fylaktos (The Cyprus Institute)

The study advisors:

Costas Papanicolas (The Cyprus Institute), Robert Armstrong (MIT),
Richard Cooper (Harvard University), Kenneth Smith (MIT),
Jos Lelieveld (Max Plank Institute/The Cyprus Institute)

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MIT and Cyprus

In 2007, MIT signed an agreement with the Government of Cyprus to aid in the development of The Cyprus Institute (CyI) Center for Energy, Environment, and Water Resources through human resource development and joint research. Since its inauguration, MIT and CyI researchers have been working together on initiatives of importance to the Mediterranean island nation and the region with the focus on water, energy, and climate change.

Cyprus faces serious shortages of both drinking water and energy — and the nation uses fossil fuels to power water desalination, so the two problems are intertwined. A major joint research project has therefore been investigating the use of concentrated solar power to produce both electricity and desalinated seawater. Analysis has shown that this novel cogeneration concept is technologically viable in Cyprus. Among the concepts coming out of this work are an innovative storage system, installation of heliostats on hillsides, and an advanced-design desalination system.

During the past two years, a deep budget problem in Cyprus led to a slowdown of the project with three projects selected for 2012–2014 extension of the original five-year agreement. The projects involve underground exploration which has strong implication for gas and oil exploration offshore of Cyprus, technologies for joint production of solar energy and desalinated water, and a study on natural gas monetization options for recent gas discoveries offshore Cyprus. All three projects deal with the theme of Energy, Environment, and Water Resources.

The funding for this study is provided solely by The Cyprus Research Promotion Foundation. While Eni S.p.A. and Total are members of MITEI and have exploration interests in Cyprus as described in the report, they have not contributed to any input, output, or funding related to this research. The views and opinions expressed in this report are those of the authors.

MIT Energy Initiative

MITEI is an Institute-wide initiative that links science, innovation, and policy to transform the world's energy system in order to meet the challenges of the future. As MIT's energy hub, researchers from across the Institute work with MITEI and with government and industry to identify tomorrow's energy challenges, develop cutting-edge solutions, and implement change by bringing new approaches to policy makers and new technologies to the marketplace. Through research, education, and outreach, MITEI's interdisciplinary approach covers all areas of the energy spectrum — from supply and demand, to security and environmental impact.

In May of 2013, Deputy Director Robert C. Armstrong was named MITEI director, as outgoing Director Ernest Moniz left the Institute to head the US Department of Energy as Secretary of Energy. It was announced in October 2013 that Robert Stoner, deputy director for science and technology; Martha Broad, executive director; Louis Carranza, associate director; and Francis O'Sullivan, director of research and analysis, have been appointed to the MITEI leadership team.

MITEI is designed to mobilize the Institute's research and educational capabilities to help meet the world's most pressing energy challenges. The MITEI study on natural gas monetization pathways focuses on Cyprus and looks at its options using a consistent approach that provides a useful guidance for decision-making based on relative economics of the options. This report provides an opportunity for an independent analysis of the major options: an onshore LNG plant, a transnational undersea pipeline, and the deployment of a CNG marine transport system. While developed for Cyprus conditions, the approach can be applied to other regions that are in the process of developing their natural gas resources. A multi-dimensional DCF model, developed for this project, allows for a wide variety of scenario and sensitivity analyses. An advantage of this approach is in its relative simplicity that still captures the major factors that will drive the economics of the projects. In addition, its openness allows any third party to change any input assumption in the DCF model and assess the corresponding results.

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The MIT Energy Initiative's Study on Natural Gas Monetization Pathways for Cyprus: Interim Report

SECTION 1 INTRODUCTION

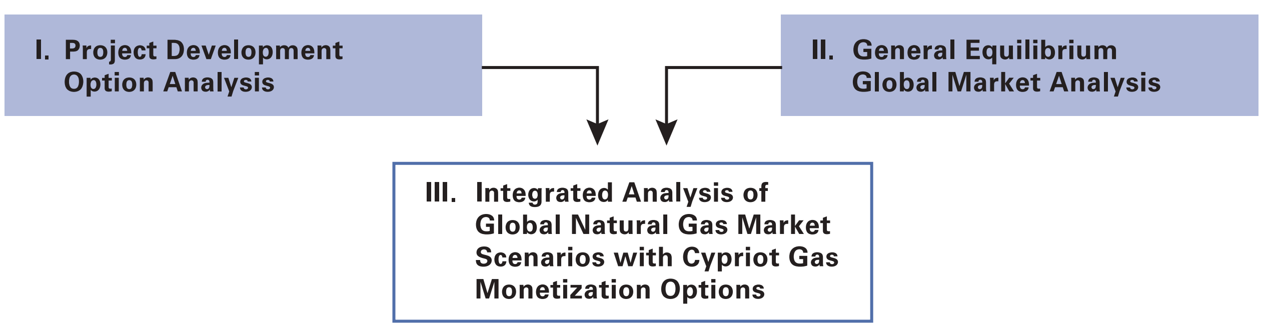
Purpose of Study

The objective of the MIT Energy Initiative (MITEI) study, *Natural Gas Monetization Pathways for Cyprus*, is to investigate the economic implications of key technology and policy options for natural gas development in Cyprus. The discovery of natural gas resources in the deep water off the southern coast of Cyprus has created opportunities for natural gas exports and a major transformation of the country's energy system.

This study seeks to provide an independent and transparent analysis of options for Cyprus natural gas resource development and exports. It will serve as a foundation for a basic understanding by Cypriot decision-makers, the business community, and international and local stakeholders about the strategic options for utilizing the Cypriot natural gas resource and ultimately will provide a basis for better decision-making.

The two-year study is being carried out by the Massachusetts Institute of Technology in collaboration with the Cyprus Institute, and was commissioned by Cyprus's Research Promotion Foundation in September 2012. Figure 1 provides the structure of the full report, which is expected to be completed in August 2014. This document serves as an interim report, which focuses on project development option analysis (block I in Figure 1).

Figure 1 – Structure of Full Report (expected to be completed in August 2014)



Overview of Full Study

The full study consists of the following three major elements: project development option analysis, general equilibrium global gas market analysis, and integrated analysis of global natural gas market scenarios with Cypriot gas monetization options.

Project Development Option Analysis – This portion of the study analyzes the economics of various project development options for Cyprus in exporting its natural gas. To compare different options, the MIT team has developed a multi-dimensional discounted cash flow (DCF) model which allows for a wide variety of scenario and sensitivity analyses. Options to be assessed include an onshore liquefied natural gas (LNG) plant, a transnational undersea pipeline, and the deployment of a compressed natural gas (CNG) marine transport system. Experience with the development of a gas-to-chemicals (GtC) option is also explored. Considering the priority the government of Cyprus has given to an LNG plant at Vasilikos (Cyprus Gas News, 2013a; Tsakiris, 2013), the report focuses on the LNG option, but also considers other options as they might serve as diversification strategies.

General Equilibrium Global Gas Market Analysis – This part of the study addresses the rapidly changing dynamics of the global gas markets, how distinct regional markets might interact in different ways over time, and the implications all this has for Cyprus in planning a long-term export strategy. The analytical basis of this section will employ MIT's Emissions Prediction and Policy Analysis (EPPA) model (Paltsev et al., 2011), a global general-equilibrium economic model that tracks both energy and non-energy commodity flows. This model was used in the scenario analysis for the *MIT Future of Natural Gas* study (MIT, 2011). Issues to be addressed in this report will include the impacts of shale gas development, the movement to globalization of natural gas trade, and the potential introduction of global climate mitigation policies.

Integrated Analysis of Global Natural Gas Market Scenarios with Cypriot Gas Monetization Options – The third section of the report brings together the previous two sections, understanding the meaning of the combined results for the long-term development of a natural gas exporting industry in Cyprus. Furthermore, these results will be contextualized within a broader assessment of the economic, geopolitical, and environmental risks that Cyprus faces in pursuing its natural gas development plans.

Focus of Interim Report

This interim report, *Economics of Project Development Options*, provides an initial analysis that mostly focuses on the *Project Development Option Analysis* section described above.

SECTION 2 CONTEXT

Cyprus's Discovery and Continued Exploration

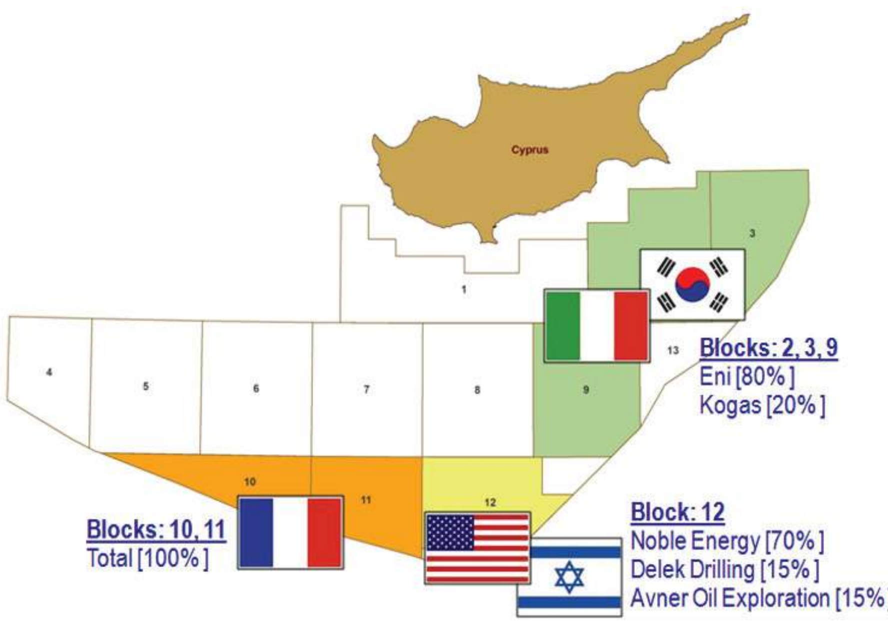
In December 2011, Noble Energy, a Houston-based oil and gas company, announced the discovery of a major natural gas reservoir offshore Cyprus, in Block 12 of its Exclusive Economic Zone (EEZ). The "Aphrodite Field" is located 1,700 meters below sea level with initial estimates of recoverable volumes in the 5–8 trillion cubic feet (Tcf) range.[1] As of August 2013, Noble is drilling its second appraisal well, which will provide more certainty on this range, with information to be released in the October–November 2013 time frame (Cyprus Mail, 2013). In the meantime, the government has licensed four additional blocks for exploration. The companies involved include Total, Eni, and Kogas (see Figure 2). As of August 2013, drilling has not commenced in these other blocks.

Broader Activity in the Region

Events offshore Cyprus are, in fact, part of a broader dynamic in the Eastern Mediterranean Sea, an area which has, in the past decade, become an active region for offshore oil and gas exploration. In 2010, the US Geological Survey (USGS, 2010) estimated that the Levant Basin — the basin of which the Aphrodite Field is a part — held 122 Tcf of potentially recoverable natural gas, while the Nile Delta Basin's potential stood even higher at 223 Tcf (see Appendix 1).

The first major discovery in the region occurred in 2003, offshore Egypt, where Shell discovered 1.5 Tcf of natural gas in the North East Mediterranean (NEMED) block, adding to its extensive reserves already being monetized onshore.[2] Then, in January 2009, Noble Energy discovered the 9 Tcf "Tamar Field" offshore Israel. In October 2010, Noble discovered another field in Israeli waters, the 17 Tcf "Leviathan Field." This latter field is located 36 km from Cyprus's Aphrodite Field and is the largest discovery in the region. Initial exploration activity has now commenced off the coasts of Lebanon and Turkey (Faustmann et al., 2012), and — prior to the emergence of

Figure 2 – Cyprus Offshore Hydrocarbon Exploration Blocks (Block 12 is in Yellow)

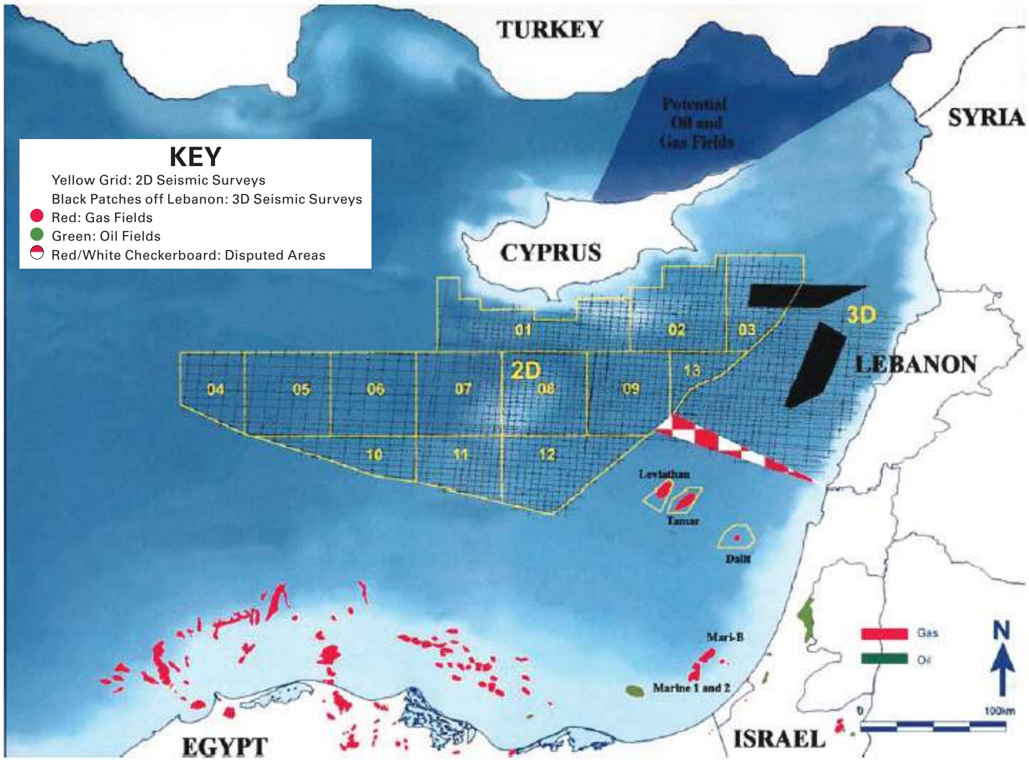


Note: Noble has revised the appraisal of the field in Block 12 from 3.6 to 6 tcf, with a mean of 5 tcf (as opposed to the 7 they are using.

Source: Cyprus Gas News (2013c).

the recent conflict — it was expected Syria would follow suit. Figure 3 shows the exploration and production activity in the Eastern Mediterranean. The Levant Basin contains the activity closer to Cyprus, while the gas production offshore Egypt is a part of the Nile Delta Basin.

Figure 3 – Fossil Fuel Activity in the Eastern Mediterranean



Source: Natali (2012).

The Eastern Mediterranean is well located for resource development, with its proximity to Europe and the Suez Canal (a route to export its natural gas to Asia). In addition, it provides a diversification option for European gas supply (as it allows bypassing the existing and potential pipeline routes from/via Russia and Turkey). At the same time, the region has substantial geopolitical tensions with a potential for territorial disputes. Importantly, Cyprus has signed delimitation agreements with Egypt, Israel, and Lebanon,[3] but not with Turkey or Syria. Moreover, Lebanon and Israel have a disputed maritime border which could affect Cyprus should they wish to pursue tripartite collaboration.[4]

Global Gas Development

Analysis regarding any potential future natural gas production in the Eastern Mediterranean must be carried out in the context of the broader global natural gas production, consumption, reserves, and resources. The current estimates for Cyprus Block 12 are in the range of 5–8 Tcf, and there certainly appears to be the potential for other discoveries considering the mean estimated recoverable resource base in the Levant Basin of 122 Tcf.

According to BP (2013), the global proved reserves of natural gas (those that can be recovered with reasonable certainty in the future from known reservoirs under existing economic and operating conditions) are 6,600 Tcf, including Russia's reserves of 1,160 Tcf, Qatar's reserves of 880 Tcf, and Turkmenistan's reserves of 620 Tcf. In addition, there is a substantial potential for shale gas with a recent estimate of 7,200 Tcf of technically recoverable resources (EIA, 2013).

To put these numbers into context, global gas use in 2012 was 117 Tcf (BP, 2013). There are plenty of alternative gas suppliers to satisfy a projected increase in global natural gas demand (see Appendix 2 for a summary of global gas use projections). Due to its location and geopolitical considerations, Eastern Mediterranean gas has potential, but most likely it will not be a major player in global gas markets.

Domestic Political Context

In addition to the regional territorial disputes, Cyprus's natural gas monetization strategy might be affected by its domestic affairs and its conflict with Turkey. The Republic of Cyprus gained its independence from Britain in 1960. Since 1974, the island is de facto divided (see Figure 4) after a coup d'état supported by the military junta in Greece against Cypriot President Makarios and the subsequent intervention of the Turkish army. Despite numerous efforts to reunify the country, it remains divided to this day (EU, 2013).

The Republic of Cyprus is a member state of the European Union. Turkey does not recognize the Republic of Cyprus and disputes its EEZ area. In terms of exploration blocks (shown in Figure 2), there are reports that Turkey claims a partial territory in almost all blocks except for Blocks 10 and 11 (see, for example, Faustmann, 2012; Gurel et al., 2013; Tsakiris, 2013). In the absence of a political settlement, these circumstances exclude, for example, a pipeline option from Cyprus to Turkey for the foreseeable future.

Developing a Monetization Plan — Why Focus on Exports?

The focus of this study is on the portion of the monetization strategy that concerns revenue generation via exports, and a comprehensive strategy should also take into consideration how to utilize the resource domestically. This study does not assess opportunities for domestic utilization because Cyprus will likely have sufficient resources for developing export capabilities regardless of the extent of domestic gas substitution in the coming years. This can be illustrated by comparing Cyprus's rather small energy consumption profile relative to the (estimated) size of the Aphrodite

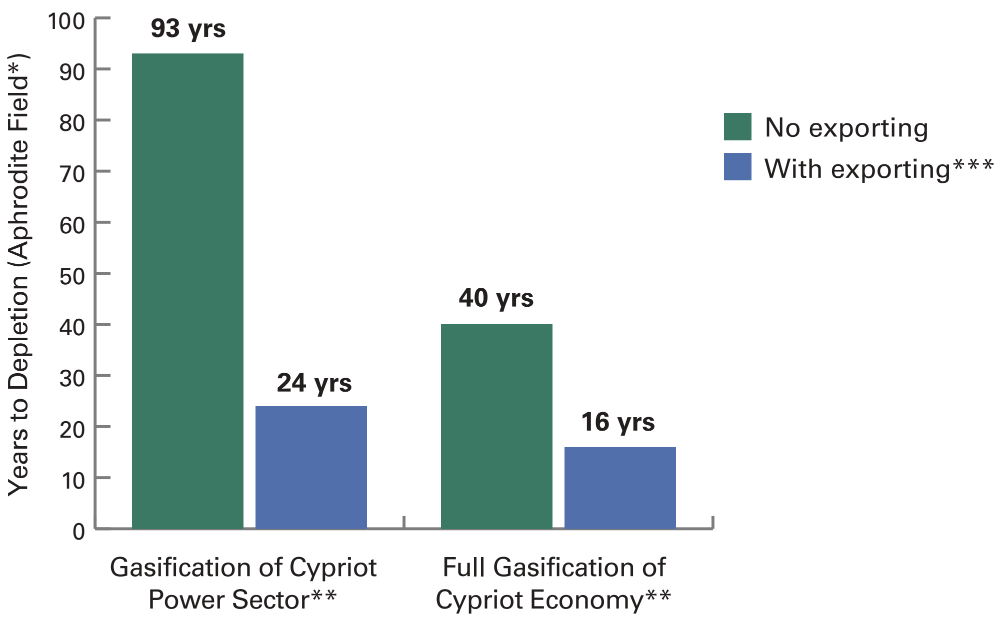
Figure 4 – Map of Cyprus

Source: US CIA (2013).

Field. It is reasonable to assume that Cyprus — which remains predominantly dependent on oil imports for energy consumption — will substitute natural gas for oil in at least part of the economy (power generation being most readily convertible). But even if Cyprus gasifies its *entire* economy — and no new discoveries are made — there would likely still be sufficient resource left to consider exporting.

One way of illustrating this point is to consider the number of years it would take Cyprus to deplete its estimated gas reserves, with and without exporting (Figure 5). At the limit — that is with full gasification and no new discoveries — the field would still last 16 years. On the other hand — if Cyprus gasifies its power sector alone and does not export — the gas would last nearly a century (see Appendix 3 for Cyprus energy and electricity use). Consequently, planning the development of export capabilities can be executed without jeopardizing opportunities for domestic utilization.

Figure 5 – Years to Depletion of the Aphrodite Field with and without Exporting



* Assumes mean estimate of Aphrodite Field (7tcf)

** Based on 2012 energy consumption with 1.5% annual growth

*** Assumes 250bcf/yr export throughout (equivalent to single-train LNG plant)

SECTION 3 OVERVIEW OF ECONOMIC MODELING METHODOLOGY

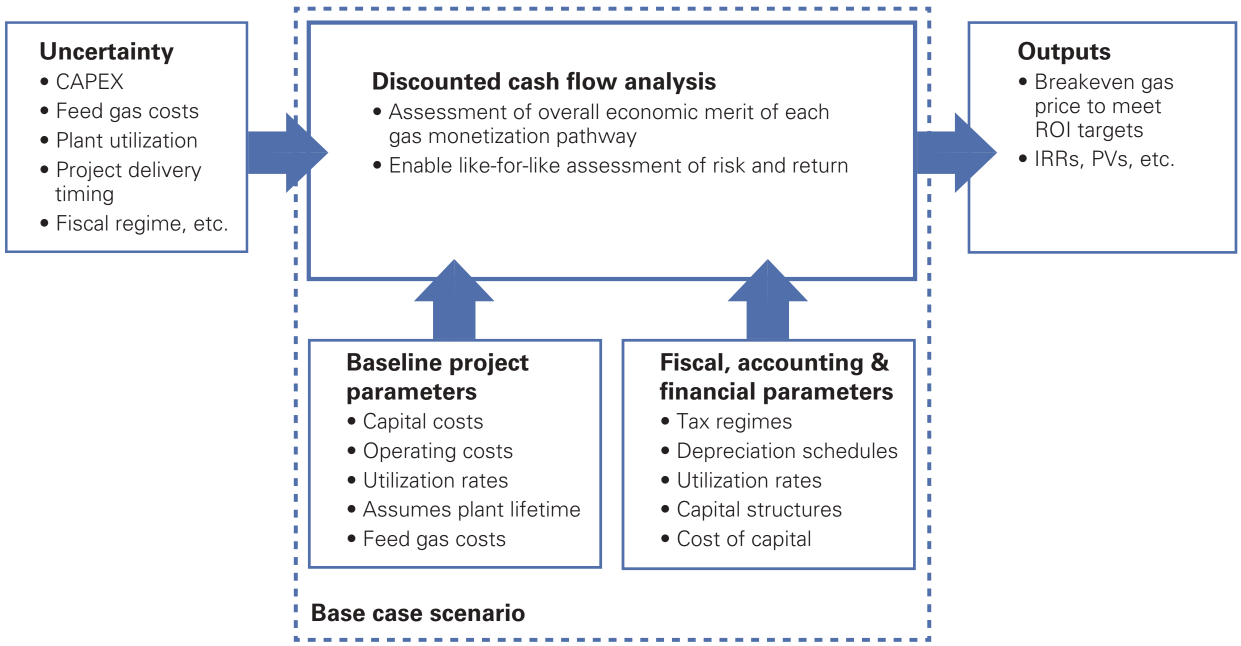
The primary objective of this report is to provide insight regarding the relative economics of the various gas monetization pathways that exist for the recently discovered Cypriot gas resources in the Levant Basin. Of course, economics alone will not dictate the ultimate pathway selection; however, they do play an important role, and help in providing context and a degree of guidance to any decision-making process that is also contending with multiple non-economic considerations.

The economic analysis of the gas monetization pathways presented in this document is primarily based on discounted cash flow, or DCF, techniques. These methodologies are used for assessing the “economic merit” of large-scale, capital-intensive projects, and are a ubiquitous analysis tool across the financial and commercial sectors (Appendix 4 provides a technical description of the DCF method and the model used in this study). A feature of the DCF approach that makes it particularly attractive for use in this report is its ability to enable the “apples-to-apples” comparison of projects with, among other things, differing capital scales, risk characteristics, and timelines to delivery.

Inputs to DCF analysis include all of the capital and operating expenses associated with a project along with financial and fiscal parameters, and assumptions regarding plant utilization levels and operating lifetimes. The DCF analysis output is a metric that reveals the economic merit of the project. In reality, there are many output metrics from a DCF; however, they are all related and quantify in one way or another whether a particular project will create or destroy value. Common generic outputs from DCF analysis include *net present value (NPV)* and *internal rate of return (IRR)*. The NPV quantifies, in today’s money, the net value of all of a project’s future revenue and expense streams assuming a fixed economic discount rate. The IRR of a project is simply the economic discount rate that results in the NPV being zero. If a project has an NPV greater than zero, the project creates value and should be undertaken. The output of a DCF analysis can also be represented in more market-specific terms. For example, in this report the output of the DCF analysis is presented in terms of *breakeven gas price (BEP)*, which represents the gas price needed to ensure that a project’s NPV is zero, and as such that it is the price needed for the project to be value neutral. If the realizable price is above the BEP, then the project will create value and should be pursued. If not, then the project would destroy value and should not be undertaken.

The specific approach taken in using DCF techniques to assess the economics of the gas monetization pathways being examined in this report is illustrated in Figure 6. For each pathway, a “base case” scenario was defined and subjected to the DCF analysis. The inputs to these base case scenarios were selected to represent “likely” costs, etc., for each pathway, but should not be considered “exact,” since assumptions were required regarding some parameters and, even for those for which significant detail is available, the values used are subject to unforeseeable changes in market conditions. Using these inputs, the base-case economics of each pathway were established. The sensitivity of base case economics to uncertainty regarding key inputs was then assessed. This approach is useful in that it yields an “economic envelope” for each pathway that provides guidance regarding both the central tendency and uncertainty in economic performance.

Figure 6 – Illustration of How the Economic Analysis of Gas Monetization Pathways Is Implemented Using DCF Techniques



SECTION 4 LIQUEFIED NATURAL GAS ANALYSIS

Historical Background and Current Developments in the LNG Industry

The very first commercial LNG shipments took place in 1964, with gas being shipped from a liquefaction facility in Arzew, Algeria, to receiving terminals in the United Kingdom and France. Since those early shipments, the LNG trade has grown significantly. In 2012, over 11 Tcf, or 32% of international gas trade, was via LNG (International Gas Union, 2013; BP, 2013). Over the half century of its existence, the nature of the LNG business has developed in a manner dictated by the industry's specific features. LNG was originally conceived as a method for monetizing stranded gas reserves, and as such the industry evolved as a collection of individual projects. The large capital requirements of these projects necessitated the use of long-term contracts between the supplier and purchaser counterparties in order to manage risk and secure financing. These contracts usually imposed price risk on the supplier, while putting volume risk onto the purchaser, a classic "take-or-pay" arrangement. The custom nature and limited number of individual projects also meant that spot markets for LNG were not readily available, and because of this, LNG price setting mechanisms linked to oil or oil products were used.

Today, many of the factors that shaped the structure of the LNG industry during its formative years remain relevant, and in many regards, the industry has not changed much since its genesis. Capital requirements are still enormous and risk management is still complex and central to a project's success. However, the past few years have borne witness to some changes in the industry. In particular, spot and short-term trading in LNG cargos are now becoming significant aspects of the business. In 2000, less than 5% of global LNG volumes were traded as spot cargos. In 2012, 31% of LNG was traded as spot or via short-term contracts (International Gas Union, 2013). Multiple factors have contributed to this dynamic. The growth in the popularity of contracts that include a destination flexibility clause is one reason. With these contracts some flexibility is provided for cargos to be redirected from their "usual" destination if a higher price can be captured at an alternative port. This development highlights one of the more fundamental changes in the LNG industry over the recent past. Unlike the traditional LNG arrangement in which a project was established to supply a specific customer — e.g., an Asian utility without access to gas via pipeline — today the output from many LNG projects is being purchased by companies engaged in the international gas trade, that are looking to capture maximum value from each cargo by delivering it to whichever market provides the highest return.

As the industry moves forward over the next couple of decades, the ever-increasing scale of the LNG trade and the availability of flexible shipping and regasification infrastructure are likely to result in spot and shorter-term LNG trading becoming even more important aspects of the industry. These dynamics coupled with changes in the global gas supply balance also have the potential to alter significantly the manner in which LNG pricing occurs. Today, gas pricing in Asia, and to a lesser extent Europe, is still dominated by the oil-linked mechanisms used to price LNG (and pipeline supplied gas in Europe) for decades. Going forward, it is likely that in Europe at least, gas pricing will include some greater level of gas-on-gas hub indexation. Having gas prices indexed to a tradable hub price brings advantages in terms of price transparency and risk management for gas customers. In Europe, major gas customers have been placing increasing pressure on suppliers to add some hub indexation to contracts, and in light of this pressure, new Russian and Norwegian contracts now include some indexation (Jensen, 2012). The wider adoption of hub indexation in gas pricing in the East Asian gas market is more uncertain. The potential of gas imports from the United States, where gas trades in a pure gas-on-gas market, does provide a vector for introducing some degree of Henry Hub-based indexation to pricing; however, tangible steps in this direction have not yet occurred. In the medium term, it is perhaps more likely that the current oil-linked formulas used for pricing will be modified in a manner that eases the oil linkage, without adopting hub indexation (Jensen, 2012).

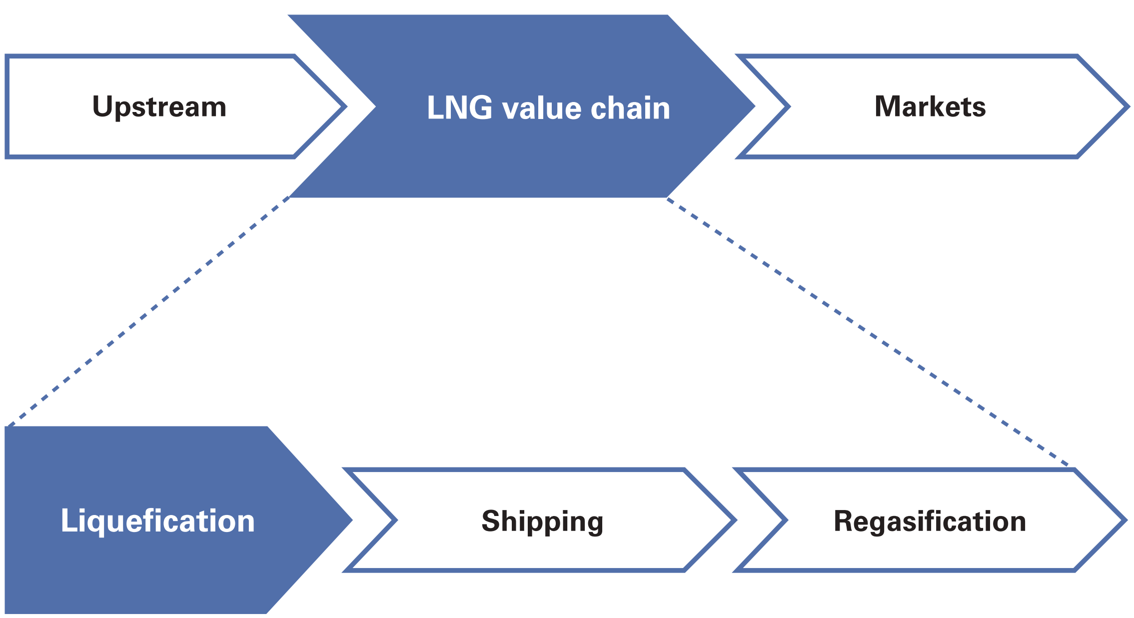
Analysis of LNG as a Gas Monetization Pathway for Cyprus

The discovery of a significant gas resource within the Cypriot EEZ represents a potentially transformative economic opportunity for the Republic of Cyprus. However, owing to the limited scale of domestic demand — even accounting for a significant future "gasification" of the Cypriot energy system — it will be necessary to find external markets for these gas resources if the economic potential of the resource is to be fully realized. As described in the introductory remarks, a number of options exist for getting Cypriot gas to external markets. In this section, the economics of the LNG export pathway are explored.

A deep-dive analysis of the LNG option is appropriate in the current context, as it appears to be the export pathway closest to realization. Noble Energy Inc.'s exploration efforts led to the discovery of the Aphrodite Field. The company is actively pursuing the LNG export option, and in what is certainly a sensible move, they are engaging with Australia's Woodside in this endeavor. Woodside brings a wealth of expertise to the table, having developed five LNG trains over the past quarter century (Noble Energy, 2012).

In order to effectively constrain the uncertainties incorporated within the economic analysis of the LNG pathway, it is important to explicitly define the analysis' boundaries. At the most abstract level, the LNG value chain is the connective element between the *upstream* and natural gas *markets*. This linkage is illustrated in Figure 7. The figure also shows how the LNG value chain disaggregates into its sub-elements, *liquefaction*, *shipping,* and *regasification*. The focus of the analysis in this report is on the economics of the liquefaction stage in particular.

Figure 7 – Illustration of the Positioning and Elements of the LNG Value Chain in the Context of the Overall Natural Gas Monetization Value Chain

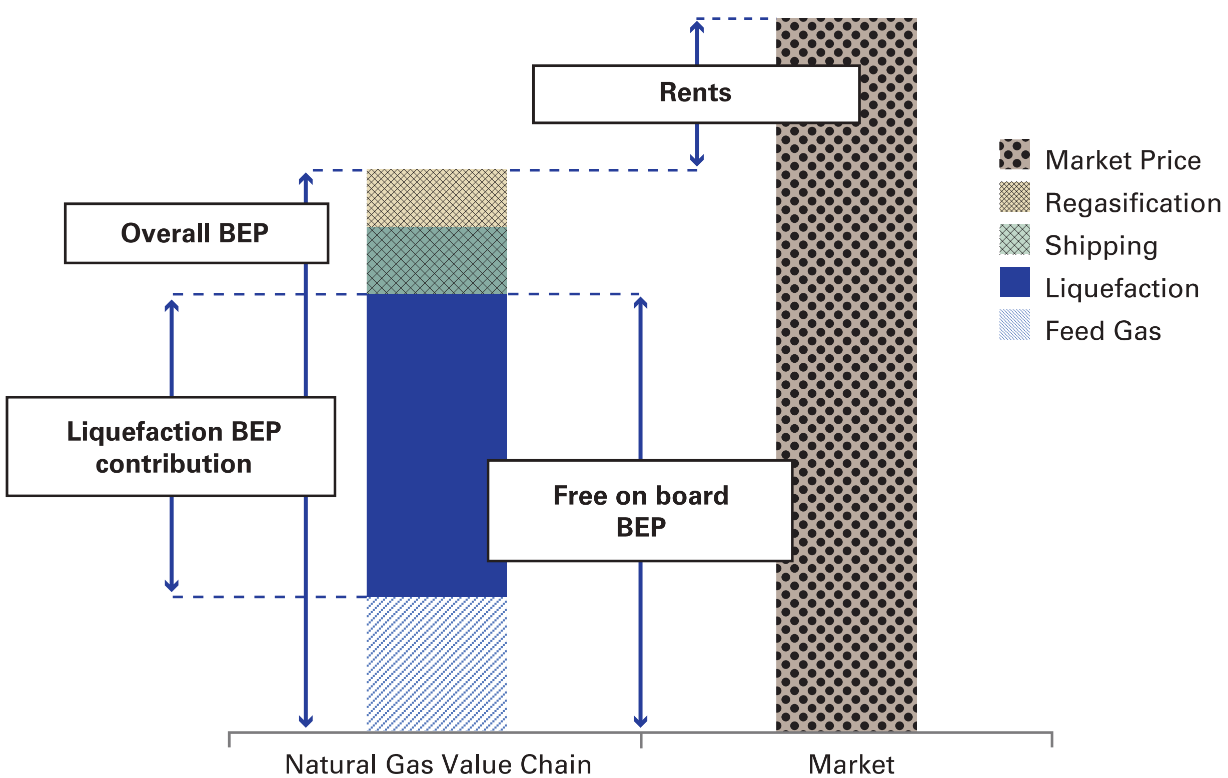


There are a number of reasons for specifically focusing on liquefaction. The first is simply that the scale of investment associated with liquefaction is much larger than with shipping and regasification, and so liquefaction dominates the economics of the complete LNG value chain. The second reason for the liquefaction focus is that in the Cypriot case it is likely that the state will only participate in the liquefaction stage, and will not hold equity in shipping or regasification. Of course, this may change as Cypriot LNG is developed; however, at this stage it is a reasonable approach.

The overarching issue being examined by the economic analysis of gas monetization pathways in this report is how the all-in costs of different gas monetization pathways compare to the price that might be achievable in the various destination markets. Because of this, the BEP is a very useful metric. Basically, the economics of a pathway are represented in terms of the BEP, which effectively says that in order for the pathway under consideration to be attractive, the market price needs to be at least the BEP. Furthermore, using the DCF approach allows the BEP for the entire monetization value chain to be disaggregated such that the contribution of individual stages to the overall BEP can be quantified.

The utility of the BEP in describing the economics of the LNG value chain is illustrated in Figure 8. In the figure, the left-hand column represents the BEP of a notional LNG-based gas monetization value chain, while the right-hand column represents the gas price in the destination market. The overall LNG value chain disaggregates into four individual components: feed gas, liquefaction, shipping, and regasification. The overall BEP represents the gas price necessary to compensate for all the costs associated with the entire value chain. In Figure 8, the overall BEP is shown as being lower than the market price. This would indicate that LNG is a value-creating enterprise. The economic rents, or the difference between the BEP and the market price of gas, would be distributed between parties involved in the trade based on the specific contractual structures in place.

Figure 8 – An Illustration of the Elements of the LNG Value Chain BEP and How They Relate to the Natural Gas Market Price



Now, because ownership of the LNG value chain is increasingly disaggregated, the overall BEP is often not the most useful metric. For example, in the Cypriot case, if the state is only involved in liquefaction, the economic metric of greater interest might be the free-on-board (FOB) BEP (equivalent to the liquefaction-only portion of the BEP).

LNG Economic Analysis — Base Case and Sensitivity Definitions

Every LNG project has its own unique characteristics, and these can change even as the project is under development and in operation. Nevertheless, for most projects it is possible to establish a reasonable base case for the purpose of economic analysis. Furthermore, the careful modification of key input parameters can then be used to establish sensitivities and to develop an economic envelope for the project.

As mentioned earlier, the LNG economic analysis presented in this report focuses on the liquefaction stage of the value chain. Given the current level of proved reserves, 5–7 Tcf, the analysis assumes the construction of a single 5-Mt LNG liquefaction train, with an expected operational lifetime of 20 years. The scale of the recoverable resource in Cyprus's EEZ is likely larger than the currently proved reserves (USGS, 2010); however, until such time as more resources transition into the proved reserve category, it is appropriate to only consider the single train scenario.

Multiple input parameters must be defined in order to execute the DCF analysis (see Appendix 5 for input parameters to the LNG DCF model). These include the project's capital costs, its operating costs, the plant's fuel loss factor, and the plant's utilization rate. The fiscal structures relevant to the project must be defined. These include the tax rates and applicable depreciation schedules. Finally, the financial parameters relevant to the project, and in particular the relevant cost of capital, must be selected.

For the base case assessed here, the capital cost of the LNG plant was set at $1,200/tonne of nameplate capacity. Operating maintenance costs were set at $0.20/Million British Thermal Units (MMBtu) of throughput, the plant's fuel loss factor was set at 8% of output, and the plant's utilization level was set at 85% of nameplate. No reliable information on the fiscal structures that will likely apply to a Cypriot liquefaction facility was available, so for the analysis in this report a corporate tax rate of 35% was assumed for the project with straight-line depreciation over 12 years. An inflation rate of 1.5% was assumed for all cases. The real discount rate used in the analysis was set at 10%. This rate was based on an assessment of the weighted average cost of capital for a range of corporate entities active in the upstream and LNG sectors. Because any initial Cypriot liquefaction project is likely to be a stand-alone entity and not integrated with upstream development, it is assumed that the plant will pay a rate for its feed gas to the upstream development operator. In the base case scenario, this feed gas cost was assumed to be $2.50/MMBtu.

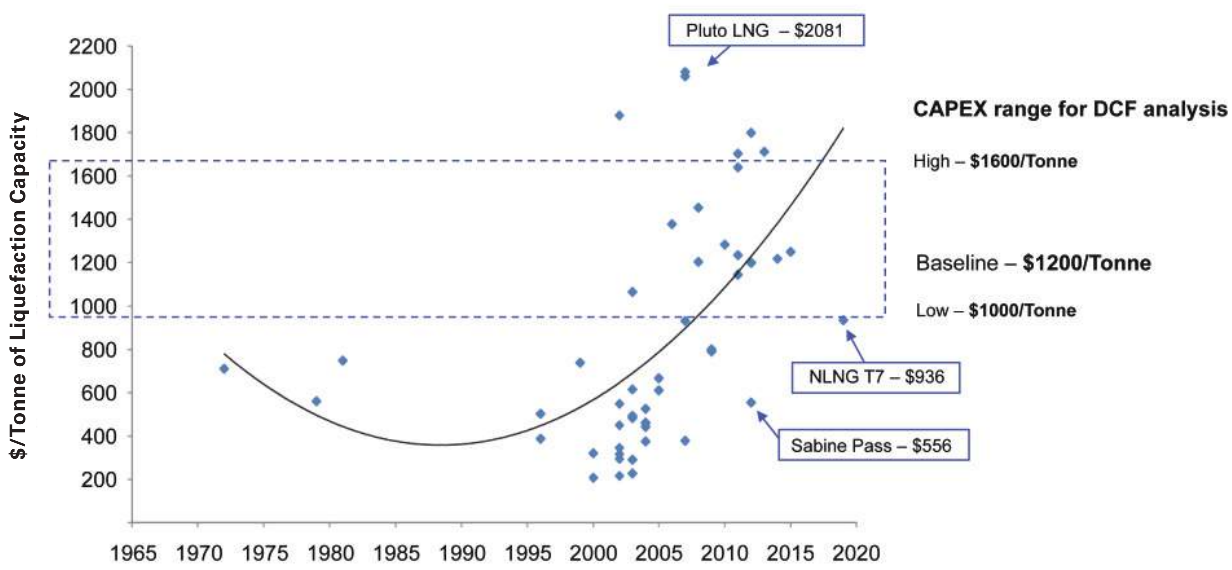
The cost and other assumptions included in the base case scenario should not be considered exact. Rather, the base case parameters were selected to represent a likely scenario. In order to capture the uncertainty surrounding the base case, a number of parameter sensitivities were carried out that enable the construction of an economic envelope around the base case performance. Of course, the sensitivity of a project's economics to any number of parameters can be explored; however, only a subset of these has a major impact. For the purposes of this report, the sensitivity analysis focused on three input parameters: the project's capital costs, the project's feed gas costs, and the project's utilization levels (additional results for the LNG sensitivity analysis are provided in Appendix 5). The high and low sensitivity values studied for each of these three parameters are given in Table 1 (note that the input parameters have changed one at a time in the sensitivity analysis).

Table 1 – Base Case/High/Low Scenario Values for Capital Costs, Feed Gas Costs, and Plant Utilization Levels

	Baseline	Low	High
Plant CAPEX – $/Tonne of capacity	1,200	1,000	1,600
Feed gas cost – $/MMBtu	2.5	2.0	4.0
Plant utilization rate – %	85	75	95

Selection of both the base case and sensitivity values is non-trivial. Significant opaqueness exists regarding costs in the LNG industry. Over the past decade or more, the capital costs of LNG liquefaction projects have risen considerably. Figure 9 illustrates how the capital costs of LNG liquefaction projects have varied (Deutsche Bank, 2012). Clearly, there is a wide range; however, contemporary analysis indicates that a cost of at least $1,200/tonne of nameplate capacity is likely for projects being developed over the next decade (International Gas Union, 2013; Deutsche Bank, 2012; Ernst & Young, 2013). This consensus led to the choice of $1,200/tonne as the base case scenario capital cost for a 5-Mt Cypriot liquefaction facility to be constructed by 2020. The high and low sensitivities were chosen to be $1,600 and $1,000/tonne, respectively. As shown in Figure 9, there are contemporary projects outside this range; however, they have some specific characteristics not applicable to Cyprus. On the high side, most of the very expensive capacity currently in development is in Australia, where capital cost inflation has been severe owing to multiple parallel LNG developments, several in extremely remote locations (Pluto LNG being a good example). Of the lower-cost projects, all of the US-based capacity, e.g., Sabine Pass, should be ignored. These projects are brownfield expansions of existing facilities with much of the necessary infrastructure for enabling export already in place. A similar situation exists with Nigeria LNG's Train 7.

Figure 9 – Illustration of LNG Liquefaction Capacity Cost Evolution

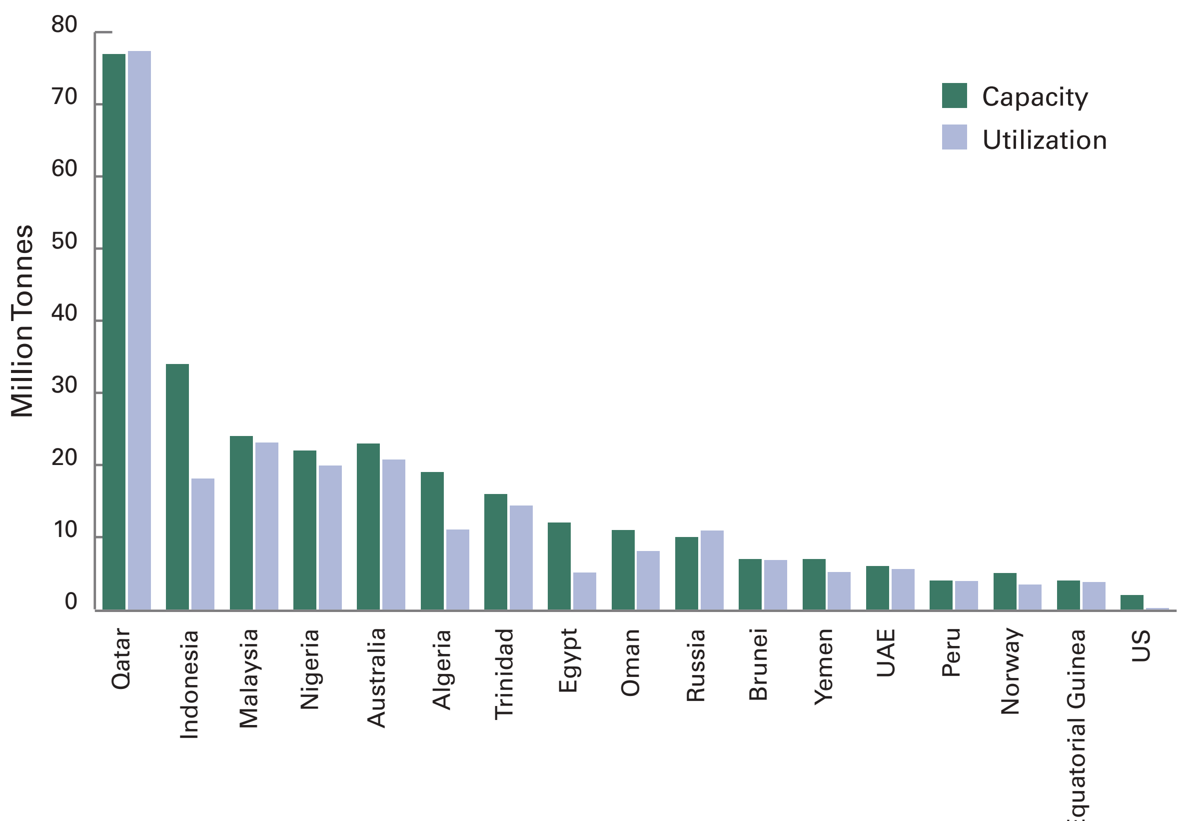


Source: Deutsche Bank (2013) and author's calculations.

Along with the capital costs of the LNG facility itself, the cost of feed gas is also an important factor. In the Cypriot case, it is assumed that the upstream offshore development and delivery to shore will be executed by a separate entity and that the liquefaction facility will purchase the feed gas. Very limited data is available regarding the likely costs of developing the Aphrodite Field; however, Noble Energy Inc. did indicate development costs on the order of $2.00/MMBtu in a recent analyst communication (Noble Energy, 2012). For the base case scenario here the feed gas cost is assumed to be $2.50/MMBtu. The slightly higher value is warranted due to relative lack of third-party analysis. For the feed gas sensitivities, the low case used Noble's own $2.00/MMBtu estimate. The high case assumes a feed gas cost of $4.00/MMBtu. Although twice the Noble estimate, this is well under the development costs seen for other offshore developments supplying onshore liquefaction facilities, particularly those in Australia (Jensen, 2012).

The third input factor for sensitivity analysis studied in this report is the plant utilization rate. Naturally, for a very capital-intensive project like an LNG liquefaction facility, maximizing throughput is an important driver of economic performance. The traditional LNG business model involving long-term customer agreements enables plant "right sizing" and high levels of utilization. As the business of LNG changes, it is not entirely clear that it will be possible for plants to consistently remain highly utilized, particularly plants that have more marginal economics. In 2012, the global LNG liquefaction fleet had an overall utilization rate of 85%, and this is the utilization rate selected for the Cypriot base case scenario. However, as shown in Figure 10, the level of utilization varies from country to country (International Gas Union, 2013). Qatar, for example, had 100% utilization in 2012 (in fact slightly greater than 100% owing to some storage effects); however, other countries had much lower levels. Norway, for example, had a utilization of 75%. The utilization of a Cypriot facility will be linked to its ability to come online with attractive economics and acquire high-quality customer contracts. To reflect how success or failure in this regard would impact utilization, the high and low sensitivities for the utilization rate were set at 95% and 75%, respectively.

Figure 10 – 2012 Global LNG Liquefaction Capacity Utilization by Country



Source: International Gas Union (2013).

LNG Economic Analysis Results

Given the base case cost, utilization, fiscal, and financial input parameters discussed in the previous section, the overnight FOB breakeven gas price for a 5-Mt Cypriot LNG liquefaction project is approximately $7.25/MMBtu. Of this, $4.55/MMBtu relates to the capital and other costs of the liquefaction stage, while the balance relates to the feed gas. This base case result, along with the overnight FOB breakeven prices assuming the high and low case liquefaction capital costs of $1,600 and $1,000/tonne are shown in Figure 11. As can be seen, the escalation of capital costs to the high-cost scenario drives the overnight FOB breakeven gas price to $8.70/MMBtu, while delivery of the project at $1,000/tonne would reduce breakeven to $6.53/MMBtu.

The impact of variations in the feed gas cost on the overnight FOB breakeven gas price are shown in Figure 12. The low feed gas scenario reduces the price from $7.25/MMBtu to $6.71/MMBtu, while the higher feed gas cost increases the overnight breakeven price to $8.87/MMBtu. Given the importance of the feed gas cost to the overall competitiveness of the liquefaction project, it is important that Cyprus obtain greater resolution on the exact upstream economics as soon as possible.

Figure 11 – Illustration of Overnight FOB Breakeven Gas Price for Base Case Scenario along with Sensitivities for High and Low Capital Costs

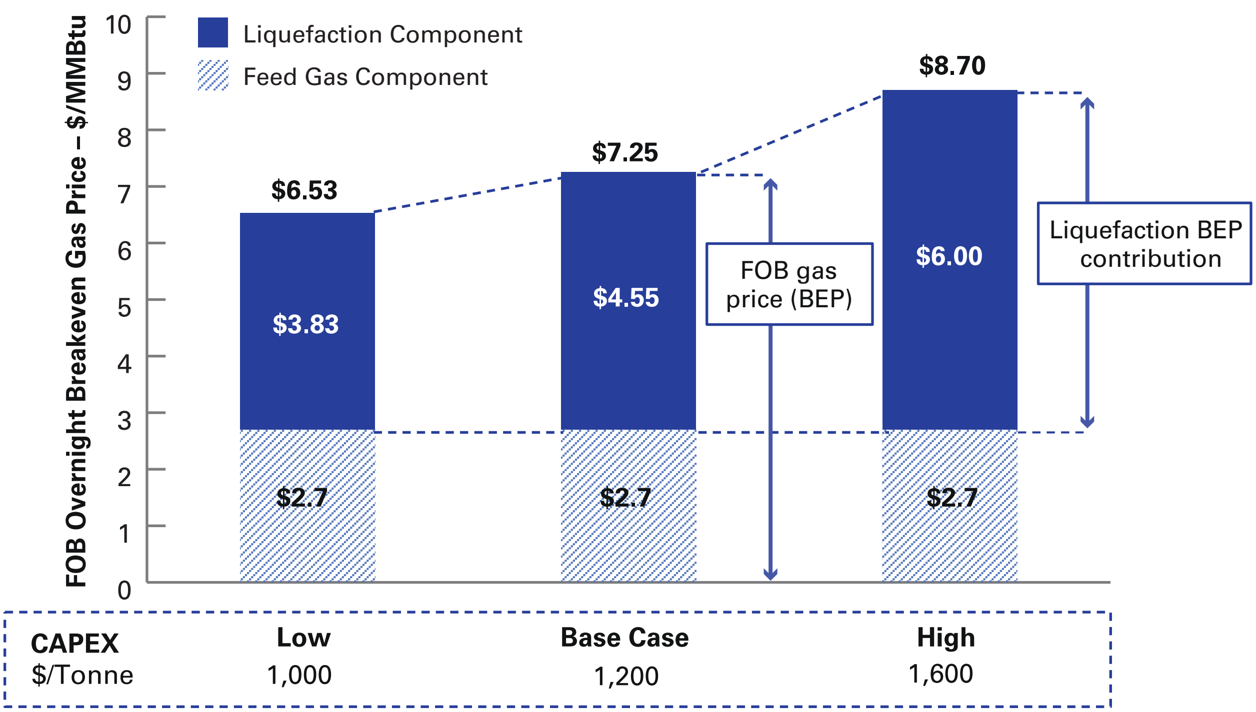
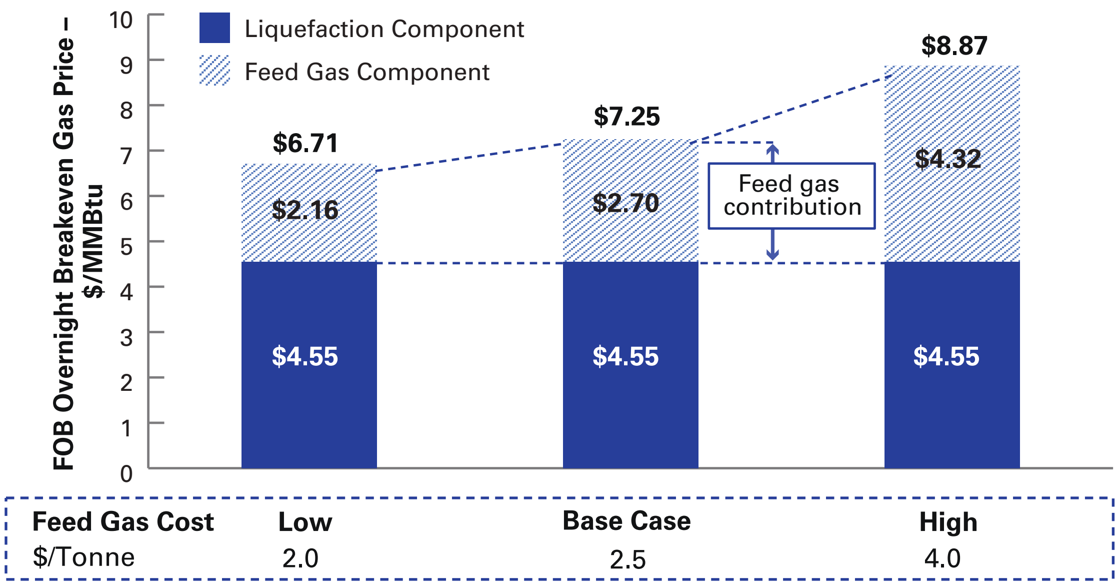
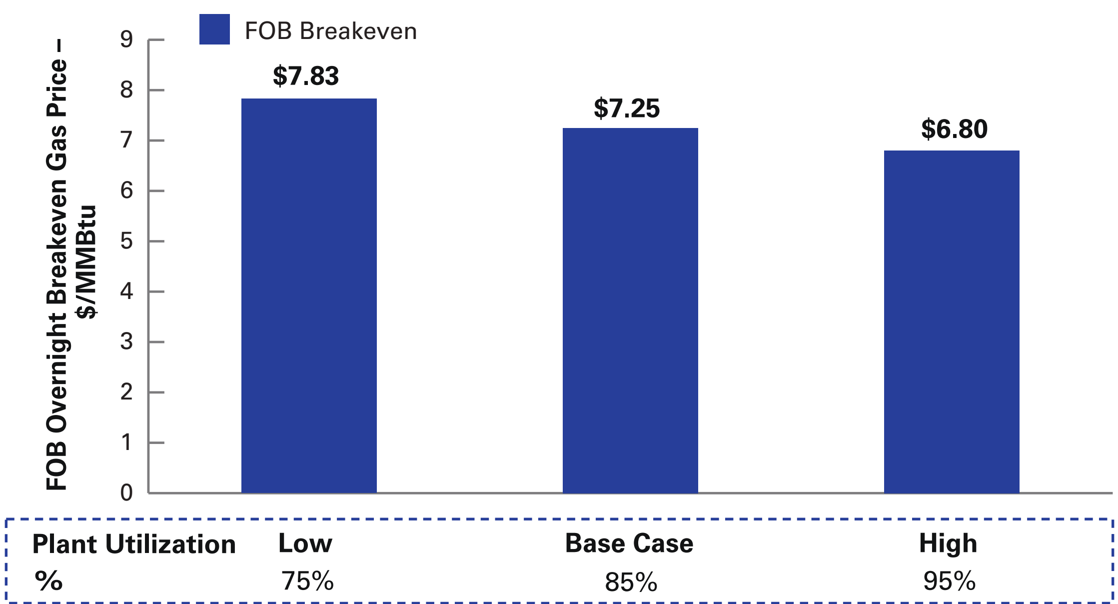


Figure 12 – Illustration of the Impact that Variation in the Feed Gas Cost Has on the Overnight FOB Breakeven Gas Price of the Liquefaction Project



The impact of variation in the assumed plant utilization rate on the overnight FOB breakeven gas price is illustrated in Figure 13. In the case of lower utilization, a 10% reduction in assumed throughput increases the breakeven price for the plant from $7.25 to $7.83/MMBtu, while increasing utilization to 95% reduced the overnight FOB breakeven price for the project to $6.80. Clearly, achieving high utilization levels represents a pathway to attractive economic performance.

Figure 13 – Illustration of the Impact that Variation in the Plant Utilization Rates Has on the Overnight FOB Breakeven Gas Price of the Liquefaction Project

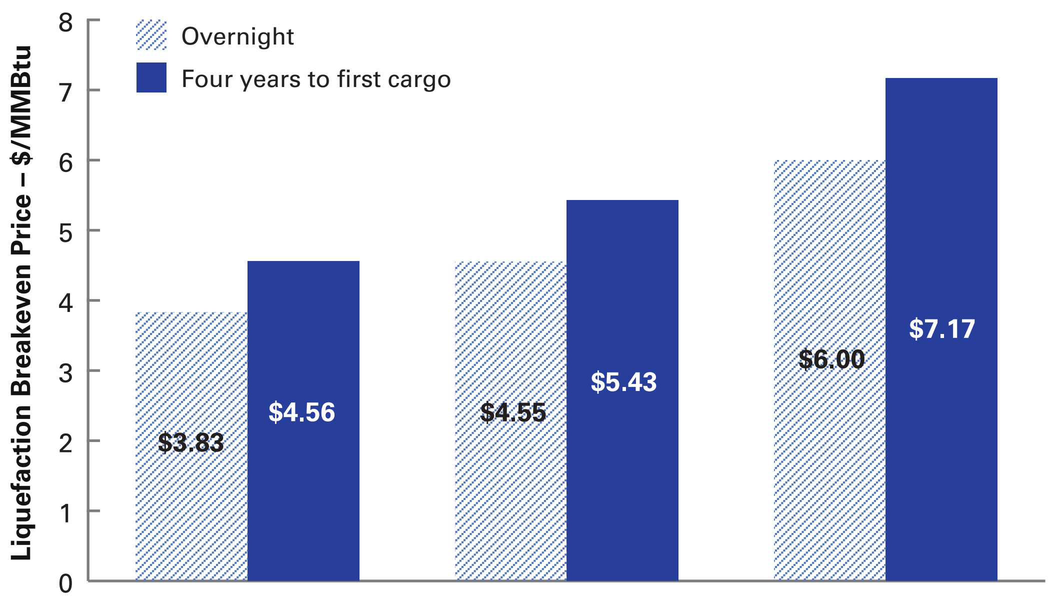


The Economic Implications of Effective Project Delivery

All of the economic modeling results presented in the preceding section represent "overnight" or "first year" economics. In other words, in the DCF analysis, it is assumed that the capital is spent in year 0, and that LNG cargos and the associated revenue generation begin in year 1. This approach replicates a situation in which the interest rate is zero during the period when capital is being spent. There are instances in which this approach is reasonable, for example, when a project is being financed entirely by a sovereign or other entity with access to ultralow-cost capital. The reality for an LNG project such as is likely in the Cypriot case is that such ultralow-cost will not be available. As a result, interest, both on debt and in the form of expected return on equity incurred during the construction phase when the project is not earning revenue, will need to be remunerated. Meeting these needs effectively increases the cost of the project and ultimately the required breakeven price.

For a liquefaction project such as the 5-Mt train being considered in this report, it is not unreasonable to expect that capital drawdown and construction will require four or more years, and the impact of this on breakeven price is appreciable. Figure 14 illustrates how a construction period of four years alters the liquefaction-only breakeven price for projects assuming the base case/high/low-capital cost scenarios. The need to cover interest costs during the four-year construction period adds on the order of $1.00/MMBtu to the breakeven price. This highlights the need for a very sharp focus on project development execution. Once construction begins, delays add significant cost, typically $0.25–$0.35/MMBtu per year in breakeven price terms. Given this, even if a project starts out with a relatively attractive economic profile, it can easily lose competitiveness if delays occur, either as the result of poor technical planning and execution, or indeed, due to bureaucratic and regulatory delays.

Figure 14 – Illustration of How a Four-Year Construction Period Alters the "Overnight" Economics of the Liquefaction Project



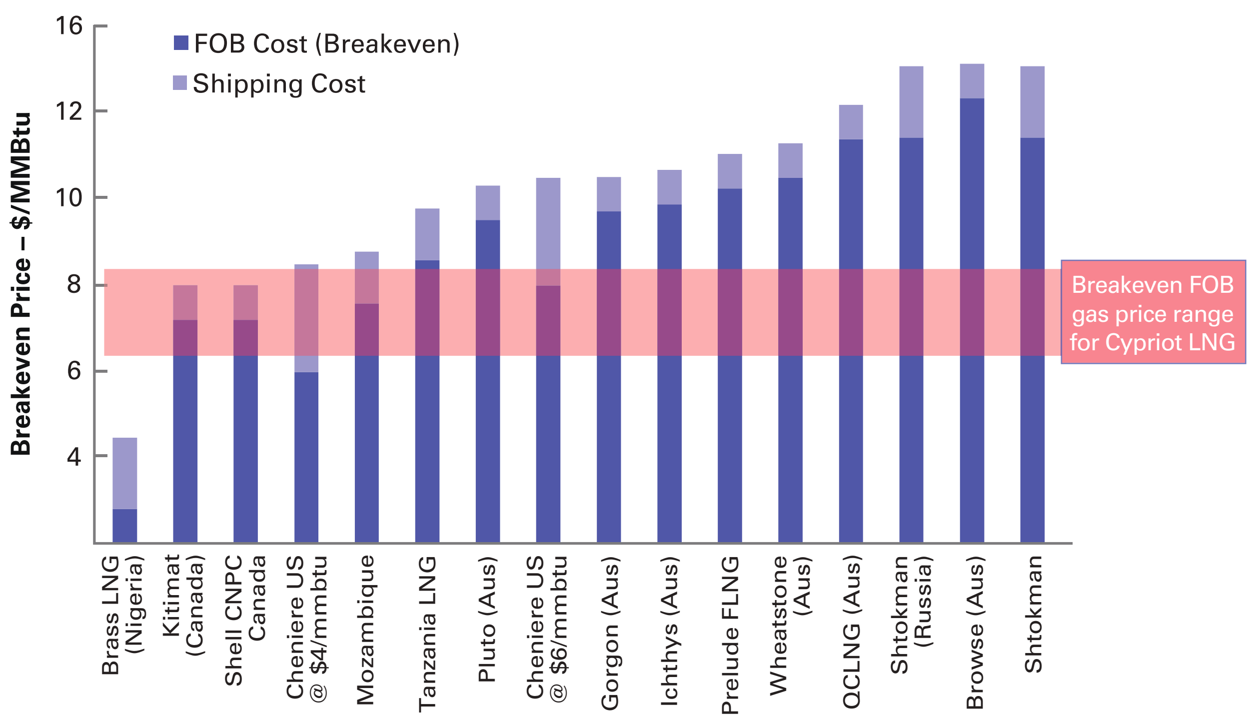
CAPEX	Low	Base Case	High
$/Tonne	1,000	1,200	1,600

Cyprus in the Context of the Global LNG Supply Picture

The analysis of liquefaction economics presented in the preceding sections has been limited to considering a single 5-Mt train. In terms of today's global liquefaction capacity, this is not significant, being less than 2% (International Gas Union, 2013). However, for Cyprus, a 5-Mt train is a very big project. Given the available data, the preceding analysis also suggests that Cypriot LNG is likely to be relatively competitive, at least compared to the cost of LNG from many of the other greenfield projects now under consideration across the globe. Consider Figure 15, which illustrates some contemporary analysis regarding the likely breakeven price for a range of LNG projects currently at various stages of development (Deutsche Bank, 2012). This analysis highlights that a considerable number of these projects have FOB breakeven prices of $9.00/MMBtu or more. The base case scenario for Cypriot LNG including construction carrying costs is an FOB breakeven price on the order of $8.00/MMBtu. Clearly, a very considerable amount of uncertainty still surrounds many of the analysis inputs, with the cost of feed gas and a more nuanced assessment of capital costs being required; however, what is clear is that Cypriot LNG does have the potential to be cost competitive with other greenfield projects.

Of course, having relatively attractive economics is only part of the picture. The success of any new liquefaction project also rests on there being enough new demand to absorb the additional volumes of LNG. Because of the widespread use of long-term supply contracts, new volumes, even if less expensive, cannot simply displace higher-cost supply. Looking forward over the next decade, there will certainly be growth in global demand for natural gas. The International Energy Agency (IEA) predicts global gas demand will rise to 140 Tcf by 2020 from 117 Tcf in 2012 (IEA, 2012). Current commercial analysis suggests that 9–10 Tcf of the additional 23 Tcf of demand will be in the form of LNG, equating to about an 80% expansion in demand from 2012 levels

Figure 15 – Estimated Breakeven Gas Prices for Set of Major Contemporary LNG Projects



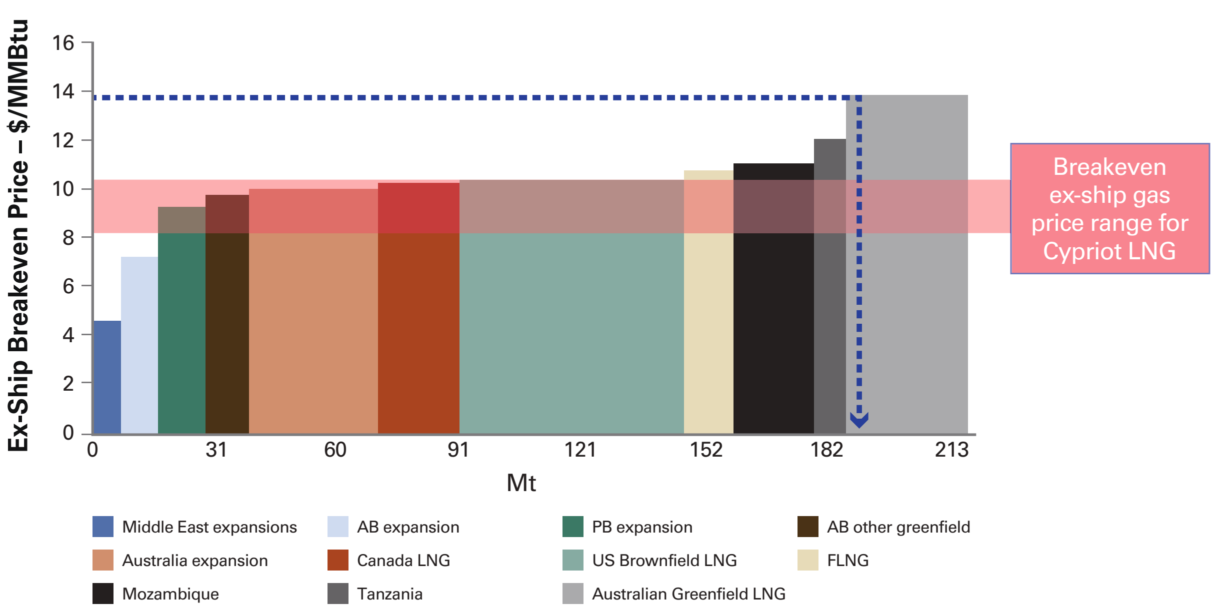
Source: Deutsche Bank (2012) and author's calculations.

(International Gas Union, 2013; Deutsche Bank, 2012; Ernst & Young, 2013). A proportion of this demand will be met by the expansion of existing facilities and certainly through the turnaround of some US import capacity. However, there will likely be space for competitive new entrants, a category that Cyprus would target. Figure 16 shows a supply stack of new liquefaction capacity expected to come online between now and 2020 (Deutsche Bank, 2012), where "ex-ship" price means that it excludes regasification cost. This analysis highlights that greenfield Australian liquefaction will likely be at the margin assuming additional demand cuts off in the 190-Mt range. The economics of a potential Cypriot project fall somewhere in the middle of the overall supply curve; however, it is worth noting that the bulk of the curve is very flat so any upward shift in the economics of a Cypriot project owing to capital cost escalations, or higher cost feed gas (both issues of appreciable uncertainty), could quickly blunt the attractiveness of such a project.

Impacts and Risks of LNG Development

As stated earlier, the discovery of natural gas within the Cypriot EEZ brings with it tremendous economic potential. However, LNG development is not without major risks, particularly for small nations like Cyprus in which the necessary investment, even for modest LNG projects, is on the same order of magnitude as the country's Gross Domestic Product (GDP). The potential benefits of growing an LNG industry in Cyprus will include employment opportunities and, of course, a potentially large revenue stream for the nation through taxes and royalty payments as well as dividends from entities in which the nation holds equity. In terms of the employment opportunities, the construction phase will certainly be responsible for the lion's share of job creation. It has been estimated that on the order of 7,500 jobs would be created during the initial development of the Cypriot LNG export facility, and should Cyprus find additional gas, the expansion of LNG capacity could support activity on such a scale for a decade or more (Ellinas, 2013). The level of employment during actual plant operations will be much lower owing to the extensive automation employed in contemporary industrial facilities; however, these positions will be skilled. Skill

Figure 16 – Estimation of New LNG Supply Curve to 2020 Based on Projects with High Probability of Completion



Source: Deutsche Bank (2012) and author's calculations.

availability is an issue that warrants consideration. LNG construction requires specialized expertise in a range of areas from professional services to specialized welding. If Cyprus intends to capture as much employment benefit as possible from LNG development, it will need to ensure that the local workforce is prepared. If not, much of the opportunities will flow to international workers.

In developing an LNG industry, Cyprus should also take note and plan to mitigate to the maximum extent possible, the many exogenous risk factors to the success of an LNG development. The first is price risk. Today, supplying LNG to high-price markets such as those in East Asia appears exceptionally attractive. However, no guarantees exist regarding prices remaining at their current levels over the longer term. Certainly they might, but there are legitimate scenarios in which prices could fall appreciably. Therefore, when assessing the economic potential of LNG development, conservative assumptions should be made regarding the future price for LNG. Similarly, the entire set of cost assumptions used in any analysis should be stress-tested. This report has carried out some such stress testing; however, it would likely be prudent to explore even more extreme scenarios of cost inflation. Plant utilization and overall contracting of volumes are other important risk considerations. The ever-increasing role of spot cargos and the increasing flexibility around contracting means that in the future, maintaining very high facility utilization might become more difficult. Cyprus will need to carefully manage the contracting for its facilities in order to ensure that they are utilized to the maximum extent possible. Finally, Cyprus must also carefully consider the upstream risks that could impact any liquefaction project. In the analysis in this report, the assumption is made that any liquefaction project will purchase feed gas from the upstream developer. How the cost of that gas is established and how the rents and risks associated with upstream development are shared are both important. Agreeing to a fixed feed gas price helps eliminate upstream risk to the liquefaction project's economics, but may also result in the upstream developer capturing rents. Alternatively, if a "cost-plus" structure is used to price the feed gas, any cost overrun during upstream development will flow into the liquefaction economics and could, if overruns are severe, significantly erode the economic attractiveness of Cypriot LNG.

SECTION 5 SUBMARINE PIPELINE ANALYSIS

Project Overview

With all the benefits of LNG export possibilities described in the previous sections, pipelines remain the dominant mode of transportation for natural gas (68% of 36 Tcf of natural gas that was traded internationally in 2012 (BP, 2013)). Previously built pipelines are still in place, new pipelines are being built due to their relatively lower upfront investment requirements in comparison to LNG, and many pipelines exist simply because some destinations cannot be reached by sea with LNG tankers. Even with LNG deliveries, pipelines are still needed to bring natural gas from regasification facilities to the customers. While onshore pipeline technologies are well established, offshore pipeline technologies continue to pose difficult challenges in their deployment and maintenance. Consequently, the industry is actively innovating and trying to push the limits of the technology to date (see Appendix 6 for a description of major offshore pipelines).

If Cyprus considers a pipeline option for its export strategy, then as an island nation, it obviously needs to consider an offshore pipeline. In the case of the monetization of Cypriot gas, the construction of one or more offshore pipelines is already anticipated — a 200-km line from the Aphrodite Field to Vasilikos — as part of the plan to build an LNG plant onshore.[5] In fact, such an "upstream" pipeline will likely be a necessary precursor to every monetization option for Cyprus (with the possible exceptions of "floating" CNG and LNG technologies).

The current estimate of natural gas in the Aphrodite Field — the only field discovered to date in Cypriot waters — would not be sufficient for *both* LNG and an export pipeline, unless it could secure resources from other countries in the region (primarily Israel). As discussed in the previous section, 5–8 Tcf of natural gas can justify one LNG train. Therefore, if additional gas is discovered or secured from other countries, the pipeline option may be considered in addition to the LNG option.

For the case of Cyprus, two pipeline export options have been discussed, one to Greece and one to Turkey, both with the option of interconnecting to the broader continent of Europe. The pipeline-to-Greece option has several routes under consideration by a Greek gas company (DEPA, 2012). One scenario envisages the gas running the 700 km from Cyprus to Crete and then splitting between two segments, one to the Greek mainland (with the additional possibility of interconnecting to Italy), and one to Bulgaria (see Figure 17).

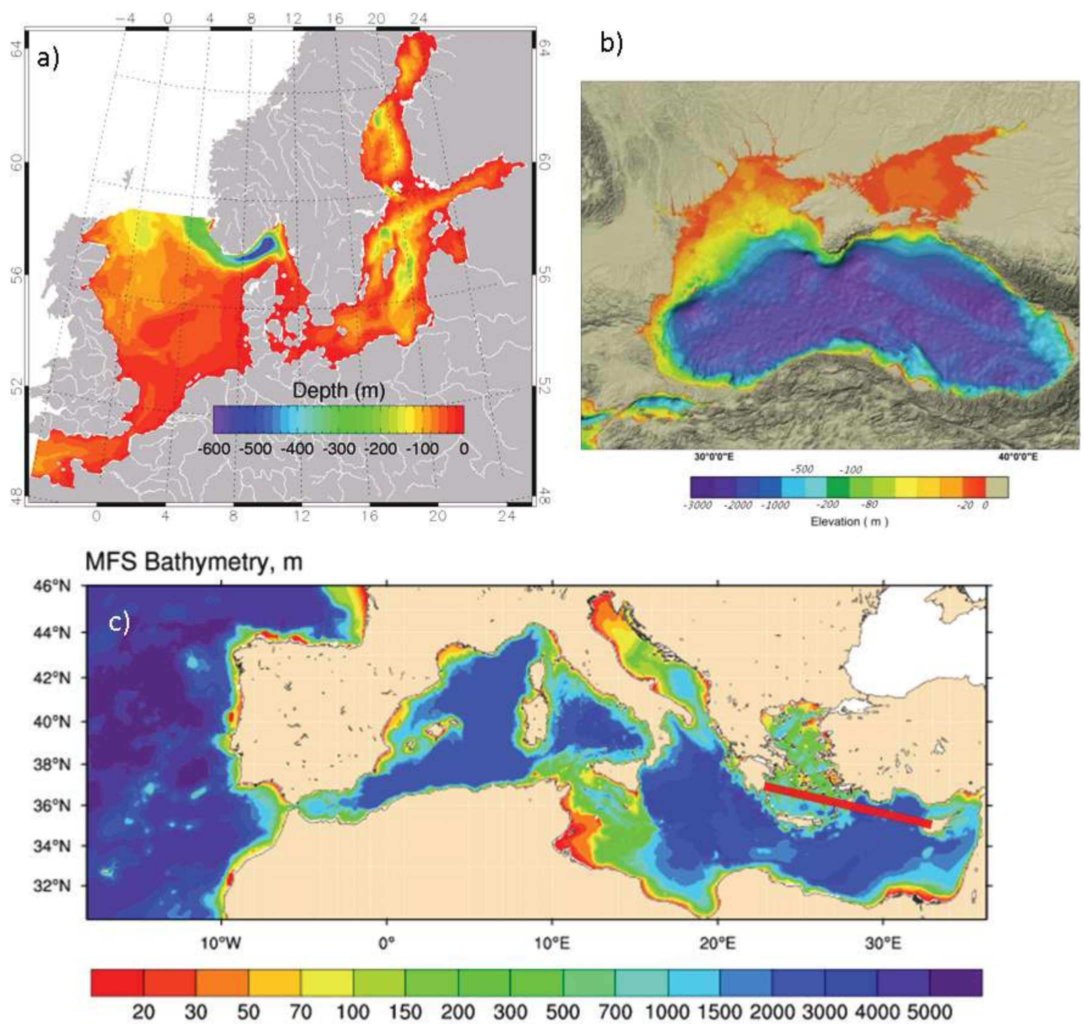
Figure 17 – Potential Route for a Pipeline from Cyprus to Greece and Onward to Italy and Bulgaria

Source: DEPA (2012).

The second pipeline export option discussed has been to lay a line from Cyprus to Turkey, which is less than 100 km north of the island (across the Mediterranean Sea). Obviously, such a scenario is replete with controversy. It is clear that the attractiveness of this option is, first and foremost, a question of *geopolitical feasibility*. For a discussion of geopolitical aspects of the pipeline-to-Turkey option, see for example, Gurel et al., (2013) and Tsakiris (2013). While such analysis is not in the scope of this study, the *techno-economic feasibility* of such an option is, and it is on these grounds that the study has carried out its analysis (see Appendix 7).

From an engineering perspective, the pipeline-to-Greece option is challenging in several dimensions. Figure 18 illustrates a sea depth in the North Sea (where pipelines from Norway to Europe are built), the Baltic Sea (where pipelines from Russia to Germany are built), the Black Sea (where a pipeline from Russia to Turkey is built and a pipeline from Russia to Europe, via Bulgaria, is being planned), and the Mediterranean Sea. The North Sea and Baltic Sea are relatively shallow (around 100–200 meters) and mostly flat. The Black Sea is deep (around 2,000 meters) and mostly flat. The areas of the Mediterranean Sea, where pipelines from Algeria and Libya are built, are also relatively shallow and flat. However, the routes considered for the pipeline to Greece are in the deep areas of the Mediterranean Sea that also include substantial variations in sea depth along the way. These depth and gradient challenges most likely would increase costs for the pipeline option.

Figure 18 – Submarine Bathymetry of (a) North Sea and Baltic Sea, (b) Black Sea, and (c) Mediterranean Sea. From Cyprus to Greece (Illustrated by the red line in (c)), There Are Substantial Changes in Sea Depth.



Source: DMI (2012), INGV (2009).

Figures 19 and 20 show another dimension of the potential challenge for an offshore pipeline, this time related to earthquakes. Figure 19 provides an indicator that relates a probability of earthquake with the potential devastation of its effect. It shows peak ground acceleration for a 10% probability of an earthquake in the next 50 years (red means severe effects, yellow means moderate). The figure shows that there is a high risk of severe effects for a route from Cyprus to Greece. Figure 20 shows that Cyprus and Greece lie in two different tectonic plates, causing an increase of earthquake incidents near the plates' border. Yellow dots on the figure show the earthquake events that happened between 2000 and 2010. Building pipelines in such a seismically active area complicates the project.

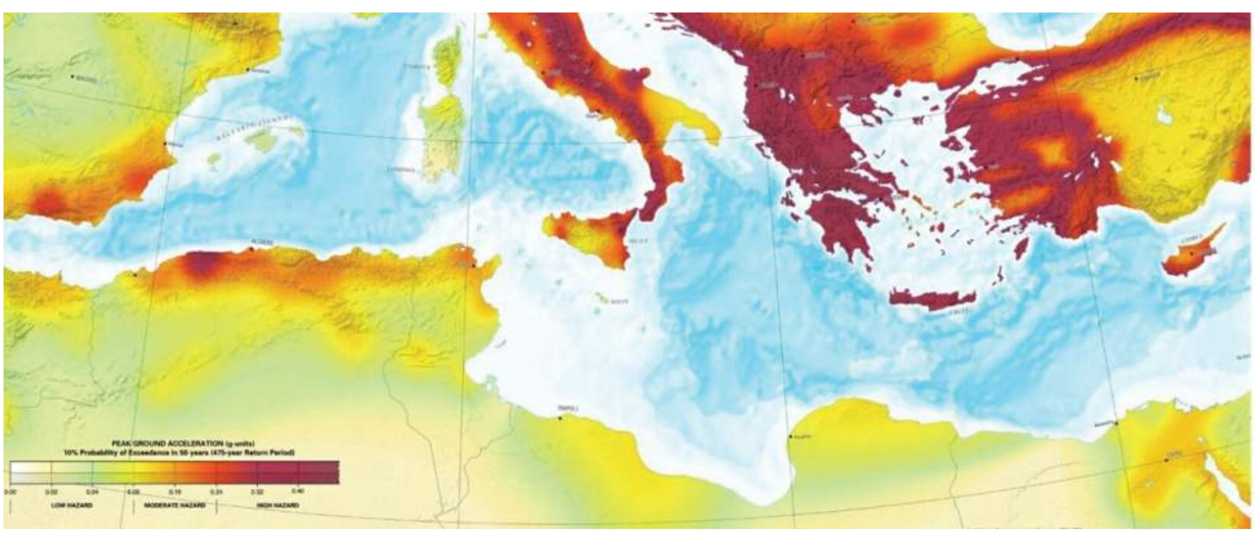
Base Case Results for Pipeline to Greece

In our base case, we consider a 240 trillion-Btu/year (about 7-bcm/year) pipeline from Cyprus to Greece, assumed to depart Vasilikos and land in the Peloponnese via Crete, totaling 1150 km (equivalent to the lower leg of the scenario illustrated in Figure 17). The amount of exported gas is assumed to be the same as with the LNG option. We tried to make an apples-to-apples comparison of the LNG and pipeline options, but there are several important caveats. We provide breakeven prices for both options. In the case of LNG we focus on the FOB prices that should be adjusted for transportation costs from Cyprus (either to European or Asian destinations), regasification costs, and delivery costs from a regasification facility. For the pipeline option, we focus on "landed" prices, i.e., prices at delivery at the coast of the Greek mainland. These prices also should then be adjusted for any additional transportation costs for a delivery in Greece or even further to other European countries.

The breakeven landed gas price means that a selling price upon landing above this threshold would make the project economical. We do not focus on the potential developments of natural gas prices in different world regions in the interim report. They obviously are going to affect the ultimate economics of different options, and will thus form the focus of the second phase of the study.

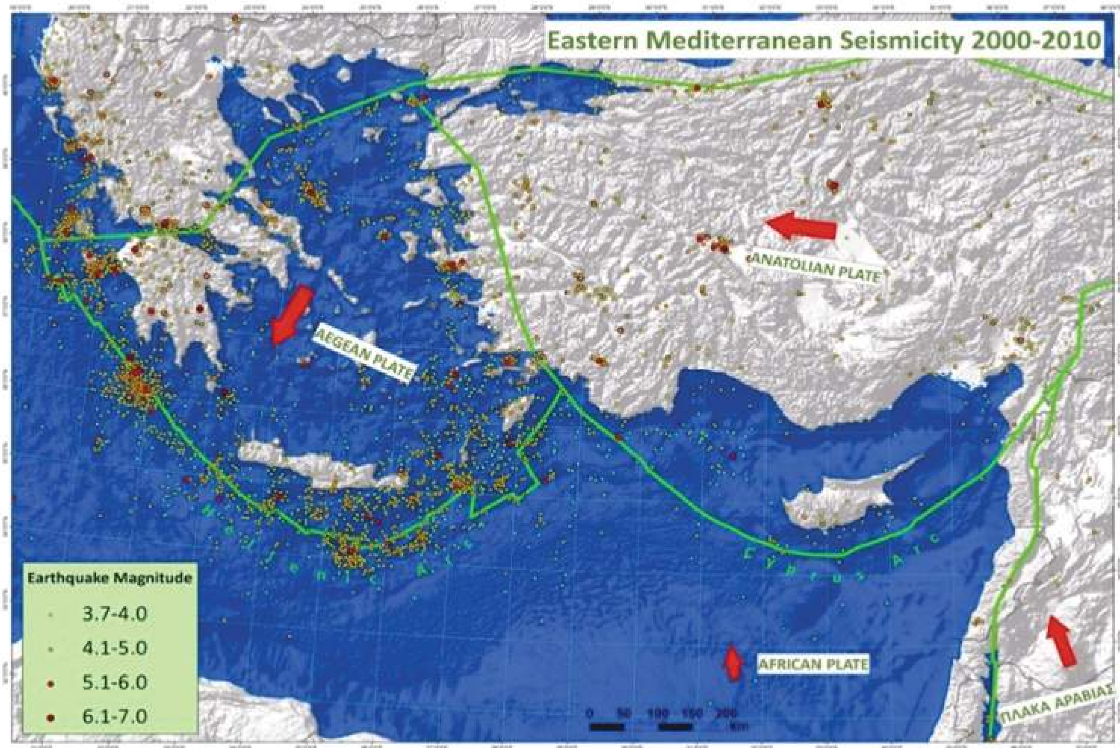
The input parameters to the Pipeline DCF model are described in Appendix 7. The data for input costs are limited for several reasons: (1) there are very few existing submarine pipelines around

Figure 19 – East Mediterranean Seismic Hazard Map



Source: Jimenez et al. (2003).

Figure 20 – East Mediterranean Seismicity 2000–2010



Source: Cyprus Geological Survey Department (2013).

the world; and (2) for those pipelines that do exist, there is a wide variability in local conditions, from water depth, to sea floor terrain, to prospect of soil erosion, to seismicity. Unlike in the case of LNG, instead of developing a fixed per-unit Capital Expenditure (CAPEX) baseline, a general relationship between CAPEX and some of the relevant variables is shown. As part of the report, a simple semi-empirical analysis of CAPEX per-unit distance per-unit diameter has been developed on the existing offshore pipeline data (see page 70 for more details about CAPEX estimation). The Operations and Maintenance (O&M) cost, in turn, is estimated based on this estimate, assuming it is equal to 5% of the CAPEX. Based on these pipeline CAPEX and O&M cost estimates, along with a feed gas cost of $2.5/MMBtu (the same as in the base case for the LNG option), the landed breakeven price for a pipeline to Greece is $7.82/MMBtu.

Sensitivity Analysis for Pipeline to Greece

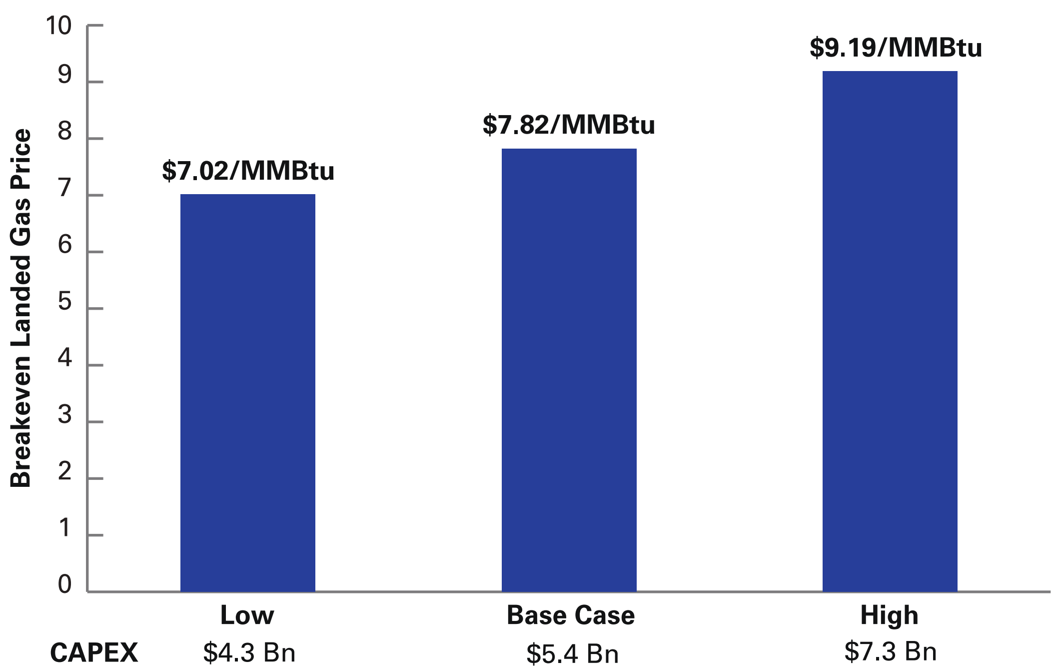
With CAPEX and the rest of the input parameters chosen for the base case, one can then vary some of these assumptions to see how it affects the results (see Appendix 7 for details). As in the case of LNG, it was determined that project economics were most sensitive to CAPEX. But unlike the LNG model, the CAPEX estimate itself is highly uncertain, amplifying the need to understand how variability in this parameter would affect the economics. Figure 21 illustrates one such sensitivity analysis, with three scenarios: “low” ($4.3 Bn), “base case” ($5.4 Bn), and “high” ($7.3Bn). The impact on the breakeven price is significant.

The "high" scenario is especially important to consider, as certain risks that would cause cost escalations could not fully be internalized in the semi-empirical model used to estimate the baseline CAPEX. These risks have to do with the unique characteristics of the Eastern Mediterranean and, in particular, the presence of undersea mountains and the higher relative seismicity of the region (relative to other regions in which similar projects have been done). These risks need to be thoroughly assessed before moving forward with such a project.

The pipeline CAPEX turns out to be the most sensitive parameter. An increase from the base case value of $5,400 million to the high value of $7,300 million (approximately a 35% increase, which might occur due to material or labor cost escalations) increases the breakeven price from $7.82/MMBtu to $9.19/MMBtu. On the other hand, the 20% reduction in CAPEX (to $4,300 million) reduces the breakeven price to $7.02/MMBtu. The feed gas cost follows closely in importance to the economics of the pipeline to Greece. An increase from $2.5/MMBtu to $4/MMBtu in the feed gas price causes an increase in the breakeven price from $7.82 to $9.32/MMBtu. Conversely, a lower feedstock of $2/MMBtu causes a corresponding reduction in the breakeven price, down to $7.32/MMBtu. The report also evaluates the effect of project delay on the breakeven price. If the project delivery is delayed by three years, the breakeven gas price would go up from $7.82/MMBtu to $8.61/MMBtu. Additional results for sensitivity analysis are provided in Appendix 7.

Considering the pipeline option, it should be noted that the natural gas exporter does not have the same flexibility to react to the changing market conditions (and, for example, to re-orient the flows from European to Asian customers) as the exporter has with the LNG option. There is also an issue of potential disputes with transit countries (like the one between Russia and Ukraine in recent years). An LNG terminal might be more costly to develop than a pipeline to Greece (or a pipeline to Turkey) up front, but the relative flexibility of supply to different markets based on changing market conditions will likely outweigh such a difference in capital costs. If more gas is discovered, then the pipeline options could become more attainable.

Figure 21 – A Sensitivity Analysis of the Breakeven Price of a Pipeline to Greece to CAPEX Variability



SECTION 6 COMPRESSED NATURAL GAS MARINE TRANSPORT

Project Overview

Sometimes referred to as a "floating pipeline," a CNG marine transport system is the continuous compression, transport, and delivery of natural gas via ship (see Figure 22 for illustration). CNG cannot achieve the same energy density of LNG, thus reducing the economies of scale to long-haul shipment. However, recent technological innovations in compression have seen the achievement of up to *half* the energy density of the liquefied product (Stenning, 2012). Moreover, when comparing against LNG, proponents of such a system claim that what is lost in long-haul efficiency is recovered in lighter infrastructure costs (essentially just a compression facility, which can be placed on a floating platform/vessel or onshore), a shorter development period (one to two years rather than four-plus years for LNG), and the potential price premium that such a system could achieve for delivery to smaller, stranded energy markets that do not have large enough demand profiles to justify the investment in regasification infrastructure (or a pipeline).

The Eastern Mediterranean market surrounding Cyprus is well situated for a CNG marine transport delivery system, since it encompasses a set of fragmented energy markets which are, nonetheless, in relative proximity to each other. In particular, many of the islands in the region are primarily dependent on oil imports for electricity production, which are both highly priced and highly polluting (for which those countries that are members of the EU potentially have to pay penalties). Indeed, prior to the discovery of the Aphrodite Field, Cyprus itself was considered several times as a potential *customer* for a CNG marine transport system (in fact, it continues to be advocated as an interim import solution for Cyprus until its own indigenous supplies are running to the island).

Figure 22 – Overview of a Compressed Natural Gas Delivery System

Source: Stenning (2012).

However, the biggest hurdle for this fledgling industry in Cyprus is the same hurdle it faces around the world: "bankability," i.e., the willingness of investors to take on the liability of such a project, given that marine CNG storage and transport has never been deployed at scale (although many CNG-*fueled* vessels already exist, as well as on-land CNG storage and transport). Consequently, many governments — and historically, Cyprus included — have been hesitant to take on the perceived "first mover" risks of this innovative approach to natural gas monetization.

Given the nascent state of this industry, developing a reliable economic model for such a project was more challenging than the other more established options considered in this study. Without data from existing projects, the following analysis relies on industry data — so conclusions drawn from these results should be considered with this disclaimer in mind. With that said, a preliminary base case has been developed based on the technology for Sea NG, the company that has been most active in the Eastern Mediterranean. The base case assumes an onshore facility at Vasilikos, with a shuttle system that can reach as far as the Greek mainland.

CNG Base Case

Figure 23 illustrates the base case results for an onshore CNG marine transport system, spanning from Vasilikos to mainland Greece (see Appendix 8 for a description of inputs to the study's CNG DCF model and sensitivity analysis regarding the input parameters). It is worth noting that the capacity of such a system is lower than the other options considered in this study, given the limitation in scale to CNG. The base-case capacity was set to 110 bcf/yr (employing five ships or "shuttles," each with a storage capacity of 350 Mcf). The breakeven landed gas price from this model is $5.86/MMBtu. If this were to be a realistic result, it would suggest CNG has huge economic appeal. However, this result should not be taken as conclusive, given the potential bias in the source material available.

Figure 23 – Base Case Result for an Onshore CNG Marine Transport System

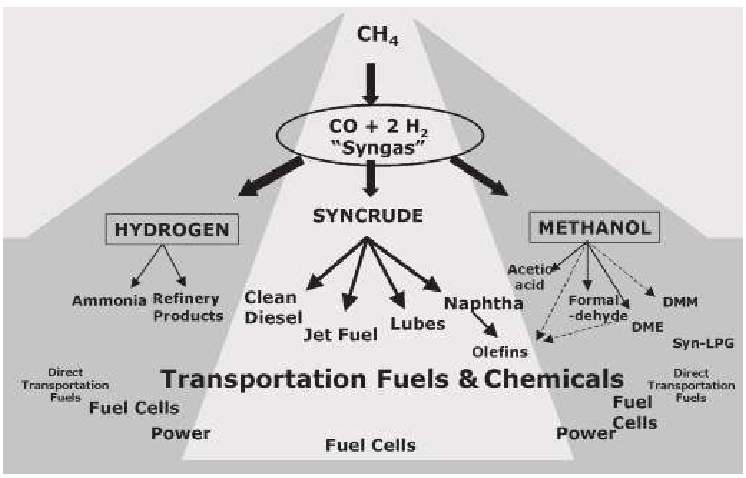
Input Parameters	Output Parameters
Capacity: 110bcf/yr	Breakeven Landed Natural Gas Price $5.86/MMBtu
Origin: Vasilikos	
Destination: Peloponnese, GR	
Project Life: 20 years	
CAPEX: $1.7 billion USD	
Capacity Utilization: 85%	
Feedback Price: $2.5/MMBtu	
Discount Rate: 10%	
OPEX: $0.45/MMBtu	
Corporate Income Tax: 35%	
Depreciation: 12-yr starting line	
Inflation: 1.5%	

SECTION 7 CONVERSION OF GAS TO CHEMICALS

If a pipeline is constructed to bring gas to the island, Cyprus would be in a position to explore the development of a GtC industry (otherwise known as a gas-based "petrochemicals" industry). This involves the conversion of methane into a "syngas," which can then be further refined into a number of higher-value products, including ammonia, urea, naphta, diesel, olefins (plastics), methanol, and acetic acid (see Figure 24). These products might be utilized domestically, but with the small size of the Cypriot market, they would principally offer additional export options for Cyprus.

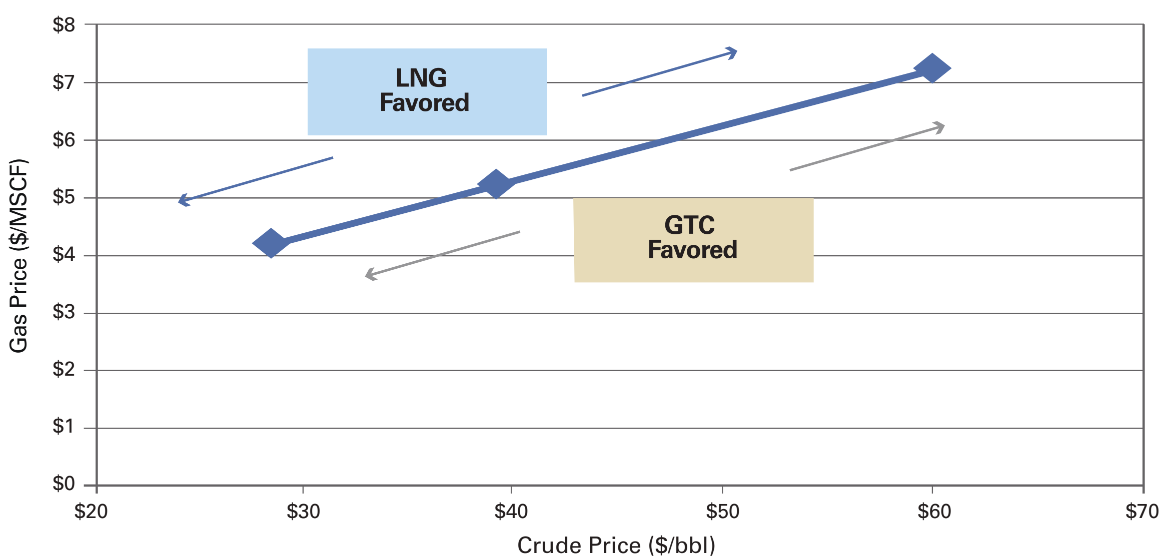
Conversion of GtC is an appealing candidate as a supplement to direct gas exportation. In particular, it offers portfolio diversification, as many chemical exports are pegged to the global oil market, rather than natural gas markets (since many chemical products are petroleum-based). Consequently, if Cyprus were to invest in GtC alongside LNG, for example, one option could potentially provide a hedge against volatility in the market for the other (see Figure 25).

Figure 24 – Overview of Gas-to-Chemical Conversion Pathways



Source: Fleisch (2002).

Figure 25 – The Different Market Dynamics of LNG and GtC Might Allow Cyprus to Use One Option to Mutually Hedge against the Other



Source: Economides (2005). (Figure is illustrative only.)

A second key advantage of GtC is that it tends to be more labor intensive than directly exporting the resource by LNG or pipeline. Indeed, a common issue with the oil and gas industry is that, although a significant number of jobs are created during initial construction and development, long-term employment opportunities tend to be limited. By investing in a domestic GtC conversion capability, Cyprus could potentially mitigate this problem.

A useful case study in this regard is Trinidad and Tobago (see Appendix 9 for a more detailed case study of the natural gas industry in Trinidad and Tobago), an island nation in the Caribbean Sea that chose to supplement its LNG industry with GtC due, in part, to unemployment concerns. A side-by-side comparison (see Table 2) of these two industries in Trinidad and Tobago in 2003 illustrates the higher industrial employment density of GtC relative to CNG.

Table 2 – Trinidad and Tobago Shows the Employment Opportunity Advantage of GtC Relative to LNG

Industry	Capacity	Permanent Jobs
GtC	9.6 MT/yr	2,400+
LNG	6.5 MT/yr	500

Source: Adapted from Barclay (2004).

However, there are challenges that must be considered before pursuing a diversification strategy like GtC. First of all, if Cyprus pursues an LNG plant, its small economy will already be challenged with an extremely capital-intensive undertaking, making simultaneous additional infrastructure investments difficult to manage (though a staged approach could be possible). Secondly, initial assessments suggest that the gas in the Aphrodite Field is “dry,” i.e., lacks significant quantities of natural gas liquids (NGL), which reduces the appeal of a GtC industry.[6] Finally, a substantial number of similar investments in chemical production capacity have been made in gas-rich countries in the Middle East in recent years, which would mean strong competition of supply in the region.

SECTION 8 CONCLUDING REMARKS

Relative economics of different options for Cyprus in monetization of its natural gas resource provide a useful guidance for any decision-making. This report provides an opportunity for an independent analysis of the major options: an onshore LNG plant, a transnational undersea pipeline, and the deployment of a CNG marine transport system. Our multi-dimensional DCF model, developed for this project, allows for a wide variety of scenario and sensitivity analyses. An advantage of this approach is its relative simplicity that still captures the major factors that will drive the economics of the projects. In addition, its openness allows any third party to change any input assumption in the DCF model and assess the corresponding results.

This report has focused on the BEP as a measure of the value of the project. A comparison of BEP with a realized (or expected) natural gas price provides guidance for undertaking the project. According to BP (BP, 2013), in 2011 average natural gas prices were $4.01/MMBtu in the United States (Henry Hub), $9.04/MMBtu in the United Kingdom (Heren NBP Index), $10.48/MMBtu in Germany (average German import cif – cost + insurance + freight), and $14.73/MMBtu in Japan (Japan cif). These prices are subject to variation and, as any option for Cyprus natural gas will take some time to develop, the projections for gas prices in 2020 also can be considered. IEA (2012) projects Europe's import prices to be $11.50/MMBtu and Japan's import prices to be $14.30/MMBtu (both prices are in real terms — in 2011 US dollars).

According to the analysis in this report, in the base cases, BEP prices are $9.75/MMBtu for the Cyprus LNG option to the European markets, $10.25/MMBtu for the Cyprus LNG option to the Asian markets, and $10.32/MMBtu for the Cyprus offshore pipeline option to the European markets.

The results can also be illustrated by looking at an IRR of different options. Higher IRR provides a better justification for a project. Our base case assumptions lead to the following IRRs: 14.8% for the Cyprus LNG option to the European markets, 20.5% for the Cyprus LNG option to the Asian markets, and 13.6% for the Cyprus offshore pipeline option to the European markets.

Considering the pipeline option, it should be noted that a natural gas exporter does not have the same flexibility to react to the changing market conditions (for example, to re-orient the flows from European to Asian customers) as an exporter does with the LNG option. There is also an issue of potential disputes with transit countries. An LNG terminal might be more costly to develop than a pipeline up front, but the relative flexibility of supply to different markets based on changing market conditions will likely outweigh such a difference in capital costs.

LNG development is also not without major risks, particularly for small nations like Cyprus in which the necessary investment, even for modest LNG projects (around $6 billion) is on the same order of magnitude as the country's GDP (around $25 billion). The potential benefits of growing an LNG industry in Cyprus will include employment opportunities and, of course, a potentially large revenue stream for the nation through taxes and royalty payments and dividends from entities the nation holds equity in.

The exact tax and royalty schemes are unknown at this moment, but one can estimate an NPV of tax revenue that Cyprus will collect if it taxes the projects at 35%. Assuming a project life of 20 years, the NPV of tax revenue for the LNG option is $1.5 billion, while the NPV of tax revenue for the pipeline to Greece option is $1.4 billion.

There are additional potential options for natural gas monetization. The above-mentioned CNG option looks attractive based on very preliminary engineering data. It has a BEP of $5.86 (for a landed price in Greece) and an IRR of 23%. However, no real world CNG projects of this scale exist so far, and experience with new technologies shows that engineering costs might substantially underestimate the realized costs of the projects. The GtC option is attractive when the gas resource is rich in natural gas liquids (i.e., higher-order hydrocarbons than methane), which seems not to be the case with the Cypriot gas resource. Gas-to-wire (i.e., production of electricity from natural gas in Cyprus and exporting it via electric cables) is another potential option (to be assessed in the second stage of the study).

Regardless of the chosen option, projects that start out with a relatively attractive economic profile can easily lose competitiveness either as the result of poor technical planning and execution, or due to bureaucratic and regulatory delays. We have illustrated some of the additional costs by providing the scenarios with project delays. A three-year project delay changes the FOB (i.e., price net of transport and regasification costs) BEP for an LNG project from $7.25/MMBtu to $8.13/MMBtu. A similar delay for the pipeline option changes the landed BEP for a pipeline to Greece from $7.82/MMBtu to $8.61/MMBtu.

Any monetization option carries its risks. CNG and gas-to-wire are relatively untested options and Cyprus might not want to be the first country to prove that the engineering calculations are realized as expected. Experiences with LNG and pipelines are more robust. However, even with a more attractive LNG option, there are many exogenous risk factors, such as price risks, cost overruns, overall contracting, and many others. Neglecting a proper mitigation of those risks can erode the economic attractiveness of Cypriot LNG. Some of those additional risks related to the rapidly changing dynamics of the global gas markets, including how distinct regional markets might interact in different ways over time and the implications all this has for Cyprus in planning a long-term export strategy will be explored in the second stage of the study.

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ENDNOTES

1 A description of the Aphrodite gas field and the project status is available at: http://subseaiq.com/data/Project.aspx?project_id=1008&AspxAutoDetectCookieSupport=1

2 Egypt has historically exported natural gas via pipeline and LNG. It has 2 LNG plants with a total capacity of 12.2 million tons (Mt) of LNG. Due to its domestic concerns in 2012, Egypt's LNG plants exported only 4.7 Mt. There are reports that they are interested in getting feedstock gas from Israeli fields (Globes, 2013).

3 Lebanon has not ratified the agreement yet.

4 Several countries in the region have been promoting their own locations be used for the development of "natural gas" hubs, hoping that natural gas for exports could also come from nearby countries. Cyprus is considering up to five LNG production lines (called trains) to accommodate gas from Israel and Lebanon (Bloomberg News, 2013). Egypt is looking to bring natural gas from Israel to increase its exports from the existing LNG plants (Globes, 2013). Turkey and Israel are considering the possibility of a pipeline to Turkey, which would require a lower upfront capital investment in comparison to LNG terminals (Reuters, 2013). All these activities are still at the preliminary stage of consideration.

5 Moreover, this pipeline will serve to provide Cypriot gas for domestic consumption over the long term. However, separate options for importing gas are being considered for domestic consumption in the interim, while gas from the Aphrodite field is not available for domestic use. This "interim solution" is outside the scope of this study.

6 "Natural gas liquids" (NGLs) are higher-order hydrocarbons present alongside methane, the primary constituent in natural gas. For many complex chemical products, it takes less energy to use NGLs as a feedstock relative to methane.

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ABBREVIATIONS / ACRONYMS

BEP	Breakeven Gas Price
Bcm	Billion Cubic Meters
CAPEX	Capital Expenditure
CNG	Compressed Natural Gas
DCF	Discounted Cash Flow
DPC	Discounted Project Cash
EEZ	Exclusive Economic Zone
EPPA	Emissions Prediction and Policy Analysis model
FCNG	Floating Compressed Natural Gas system
FOB	Free on Board
GDP	Gross Domestic Product
GtC	Gas to Chemicals
GTL	Conversion of Gas to Liquids
IEA	International Energy Agency
IRR	Internal Rate of Return
LNG	Liquefied Natural Gas
MITEI	MIT Energy Initiative
MMBtu	Million British Thermal Units
MOU	Memo of Understanding
Mt	Million tons
MtOE	Million tons of Oil Equivalent
MtPA	Million tons Per Annum
NEMED	North East Mediterranean
NG	Natural Gas
NGC	Natural Gas Company
NGL	Natural Gas Liquids
NPV	Net Present Value
O&M	Operations and Maintenance
QBtu	Quadrillion British Thermal Units
PV	Present Value
Tcf	Trillion cubic feet
USGS	US Geological Survey
WACC	Weighted Average Cost of Capital

APPENDIX 1. NATURAL GAS IN THE EASTERN MEDITERRANEAN

Appendix 1 provides a short description of the natural gas resources in the Eastern Mediterranean. Table A1.1 shows the proven reserves and additional estimated recoverable reserves reported by US EIA (2013) for the countries in the region.

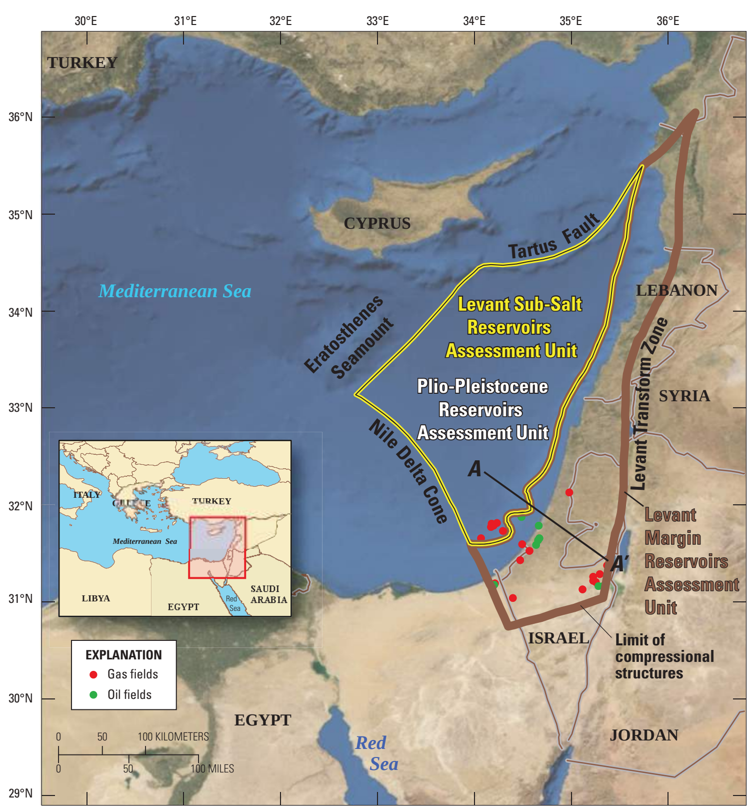
Table A1.1 – Eastern Mediterranean Natural Gas Reserves

	Proven Reserves (Tcf)	Additional Estimated Recoverable Reserves* (Tcf)
Cyprus	0	7
Egypt	77.2	0
Israel	9.5	23
Lebanon	0	0
Palestinian Territories	0	1
Syria	8.5	0
Turkey	0.2	0

*Sums the reserves of all discovered natural gas fields estimated to be recoverable but not yet proven.
Source: US EIA (2013).

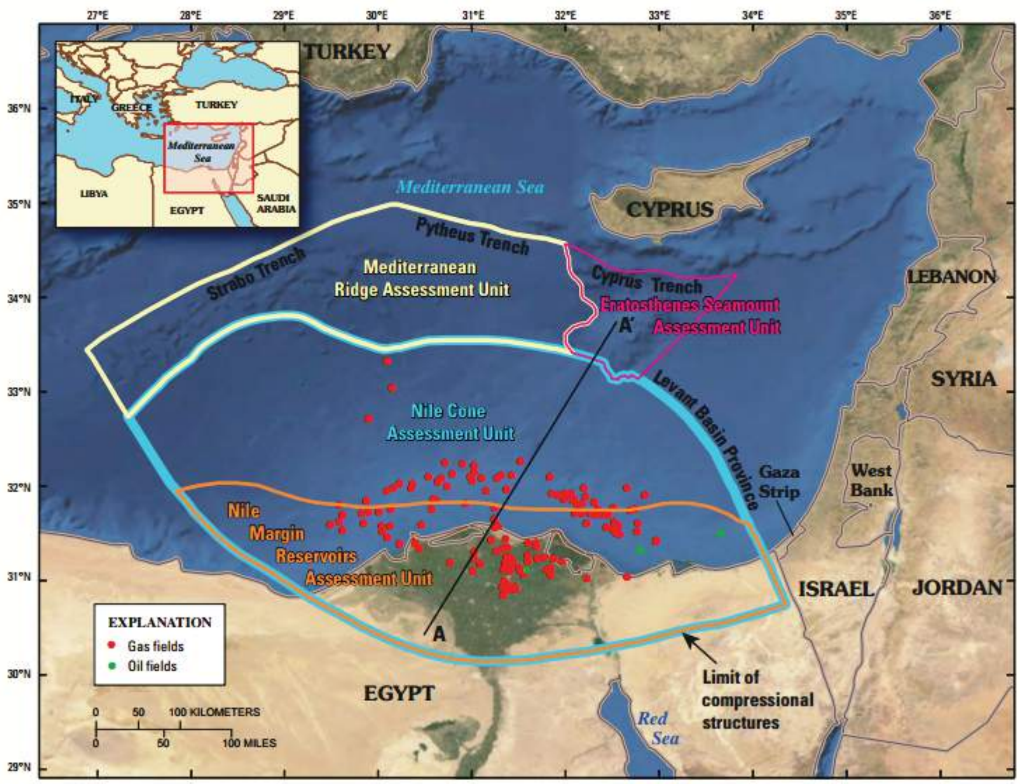
There is room for further increases in the proven reserves in the region, as the USGS, 2010 estimated that the Levant Basin — the basin of which the Aphrodite Field is a part — held 122 Tcf of potentially recoverable natural gas, while the Nile Delta Basin's potential stood even higher at 223 Tcf. Figures A1.1 and A1.2 provide the maps of these basins and their proximity to the countries in the region.

Figure A1.1 – USGS Levant Basin Assessment Unit



Source: USGS (2010a).

Figure A1.2 – USGS Nile Delta Basin Assessment Unit



Source: USGS (2010b).

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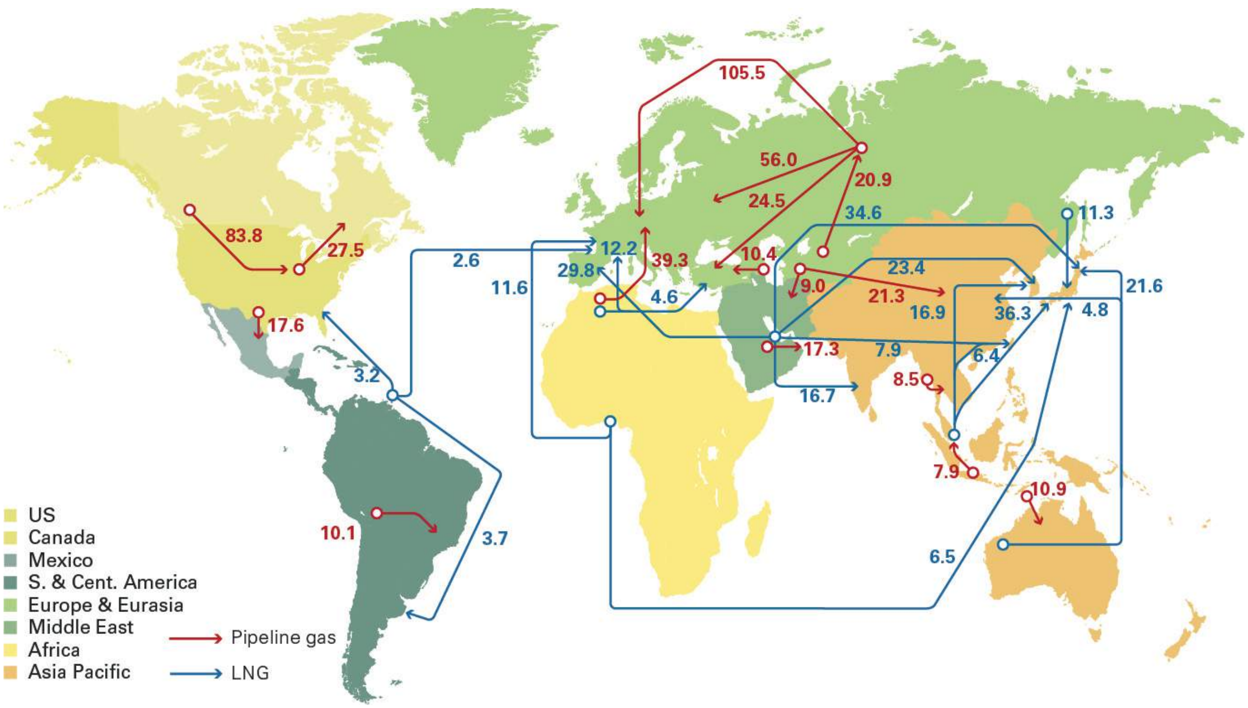
APPENDIX 2. CURRENT INTERNATIONAL GAS TRADE AND GLOBAL GAS USE PROJECTIONS

Figure A2.1 – Major Gas Trade Movements in 2012 (Billion Cubic Meters)



Source: BP (2013).

Table A2.1 – Global Natural Gas Use Projections in Billion Cubic Meters and Trillion Cubic Feet

Bcm			
	2010	2020	2030
IEA	3,307	3,943	4,610
BP	3,160	4,039	4,726
ExxonMobil	3,221	4,062	4,753

Tcf			
	2010	2020	2030
IEA	117	139	163
BP	112	143	167
ExxonMobil	114	143	168

Source: BP Outlook (2013), IEA (2012), ExxonMobil (2013).

Note: IEA reports in Bcm, BP in Million tons of Oil Equivalent (MtOE), ExxonMobil in Quadrillion British Thermal Units (qBtu). The numbers are converted to Bcm and Tcf using the conversion factors (BP, 2013) provided in Appendix 10. ExxonMobil reports the numbers for 2025 and 2040, and for the use in Table A2.1 they are linearly interpolated for 2020 and 2030.

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APPENDIX 3. CYPRUS ENERGY AND ELECTRICITY USE

Table A3.1 – Petroleum Imports, Energy Use, and Electricity Use in Cyprus

Year	Net petroleum imports (Picajoules (PJ))	Primary energy consumption (Picajoules (PJ))	Net electricity consumption (Picajoules (PJ))
1980	41	44	3.3
1981	35	38	3.3
1982	37	41	3.6
1983	42	45	3.9
1984	42	46	4.0
1985	44	49	4.2
1986	46	51	4.5
1987	50	57	4.8
1988	51	57	5.3
1989	62	69	5.9
1990	66	74	6.3
1991	67	74	6.5
1992	79	86	7.6
1993	80	77	8.3
1994	90	98	8.6
1995	90	98	8.0
1996	88	96	8.2
1997	90	97	8.5
1998	97	105	9.4
1999	102	111	9.9
2000	100	109	10.7
2001	108	119	11.2
2002	107	117	12.2
2003	108	118	13.1
2004	114	124	13.4
2005	116	126	14.2
2006	121	133	14.9
2007	121	134	15.7
2008	125	139	16.6
2009	120	131	16.7
2010	116	128	17.3
2011	121	133	
2012	125		

Source: US EIA (2013).

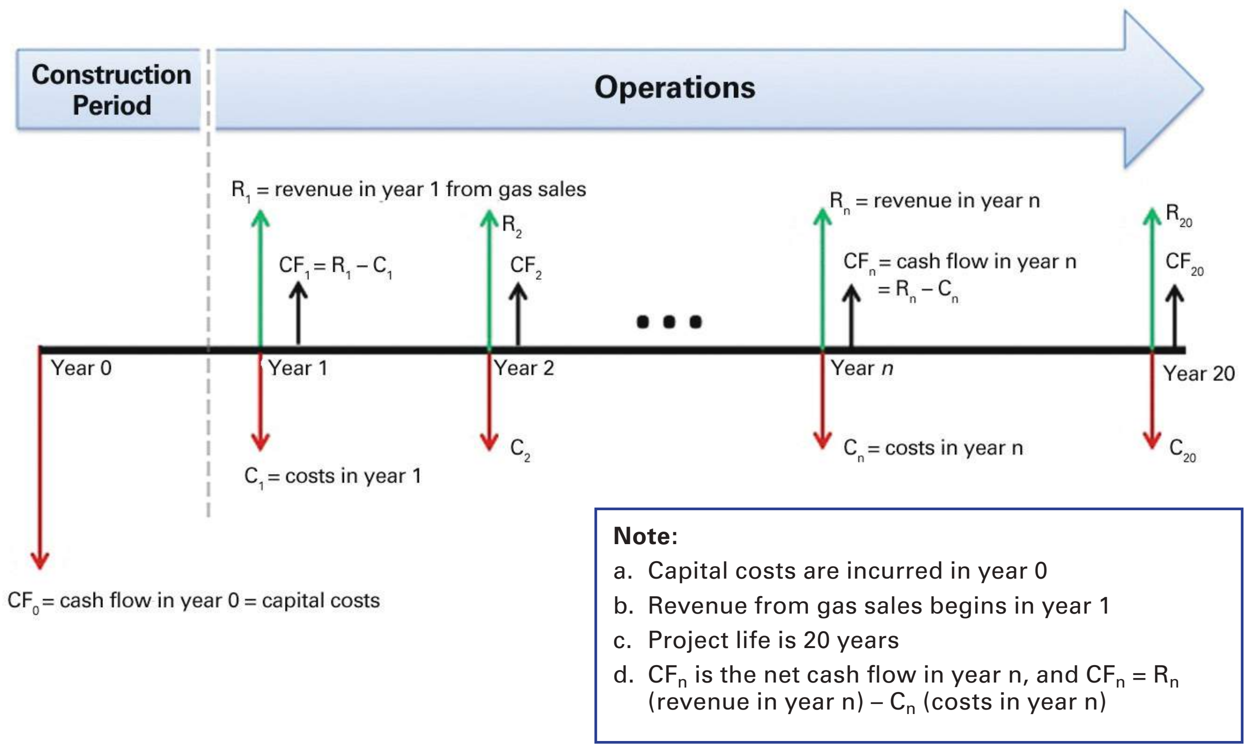
References for Appendix 3

Source: US EIA [US Energy Information Agency] (2013). "Overview data for Cyprus," May 2013 (http://www.eia.gov/countries/country-data.cfm?fips=CY).

APPENDIX 4. DISCOUNTED CASH FLOW MODEL METHODOLOGY

A DCF model has been constructed to evaluate the financial performance of the different monetization options including LNG, pipeline, and CNG. The DCF model accounts for the cash flows during the project lifetime and discounts them to evaluate the project's NPV. Figure A4.1 below illustrates the flow of cash flows through the project life.

Figure A4.1 – Illustration of Project Cash Flows



The report assumes a project life of 20 years and evaluates the cash flows over the project lifetime. The red arrows in the figure indicate costs incurred, and the green arrows indicate revenues. The revenue in the project would come from gas sales, and the costs include capital investment, O&M costs, feed gas cost, and tax payments. The net cash flow in any year is the difference of revenues and costs. As seen in Figure A4.1, the analysis assumes the entire capital investment is in year 0. The project operations begin in year 1 and end in year 20.

The project NPV is calculated using the DCF formula expressed as:

$$NPV = \frac{CF_1}{(1+d)^1} + \frac{CF_2}{(1+d)^2} + \ldots + \frac{CF_n}{(1+d)^n}$$

where CF_n is the "net" cash flow in year n, and d is the discount rate (cost of capital).

The project is a good investment if the NPV of the project is positive.

The DCF spreadsheet model which is available for viewing on the MITEI website has 12 tabs, which evaluate the project NPV for the following cases:

1. **"LNG"** gives the LNG base case model
2. **"LNG-delayed-three years"** gives the model for LNG project delayed by three years
3. **"LNG Results"** gives the results for the sensitivity analysis for LNG breakeven price with regard to different risk factors
4. **"Pipeline-Greece"** gives the pipeline-to-Greece base case model
5. **"Pipeline-Greece-delayed-three years"** gives the pipeline-to-Greece project delayed by three years
6. **"Pipeline-Turkey"** gives the pipeline-to-Turkey base case model
7. **"Pipeline-CAPEX"** gives the pipeline-CAPEX calculation methodology
8. "**Pipeline-Greece-Results"** gives the results for sensitivity analysis for pipeline-to-Greece breakeven price with regard to different risk factors
9. **"CNG"** gives the CNG base case model
10. **"CNG-delayed-three years"** gives the model for CNG project delayed by three years
11. **"CNG Results"** gives the results for the sensitivity analysis for CNG breakeven price with regard to different risk factors
12. **"IRR Results"** gives the IRR for the different monetization options

The DCF model involves three key steps: specifying model inputs, calculating the project cash flows, and finally calculating the project net present value. Following is a description of each of the steps.

Step 1. Inputs

The inputs into the DCF model include the capacity of the project, capacity utilization factor, fuel loss factor, capital costs, O&M costs, feed gas cost, and the gas price. Other financial parameters include the inflation rate, tax rate, and the "real" cost of capital (or the discount rate).

The total gas delivered (output) is calculated as the "capacity × capacity utilization factor." The gas price in the LNG model is the FOB price (not accounting for the LNG transportation and regasification costs). The unit O&M costs in the pipeline model is calculated as 5% of the capital costs. The CAPEX is calculated differently for the LNG, Pipeline, and the CNG models:

- CAPEX in the LNG model is calculated as the "unit capital cost ($/t) × capacity (t)."
- CAPEX in the Pipeline model is input in absolute ($) terms. The calculation accounts for the onshore and offshore pipeline diameter, distance, and thickness. The method is described in the DCF spreadsheet tab "Pipeline-CAPEX."
- CAPEX in the CNG model is input in absolute ($) terms. The source for the capital cost is referenced in the CNG section of the report.

After specifying the inputs, the next step is to calculate the project cash flows.

Step 2. Cash Flows

A project life of 20 years is assumed (unless there is a project delay), and the cash flows are evaluated over the project lifetime. The analysis assumes the entire capital investment is in year 0, except when the project is delayed and the capital is spread over multiple years. All cash flows are evaluated in “nominal” terms and the costs and revenues are multiplied by the inflation factor. Working in nominal terms makes it easier to evaluate depreciation and calculate taxes. A linear 12-year depreciation is assumed.

The cost cash flows include CAPEX, depreciation, O&M costs, and the feed gas cost. The O&M costs and the feed gas cost account for the fuel loss factor, and are calculated as “unit cost (\$/MMBtu) × gas output (MMBtu) × (1 + fuel loss factor).”

The project expenses are evaluated for tax purposes, and are a sum of depreciation, O&M costs, and the feed gas cost. The revenue from gas sales is calculated as the gas price multiplied by the gas output. The total taxable income is the difference between the project revenue and the expenses. The amount of tax payable is calculated by multiplying the tax rate with the total income.

The cost cash flows of the project are a sum of capital investment or CAPEX, O&M costs, feed gas cost, and taxes. The net project cash flows are the difference between the project revenue and the costs. After we have calculated the net project cash flows, we can now evaluate the NPV of the project.

Step 3. Project Net Present Value

The project NPV is the sum of the Discounted Project Cash (DPC) flows. To calculate the DPC flows, the “nominal” project cash flows (calculated in Step 2) are divided by the inflation factor and the discount factor. The cash flows are divided by the inflation factor to convert from “nominal” to “real” terms, and then the “real” cash flows are divided by the “real” cost of capital.

This is the DCF methodology to evaluate the project NPV. The BEP and the IRR are also evaluated using the same DCF model.

The BEP is calculated as the gas price at which the project NPV would be zero. The IRR is calculated as the cost of capital at which the project NPV would be zero. To evaluate the IRR, gas price projections by the 2012 IEA World Energy Outlook are used.

The DCF model is also used to analyze the impact of project delay on the NPV and the breakeven gas price. The impact of a three-year project delay on the project’s financial value is also analyzed. A three-year project delay extends the construction phase of the project over four years, and the project life extends to 23 years. The DCF models with project delay are given in the spreadsheet tabs: **“LNG-delayed-three years,” “Pipeline-Greece-delayed-three years,”** and **“CNG-delayed-three years.”**

APPENDIX 5. INPUTS TO LNG DCF MODEL

This section presents the different inputs into the LNG DCF model. Results from the sensitivity analysis are also presented with respect to the key inputs in the DCF model. Table A5.1 below lists the different inputs for the LNG DCF model, and includes the sources for these inputs.

Table A5.1 – Inputs to the LNG DCF Model

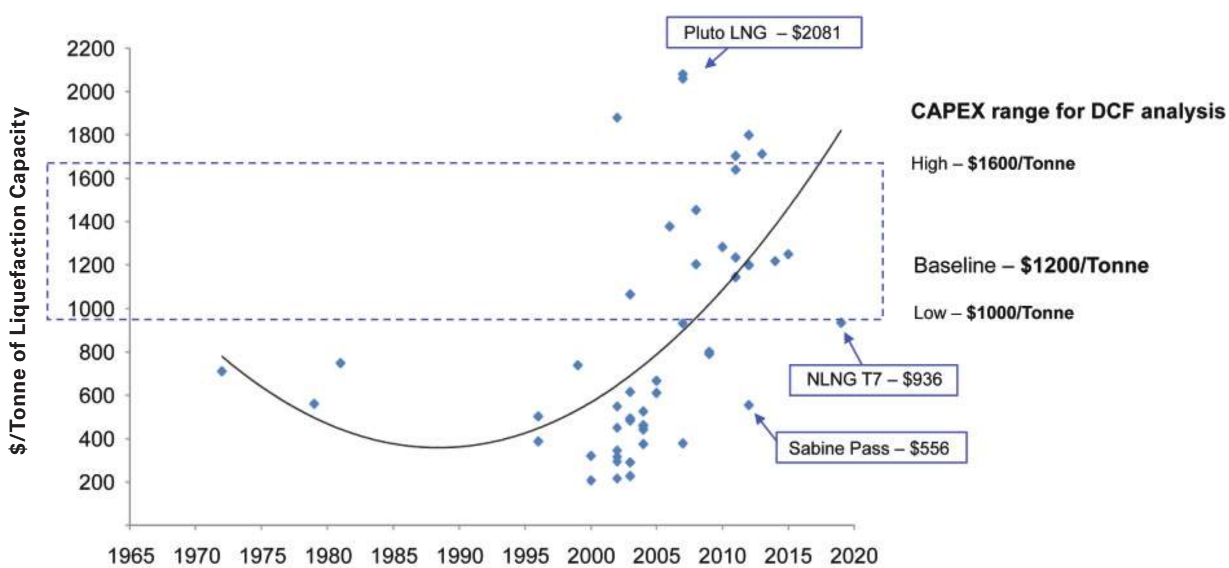
Input	Value	Source
Capacity	5 Mt/year	based on current proved reserves [1]
CAPEX	$1,200/tonne	[2, 3, 4]
O&M cost	$0.2/MMBtu	[5]
Plant utilization rate	85%	[6]
Feed gas cost	$2.5/MMBtu	[7]
Tax rate	35%	assumption
Fuel loss factor	8%	[8]
Inflation	1.5%	assumption
Cost of capital	10%	[9, 10]

Sources: [1] Gürel et al, 2013 ; [2] IGU, 2013; [3] Deutsche Bank, 2012; [4] E&Y, 2013; [5] NERA, 2012; [6] Lurin, 2010; [7] Noble, 2012; [8] DWA, 2009; [9] Fermandez et al, 2013; [10] WACC misc. sources.

Given the current level of proved reserves, 5–8 Tcf (Gürel et al., 2013), the DCF analysis assumes the construction of a single 5-Mt LNG liquefaction train, with an expected operational lifetime of 20 years. Next, is a discussion of how the values of the key cost and economic parameter inputs into the LNG model — capital cost, plant utilization rate, feed gas cost, and cost of capital — are determined.

Figure A5.1 illustrates how the capital costs of LNG liquefaction projects have risen over the years (Deutsche Bank, 2012). Clearly, there is a wide range; however, contemporary analysis indicates

Figure A5.1 – Illustration of LNG Liquefaction Capacity Cost Evolution



Source: Deutsche Bank (2013) and author's calculations.

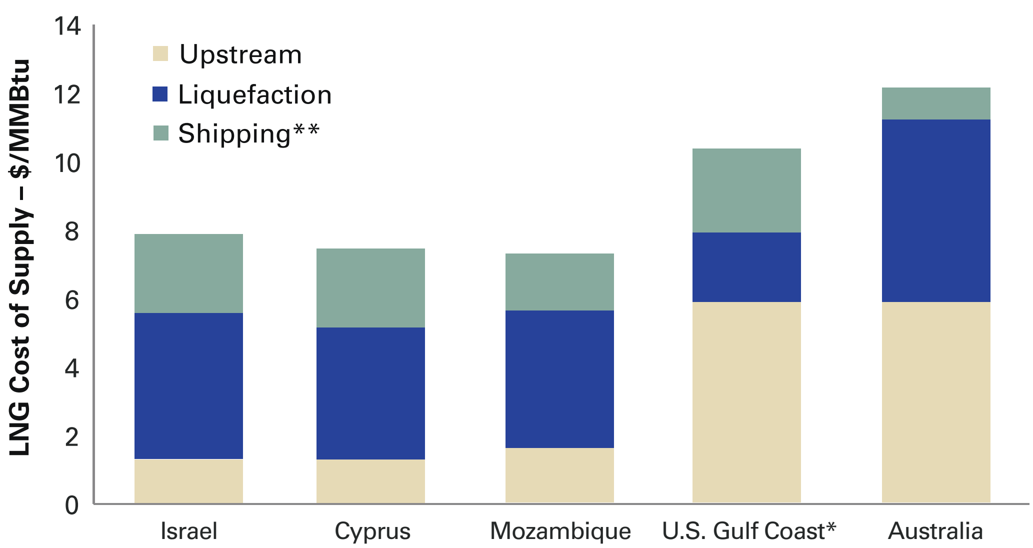
that a cost of at least $1,200/t of nameplate capacity is likely for projects being developed over the next decade (IGU, 2013; Deutsche Bank, 2012; E&Y, 2013). This consensus led to the choice of $1,200/t as the base case scenario capital cost for a 5-Mt Cypriot liquefaction facility to be constructed by 2020.

A key factor for determining LNG project economics is the plant utilization rate. Naturally, for a capital-intensive project like an LNG facility, maximizing throughput is an important driver of economic performance. The traditional LNG business model involving long-term customer agreements enables plant "right sizing" and high levels of utilization. As the business of LNG changes, it is not entirely clear that it will be possible for plants to consistently remain highly utilized, particularly for plants that have more marginal economics. In 2012, the global LNG liquefaction fleet had an overall utilization rate of 85% (IGU, 2013), and this is the utilization rate selected for the Cypriot base case scenario.

It is critical for the model in this report to have the best possible estimate on the upstream cost of developing the Aphrodite Field and bringing it to shore. This is represented in the "feed gas cost" input parameter. At the time of writing, very limited publicly available information has been released concerning this parameter. Figure A5.2 below illustrates Noble's most recent analyst report suggesting that the Aphrodite Field's feed gas cost would be roughly $2/MMBtu. However, upon consultation with a variety of experts inside and outside Cyprus, the authors believe that this estimate is too low, and is more likely to be around $2.5/MMBtu. Results from the second appraisal well (yet to be released at the time of writing) will help narrow the uncertainty around this factor.

The real discount rate used in the analysis was set at 10%. This rate was based on an assessment of the WACC for a range of corporate entities active in the upstream and LNG sectors. Next, how WACC is calculated is described.

Figure A5.2 – Noble's Estimate of Cypriot LNG Supply Cost Relative to Other Countries



*US Gulf Coast assumes projects feed gas at Henry Hub prices ($5.50/MMBtu assumed)

**Shipping to Far East

Source: Noble, 2012.

Weighted Average Cost of Capital

WACC for use as a discount rate in evaluating natural gas monetization options is computed. WACC refers to how much it costs the company to raise money. Projects can be financed with debt or equity and typically companies use the combination of the two. The WACC reflects the cost of debt and equity financing, weighted for the mix of financing. The WACC will vary by company because the cost of debt, the cost of equity, and the weight depend on a company's individual circumstances. The inflation rate is implicit in the WACC estimation (Lurin, 2010).

WACC is expressed as:

WACC = Cost of Equity × Market Capitalization/(Market Capitalization + Total Debt) +
Cost of Debt × Total Debt/(Market Capitalization + Total Debt) × (1 – Corporate tax rate)

Where cost of equity and cost of debt are calculated as:

Cost of Equity = Interest rate + Equity Risk Premium × Company Beta

Cost of Debt = Company bond yield + geopolitical risk premium

Cypriot government bond yield is used for interest rate in "Cost of Equity" to capture the country risk of undertaking projects in Cyprus. Cost of Debt is adjusted by a geopolitical risk premium term to reflect the geopolitical risk specific to natural gas development in Cyprus, e.g., lack of agreement between Greek and Turkish Cypriots on hydrocarbon revenues. We assume a Corporate tax rate of 35%.

Table A5.2 reports the WACC for range of corporate entities active in the upstream and LNG sectors (Fermandez et al., 2013; WACC misc. data). Assuming a geopolitical risk premium at 5%, we found the average WACC is 10.03%. Thus, we use a 10% cost of capital as the discount rate for the LNG DCF model.

Table A5.2 – WACC for Corporate Entities Active in the Upstream and LNG Sectors

Company	WACC	Cost of Equity	Cost of Debt	Market Capitalization ($mm)	Total Liabilities ($mm)
Shell	9.55%	10.41%	7.27%	211,065	37,754
BP	11.25%	13.44%	8.08%	134,216	48,797
Total	9.45%	10.89%	8.62%	88,580	33,290
Eni	11.14%	13.22%	8.75%	64,071	24,463
GDF Suez	7.62%	11.48%	7.85%	36,192	55,681
Statoil	8.72%	10.42%	7.44%	43,062	18,851
Woodside	14.07%	14.49%	9.07%	29,937	1,540
Cheniere	8.64%	13.05%	9.36%	6,376	10,976
Conocophilips	10.92%	13.05%	7.82%	70,289	25,599
Noble	10.50%	12.39%	8.72%	19,166	7,500
KOGAS	11.54%	11.76%	7.59%	553,357	18,537
ExxonMobil	9.55%	9.70%	7.26%	390,944	11,581
EDF	7.47%	11.96%	8.67%	29,388	72,073

We listed the inputs into the LNG DCF Model. These cost and other assumptions included in the base case DCF model should not be considered exact. Rather, the base case parameters were selected to represent a likely scenario. In order to capture the uncertainty surrounding the base case, a number of parameter sensitivities were carried out that enable the construction of economic envelopes around the base case performance.

Next, the results from sensitivity analysis are presented with respect to the key inputs into the DCF model.

Sensitivity Analysis

The sensitivity of the project economics to any number of parameters can be explored; however, only a subset of these has a major impact. The sensitivity analysis in this section focuses on six input parameters: the project's capital costs, O&M costs, feed gas costs, the utilization levels, corporate tax rate, and a delay in project delivery. The high and low sensitivity values studied for each of these parameters are given in Table A5.3.

Table A5.3 – Base Case/High/Low Scenario Values for Key Inputs in the LNG DCF Model

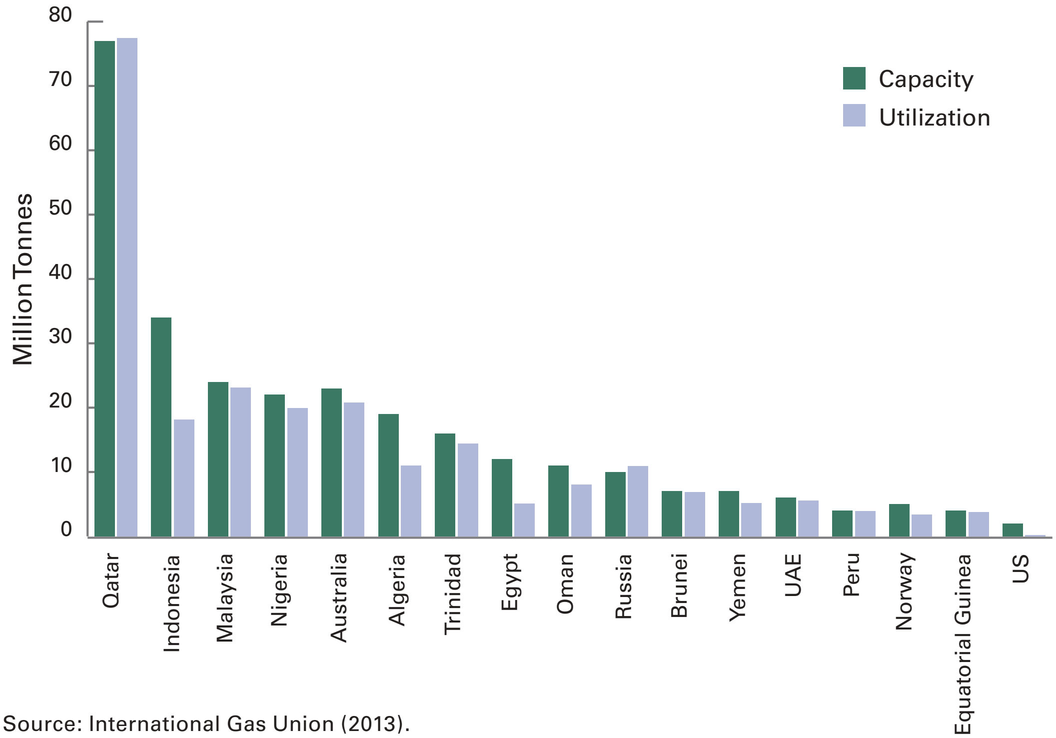
Parameters	"Low" Value	Base Case Value	"High" Value	Source
CAPEX	$1,000/tonne	$1,200/tonne	$1,600/tonne	[1, 2, 3]
O&M cost	$0.3/MMBtu	$0.2/MMBtu	$0.1/MMBtu	assumption
Plant utilization rate	95%	85%	75%	[2]
Feed gas cost	$4/MMBtu	$2.5/MMBtu	$2/MMBtu	[4, 5]
Tax rate	50%	35%	20%	assumption
Project delay		0 years	3 years	assumption

Sources: [1] E&Y, 2013; [2] IGU, 2013; [3] Deutsche Bank, 2012; [4] Noble, 2012; [5] Jensen, 2012.

The high and low sensitivities for the CAPEX were chosen to be $1,600 and $1,000/t respectively. As shown in Figure A5.1, there are contemporary projects outside this range; however, they have some specific characteristics not applicable to Cyprus. On the high side, most of the very expensive capacity currently in development is in Australia, where control of capital cost inflation has been severe owing to multiple parallel LNG developments, several in extremely remote locations (Pluto LNG being a good example). Of the lower-cost projects, all of the US-based capacity, (e.g., Sabine Pass) should be ignored. These projects are brownfield expansions of existing facilities with much of the necessary infrastructure for enabling export already in place. A similar situation exists with Nigeria's LNG Train.

In 2012, the global LNG liquefaction fleet had an overall utilization rate of 85%. This is the utilization rate selected for the Cypriot base case scenario. However, as shown in Figure A5.3, the level of utilization varies from country to country (IGU, 2013). Qatar, for example, had 100% utilization in 2012 (in fact, slightly greater than 100% owing to some storage effects); however, other countries had much lower levels. Norway, for example, had a utilization of 75%. The utilization of a Cypriot facility will be linked to its ability to come online with attractive economics and acquire high-quality customer contracts. To reflect how success or failure in this regard would impact utilization, the high and low sensitivities for the utilization rate were set at 95% and 75%, respectively.

Figure A5.3 – 2012 Global LNG Liquefaction Capacity Utilization by Country



Source: International Gas Union (2013).

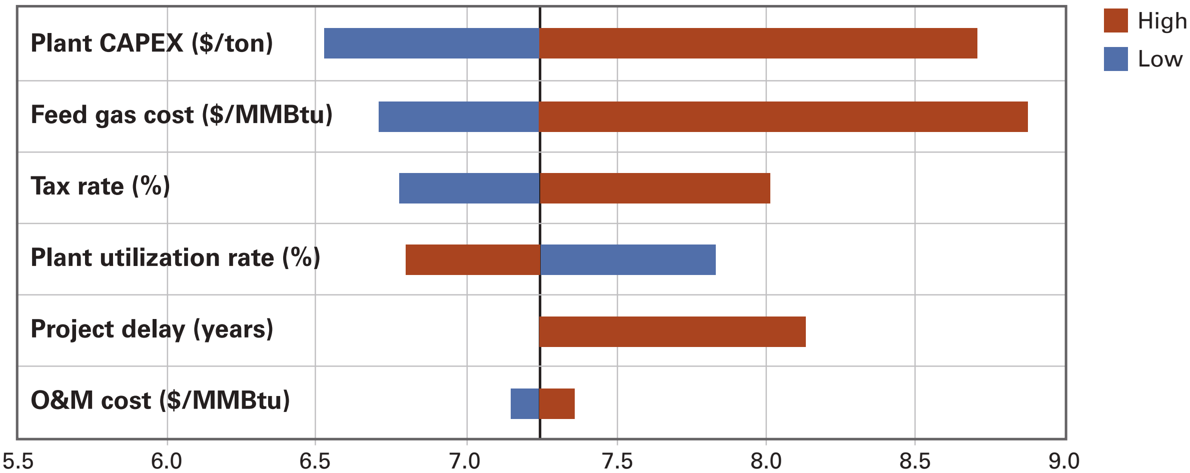
At the time of writing, very limited publicly available information has been released concerning the feed gas price parameter. Figure A5.2 illustrates Noble's most recent analyst report suggesting that the Aphrodite Field's feed gas cost would be roughly $2/MMBtu. However, upon consultation with a variety of experts inside and outside Cyprus, our team believes this estimate is too low, and is more likely to be around $2.5/MMBtu. Results from the second appraisal well (yet to be released at the time of writing) will help narrow the uncertainty around this factor. For the base case scenario here the feed gas cost is assumed to be $2.50/MMBtu. The slightly higher value is warranted due to relative lack of third-party analysis. For the feed gas sensitivities, the low case used is estimated at $2.00/MMBtu. The high case assumes a feed gas cost of $4.00/MMBtu. This is well under the development costs seen for other offshore developments supplying onshore liquefaction facilities, particularly those in Australia (Jensen, 2012).

The high and low value estimates for the O&M costs are assumed as a 50% change from the base case value. The tax rate high and low values are assumed to be 50% and 20%, respectively. We also analyze the impact of a three-year project delay on the LNG project economics.

Given the base case costs, utilization, tax rate, and on-time project delivery, the FOB breakeven gas price for the LNG project is $7.25/MMBtu. Figure A5.4 presents the sensitivities of the FOB price to the high and low values of the different costs, utilization, tax rate, and three-year delayed project delivery.

Figure A5.4 shows that the FOB price is most sensitive to the changes in capital costs. The escalation of capital costs to the high-cost scenario ($1,600/t) drives the FOB breakeven gas price to $8.70/MMBtu, while delivery of the project at $1,000/t would allow the project breakeven at $6.53/MMBtu. The second largest impact on FOB price is from changes in the feed gas cost. The low feed gas scenario reduces the FOB breakeven gas price from $7.25/MMBtu to $6.71/MMBtu, while the higher feed gas cost increases the breakeven price to $8.87/MMBtu. An increase in tax rate from 35% to 50% will drive up the breakeven price to $8.01/MMBtu, and a low tax rate of 20% will reduce the breakeven price to $6.78/MMBtu.

Figure A5.4 – Sensitivities of FOB Breakeven Gas Price for High and Low Values of Input Parameters



In the case of lower plant utilization, a 10% reduction in assumed throughput increases the FOB breakeven price for the plant from $7.25 to $7.83/MMBtu, while increasing utilization to 95% reduces the FOB breakeven price for the project to $6.80. If the project delivery gets delayed by three years, the FOB price will go up from $7.25 to $8.13/MMBtu. The change in O&M costs has the smallest impact on the FOB price. A 50% increase in O&M costs will drive up the FOB price from $7.25 to $7.36/MMBtu, and a 50% decrease in O&M costs reduces the FOB price by 10 cents to a value of $7.15/MMBtu.

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[WACC misc. sources] Sources for calculating cost of capital (WACC) for corporate entities engaged in LNG:

i. Cypriot government bond yield: monthly data reported by EuroStat, Thomson Reuters Datastream (http://libguides.mit.edu/finance/); latest value is 7% for March 2013.

ii. Company Beta: Reuters finance (http://www.reuters.com/finance/stocks/).

iii. Company Bond Yield: 10-yr bond yields reported by Thomson Reuters Datastream (http://libguides.mit.edu/finance/). If company bond yield is not available for a company, use composite yield of the company's S&P credit rating (source: Bloomberg).

iv. Market Capitalization and Total Liabilities: Thomson one finance database (http://libproxy.mit.edu/login/thomsonone/).

APPENDIX 6. MAJOR OFFSHORE PIPELINES

Figure A6.1 – Routes of Several Major Offshore Pipelines
Major offshore pipelines are either built in shallow water (Nord Stream and Green Stream) or deep water, but with flat surfaces (South Stream and Blue Stream), or with short distances (Galsi and Greece-to-Italy). Long-distance pipelines crossing deep sea simultaneously with large depth discontinuities have not been built.

Table A6.1 – Major Russian Offshore Pipelines

	Blue Stream	Nord Stream	South Stream
Location	Black Sea	Baltic Sea	Black Sea
Offshore length (km)	396	1222	930
Capacity (bcm/year)	16	55	63
Number of pipelines	1	2	4
Pipeline diameter (in)	24	48	32
Max depth (m)	2200	210	2250
Status	completed	completed	planned

Source:

Nord Stream (2013). Nord Stream Fact Sheet, April 2013 (http://www.nord-stream.com/download/document/177/?language=en)

Gazprom (2013). http://www.gazprom.com/about/production/projects/pipelines/south-stream/

South Stream (2013). http://www.south-stream.info/en/pipeline/

APPENDIX 7. INPUTS TO PIPELINE DCF MODEL

Inputs

This appendix presents the different inputs into the Pipeline DCF model. Two pipeline options are evaluated — pipeline to Greece and pipeline to Turkey. Results from the sensitivity analysis done with respect to the key inputs in the DCF model are also presented. Table A7.1 below lists the different inputs for the Pipeline DCF model, and includes the sources for these inputs.

Table A7.1 – Inputs to the Pipeline DCF Model

Input	Value	Source
Capacity	240 trillion Btu	Same as LNG
CAPEX – Greece	$5,401 million	See page 70
CAPEX – Turkey	$624 million	See page 70
O&M cost – Greece	$1.13/MMBtu	(Degermenci O., 2001)
O&M cost – Turkey	$0.13/MMBtu	(Degermenci O., 2001)
Utilization rate	85%	Same as LNG
Feed gas cost	$2.5/MMBtu	Same as LNG
Tax rate	35%	assumption
Fuel loss factor	8%	Same as LNG
Inflation	1.5%	assumption
Cost of capital	10%	Same as LNG

The Pipeline DCF model has been developed for the same nameplate capacity as LNG: 5-Mt per year or 240 trillion Btu. The pipeline CAPEX numbers are derived from a CAPEX model that is described on page 70. The O&M costs are estimated as 5% of the capital costs (Degermenci, 2001). The feed gas cost for the base case is assumed to be $2.5/MMBtu, this assumption is explained in the section on LNG. The inflation rate, tax rate, and cost of capital are taken to be the same as in the LNG model. In the absence of good data to get estimates on the fuel loss factor and utilization rate, the same parameters are used as in the LNG model. The rationale for selecting these values is described in the LNG section.

The inputs into the pipeline DCF model have been listed. These cost and other assumptions included in the base case DCF model should not be considered exact. In order to capture the uncertainty surrounding the base case, a number of parameter sensitivities were carried out that enable the construction of economic envelopes around the base case performance. Next, the results from sensitivity analysis done with respect to the key inputs into the DCF model are presented as are the sensitivity results for the pipeline-to-Greece model.

Pipeline-to-Greece Sensitivity Analysis

The sensitivity analysis in this section focuses on six input parameters: the project's capital costs, feed gas costs, O&M costs, corporate tax rate, utilization levels, and project delay. The high and low sensitivity values studied for each of these parameters for a pipeline to Greece are given in Table A7.2.

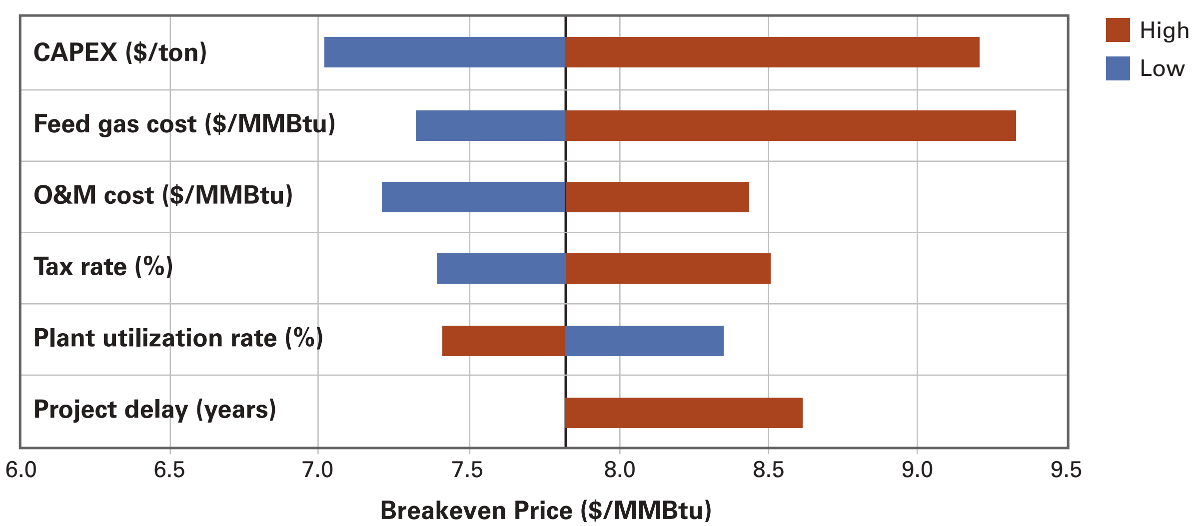
Table A7.2 – Base Case/High/Low Scenario Values for Key Inputs in the Pipeline-to-Greece DCF Model

Parameters	'Low' Value	Base Case Value	'High' Value	Source
CAPEX	$4,300 MM	$5,401 MM	$7,300 MM	% change as LNG
Feed gas cost	$2/MMBtu	$2.5/MMBtu	$4/MMBtu	same as LNG
O&M cost	$0.56/MMBtu	$1.13/MMBtu	$1.69/MMBtu	% change as LNG
Tax rate	20%	35%	50%	assumption
Plant utilization rate	75%	85%	95%	same as LNG
Project delay	–	0 years	3 years	assumption

The high and low values for the CAPEX are calculated using the same uncertainty spread as evaluated for the LNG model. In the LNG model, the sensitivities for a 20% reduction and a 35% increase in the capital costs are evaluated. Similarly, for the pipeline sensitivity analysis, how the BEP would change if the CAPEX were reduced from $5,401 million to $4,300 million (20% decrease), or if the CAPEX increased to $7,300 million (35% increase) is evaluated. For the O&M costs, the low and high case values are evaluated as a 50% decrease and 50% increase in the base case value. The high and low case values for the feed gas costs, tax rate, and utilization rate are the same as analyzed in the LNG sensitivity results. Also analyzed is the impact of a three-year project delay on the pipeline to Greece project economics.

Given the base case costs, utilization, tax rate, and on-time project delivery, the breakeven gas price for the pipeline project is $7.82/MMBtu. Figure A7.1 presents the sensitivities of the BEP to the high and low values of the variables stated above.

Figure A7.1 – Sensitivity of Breakeven Gas Price in the Pipeline-to-Greece Project to Key Input Parameters



The pipeline CAPEX turns out to be the most sensitive parameter. An increase from the base case value of $5,400 million to the high value of $7,300 million (approximately a 35% increase, which might occur due to material or labor cost escalations) increases the BEP from $7.82/MMBtu to $9.19/MMBtu. On the other hand, a 20% reduction in CAPEX (to $4,300 million) reduces the BEP to $7.02/MMBtu.

The feed gas cost follows closely in importance to the economics of the pipeline to Greece. An increase from $2.5/MMBtu to $4/MMBtu in the feed gas price causes an increase in the BEP from $7.82 to $9.32/MMBtu. Conversely, a lower feedstock of $2/MMBtu causes a corresponding reduction in the BEP, down to $7.32/MMBtu.

Deviations in O&M cost follow in order of importance after the feed gas cost. A 50% increase in the O&M cost from the base case of $1.13 to $1.69/MMBtu raises the BEP from $7.82/MMBtu to $8.43/MMBtu, and a 50% fall in O&M costs to $0.56/MMBtu reduces the BEP from $7.82/MMBtu to $7.21/MMBtu.

Tax rates also have a significant effect on project economics. A rise in the corporate tax rate from 35% to 50% attenuates the economic appeal of the project, raising the BEP from $7.82 to $8.5/MMBtu. On the other hand, a lower tax rate of 20% reduces the BEP to $7.39/MMBtu.

Deviations in the capacity utilization rate also affect the breakeven gas price. An increase in the utilization rate from 85% to 95% reduces the BEP from $7.82/MMBtu to $7.41/MMBtu. However, a fall in utilization to 75% would raise the BEP to $8.34/MMBtu. We also evaluate the effect of project delay on the BEP. If the project delivery is delayed by three years, the BEP will go up from $7.82/MMBtu to $8.61/MMBtu.

Results from Pipeline-to-Turkey DCF Model

The BEP for the pipeline from Vasilikos, Cyprus to Aydincka, Turkey (including an onshore part from Vasilikos to Kyrenia), is $3.29/MMBtu (DCF model inputs are listed in Table A7.1). Not surprisingly, the much shorter distance of such a pipeline demonstrably improves the project economics relative to the pipeline to Greece, with a BEP that is less than half that of the base case for the Greek pipeline (for pipeline to Greece, the BEP is $7.82/MMBtu).

However, such a comparison is misleading. The (current) geopolitical risk regarding a joint project between Cyprus and Turkey is so high that a more practical assessment of such a project would require a *risk-adjusted discount rate* that is much higher than the 10% used in this analysis, likely eviscerating the economic appeal of such a project. In addition, there is a transportation cost of moving natural gas from Aydincka to other locations in Turkey to serve its customers. Moreover, as in the case of the pipeline to Greece, a more nuanced look at the potential market demand for such a pipeline is needed for the Turkish natural gas market, as well as the potential for interconnecting pipelines to Europe — before drawing any conclusions about the viability or appeal of such a project (natural gas market scenarios will be considered in the second stage of this study).

Description of CAPEX Model

In a typical report for an existing onshore or offshore pipeline, several parameters are provided, including the pipeline diameter, thickness, throughput, distance, etc. Based on these parameters, a semi-empirical model has been constructed, in which parameters for existing pipelines are put into a regression to extract the cost per distance per diameter (unit cost). This unit cost can further be used to estimate the total cost for a particular pipeline by inputting a set of parameters.

CAPEX can be divided into the cost for the pipeline itself and compressor station as in equation (A7.1):

(A7.1)
$$\begin{aligned} CAPEX &= PpLCost + CompCost \\ &= PpLCost_{on} + PpLCost_{off} + CompStat_{on} + CompStat_{off} \end{aligned}$$

where $PpLCost_{on}$ is the cost from onshore section of Pipeline,

$PpLCost_{off}$ is the cost from offshore section of Pipeline,

$CompStat_{on}$ is the cost from compressors onshore,

$CompStat_{off}$ is the cost from the compressor station at the beginning of offshore.

The semi-empirical model has been built for each of the four terms in eq. (A7.1), respectively. The unit cost, which is defined as cost per distance per diameter, can be written as a portion which is proportional to the consumed material (thus is proportional to the pipeline ring-shaped area), and another portion less affected by the material, such as the cost for pipeline laying. In this perspective, the 1st and 2nd term from eq. (A7.1) can be written as:

(A7.2)
$$PpLCost_{\substack{on\\off}} = UC_{\substack{on\\off}}(\Phi_{\substack{on\\off}}, t_{\substack{on\\off}}) \times L_{\substack{on\\off}} \times \Phi_{\substack{on\\off}} = \left[A_{\substack{1\\3}}\pi\left(\Phi^2_{\substack{on\\off}} - (\Phi_{\substack{on\\off}} - t_{\substack{on\\off}})^2\right) + A_{\substack{2\\4}}\right] \times L_{\substack{on\\off}} \times \Phi_{\substack{on\\off}}$$

where $UC_{on/off}$ is the unit cost for onshore/offshore, in \$/km/inch.

$L_{on/off}$ is the onshore/offshore distance in km.

$\Phi_{on/off}$ is the onshore/offshore diameters of the pipeline in inch.

$t_{on/off}$ is the onshore/offshore pipeline thickness.

A_1 and A_2 (A_3 and A_4) are constants obtained from regression for onshore and offshore, respectively. The regression constant A_1 (or A_3) consumed material term, while A_2 (or A_4) term are constant.

The third and fourth terms can be written in a different fashion. For polytropic gas compression, the power needed for compression can be determined from pressure drop,

$$\textbf{(A7.3)}\quad Pow = \frac{nVRT_1}{n-1}\left[\left(\frac{p_2}{p_1}\right)^{1-1/n} - 1\right] \alpha \frac{n}{n-1}\left[\left(\frac{p_2}{p_1}\right)^{1-1/n} - 1\right]$$

where n > γ > 1, where γ is the adiabatic compression ratio

$p_{1,2}$ is the start/end of pipeline in [bar] the relation can be obtained from Renouard equation:

$$\textbf{(A7.4)}\quad p^2_{1,\substack{on\\off}} - p^2_{2,\substack{on\\off}} = 46742 \times S_g \times L_{\substack{on\\off}} \times q^{1.82} \times \phi^{4.82}_{\substack{on\\off}}$$

where

$p_{1,2}$ is the start/end of pipeline [bar]

L is the pipeline length [km]

$\phi_{\substack{on\\off}} \equiv \Phi_{\substack{on\\off}} - t_{\substack{on\\off}}$ is the internal pipeline diameter [mm],

q is the volumetric flow rate [m3/h]

S_g is the relative density, $S_g = \dfrac{\rho_{NG}}{\rho_{AIR}} = \dfrac{0.78kg/m^3}{1.226kg/m^3} = 0.64.$

Notice equations (A7.3-A7.4) apply both onshore and offshore cases. However, in onshore cases, there are multiple compressors, while for offshore, there is only one compressor station near the sea, i.e., at the starting point of offshore. This high-power offshore compressor station needs to drive offshore longer distance, so the pressure drop is also higher. Based on the pressure drop, by assuming that the cost is proportional to the power of the compressor station, the cost for compressor station can then be written as:

$$\textbf{(A7.5)}\quad CompStat_{on} = Pow_{on} \times UCC_{on} \times N = A_5 \times \frac{n}{n-1}\left[\left(\frac{p_{2,on}}{p_{1,on}}\right)^{1-1/n} - 1\right] \times N$$

$$\textbf{(A7.6)}\quad CompStat_{off} = Pow_{off} \times UCC_{off} = A_6 \times \frac{n}{n-1}\left[\left(\frac{p_{2,off}}{p_{1,off}}\right)^{1-1/n} - 1\right]$$

where $Pow_{on/off}$ is the power for each onshore compressor, or offshore compressor

N is the number of onshore compressors

$UCC_{on/off}$ is the unit compressor cost per power unit.

However, compared to the easily accessible values of pipeline diameter and distance, the working pressures and the cost for the compressor stations are seldom reported. Thus, the onshore and offshore compressor station cost has been incorporated into the onshore and offshore total cost, respectively. To summarize, the semi-empirical CAPEX can be written as:

$$\text{CAPEX} = \left[A_1\pi\left(\Phi_{on}^2 - (\Phi_{on} - t_{on})^2\right) + A_2\right] \times L_{on} \times \Phi_{on} + \left[A_3\pi\left(\Phi_{off}^2 - (\Phi_{off} - t_{off})^2\right) + A_4\right] \times L_{off} \times \Phi_{off} \quad \textbf{(A7.7)}$$

Onshore Pipeline Regression

The onshore parameters of several representative existing pipelines are listed in Table A7.3. Values have been adopted for averaged pipeline construction year, diameter, and thickness.

Table A7.3 – Useful Parameters of Several Natural Gas Pipelines for Regression of Onshore Part of CAPEX

Pipeline Name	L_{on}(km)	Φ_{on}(inch)	Onshore Cost (bn$)	Year	Capacity (bcm/yr)	t_{on}(mm)
Trans-Med (2 pipelines)	920	48	2.95	1978–1990	30.2	14.3
Nord Stream (includes OPAL and NEL) (2 pipelines)	1,824	56	6.5	2012	55	30.9
South Stream (3 pipelines)	1,455	56	8.45	2015	63	30.9
Blue Stream	817	47–55 (avg 51)	1.5	2002	16	14.3
Medgaz	547	48	1.26	2010	8	14.3

Sources: Nord Stream, 2013; Trans-Med; Gazprom, 2011; Blue Steam, 2003.

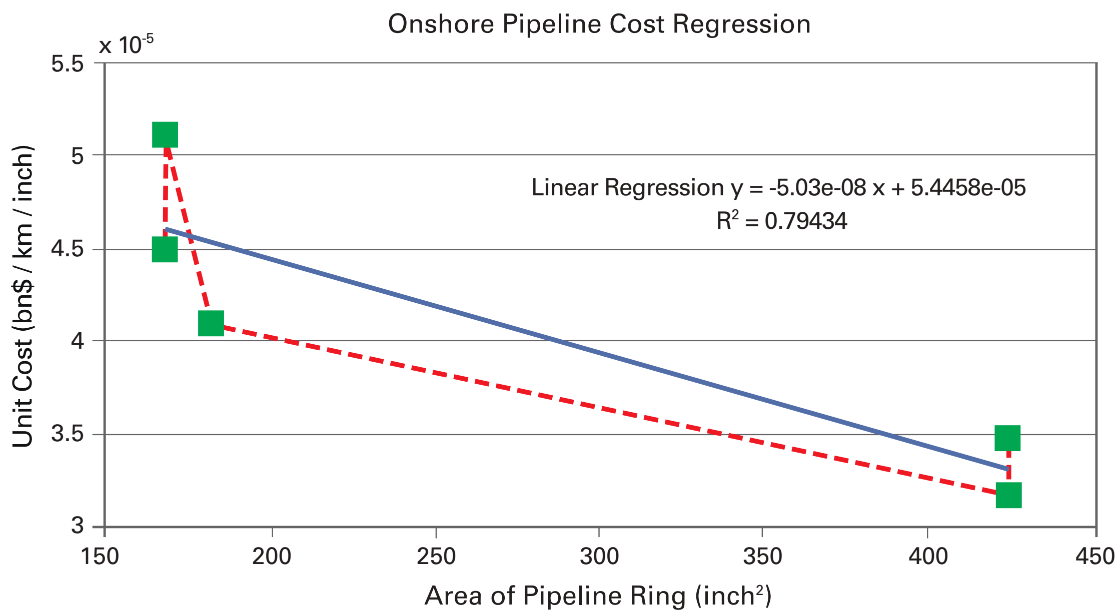
Defining

$$y \equiv PpLCost_{onshore} / L_{on} / \Phi_{on}$$

$$x \equiv \pi\left(\Phi_{on}^2 - (\Phi_{on} - t_{on})^2\right)$$

and assuming a 1.5% inflation rate, the regression for onshore pipeline cost can be determined:

Figure A7.2 – Linear Regression of the Onshore Pipeline CAPEX
The negative slope is reasonable, in that the larger the project is, the less it costs per unit.



This regression result can be used to be compared with the report by Mott Macdonald House (Mott Macdonald, 2010). Table A7.4 gives the CAPEX per distance as a function of solely diameter; this table has been reproduced from Table 5.1 in Mott Macdonald report (Mott Macdonald, 2010).

Table A7.4 – Estimated Onshore/Offshore Cost per km as a Function of Pipeline Diameter from Mott Macdonald Report, 2010

Facility	CAPEX (€million)
Onshore Pipelines	**Total Rate per km (Supply and Install)**
22 inch	€0.792
26 inch	€0.880
30 inch	€1.024
36 inch	€1.312
42 inch	€1.760
48 inch	€2.160
56 inch	€2.480
Offshore Pipelines	**Total Rate per km (Supply and Install)**
20 inch	€8.400
22 inch	€9.680
26 inch	€10.720
36 inch	€12.500

Source: Mott Macdonald, 2010.

Table A7.5 compares the CAPEX for the onshore part of the pipelines obtained by using the values in Mott Macdonald report (Table A7.4) and calculated using the semi-empirical model (eq. A7.2). In all cases the inflation rate is assumed to be 1.5%.

Table A7.5 – Onshore CAPEX Comparison

Pipeline Name	Trans-Med	Nord Stream	South Stream	Blue Stream	Medgaz
Based on Table A7.4 in Mott Macdonald Report	3.84 (2 pipelines)	11.76 (2 pipelines)	14.07 (3 pipelines)	2.11	1.49
Cost from Regression (bn$)	3.03 (2 pipelines)	6.79 (2 pipelines)	8.12 (3 pipelines)	1.64	1.18

Source: Mott Macdonald, 2010; Author's calculations.

Offshore Pipeline Regression

Similar to Table A7.3, the regression for offshore parameters is listed in Table A7.6:

Table A7.6 – Useful Parameters of Several Natural Gas Pipelines for Regression of Offshore Part of CAPEX

Pipeline Name	L_{off}(km)	Φ_{off}(inch)	Offshore Cost (bn$)	Year	Capacity (bcm/yr)	t_{off}(mm)	H(km)
Trans-Med (2 pipelines)	155	20	1.5	1983–1997	30.2	20	0.61
Nord Stream (2 pipelines)	1,222	48	11.44	2012	55	38	0.2
South Stream (3 pipelines)	925	32	13	2015	63	39	2.1
Blue Stream	396	24	1.7	2002	16	32	2.1
Medgaz	210	24	0.882	2010	8	28	N/A

Source: PennEnergy, 2013; Driel et al, 2011; Gazprom, 2011; Chaudhuri et al, 2005; Blue Steam, 2003; True, 1994.

The effect of laying depth to the pipeline underneath the sea is incorporated into the pipeline thickness *t*, where the deeper it lays, the thicker the pipeline should be. In addition, the cost of laying (A4 part) should also be a function of depth. For simplicity, it is assumed as a constant, since in general the offshore cost is already much higher than onshore cost.

Figure A7.3 – Linear Regression of the Offshore Pipeline CAPEX

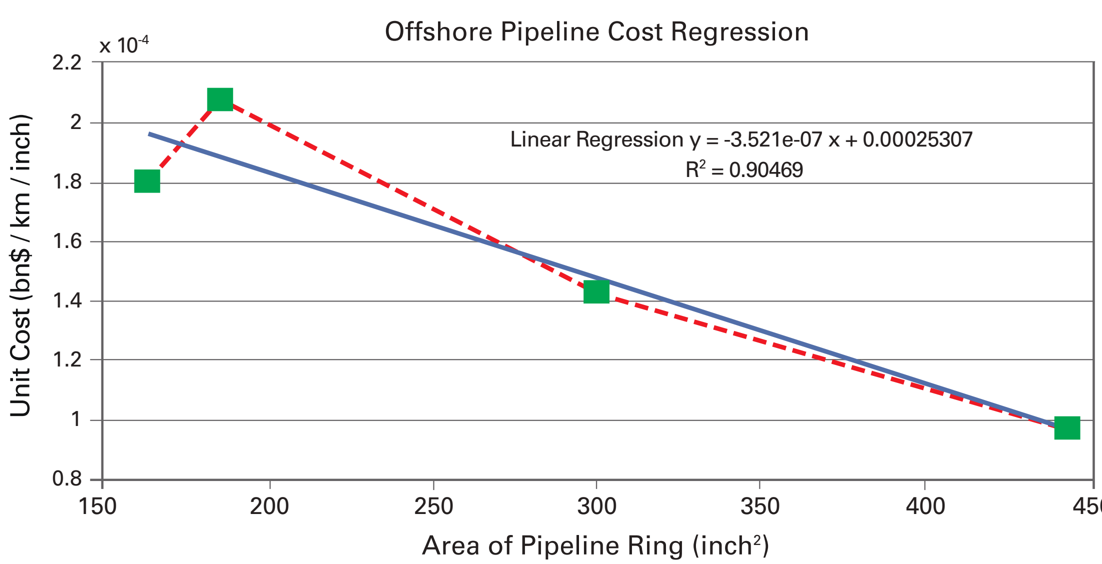


Table A7.7 compares the CAPEX for the offshore part of the pipelines obtained by using the values in Mott Macdonald report (Table A7.4) and calculated using the semi-empirical model (eq. A7.2). To achieve a better fit, the Mott Macdonald report has to be considered for one pipeline only, rather than the actual case of several parallel pipelines. In all cases the inflation rate is assumed to be 1.5%. The values for the Trans-Med pipeline were removed from the regression since it was built more than 20 years ago and the cost difference may not be solely accounted for by inflation, but other issues such as technological advancement.

Table A7.7 – Offshore CAPEX Comparison

Pipeline Name	Trans-Med	Nord Stream	South Stream	Blue Stream	Medgaz
Based on Table A7.4 in Mott Macdonald Report	1.26 (1 pipeline)	N/A	14.32 (1 pipeline)	4.56 (1 pipeline)	2.73 (1 pipeline)
Cost from Regression (bn$)	Not considered for a better fit	11.52 (2 pipelines)	13.15 (3 pipelines)	1.55	0.96

Source: Mott Macdonald, 2010; Author's calculations.

Based on the above described semi-empirical model, the total pipeline CAPEX can be written as

$$\textbf{(A7.8)} \qquad \text{CAPEX} = \left[-5.03 \times 10^{-8} \times \pi \left(\Phi_{on}^2 - (\Phi_{on} - t_{on})^2\right) + 5.45 \times 10^{-5}\right] \times L_{on} \times \Phi_{on}$$

$$+ \left[-3.52 \times 10^{-7} \times \pi \left(\Phi_{off}^2 - (\Phi_{off} - t_{off})^2\right) + 2.53 \times 10^{-4}\right] \times L_{off} \times \Phi_{off}$$

where the diameter Φ and thickness t are inputs using the unit of inch, while the distance L uses units of km. This is the central result to obtain pipeline CAPEX based on its onshore and offshore distance, diameter, and thickness.

In principle, this formulism can be applied to any natural gas pipeline project as long as the parameters are given. The rest is to simply apply it to a specific scenario, such as pipeline to Turkey and pipeline to Greece. Table A7.8 gives the input parameters for the calculation of capital costs of pipeline to Greece and pipeline to Turkey. We see that the total capital cost of the pipeline to Greece is $5,401 million, and the pipeline to Turkey would have a capital cost of $624 million.

Table A7.8 – CAPEX Calculations and Input Parameters for Pipeline to Greece and Turkey

Inputs for CAPEX Calculation: Greece		
Onshore Section		
Pipeline Diameter	(inch)	48
Pipeline Distance	(km)	0
Pipeline Thickness	(mm)	14.3
Offshore Section		
Pipeline Diameter	(inch)	24
Pipeline Distance	(km)	1,150
Pipeline Thickness	(mm)	28
CAPEX		
Onshore CAPEX	($ million)	0
Offshore CAPEX	($ million)	5,401
Total CAPEX	**($ million)**	**5,401**

Inputs for CAPEX Calculation: Turkey		
Onshore Section		
Pipeline Diameter	(inch)	48
Pipeline Distance	(km)	70
Pipeline Thickness	(mm)	14.3
Offshore Section		
Pipeline Diameter	(inch)	24
Pipeline Distance	(km)	100
Pipeline Thickness	(mm)	28
CAPEX		
Onshore CAPEX	($ million)	155
Offshore CAPEX	($ million)	470
Total CAPEX	**($ million)**	**624**

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APPENDIX 8. INPUTS TO CNG DCF MODEL

This section presents the different inputs into the CNG DCF model. Also presented are results from the sensitivity analysis done with respect to the key inputs in the DCF model. Table A8.1 below lists the different inputs for the CNG DCF model, and includes the sources for these inputs.

Table A8.1 – Inputs to the CNG DCF Model

Input	Value	Source
Capacity	2.3 MT	(Stenning et al., 2012)
CAPEX	$1,700 million	(Stenning et al., 2012)
O&M cost	$0.45/MMBtu	(Stenning et al., 2012)
Utilization rate	85%	Same as LNG
Feed gas cost	$2.5/MMBtu	Same as LNG
Tax rate	35%	assumption
Fuel loss factor	8%	(Stenning et al., 2012)
Inflation	1.5%	assumption
Cost of capital	10%	Same as LNG

The capital costs and the O&M costs in our model are calculated based on a paper by the engineers at the Sea NG Corporation (Stenning et al., 2012). The model is based on a gas production rate of 2.5 million ton/year, and the same number as the gas production rate is used in this model.

The report's assumption is that the distance for CNG transport between Cyprus and Greece would be about 1,100 km. For this distance, the Sea NG paper estimates that the capital investment would involve one floating compressed natural gas (FCNG) vessel, and five C84 ships. The paper points out the capital cost of FCNG vessel to be $610 million, and cost per ship is $210 million. The total capital cost comes out to be $1,660 million. A conservative capital cost estimate of $1,700 million has been used, which would account for additional travel distance that might be required, and differences between an offshore CNG facility and an onshore CNG facility.

This 8% fuel loss factor is used in this model. For a distance travelled between 1,050 km and 1,400 km, the fuel loss factor estimated in the Sea NG paper is between 6.6% and 8.3%.

An 8% fuel loss factor implies the capacity of the CNG project is 2.4 million ton/year.

The O&M costs are estimated in the Sea NG paper as $14.1 million per year for the FCNG vessel, and $6.1 million per year per ship. For five ships, the total O&M costs would be about $45 million per year. A conservative estimate of $50 million per year accounts for various uncertainties, and differences in O&M costs in an offshore and onshore CNG facility. $50 million per year O&M implies unit O&M cost of $0.45 per MMBtu of project capacity.

The feed gas cost for the base case is assumed to be $2.5/MMBtu; this assumption is explained in the section on LNG. The inflation rate, tax rate, and cost of capital are taken to be the same as in the LNG model. The rationale for selecting these values is described in the LNG section. In the absence of good data to get estimates on the utilization rate, the same parameters are used as those used in the LNG model. In the base case, the utilization rate is modeled to be 85%.

The inputs into the CNG DCF model have been listed. These cost and other assumptions included in the base case DCF model should not be considered exact. In order to capture the uncertainty surrounding the base case, a number of parameter sensitivities were carried out that enable the construction of economic envelopes around the base case performance. The results from sensitivity analysis are presented with respect to the key inputs into the CNG DCF model.

Sensitivity Analysis

The sensitivity of the project economics to any number of parameters can be explored; however, only a subset of these have a major impact. The sensitivity analysis in this section focuses on six input parameters: the project's capital costs, feed gas costs, O&M costs, corporate tax rate, utilization levels, and project delay. The high and low sensitivity values studied for each of these parameters for a CNG DCF model are given in Table A8.2.

Table A8.2 – Base Case/High/Low Scenario Values for Key Inputs in the CNG DCF Model

Parameters	"Low" Value	Base Case Value	"High" Value	Source
CAPEX	$1,350 MM	$1,700 MM	$2,300 MM	% change as LNG
Feed gas cost	$2/MMBtu	$2.5/MMBtu	$4/MMBtu	same as LNG
Tax rate	20%	35%	50%	assumption
Plant utilization rate	75%	85%	95%	same as LNG
Project delay		0 years	3 years	assumption
O&M cost	$0.23/ MMBtu	$0.45/ MMBtu	$0.68/ MMBtu	% change as LNG

The high and low values for the CAPEX are calculated using the same uncertainty spread as evaluated for the LNG model. In the LNG model, we evaluate the sensitivities for a 20% reduction and a 35% increase in the capital costs. Similarly, for the CNG sensitivity analysis, how the break-even price would change if the CAPEX reduced from $1,700 million to $1,350 million (20% decrease), or if the CAPEX increased to $2,300 million (35% increase) has been evaluated.

For the O&M costs, it is evaluated that the low and high case values as a 50% decrease and 50% increase in the base case value. The high and low case values for the feed gas costs, tax rate, and utilization rate are same as analyzed in the LNG sensitivity results. The rationale for selecting these values is described in the LNG section. The impact of a three-year project delay on the CNG project economics is also analyzed.

Given the base case costs, utilization, tax rate, and on-time project delivery, the breakeven gas price for the CNG project is $5.86/MMBtu. Figure A8.1 presents the sensitivities of this price to the variables stated above.

For the CNG project, the most sensitive parameter is the feed gas cost (CAPEX is not the dominant factor as the CNG system is relatively less capital intensive). An increase from $2.5 to $4/MMBtu in the feed gas cost causes an equivalent increase in the breakeven price from $5.86 to $7.36/MMBtu, once again demonstrating the importance of upstream economics. Conversely, a lower feed gas cost of $2/MMBtu causes a corresponding reduction in the breakeven price, down to $5.36/MMBtu.

Figure A8.1 – Sensitivities of Breakeven Gas Price for CNG to Key Input Parameters

Capital costs are the second most important parameter for CNG. An increase from $1,700 million to $2,300 million causes the BEP to rise from $5.36/MMBtu to $6.80/MMBtu, whereas a fall in the CAPEX to $1,350 million leads to a BEP to reduce to $5.31/MMBtu.

Tax rates are the third most important variable in the CNG sensitivity analysis. A rise in the corporate tax rate from 35% to 50% reduces the economic appeal of the project, raising the BEP from $5.86/MMBtu to $6.33/MMBtu. On the other hand, a lower tax rate of 20% improves the BEP to $5.57/MMBtu.

Variations in the capacity utilization rate follow in importance behind the tax rate. A higher capacity utilization, from 85% up to 95%, reduces the BEP from $5.86/MMBtu to $5.58/MMBtu, while a lower utilization rate of 75% increases the price to $6.22/MMBtu. Following in importance is the effect of project delays. A project delay of three years raises the BEP from $5.86/MMBtu to $6.4/MMBtu. Finally, O&M costs have a nontrivial effect on the project economics. An increase in the O&M cost from the base case of $0.45/MMBtu to $0.68/MMBtu raises the BEP from $5.86/MMBtu to $6.11/MMBtu, and a reduction to $0.23/MMBtu leads to a lower $5.62/MMBtu BEP.

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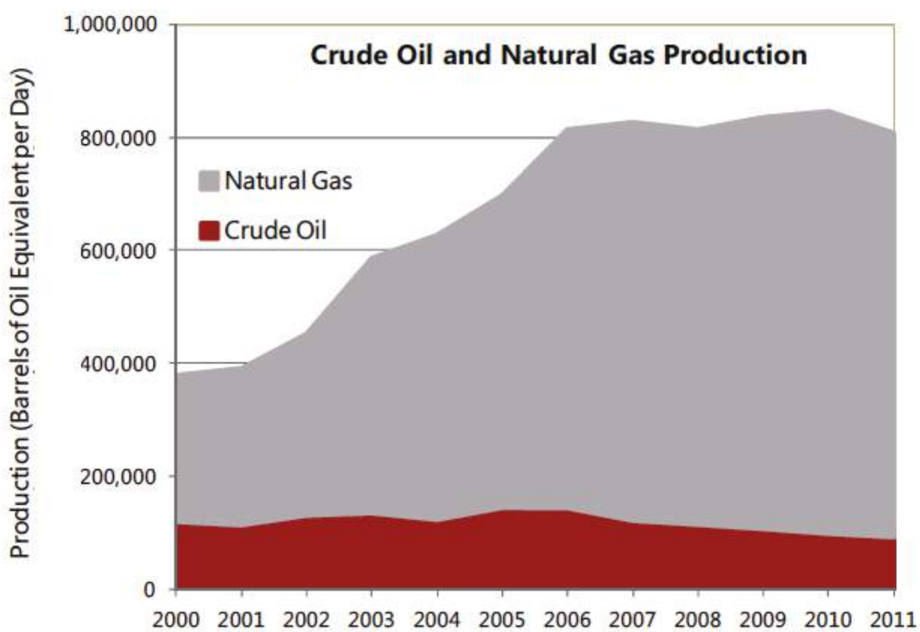
APPENDIX 9. NATURAL GAS IN TRINIDAD AND TOBAGO AND ITS RELEVANCE TO CYPRUS

Context

In the Caribbean Sea, just 17 km off the coast of Venezuela, sit two small islands that comprise the nation of Trinidad and Tobago. Trinidad and Tobago, with a combined landmass equivalent to just over *half* that of Cyprus, provides a useful example of a small island nation that has successfully developed an export-based monetization strategy for its offshore natural gas reserves. Indeed, the energy industry accounts for the vast majority of the country's exports, the majority of government revenue, and just less than half of the national economy (IMF, 2012). While natural gas was, originally, secondary to oil in Trinidad and Tobago's economy, the importance of natural gas has grown dramatically over the last two decades, with total production of gas now about eight times the magnitude of that of oil (Figure A9.1). Current proven natural gas reserves stand at 13 Tcf (with proven oil reserves of 730 million barrels), most of which is offshore (US EIA, 2013).

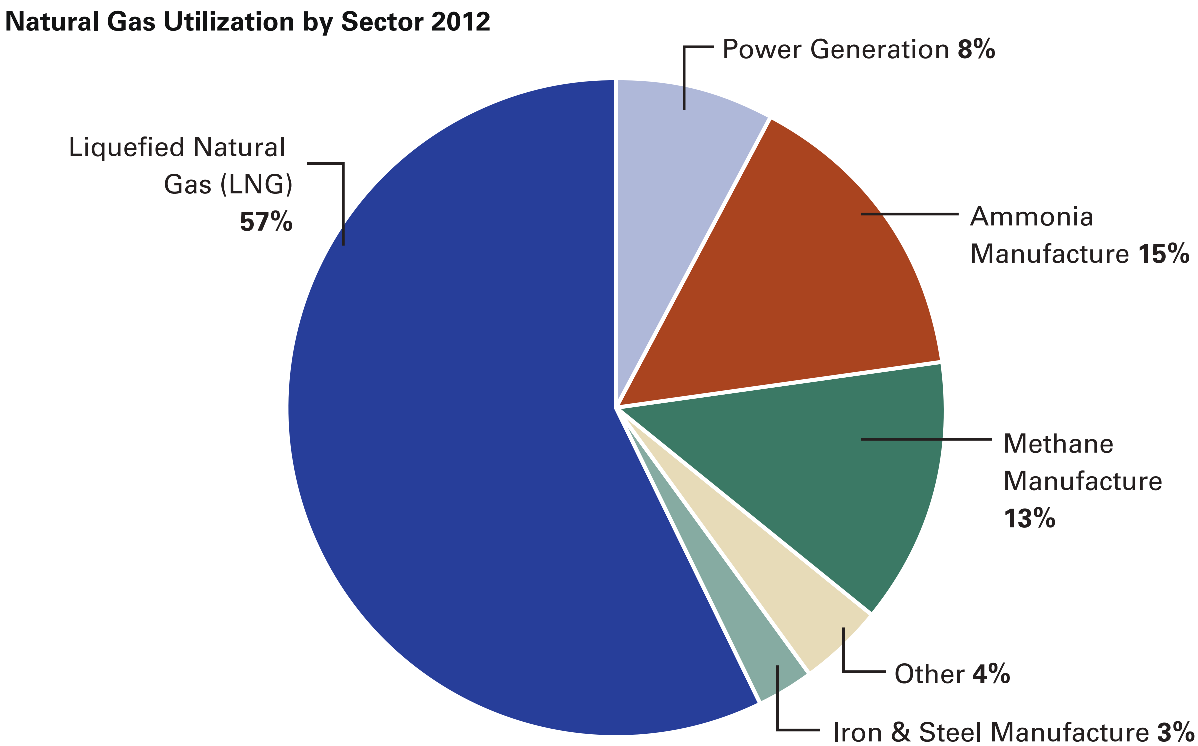
In monetizing its natural gas, Trinidad and Tobago has developed a diversified set of monetization options (Figure A9.2). The majority of the output is exported via its LNG industry (57%). The second and third biggest pathways are the manufacturing and exportation of ammonia (15%) and methanol (13%), collectively part of its growing "petrochemical" industry. The development of both these industries in Trinidad and Tobago will be explored.

Figure A9.1 – Oil and Gas Production in Trinidad and Tobago



Source: IMF, 2012.

Figure A9.2 – Gas Utilization in Trinidad and Tobago



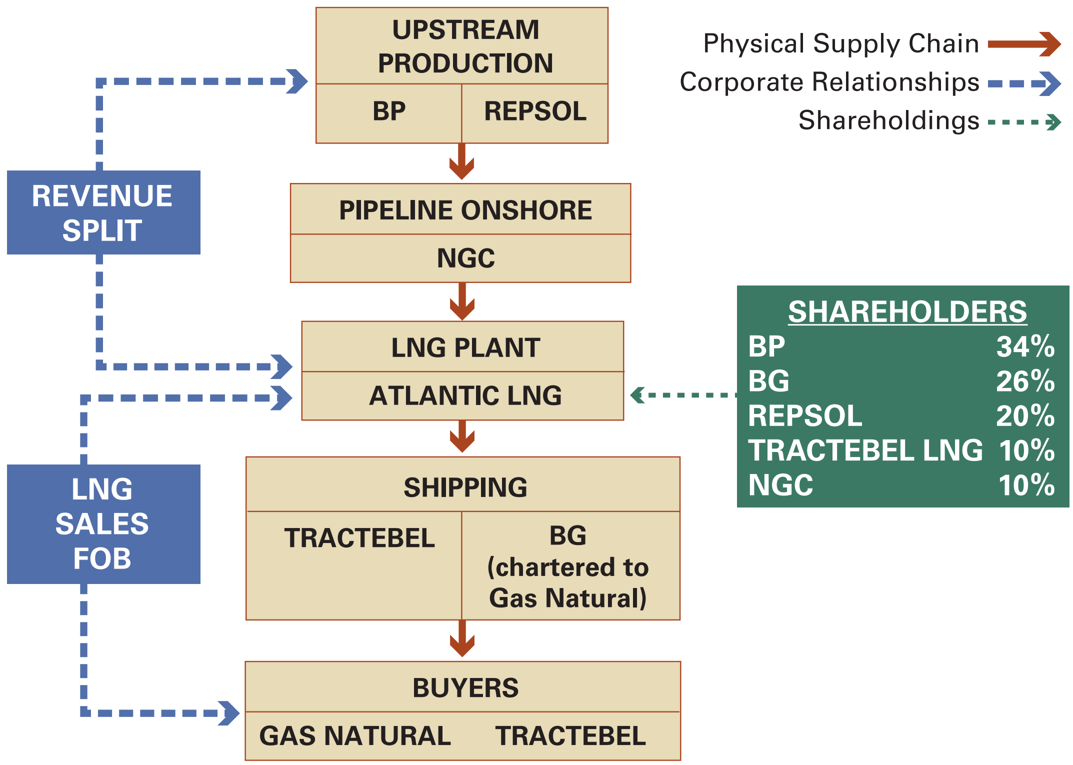
Source: IMF, 2012.

Trinidad and Tobago's LNG Industry

Trinidad and Tobago has a four-train LNG complex (with a total capacity of 15.2 Million tons Per Annum (MtPA)) located at Point Fortin in the southwest of the island of Trinidad. The development of this project was first initiated in 1992 when Cabot LNG, a small LNG importer and owner of the Everett LNG receiving terminal in Boston, approached the Trinidad and Tobago government about developing a one-train LNG facility. Cabot signed a memorandum of understanding (MOU) with the National Gas Company (NGC) of Trinidad and Tobago, along with Amoco and British Gas (both had significant gas prospects in the region), and a feasibility study was launched in 1993. In 1995, Atlantic LNG was formed as a joint venture company to run the project. Two 20-year FOB sales contracts were signed with Cabot and with Enagas of Spain in 1995 for a total of 3 Mt of LNG. The final investment decision was made in June 1996, and construction started that same year. In April 1999, the first cargo was shipped to Boston.

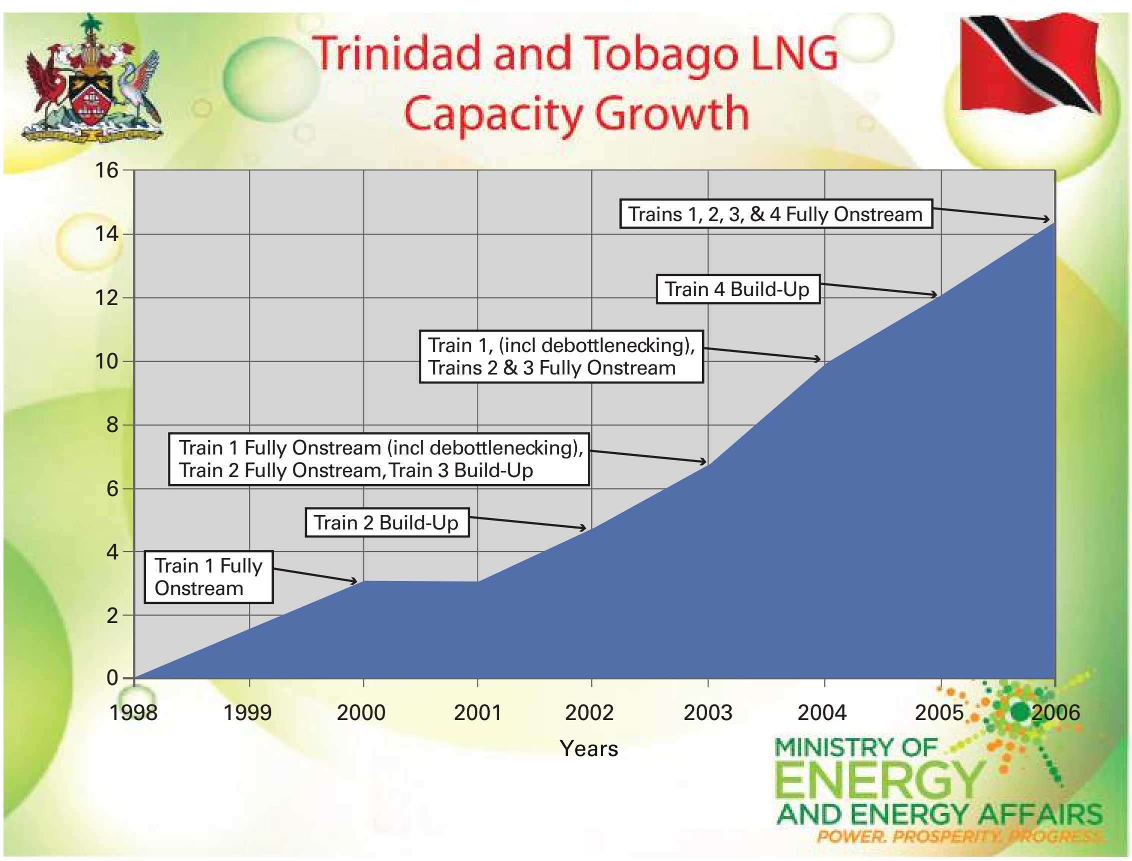
Train 1 ownership is divided between BP (formerly Amoco), BG, Spain's Repsol, Belgium's Tractebel (formerly Cabot), and Trinadad and Tobago's NGC (Figure A9.3). The reported cost of the plant was US$695 million, including an associated onshore pipeline and storage facilities. The project was supported by a US$600 million loan, $391.4 million of which was guaranteed by the United States' Export-Import Bank and $180 million by the World Bank's Overseas Private Investment Corporation. The remainder was financed directly by the shareholders. By 2006, three additional trains were brought online (Figure A9.4). This four-train development is one of the fastest in the history of the global LNG market.

Figure A9.3 – Train 1 Ownerships Structure



Source: Shepherd et al., 2004.

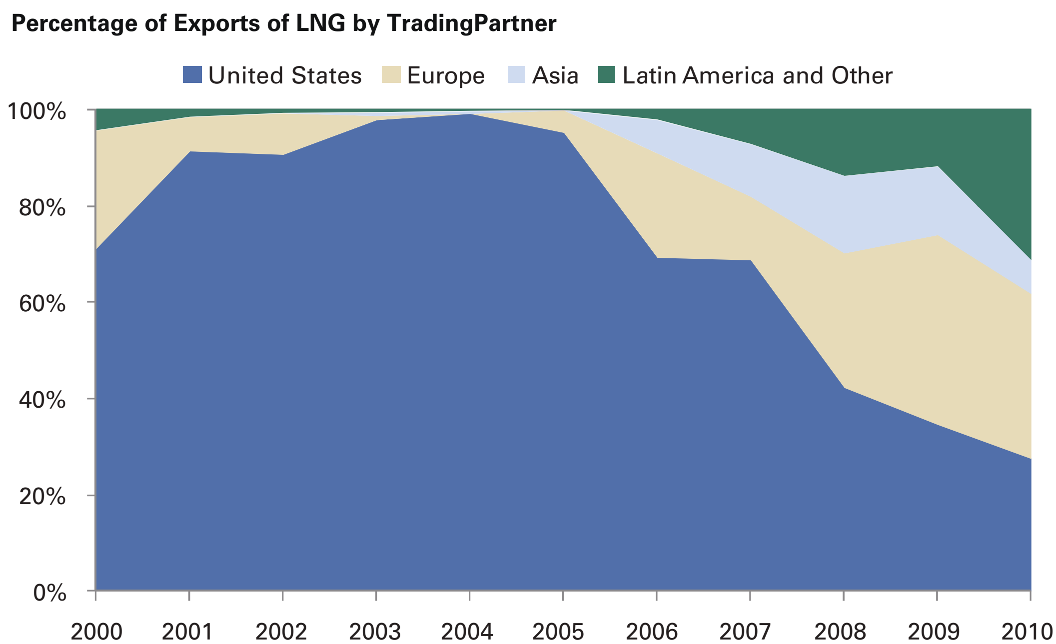
Figure A9.4 – Timeline of LNG Development in Trinidad and Tobago



Source: Ministry of Energy, 2010.

Significant flexibility built into the Atlantic LNG sales contracts allows for destination switching, which has enabled the country to adapt to a rapidly changing market, particularly to its largest — but it turns out most fickle — customer, the United States (see Figure A9.5). In the early 2000s when demand in that country grew unexpectedly, Atlantic LNG was able to re-route some of its gas destined for Spain to the United States. More recently, due to the precipitous downfall in demand from the United States following its domestic shale gas revolution, LNG shipments have yet again been re-routed, this time from the United States to a number of other customers, particularly in Latin America. In fact, in 2009, the United States consumed approximately 75% of Trinidad and Tobago's LNG exports; only three years later, that number had plunged to *less than 20%* (and may fall to zero eventually). And yet, the flexible contracts of Atlantic LNG enabled Trinidad and Tobago to be remarkably adaptive. Indeed, in the year 2011 — in the midst of this dramatic transition — Trinidad and Tobago still managed to achieved an extraordinarily high-capacity utilization rate of 91% (US EIA, 2013).

Figure A9.5 – Distribution of Trinidad and Tobago's LNG Exports to Trading Partners over Time

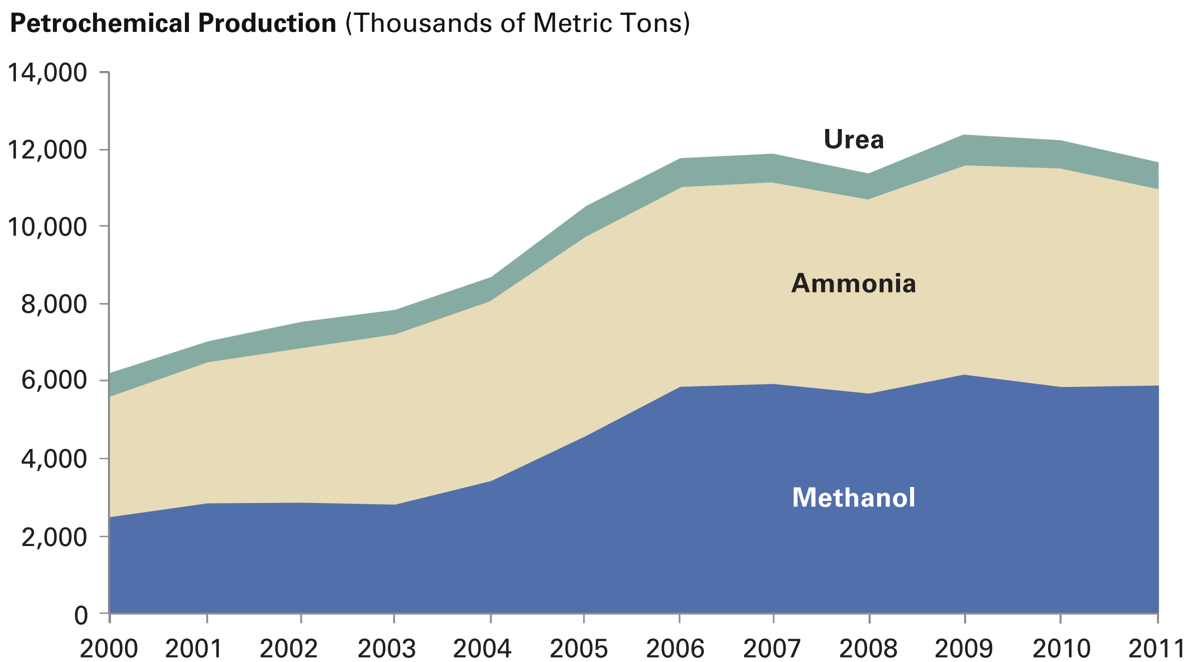


Source: IMF, 2012.

Trinidad and Tobago's GtC Industry

In the 1970s — when Trinidad and Tobago's primary business was still oil — the country benefited from the unprecedented increased in oil prices following the twin shocks of 1973 and 1979. With a sudden flood of new revenue, the government sought to invest in social and economic infrastructure in the country. One key opportunity was to invest in local industries that could make use of the associated natural gas that accompanied the oil and, in doing so, attempt to create more permanent jobs than were created by the oil industry. This was the impetus behind Point Lisas, a government-built industrial complex on the coast, 25 miles south of the capital Port of Spain. Five natural gas, export-oriented projects were developed, including ammonia, methanol, urea, and direct-reduced iron, amounting to a total of USD $1.1 billion (1985 dollars). Many more plants have been constructed since, with growth in natural gas-based petrochemical industries mirroring the growth in the country's natural gas production (Figure A9.6). The United States continues to be the principal customer for these industries, despite the shale gas revolution.

Figure A9.6 – GtC Production over Time in Trinidad and Tobago



Source: IMF, 2012.

Relevance to Cyprus

The development of the export-based natural gas industry in Trinidad and Tobago provides a useful case study for Cyprus. First and foremost, Trinidad and Tobago demonstrated the appeal of diversification in its development of multiple monetization pathways for its natural gas industry (i.e., LNG and a multi-faceted petrochemical industry). With regard to the LNG option in particular, Trinidad and Tobago illustrated how flexible FOB sales contracts help a gas-export-based country effectively manage risk in the face of a rapidly changing global gas market. In addition, the development of the LNG facility demonstrated that the staged approach — beginning with a single train and incrementally scaling up from there — can be quite effective. Finally, the effective implementation of a joint venture for the development of the LNG facility — which comprised the government, Cabot LNG (a small American company not unlike Noble Energy), and the relevant oil and gas majors — illustrates how a triangular relationship of this nature can function.

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APPENDIX 10. UNITS AND CONVERSION FACTORS

Natural Gas Conversions from: ↓ to: →	Billion Cubic Feet NG	Billion Cubic Metres NG	Million Tonnes LNG	Trillion British Thermal Units	Million Barrels Oil Equivalent
1 Billion Cubic Feed NG	1.0	0.028	0.021	1.1	0.19
1 Billion Cubic Metres NG	35.3	1.0	0.74	35.7	6.6
1 Million Tonnes LNG	48.0	1.36	1.0	48.6	8.97
1 Trillion British Thermal Units	0.99	0.028	0.021	1.0	0.18
1 Million Barrels Oil Equivalent	5.35	0.15	0.11	5.41	1.0
Units					
1 metric tonne = 2,204.62 lb. = 1.1023 short tons					
1 British thermal unit (Btu) = 0.252 kcal = 1.055 kJ					
1 kilowatt-hour (kWh) = 860 kcal = 3,600 kJ = 3,412 Btu					

Source: BP (2013). “Conversion Factors,” Statistical Review of World Energy 2013, August 2013 (http://www.bp.com/conversionfactors.jsp).

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Energy Initiative
Massachusetts Institute of Technology

Mailing address
77 Massachusetts Avenue, E19-307
Cambridge, MA 02139 USA

Visiting address
400 Main Street, E19-307 (3rd Floor)
Cambridge, MA 02142 USA

617.258.8891
web.mit.edu/mitei