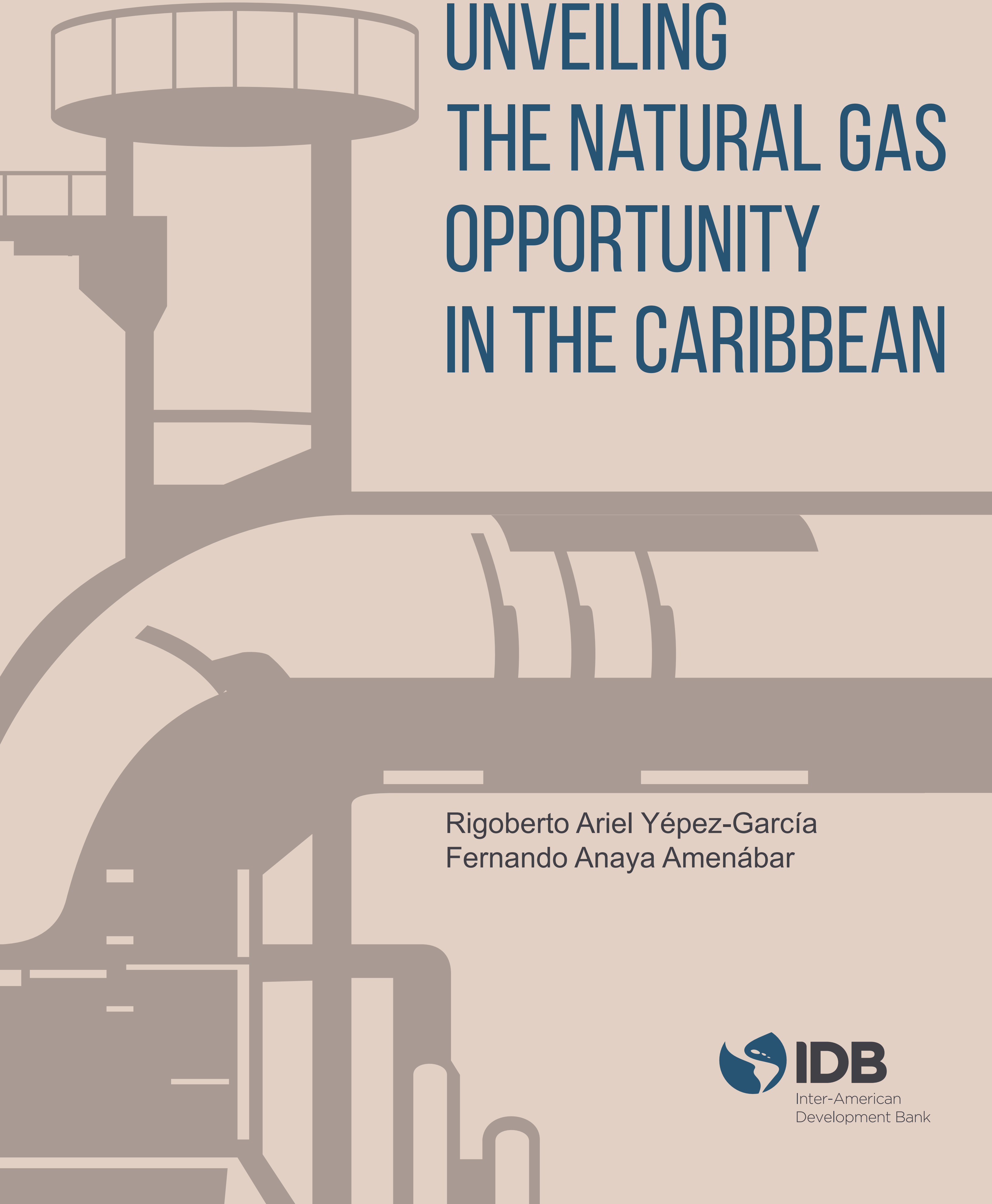
UNVEILING THE NATURAL GAS OPPORTUNITY IN THE CARIBBEAN



Rigoberto Ariel Yépez-García
Fernando Anaya Amenábar

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Rigoberto Ariel Yépez-García and Fernando Anaya Amenábar

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01 Introduction

Rigoberto Ariel Yépez-García
and Fernando Anaya Amenábar

The Caribbean countries that depend on heavy fuel oil as the main power generation source face high electricity prices. Countries heavily dependent on imported oil to power a significant portion of their electricity generation are especially vulnerable to volatile oil prices. In net oil-importing countries worldwide, high and volatile oil prices ripple through the power sector to numerous segments of the economy. As prices move up and down, so does the cost of electricity production, which has far-reaching effects on fiscal and trade balances, businesses, and household living standards1.

Natural gas can provide a feasible alternative to reduce fuel oil dependency in the Caribbean and alleviate pressures that increase electricity prices by introducing an additional energy source. Lower electricity prices may increase the competitiveness of each country. Energy consumption is part of the cost structure of all the exporting and importing sectors and their competitiveness, or lack of it, impacts on their average productivity. Additionally, competitiveness is not only the final price at which the products are offered but also includes the reliability in the supply. Therefore, including another reliable source of energy in the countries' energy mix like natural gas may reduce supply risks that could interrupt the domestic value chains of products and goods.

Nowadays natural gas plays an important role in global energy demand, and its importance is expected to increase in the future as continued technological innovation, environmental pressures, and economic growth support strong growth in natural gas demand for decades to come. Natural gas's share in global energy demand has risen considerably over the last two decades, namely driven by the growing use of this energy source in power generation and the economic and environmental benefits of natural gas compared to other fossil fuels.

Late changes in global natural gas markets are creating an opportunity to bring natural gas to the Caribbean countries. These include firstly an expected global oversupply of LNG

1 Mitigating Vulnerability to High and Volatile Oil Prices: Power Sector Experience in Latin America and the Caribbean. World Bank, 2012.

in the medium term, secondly the emergence of nearby markets in the US providing new sources of LNG exports, thirdly a competitive gas pricing regime in the US resulting in low gas prices, fourthly the increasing relevance of spot or short-term markets and fifthly technological advances bringing down the scale of cost-efficient transport, storage and regasification.

Entry and more supply competition may lead to natural gas price decreases and significant commercial gains from oil substitution. In addition, more competition and growing trade could contribute to increasing contract flexibility and easing credit conditions.

Further relevant areas in which to consider natural gas for energy diversification include transportation and distribution facilities. Small-scale LNG and floating regasification and storage ships or satellite LNG stations using container-sized storage units bring suitable transportation alternatives for small markets. LNG delivery innovations in small-scale shipping and floating regasification units make it possible to economically deliver natural gas to the Caribbean countries.

The Inter-American Development Bank (IADB) hired Castalia Strategic Advisors in 2015 to assess competitive commercial supply chains for natural gas in The Bahamas, Barbados, Belize, Dominican Republic, Guyana, Haiti, Jamaica, Suriname, and Trinidad and Tobago. The study evaluates the economic rationale of introducing natural gas into the Caribbean and the approach that could be followed for the initial development of a competitive gas market in the region. This includes analyses of natural gas demand, cost comparison for Liquid Natural Gas (LNG), Compressed Natural Gas (CNG) and pipelines, the possible competitive market alternatives for the successful development of natural gas import facilities in the region, an assessment of the risks faced by investors seeking to develop these types of projects in a small country context, and a brief analysis of the existing regulatory frameworks in the Caribbean for electricity and gas. This study was the main input to this report which is intended to highlight key aspects and assessments undertaken by Castalia.

The monograph is structured into the following sections:

- Part 2 presents the background of the selected countries.
- Part 3 gives a summary of global LNG supply and demand.
- Part 4 presents the estimated demand in the Caribbean region.
- Part 5 describes ad-doc facilities and services to transport, off-load, store and distribute natural gas in the Caribbean.
- Part 6 describes the options for introducing natural gas in the region and moves on to present the economic assessment of the cost of natural gas to each of the countries.
- Part 7 evaluates plausible LNG markets in the Caribbean, saving benefits and capital cost of necessary infrastructure for delivering natural gas
- Part 8 summarizes the challenges to developing infrastructure to deliver natural gas in the selected countries
- Part 9 analyses risks throughout the value chain, along with environmental and social risks
- Part 10 provides an overview of the key legal and regulatory requirements for developing LNG terminals in the region
- Part 11 gathers the main conclusions relating to the introduction of natural gas in the Caribbean countries

02 Background

Unveiling the natural gas opportunity in the Caribbean

1. COUNTRIES IN THE CARIBBEAN

The Caribbean countries have important differences in population, GDP, and energy consumption, among others. Understanding these differences is necessary for identifying market constraints and regulatory frameworks relevant for attracting investors and providing confidence in finance mechanisms for building the infrastructure to introduce natural gas in the Caribbean.

The selected countries for this assessment (The Bahamas, Barbados, Belize, Dominican Republic, Guyana, Haiti, Jamaica, Suriname and Trinidad and Tobago) have populations that range from about 286,000 (Barbados) to about 11 million (Haiti). Furthermore, the countries' current per capita GDPs vary from US$766 (Haiti) to US$30,762 (The Bahamas), while primary energy consumption ranges from about 393 ktoe (Haiti) to about 14,447 ktoe (Trinidad and Tobago)[2]. Table 1 gives an overview of key socio-economic, and energy indicators for the selected countries.

TABLE 1 - Economic and energy indicators in the Caribbean countries

Country	Population	GDP per Capita		Primary Energy Consumption (ktoe)	% of Energy Use from Fossil Fuels
		(current US$)	(constant 2010 US$)		
The Bahamas	395,361	30,762	26,538.95	2,071	..
Barbados	285,719	16,789	16,503.48	1,452	..
Belize	374,681	4,906	4,315.22	597	..
Dominican Republic	10,766,998	7,052	7,153.08	734	87
Guyana	777,859	4,725	3,871.39	669	..
Haiti	10,981,229	766	728.92	393	22
Jamaica	2,890,299	5,110	4,798.21	981	81
Suriname	563,402	5,901	8,043.46	1,259	76
Trinidad and Tobago	1,369,125	16,145	15,350.85	14,447	100

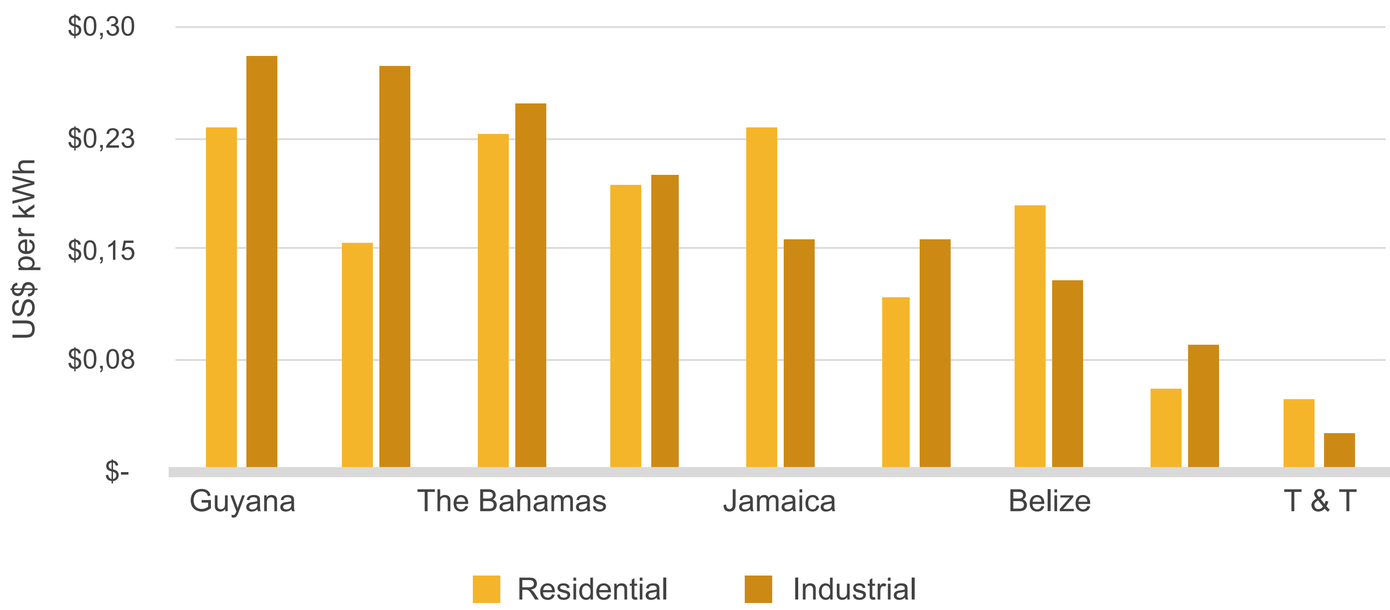
Source: Author's elaboration based on United Nations Population Division, World Bank national accounts data and IEA Statistics.
Note: 2017 data or latest available

2 IEA Statistics, 2017

2. ELECTRICITY SECTOR IN THE CARIBBEAN

Most power generation in the Caribbean relies on oil products. In the selected countries that are net fossil fuel importers, 74 percent of energy demand is met by oil products and this is also seen in power generation, which mostly relies on fuel oil and diesel. Large electricity price differences (three or four times higher) are noticed when comparing net energy importers, such as Dominica, with countries like Trinidad and Tobago. Figure 1 shows average electricity prices in the Caribbean.

FIGURE 1 - Average Electricity Tariffs in the Caribbean (2017).



Source: IDB Energy Division and IDB Group Climatescope

The countries analyzed show three main market models for delivering electricity. First, state-owned utilities vertically integrated (as Bahamas, Guyana, Haiti, and Trinidad and Tobago). Second, privately-owned utilities also vertically integrated such as Barbados, and Jamaica. And third, unbundled electricity markets like the Dominican Republic, with state-owned distribution companies that buy power from Independent Power Producers (IPPs). Table 2 summarizes key attributes of the electricity market structures in these countries' jurisdictions.

TABLE 2 - Market Structure and Government Ownership of Utilities

Country	Jurisdiction	Government Ownership (%)	Role	IPP participation
The Bahamas	All, except Grand Bahama	100%	Generation, transmission and distribution	No
Barbados	All (only license, but no monopoly)	6.3%	Generation, transmission and distribution	No
Belize	All	97.1%	Generation, transmission and distribution	Yes
Dominican Republic	North, South and Eastern Dominican Republic	100%	Distribution	Yes
Dominican Republic	All	100%	Transmission	No
Guyana	All	100%	Generation, transmission and distribution	Yes
Haiti	All (monopoly)	100%	Generation, transmission and distribution	Yes
Jamaica	All	19.9%	Generation, transmission and distribution	Yes
Suriname	All (except 2 mines and rural areas)	100%	Generation, transmission and distribution	Yes
Trinidad and Tobago	All (not exclusive)	100%	Generation, transmission and distribution	Yes

Source: Castalia, 2015

Planning and investment in generation depends on the market structures. Most of the selected countries have state-owned and vertically integrated electricity utilities. In these cases, the utility makes generation asset planning and financing decisions. In some cases, the utility or the government finance and operate new generation assets directly, while in

other cases, the government or the utility issue tenders to buy electricity from an IPP.
Planning and financing differ across Caribbean countries. Particularly market size and degree of competition might influence investment decisions, and pricing dynamics. These disparities must be considered when developing options for a regional energy market.

3. REGULATORY AND LEGAL FRAMEWORK IN THE CARIBBEAN

The selected countries have primary laws and regulations in the power sector that either establish the state-owned utilities or provide licenses. In some cases, the law provides for a single license for electricity generation, transmission, and distribution. This license is often granted to a vertically integrated utility, such as in Barbados. In other cases, the license is granted to a state-owned utility, such as in Guyana and Haiti. In a few countries, such as Jamaica and the Dominican Republic, separate licenses are granted for generation, transmission, and distribution.

In most of the selected countries the regulatory entities have the responsibility over setting tariffs[3], granting licenses, and setting and enforcing service standards. The credibility of regulators in some of the selected countries is low due to lack of accordance with guidelines established by law. There are cases where regulators have set tariffs below the cost of service, which has endangered the financial viability of the utility. In some countries political pressure has led to tariff levels that are well below the cost of providing service. Nevertheless, exceptions such as the OUR in Jamaica, and the FTC in Barbados, are both multi-sector regulators with well-developed processes for tariff setting.

Regulatory weaknesses defining the assets under regulation reduce the incentive to invest in least-cost electricity generation technologies. Many regulatory frameworks guarantee the utility a return on their investment in generation assets, therefore there are no incentives to reduce costs and pricing.

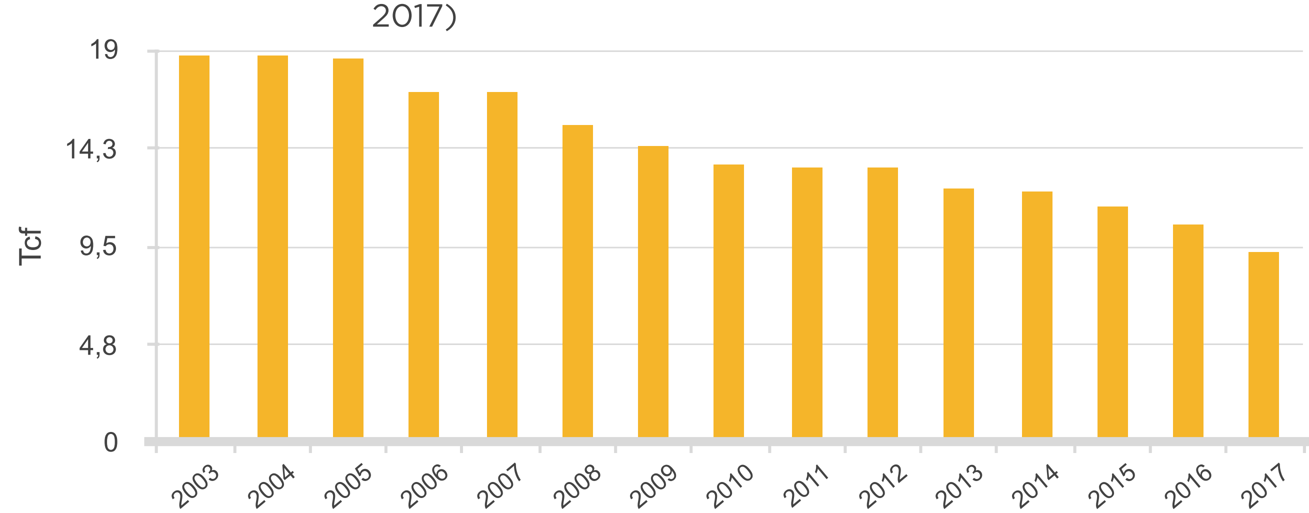
3 In Haiti, rather than an independent regulator, the tariff policy is set by the Ministry of Public Works, Transport and Communication.

4. COUNTRIES IN THE CARIBBEAN WITH NATURAL GAS RESERVES

Trinidad and Tobago and Barbados are the only countries in the Caribbean with natural gas reserves. Trinidad and Tobago is the fourth largest natural gas producer in the western basin. It has exported LNG since 1999, primarily suppling the United States and Europe[4]. On the other hand, the natural gas reserves in Barbados are very low when compared to the existing reserves (only 0.03%) in Trinidad and Tobago.

Trinidad and Tobago's proven natural gas reserves have remained stable over the past few years. Besides, this country has experience exporting LNG to the Caribbean region[5]. Figure 2 shows the evolution of Trinidad and Tobago's proven natural gas reserves over the past decade.

FIGURE 2 - Proven Reserves of Trinidad and Tobago (2003-2017)



Source: Castalia and BP Statistical Review of World Energy, 2004 - 2018.

4 Kevin Ramnarine, "The State of the Natural Gas Sector – 2013," 31 July 2013.
5 AES signed a 20 year long term contract with BPGM for the supply of LNG from Trinidad and Tobago.

5. BENEFITS OF USING NATURAL GAS IN THE CARIBBEAN ENERGY SECTOR

Replacing oil products with natural gas in the Caribbean might reduce energy prices in the region. In the last decade U.S. natural gas prices remained below heavy fuel oil (HFO) prices, and projections suggest the difference will remain for the next two decades. In 2013, industrial consumers in the East South-Central United States paid 75 percent less for natural gas than they did for HFO and 82 percent less for natural gas than they did for distillate fuel oil. The U.S. Energy Information Administration projects that natural gas prices will remain more than 50 percent less than HFO prices for this market through 2020[6].

Natural gas is also cleaner energy source. On average, natural gas emits lower SO2, NOx and carbon dioxide than either fuel oil or diesel.

The combination of the low price of natural gas and its environmental benefits could transform the regional energy sector. While natural gas is not yet widely used in the Caribbean, the price difference between HFO and diesel and natural gas creates an opportunity for fossil fuel offtakers to substitute oil products for natural gas to reduce their fuel costs. The resulting savings could be passed along to consumers. Furthermore, using natural gas for electricity generation might reduce regional emissions of carbon dioxide and local pollutants.

6 Castalia, 2015.

6. OPTIONS FOR DELIVERING NATURAL GAS TO THE CARIBBEAN

LNG, pipelines and CNG are plausible market technologies for delivering natural gas in the Caribbean. CNG is an already proved technology and there are economic and environmental reasons to develop this market in the different countries. CNG technology is a cost-effective solution to supply gas to areas which are not reached by the grid and do not reach the minimum required volume to invest in a traditional infrastructure. In general, on shore CNG can be economically viable for volumes up to around 5 MMscf/d and distances up to around 500 miles (800 km). Marine CNG is not yet commercially proven but could be economically viable for large volumes and distances up to around 2000 nautical miles. Regarding the environmental aspect, CNG technology is an alternative to reduce CO2 emissions from transport and small power plants (The World Bank Group).

However, LNG is the most likely alternative for introducing natural gas in the region. The LNG market is mature and uses proven technology. This alternative is more flexible than either CNG or pipelines and is likely the most competitive option for the selected countries. When compared with CNG, technological development of suitably worldwide scaled LNG is far more widespread and is developing more rapidly (particularly in shipping). Using CNG could pose technology risk as the project would be one of the first commercially deployed in the world. In addition, a CNG supply chain would require dedicated ships built specifically for serving small clients in the Caribbean. This implies less flexibility in adding or redirecting individual cargoes or in negotiating shipping rates and supply costs.

When compared with pipelines, LNG imports can provide greater protection against counter-party risk because it can be shipped from multiple suppliers. Pipelines connect a limited number of supply and demand points, and so have much less flexibility. In addition, pipelines that connect multiple markets rely on the ongoing cooperation of each

participant to ensure natural gas supplies continue to flow. LNG is a well-established technology that has been used on a global scale for decades, and so is best able to take advantage of this flexibility.

03 Global supply demand balance: implications for the Caribbean

Globally, natural gas consumption reached 118 trillion cubic feet (Tcf) in 2013. This accounted for 24 percent of total primary energy consumption, placing natural gas among the top three energy sources supplying the world's energy needs.

1. SUPPLY

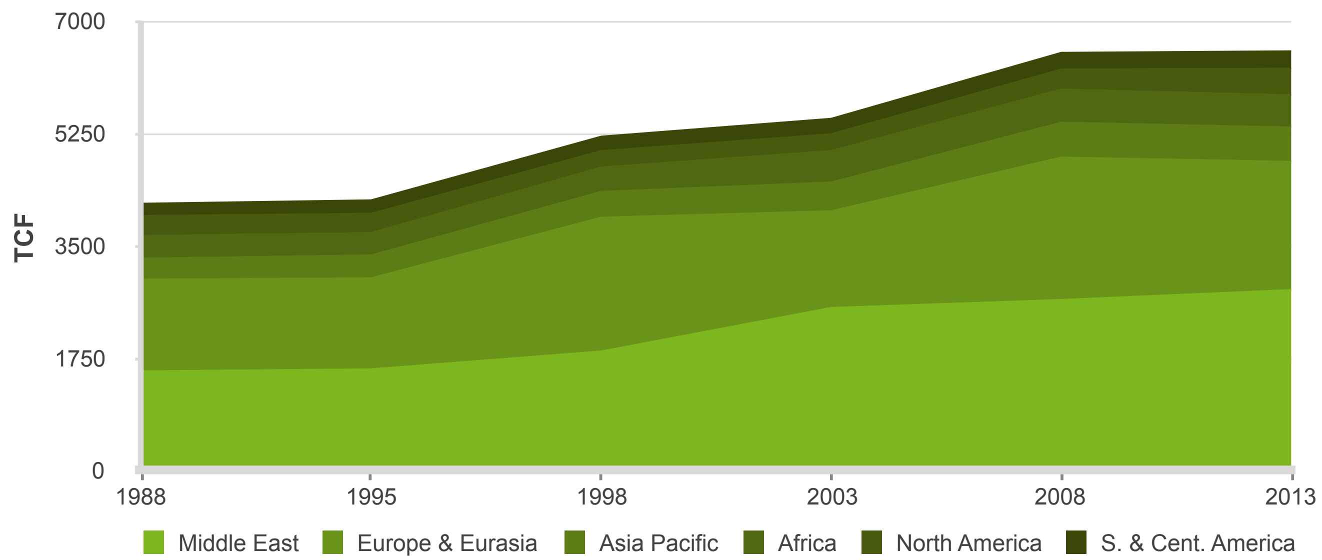
Large natural gas reserves will enable continuous growth of natural gas production in the coming years. In 2013, global natural gas production reached nearly 120 Tcf. The vast majority of natural gas production (86 percent in 2010)7 comes from conventional resources, including gas associated with oil production and non-associated gas that is produced alone. Unconventional resources, such as shale gas or similar are a much smaller share of global production but represent the fastest growing resource8.

The main natural gas producers are United States and Russia, accounting for 38 percent of total global production with 24.2 Tcf and 21.3 Tcf respectively. Other producers are much smaller, with Iran producing 5.9 Tcf per year and Qatar and Canada each producing 5.5 Tcf[9].

At the end of 2013, proven natural gas reserves economically produced at 2015 prices were just over 6,550 Tcf. The Middle East is home to 43 percent of the total (primarily Iran with 1,193 Tcf and Qatar with 871 Tcf), and a further 30.5 percent is in Europe and Eurasia (primarily Russia 1,103 Tcf and Turkmenistan 617 Tcf). Global proven natural gas reserves have more than doubled in the past 30 years, despite cumulative natural gas production of 2,340 Tcf in that period (see Figure 3).

7 BP, Statistical Review of World Energy, 2013.
8 Shale gas has undergone a boom in production growth, especially in the United States. In 2002, shale gas represented just 2.4 percent of U.S. natural gas production, and a decade later accounted for 39 percent.
9 Castalia, 2015.

FIGURE 3 - Evolution of Global Proven Natural Gas Reserves



Source: Castalia 2015 based on BP Statistical Review of World Energy, 2014.

Shale gas has the potential to remake global supply as many other countries also have significant shale resources. Although, the pace and ultimate volume of natural gas that can be economically produced remains highly uncertain. As new information becomes available, initial estimates can change dramatically.

Shale gas has transformed the United States from an LNG importer to a potentially massive LNG exporter. Therefore, this country is the most likely supplier to the Caribbean region among the emerging suppliers in the LNG market.

2. DEMAND

Natural gas demand comes mainly from the industry; residential and commercial sector; electricity generation; and transport sector. Worldwide, the industrial sector is the largest natural gas consumer, accounting for two- fifths of the global total in 2010[10].Power generation consumed a further one-third, with space heating (residential and commercial) accounting for one-quarter. The transport sector, including vehicles and more recent marine uses, was just 3 percent of global demand.

In 2012, the United States gathered the largest natural gas demand, consuming 25.5 Tcf, or roughly 70 Bcf per day on average. Russia was the second largest consumer, but far smaller at 14.7 Tcf, despite its relatively similar levels of production. Russia exports much of its natural gas while the United States imports significant volumes from Canada. The world's next three largest gas consumer include Iran (5.5 Tcf or 15 Bcf per day), China (5.1 Tcf or 14 Bcf per day), and Japan (4.1 Tcf or 11 Bcf per day). Although North America and Europe/Eurasia remain the largest gas consuming regions, Asia Pacific and the Middle East are growing rapidly.

10 It is projected that the transportation and industrial sectors will account for as much as 92 percent of global liquid fuel demands in 2040. US EIA, "International Energy Outlook," (2014).

3. TRADE

For much of the industry's history, global LNG markets were split into two major regional markets: Asia-Pacific, and the Atlantic basin, which focused on supplying Europe and, to a lesser extent, the United States. These regional markets have become less distinct over the past decade as a surge of new capacity—including liquefaction, shipping, and regasification—have greatly expanded the volume of globally traded LNG.

- LNG MARKET IN ASIA-PACIFIC

  Asia-Pacific is the largest LNG market, accounting for 75 percent of global demand in 2014[11]. The Asia-Pacific market is centered on supplying LNG to Japan, Korea, and Taiwan, primarily from suppliers in South-East Asia and, to a lesser extent, the Middle East, Australia and the United States (via Alaska).

  The lack of domestic natural gas supply led to LNG pricing linked to an oil-index. This allowed importing countries to remove the risk that natural gas prices could become more expensive than their alternative fuel, namely diesel and fuel oil. The most frequently used index is the Japan customs-cleared crude price (JCC, also known as the Japan crude cocktail), which is an average of imported crude oil prices in Japan. The JCC is used to index LNG imports not only in Japan but also for contracts in Korea and Taiwan[12].

  The Asia-Pacific region has also tended to have higher LNG prices than the Atlantic Basin. This is in part due to the greater shipping distances involved but is also influenced by the import-dependent countries prioritizing security of supply over cost competitiveness. This trend has been exacerbated in recent years as persistently high oil prices have driven Asian LNG prices to multiples of prices at competitive hubs in the United States and UK.

11 Castalia, 2015 based on "The LNG Industry," GIIGNL, 2014.
12 Andrew Inkpen & Michael Moffett, The Global Oil & Gas Industry: Management, Strategy & Finance, Chapter 9.

- LNG MARKET IN THE ATLANTIC BASIN

  The Atlantic Basin encompasses all countries that border the Atlantic Ocean or Mediterranean Sea. In 2012, roughly 20 million tons of LNG was exported from the Atlantic Basin to the Pacific region, representing almost 10 percent of total global trade[13].

  Unlike the main demand centers in the Asia-Pacific, natural gas consumers in the Atlantic Basin already had alternative supply options—the United States, UK, and Norway all had substantial volumes of domestic natural gas production, and continental Europe and the United States also imported natural gas via pipeline (from Canada to the United States and from the Soviet Union to continental Europe).

  Traditionally, natural gas prices in the Atlantic Basin have been linked to oil prices to secure long-term natural gas contracts. However, an extended period of high oil prices and the availability of low-priced gas in the United States are shifting the region's historical emphasis on energy security to one that encourages greater competition and price flexibility. Since 2000, growing market flexibility and the development of trading hubs in the Atlantic basin has favored portfolio trading strategies that aim to exploit arbitrage opportunities in higher value markets. Portfolio players, who have increased their presence in recent years, operate a portfolio of LNG contracts and have the ability to optimize between their LNG sourcing and their LNG delivery commitments. They may secure LNG in excess of their delivery commitments and have additional volumes to trade exploiting arbitrage opportunities.

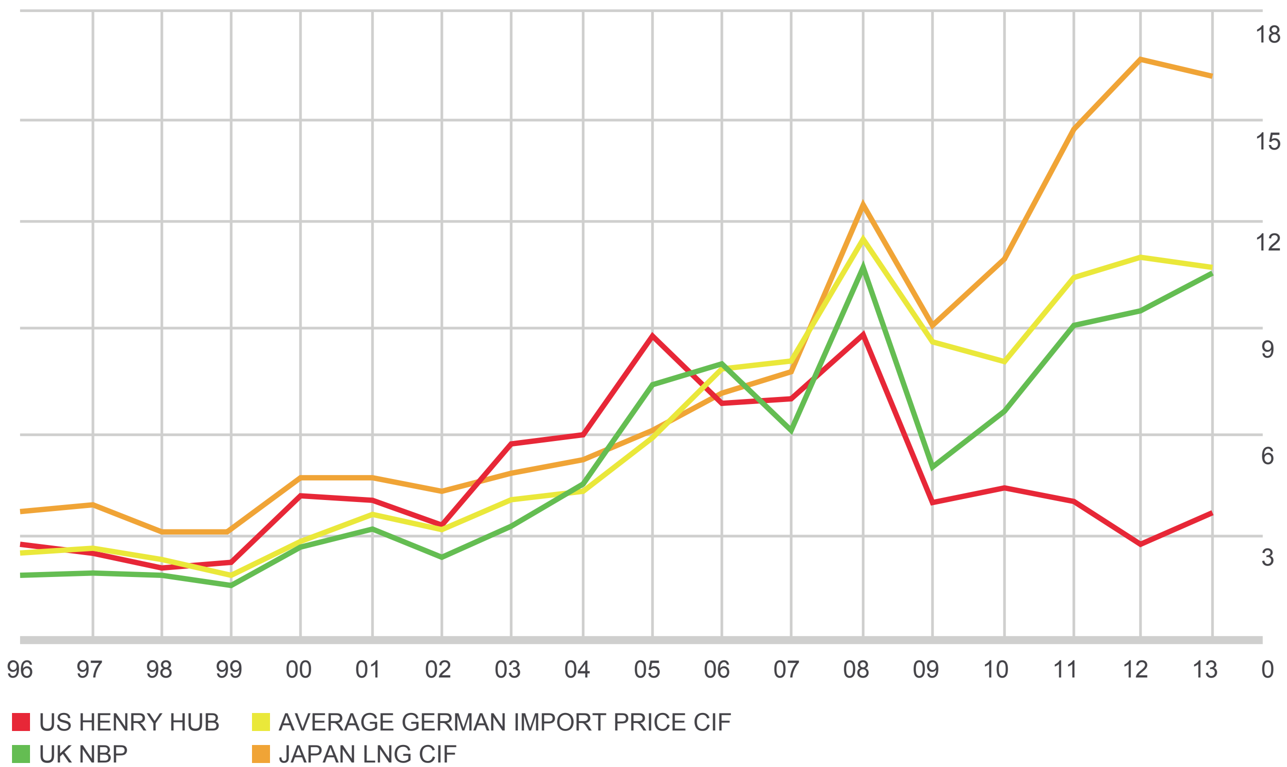
Natural gas markets remain relatively isolated due to the high transport costs. In 2013, only 36.6 Tcf of natural gas was traded across borders, representing 30 percent of total global demand. Just over two-thirds of this total was transported via pipelines, with over half of that volume coming from just two major pipeline systems: The North American system connecting the United States, Canada and Mexico (4.35 Tcf); and, the Europe/Eurasian system connecting Europe with Russia and the countries of the former Soviet Union (8.44

13 "The LNG Industry," GIIGNL, 2014.

Tcf).
The remainder of global gas trade was in the form of liquefied natural gas (LNG). Major LNG exporters include Qatar, Australia, Nigeria, Algeria, and Trinidad and Tobago. Qatar alone accounts for roughly one-third of global LNG exports, sending more than 3.7 Tcf to markets in Asia and Europe. Trinidad and Tobago, although among the top five LNG exporters in 2012, only shipped the equivalent of 675 Bcf of LNG.

The relative geographic isolation of regional natural gas markets has allowed a wide range of natural gas market structures and pricing systems to evolve and co-exist. Industry structures range from the single provider model to highly competitive markets of multiple suppliers and consumers. In recent years, regional LNG prices - supported by differences in regional demand and supply dynamics - have tended to diverge (see Figure 4).

FIGURE 4 - Natural Gas Wholesale Prices 1996-2013 ($/MMbtu).



Source: Castalia 2015 based on BP Statistical Review of World Energy, 2014

During 2009 and 2013, the United States had the lowest prices of natural gas market, with wholesale prices at the Henry Hub averaging between $3 per MMBtu and $6 per MMBtu. Henry Hub prices fell as low as an annual average of $2.78 per MMBtu in 2012 before rebounding to $4.36 in 2014[14]. On the other hand, in 2015 the world's highest natural gas prices were found in Asia, especially Japan, where prices linked to imported oil prices picked to nearly $17 per MMBtu on the back of global oil prices that remained near $100 per barrel.

The gaps among regional natural gas prices respond to differences in market size and structure, and regulations in the trading countries. United States and Japan concentrate the most important natural gas markets.

14 EIA, "Henry Hub Natural Gas Spot Price," Accessed 21 April 2015, http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

4. NATURAL GAS OUTLOOK

Natural gas is expected to continue to play an important role in future global energy demand as continued technological innovation, environmental pressures, and economic growth support strong growth in natural gas demand for decades to come. The EIA's Base Case projection in the 2013 International Energy Outlook forecasts natural gas consumption to increase to over 130 Tcf per year by 2020 (8% increase compared to 2013) and to 185 Tcf per year by 2040 (54% increase compared to 2013).

Natural gas trade and competition are also expected to grow rapidly as new pipelines and LNG facilities are built to link supply regions with demand. In addition to expanding total trade, patterns of global trade are expected to shift, largely in response to growing natural gas production in the Americas.

Increasing levels of portfolio trading represents an opportunity for Caribbean countries, as annual flexible volumes with low levels of take or pay are more adapted to their LNG needs. Nevertheless, competing in this market also poses challenges for the region, as in the spot or short-term market volumes are sold to the highest bidder and Caribbean countries would have to compete with buyers in more established and larger markets.

5. EXISTING NATURAL GAS TRADERS IN THE CARIBBEAN

Trinidad and Tobago is the only country in the Caribbean that exports natural gas as LNG. On the other hand, Barbados has small, proven natural gas reserves, although neither imports nor exports natural gas.

Since 2000, there have been two significant changes to Trinidad and Tobago's LNG exports. First, LNG exports have increased dramatically, from 124 Bcf in 2000 to 699 Bcf in 2013. Second, Trinidad and Tobago has increased the number of countries to which it sells LNG. In 2000, Trinidad and Tobago's exports were dominated by the United States. Almost 77 percent of Trinidad and Tobago's LNG exports were sent to this country, and the remainder LNG was sent to Spain. In contrast, in 2013, Trinidad and Tobago sold LNG to 17 countries. The countries that received the largest volume of exports were Argentina (18 percent), Chile (18 percent), Brazil (13 percent), Spain (10 percent) and the United States (10 percent)[15].

In 2015, the Dominican Republic and Puerto Rico were the only jurisdictions in the Caribbean that import natural gas—both import natural gas only as LNG. Haiti then imports LNG from the Dominican Republic by truck. The only regasification terminal in the Dominican Republic was opened in 2001[16]. In 2013, the Dominican Republic imported 1 million metric tons from Trinidad and Tobago. More recently, in 2017, Jamaica and Barbados also imported natural gas, gathering respectively LNG demands of 7,015,000 MMBTU and 250,000 MMBTU.

15 Castalia, 2015
16 Ibid

6. IMPLICATIONS OF GLOBAL TRENDS FOR THE CARIBBEAN

Changes in the global natural gas markets are creating an opportunity to bring natural gas to the Caribbean region. These include firstly an expected global oversupply of LNG in the medium term, secondly the emergence of nearby market in the US for new sources of LNG exports, thirdly a competitive gas pricing regime in the US resulting in low gas prices, fourthly the increasing relevance of spot or short-term markets and fifthly technological advances bringing down the scale of cost-efficient transport, storage and regasification. These market fluctuations and their impact in the Caribbean natural gas supply chain are described below.

I. VOLATILITY OF SUPPLY

Future natural gas prices will be driven by the success of shale gas developments in the U.S. Given the price flexibility of the U.S. market, LNG investments can become stranded quickly when alternative sources of natural gas or cheaper alternative fuels become available. As a result, price volatility in natural gas markets in the U.S. will be accompanied by LNG supply volatility.

Even for Caribbean countries with experience as small energy importing countries it may be difficult to manage this risk for natural gas imports than for oil imports. This is because of the much smaller number of potential supply sources and relative difficulty of securing spot cargoes. Flexibility on the consuming side can help moderate price volatility.

II. COMPETITION AND PRICE FLEXIBILITY

The availability of low-priced gas in the United States encourages greater competition and price flexibility. Growing supply competition creates opportunities for the Caribbean region, as may indicate natural gas price decreases and significant commercial gains from oil substitution. In addition, growing trade could contribute to increasing

contract flexibility and easing credit conditions. Nevertheless, Caribbean countries may have difficulty securing Henry Hub-linked prices, since they are small individual markets, many of which do not have LNG import facilities and have weak investment grade credit ratings.

III. TECHNOLOGY INNOVATIONS

The expected supply surge from shale gas, and pressure from the demand side for more environmentally friendly energy sources, is driving innovation across the natural gas value chain. Key relevant areas include transportation (such as small-scale LNG and sea-borne CNG), regasification and storage (such as floating regasification and storage ships, or satellite LNG stations using container-sized storage units), and LNG uses (such as directly using LNG in fleet vehicles and ships).

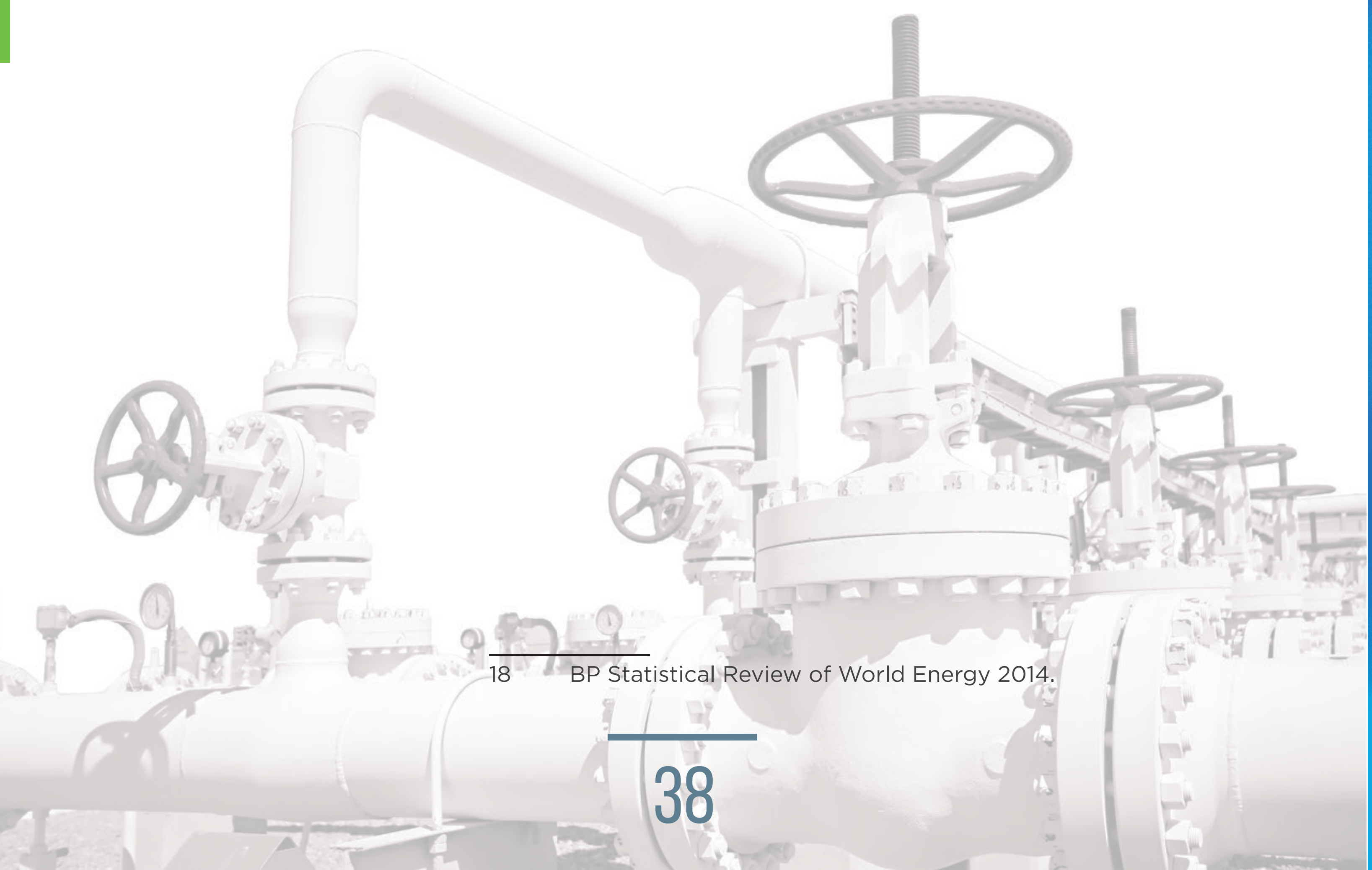
LNG delivery innovations in small-scale shipping and floating regasification units make it possible to deliver economically natural gas to the Caribbean countries. Further cost reductions are expected as research and development mature smaller scale technologies currently under development.

In general, market changes between 2009 and 2013 point to natural gas being available at competitive prices in the Caribbean[17]. Many other competing importing countries can also offer far larger markets for gas exporters. Natural gas projects, especially LNG projects, benefit from economies of scale, suggesting the potential for greater returns from larger markets than from smaller ones— some developers may charge a premium for the intermittent, spot cargoes that may be all that smaller Caribbean markets require. Larger markets such as Japan also have more flexibility in diversifying their sources of natural gas imports, providing greater security of supply and reducing their dependence on any one project. In 2012 this country received LNG from 18

17 Section 7 evaluates three market scenarios to introduce natural gas at competitive prices. A distribution hub formed by a private company or group of companies in a country gathers larger benefits. This alternative might enable the region to agree natural gas contracts at US$7.1 per MMBtu in 2023 which implies a premium over Henry Hub, at US$5 of 43 percent.

suppliers located in different countries[18].

Finally, investment across the many stages in the natural gas value chain—from upstream supply through liquefaction, shipping, and regasification—is often mistimed, creating shifting bottlenecks and rapidly changing costs as different parts of the chain face shortages or oversupply. As a small participant in a very large global market, Caribbean countries will have little ability to influence these trends.



18 BP Statistical Review of World Energy 2014.

04 Demand for gas in the Caribbean

1. USES OF FOSSIL FUELS IN THE CARIBBEAN

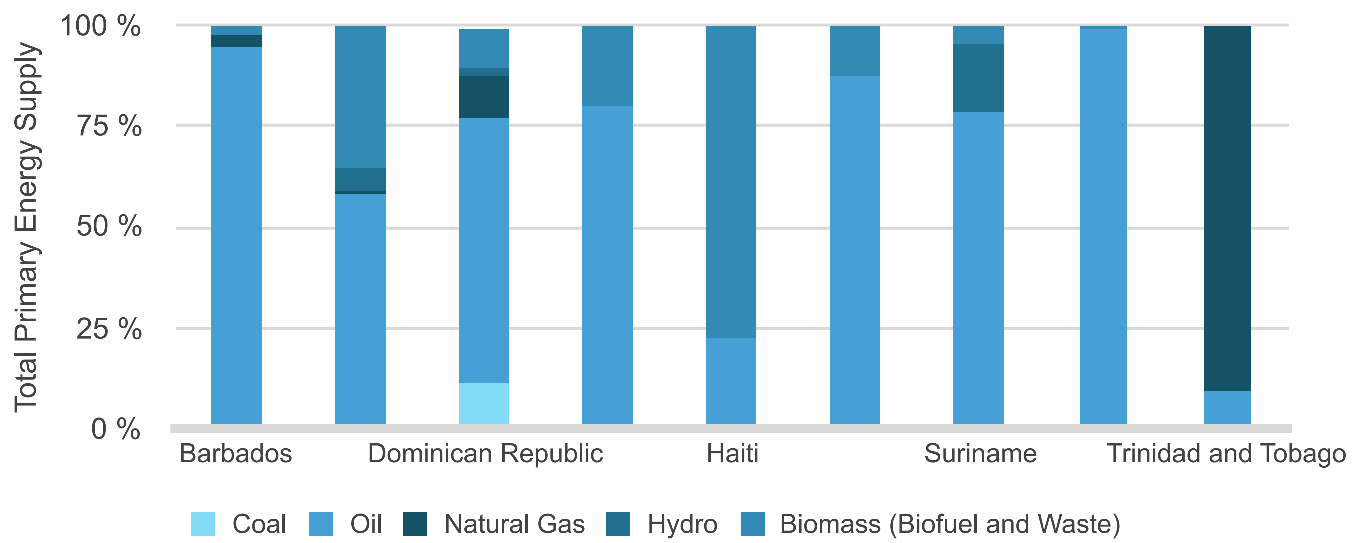
The countries under analysis are The Bahamas, Barbados, Belize, Dominican Republic, Guyana, Haiti, Jamaica, Suriname and Trinidad and Tobago. Total primary energy supply (TPES) for the nine selected countries is 37,703 ktoe. Fossil fuels—oil, natural gas, and coal—account for 89 percent of TPES in these countries (see Figure 5). Natural gas accounts for 53 percent of all energy use in the countries, nevertheless Trinidad and Tobago alone accounts for 96 percent of this use. Oil products account for 34 percent of TPES, followed by biomass as the third most important energy source, and the most important renewable resource, at 11 percent of TPES[19].

For the countries importing fossil fuels[20], oil is by far the most important energy source, making up 67 percent of TPES. Biomass is the second most important energy source, at 23 percent of TPES. Natural gas accounts for only 5 percent of TPES, and coal 4 percent—the Dominican Republic accounts for nearly all use of both sources.

Most countries that depend on energy imports have no indigenous fossil fuel resources, and must therefore import all oil, natural gas, and coal that they use. The price of fuel imports is a major burden for many of these countries. For example, in Jamaica and Barbados, imports of oil products account 12 percent or more of gross national income.

19 Castalia, 2015.
20 Except Trinidad and Tobago.

FIGURE 5 - Primary Energy Sources per Country



Source: IEA data (Suriname, Jamaica, Haiti, Dominican Republic and Trinidad and Tobago), UN Statistics (The Bahamas, Barbados, Belize and Guyana).

On average, electricity generation accounts for 44 percent of fossil fuel use in these fossil fuels importers (see Table 3). The transport (29 percent) and industrial (5 percent) sector are the next largest users of oil products.

TABLE 3 - Average Fossil Fuel Use in the Selected Countries[1]

Sector	Oil (ktoe)	Natural Gas (ktoe)	Coal (ktoe)	Total (ktoe)	% of Total
Electricity Generation	4,422	704	489	5,615	44%
Transport	3,699	0	0	3,699	29%
Residential	1,142	2	0	1,144	9%
Commercial and Services	262	0	0	262	2%
Industrial	546	1	106	653	5%
Agriculture and Forestry	725	0	0	725	6%
Other[2]	634	97	54	770	6%

NOTE:
1. Data corresponds to net fossil fuel importers (2011 or 2010): The Bahamas, Barbados, Belize, Dominican Republic, Guyana, Haiti, Jamaica, and Suriname.
2.Other includes non-energy use, non-specified uses, and other conversions.

Source: Castalia 2015, based on International Energy Agency, UN Statistics, Belize National Energy Policy, Inter-American Development Bank

2. POTENTIAL DEMAND FOR NATURAL GAS FOR TRANSPORTATION AND OTHER USES

The potential secondary markets for natural gas include transportation, industrial processes, and residential and commercial use. These markets represent a significant share of each country's total oil consumption that could be substituted with natural gas. In each case, however, the potential demand is spread across a much larger number of potential customers than for electricity generation.

The potential demand for natural gas for transportation and other uses is estimated using assumptions under a pessimistic and optimistic scenario for the ultimate total penetration of natural gas in the transport, industry and residential and commercial sector.

I. TRANSPORT

The transportation sector has a significant share of total oil consumption in most of the selected countries, accounting for 32 percent of the total on average. Replacing this fuel with natural gas would increase natural gas demand by roughly 90 Bcf per year[21]. However, it would require the construction of suitable distribution and retail fueling infrastructure, as well as converting all road vehicles to run on natural gas.

Electric vehicles (EV) offer the potential to decrease CO_2 emissions from the transport sector. Mass adoption of EVs might assist in the integration of renewable energy into existing power generation capacity. Economic, environmental and power generation impacts of EVs are relevant to assess in the Caribbean region.

A number of positive impacts can be expected from the introduction of EVs, including lower vehicle operating costs, reduced CO_2 emissions, and the ability to support and

21 Castalia, 2015.

contribute to grid power quality and stability if the right infrastructure is adopted. Perhaps most significant, though, is the ability of EVs to assist in the integration renewable energy sources into the electric grid. This has the potential to reduce the carbon emissions from both power generation and transportation. It should be noted that while EVs can substantially reduce some of the negative impacts of large-scale renewable deployment, other methods and technologies are likely necessary to completely integrate a high penetration of renewable energy (Richardson, 2013).

In the pessimistic and optimistic scenario, the conversion to natural gas is assumed to occur in a 20-year period. Vehicular natural gas consumption is expected to begin three years after natural gas is first introduced to each country and will reach maximum penetration 20 years after natural gas is first introduced[22].

The total natural gas penetration will be affected by the size of each country. Countries with smaller territory have higher concentration of retail fueling stations, and so present fewer logistical challenges in making vehicular natural gas available to a greater share of the total vehicle fleet. Thus, countries such as Barbados, the Bahamas, and Jamaica that have less territory are projected to have a higher penetration rate in both the pessimistic and optimistic alternatives.

II. INDUSTRY

Except Belize and Haiti, industrial oil consumption is relatively low in the Caribbean, averaging 5 percent of total oil consumption in the countries of interest. Replacing this oil consumption with natural gas is technically possible and would not require as extensive deployment of distribution infrastructure. Industrial customers will likely be the first to be approached once the natural gas supply chain is established. Furthermore, converting these industrial consumers to natural gas might help to support investment in distribution infrastructure, which can later be used for other sectors as well.

In the pessimistic and optimistic scenario, the conversion to

22 Ibid.

natural gas is assumed to occur in a 15-year period. Industrial natural gas consumption is expected to begin two years after natural gas is first introduced to the country in question and will reach maximum penetration 15 years after natural gas is first introduced. The pace of penetration is quicker for the industrial sector because individual consumers are larger, simplifying the development of any required additional infrastructure[23].

III. RESIDENTIAL, COMMERCIAL AND OTHER USES

The remaining sectors account for 25 percent of total oil demand in the selected countries. However, substituting natural gas for oil in the residential, commercial and other sectors might be difficult. Consumption per user is very small, particularly in the residential sector where water heating and cooking are the only domestic uses for natural gas. Building underground pipelines to connect each household or business to the natural gas supply would likely be expensive.

Under a pessimistic scenario, there is virtually no consumption of natural gas outside of the transportation and industrial sectors, except for Barbados[24], where a natural gas distribution grid already exists, serving some commercial and residential customers. For the optimistic alternative, on the other hand, the distribution networks are only developed within major urban areas given the greater density of households and commercial establishments. For this alternative, the maximum potential penetration of natural gas would be 10 percent of the share of the total population living in urban areas as reported by the World Bank's Global Development Indicators. Furthermore, residential and commercial natural gas consumption is expected to begin four years after natural gas is first introduced to the country in question and will reach maximum penetration 25 years after natural gas is first introduced. Only Barbados shows different assumptions, where the existing natural gas distribution grid means that

23 Ibid

24 Barbados National Oil Company Ltd (BNOCL) has produced indigenous oil and gas for over 30 years, part of which has been used to supply the National Gas Corporation (NPC), which in turn has established a thriving gas distribution and sales service to over 20,000 customers, producing the equivalent of 500 BOPD.

30 percent of residential demand for oil products can be met by 2030. The penetration rate is slower for these sectors given the greater logistical challenges in connecting larger numbers of smaller individual customers[25].

Total expected non-power demand for natural gas results from adding the demand in the transport, industrial, and other sectors. Table 4 and Table 5 summarize this forecast under a pessimistic and optimistic scenario.

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25 Castalia, 2015

TABLE 4 - Pessimistic scenario for non-power gas demand

Country	Gas demand (MMcf per day)																	
	2018			*2019*			*2020*			*2021*			*2022*			*2023*		
	T	*I*	*R,C*	*T*	*I*	*R,C*	*T*	*I*	*R,C*	*T*	*I*	*R,C*	*T*	*I*	*R,C*	*T*	*I*	*R,C*
The Bahamas	0	0	0	0	0	0	0	0	0	0.02	0	0	0.04	0	0	0.07	0	0
Total	*0*			*0*			*0*			*0.02*			*0.04*			*0.07*		
Barbados	0.08	2.91	0.28	0.08	2.91	0.28	0.08	2.91	0.28	0.09	2.91	0.28	0.1	2.91	0.28	0.11	2.91	0.28
Total	*3.27*			*3.27*			*3.27*			*3.28*			*3.31*			*3.35*		
Belize	0	0	0	0	0	0	0	0.04	0	0.01	0.09	0	0.01	0.18	0	0.01	0.36	0
Total	*0*			*0*			*0.04*			*0.10*			*0.19*			*0.37*		
Dominican Republic	1.81	2.14	0	1.81	2.14	0	1.81	2.63	0	1.81	2.85	0	1.81	3.28	0	1.81	4.16	0
Total	*4.22*			*4.22*			*4.44*			*4.66*			*5.10*			*5.97*		
Guyana	0	0	0	0	0	0	0	0.04	0	0.01	0.08	0	0.02	0.17	0	0.03	0.33	0
Total	*0*			*0*			*0.04*			*0.08*			*0.19*			*0.36*		
Haiti	0	0	0	0	0	0	0	0.19	0	0.01	0.38	0	0.04	0.75	0	0.06	1.51	0
Total	*0*			*0*			*0.19*			*0.39*			*0.79*			*1.57*		
Jamaica	0	0	0	0	0	0	0	0.04	0	0.08	0.07	0	0.16	0.15	0	0.23	0.29	0
Total	*0*			*0*			*0.04*			*0.15*			*0.31*			*0.52*		
Suriname	0	0	0	0	0	0	0	0.30	0	0.01	0.06	0	0.03	0.11	0	0.04	0.22	0
Total	*0*			*0*			*0.30*			*0.07*			*0.14*			*0.26*		
Selected countries	**7.49**			**7.49**			**8.05**			**8.77**			**10.06**			**12.8**		

Note: Transport (T), Industry (I) and residential, commercial and other sectors (R,C)
Source: Castalia, 2015

In 2015, the Dominican Republic consumed natural gas in the transport and industrial sector, therefore natural gas demand starts from the first year of the projected period. All other countries show a delay period as natural gas is first delivered to the electricity sector and later extends to the rest of the economy. The pace at which natural gas penetrates in each market limits its total impact in reducing liquid fuel consumption during the forecasted period.

TABLE 5 - Optimistic scenario for non-power gas demand.

Country	Gas demand (MMcf per day)																	
	2018			*2019*			*2020*			*2021*			*2022*			*2023*		
	T	*I*	*R,C*	*T*	*I*	*R,C*	*T*	*I*	*R,C*	*T*	*I*	*R,C*	*T*	*I*	*R,C*	*T*	*I*	*R,C*
The Bahamas	0	0	0	0	0	0	0	0	0	0.11	0	0	0.22	0	0.10	0.33	0	0.21
Total		*0*			*0*			*0*			*0.11*			*0.32*			*0.54*	
Barbados	0.08	2.91	0.28	0.08	2.91	0.28	0.08	2.91	0.28	0.28	2.91	0.28	0.47	2.91	0.31	0.67	2.91	0.33
Total		*3.27*			*3.27*			*3.27*			*3.27*			*3.69*			*3.91*	
Belize	0	0	0	0	0	0	0	0.11	0	0.03	0.22	0	0.06	0.44	0	0.10	0.89	0.01
Total		*0*			*0*			*0.11*			*0.25*			*0.50*			*1*	
Dominican Republic	1.81	2.41	0	1.81	2.41	0	1.81	2.96	0	2.26	3.50	0	2.72	4.60	0.31	3.17	6.79	0.62
Total		*4.22*			*4.22*			*4.77*			*5.77*			*7.63*			*10.58*	
Guyana	0	0	0	0	0	0	0	0.10	0	0.05	0.21	0	0.09	0.41	0	0.14	0.83	0.01
Total		*0*			*0*			*0.10*			*025*			*0.51*			*0.97*	
Haiti	0	0	0	0	0	0	0	0.47	0	0.10	0.94	0	0.19	1.88	0.02	0.29	3.77	0.04
Total		*0*			*0*			*0.47*			*1.04*			*2.10*			*4.10*	
Jamaica	0	0	0	0	0	0	0	0.09	0	0.40	0.18	0	0.79	0.37	0.05	1.13	0.74	0.10
Total		*0*			*0*			*0.09*			*0.58*			*1.37*			*2.34*	
Suriname	0	0	0	0	0	0	0	0.07	0	0.07	0.14	0	0.15	0.28	0.01	0.22	0.56	0.02
Total		*0*			*0*			*0.07*			*0.21*			*0.47*			*0.87*	
Selected countries		**7.49**			**7.49**			**8.88**			**11.68**			**16.61**			**24.3**	

Note: Transport (T), Industry (I) and residential, commercial and other sectors (R,C)
Source: Castalia, 2015

3. POTENTIAL DEMAND FOR NATURAL GAS FOR ELECTRICITY GENERATION

Electricity generation consumes more energy than any other use in the Caribbean. This, along with the structure of the electricity sector, usually with a single utility in each country, makes it the most promising market for natural gas in the region.

The electricity sector is expected to be the anchor client for natural gas imports in each of the selected countries. As such, the potential demand for natural gas by the electricity sector will define the size of the infrastructure required for importing and using natural gas.

The projected demand for natural gas from power generation is based on (i) the expected demand for electricity; (ii) the total installed capacity per country to meet the expected demand, and (iii) the electricity generation and installed capacity using natural gas.

(I) EXPECTED DEMAND FOR ELECTRICITY

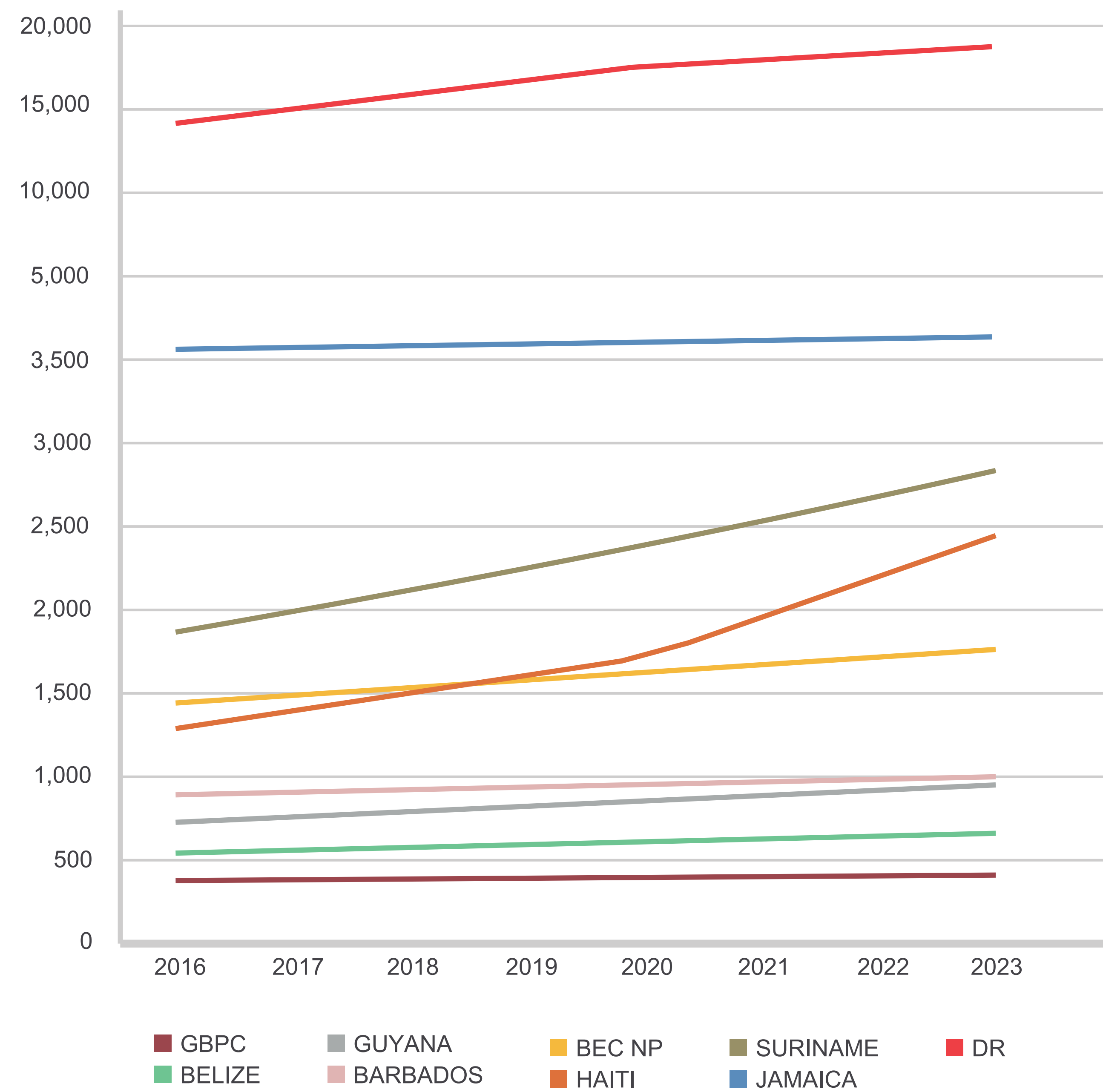
Total required net generation in the Dominican Republic in 2023 is projected to be about five times that of Jamaica (19,069 GWh and 4,848 GWh, respectively), which in turn is more than 1.5 times the size of the next largest market, Suriname (3,191 GWh). Net generation is expected to grow rapidly in Haiti, reaching nearly 3,000 GWh in 2023. New Providence, Barbados, and Guyana are of a similar size, with total required net generation expected between 1,000 GWh and 2,000 GWh in 2023. Belize's total required net generation is projected to remain just above 700 GWh, and Grand Bahama is expected to require less than 500 GWh in 2023[26].

Projections on electricity demand must be met in terms of total annual consumption of electricity and peak demand.

26 Castalia, 2015

Total annual electricity consumption, together with system losses, determines the required annual net generation for each country; while peak demand determines the required installed capacity in each country.

FIGURE 6 - Expected Net Generation, 2016-2023 (GWh)



Source: Castalia, 2015

To forecast net generation of electricity by country, it was necessary to estimate electricity consumption and add system losses. Historical electricity consumption in each country served as reference to forecast the electricity consumption growth each year at an average annual growth rate. The assumed annual growth rates on electricity consumption were based on the expected growth rates of the real GDP. Table 6 summarizes the existing data and projections for each country.

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TABLE 6 - Electricity Consumption, 2013-2023 (GWh).

Country	Historic data			Projected electricity consumption							
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Bahamas BEC	1,269	1,307	1,345	1,385	1,426	1,468	1,512	1,557	1,603	1,650	1,699
Bahamas GBPC	319	326	332	339	346	352	360	367	374	382	389
Barbados BL&P	914	913	917	925	936	949	965	983	1,001	1,018	1,034
Belize, BEL	481	495	510	525	540	556	573	590	607	625	643
DR, All	9,817	9,991	10,336	10,827	11,404	11,877	12,335	12,810	13,037	13,268	13,516
Guyana, GPL	474	493	512	533	554	575	598	622	646	672	698
Haiti, EDH	455	691	746	805	869	937	1,012	1,092	1,225	1,376	1,545
Jamaica, JPS	3,070	3,096	3,127	3,160	3,194	3,248	3,319	3,393	3,469	3,553	3,636
Suriname, EBS	1,544	1,672	1,819	1,941	2,071	2,191	2,320	2,456	2,603	2,761	2,929

27 GDP projections: The Bahamas, BEC 4%, The Bahamas, GBPC 2%, Barbados 1.3%, Belize 4%, Dominican Republic 3.8%, Guyana 5%, Haiti 14%, Jamaica 2.7% and Suriname 6.6%. World Economic Outlook, IMF 2014 to 2018.

Source: Castalia, 2015

The projection of system losses is a percentage of net generation, assumed to remain constant from 2012 to 2023. The system losses for each year were calculated as a function of projected electricity consumption of each year and the percentage of system losses in 2015. Haiti has the highest losses accounting for 77% of total electricity generation, followed by Guyana (52%), Dominican Republic (41%), Jamaica (33%), Bahamas GBPC (18%), Bahamas BEC (16%), Belize (15%), Suriname (9%) and Barbados (7%)[28]. Adding the system losses to the total electricity consumption in Table 6, results in the required net generation[29].

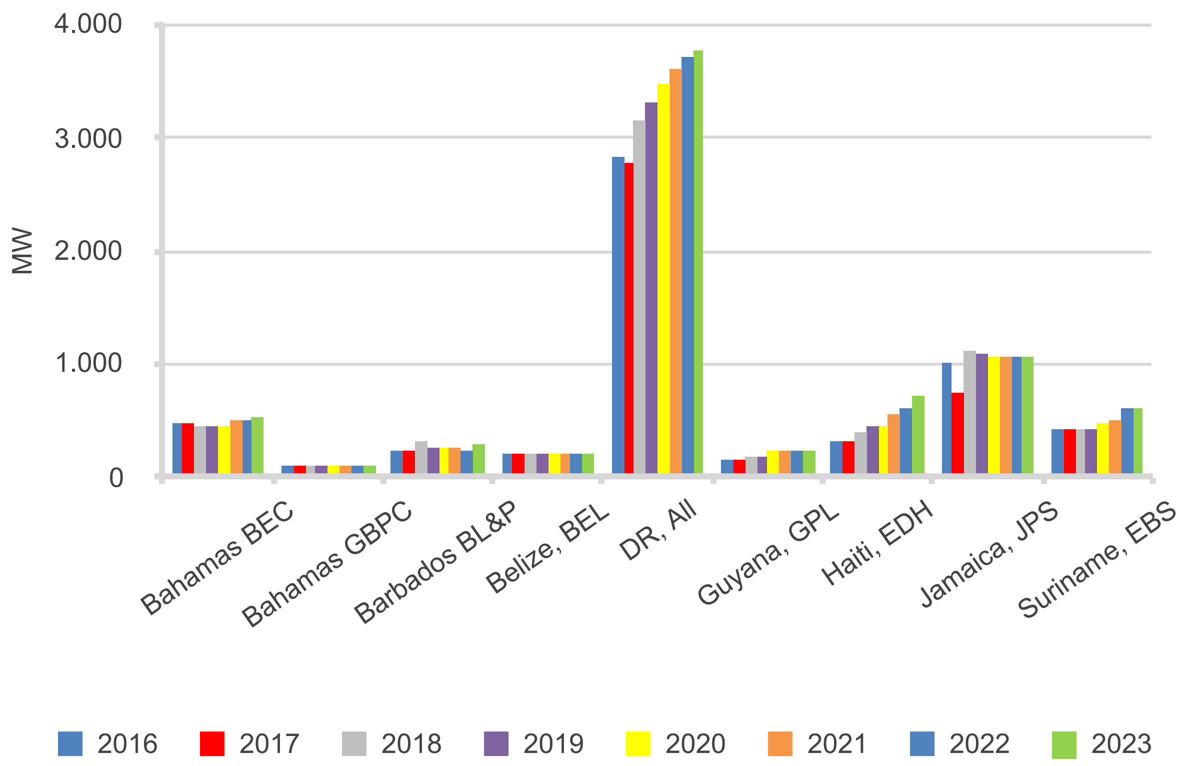
(II) EXPECTED INSTALLED CAPACITY PER COUNTRY

Dominican Republic is by far the largest electricity market in the region. By 2023, the Dominican Republic's installed capacity is projected to reach about 3,767 MW. This is more than double the next largest market, Jamaica, at 1,060MW. Installed capacity in Suriname, New Providence in The Bahamas, and Haiti, and is expected to be between 534MW and 706MW by 2023. For Barbados, Belize, and Guyana our forecast of installed capacity is between 198MW and 275MW in 2023. With an installed capacity of 101MW in 2023, Grand Bahama is the smallest of the forecast markets[30]. Figure 7 shows the new generation capacity each country will need to add to 2015 installed capacity between 2016 and 2023.

Annual estimation of installed capacity is based on peak demand historical data[31] for each country by the respective annual growth rate of electricity consumption. Assuming constant load factors is in line with projections from other sources, the total installed generation capacity is obtained by applying reserve margins to the projected peak demand from 2013 to 2023 in each country[32].

28 Castalia, 2015.
29 Ibid.
30 Ibid.
31 Peak demand in 2012 multiplied by annual growth rate of electricity consumption.
32 Castalia, 2015.

FIGURE 7 - Expected Installed Generation Capacity in MW, 2016-2023.



(III) ELECTRICITY GENERATION AND INSTALLED CAPACITY USING NATURAL GAS

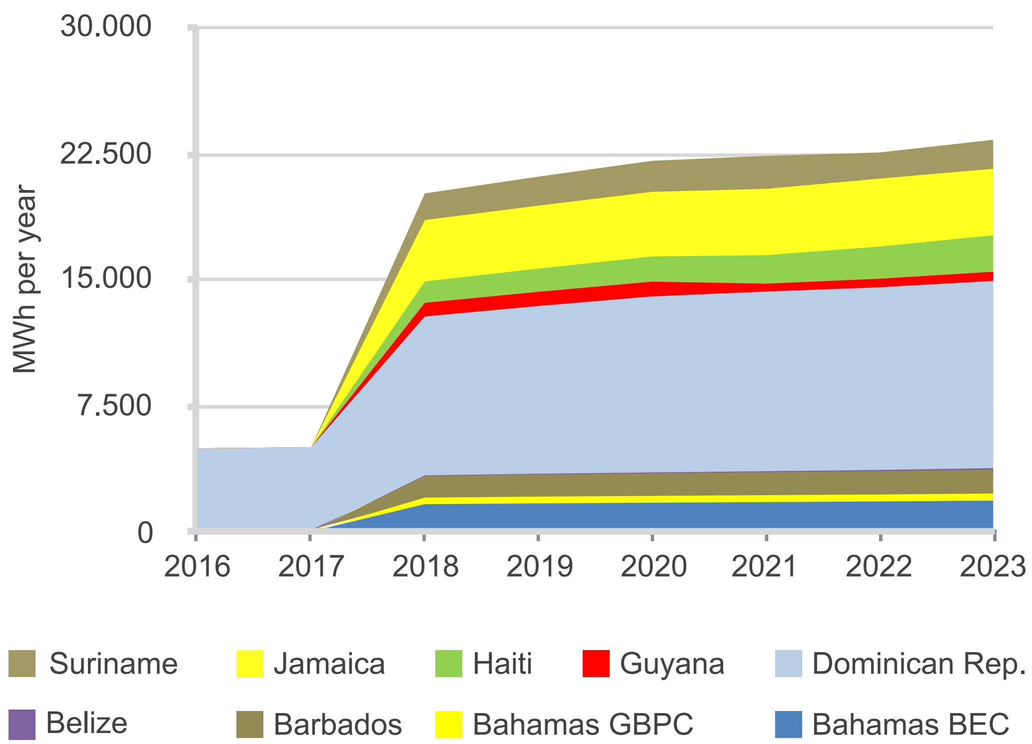
The fact that most of the selected countries have relatively small electricity generation sectors, with only a few power plants meeting each country's needs, makes it easier to convert a substantial part of a country's capacity to natural gas-fired capacity. There are fewer locations that must be connected to the natural gas supply and many plants are located close to each other.

Future electricity consumption from natural gas power plants is calculated considering a Low and High renewable energy (RE) scenarios. The methodology applied examines possible RE futures paths in the Caribbean region by combining information from (1) historical and newly added RE capacity, (2) planned RE power generation, and (3)

countries' Renewable Energy Targets by 2022, and 2030. Low RE scenario accounts for business as usual RE growth under (1) and (2) data, while High RE scenario assumes that all countries achieve their RE targets (3).

On average, the expected natural gas installed capacity under Low RE scenario differs only in 6% between 2016 and 2023 when compared with High RE scenario. Therefore, this analysis refers to the expected gas-fired electricity consumption as the average electricity generation between these two scenarios. Figure 8 shows average electricity generation for natural gas-fired plants from 2016 to 2023. In 2018, most of the generation would switch from fuel oil-based plants to natural-gas fired plants in all countries, except for Belize and Suriname.

FIGURE 8 - Electricity Generation Scenario using Natural Gas, 2016 – 2023.

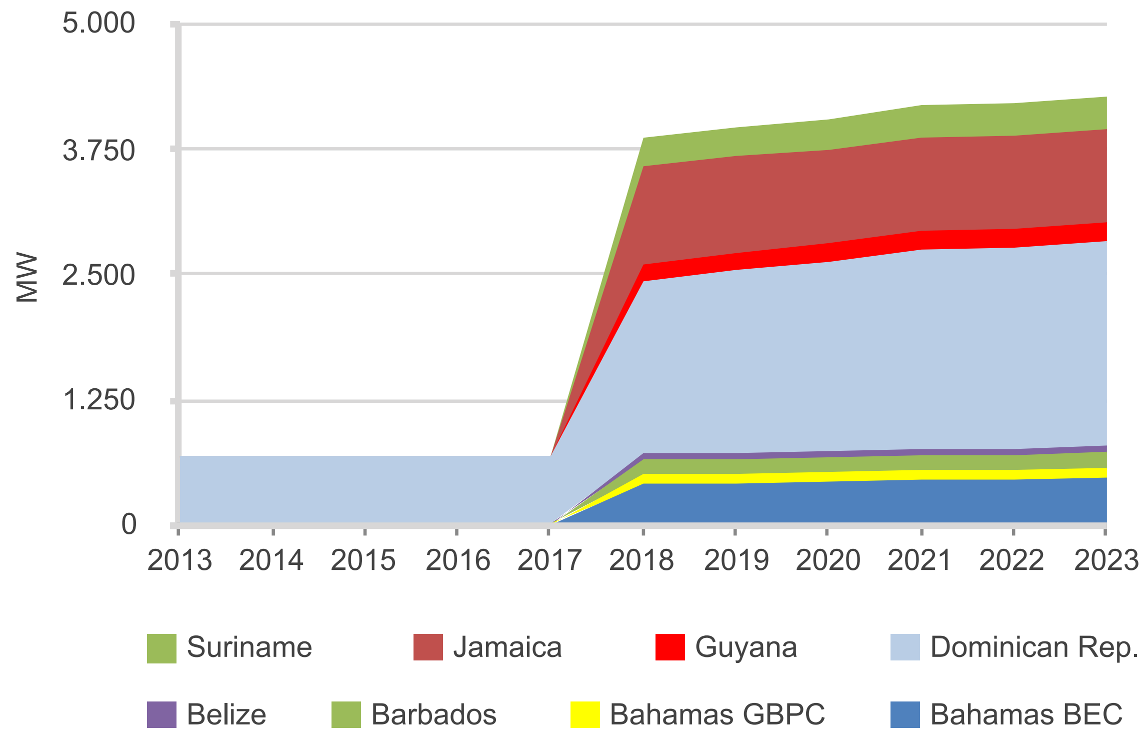


Source: IADB based on estimations from Castalia 2015.

The estimation of electricity generation from each source from 2016 to 2023 assumes that all existing non-natural gas and non-fuel oil sources—that is coal, hydro, wind or bagasse plants—would be used as baseload plants, and generate electricity with same availability factors as plants existing in 2012. These plants would be dispatched as available and generate electricity with a utilization factor of 90 percent.

The required natural gas-based capacity in each country is calculated considering projections on peak demand and reserve margin. The reserve margins are assumed to remain constant between 2013 and 2023. These values are higher than 15 percent[33]. Most of the selected countries have relatively small electricity generation sectors, with only a few power plants meeting each country's needs. Therefore, smaller countries are required to maintain a higher reserve margin than larger countries with a greater number of power plants because taking a single power plant out of service for maintenance can significantly affect total available capacity. Figure 9 shows the resulting forecast for natural-gas-fired and non-gas-fired installed capacity from 2013 to 2023 (average between high and low RE scenarios).

FIGURE 9 - Expected NG Installed Capacity, 2016 – 2023.



Source: IADB based on estimations from Castalia 2015.

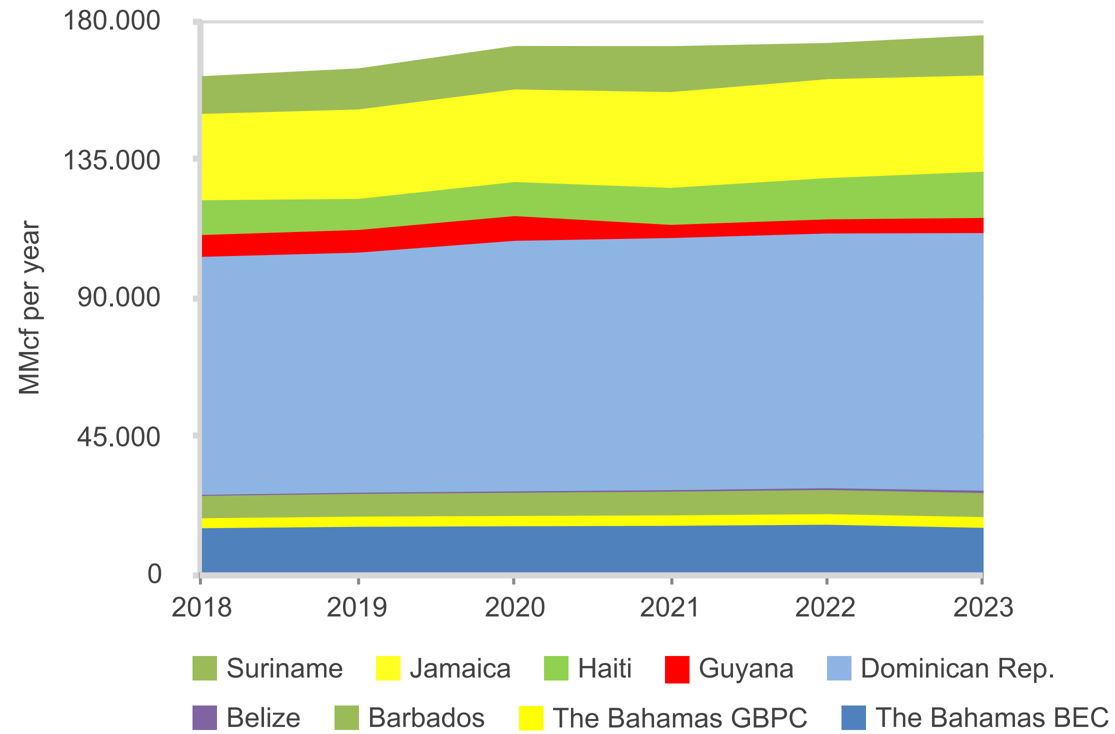
33 Castalia, 2015.

(IV) PROJECTIONS OF POTENTIAL NATURAL GAS DEMAND FOR POWER GENERATION

Finally, the projected natural gas demand for generating electricity results from using the amount of electricity generated from natural gas fired plants multiplied by the estimated heat rate of the plants. Converted plants are assumed to operate at an average heat rate equal to average heat rate of fuel oil plants operating in 2015[34].

On average, the expected natural gas demand for power generation under Low RE scenario differs in 13% between 2018 and 2023 when compared with High RE scenario. Therefore, this analysis refers to the expected natural gas consumption as the average natural gas demand between these two scenarios. Figure 10 depicts total NG demand per country. Total NG demand would increase from 162,329MMcf in 2018 to 175,654MMcf in 2023[35].

FIGURE 10 - Total Natural Gas Demand, 2018 – 2023



Source: IADB based on estimations from Castalia 2015

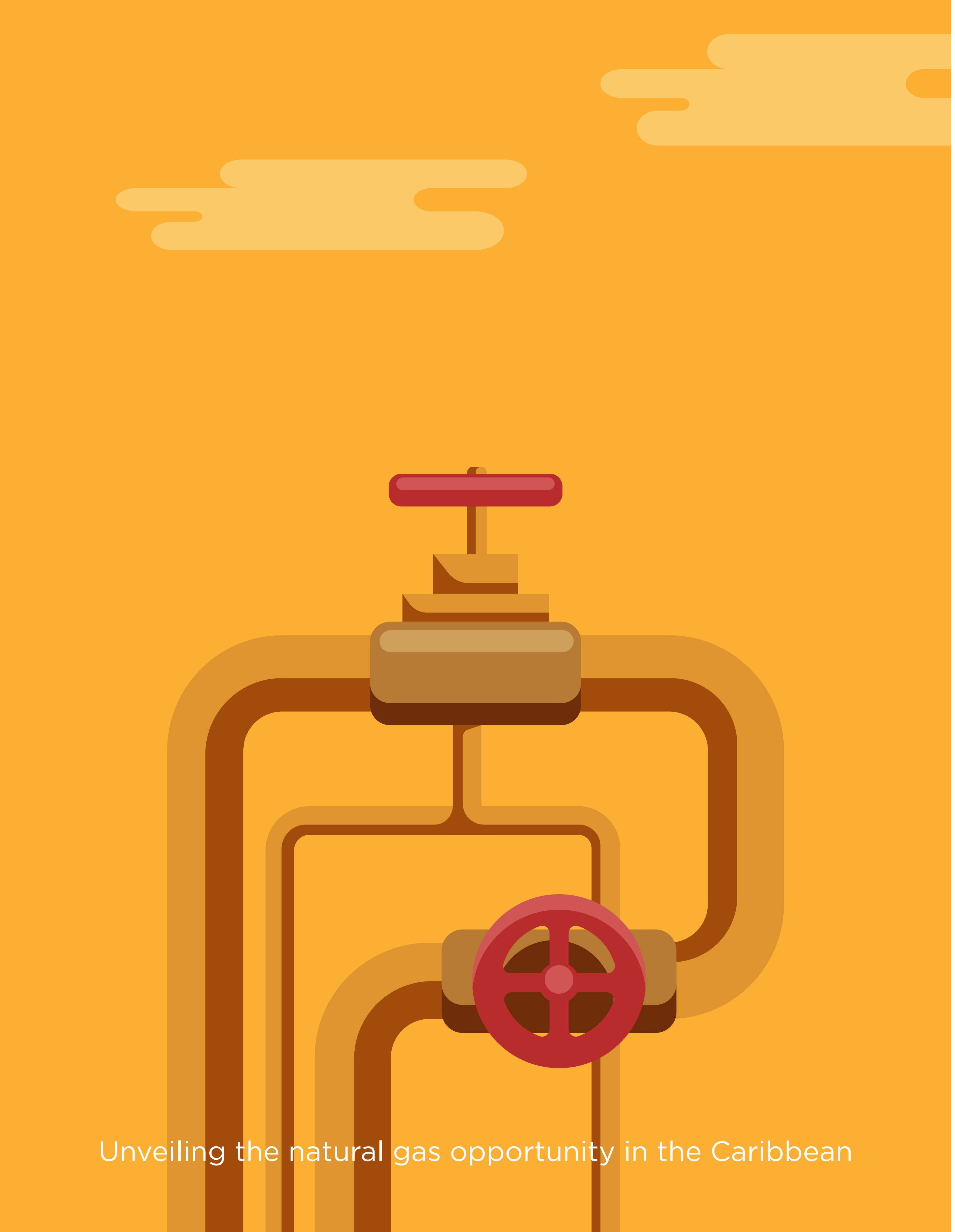
34 These heat rates range from 7,954 Btu/kWh in Suriname to 10,830 in Jamaica.
35 Castalia, 2015.

The maximum volume of natural gas the selected countries would buy per day for electricity generation in 2018 is approximately 425 MMcfd. This would rise to about 470 MMcfd in 2023. Daily demand information is necessary to size the required natural gas pipeline capacities as well as the throughput capacities of the LNG regasification plants and CNG decompression facilities[36].

36 Castalia's estimation, 2015.

05 Natural Gas transport and storage technologies

Unveiling the natural gas opportunity in the Caribbean



This section describes the available technologies to deliver natural gas in the Caribbean. Specifically, it identifies ad-doc facilities and services for small markets to transport, off-load, storage and distribute natural gas.

1. LNG

In 2015 the operating receiving terminals in the Dominican Republic and Puerto Rico delivered LNG to the Caribbean region. Other potential LNG suppliers, such as Panama, are already positioning themselves. In May 2017, AES Panama announced a partnership with Engie at the Costa Norte LNG project to market LNG in the region. The joint venture will add a total capacity of 1.5 million tons per annum, of which 25% will be used for the 380 MW AES Colón gas-fired power plant currently under construction[37]. The remaining 75% of LNG capacity is available for AES Panama and Engie to market and sell to third parties. In June 2018, Costa Norte received its first commissioning cargo from Cheniere's Sabine Pass liquefaction plant[38].

For most Caribbean natural gas markets, medium and small-scale LNG would be the most applicable. LNG transportation and storage technologies that fit best for the region are described below. For instance, the introduction of LNG in Jamaica came as a result of a project that saw the conversion of the fuel supply of a 120MW Combine Cycle generation plant in December 2016. The same year the Barbados National Oil Company Ltd (BNOCL) built and commissioned an LNG regasification facility at Woodbourne and commenced the importation of Liquid Natural Gas (LNG) to improve gas supply stability at a competitive cost supply, leading to the establishment a firm contract, in October 2018. In 2015, the Barbados' fuel input sources for electricity production was registered with 0.2% for Natural Gas, accounting for production of electricity in the manufacturing sector. Given the successful stabilization of gas sales at a competitive price significantly lower than the main competing products (diesel and LPG), over 6,000,000 million gallons of LNG have been imported /re-gassed, turning LNG into a major component

37 AES, 2018.
38 GIIGNL, 2018.

of natural gas sales for National Petroleum Corporation (NPC)[39].

(I) LNG VESSELS

In 2015, a range of ship sizes were in production, including sizes that are suitable to Caribbean markets. While most LNG carriers are non-pressurized, a small number are certified to transport gases at high pressure. These vessels are generally small in size and are used to transport a variety of cargoes, including LPG or ethylene.

In the 2000s, ship sizes averaged between 140,000 and 160,000 cubic meters. For most Caribbean markets, ships of this size would be too large, requiring very large storage systems relative to the market size at the receiving terminals. The smaller end of the range is much better suited to the size of the expected demand in the Caribbean. According to the GIINGL Annual Report 2014, 17 LNG vessels were operating worldwide with a capacity below 18,000 cubic meters[40].

(II) ON-SHORE LNG STORAGE AND OFF-LOADING SYSTEMS

An on-shore LNG receiving terminal consists of a jetty or pier for berthing the LNG carrier and related pipelines to transfer the LNG in liquid form from the ship to land. The jetty and related harbor facilities are relatively inexpensive when deep draft is not necessary. Assuming no marine terminal modifications are required, the storage tanks are generally the largest single cost component for the regasification plant, accounting for roughly one-third of the overall cost.

(III) FLOATING STORAGE AND REGASIFICATION

A floating storage and regasification unit (FSRU) is an LNG

39 Barbados' energy demand in the transition phase towards alternative energy (e.g. Wind and Solar) require importation of additional imports of LNG, with current gas sales averaging circa 1.4-1.8 MMcfd and with the intentions to reach 3.0 MMcfd 60 months (with a current average demand of approximately 1.6MM). To meet current and future NG needs, BNOCL is seeking to install a LNG regasification facility located within the Port Authority.
40 GIIGNL, 2014.

tanker with onboard regasification capabilities. FSRUs allow a country to import LNG without building a land-based receiving terminal. They can be developed more quickly than land based systems, and have been used as an initial import option while larger land-based terminals are developed.

Nevertheless, FSRUs have a number of constraints. These units have higher operating costs than land- based systems, as the on-board regasification systems tend to be less efficient than land- based options. They are also limited to the storage capacity onboard the ship, while land- based LNG storage systems can be tailored to the market needs and are often sufficient to hold multiple ship-loads of supply. Furthermore, LNG regasification costs are highly site specific. These costs are driven by the size of the facility, the size of the storage tanks, and the regulatory requirements in each country.

(IV) CRYOGENIC ROAD TANKERS

Cryogenic road tankers are an option for distributing LNG to a variety of offtakers. They require an LNG loading facility which can be a stand-alone small-scale liquefaction plant or can be incorporated with a larger scale liquefaction plant or LNG import facility.

Road-based LNG transportation technology brings natural gas to inland markets that are too small to justify the construction of a pipeline or to supplement available pipeline gas in order to meet seasonal or daily demand peaks.

2. CNG

Although Compressed Natural Gas (CNG) has been used for decades, seaborne CNG is a much newer concept. The competitive advantage of seaborne CNG is the lower cost of compressing gas relative to liquefying it. This section describes the proposed technologies for transporting and delivering CNG to the Caribbean, including CNG carriers, storage and off-loading system and road tankers[41].

41 Because there are no commercially operating ships purpose-built to transport CNG, the analysis relies on information from the technology developers.

(I) CNG VESSELS

Several companies have competing designs for large-scale CNG ships, but none are in commercial operation to date[42]. CNG ships are essentially floating platforms for high - pressure pipelines. Some available technologies that are being developed for seaborne CNG are the Coselle System[43], which uses modules of coiled high- pressure pipes to store the CNG for shipping; VOTRANS technology[44], which allows a greater compression ratio at lower pressures; and Compressed gas liquid (CGL) technology, which mixes the natural gas to be transported with a liquid hydrocarbon at low temperature and moderate pressure.

For the seaborne CNG technologies noted above, the transportation ship itself would serve as storage, remaining at dock until its load had been consumed. Unloading CNG from the Coselle System simply requires a high-pressure gas handling system to reduce the pressure of the outflowing gas to match the requirements of the destination pipeline system or final consumer. As a result, Coselle CNG ships do not require large shore-based facilities and can link directly to the final market. VOTRANS and CGL based systems require additional liquids handling systems to unload the natural gas, but also do not require high pressure gas handling equipment.

(II) CNG ROAD TANKERS

CNG road tankers are similar in size to LNG tankers. A fully loaded CNG trailer may have an effective capacity y of 140,000 cubic feet[45]. Nevertheless, this scale is not suitable for utility scale power generation, even for the smallest Caribbean markets. For example, a 5 MW reciprocating engine would consume a trailer of CNG in just 3.5 hours.

Although not suitable for utility-scale power generation,

42 In a few cases, CNG is transported in containers. However, there are no operational purpose- built CNG ships.

43 "Coselle System Overview," Sea NG, accessed 29 April 2015, http://www.coselle.com/coselle-system/overview.

44 "Cost Effective Technology," EnerSea Transport LLC, accessed 29 April 2015, http://enersea.com/cng-technology/.

45 Marlin CNG Services, accessed 29 April 2015, www.marlingas.com/faq.html.

CNG road tankers could be used to distribute natural gas to secondary demand centers, such as a filling station for vehicular natural gas or an industrial customer for on-site use or electricity self-generation.

3. PIPELINES

Natural gas pipelines are a well-established technology that have the advantage of allowing gas flow to reverse more easily than with LNG or CNG. Nevertheless, they are capital intensive and not flexible in linking multiple sources of supply with multiple demand centers. The capital cost to build an undersea or on-shore pipeline is largely driven by the pipeline length with relatively little variation from changes in the pipeline diameter. As such, the cost per unit of natural gas transported can increase significantly for smaller diameter pipelines.

Undersea pipelines also face water depth and economic limitations. Potential pipeline routes that would be technically feasible include from Florida to The Bahamas, from Trinidad and Tobago or Venezuela to the smaller islands in the Eastern Caribbean ranging from Grenada to as far as Puerto Rico and the island of Hispaniola, and between Hispaniola and Jamaica. Although certain routes would be technically feasible, submarine pipelines would face strong economic challenges in the Caribbean. For many of the potential routes, several countries would need to be linked together in order to reach a sufficient scale to justify the pipeline's capital cost.

4. COST COMPARISON OF DELIVERING LNG, CNG, AND NATURAL GAS BY PIPELINE

This section compares the cost of delivery for each technology. The price of natural gas is assumed uniform and used to calculate the price of delivery based on each segment in the supply chain[46].

46 For CNG, the estimated costs based on projections from CNG shipping companies. To compare costs of the delivery technologies, the

These estimates serve to compare costs between the delivery technologies from the potential supply points. Nevertheless, the final delivered price for natural gas in the Caribbean will depend on global and local supply and demand for natural gas, as well as regional market trends and developments in the LNG and CNG markets. Table 7 shows cost ranges for delivered natural gas.

TABLE 7 - Cost of Delivered Natural Gas in the Caribbean

	Price for LNG (US$/MMBtu)*	Price for CNG (US$/MMBtu)	Price via pipeline (US$/MMBtu)
The Bahamas, New Providence	9.4 – 12	10.5 – 14.2	16.1
Shipping costs (1)	0.7	6.84	n.a
The Bahamas, Grand Bahama	10.7 – 13.3	17.8 – 20	7.2 – 12.3
Shipping costs (1)	0.43	12.04	n.a
Barbados	9.8 – 12.7	14 – 18.8	10.5
Shipping costs (1)	0.37	8.45	n.a
Belize	13.7 – 17.3	65.4 – 67.6	n.a
Shipping costs (1)	1.8	56.98	n.a
Dominican Republic	8.8 – 11.2	8.2 – 11.3	n.a
Shipping costs (1)	0.16	2.33	n.a
Guyana	9.7 – 12.8	13.6 – 18.3	9.8 – 10.1
Shipping costs (1)	0.34	8.07	n.a
Haiti	9.6– 12	10.2 – 14.6	n.a
Shipping costs (1)	0.74	7.24	n.a
Jamaica	8.8 – 11.4	9.1 – 12.6	n.a
Shipping costs (1)	0.23	3.97	n.a
Suriname	9.5 – 12.5	10.5 – 17.6	9.1 – 14.6
Shipping costs (1)	0.36	5.08	n.a

upstream costs are identical regardless of the technology used to transport the gas to market.

Note 1: Costs are the range of estimate costs from the seven supply points: U.S., Sabine Pass; Canada, Guysborough; U.S., South Florida; Mexico, Altamira; Trinidad, Point Fortin; Venezuela, Guiria; Colombia, Covena. These costs were calculated assuming that natural gas acquired prices would be linked to Henry Hub, at EIA's forecasted price of US$4.8 per MMBtu in 2018 based on information updated in 2015.

Source: Castalia, 2015

In most cases LNG is likely to be the least-cost technical option for delivering natural gas. The exceptions are some countries where pipelines could be lower cost, and the Dominican Republic, where CNG could be lower cost. In the Dominican Republic, the technology and price risk surrounding CNG likely makes LNG a more attractive option.

Pipeline costs are lower than LNG for Grand Bahama only if it is part of a pipeline that continues to New Providence. However, Grand Bahama would have to coordinate with New Providence to build the pipeline, and New Providence would likely prefer to use LNG, its least-cost option, rather than coordinate with Grand Bahama to build a pipeline to both islands. A pipeline that only reaches Barbados from Trinidad and Tobago would be about the same cost as importing natural gas as LNG. However, this option would tie Barbados to a single supplier with limited natural gas resources, meaning that LNG is likely a better option. For a pipeline that reaches both Guyana and Suriname, the cost of natural gas would be about the same delivered as LNG for both countries. However, building a pipeline would require complex coordination and tie each country to a single supplier and each other. As such, importing LNG is likely a better option for both.

The cost to deliver natural gas varies slightly across transportation technology options. The average cost from the most expensive source to the least expensive source for LNG is US$2.8 per MMBtu, while for CNG is US$4 per MMBtu. This cost difference is due to shipping on overall costs. This suggests that any supply source within the region could potentially compete with U.S. Gulf Coast exports, meaning that the timing of available supplies will play an important role. Out of all the supply points, Canada is the

most expensive source, because of a higher premium over Henry Hub and higher shipping costs.

The assessment indicates that LNG is likely the least expensive option for natural gas delivery in the Caribbean. In almost all cases, LNG is projected to be either the least-cost delivery option or competitive with another delivery option.

CNG is forecast to be higher cost for every country except for the Dominican Republic, but cost uncertainty and technology risk is high, since no ship has been purpose-built to transport CNG. Cost estimates for CNG could rise or fall as the technology and market develop. For example, CNG suppliers could offer gas at much lower price than LNG if they are able to source low-cost gas reserves. This could make it the least- cost option for one or more offtakers, especially if the CNG supplier is supplying gas from a field close to the offtaker.

5. COSTS FOR ASSETS AND TECHNOLOGIES IN THE LNG SUPPLY CHAIN

This section presents detailed capital cost estimates for regasification facilities, converting existing generation plants to gas-fired plants, building new plants for generating electricity, followed by the liquefaction and shipping costs. Table 8 shows the capital costs in infrastructure to form the LNG value chain in the Caribbean.

- Regasification facilities[47]. The total investment to build regasification terminals ranges from US$52 million for Belize to US$261 million for the Dominican Republic. After 2023, the Dominican Republic, Jamaica, The Bahamas, and Suriname are assumed to have full-scale receiving terminals with costs to build that are on par with international averages. The estimated capital cost to build regasification terminals of this type is roughly US$900 per cubic meter of storage capacity[48]. This would set the initial cost of the facility in the Dominican Republic at US$184.5 million and the cost of the facility in Jamaica at roughly US$227 million.

  The smaller selected countries would use similar single containment storage tanks. However, the cost per unit to build these facilities will be higher, as many of the cost components are fixed or do not scale down at the same rate as the terminal capacity. The estimated capital cost to build regasification terminals with capacity between 30,000 and 60,000 cubic meters of storage is US$1,500 per cubic meter of storage capacity. Also, the basic offloading and related infrastructure requires a minimum investment of US$10 million.

- Converting existing generation plants to gas-fired plants. All participating offtakers are assumed to convert to natural gas the installed capacity using fuel oil by 2018[49]. The capital costs for converting the plants are estimated in US$100,000 per MW converted[50]. Some countries may have the opportunity to build low-cost hydroelectric power plants or other alternatives, but most countries will continue to rely on thermal power plants that use oil products or natural gas, for at least the medium term.

- Building new plants for generating electricity[51]. All offtakers, regardless of whether they use natural gas or not for generating electricity, will have to build new capacity for generating electricity. When assessing the feasibility of increasing the use of natural gas in the

47 It is assumed that on-shore facilities would be built. However, FSRUs may be a cheaper or more technically alternative for some of the assessed countries.

48 The price includes the cost to build the entire facility.

49 Except for Barbados. This assumption follows BL&P's "Integrated Resource Plan" dated February 2014.

50 Castalia, 2015.

51 Capital costs of building new gas-fired power plants: Combined cycle plants: US$917 per kW (Castalia's estimations based on EIA, April 2013, Table 1, Conventional Combined Cycle), Simple cycle plant: US$676 per kW (Castalia's estimations based on EIA, April 2013, Table 1, Advanced Combustion Turbine), Reciprocating engine plant: US$1,130 per kW (Castalia's estimations based on "Technology Characterization: Reciprocating Engines, Prepared for: Environmental Protection Agency," Energy and Environmental Analysis, Inc. an ICF Company, December 2008, Table 2 System 5).

Caribbean for generating electricity, it is necessary to make assumptions regarding the additional generation capacity

to be added and the cost of that generation capacity.

The specific capital costs for the countries in the Caribbean would vary by site. For example, estimates for a 100MW plant range from US$875[52] to US$2,240[53]. As such, the estimates above are within the range the capital expenditures that will be incurred by utilities and generators, but actual costs may be higher or lower.

TABLE 8 - Capital Cost to introduce LNG in the Caribbean, 2018 - 2023.

	LNG regasification		Converting existing power plants to NG	
	Capacity (in MMcf)	**(in US$)**	*Capacity (in MW)*	**(in US$)**
The Bahamas, BEC	14,000–16,000	133,100,000	393	39,250,000
The Bahamas, GBPC	3,000-4,000	55,000,000	240	24,010,000
Barbados	7,000-8,000	88,000,000	226	5,940,000
Belize	300-800	52,250,000	62	6,186,000
Dominican Republic	77,000-85,000	261,000,000	1,025	102,459,000
Guyana	7,000-9,000	96,250,000	140	14,010,000
Haiti	11,000-15,000	96,250,000	238	23,805,000
Jamaica	28,000-33,000	197,450,000	621	62,100,000
Suriname	12,000-13,000	167,750,000	299	29,911,775
Total		**1,147,050,000**		**307,671,775**

Source: Castalia, 2015

52 Castalia estimate, adapted from price data in Gas Turbine World, “2013 GTW Handbook.” Volume 30. Pequot. Mid- Year 2013.
53 ETESA Panama, “Revisión del plan de Expansión 2013.”

O LIQUEFACTION COST

Liquefaction capacity will not be built and directly financed by Caribbean consumers in any of the commercial supply alternatives. Nevertheless, liquefaction is an important share of the total cost to deliver natural gas to the region as LNG.

Liquefaction costs depend mostly on the supply point. Therefore, they are the same for all projects that secure natural gas contracts from the same points of supply. Liquefaction includes capital costs, non-fuel operations and maintenance costs, and fuel costs. The following assumptions explain each of these costs:

- **NON-FUEL O&M COSTS:** it is assumed that this cost is US$0.16 per MMBtu and is the same for all supply points.[54]
- **FUEL OPEX:** it is assumed that fuel costs equal the purchase price of the natural gas to be shipped plus 9 percent (to account for the natural gas consumed in the liquefaction process)[55].
- Capital costs: it is assumed that capital costs for liquefaction to be at US$802 million per MMTPA capacity for projects in South America and for green-field projects in the United States. The value is reduced to US$544 million per MMTPA capacity for brown-field projects in the U.S. Gulf Coast. The capital cost would be amortized over 25 years at a real cost of capital of 10 percent, and with a utilization factor of 72 percent[56].

Based on the assumptions above, Table 9 shows the calculated cost to liquefy natural gas, excluding fuel costs, at Sabine Pass. The table excludes fuel costs because they depend on the chosen supply alternative, the acquired price for natural gas for each year, and the point of supply.

54 Castalia, 2015.
55 Castalia, 2015.
56 Ibid.

TABLE 9 - Calculation of Liquefaction Costs (in US$ per MMBtu).

	U. S., Sabine Pass	Other Supply Points analyzed
Non-fuel O&M	0.16	0.16
Capital Cost	1.60	2.36
Liquefaction costs excluding fuel costs	1.76	2.52
Difference with Sabine Pass		0.76

Source: Castalia, 2015

The reduced capital cost for brown-field projects on the U.S. Gulf Coast results in a discount of $0.76 per MMBtu (or 30 percent) from other supply sources. Because liquefaction is such a large share of the total transportation cost of delivered LNG, the assumed lower capital cost for liquefaction projects on the Gulf Coast in the U.S. gives them a significant cost advantage over other sources.

The calculated liquefaction costs are close to the reported LNG prices that Cheniere Energy contracted for its initial trains at Sabine Pass. Its first contract with British Gas was set at Henry Hub plus 15 percent, plus a charge of US$2.25 per MMBtu for liquefaction[57].

O LNG SHIPPING COSTS

The ships size varies depending on each country's demand. Large Caribbean countries like the Dominican Republic would require full-sized vessels with a capacity of about 149,000 cubic meters, while countries like Belize require vessels with a capacity below 10.000 cubic meters. The sizes chosen and the resulting daily charter rate, charter cost per MMBtu per day of shipping, and ship speed are shown in Table 10 below.

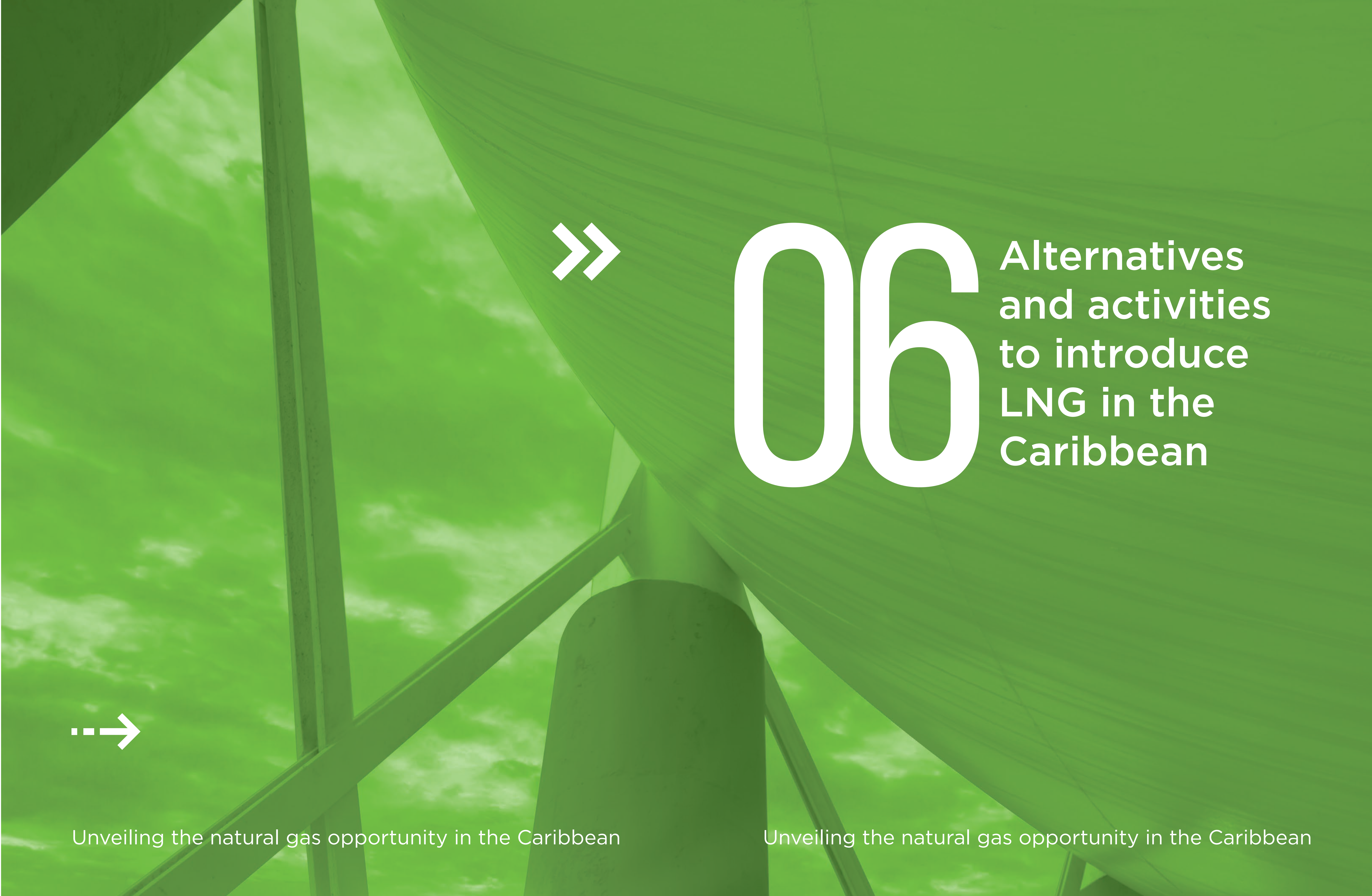
57 Castalia, 2015.

TABLE 10 - LNG Shipping Costs

Country	LNG Capacity (cubic meters)	Charter Rate per day (US$)
Belize	6,000	17,667
The Bahamas (Grand Bahama)	15,000	30,000
The Bahamas (New Providence), Barbados, Guyana, Haiti, Suriname	45,000	58,000
Dominican Republic, Jamaica	149,000	80,000

Note 1: Shipping costs are calculated assuming a daily charter rate and ship speed for full-scale ships at the average rate for long-term charters as reported in the IGU World LNG Report, 2013 Edition.
Note 2: The daily charter rates for ships smaller than full scale are estimated using the daily charter rate for similarly sized LPG ships as reported in the BRS The LPG Shipping Market, 2013 Annual Review.
Note 3: The ship speed for smaller ships is based on figures reported by Anthony Veder, a Dutch shipping company that operates 30 small-scale LPG, LNG, and multi-fuel carriers.

Source: Castalia, 2015.



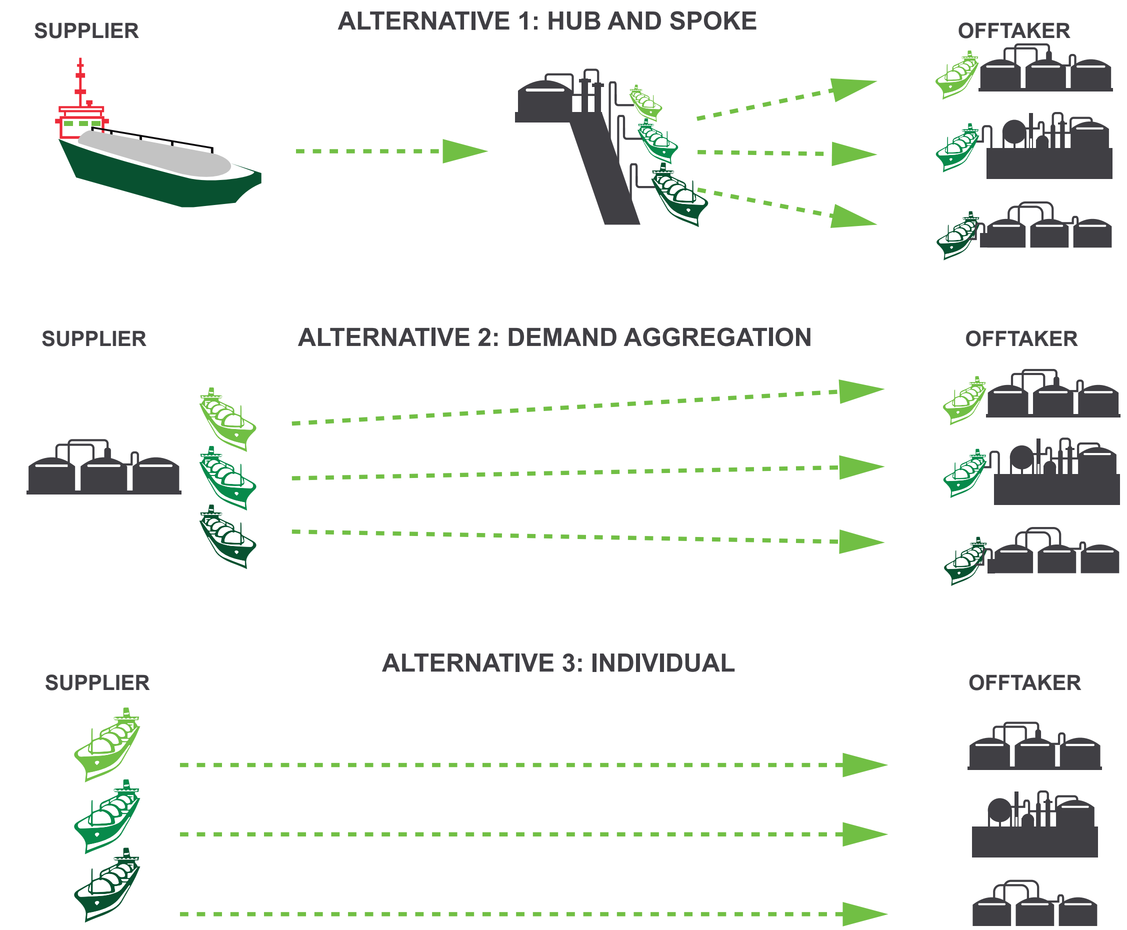
06 Alternatives and activities to introduce LNG in the Caribbean

Unveiling the natural gas opportunity in the Caribbean

1. LNG MARKET ALTERNATIVES

The LNG market in the Caribbean can be developed under at least three alternatives that provide different commercial options for supplying natural gas to the region. First, the distribution hub alternative, in which there is a physical regional hub for LNG. The second alternative consists in aggregate LNG demand, in which a single private company provides LNG directly to all countries. The third market alternative is based on individual contracts, in which each country agrees separately the provision of LNG. Figure 11 depicts the alternatives analyzed.

FIGURE 11 - Plausible Market Alternatives



Source: Author's elaboration based on Castalia's report 2015.

- **ALTERNATIVE 1: DISTRIBUTION HUB**

A distribution hub is formed by a private company or group of companies in a country in the Caribbean that act as a hub for purchasing large shipments of LNG. This LNG is then redistributed in smaller ships to offtakers in other countries. The volume of gas demanded in this option could be sufficiently large for the company purchasing the LNG to access full-sized LNG terminals in the Gulf Coast of the United States or at Atlantic LNG in Trinidad and Tobago.

- **ALTERNATIVE 2: DEMAND AGGREGATION.**

In this alternative a single private company provides LNG directly to all countries with interested offtakers. The single supplier of natural gas acts as a dispatch hub that allows all interested countries to be part of the same arrangement and obtain the natural gas at a feasible price. This supplier would deliver the gas directly from the supply point to each of the offtakers. Since there would be no facilities for transferring LNG once it is purchased from the supply point, this model would require LNG terminals that could provide access to smaller sized vessels.

- **ALTERNATIVE 3: INDIVIDUAL CONTRACTS**

Only those countries gathering sufficient natural gas demand to make the market economically viable contract the natural gas supply on its own. This alternative would only be viable for countries that can individually and directly negotiate natural gas contracts at prices at least 20 percent lower than what they pay for fuel oil.

2. POTENTIAL SUPPLIERS OF LNG FOR THE CARIBBEAN

The countries that possibly supply natural gas to the Caribbean are the United States, Canada, Trinidad and Tobago, Mexico, Colombia, and Venezuela. Each of these countries is geographically close to the Caribbean and has substantial natural gas reserves (see Table 11). Furthermore, most of these countries have large shale gas resources that are under evaluation or development.

TABLE 11 - Potential Suppliers of Natural Gas for the Caribbean.

	Proved Reserves (Tcf)	Shale Reserves (Tcf)	Production (Bcf)	Consumption (Bcf)	Net Exports (Bcf)
Canada	71.4	573	5,468	3,655	1,836
Colombia	5.7	55	446	378	76*
Mexico	12.3	545	2,000	2,922	-933
Trinidad & Tobago	12.4	N/A	1,513	791	697
United States	330	665	24,282	26,034	-1309
Venezuela	196.8	167	1,005	1,078	-76*

Note: 2012 data for Trinidad and Tobago.

Source: Castalia, 2015 based on BP Statistical Review of World Energy June 2014 and U.S. EIA Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of Shale Formations in 41 Countries Outside the United States, June 2013.

The United States is the strongest likely supplier for the Caribbean countries. U.S. LNG exports are projected to range between 0.36 to 2.13 Tcf per year in 2018, based on variations in the rate of LNG export growth and in the global gas market balance. By 2028, U.S. LNG exports are projected to reach a range of 1.63 to 5.25 Tcf per year[58].

Multiple LNG liquefaction projects are under development in the U.S. Gulf coast region, including six that have received licenses to export to non-Free Trade Agreement (FTA) countries. Many of these facilities are close to Henry Hub,

58 Castalia, 2015 based on "Summary of LNG Export Applications," US Department of Energy, accessed 24 April 2015, http://energy.gov/fe/downloads/summary-lng-export-applications.

the United States' main natural gas pricing point, and are in a highly industrialized region with a long history of hydrocarbon development and related industries.

3. MARKET ACTIVITIES FOR DELIVERING LNG IN THE CARIBBEAN

Delivering LNG to offtakers in the Caribbean requires market agents to carry out natural gas production, transport, liquefaction, LNG shipping from the liquefaction facility to the regasification facilities and LNG regasification. These market agents can be a mix of private sector companies, public sector entities, and public-private partnerships.

The market agents involved in each activity along the commercial chain will in turn be linked through a combination of relationships defined by ownership and contractual structures, as well as regulatory and financial structures. These market agents, and the requirements for each, include:

- **WHOLESALER OF NATURAL GAS.** This agent provides the natural gas that is to be liquefied and transported to the Caribbean market. Requirements for natural gas wholesalers include availability of sufficient natural gas volumes within the time period (both physical availability and contractual availability), authorization to export to the Caribbean, and the willingness to sell small volumes of natural gas on a firm basis for the long term.

- **LIQUEFACTION SERVICE PROVIDER.** This agent owns the liquefaction assets that convert the natural gas into LNG for shipping. In order to serve the Caribbean market, these agents must have sufficient liquefaction capacity available in the required timeframe to meet the demand of the Caribbean market, have suitable port facilities to accommodate smaller LNG vessels, and be willing to enter into long-term supply contracts for smaller volumes of LNG.

- **LNG SHIPPING PROVIDER.** This market agent owns and operates the LNG vessels used to transport LNG from the liquefaction supply point to the receiving terminal. This agent must have suitable ships available for long-term charter in the needed timeframe, be able to operate and maintain the ships on behalf of the chartering agents and be willing and able to enter into a long-term contract with multiple offtakers based in multiple countries in the Caribbean region.

- **HUB OPERATORS.** This market agent owns and operates a trans-shipment facility, allowing LNG shipments to be delivered in full-scale LNG carriers, stored as LNG at the trans-shipment facility, and then re-loaded onto smaller scale LNG carriers for delivery to individual markets in the Caribbean. This agent provides a port facility and LNG loading jetty that is able to accommodate both full scale and smaller scale LNG vessels; LNG offloading and reloading equipment, and LNG storage capacity to accommodate the required supply for each final market that is served by the trans-shipment facility. Similarly to other market agents, hub operators must be willing and able to enter into long-term agreements with LNG suppliers and multiple LNG offtakers.

- **DEVELOPERS OF REGASIFICATION TERMINALS.** This agent owns the regasification assets that convert the LNG back into natural gas for consumption in the destination market. In order to serve the Caribbean market, these agents must have sufficient regasification capacity to meet the demand of the individual market in question; have suitable port facilities to accommodate smaller LNG vessels; and, be willing to enter into long-term supply contracts for smaller volumes of LNG.

- **OFFTAKERS.** These market agents are the final link in the LNG commercial chain, representing either the ultimate consumer of the LNG or the wholesaler of the natural gas within the final destination market. As noted, the primary offtakers for LNG in the selected countries are assumed to be power generation companies.

- **SOVEREIGN GOVERNMENTS.** The government's

role includes passing and enforcing any necessary legislative or regulatory changes to address natural gas imports and monitoring the creation of a natural gas market. Governments can also enforce changes to the laws and regulations governing the electricity sector to enable the conversion from oil to natural gas and allow suitable modifications to the tariffs paid by the final electricity consumers; authorizing any tax waiver for the import of related equipment and supplies to build the necessary infrastructure; and, providing sovereign guarantees or direct financial support for the required investment in the NG value chain.

- **FINANCIAL INSTITUTIONS.** These agents provide the financing for the purchase and construction of new infrastructure. They can include private financial institutions, public financing arms, multilateral finance agencies, and export credit agencies. These institutions can also guarantee performance of the various long-term contracts linked with each activity along the value chain.

4. LNG CONTRACTING STRUCTURES

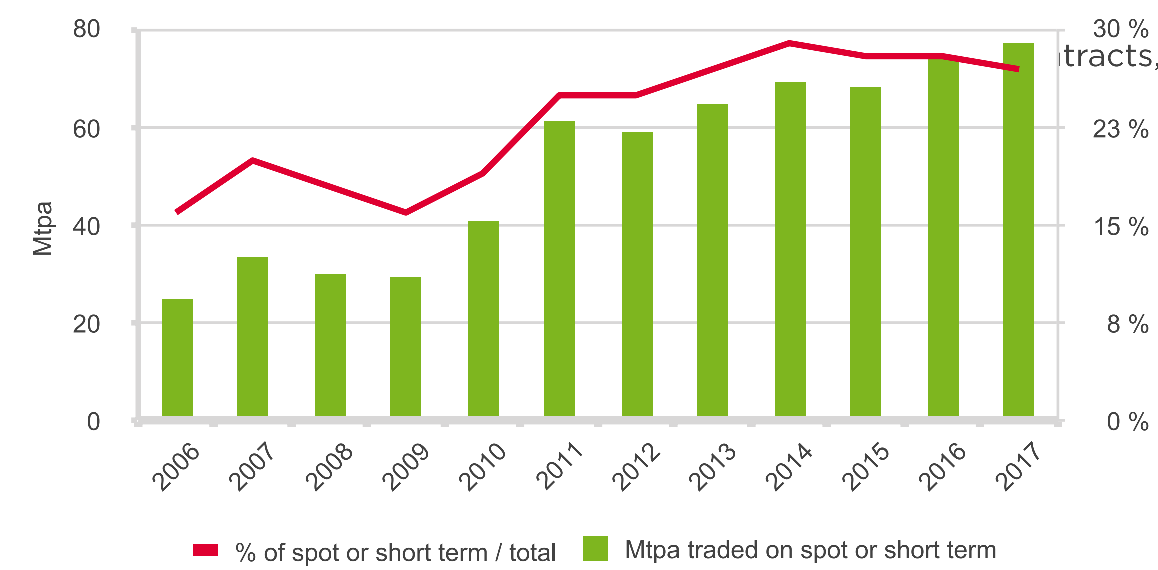
Several agreements and contracts are in place for LNG markets. The key agreements depend on which parts of the value chain are integrated as regards ownership. Three main entities are involved in the business models when LNG is introduced to a power system: the natural gas supplier, the terminal project company (the regasification terminal owner) and the gas offtaker(s). Typically, the project company will have an operation and maintenance (O&M) agreement with a terminal operator to run the terminal. Additionally, the LNG supplier or the LNG buyer will have a transportation agreement with the LNG shipper.

LNG is usually supplied through long term sales (for 20 years or more) and supply purchase agreements (SPAs). Nevertheless, this type of contract is frequently used in combination with short term contracts to tackle unexpected or seasonal changes in demand, as it is the case in the Dominican Republic.

LNG under short term contracts is a growing trend. In some cases, LNG is supplied under short term contracts, either exclusively or in combination with long term contracts. As short-term contracts are usually present – in varying degrees – in LNG import strategies, the Caribbean countries might use their benefits to support LNG purchases.

Contractual terms are increasing in flexibility as the industry expands. More supply competition could favor ease credit conditions and demand scale, facilitating LNG introduction in the Caribbean. In addition, more competition in the medium and long term will favor natural gas price decreases, leading to significant commercial gains from oil substitution.

Growing shipping and liquefaction capacity make short-term arrangements more feasible, increasing the number of shipments being made on a spot basis. Spot market trade has grown rapidly over the past decade: in 2002, total spot or short-term contracts accounted for less than 10 million tons of LNG, or slightly less than 10 percent of the total market at that time. In 2014, 69.6 million tons of LNG were traded on a spot or short-term contract basis, equal to roughly 29 percent of total LNG trade that year[59]. Figure 12 shows the volumes of LNG traded each year in the sport market, and the percentage of these sales to total LNG trade each year from 2006 to 2013.



Source: IADB based on GIIGNL 2006 to 2018 publications.

59 Castalia, 2015.

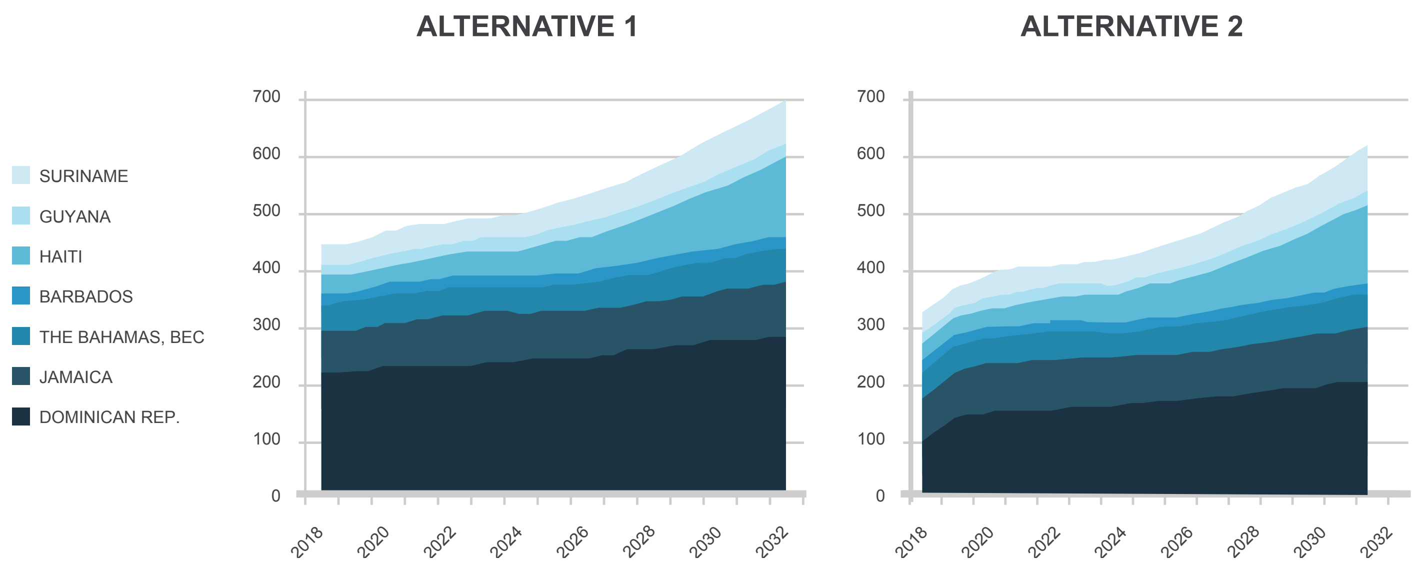
07 Market assessment to introduce LNG in the Caribbean

Market Alternative 3 would be the easiest to implement for introducing LNG in the region. This option would naturally evolve from the interaction of demand with supply. In contrast (with Alternatives 1 and 2), Alternative 3 does not require any coordination of logistics, agreements, or infrastructure across multiple countries. In fact, based on 2015 market activity, several of the individual contracts that form part of Alternative 3 might materialize within the next few years. In the case of Jamaica, the LNG is supplied by New Fortress Energy under a 10-year take or pay gas supply agreement with Jamaica Public Service Company Limited to provision gas-converted and new power plants[60]. This section compares market size and fuel prices for these three alternatives.

1. MARKET SIZE

The forecasts of demand for natural gas in each country show that Alternative 1 would be the option with the largest LNG volume contracted. This option is followed by Alternative 2, and then by an individual contract in the Dominican Republic under Alternative 3. Figure 13 depicts the natural gas demand under Alternative 1 and Alternative 2.

FIGURE 13 - Demand of Natural Gas in MMcdf, 2018 - 2032.



Source: Castalia, 2015

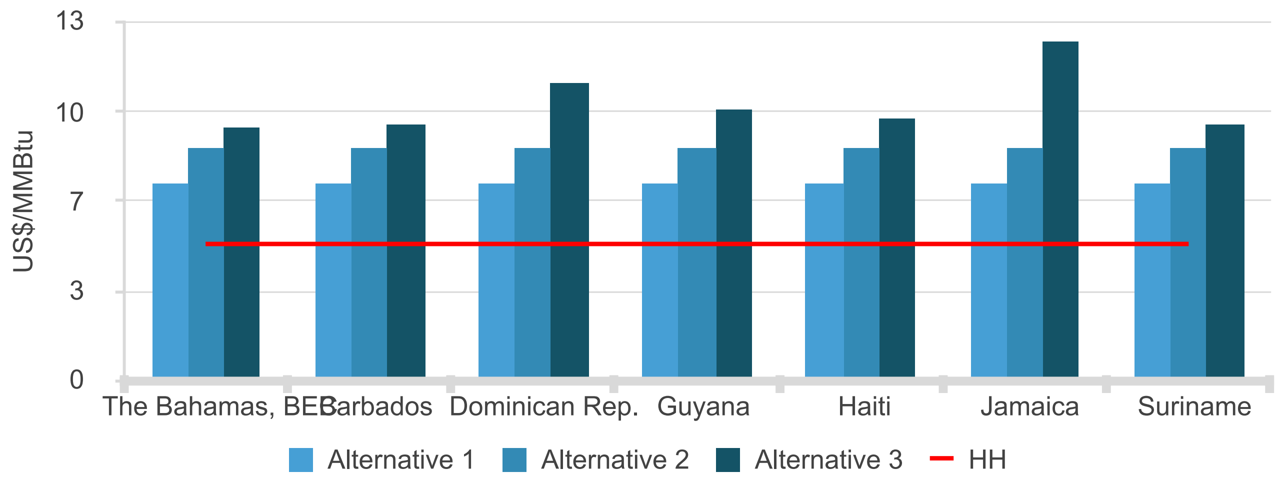
60 New Fortress Energy, 2018.

A larger market would be beneficial because it allows more countries to access natural gas and, therefore, benefit from lower electricity prices. Alternative 1 makes sure that the region is in a strong position to secure a long- term contract and to negotiate the price at which interested offtakers in the region will buy natural gas. Therefore, this alternative allows the region to buy larger quantities of natural gas than they could buy if each country bought gas on an individual basis, and as such, would increase the possibility of getting better prices. Because all the existing demand for natural gas from the Dominican Republic is part of Alternative 1, the contract for natural gas would be the largest possible in the region, and therefore should allow for the best pricing option.

2. PRICES AND SAVING BENEFITS

- **NATURAL GAS PRICES**
  A demand hub formed by a private company or group of companies (Alternative 1) should yield lower prices for the offtakers. Under this market array natural gas could be purchased at around fuel oil parity minus 30 percent for all offtakers involved. The acquired price of natural gas for Alternative 1 is estimated from fuel oil parity minus 30 percent with a resulting price that must be at least equal to Henry Hub plus 20 percent[61] to secure potential suppliers. Under Alternative 2, the acquisition prices are higher than those in Alternative 1. Natural gas could be purchased at around fuel oil parity minus 25 percent and must be at least equal to Henry Hub plus 40 percent[62] to be commercially viable. Individual contracts (Alternative 3) is not feasible for offtakers with volumes lower than what is required to secure suppliers. Under Alternative 3 natural gas could be purchased at around fuel oil parity minus 20 percent and have to be at least equal to Henry Hub plus 59 percent[63] to be commercially viable. Figure 14 compares the acquired price of natural gas in 2023 for the offtakers.

FIGURE 14 - Acquired Price of Natural Gas and HH Price, 2023



Source: Castalia, 2015

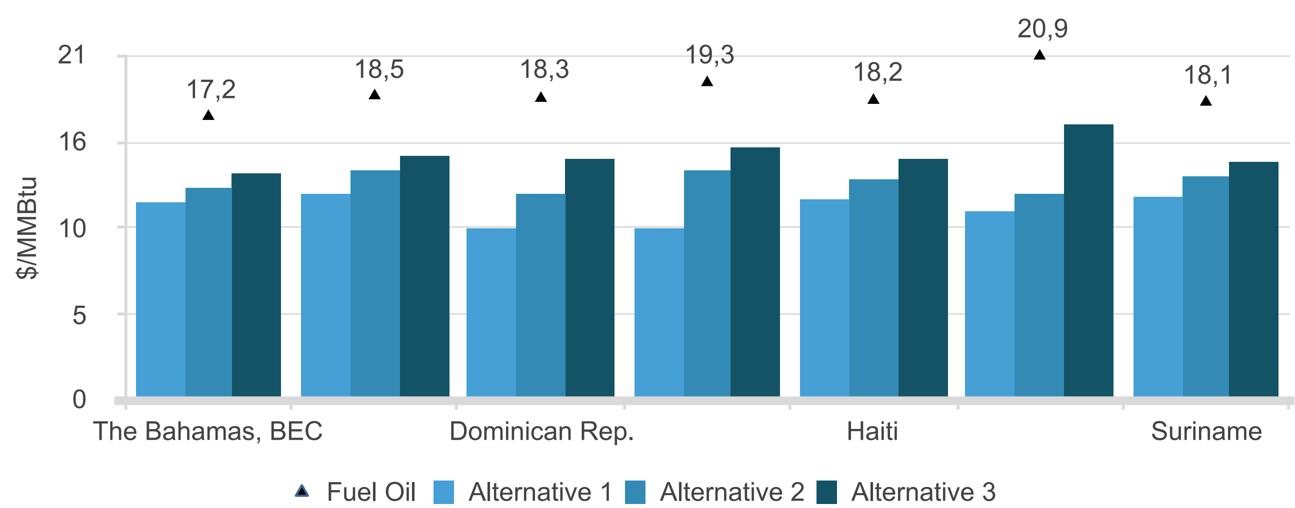
Alternative 1 would be the option that would allow offtakers to contract natural gas at the lowest price (US$7.1 per MMBtu in 2023 which implies a premium over Henry Hub, at US$5 of 43 percent). Under this alternative, all offtakers would be part of the same contract and would have the same acquired price. Alternative 2 would allow offtakers to contract natural gas at somewhat higher prices than Alternative 1 (US$8.5 per MMBtu in 2023, which implies a premium over Henry Hub of 71 percent) because the volumes contracted in this alternative would be lower. Alternative 3 would result in the highest acquired prices of natural gas. These prices would be different for each country with pricing variances up to 25%. Acquired prices of natural gas for this option would range from US$9.2 per MMBtu in the Bahamas to US$12.3 per MMBtu in Jamaica[64].

61 Premium on Henry Hub would always be higher than 20 percent, with an average premium over the life of the contract of 42 percent. Castalia, 2015.
62 Premium on Henry Hub would always be higher than 40 percent, with an average premium over the life of the contract of 67 percent. Castalia, 2015.
63 Premium on Henry Hub would always be higher than 59 percent or higher for all contracts, and above 100 percent for Jamaica. Castalia, 2015.
64 Castalia, 2015.

- **TOTAL COST OF DELIVERED NATURAL GAS IN THE CARIBBEAN** The final cost of delivery LNG includes the cost of extraction and delivery to export point (upstream), liquefaction, shipping to each country, and regasification and delivery to the power plant where the gas will be used. The actual final delivered price for natural gas in the Caribbean will depend on global and local supply and demand for natural gas, as well as regional market trends and developments in the LNG and CNG markets.

  The estimates in Figure 15 serve to compare costs between the delivery technologies from the potential supply points. The total price varies between a minimum of US$10.5 per MMBtu under Alternative 1 (in the Dominican Republic and Guyana) to a maximum of US$16.7 per MMBtu for Alternative 3 (in Jamaica)[65].

FIGURE 15 - Cost of Delivered Natural Gas vs Fuel Oil in 2023.



Note: Fuel Oil prices in 2023 are estimated at US$107.1
Source: Castalia, 2015.

The figure above shows that Alternative 1 would allow offtakers to achieve the highest savings in cost of fuel for generating electricity when compared with fuel oil electricity generation. A key contributor to the cost of delivering

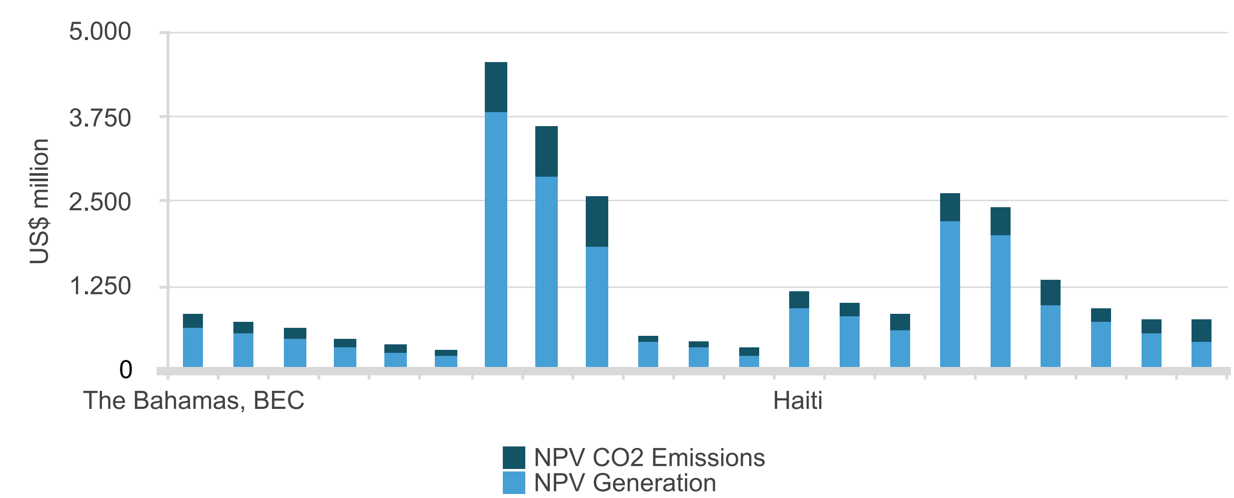
65 Total Costs of Delivered NG includes capital costs on regasification facilities and converting existing plants to NG-fired technology.

LNG, and therefore the final price of LNG, is the size of the market for natural gas in each country. Larger countries like

Dominican Republic will be able to take advantage of relative economies of scale, contracting larger ships to transport LNG and building larger regasification units.

- **NET BENEFITS OF REPLACING FUEL OIL USING NATURAL GAS** The net benefits of each alternative were estimated as total economic costs of business as usual alternative, less total economic costs. Furthermore, the analysis differentiates the financial savings—which only consider the cost of generation and exclude the costs of CO2 emissions, since these are not financial costs but economic costs. The financial savings are calculated for each natural gas market alternative by subtracting the cost of generating electricity in that alternative from the cost of generating electricity in choosing the business as usual alternative. Figure 16 summarizes net benefits for each market alternative.

FIGURE 16 - Net Benefits of Alternatives 1,2 and 3 (NPV in 2018 in US$ million).



Source: Author's elaboration based on data from Castalia, 2015.

All three market alternatives for introducing natural gas in the Caribbean bring large economic and financial benefits to the countries that participate. As per economic benefits,

Alternative 1 has the highest savings for all countries, while Alternative 2 has higher net benefits for all countries when compared with Alternative 3.

The financial savings follow the same patterns as the economic savings — Alternative 1 generates the highest financial savings for all countries, while Alternative 3 has lowest financial savings for all countries. Table 12 shows the financial saving for each alternative.

TABLE 12 - Financial Savings in the Alternatives (NPV in 2018 in US$ million).

Country	Alternative 1	Alternative 2	Alternative 3
The Bahamas, BEC	649	549	455
Barbados	357	276	217
Dominican Republic	3,802	2,881	1,852
Guyana	409	332	235
Haiti	944	781	586
Jamaica	2,213	2,010	947
Suriname	710	556	432

Note: The discount rate is assumed to be 10 percent. Calculations are for the period 2018 to 2032.
Source: Castalia, 2015.

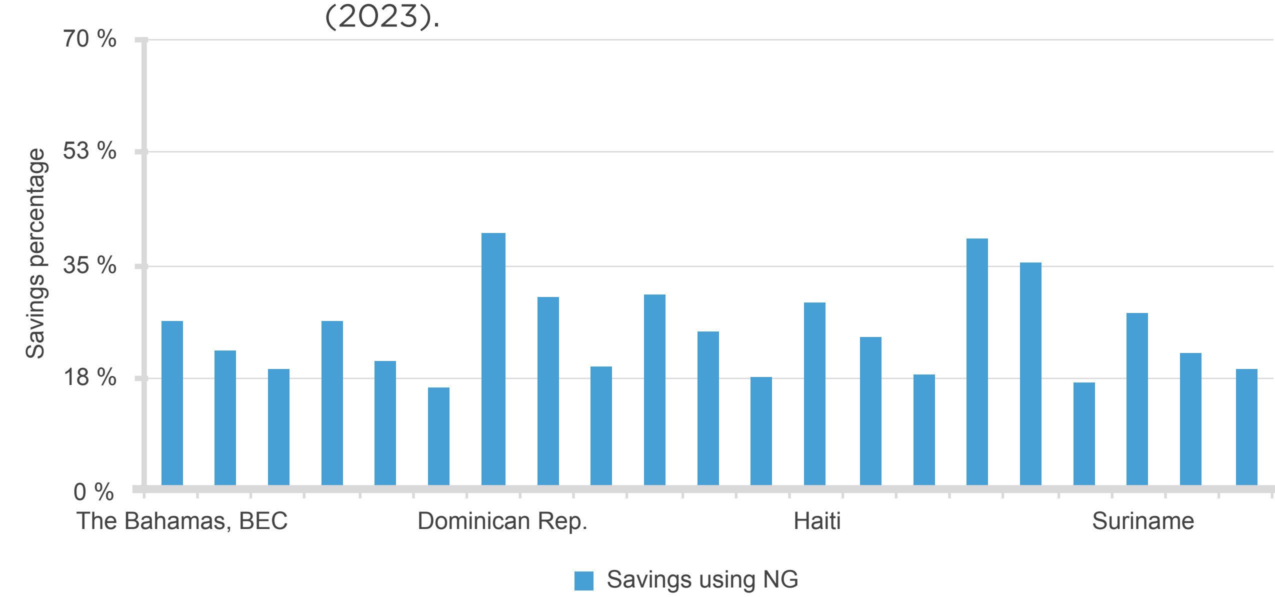
Alternative 1 is likely the best for the region, because it offers the maximum potential to aggregate demand that results in the lowest cost of generation. This would maximize the environmental benefits and reduction in electricity prices for all countries. The results of the cost benefit analysis confirm that net economic and financial benefits are highest for Alternative 1. As Alternative 1 would likely lead to the lowest natural gas prices for all offtakers, there is a strong incentive to coordinate. Aligning offtakers' incentives might help to coordinate timing and reach the agreements necessary to develop a regional hub.

- **FINAL REMARKS ON LNG MARKET ASSESSMENT**

All three alternatives for a regional natural gas market lead to reduced fuel prices for electricity generation. Also, because fuel costs would decrease in all three alternatives, natural gas would reduce the average cost of electricity generation for all countries that participate in the regional market, and fuel costs will account for a lower percentage of generation costs. These impacts are further described below.

The cost of electricity generated with natural gas will be lower than the cost of electricity generated with fuel oil. The all-in cost[66] for fuel oil plants is higher than the all-in cost for natural gas plants in all countries under any of the natural gas market alternatives. For the three natural gas alternatives, the all-in costs of generation vary between US$0.09 per kWh and US$0.16 per kWh, while the all-in cost for the fuel oil (business as usual) ranges between US$0.15 per kWh and US$0.20 per kWh. Given that the maximum all-in cost in the natural gas alternatives is nearly equivalent to the minimum cost generating electricity with fuel oil, it is not surprising that the countries would see savings as a result of replacing fuel oil with natural gas. To further illustrate this point, Figure 17 below presents the savings that each country could benefit from by using natural gas instead of fuel oil.

FIGURE 17 - Savings by Replacing Fuel Oil with Natural Gas (2023).



Source: Author's elaboration based on data from Castalia, 2015.

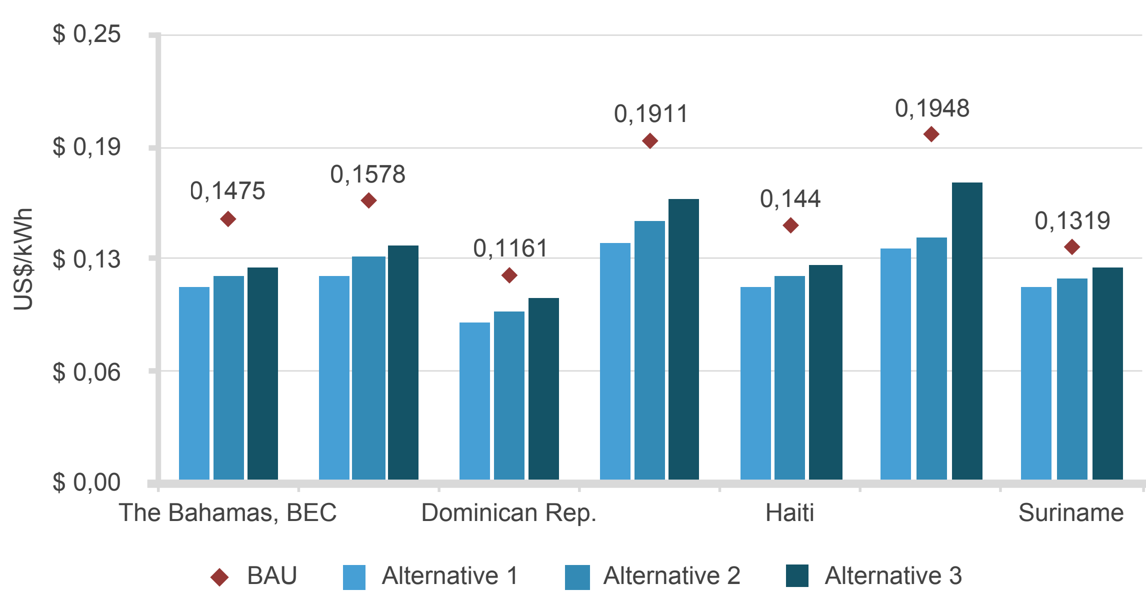
66 Long-run marginal cost of building, operating and maintaining a power plant.

The savings by replacing fuel oil with natural gas would be between 16 percent and 40 percent for Alternatives 1, 2, and 3. The capital costs vary for each market alternative—since those include the construction of new plants and conversion of existing plants to natural gas.

The market average cost of electricity will decrease by replacing fuel oil power plants with natural gas plants. The average cost of generation for a system is calculated by considering all technologies used for generating electricity. Essentially, the average cost of generation is the weighted average of the all-in costs (Unit Capital Cost, Variable O&M costs, Fixed O&M costs and Fuel cost per kWh) of all the technologies that generate electricity in a system.

All electricity generation systems in the selected countries will have sources other than fossil fuels in their generation matrices. However, because a large percentage of the electricity in most of those systems is generated using fuel oil—which would be substituted for natural gas— the average cost of generation in each country presented in Figure 18 below, approximates the all-in costs presented in Figure 17 above. Figure 18 shows how the average cost of generation for each system would change by introducing natural gas as a generation source, and using it instead of fuel oil.

FIGURE 18 - Average Generation Cost of Systems with Natural Gas (2023).



Source: Castalia, 2015.

In the event that the countries under analysis switch to using natural gas in place of fuel oil, they could reduce their average cost of generation between 8 percent and 32 percent in 2023. The lowest savings account US$0.01 per kWh for Suriname under Alternative 3, while the highest savings estimated in US$0.06 per kWh take place in Jamaica and Guyana under Alternative 1.

Although the price of natural gas would be highest in Alternative 3 for all countries, this option would still reduce the cost of generation for all the selected countries. Individual natural gas supply contracts would reduce the average costs compared to fuel oil by between US$0.02 per kWh and US$0.03 per kWh for all countries that would participate in Alternative 3, except for Jamaica, where prices would only fall by US$0.01 per kWh.

3. INFRASTRUCTURE CAPITAL COST

The costs of capital investments for Alternative 1 and 2 are fairly similar[67] (see Table 13). Other than the cost of the Hub, the only difference between the two alternatives is the higher investment in regasification facilities in Alternative 2. This difference is due to the assumed difference in the costs for the Dominican Republic[68]. In Alternative 1 assumptions include additional LNG capacity in Dominican Republic to supply conversion of plants and new plants in the already existing site. In Alternative 2 assumptions contain another party building a new facility to supply conversion of plants and new plants. Therefore, the cost of building the new facility is higher than the cost of AES Dominicana expanding the existing one.

67 While costs for Alternative 2 and 3 are equal.
68 By 2018, AES already expanded its LNG facility “AES Dominicana”.

TABLE 13 - Capital Costs by Activity and Alternative, 2015-2022

Item	Alternative 1 (US$ million)	Alternative 2 (US$ million)	Alternative 3 (US$ million)
Hub	314	-	-
Small Ships	180	270	270
Regasification	1,200	1,310	1,310
Conversion of Power Plants	277	277	277
New Power Plants	1,745	1,745	1,745
Total	**3,717**	**3,603**	**3,603**

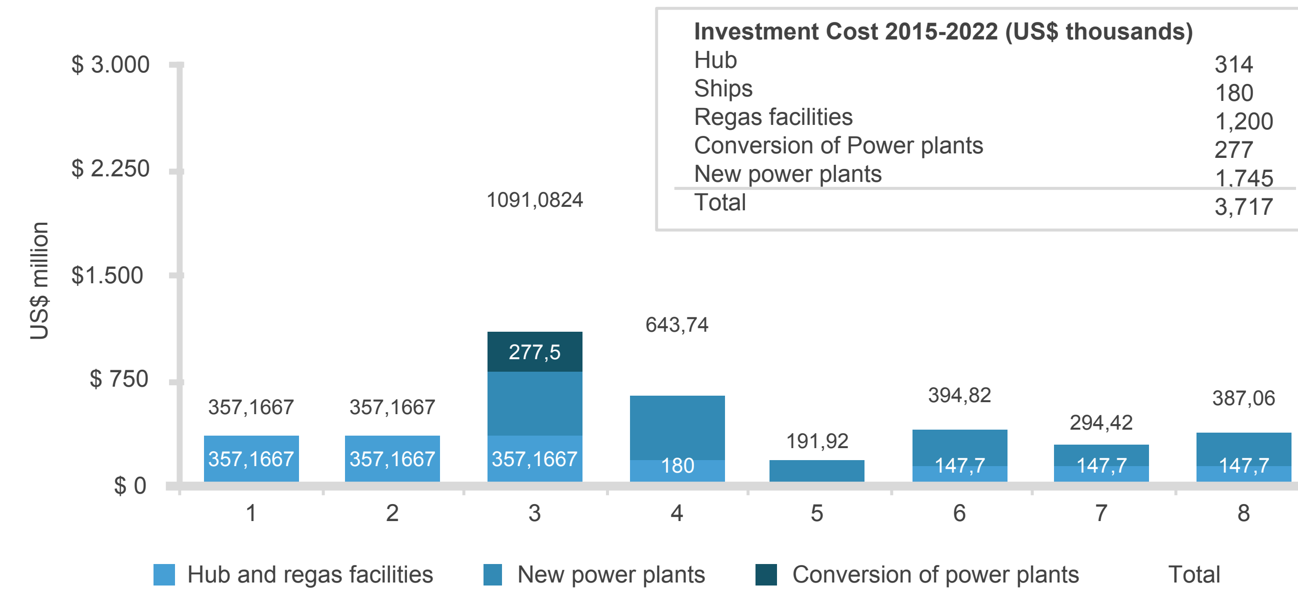
Source: Castalia, 2015.

(I) MARKET ALTERNATIVE 1

All the assets for delivering natural gas to the power plants would require investment costs of about US$1.7 billion over an eight-year period (from 2015 to 2022). Of these investments, regasification facilities would represent the highest capital cost (representing 70 percent of these costs), with a total capital investment of about US$1.2 billion dollars. The cost of the hub and regasification facilities is divided evenly over the three years needed to build these facilities (from 2015 to 2017) and expand the facilities (from 2020 to 2022).

The costs of converting power plants are a cost directly associated with introducing a natural gas market in the region (these costs total US$277 million, about 7 percent of total investment costs). However, the investments in power plants (which make up the largest investment cost at nearly US$1.8 billion, or about 50 percent of the costs) would have to be made even without introducing natural gas into the market. In other words, the investment in new power plants relates to the investment in power expansion plans for each country—if these investments are not made for developing natural gas fired generation plants, they would have to be made for developing other types of generation capacity, most likely fuel oil fired power plants (depending on the technology chosen, the costs would vary somewhat but would be of the same magnitude). Figure 19 shows the investment costs in infrastructure for delivering natural gas to the power plants, and capital costs of converting existing power plants and costs of new power facilities.

FIGURE 19 - Investment Costs under Market Alternative 1, 2015-2022



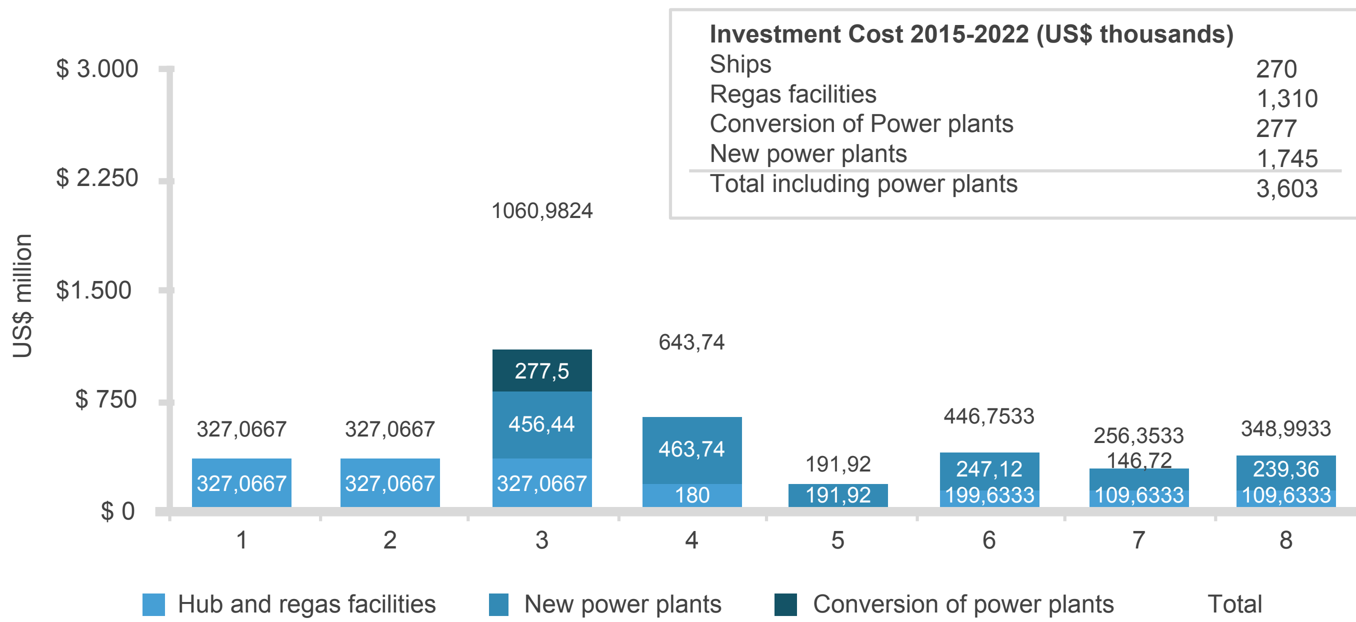
(II) MARKET ALTERNATIVE 2

All the assets for delivering natural gas to the power plants would require investment costs of about US$1.6 billion over an eight-year period (from 2015 to 2022). Of these investments, regasification facilities would represent the highest capital cost (representing 83 percent of these costs), with a total capital investment of US$1.3 billion.

The capital costs related to power plants are divided into costs of converting existing power plants and costs of new power plants. The costs of converting power plants are directly associated with introducing a natural gas market in the region (these costs total US$277 million, around 8 percent of total investment costs). The cost of new power plants is the largest investment cost at US$1.8 billion, or about 50 percent of the costs. Figure 20 shows the investment costs

that would be required to make sure that all the assets for delivering natural gas to the power plants are in place.

FIGURE 20 - Investment Costs under Market Alternative 2, 2015-2022.



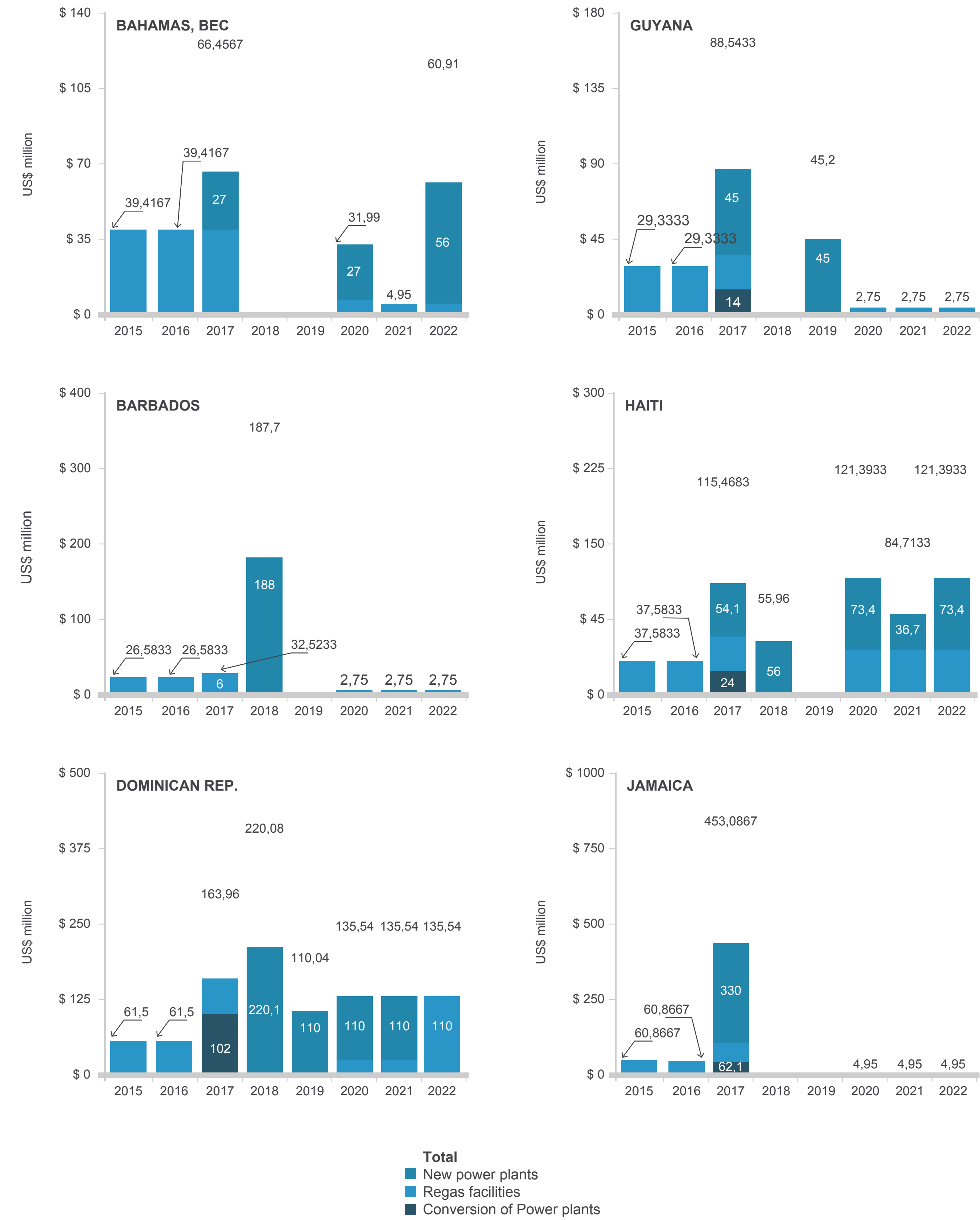
Investment Cost 2015-2022 (US$ thousands)	
Ships	270
Regas facilities	1,310
Conversion of Power plants	277
New power plants	1,745
Total including power plants	3,603

(III) MARKET ALTERNATIVE 3

All the assets for delivering natural gas to the power plants would for each of the six individual contracts require investment costs that range from US$88 million (for Barbados) to over US$257 million (for Haiti) in a seven-year period (from 2015 to 2022).

The capital costs of converting existing power plants and costs of new power facilities ranges between US$ 104 million (for Guyana) to US$ 793 (for Dominican Republic). The results indicate that Dominican Republic would require by far the highest investments, and that the investments in power plants would be the highest investments for all participating offtakers. Figure 21 shows the investment costs in infrastructure for delivering natural gas to the power plants, and capital costs of converting existing power plants and costs of new power facilities.

FIGURE 21 - Investment Costs under Market Alternative 3, 2015-2022.



08 LNG supply considerations

Unveiling the natural gas opportunity in the Caribbean

Unveiling the natural gas opportunity in the Caribbean

Spreading LNG participation in the energy mix in the Caribbean poses a number of risks and complexities. Some of these risks are inherent to any change in the main fuel for electricity generation, while others are specific to LNG. The main challenges are related to financing, the legal and regulatory framework, commercial arrangements, and technical and environmental aspects of using LNG.

1. FINANCING CHALLENGES

The region must secure sufficient financing to backstop the LNG supply contract, as well as support the construction of required infrastructure to transport and deliver the LNG to each destination market. This will be especially difficult for the region because many Caribbean countries have high levels of sovereign debt. Also, many of the region's utilities have poor credit ratings.

Project financing involves two separate but related requirements: securing the actual funds to pay for the needed investment, whether through capital or debt; and, providing the necessary financial guarantees and assurances that the companies that enter into long-term natural gas supply contracts will need to cover the agreement's costs for its entire duration. Each of these aspects is reviewed in detail below.

FINANCING TO COVER CAPITAL COSTS

Depending on the arrangements, parts of the value chain would need to be financed by the offtakers (for example regasification facilities). The type of financing available to each offtaker would depend on its financial capacity as well as any support the host government may be able to provide. Other segments, such as the construction of appropriate transportation vessels, can be financed by the private companies that make the vessels available for hire and operate them on behalf of the chartering client.

While multilateral banks can support a portion of the project, funding from private financial institutions and the project sponsors themselves will also be required. This allocation

of the funding requirement across the various participants has implications for the ultimate ownership and contractual structure of the commercial chain.

CREDIT REQUIRED TO ENTER INTO LONG-TERM GAS SUPPLY AGREEMENTS

Due in part to the capital intensity of new LNG infrastructure, LNG purchase and sale contracts tend to have 15 to 20 years duration. These contracts in turn require a guarantee of payment for the length of the contract to allow the seller to secure the financing it would require building the necessary infrastructure.

This long-term take-or-pay requirement, and the related guarantee, is different from contracts to buy fuel oil, where a liquid and fungible global market helps protect sellers from any default by their buyer. Some sellers would require a guarantee that covered 1 to 2 years of costs of natural gas delivered in each country[69]. This suggests a required guarantee of about US$70 million to US$140 million for the smaller countries in the region, such as Barbados, to as much as US$0.7 billion to US$1.4 billion for the larger countries, such as the Dominican Republic. Securing this type of guarantee will be difficult, given the poor credit ratings of most offtakers and governments in the region.

Managing this disconnect between the financial guarantees required by infrastructure developers and the credit capacity of the ultimate natural gas offtakers will require careful financial planning and coordination among buyers, sellers, financing providers, multilateral lenders, and governments.

2. LEGAL AND REGULATORY CHALLENGES

Except for the Dominican Republic and Trinidad and Tobago, in 2015 the selected countries lacked a domestic natural gas market. Creating a new LNG market will require introducing regulations and requirements for controlling and monitoring

69 Castalia, 2015 based on Gunvor (commodity company).

the value chain development on each country.

A related issue concerns the risk of contracting LNG supply to a single monopoly supplier. An open tender process and sufficiently attractive market, legal, and regulatory regime can help ensure that the largest possible number of suppliers compete in the tender. This approach would limit the competition for market access to a single point in time and also establish the most attractive opportunity for the region, thereby potentially increasing the level of competition at that point.

A key aspect in ensuring the market does eventually become more competitive would be to limit the contract period to a relatively short length (15 years). This would allow further competitive elements to be introduced quickly.

3. COMMERCIAL ARRANGEMENTS

The commercial arrangements should allocate risks to those entities that are best able to manage them. In each case, the shifting of risk from one entity to another will likely have an impact on the final price to be negotiated between buyer and seller.

A critical risk facing Caribbean countries is the limited size of each individual market. Countries with the smallest potential natural gas demand also face the highest costs in delivering the gas, as the cost to build many components along the supply chain are relatively insensitive to the size of the project. The challenges with these smaller volumes of demand are:

- **SECURING LONG-TERM GAS SUPPLY AGREEMENTS.** Owners of liquefaction terminals have a strong incentive to sign a few supply contracts with a small number of large, credit worthy offtakers rather than spend the greater amount of time and expense required to negotiate a much greater number of supply contracts with small offtakers.

- **COORDINATING INFRASTRUCTURE AND SERVICES ACROSS MULTIPLE COUNTRIES.** One way to overcome these difficulties is for a number of small offtakers to jointly negotiate a single contract for the sum total of their individual requirements. This approach, however, may in turn create additional difficulties. The added complexity of negotiating supply agreements with multiple customers, as well as managing government relations and regulatory compliance with multiple jurisdictions, can slow down the development process significantly. A project that is economically viable serving a single country may be better phased to serve that single customer first before expanding to include additional countries. For projects that are not economically feasible without including multiple countries, or are very difficult to increase in scale once built (such as for undersea pipelines), this suggests that the value chain development process will be slow, taking many years to manage the resulting complexity.

4. TECHNICAL ASPECTS OF USING LNG

New natural gas markets have a number of technical challenges as well. Most importantly, electricity generation capacity in the destination markets has to be converted in order to burn natural gas. Each of these technical aspects is discussed in detail below.

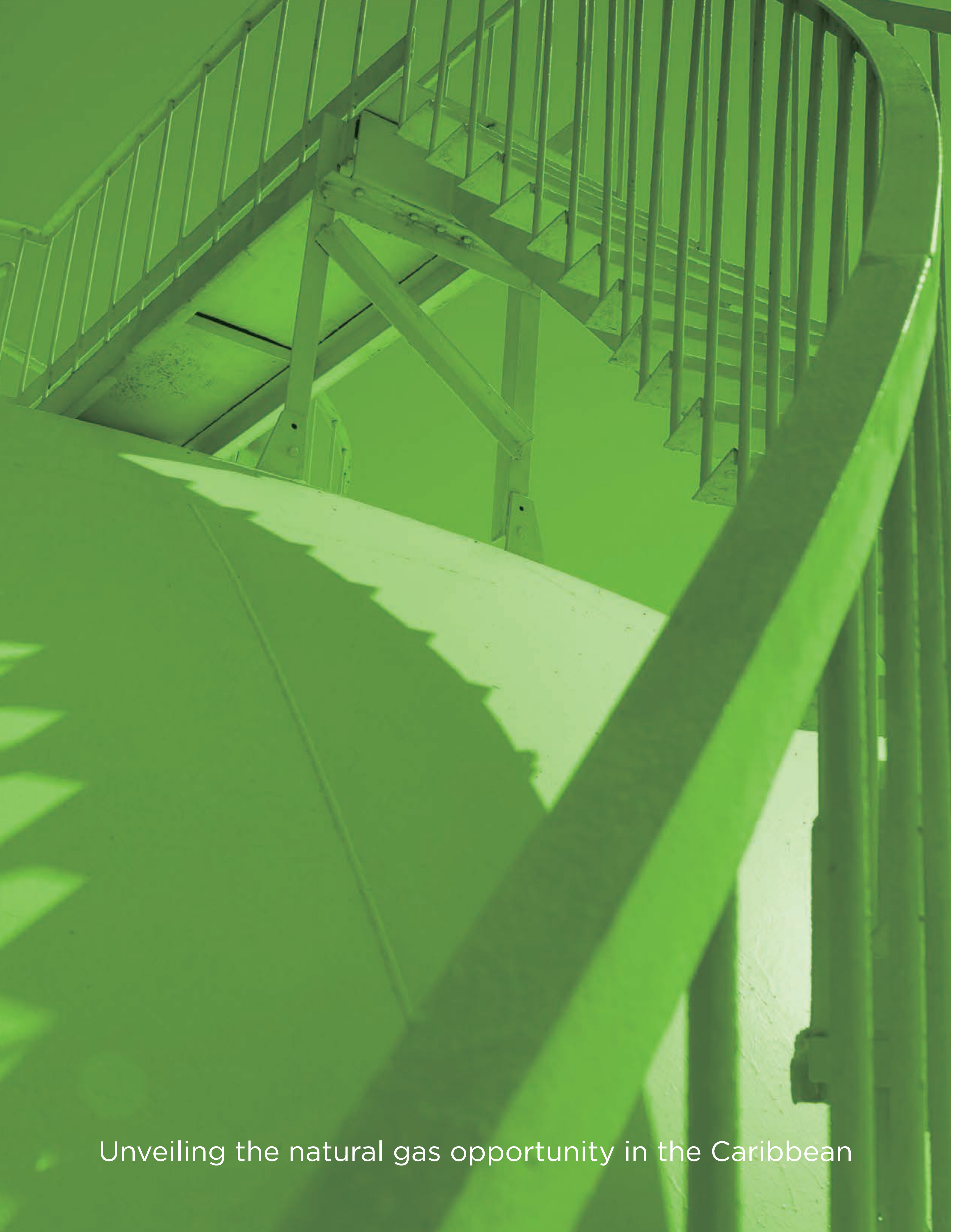
- **TRANSPORTING SMALL VOLUMES OF LNG.** Smaller volumes of demand in the Caribbean impose challenges to the physical access to standard terminals. Potential constraints can include the height of the jetty, the size and positioning of the LNG loading arms, and the flow volume and configuration of off-loading pumps and connectors. A liquefaction facility that has been optimized to serve full-scale ships could therefore face operational challenges supplying smaller ships that could only take on a fraction of the expected supply in each loading cycle.

- **CHANGING ELECTRICITY GENERATION TECHNOLOGIES.** The Caribbean region's fuel oil fired electricity generation technologies are feasible to convert, although the specific cost to convert each unit will depend greatly on the specific manufacturer and model.

  The conversion process might allow the units to burn both fuel oil and natural gas. By having this flexibility, offtakers might switch to liquid fuels as a back-up to any disruption in natural gas supply. This capacity can also help introduce a hedge against changes in the relative delivered price of natural gas and liquid fuels, as the generators could readily switch to whichever fuel was cheapest.

09 Risk Analysis

Unveiling the natural gas opportunity in the Caribbean



1. VALUE CHAIN RISKS

Within the group of contracting risks, five specific risks were assessed:

- **CONTRACTING RISK.** Assesses the risk that individual countries within the Caribbean will be unable to secure a long-term contract for LNG. Alternative 1, using a Hub and Spoke model to aggregate regional demand, offers the greatest opportunity for countries of all sizes in the region to secure access to LNG supplies. Alternative 2 also brings benefits by aggregating demand into a single contract, but without the backing of a unified physical supply chain. In contrast, Alternative 3 in which each country negotiates its own supply agreement, presents the greatest difficulty for countries in the Caribbean, the smaller ones in particular, to secure natural gas supply owing to the lack of scale.

- **PARTICIPATION RISK.** Assesses the risk that not all countries in the region will be able to secure access to LNG supply, in particular the risk that smaller countries will be left out. A more favorable ranking indicates a greater number of countries participating. Owing to the contracting difficulties noted under contracting risk above, both Alternative 2 and Alternative 3 are expected to have fewer countries participating in any natural gas supply arrangement. Under each of these alternatives, the smaller countries are most vulnerable to being left out.

- **SUPPLY RISK.** Assesses the risk that natural gas supply will be unavailable in the volumes that are contracted for the long-term. It is a measure of the reliability of potential natural gas suppliers to the region

- **DEMAND RISK.** Assesses the risk that natural gas demand in the receiving countries will be lower than the volumes contracted. It is a measure of the risk that natural gas demand may not grow as quickly as anticipated. Alternative 1 is expected to result in the greatest price

discount relative to fuel oil given the relative negotiating strength for LNG buyers in that alternative. Alternative 2 and 3 are expected to have a smaller price discount, thereby reducing the barrier to entry for other power generation technologies. This, in turn, increases the risk that demand for natural gas may be smaller than anticipated in each of these alternatives.

- **PRICE RISK.** Assesses the risk that delivered natural gas prices will move higher than alternative fuels. As in the demand risk assessment above, the smaller discount relative to fuel oil prices in both Alternative 2 and Alternative 3 increases the risk that natural gas prices could move unfavorably relative to alternative fuels

Within the group of operational risks, five specific risks were assessed:

- **TECHNOLOGY RISK.** Assesses the risk that critical technologies within the commercial chain will fail to be developed or prove to be unviable.

- **CONSTRUCTION RISK.** Assesses the risk that the construction of new infrastructure and assets required for the commercial chain will be delayed or cost well above expectations.

- **TIMING RISK.** Assesses the risk that some segments of the commercial chain are delayed, impacting the financial performance of the already completed assets. The greater interdependence of the development of each country's assets, in addition to the development of the trans-shipment hub infrastructure, greatly increases the risk that variations in the development of individual assets could affect the overall project's success in Alternative 1. Alternative 2 also requires greater coordination of development schedules, although not to the same degree as Alternative 1.

- Operations risk. Assesses the risk that the assets will not be operated properly, leading to an extended shut down or shortened lifespan for the assets. The addition of a trans-shipment center in Alternative 1 requires a company with deep expertise in LNG operations to manage the LNG shipments in and out of the transshipment center, leading to a slightly lower risk of an accident or extended shut down relative to the other alternatives. Alternative 3, with each country contracting its own supply and transportation, has a slightly higher risk of a less experienced company operating assets at some link in the chain.

- **COORDINATION RISK.** Assesses the risk that a failure to coordinate each stage of the commercial chain would result in delayed deliveries or other shortfall in available natural gas for the final consumers. As was noted in the timing risk assessment above, Alternative 1 requires far more complicated coordination of activities in order to manage the supply of LNG to the transshipment center and the re-shipment to each participating country. This coordination challenge is avoided in Alternatives 2 and 3 where LNG shipping is managed independently for each participating country.

Within the group of financial risks, five specific risks were assessed:

- **CAPITAL REQUIRED.** Indicates the risks to attract the capital required to build the assets and infrastructure for each alternative. The addition of a transshipment center in Alternative 1 increases the capital requirements for that alternative relative to the other two. This additional capital is minimal if an existing LNG receiving terminal is adapted to be used as a trans-shipment center, but could be significant if an entire new facility must be built.

- **LENDING RISK.** Assesses the relative risk to financial institutions that are directly lending funds in order to build the required assets and infrastructure.

- **GUARANTEES RISK.** Assesses the relative risk to financial institutions that are providing financial guarantees and credit enhancements in order to backstop the natural gas contracts signed between consumers and suppliers. In Alternative 3, only the larger consuming markets would participate in the LNG commercial chain, thereby reducing the total volume of natural gas to be contracted as well

as potentially reducing the level of guarantees that the participants would need.

- **LIQUIDITY RISK.** Assesses the need for liquidity instruments or working capital to manage delays in payments along the commercial chain. The addition of a central aggregator in Alternative 1 (with the physical hub) and Alternative 2 (with the demand aggregation) adds an additional point in which mistiming of payments between each link in the chain can create liquidity issues. In each of these alternatives, the aggregator will take on a certain amount of risk that each final consumer will remain up to date on their payments, and so will want to have sufficient working capital to cover any potential payment delays.

- **CURRENCY RISK.** Assesses the risk of foreign exchange variations. In particular evaluates situations in which the investments are being made in U.S. dollars or other hard currency while the offtakers revenue stream is based in local currency. As in the liquidity risk noted above, the central aggregator in Alternatives 1 and 2 will also take on any currency risk, as the main supply agreement with the LNG provider will likely be in U.S. dollars or other hard currency. In this case, the aggregator will also likely require guarantees or similar support to manage this risk.

Within the group of government risks, two broad areas were assessed:

- **LEGAL AND REGULATORY RISK.** This is a broad measure of the relative legal and regulatory stability and preparedness of the countries receiving the LNG deliveries.

- **POLITICAL AND SOVEREIGN RISK.** This is a broad measure of the relative political stability and government support for the project by the countries receiving the LNG deliveries.

Table 14 below compares the relative risks facing the development of an LNG commercial chain under Alternative 1,2 and 3. These risks are divided into four broad groups: contracting risks, operational risks, financial risks, and governmental risks. The risks were assessed in the context of the Caribbean region, such that an average risk ranking was calibrated to match the average risks facing similar sized investments in the region.

The ranking symbols in Table 14 are five. A full circle represents the most favorable ranking (in this case, the lowest risk), while an empty circle represents the least favorable ranking (in this case, the highest risk). In addition to ranking each category across the three alternatives, the relative importance of each category is assessed to the overall success of the LNG commercial chain. Those categories shown to have a "High" importance are most critical to the project's success, while those with a "Low" importance are less relevant or less likely to pose a constraint on the project.

TABLE 14 - Risk Matrix

	Importance	Alternative 1	Alternative 2	Alternative 3
Contract Risks				
Contracting Risk	High			
Participation Risk	High			
Supply Risk	Low			
Demand Risk	Medium			
Price Risk	Medium			
Overall Contract Risk	Medium			
Operational Risks				
Technology Risk	Low			
Construction Risk	Medium			
Timing Risk	Medium			
Operations Risk	Low			
Coordination Risk	Medium			
Overall Operational Risks	Low			
Financial Risks				
Capital Required	Medium			
Lending Risk	High			
Guarantees Risk	High			
Liquidity Risk	Medium			
Currency Risk	Medium			
Overall Financial Risks	High			
Government Risk				
Legal and Regulatory Risk	Medium			
Political and Sovereign Risk	Medium			
Overall Government Risk	Medium			

Source: Castalia, 2015

2. ENVIRONMENTAL RISKS

Infrastructure development carries environmental impacts and risks. Nevertheless, risks of handling and using LNG for electricity generation can be lower than risks with liquid fuels, and emissions from burning natural gas for electricity generation are lower than those from burning fuel oil.

The most prevalent environmental threats among the countries are biodiversity loss, erosion of coastal lines, and deforestation. These threats could be intensified due to poor coastal planning and overexploitation of natural resources.

- **OPTIONS FOR MITIGATING ENVIRONMENTAL RISKS**

  Environmental risks will vary depending on the selected locations to build LNG facilities. An Environmental Impact Assessment (EIA) and Environmental Management Plan (EMP) must be developed for each country, in accordance with national laws.

  The full EIA must describe environmental concerns specific to each country's project site or sites, and recommend impact mitigation measures. The EMP outlines construction and operation procedures that incorporate mitigation measures to guide these phases throughout the project site's development and operation. The EMP also includes plans for natural hazards preparedness, spill contingency, hazardous materials storage, and waste management.

  Legislation and regulations would be needed in each country to ensure that basic environmental and safety standards are followed for construction and operation. National agencies with responsibility for oversight will have to be staffed with trained personnel.

  Further actions to mitigate risks specific to the transportation, storage, and use of LNG include (i) developing advanced models, such as computational fluid dynamics (CFD) models, prior to construction of

  LNG facilities to provide safety mechanisms to detect and prevent a catastrophic failure, including multiple containment systems to protect LNG storage tanks, or a raised earthen "dam" surrounding LNG tanks in order to contain the spread of the LNG pool in the event of a major leak, (ii) monitoring and evaluating equipment and materials to handle LNG, (iii) implementing plans for methane emissions reduction Natural Gas STAR International and the Methane to Markets Partnership are examples of global initiatives that Caribbean countries can participate in, (iv) implementing turbidity control methodologies during dredging, including silt curtains and booms, and (v) installing appropriate navigational aids for ships, as well as proper anchoring or berthing facilities to avoid ship anchoring or grounding and accidents at sea.

3. SOCIAL RISKS

Social risks from operating the supply chain and power plants for LNG consist of risks to on-site personnel and risks to the public. Risks to on-site personnel include exposure to oxygen depletion and extreme low-temperature materials. LNG leaks could endanger on-site personnel and the public as well as the environment.

Other impacts and risks for the public include fires or explosions from flammable and combustible materials stored on the project site, loss of fishery resources which are important as food and income sources for local populations, and noise pollution.

- **OPTIONS FOR MITIGATING SOCIAL RISKS**

  To mitigate risks to on-site employees of facilities that transport and use LNG, personnel must be trained in handling equipment operating at very low temperatures. This includes training managers and workers on protocol for safe storage and handling of hazardous materials, worker safety procedures, and appropriate actions and

their assigned responsibilities for implementation of response plans for natural hazards and spills. Suitable protective clothing and training can mitigate risks during normal operations. On the other hand installing appropriate navigational aids for ships, as well as operational protocols (such as speed limits in channels), can help to avoid accidents at sea, in accordance with national and international regulations and standards. Finally monitoring the quality of groundwater, seawater, freshwater, air, and soil is important for early spilling detection.

10 Regulatory framework to introduce natural gas in the Caribbean

Unveiling the natural gas opportunity in the Caribbean

There are a number of key components of the natural gas regulatory framework that need to be in place for establishing a natural gas market in the Caribbean. The initial regulatory framework for a new market is likely to be quite different from the regulatory framework in a mature gas market. A sensible approach is that the initial framework should not preclude different options for the shape of the market that will develop over time, while recognizing that if initial investments are carried out by the private sector, a degree of monopoly must be conferred to underpin the financing of those investments. On the other hand, if the public sector carries out the initial investments, such as to create an import facility, initial gas transmission system and possibly also local distribution networks, the regulatory framework to support multiple gas suppliers needs to be in place from the beginning.

The Caribbean countries have different opportunities, constraints and objectives. These differences have to be included while assessing impacts on areas such as the role of private vs public sectors, the focus on power compared to non-power gas sectors, and the degree and form of regional integration.

This section covers two regulatory aspects: Country-Level Policies and Laws, and the market structure and conditions to underpin the financing of gas infrastructure. The first part describes briefly the state of the legislative and regulatory framework in the Caribbean in year 2015, and it is followed by recommended steps for developing the regulatory frameworks in the Caribbean. The second part assesses regulatory issues which could potentially affect the structuring of financing for the natural gas value chain.

1. COUNTRY-LEVEL POLICIES AND LAWS

Laws and regulations in the selected countries set out different legal frameworks for the environmental and social approvals needed for infrastructure development. However, all countries that would import natural gas in Alternative

1 require an assessment of the environmental and social impacts of projects, as well as planning or land-use approval for the site where the project is built. Regulations on the safe handling, storage, and use of LNG often consist of regulations that protect on-site employees and other people, and regulations that protect the environment.

National development plans, national energy policies, and other national policy documents in the selected countries prioritize reducing energy costs, reducing the environmental impact of the energy sector, increasing access to electricity and other forms of modern energy, and diversifying energy sources.

Furthermore, these countries participate in various international treaties and conventions that set out safety and environmental regulations related to shipping and infrastructure development. The agreements that apply to shipping will be relevant to any LNG project. Other agreements apply to some of the infrastructure to import and use LNG for electricity generation, depending on the type of infrastructure and where it is built.

2. THE DEVELOPMENT OF A REGULATORY FRAMEWORK

The development of each country's regulation requires certain steps to accompany the process of attracting investment, from general sector regulation, through regulations for specific activities, finally to detailed implementation regulation.

At present in most of the Caribbean countries, the lack of a normative and clear regulatory direction to support gas market development will create an uncertain environment for investment. Therefore, the initial normative development that would be required to facilitate formation of the market would be to establish general rules to attract investors to the business. This would correspond to developing the primary legislation focused on gas and the main sector regulation to reflect the intended structure, ownership and operation of

the market. At this stage, it will be important to keep these simple but clear to avoid imposing an excessive regulatory burden on new investors or the risk of ambiguity in the regulatory framework.

In order to attract large private investment in infrastructure, it will be necessary to make progress with the specific regulation, such as secondary regulations and decrees. These legislations should be focused on defining the activities and rights of investors, as well as the boundaries of their operation and obligations to the public. The requirement and scope for the regulatory framework will depend to the extent there is actual or intended competition in various segments of the market. This corresponds to the last stage of regulation and market design.

In the gas sector, import terminals and transmission networks have the character of natural monopoly. Prices may be set by regulation if publicly owned but for private ownership a defined monopoly is likely to be needed and prices set in the tendering. This condition may not be the same for distribution, where the whole sector can be split into more than one distribution concession area, but the infrastructure investment will still require a firm price commitment.

- **GENERAL REGULATION**

  The general regulations excluding the specific aspects of the gas market might become a constraint for investors. Consequently, it will be important to ensure that any new regulation is clearly focused on activities which need to be regulated and does not create barriers to investment.

  Having a unified regulation drafted into a single document may result in difficulties to introduce small changes later on. Nevertheless, unbundling the regulatory framework into several different regulations might create the risk of different interpretations or contradictions. Neither approach is uniquely better for the start of a market, but the guiding principle is that rules which are unlikely to change may be combined into a single regulation, while those which will change as the market changes, are better left in separate documents.

In a general regulation, it is convenient to include and define the function of an oversight body for the market. This may be entrusted to an existing entity or a new specific entity that is created for this purpose. At the starting stage of the market, a specific regulator may not be necessary as it is unlikely that there will be a competitive gas market. Instead, a regulated monopolist player may prove to be more effective. The key regulatory function is to enforce the conditions of the concession contract, of which the most difficult may be the obligations on investing in infrastructure to build out the network.

With regulated monopolists, such as import terminal or distribution concessions, the framework should incorporate an entity to deal with anti-trust matters and the prevention of abuse of a dominant position, excessive concentration, and other actions detrimental to the intended structure and operation of the market as a whole.

- SPECIFIC REGULATION

Specific sector regulation is created at the time of initiating the development of the market. At this stage, it might be preferable to separate gas out into a primary gas law. This facilitates the ability to make changes in the primary legislation for gas without having to revise the main energy/petroleum law, and avoids ambiguity which might be created by a clause intended to be related to a different subsector (e.g. electricity).

Such regulations might be convenient to develop its application to different parts of the sector in several stages, depending on the progress of supply, and covering the different activities: production, imports, storage and regasification, transportation, and distribution.

- DETAILED REGULATION

Finally, the detailed regulation stage refers to the instruments and activities related to each initiative, such as permits, licenses, contracts, concessions, investments, import, export or transit authorizations, and environmental

licenses.

Such instruments are specific to each activity. Their coherence with the country's general energy strategy should be ensured by their conformity to the national laws (e.g. Gas Law) and other key secondary regulations such as gas market regulation.

3. CONSIDERATIONS FOR REGULATING MARKET STRUCTURES

Regulatory issues might affect the structuring of financing NG projects by indicating whether demand and sector development will be solely national or could be regional. Most of these issues are not contemplated in the countries' regulatory frameworks.

This relates to the issue of whether gas markets will be developed in individual countries in isolation, or a regional gas market could be established. The latter would require coordination between the countries across a broad range of regulations. While this is not necessarily expected to be done initially, it is more likely to happen in the long term.

The following considerations describe key issues that need to be taken into account when establishing regulatory frameworks for either individual or regional natural gas markets.

- DOMINANT POSITION REGULATION

An approach to vertical integration and how to deal with regional competition issues around it would need to be agreed by all countries party to a regional agreement. There are several options for vertical integration such as no ban or limits to vertical integration, absolute ban on vertical integration and partial ban or limits to vertical integration (unbundling).

In the event some partial limitations are established, their implementation could be done through one of several mechanisms implying increasing degrees of functional separation: simple accounting unbundling, functional unbundling, legal unbundling and actual ownership unbundling.

- **REGULATION OF LNG TERMINALS OR SUPPLY PIPELINES**

A business model, and its regulation, will need to be chosen for the operation of LNG regasification terminals. The regulatory aspects relate both to storage and regasification operations, and include at least no access to third parties, regulated access to third parties and freely negotiated (open) access to third parties.

This is important for contemplating market competition. On the one hand, market volumes are small especially in the early years; and splitting that volume between two or more parties could increase costs of LNG procurement as volumes fall below the economic scale. Furthermore, the financing of the LNG terminal(s) will require contracts from gas offtakers (or power offtakers) that guarantee the financing of the facility. In the early years the volumes may be low, causing an imbalance between terminal fees and financing payments. Splitting the (small) offtake contracts between multiple parties will add considerably to the riskiness of each project. It therefore seems likely that third party access would either have to be very limited at the start or delayed entirely until much of the financing was repaid.

If third party access is granted, a mechanism to allocate primary capacity will need to be chosen from the following options: open season, first-come first-served, pro-rata of demanded capacity, and bilateral negotiation.

Open season is now commonly used (for pipelines and LNG) as an effective and competitive process for allocating some capacities. On the one hand, it allows all interested parties to participate; on the other, it ensures full contracting of capacity from the start.

- **OPERATING TARIFFS AND PRICES**

Another relevant regulatory aspect to be considered will be whether terminal fees and gas transportation tariffs will be left for the market to set or whether a regulated tariff model will be employed. It would be essential that the tariffs allowed the investor to cover full financing costs, which are likely to be high in the early years before volumes build-up.

Therefore, the introduction of regulated tariffs would preferable to be delayed until demand came close to matching capacity and third party access, and the regulation would need to be multi-period and forward looking to ensure regulated revenues were sufficient given financing requirements.

The pricing of natural gas or LNG will also need to cover the terms of the LNG import contract, which is quite likely to contain indexation terms. Given the profile of possible growth of gas demand, and its uncertainty, regulation of gas prices would seem to be unsuitable at least for the early years, say the first 5 or 10 years.

However, if the main offtake is power and gas prices to power are not regulated, there is an option to regulate the prices to the smaller non-power demands; industry, and large commercial. Whether this is worth contemplating will depend on the market conditions at the time of tendering/contracting for the terminal. Since gas will be a new and alternate fuel for non-power customers, they are not obliged to switch to gas, while the gas investor would have every incentive to build out their network and connect all potential customers as quickly as possible. The more important regulatory instrument would be the commitment of the investor to undertake investments to expand the gas distribution area to reach more potential consumers.

11 Conclusions

Unveiling the natural gas opportunity in the Caribbean

The selected countries can develop a gas market by importing LNG or thorough pipelines. The supply options for gas pipelines and LNG are complementary and do not substitute each other. Nevertheless, LNG is likely to be the preferred technology since the results point it as the cheapest technical option to deliver natural gas to the Caribbean. Furthermore, LNG is a mature technology that is technically feasible for nearly all countries.

The LNG market may be developed under at least three alternatives that involve individual projects and regional integration. Individual and regional integration projects are the most feasible alternatives in the short and medium term. For the development of individual projects, it is possible to open the market with the construction of one or two regasification terminals under a vertical integration chain. These projects facilitate the financing of the chain and reduce the risks of regional coordination, although they limit the power of negotiating prices with gas suppliers. Regional integration projects, on the other hand, are an option to take advantage of economies of scale and allow negotiating better gas prices for the region, although they have high risks of regional coordination.

A natural gas market organized by a distribution hub would allow the maximum number of countries to buy LNG at the lowest price possible. This array would maximize the environmental benefits and reduction in electricity prices for all countries. Moreover, a distribution hub would likely lead to the lowest natural gas prices for all offtakers. Aligning offtakers' incentives might help to coordinate timing and reach the agreements to develop a regional hub under one contract for natural gas supply, although these steps will still be difficult.

The United States is the likely supply source for the Caribbean countries. Multiple LNG liquefaction projects are under development in the U.S. Gulf coast region that have received licenses to export to non-Free Trade Agreement (FTA) countries. The pricing mechanism for Caribbean countries to contract for LNG is uncertain and will depend on how the global and local markets evolve, but the most likely alternative is that Caribbean offtakers would pay a price for

LNG that is linked to the fuel that it is substituting (HFO).

The introduction of natural gas would bring high economic benefit for the Caribbean. Economic savings may favor public services or the governments' balance of payments. The analysis of benefits indicates that the average cost of generation of each system will decrease by replacing fuel oil power plants with natural gas plants. In the event that the selected countries switch to using natural gas in place of fuel oil, they could reduce their average cost of generation between 17 percent (Suriname) and 40 percent (Jamaica and Guyana). Also, introducing LNG competitive markets in the selected countries would increase energy affordability for end users, which may contribute to increase access to public services and reduce poverty.

There are at least three qualitative elements to consider when deciding whether to build an in-site regasification plant or bringing floating storage and regasification units (FSRU) while the new LNG market reaches its maturity. The first is the instability of demand. The greater uncertainty about demand, the greater will be the interest in making the conditions of supply contracts more flexible. If the gas demand increases or falls, FSRU's can be replaced by adjusted units to the existing market conditions. The second element is financing. The FSRU require considerably lower investments compared to land terminals for similar volumes. Finally, the third element is the versatility of location. The FSRU terminals can be installed in the vicinity of the generation plants and / or in areas that do not require the dredging of access to the ports to allow the unloading of methane tankers.

In general, the risk profile of the first project to develop the market in the region will be high. This assessment might change as the demand grows and new participants enter the market. The most relevant risks for the projects are contractual uncertainty, low demand, control of electricity prices and access to financing. The reduction of demand risk is difficult to eliminate; however, this risk can be mitigated by avoiding the execution of long-term contracts and by installing FSRU terminals. Public-private partnerships are an effective alternative to reduce political and financial risks. These associations facilitate the assessment of public and private sector risks, assigning them to the most capable party to manage them.

The new gas market requires a regulatory framework that can include a national and regional approach. National regulations have to define, among others, the functions of regulatory bodies and establish the technical norms and legal provisions of the value chain. The regional focus of this framework must ensure compliance with energy sales contracts between countries. Also, keeping natural gas regulations independent from other fuel regulations will avoid confusion when interpreting rules in areas of production, import, storage and regasification, transportation, transit and export, and distribution to customers.

The countries have a strong interest to incorporate a degree of competition into the new market by way of third-party or open access to the terminal facilities. The starting point for open access is likely to be quite restrictive and requires negotiation. The investor is likely to accept a slightly higher price to give open access or negotiate a lower price for gas if he has assured investment returns over capacity sales. On the other hand, open access requires not only access to regasification capacity but also an independent LNG supply, which is challenging in a system starting with a small natural gas demand.

The benefits of introducing natural gas in the Caribbean are overwhelming and they include allowing greater energy security and less dependence on heavy fuel oil as the dominant source of electricity generation. The technological innovation that has taken place in the natural gas market and the geographical proximity to the United States are privileged conditions that make convenient to introduce natural gas in the region. Thus, policymakers have the opportunity to enable the regulatory, legal and institutional frameworks to take advantage of these conditions and bring benefits to the citizens of the region from a source of supply that is cheaper and cleaner than the thermal options currently used.

The introduction of natural gas in the Caribbean may bring significant environmental benefits. Carbon dioxide emissions from thermal electricity generation would be reduced.

Infrastructure development to import and distribute natural gas has the potential to reduce poverty-related environmental problems and support sustainability and development plans in each country. Furthermore, the use of LNG can reduce fuel oil consumption for electricity generation and the risk of potential oil spills. Past oil spills in the Caribbean have resulted from oil tankers colliding with each other and from failures in oil drilling equipment.

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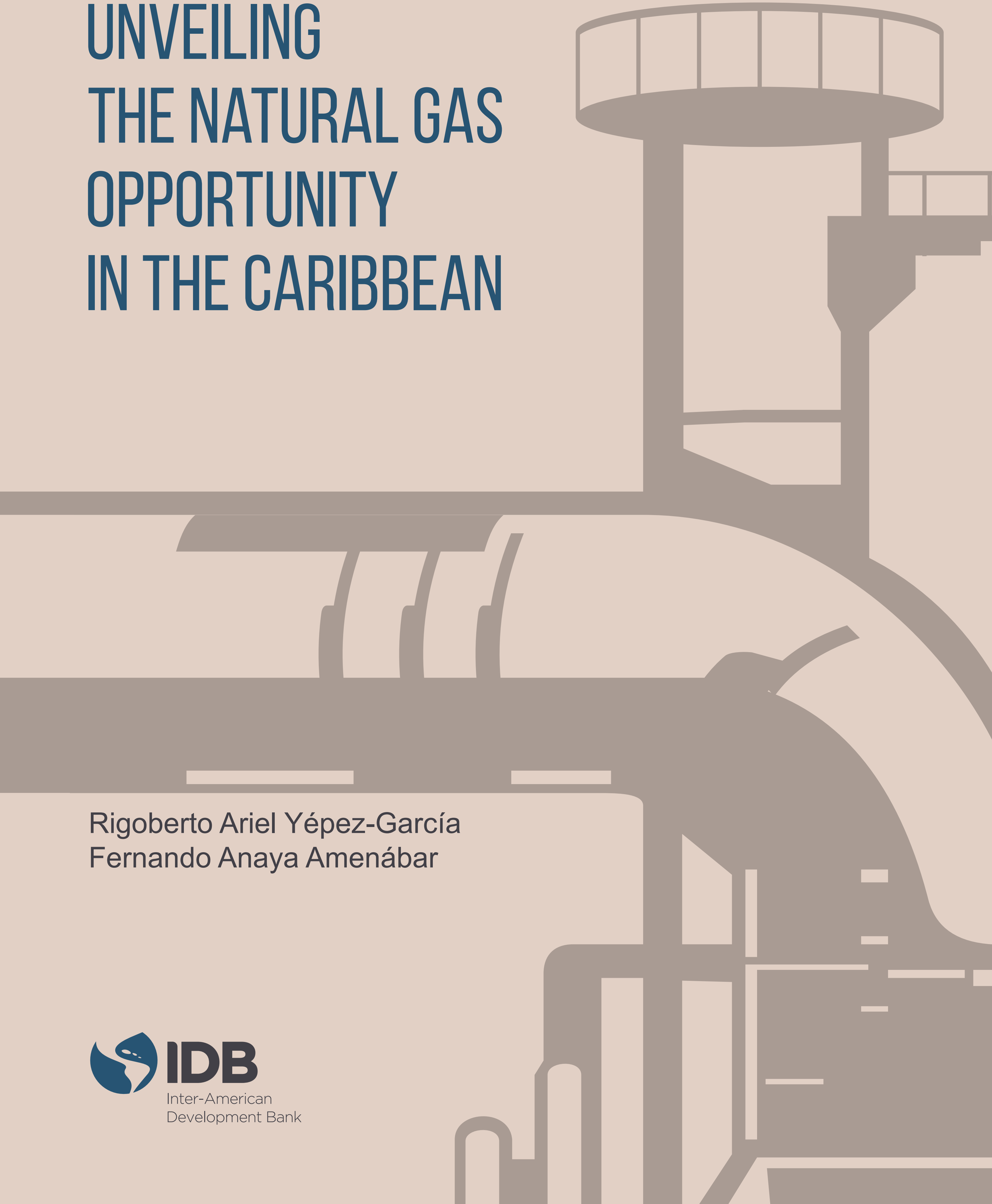

Rigoberto Ariel Yépez-García
Fernando Anaya Amenábar

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