# Caribbean Energy Initiative

## Cost Comparison of Power Generation Options in Select Caribbean Island Nations

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# Contents

# Executive Summary

Eastern and Southern Caribbean Islands currently utilize heavy fuel oil (HFO) and diesel for most of their power generation with some islands also incorporating small amounts of hydroelectricity, solar, and natural gas. This report evaluates the costs of switching from HFO and diesel generation to lower emission options over the next 20 years by comparing wind, solar, internal combustion engines (ICEs) powered by fossil fuels, turbine generators powered by fossil fuels, geothermal energy, gasification of biomass and municipal solid waste, hydrogen, and battery storage. To determine the applicability and economics for these options, we first describe the power generation and storage technologies and present their capital and operating costs along with their fuel transportation and delivery methods and costs. Lastly, we tie these together to calculate the levelized cost of electricity to help determine the most economic technologies and fuels. The options are also compared from a greenhouse gas (GHG) emissions perspective, and levelized costs are computed under three assumptions for the social cost of carbon. This Executive Summary outlines the primary takeaways, with more detail provided in the body of the report.

This report follows the Caribbean Energy Initiative: Political Economy Analysis (PEA) on Liquified Natural Gas (LNG) report conducted by ICF that identified target countries that were more willing to evaluate the full spectrum of power generation options including LNG and other kinds of fossil energy. The countries identified, which will be referred to as target countries in this report, included Antigua and Barbuda, Barbados, St. Lucia, and St. Vincent and the Grenadines. Eastern and Southern Caribbean countries are evaluating future generation projects by looking at each holistically. Some of the key factors found in this study include:

- **Costs:** Countries are very cognizant of the potential for new projects to increase rate payer costs. Countries expressed their desire to reduce costs, remaining cognizant it is hard to achieve scale given they are small island markets.
- **Renewable Targets and GHG reductions:** Countries want to make sure that future investments fit into the countries long-term energy plans. Additionally, they want to make sure these energy methods fit into their countries economy and do not detract from the island's economy (i.e., wind farms in tourist viewsheds).
- **Capital constraints:** In general, investment capacity is limited and there is a strong desire to not invest in assets only for them to become stranded assets.
- **Independence:** On-island and indigenous sources of power generation are preferred, since they aren't subject to OPEC price fluctuations or other country policies.
- **Resilience:** Technologies are evaluated based on their resilience to hurricanes and external factors. Power generation that requires fuel from off-island/out of the region are viewed as more likely to have interruptions.
- **Tested Technologies:** Countries want tried and tested technologies.

## Key Findings

ICF assessed estimates of capital costs and operations and maintenance (O&M) costs for various generation and storage technologies that were most likely to be installed in the Eastern Caribbean over the next 20 years and, as applicable, the fuel costs to run these systems. To prepare the Eastern Caribbean cost estimates, desktop research and interviews with vendors were conducted to confirm in-house knowledge of the capital cost and O&M costs for recently constructed generation projects in the continental United States. Information gathered during the review of U.S. costs was translated to a Caribbean regional context using a factor of 1.2 (built up in the Electricity Generation Technologies and Costs for Eastern Caribbean section of this report). This factor reflects the higher costs in the region for transport, labor, productivity, and other parameters relative to U.S. costs. Next, fuel cost estimates were developed based on product costs, transportation, storage, and local delivery by truck or pipeline. These were incorporated into the levelized cost of energy (LCOE) on a $/MWh basis.

### *Converting Existing Units*

When evaluating potential options of reducing costs and emissions, utilities would first like to evaluate and understand what can be done with their existing units. It is technically possible to convert internal combustion engine-generators burning HFO or diesel to enable dual-fuel blending and the replacement of up to approximately 70% of the diesel or HFO with natural gas or propane. To accomplish this, the engine's fuel trains would have to be modified and infrastructure constructed for LNG or propane off-loading, storage, vaporization, and feeding. The engine modifications would allow LNG or propane to be used as a backup fuel should diesel/HFO be unavailable or a primary fuel if LNG offered cost advantage. Despite the technical feasibility of converting an internal combustion engine generator to be dual-fuel-capable, there are a number of drawbacks to this approach including:

- During a transition to dual-fuel capability, there would likely be a reduction in the available generating capacity for several months depending on how implementation was staged.
- There is no cost advantage to dual-fuel conversion to LNG or propane when comparing against operating the existing units with diesel or HFO. Savings in the cost of fuel per million British thermal unit (MMBtu) are offset by lower efficiencies and the amortization of the conversion costs.
- Fuel consumption and greenhouse gas emissions are expected to be much higher for the dual-fuel units due to lower efficiencies as compared the lean operation of compression-ignition (diesel/HFO) engines. Furthermore, when utilizing LNG in the dual-fuel units, there are emissions of unburnt methane, known as methane slip, which also contributes to the overall effect of GHG emissions going up after conversion of an existing diesel-fueled ICE.

The study also compares the costs of replacing the existing diesel and HFO ICE with new LNG- or propane-fueled ICEs.

- When replacing diesel ICE with LNG- or propane-fueled ICE, capital costs are much higher; however, fuel costs are considerably lower for LNG and propane (even when compared to the dual-fuel case due to the efficiency differences). Therefore, LNG replacement is cheaper than the existing diesel ICE, and propane replacement is comparable in cost. Both fuels under a complete replacement scenario also have less GHG emissions than the existing ICE diesel unit. From a cost and GHG emissions perspective, it likely will be more advantageous to buy and install a new unit if a shift to LNG or propane is desired.
- When running this same comparison for HFO-fueled generators, in this study, we found that the total levelized cost of energy for the existing HFO generator was lower than the dual-fuel and full replacement LNG or propane options. When operating ICE generators with HFO, the most economic option is to keep the unit operational for as long as is possible. Dual fuel loses some efficiency and, therefore, requires more fuel. In addition conversion to dual fuel with natural gas usually will lead to some "methane slip" in which unburned fuel causes higher emissions overall.

### *Building New Units*

The costs (levelized capital costs, fixed and variable O&M costs, and fuel costs) of building new units to meet growth in electricity consumption and to replace old, retiring power plants are presented in Exhibit 1. Many of the Eastern and Southern Caribbean islands current generators are operating past typical lifetimes, so the evaluation of alternative generating technologies and fuels costs for new units is more relevant than trying to convert existing equipment.

*Exhibit 1: Economics of Installing New Generating Units in $/Megawatt hours (MWh)*

| Technology & Fuel | LCOE in $/MWh Capital Cost | Fixed O&M | Variable O&M | Fuel Costs | **Total Cost** | Fuel Cost $/MMBtu | Fuel LCA GHG kg/MWh |
|---|---|---|---|---|---|---|---|
| Solar PV | $47 | $7 | $0 | $0 | **$54** | $0.00 | 55 |
| Wind | $69 | $15 | $0 | $0 | **$84** | $0.00 | 15 |
| Geothermal: Geothermal | $87 | $29 | $1 | $0 | **$118** | $0.00 | 39 |
| Gas Turbine: LNG Contain. | $31 | $4 | $6 | $95 | **$135** | $10.44 | 630 |
| Gas Turbine: LNG Carrier | $31 | $4 | $6 | $112 | **$152** | $11.54 | 812 |
| Gas Turbine: Diesel | $31 | $4 | $6 | $150 | **$190** | $16.40 | 758 |
| ICE: Diesel | $42 | $8 | $7 | $136 | **$193** | $16.40 | 758 |
| Renewables + Battery* | $102 | $14 | $78 | $0 | **$194** | $0.00 | 74 |

*Note: Capacity utilization rates for all technologies are assumed to be 60% except for solar and wind which are assumed to be 32%.*
**The Renewables + Battery cases are based on a mix of installed capacity of 67% solar and 33% wind.*

Exhibit 1 illustrates the costs for some of the primary technologies that islands are considering, assuming a typical utilization rate for each of the power generation types. The transportation and storage costs for the fuel are factored in as part of the delivered costs. There are a number of factors that play a role in the shipping and storage costs including bulk shipments, ISO containers, days of storage desired, shipping routes, but a high-level summary of expected costs for the shipping and storage rates are outlined in Exhibit 2.

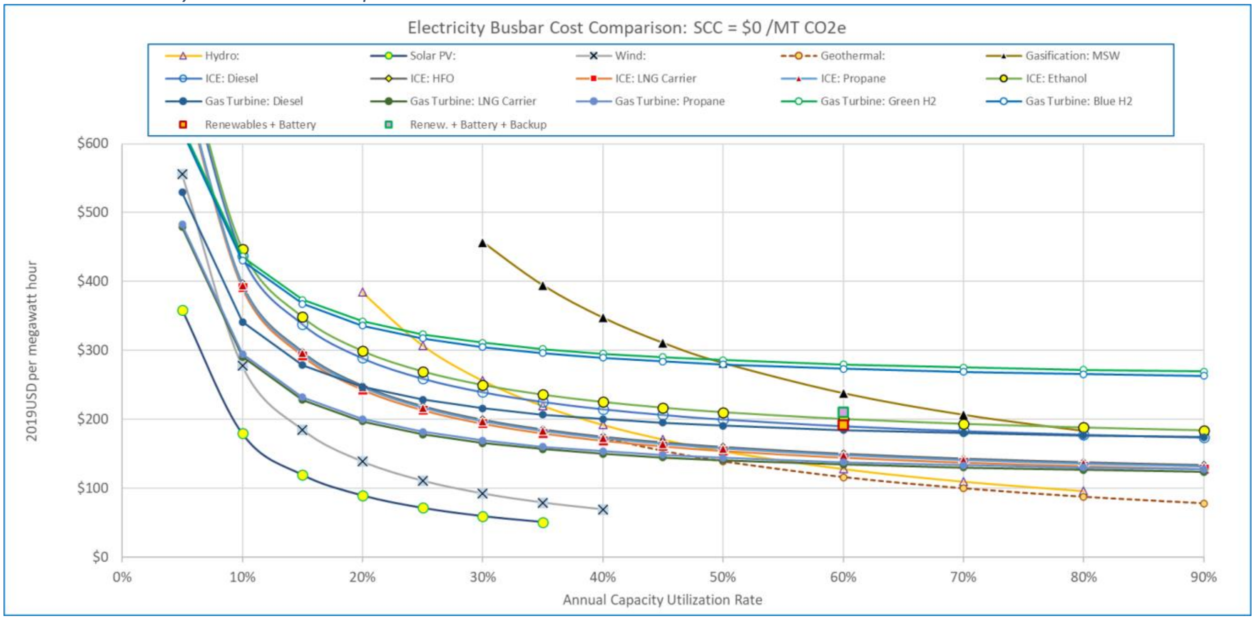
*Exhibit 2: Fuel Shipping and Storage Costs on a MMBtu basis*

| Fuel | Shipping Transportation Costs ($/MMBtu) | Storage Costs ($/MMBtu) |
|---|---|---|
| Diesel | $0.4 | $0.1 |
| Ethanol | $0.3 | $0.1 |
| Heavy Fuel Oil | $0.2 | $0.1 |
| Propane | $0.7 | $0.4 |
| LNG Container | $0.75 | $1.9 |
| LNG Carrier | $1.5 | $2.9 |
| Green H2 Container | $1.7 | $6.3 |
| Blue H2 Container | $1.7 | $6.3 |

From Exhibit 1, it becomes clear that utility scale renewable energy technologies are expected to be the lowest cost option for new generation, and therefore they should be expected to play a larger and larger role in the Eastern and Southern Caribbean. Solar and wind will likely be important pieces of the future grid, but both have limitations. Solar is only effective during daylight hours, while wind is intermittent throughout the day. As the islands adopt more wind and solar, the primary question is how the grid will meet its dispatchable power generation needs during night-time hours, high demand days, or days with low renewable generation. Utilities will need to evaluate battery storage solutions or easily dispatchable power generation to meet their voltage regulation and load balancing requirements. This report finds there is tight competition among fossil fuel solutions with LNG being the cheapest fuel option. LNG is expected to have lower costs than renewables paired with battery storage due to the high variable costs of battery storage, specifically the cost of having to replace battery storage capacity as its performance deteriorates with usage. The economic advantages of LNG can be reduced somewhat at lower capacity utilization rates, but the use of containerized shipping and storage (as opposed to gas carriers and fixed storage tanks) can provide fuel economically at low volumes.

Further, power plants are most cost-effective at high utilization rates, because the capital expenditures get spread out over greater levels of generation. Exhibit 3 compares the different technologies at various capacity utilization rates.

*Exhibit 3: Electricity Busbar Cost Comparison*




This graphic illustrates that technologies with higher capital costs but low fuel and variable operating costs such as geothermal have much steeper curves and have dramatically improved economics at higher utilization rates. For countries with geothermal potential, it can be competitive with other fuels at high utilization rates, but as solar and wind penetration increases and the potential utilization of the dispatchable technologies decline, it will become less competitive to alternative less capital-intensive solutions. For this reason, determining the optimal dispatchable power generation solution requires evaluating the dispatchable generation over its expected lifetime.

Overall, countries are basing their power generation plans on numerous factors including costs, capital limitations, renewable and carbon targets, energy independence and resilience to name a few. While this report touches on many of these topics, the focus was to determine the lowest cost options and to lay these costs out in a manner that can be utilized by countries in the Eastern and Southern Caribbean. Based on the current cost estimates, renewable generation from solar and wind are expected to be the most cost-effective technologies. Intermittent renewables penetration is therefore expected to decrease the costs for ratepayers as renewables increase towards 90%-100% of peak hour demand or approximately 50% of total power generation. Once at this level, further renewable projects would require battery storage which would raise costs to rate payers, while instead LNG could provide a low-cost solution for dispatchable power. There are many considerations countries are evaluating in their power generation plans, but one that other countries have looked at is factoring in the social cost of carbon. With a social cost of carbon, fossil-based projects will have higher costs which will make further renewable penetration attractive.

## Acronyms

| | |
|---|---|
| AC | Alternating Current |
| AEO | Annual Energy Outlook |
| AES | AES Corporation |
| APUA | Antigua Public Utilities Authority |
| BBL | Barrel |
| Bcf | Billion Cubic Feet |
| BESS | Battery Energy Storage System |
| BL&P | Barbados Light & Power Co. Ltd. |
| BMS | Battery Management System |
| BNOCL | Barbados National Oil Company Limited |
| BOP | Balance of Plant |
| CDOL | Cost Data Online (Richardson) |
| CO | Carbon Monoxide |
| CO2 | Carbon Dioxide |
| DC | Direct Current |
| E85 | Blend of Ethanol and Petroleum Fuel |
| E95 | Blend of Ethanol and Petroleum Fuel |
| EIA | Energy Information Agency |
| EMS | Emergency Management System |
| FOM | Fixed Operations and Maintenance |
| FTC | Fair Trading Commission |
| G&A | General and Administrative |
| GHG | Greenhouse Gases |
| GT | Gas Turbine |
| GTW | Gas Turbine World |
| GWh | Gigawatt hours |
| H2 | Hydrogen |
| HFO | Heavy Fuel Oil |
| ICE | Internal Combustion Engine |
| IDB | Interamerican Development Bank |
| IEA | International Energy Agency |
| IMF | International Monetary Fund |
| Kg | Kilogram |
| kV | Kilovolt |
| kW | Kilowatt |
| LCOE | Levelized Cost of Energy |
| LF | Location Factor |
| LNG | Liquefied Natural Gas |
| LPG | Liquified Petroleum Gas |
| LTSA | Long Term Service Agreement |
| LUCELEC | St. Lucia Electricity Services Limited |
| $m^3$ | Cubic Meters |

| | |
|---|---|
| MMBTU | Million British Thermal Units |
| MSW | Municipal Solid Waste |
| MWe | Megawatts Electric |
| MWh | Megawatt hours |
| NERC | North American Electric Reliability Corporation |
| NG | Natural gas |
| NPC | National Petroleum Company |
| NREL | National Renewable Energy Laboratory |
| OEM | Original Equipment Manufacturer |
| O&M | Operations and Maintenance |
| PCS | Power Conversion System |
| PEA | Political Economy Analysis |
| PV | Photo-voltaic |
| RoRo | Roll-on/roll-off Cargo Ship |
| SCC | Social Cost of Carbon |
| SCR | Selective Catalytic Reduction |
| SMR | Steam Methane Reforming |
| STG | Steam Turbine Generator |
| TMS | Thermal Management System |
| U.S. | United States |
| USAID | United States Agency for International Development |
| V | Volt |
| VINLEC | Saint Vincent Electricity Services Limited |
| WTG | Wind Turbine Generator |

# Electricity Generation Technologies and Costs for Eastern Caribbean

## I. Introduction

This chapter presents cost and performance assumptions for alternative electricity generation and storage technologies that could be employed in the Eastern Caribbean over the next 20 years. The prime movers for power generation discussed in this chapter include internal combustion engines and gas turbines fueled by one or more of natural gas, diesel, ethanol, or hydrogen. Additionally, electricity could be generated via solar, wind, or geothermal energy or with syngas produced from municipal solid waste and/or biomass in a gasifier with combustion in a boiler in combination with a steam turbine generator. Electricity storage options include storage as electricity in batteries and conversion of electricity through hydrolysis to hydrogen that can be stored and converted back to electricity in turbines.

## II. Background, Objectives, and Approach

The objective of this report is to assess reasonable estimates of capital costs and O&M costs for various generation technologies and plant configurations that are likely to be installed in the Eastern Caribbean in the near future. For this report, the technologies included are internal combustion engines, turbine generators, geothermal energy, gasification of biomass and municipal solid waste, electrolyzers, and battery storage.

To prepare the Eastern Caribbean cost estimates, desktop research and interviews with vendors were conducted to confirm in-house knowledge of the capital cost and O&M costs for recently constructed generation projects in the continental United States. Information gathered during the review of U.S. costs was translated to a Caribbean cost context to account for transport, manpower, productivity, and other parameters that may, or may not, differ from U.S. costs. U.S. costs were adjusted to Caribbean costs on a dollar per kilowatt (kW) basis using a factor of 1.2 (built up in the U.S. to Eastern and Southern Caribbean Location Factor Calculation section below).

From a high-level perspective, the generation capacity of the Eastern Caribbean facilities considered is significantly lower than units currently being installed in the United States due to the small level of demand on each island. Capital costs are shown for different size ranges for each technology in line with the sizes that would most likely be constructed on the four islands.

### Desktop Research

Desktop research on the capital and O&M costs for power generation technologies was based on generation plants within the United States. This research included the latest information from the Original Equipment Manufacturers (OEM), power generation manufacturers' representatives, Energy Information Agency (EIA), Gas Turbine World (GTW) 2019 Handbook, International Energy Agency (IEA), Lazard, and other miscellaneous internet resources for various generation technologies including simple cycle gas turbines (GT), reciprocating engines, and biomass facilities. Estimated capital costs in the United States to construct these technologies is well established and can generally be determined by escalating prices from known prior costs according to cost indices that adjust for inflation in materials and labor pricing.

Overall, there was considerable information available in the public domain on capital costs of projects in the United States from published press releases and project announcements collected from internet searches. To the extent possible, the desktop research primarily focused on capital cost information and O&M data for units in the United States in similar configurations to those contemplated for the Eastern Caribbean.

A reliable source for capital costs and O&M costs for power generation facilities is EIA which periodically publishes U.S. power plant capital cost and O&M costs for various generation technologies and the GTW 2019 Handbook which publishes gas turbine capital costs for all OEMs that manufacture combustion turbines. Reference U.S. facility capital cost expenses were taken from EIA's Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Generating Plants dated February 2020. ICF's review of the capital cost estimates within the EIA report found them to be generally reflective of generic combustion turbines, natural gas combined cycle, internal combustion engines, geothermal, solar, wind, battery energy storage systems (BESS), and biomass power plants commonly constructed in the United States. EIA costs were presented in a 2019 $/kW of generation basis at the most common capacity and configuration installed. When using the EIA report, ICF accounted for capacity differences when the plant under review had a capacity far smaller than the most common size by using the generally accepted rule of six-tenths to adjust the cost based on the size ratio to the power of 0.6.

The EIA plant construction cost information was utilized, because it is based on aggregate data from several facilities, providing a good database for the average facility desired for this exercise. Additionally, the database is updated periodically such that this report could be updated every three or four years when the EIA publishes new data for power plant capital costs.

## Vendor Interviews

To validate desktop research and to gain the most up-to-date cost information, ICF contacted various vendors to receive budgetary prices for equipment for some of the generation technologies studied. Interviews were conducted with key OEM representatives for input on technology performance and cost parameters and to help refine the data collected and verify the reasonableness of the initial assumptions.

## Convert U.S. Cost Data to Caribbean Cost

All estimated capital costs and O&M costs for the various generation technologies and fuels were initially on a U.S. basis which needed to be adjusted to Eastern and Southern Caribbean Island costs.

Using the EIA information as the basis of the analysis, the U.S. capital cost data is converted to Eastern and Southern Caribbean Islands cost data to account for additional ocean packaging, freight and handling costs for all the major equipment and construction materials, lack of local skilled labor, productivity differences, and other identifiable differences between a U.S. and an island installation in the eastern or southern Caribbean.

## U.S. to Eastern and Southern Caribbean Location Factor Calculation

The first task in the conversion effort was to translate U.S. costs to Eastern and Southern Caribbean Island costs using Richardson Cost Estimating resources, specifically the 2018 Richardson Cost Data Online (CDOL) edition and the Richardson International Location Cost Manual. Richardson did not have information for an Eastern or Southern Caribbean island but did have information for Puerto Rico which was utilized as a proxy for an eastern or southern Caribbean Island.

The Richardson data was compiled to translate the cost to construct process plants in various areas of the world; however, it is our opinion that the data is also applicable to power production facilities due to the similarities in equipment used in the construction of power generation facilities. Conversion of U.S. costs to Eastern and Southern Caribbean Island costs is done in an engineered approach as shown in the 2018 Richardson CDOL and the Richardson International Location Cost Manual that ICF subscribes to.

The comparison of costs between power generation facilities located in the U.S. and power generation facilities utilizing various technologies that may be built in an Eastern or Southern Caribbean Island is done by aggregating individual adjustments for labor, material, equipment costs, freight, and taxes to produce a composite Location Factor (LF) adjustment. This LF adjustment is used to convert costs between locations by multiplying the LF and the capital cost of a U.S. plant. The LF is based on engineering assumptions and formulas that include the following:

- Typical process plant breakdown of costs by percentage of total cost for labor, material and engineered equipment.
- Specific assumptions based on the percentage of local or imported engineered equipment and local and imported field material.
- Specific assumptions based on the percentage of available in-country skilled labor versus imported skilled labor.
- Import add-on costs for materials and capital equipment such as duties, freight, Value Added Tax (VAT) and other local or provincial taxes and fees.
- Local materials index.
- Local labor performance factor.

The following inputs were utilized to compute the percentages and formulas that the Richardson CDOL and Location Cost Manual relies upon to derive its LFs. ICF's aggregation of the individual cost differences noted above resulted in a LF of 1.2 for an installation on an eastern or southern Caribbean Island. The methodology, assumptions and formulas used in the calculation of the LF for an eastern or southern Caribbean Island using the Richardson CDOL and Location Cost Manual is shown below.

- Total of the 100% construction cost: 20% for buildings and site-related construction costs and 80% is costs associated with the process plant systems and equipment.
- The 20% of costs for the buildings and site-related construction is broken down further into 55% for field material costs and 45% for labor costs.
- The 80% of process systems construction cost is broken down further into 75% for engineered process equipment, 10% for process systems field materials, and 15% for process system installation labor costs.
- Based on this breakdown of costs, engineered process equipment represents approximately 60% of the cost of a typical process plant, field materials represents approximately 20% of the cost of a typical process plant, and labor cost represents the remaining 20% of the costs of the typical cost to construct a process plant.

Specific assumptions are used within the CDOL Richardson Cost Factors computations to adjust for international differences and have been used to generate the composite LF adjustment for Eastern and Southern Caribbean Islands. Those assumptions are shown below:

- 100% of the engineered equipment will be imported and 0% will be sourced locally;
- 10% of the field material is available locally and 90% will be imported;
- There will be a 10% duty add on cost for imported materials and engineered equipment;
- There is a 30% freight adder for imported engineered equipment and materials;
- The Local Material Factor is a 1.35 adder as there is no local manufacturing of typical required construction material and all steel, piping, and electrical filed materials are imported;
- 100% of skilled labor and technical supervision and management will be imported;
- 100% of imported personnel will require incentives and expenses or per-diem allowances;
- Local Labor Performance Factor representing productivity is a 2.65 adder, meaning it is expected that the total manhours to complete a similar installation compared to installation on an island

in the Eastern or Southern Caribbean will require 2.65 times more hours than a similar installation in the United States.

The figures above were used with the formulas in the CDOL Richardson Cost Factors-Location Cost Manual[1] to establish the LF adjustment of 1.2 for an eastern or southern Caribbean Island installation. The LF of 1.2 is appropriate to use to adjust estimated capital costs for U.S. power plants to similar facilities in an eastern or southern Caribbean Island on a $/kW basis.

# III. Reference Operation and Maintenance Costs

Once a plant enters commercial operation, the plant owners incur fixed O&M (FOM), as well as variable O&M (VOM), costs each year. O&M costs do not include the cost of the fuel. The fixed and variable O&M costs are estimated based on a variety of sources including actual projects, vendor publications, and ICF's internal resources for the generation technologies studied for this report.

FOM costs include costs directly related to the equipment design including labor, materials, contract services for routine O&M, and administrative and general costs. Land lease costs are included for solar and wind projects as part of the FOM, but all other facilities are assumed to have an outright purchase of land which is excluded from the FOM (such as property taxes and insurance).

VOM costs, such as ammonia, water, and miscellaneous chemicals and consumables, are directly proportional to the plant generating output.

## U.S. Fixed O&M

FOM expenses are those expenses (excluding fuel-related costs) incurred at a power plant that do not vary significantly with generation and include the following categories:

- Staffing and monthly fees under pertinent operating agreements
- Typical bonuses paid to the given plant operator
- Plant support equipment which consists of equipment rentals and temporary labor
- Plant-related general and administrative (G&A) expenses (postage, telephone, internet, etc.)
- Routine preventive and predictive maintenance performed during operations
- Maintenance of structures and grounds
- Other fees required to participate in the relevant North American Electric Reliability Corporation (NERC) region
- Maintenance of equipment such as water circuits, feed pumps, main steam piping, and demineralizer systems
- Maintenance of electric plant equipment, which includes service water, Distributed Control System (DCS), condensate system, air filters, and plant electrical
- Maintenance of miscellaneous plant equipment such as communication equipment, instrument and service air, and water supply system
- Plant support equipment which consists of tools, shop supplies and equipment rental, and safety supplies.

Routine labor costs include normal operations staff and regular maintenance of the equipment as recommended by the equipment manufacturers. This includes maintenance of pumps, compressors,

[1] ICF is unable to include the formulae for deriving the Puerto Rico (proxy for eastern or southern Caribbean island) construction cost data factors from Richardson due to license limitations with the publisher of the Richardson cost information data.

transformers, instruments, controls, and valves. The power plant's typical design is such that routine labor activities do not require a plant outage.

Materials and contract services include the materials associated with the routine labor as well as contracted services such as those covered under a long-term service agreement, which has recurring monthly payments. This includes plan support equipment such as equipment rentals, temporary labor, tools, shop supplies, and safety supplies.

Major scheduled maintenance costs include labor, contract services and materials that are required during scheduled plant outages for major inspections or testing services including replacement of specific plant generation components that have reached design life or have to be inspected and tested and repaired or modified or replaced based on run hours or other OEM defined schedules.

For battery energy storage cases, all O&M costs are treated as fixed costs.

### U.S. Variable O&M

VOM expenses are production-related costs (excluding fuel-related costs)[2] which vary with electrical generation and include the following categories, as applicable to the given power plant technology:

- Raw water consumption
- Waste and wastewater disposal expenses
- Purchase power, demand charges and related utilities
- Ammonia for selective catalytic reduction (SCR)
- Utility chemicals for boiler water treatment, cooling water treatment, wastewater treatment, and other utility uses
- Lubricants

### Major Maintenance

Major maintenance expenses generally require an extended outage, are typically undertaken no more than once per year, and are assumed to vary with electrical generation, equipment (prime mover) operating hours, or the number of plant starts based on the given technology and specific original equipment manufacturer recommendations and requirements. These major maintenance expenses include the following expense categories:

- Scheduled major overhaul expenses for maintaining the prime mover equipment at a power plant
- Major maintenance labor costs
- Major maintenance spare parts costs
- Balance of Plant (BOP) major maintenance, which is major maintenance on the equipment at the given plant that cannot be accomplished as part of routine maintenance or while the unit is in commercial operation.

Major maintenance expenses are included in O&M expenses for each plant. These expenses may be included in FOM or VOM depending on the cost structure of the particular plant considering such things as capacity factor, hourly and start-up cycling patterns, O&M contract structure (if applicable), and major maintenance timing triggers.

Developers and operators can attribute major maintenance costs within the fixed, variable, or a separate major maintenance cost category and those costs are normally allocated depending on how

[2] Most operators separate out fuel so that they can compare operating costs across plants.

the long-term service agreement (LTSA) fees are paid. Fees are generally based upon the number of MWh produced, the number of times that the generator is started, or on a periodic basis (usually annually). Operators that have MWh-based fees tend to include the major maintenance in the VOM costs, while starts and periodic contracts sometimes are included in the FOM costs. EIA included the major maintenance costs within the FOM category; this is how we categorize it in this study.

### Convert O&M Estimated Costs to Eastern or Southern Caribbean Island Costs

The same methodology used for establishing a LF of 1.2 for capital costs for a power generation installation of various technologies in an Eastern or Southern Caribbean island is applicable to O&M costs for the facility.

Outside of the generation facilities O&M labor cost, the next largest O&M expense are costs associated with the LTSA to the OEM for the power generation equipment. These costs cover the cost of parts for preventative and corrective maintenance, as well as the specialty labor to repair and optimize operations.

Other maintenance items require parts and shipping to an Eastern or Southern Caribbean island. In aggregate, ICF assumed that the 1.2 LF adjustment utilized for capital costs is an appropriate factor to use for maintenance in the Eastern or Southern Caribbean due to the similarities in activities between LTSA and other heavy maintenance and that of construction activities.

## IV. Generation Technologies — Capital Costs and Viability

This section describes the capital and O&M costs for the potential replacement generation technologies across the target countries that were studied. All the costs shown for capital and O&M include a 1.2 location factor adjustment to convert U.S. costs to an eastern or southern Caribbean island basis. This adjustment was to account for additional ocean packing, freight and handling costs, local skilled labor conditions, productivity differences, and other identifiable differences. The estimated costs shown should be considered to have an accuracy of plus or minus 30% and costs will vary by vendor and specification. The accuracy ranges of our estimate are directly related to the information available and the level of project definition during the preparation of the estimate. Due to time and budget constraints, this estimate was prepared with limited information and with limited engineering and design completed. We would characterize this estimate as an American Association of Cost Engineering International Class 5, or Order of Magnitude accuracy.

### Internal Combustion Engines

#### *LNG*

LNG was considered for use to fuel ICE generators on the islands. Currently, diesel- or HFO-fired ICEs produce the bulk of the power on the islands. There are some cost advantages to using LNG, as discussed in the Power Generation Pathways section of this report, and it is a cleaner burning fuel than diesel and HFO by producing lower criteria air pollution emissions. However, use of LNG would have little impact on the carbon emissions.

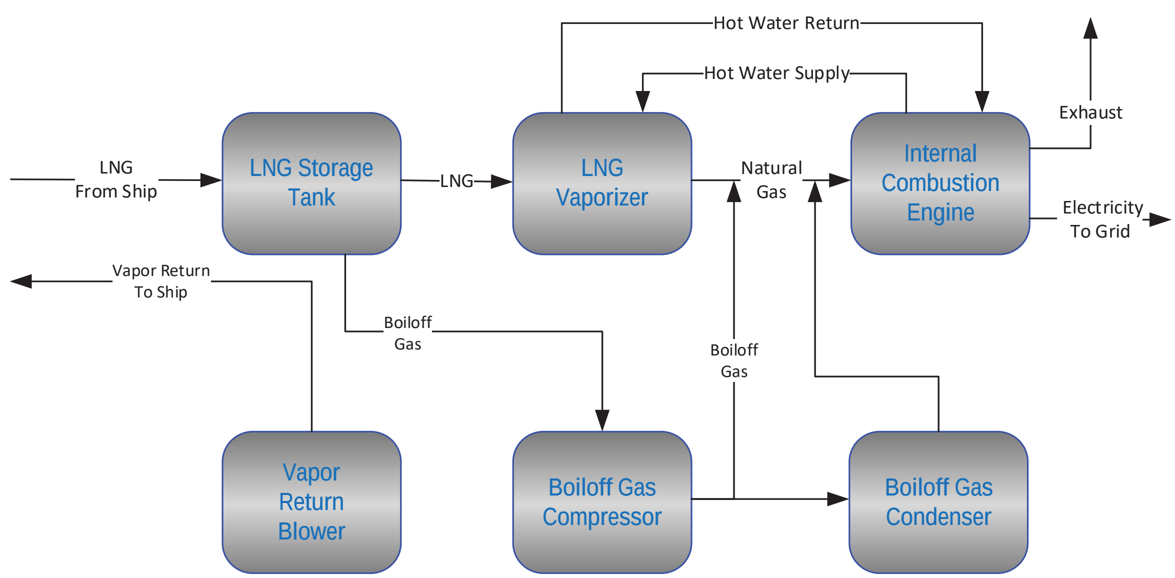
The existing engines would have to be replaced to use LNG, as diesel and HFO engines are not capable of utilizing pure natural gas. Additional infrastructure for receiving, storing, and vaporizing LNG would also be required. If existing buildings permit, it may be possible to remove the currently installed diesel or HFO generators and replace them with new LNG-capable engine generators. It is likely that foundation, ancillary and other modifications would be required.

As an alternative to this "remove and replace" scenario, manufacturers can supply complete engine generator systems for generating capacities of up to 2,000 kW in shippable containers that offer advantages to the typical "stick building" installation of ICE generators.  Engine generator containerized systems generally include all necessary ancillary systems such as electrical, control, cooling and exhaust NOx control with SCR which has been pre-assembled and tested at the OEM or packagers facility.

Some advantages that packaged ICE generator systems offer is that all the ancillary systems including cooling and radiators system piping, exhaust ductwork and exhaust emissions systems, fuel filtration and metering piping trains, control systems, oil storage and supply systems are all factory completed and tested at the OEM or packager facility. When the containerized engine generator package arrives at site, it can be installed and started-up in matter of days or weeks versus typical non-containerized installations taking months. Containerized generator systems would shift typical inefficient field installation labor hours from the island locations to OEM or packager shops with skilled installation labor hours performed in enclosed conditioned facilities. The containerization of the ICE generator systems is typically 10%-20% higher in capital cost than non-containerized ICE generator system but offers some schedule and installation quality advantages.  Capital cost pricing was provided by the vendor for containerized generator systems and shown below along with capital costs for traditional non-containerized ICE generator systems that would be assembled totally in the field.

A typical bulk system for LNG fuel would include an unloading dock with LNG piped to a pressurized and heavily insulated storage tank.  It would also include a boiloff gas capture, boiloff gas condenser and compression system, an LNG vaporizer, and a blower to return vapor to the delivering vessel.  A simplified block flow diagram of such as system is shown below in Exhibit 4.

*Exhibit 4: LNG Storage and Internal Combustion Engine Generator System Block Flow Diagram*



The estimated total installed capital costs to replace existing diesel or HFO engine generators with new LNG-fueled ICE generator sets are shown in Exhibit 5. The estimated capital costs are for the installation, commissioning and start-up of new containerized (up to 2.0 MW size) and non-containerized LNG fueled ICE generators (up to 20.0 MW) only. The estimated capital costs do not include costs for removal of the existing HFO or diesel ICE generators and accessories, costs for removal of diesel or HFO storage and unloading infrastructure, or any costs for new LNG infrastructure for off-loading, storage, vaporization and feeding. The costs for LNG infrastructure are illustrated in the Sources and Options for Transportation & Storage of Petroleum Products section of the report, but storage, regasification and transportation costs to the facility were assumed to be approximately $1.8/MMBtu, although it would depend on the ship size and the supply needed. The costs shown are inclusive of the 1.2 LF adjustment for an Eastern or Southern Caribbean Island installation and have an accuracy of ±30%.

*Exhibit 5: Capital and O&M Cost Estimates for Natural Gas-Fueled Internal Combustion Engines*

| Capital Cost Estimate | |
|---|---|
| **Natural Gas Fueled Generator Size Range, kW** | **Total Installed Capital Cost to Replace Unit ($/kW)** |
| 150 to 1,750 kW | $1,800 |
| 400 to 1,750 kW (Containerized) | $2,256 |
| 2,000 to 7,500 kw | $1,960 |
| 1,750 to 4,400 kW (Containerized) | $2,210 |
| 9,300 to 20,000 kW | $2,172 |

| Operations and Maintenance (O&M) Cost Estimate | | |
|---|---|---|
| **Natural Gas Fueled Generator Size Range, kW** | **Fixed O&M Cost ($/kW – year)** | **Variable O&M Cost ($/MWh)** |
| 150 to 1,750 | $50.63 | $8.19 |
| 2,000 to 20,000 | $42.19 | $6.82 |

### *Ethanol as Diesel Substitute (E85/E95)*

Ethanol (E85/E95) blended fuels was considered as an alternate fuel for use with ICE generators. E85 is a blend of 51% to 83% ethanol with gasoline or another hydrocarbon, and E95 is 92% to 99% ethanol blended with gasoline or another hydrocarbon. The ethanol fraction of E85/E95 is considered to be atmospheric carbon neutral from a lifecycle perspective and renewable, though the gasoline fraction is not a renewable fuel (EIA 2020). Further, E85 has approximately 64% of the energy density of diesel fuel. Therefore, about a 50% increase fuel storage volume would be required to achieve the same number of days of supply for fuel storage. The existing diesel or HFO-fueled ICE generators would need to be replaced with ICE generators specifically designed to run on E85/E95 ethanol blends. New engines, however, that are capable of burning E85/E95 fuel are generally limited in size to the portable emergency type and have insufficient capacity for even the smallest generating stations on the islands. ICF, therefore, did not evaluate new ethanol engine generators for this application.

It may be possible, however, to replace some or all of the diesel/HFO fuel with ethanol, E85 or E95, for existing diesel engines. Recent projects undertaken by The Technical University of Denmark, Danish

Technological institute, VTT Technical Research Center and Scania AB demonstrated that "neat alcohols can be applied at very high compression ratio in diesel engines with the same performance as diesel fuel." This performance was achieved with the use of an ignition additive (IEA 2016). Blends of ethanol and diesel fuel have also been trialed successfully. One or more of the islands may wish to pursue a pilot program in which existing engines are modified to enable use of ethanol fuel.

Another technology from ClearFlame Engines may provide an avenue for ethanol to be used as a substitute for diesel in compression-ignition engines. The technology works by changing the way heat is managed within an engine by using insulation and managing exhaust flow (Ethanol Producer 2020). Engine modifications would be required. The technology is not yet commercially available; however, pilot programs are reportedly planned for 2021.

Barbados has existing gas turbine generators in operation which currently burn diesel fuel. These turbines could be modified relatively easily to burn ethanol. Additionally, either existing fuel tankage would have to be modified or new storage tanks built to enable storage of ethanol. Use of ethanol in turbines has been successfully demonstrated at a power plant in Brazil (Power 2010).

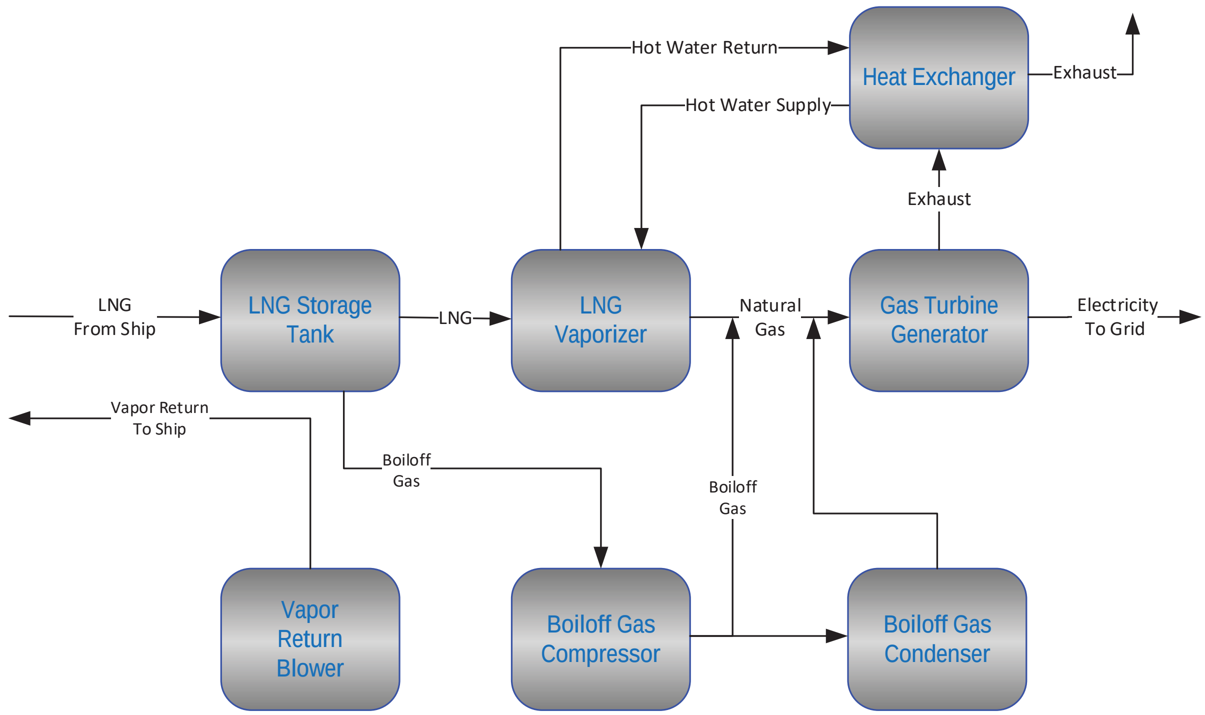
## Gas Turbine Generators

LNG was considered for use to fuel gas turbine generators on the islands. The gas turbine generators can provide significantly more power generation than ICE generators and would be considered for installation on islands with larger generation needs. Currently, diesel or HFO fuels ICEs on the islands produce the bulk of the power on the islands. The primary advantage of using LNG is that it is a cleaner burning fuel than diesel. However, implementation of LNG would involve significant capital costs. The choice between GT and ICE generators would likely be based on cost, efficiency, perceived reliability, availability, and the availability of maintenance personnel. Gas turbine generators are also available with greater generating capacity than ICEs. Typically, fewer machines result in lower capital cost and have lower maintenance costs. On the other hand, a single gas turbine generator provides no redundancy.

Existing diesel engines would have to be replaced and/or supplemented with LNG-fueled gas turbine generator sets. The available footprint for installing the gas turbine generator sets would be comparable to existing footprints utilized by the diesel- or HFO-fueled ICE generators. Additional infrastructure and storage areas however would be required on the islands for receiving, storing, and vaporizing the LNG.

A typical bulk system would include an unloading dock with LNG piped to a pressurized and heavily insulated LNG storage tank. It would also include a boiloff gas capture and compression system, an LNG vaporizer, and a compressor to return vapor to the delivering vessel. A simplified block flow diagram of such as system is shown in Exhibit 6.

*Exhibit 6: LNG Storage and Gas Turbine Generator System Block Flow Diagram*




The estimated total installed capital costs for range of sizes of new LNG fueled gas turbine generator sets are shown below in Exhibit 7. The estimated capital costs are for the installation, commissioning and start-up of new LNG-fueled gas turbine generators. They do not include costs for removal of the existing HFO or diesel ICE generators and accessories, diesel or HFO storage and unloading infrastructure. Nor do they include any costs for new LNG infrastructure for off-loading, storage, vaporization and feeding. The costs shown are inclusive of the 1.2 LF adjustment for an eastern or southern Caribbean Island installation and have an accuracy of ±30%.

*Exhibit 7: Capital and O&M Cost Estimates for Natural Gas-Fueled Gas Turbine Generators*

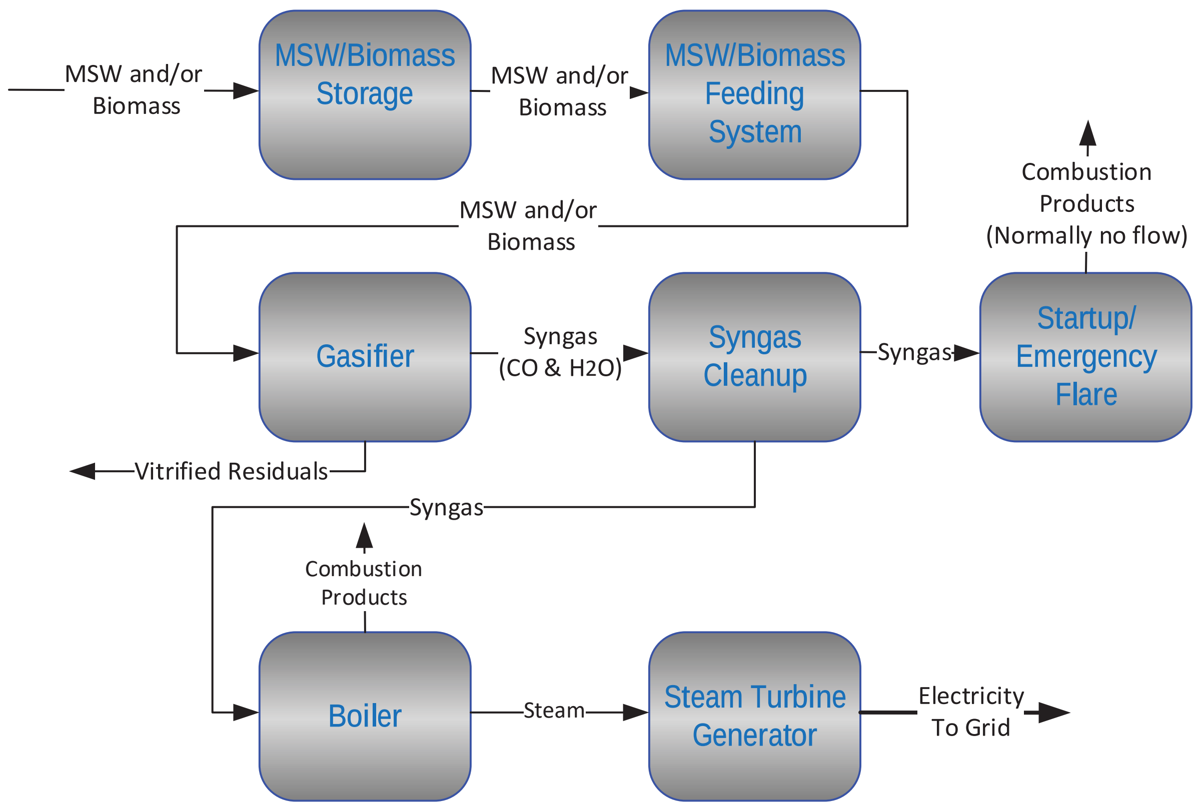
| Capital Costs | |
|---|---|
| **LNG Fuel Gas Turbine Generator Size Range, kW** | **Total Installed Capital Cost ($/kW)** |
| 3,500 to 4,600 | $2,047 |
| 5,670 to 8,180 | $1,829 |
| 8,180 to 11,350 | $1,758 |
| 11,350 to 23,000 | $1,580 |
| 23,000 to 31,000 | $1,450 |

| Operations and Maintenance (O&M) Cost Estimate | | |
|---|---|---|
| **LNG Fuel Gas Turbine Generator Size Range, kW** | **Fixed O&M Cost ($/kW – year)** | **Variable O&M Cost ($/MWh)** |
| 3,500 to 11,350 | $23.47 | $6.77 |
| 11,350 to 31,000 | $19.56 | $5.64 |

## Gasification

Gasification is a process that converts biomass or carbonaceous materials including municipal solid waste (MSW) into gases, which include carbon monoxide (CO), hydrogen ($H_2$), and carbon dioxide ($CO_2$). This is accomplished by reacting the feedstock material at high temperatures, while limiting the amount of oxygen present in the reaction. The resulting gas mixture is called syngas or producer gas and is combustible due to the $H_2$ and CO gas produced. One method for producing electricity via gasification is to combust the syngas in a boiler to produce steam which is then fed to a steam turbine generator (STG). The simplified block flow diagram in Exhibit 8 depicts a possible gasifier process configuration.

*Exhibit 8: Gasifier System Block Flow Diagram*




A benefit of using MSW as a gasification feedstock is that a significant MSW volume reduction would occur, thereby reducing the impact of MSW on island landfills. Further, the MSW feedstock would likely have a minimal cost, and its use would reduce reliance on imported fuel.

One such gasification system is supplied in modules designed to convert 200 metric tons per day of MSW and/or biomass to produce a sufficient flow rate of syngas to generate a net of 5 MW of power when coupled with a boiler and steam turbine generator.  Approximately 75% of MSW on St. Kitts and Trinidad and Tobago is convertible, e.g., paper, cardboard, wood, plastic, or textile (OAS 2008). We have assumed a similar fraction of MSW is convertible on other Caribbean islands. The table below displays the potential power generation for each country using MSW with this gasification technology. Additional feedstock may be available from agricultural waste and/or purpose grown biomass. It may also be possible to import MSW from other nearby islands which choose not to implement gasification.

*Exhibit 9: Electrical Generating Potential from MSW across the Islands Studied*

| Country | Population | Per Capita MSW Generation kg/day | MSW Metric tons/ day | Potential MSW Resource for Gasification, Metric tons/day | No. of Gasification Modules Possible | Estimated Power Generation Potential from MSW, MW |
|---|---|---|---|---|---|---|
| Barbados | 283,000 | 4.75 | 1,344 | 1008 | 5 | 25 |
| St. Lucia | 172,000 | 4.35 | 748 | 561 | 2 | 10 |
| Antigua and Barbuda | 89,000 | 5.5 | 490 | 367 | 1 | 5 |
| St. Vincent & Grenadines | 110,000 | 5 [1] | 550 | 412 | 2 | 10 |
| Sources: Wikipedia List of Caribbean Countries by Population, WOIMA's article Drowning in Waste – Case Saint Lucia<br>Note 1: Assumed, based on MSW production of other neighboring Caribbean countries | | | | | | |

The costs in Exhibit 10 for MSW gasification to produce syngas to fire a boiler to make steam for driving a steam turbine generator include the capital costs to supply and assemble the MSW gasifier and accessories and to supply and install the boiler and STG and all associated components to produce electrical power. The costs shown are inclusive of the 1.2 LF adjustment for an eastern or southern Caribbean Island installation and have an accuracy of ±30%.

*Exhibit 10: Capital and O&M Cost Estimates for MSW Gasification with Boiler and Steam Turbine Generator*

| Capital Costs | |
|---|---|
| **MSW Gasification w/ boiler & STG Size Range, kW** | **Total Installed Capital Cost ($/kW)** |
| 5,000 kW (200 tons per day MSW) | $14,000 |
| 10,000 kW (400 tons per day MSW) | $13,000 |
| 15,000 kW (600 tons per day MSW) | $11,500 |
| 20,000 kW (800 tons per day MSW) | $10,000 |

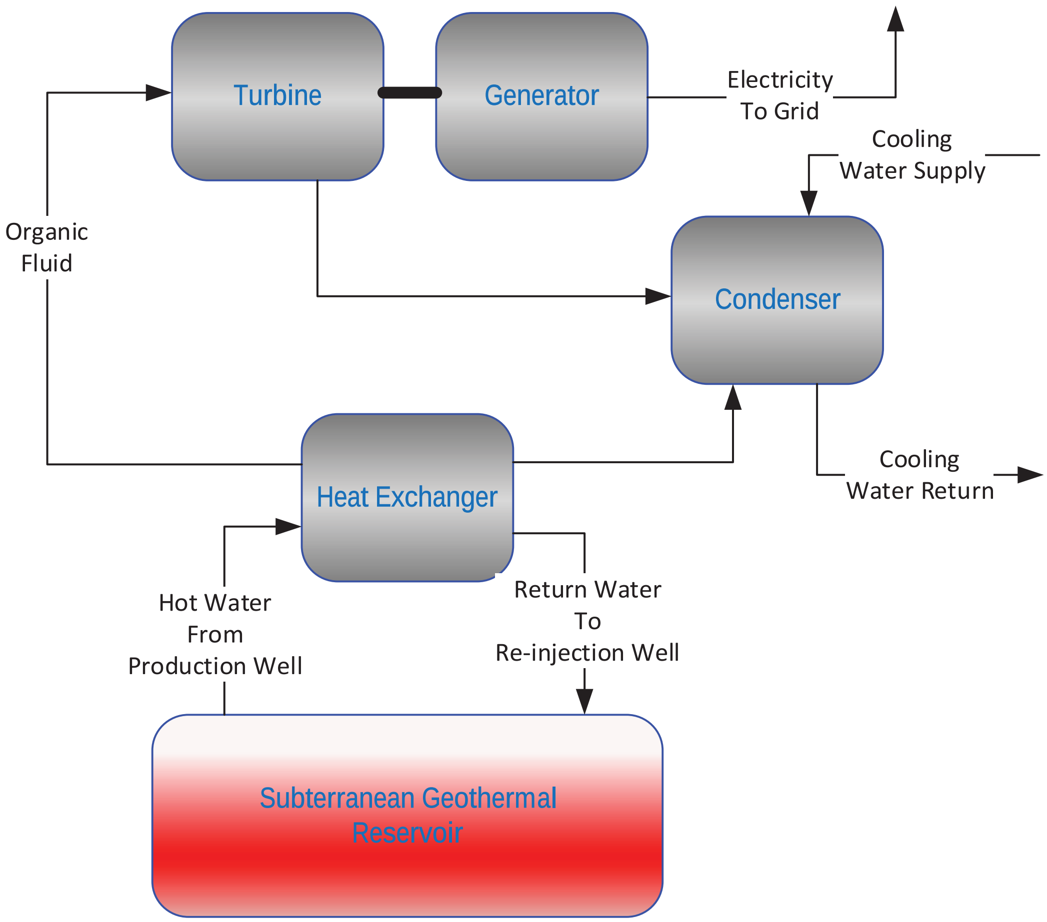
| Operations and Maintenance (O&M) Cost Estimate | | |
|---|---|---|
| **MSW Gasification w/ Boiler & STG Size Range, kW** | **Fixed O&M Cost ($/kW – year)** | **Variable O&M Cost ($/MWh)** |
| 5,000 – 20,000 kW | $150.86 | $5.80 |

## Geothermal

Geothermal power generation is a technology that was deemed to be a possible power generation technology considered for the eastern and southern Caribbean Islands. Geothermal is a desirable technology option, because the binary cycle power plants emit virtually no emissions (solid, liquid, or gaseous) and are one of the most reliable and high availability types of renewable energy sources. Their use results in no reliance on imported fuel or ongoing cost for fuel. The high cost of geothermal exploration has limited the development of geothermal in the Caribbean to preliminary and outdated studies. Two islands have been identified as having geothermal potential. St. Lucia has an estimated 680 Megawatts electric (MWe), and St. Vincent and the Grenadines have an estimated 890 MWe of geothermal potential.

Geothermal power generators require that geothermal wells be drilled for production and re-injection. It is expected that a nominal 5 MW facility would require two production wells with a single re-injection well to be drilled into the geothermal reservoir. For each additional 5 MW of power generated, an additional two production wells with a single re-injection well would be anticipated for a total geothermal power production of up to 20 MW on any one island. The re-injection of all the produced geothermal fluid back into the reservoir removes the need for brine processing and disposal, while the re-injection of all produced fluids helps maintain the reservoir pressure. Water for cooling is sourced from offsite natural sources such as the ocean, a lake, freshwater well, or river, or from a municipal supply or a saltwater desalination system. The simplified block flow diagram in Exhibit 11 depicts a typical binary geothermal power generating system.

*Exhibit 11: Binary Geothermal System Block Flow Diagram*




The total capital cost for a nominal 50 MW binary cycle geothermal power generation facility constructed per EIA's 2019 Capital Cost Report is $2,521/kW based on lower U.S. 48 state installation utilizing 19 production wells, 10 re-injection wells, and two 25 MW steam turbine generators. It is anticipated that there is an adequate geothermal resource to produce between 5 to 20 MW of geothermal power on one or more eastern and southern Caribbean islands. Capital costs for a geothermal power generation facility located on an eastern or southern Caribbean island would be expected to have a cost per kW significantly higher than the EIA 2019 Capital Cost Report cost of $2,521/kW and is projected to be the range of $4,800/kW for a 5-10 MW facility and range of $4,500/kW for a 15-20 MW facility inclusive of the location factor adjustment of 1.2 for installation on a Caribbean Island. The costs shown below have an accuracy of plus or minus 30%.

*Exhibit 12: Capital and O&M Cost Estimates for Binary Cycle Geothermal Plant*

| **Capital Costs** | |
|---|---|
| **Binary Cycle Geothermal Size Range, kW** | **Total Installed Capital Cost ($/kW)** |
| 5,000 kW – 10,000 kW | $4,800 |
| 15,000 kW – 20,000 kW | $4,500 |

| Operations and Maintenance (O&M) Cost Estimate | | |
|---|---|---|
| **Binary Cycle Geothermal Size Range, kW** | **Fixed O&M Cost ($/kW – year)** | **Variable O&M Cost ($/MWh)** |
| 5,000 – 20,000 kW | $154.25 | $1.39 |

## Renewable PV Solar

Photovoltaic solar (PV) power generation is a technology that has been deemed to be a possible option for the eastern and southern Caribbean Islands due to the amount of daylight available on a year-round basis on the islands. PV solar is a desirable technology option, as it requires no fossil fuels and emits no emissions while providing intermittent power generation during daylight hours at a low cost per kWh of generation. Often renewable PV solar power generation is teamed with BESS provide expanded capacity factors for generation during peak demand on the grid. PV solar is a reliable source for renewable power generation, providing a high availability factor during daylight hours with no reliance on imported fuel and no ongoing costs for fuel.

It is likely that PV solar would be sited on any available leased or purchased relatively flat coastal property that has access for construction and operations and that can easily be interconnected to the existing power grid on the island. Typically, a single axis tracker PV system will require approximately 5 to 7.5 acres of property per MW of installed capacity, thus a nominal 10 MW facility would require anywhere between 50 and 75 acres.

The capital costs for a PV solar facility will decrease on a cost per kW as the capacity of the facility is increased. PV solar facilities typically will have a minimum 35-year design life with degradation of the PV modules at approximately 1% per year. The estimated capital costs do not include cost to purchase the property, and it is assumed the property will be under long term lease. The FOM costs shown include costs for rental of the property on a land lease agreement for the design life of the project. PV solar facilities sited on islands or along coastal areas require upgraded robust racking systems with foundations and module attachments to resist effects of high-winds or hurricanes. Stow systems are typically included in designs to allow the tracking solar panels to be positioned in various stow positions based on winds or weather. The PV solar facilities will not create environmental damage or have environmental hazards that would be released after suffering damage or outage from high winds or hurricanes.

The construction of PV solar facilities is labor intensive but can utilize local unskilled and semi-skilled labor and does not require large construction equipment or cranes, and all materials are shipped to the installation site in 20-foot containers. Installation time for PV solar is short, and a nominal 10 MW sized facility would require 6-9 months of development then another 4-6 months for engineering and field construction.

The costs shown below are for a nominal 10 or 20 MW PV solar facility without a BESS. The capital costs include costs to develop, design, permit and to supply and assemble the ground mount single axis tracker system and interconnect to local utility grid. The costs shown are inclusive of the 1.2 LF adjustment for an eastern or southern Caribbean Island installation and have an accuracy of ±30%.

*Exhibit 13: Capital and O&M Cost Estimates for PV Solar*

| Capital Costs | |
|---|---|
| **Renewable PV Solar single axis tracker Size Range kW** | **Total Installed Capital Cost ($/kW)** |
| 10,000 kW | $1,390 |
| 20,000 kW | $1,300 |

| Operations and Maintenance (O&M) Cost Estimate | | |
|---|---|---|
| **Renewable PV Solar single axis tracker Size Range, kW** | **Fixed O&M Cost ($/kW – year)** | **Variable O&M Cost ($/MWh)** |
| 10,000 – 20,000 kW | $18.30 | $0.00 |

## Renewable Onshore Wind

Wind power generation is a technology that has been deemed to be a possible power generation technology considered for the eastern and southern Caribbean Islands due to the available wind resources. Onshore wind is a desirable technology option, because wind generation requires no fossil fuels and emits no emissions while providing intermittent power generation during times when wind speeds are available. Often renewable wind power generation is being teamed with a BESS to provide expanded capacity factors for generation when the wind is not available. Offshore wind, although a possible power generation technology to be considered, was ruled out due to typical cost on kW basis for offshore wind being 2.5 to 3.0 times more expensive per kW as for onshore wind.

Onshore wind turbine generators (WTG) would be sited on any available leased or purchased relatively flat coastal property that has access for construction and operations and that can easily be interconnected to the existing power grid on the island. Typically, a nominal 10 MW onshore wind facility would utilize four 2.8 MW size WTGs with nominal 125-meter rotor diameters and 90-meter hub heights.  Wind turbine access roads are required to allow transport and staging of WTG steel structures and turbine blades with work pads at each WTG foundation location that is required for a large crane to assemble the structure, nacelle (generating component housing), and turbine blading after the large foundations are placed.  It is estimated that a nominal 10 MW WTG facility with four wind turbines and access roads would require minimum of 60 acres and that the WTGs would be located on level area which would provide best available wind resource.

The capital costs for an onshore wind facility will decrease on a cost per kW as the capacity of the facility is increased. Estimated costs do not include cost to purchase land, and property would be assumed to be leased for the design life of the project. Costs to rent the land on lease agreement for the duration of the project are included in the FOM estimated costs. Wind facilities typically will have a minimum 25-year design life and are subject to being damaged during extended high winds or from a hurricane event. Stow systems are typically included in designs to allow the wind blades to be positioned in various stow positions designed to limit damage to the blading. The onshore wind facilities will not create environmental damage or have environmental hazards that would be released after suffering damage or outage from high winds or hurricanes.

The construction of wind generation facilities is very specialized and requires special cranes for offloading and installation of WTG structures and blades. Limited local unskilled labor would be utilized, except possibly for the foundation installations for the large gravity base turbine foundations. Assembly of the WTG will require specialized skills probably not available on the islands. All the components for 2.8 MW WTGs are large and would come to the island via a ship and need specialty handling to offload from ship to specialized transport and heavy haul trucks and trailers to transport to the installation sites. Installation time for WTG is short, and a nominal 10 MW sized facility would require 9-12 months of development and engineering and manufacturing and shipping of major components (steel tower structures, nacelle and blades), and field construction for roads and foundations along with WTG assembly and testing would take 4-6 months.

The costs shown in Exhibit 14 are for onshore wind for nominal 10 or 20 MW facility. They include the capital costs to develop, design, permit, supply, and assemble the WTG facility and interconnect to the local utility grid. The costs shown are inclusive of the 1.2 LF adjustment for an eastern or southern Caribbean Island installation and have an accuracy of ±30%.

*Exhibit 14: Capital and O&M Cost Estimates for Onshore Wind*

| Capital Cost Estimate | |
|---|---|
| **Renewable Onshore Wind w/ 2.8 MW WTG Size Range kW** | **Total Installed Capital Cost ($/kW)** |
| 10,000 kW | $2,012 |
| 20,000 kW | $1,900 |

| Operations and Maintenance (O&M) Cost Estimate | | |
|---|---|---|
| **Renewable Onshore Wind w/ 2.8 MW WTG Size Range, kW** | **Fixed O&M Cost ($/kW – year)** | **Variable O&M Cost ($/MWh)** |
| 10,000 – 20,000 kW | $42.17 | $0.00 |

# V. Energy Storage Technologies

As the islands transition from HFO and diesel generation to lower emission options over the next 20 years, it is anticipated that wind and solar power generation will increase. As the example outlined later in the Power Generation Pathway section discusses, renewable energy from wind and solar would likely start replacing the existing generators based on cost and renewable targets. However, when the intermittent renewable energy is more than the electrical grid demand, it is advantageous to store the extra electricity to be put back into the grid during high demand periods. Costs were developed for two storage options to support the grid scenarios. Battery storage systems are commercially developed and are in wide use. Hydrogen storage is a developing technology and is expected to play an important role in future decarbonization efforts.

## Battery Energy Storage Systems

Battery systems are typically used to store electricity from renewable energy sources such as PV solar panels or wind turbines. A BESS consists of several subsystems and components to realize the expected operation for a project. While the battery module and constituent cell technology are an important component of a grid-integrated BESS project, the remainder of the system plays a key role in the operating life, as well as the associated costs. The common components of a BESS are:

- Battery Module – Components comprising the energy storage capacity of the BESS, largest capital cost contributor, and the gating aspect limiting BESS operating life. Battery modules include a battery management system (BMS) which is responsible for the local management of multiple battery modules which are typically connected in series to form a battery string.
- Power Conversion System (PCS) – Electrical energy to and from battery modules are provided in direct current (DC) and as a result require conversion to alternating current (AC) for import from and export to the electrical grid. The PCS allows for bidirectional power flow to facilitate both discharging and charging.
- Energy Management System (EMS) – An EMS typically is responsible for the coordination of multiple BESS units to meet grid interconnection requirements.
- Thermal Management System (TMS) – Due to the thermal energy generated by the charge and discharge of battery cells, as well as the local environment in which the project is installed, it is necessary to actively cool the interior enclosure environment and the individual battery modules and racks.
- Safety and Fire Suppression System – Most BESS integrators include a fire detection and suppression system to minimize the impact of a cell rupture or thermal runaway event within the BESS.

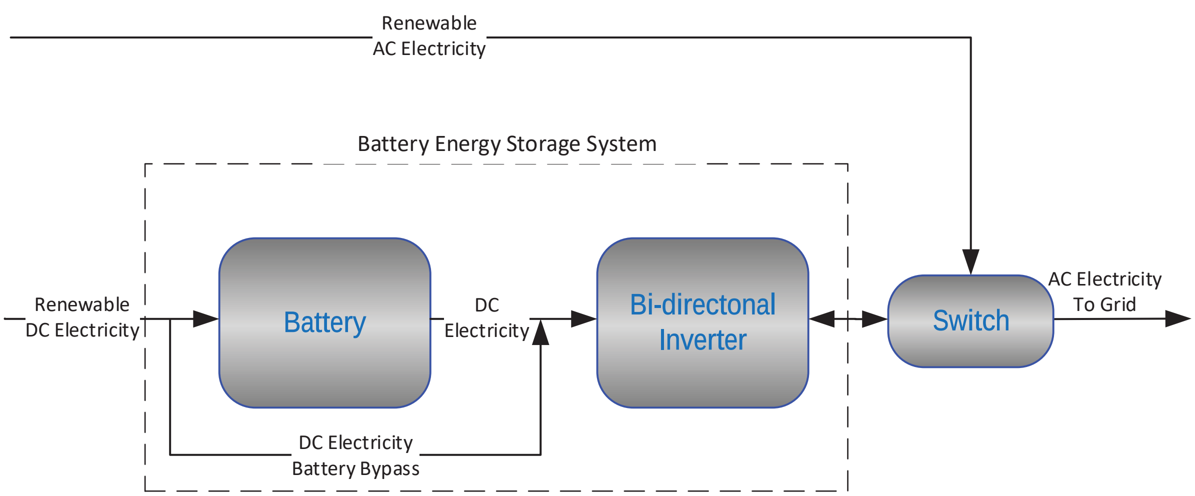
BESS offer an array of services that can be delivered to an electric grid. Generically, such services take the form of power services with a duration of one hour or less, energy services with a duration of more than one hour, and back-up services which may be provided intermittently. Services for which a BESS may be able to recognize a revenue stream, depending on the local opportunities, include:

- **Energy arbitrage** is the purchase of energy when prices are low and selling back to the grid when they are high, also known as peak-shaving or load-shifting. Generally, BESS of one hour or more duration is utilized for such services with moderate cycling daily. In this case, the BESS is simply shifting the energy timing via arbitrage methods. This service uses the full energy capacity of the BESS where the BESS discharges during peak pricing period (several hours), remains fully discharged for several hours, and then charges fully during low pricing period (several hours), and remains fully charged for several hours. This creates a full-cycle, high energy-throughput condition on the BESS. Additionally, such a BESS can used to shape the profile of intermittent generator (e.g., wind or solar) and create a dispatchable generator to match the load requirements of the grid.
- **Reserve power services** provide generation capacity to respond to contingency events or unplanned outages on the electrical grid. BESS operation requires a few minutes to one- or two-hour duration and typically dispatch on a weekly or monthly basis.
- **Black start services** are provided for restoration of grid operation to bring large grid areas back online after a fault. Similar to reserves services, BESS operation requires a few minutes to one- or two-hour duration with limited dispatch.
- **Frequency regulation** is an automated immediate response to a change in system frequency. Regulation, such as frequency regulation, load following, and ramp rate control, is used to help maintain system balance and prevent grid instability. Load following addresses inter-hour

variations in system load. Ramp rate control or ramp rate compensation is a large power output to balance opposed ramping of generation and load. BESS operation is generally short duration with relatively high number of cycles, in contrast to energy arbitrage services.

- **Voltage or power factor services** provide reactive power support to maintain line voltage and limit voltage excursions on the grid. BESS operation is generally short duration with relatively high number of cycles.

*Exhibit 15: BESS Block Flow Diagram*




BESS are specified with a power capacity and energy capacity rating or MW/MWh, where the ratio of MWh/MW is called the "duration", measured in units of hours. Most standalone or hybrid, coupled with PV or wind, grid-connected BESS have a duration of 2 to 4 hours, determined by the BESS revenue opportunities. The capital costs below in

Exhibit 16 are calculated according to the following formula:

*Equation 1*: $Total\ BESS\ Cost\ Formula$

$$Total\ Cost\ \left(\frac{\$}{kW}\right) = Balance\ of\ Plant\ Cost\ \left(\frac{\$}{kW}\right) + Energy\ Capcity\ Cost\ \left(\frac{\$}{kWh}\right) * Duration\ (hr)$$

For BESS, FOM generally involves integrator and component supplier specified maintenance including tightening of mechanical and electrical connections, fire suppression system checks, cabinet and enclosure touch up and cleaning, site maintenance, PCS and TMS maintenance.

BESS energy capacity degrades with usage, depending on energy throughput and other BESS operating conditions. Depending on the interconnection and offtake agreement requirements, BESS energy capacity may require periodic augmentation or replacement during the BESS operating term. If a minimum energy capacity is required, integrators will often overbuild the energy capacity at beginning of life and periodically augment and replace battery modules as needed. To account for future energy capacity additions, integrators typically propose additional interior footprint and/or site foundations to facilitate future installation. The costs associated with BESS energy capacity augmentation are captured via VOM costs.

*Exhibit 16: BESS Capital and O&M Estimated Costs*

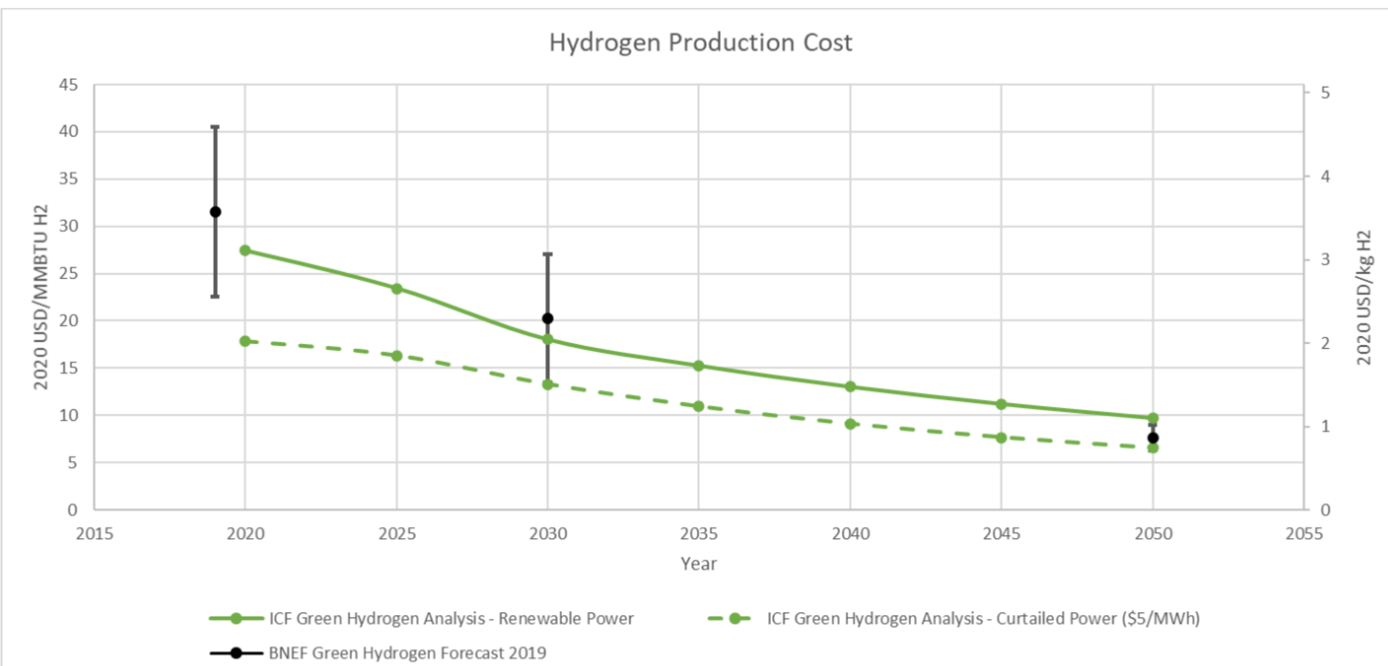
| BESS Capital and O&M Estimated Costs | | | |
|---|---|---|---|
| BESS Duration (hours) | Total BESS Capital Cost ($/kW) | Fixed O&M Costs ($/kW-yr) | Variable O&M Costs ($/MWh-yr) |
| 2 | $660 | $10 to $20 | $135 |
| 4 | $1,120 | $10 to $20 | $135 |

These capital costs were compared to publicly available, recent, actual Caribbean costs for battery projects and found to be within the reasonable margin of error (PR Newswire 2020).

## Hydrogen Storage

Green hydrogen is an emerging business model for decarbonization efforts in the power sector. Green hydrogen uses renewable energy to power electrolyzers which produce hydrogen. Because some renewable energy sources cannot provide a consistent energy supply, excess energy from such renewables can be converted to hydrogen, and the gas acts as a medium for temporary energy storage. When energy supply from renewables is low or demand is higher than usual, the stored hydrogen can be used as fuel for aeroderivative and combustion turbines. Exhibit 17 shows the cost projection of green hydrogen production in the United States based on average U.S. renewable energy costs and green hydrogen production cost based on a curtailed renewable power cost of $5/MWh. ICF's analysis assumes 12% learning curve rate[3] and Bloomberg NEF study from 2019 assumes 18-20% learning curve rate.

*Exhibit 17: Cost Projection of Green Hydrogen Production in the U.S.*



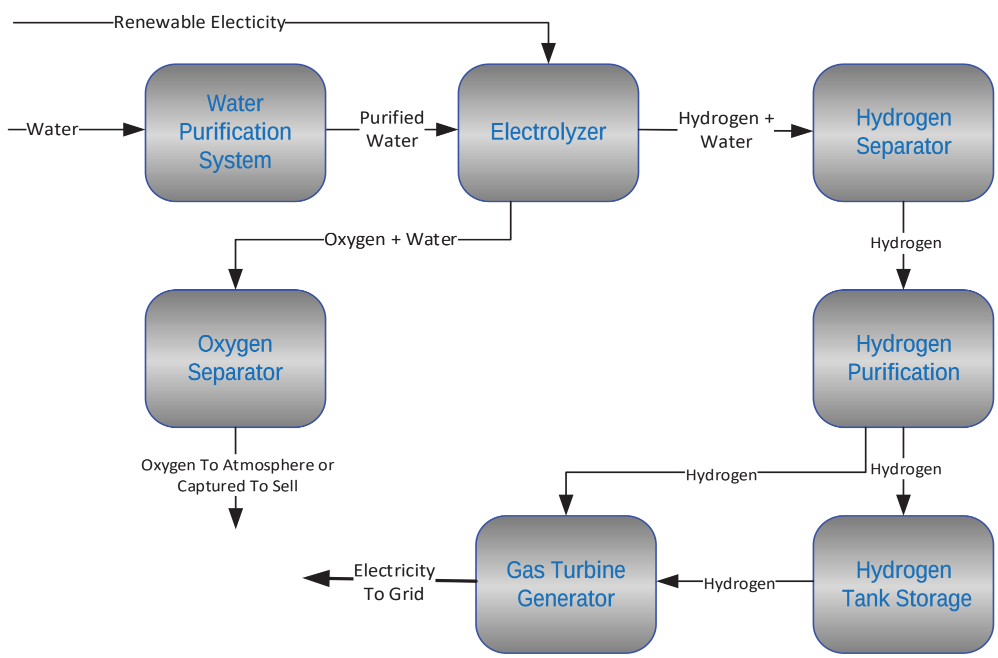

Currently, most turbines under 30 MW capacity can have up to 30% hydrogen blend capability with natural gas. Additional retrofitting of the combustion system of the turbines and fuel piping to the

[3] Technology improvements are often measured by "the learning curve rate" that represents the percent reduction in costs for each doubling of the cumulative number of units produced or capacity installed.

turbines are necessary to flow 100% hydrogen. Utilizing LNG turbine generators for incremental transition from LNG to hydrogen will result in lower carbon emissions.

The proton exchange membrane (PEM) electrolyzer is the most probable near-term option for hydrogen production. PEM electrolyzers use solid polymer material and catalysts such as titanium, platinum, etc. to electrochemically split water molecules into hydrogen and oxygen. The purity of hydrogen product is about 99.999% with a hydrogen dryer. Plug Power manufactures a 1 MW electrolyzer and BOP systems. The costs shown in Exhibit 19 and Exhibit 20 are based on Plug Power's 1 MW product which has about 84% efficiency and produces a maximum of 18 kg $H_2$/hr.

*Exhibit 18: Electrolyzer System Block Flow Diagram*




Capital and O&M costs shown in Exhibit 19 and Exhibit 20 are inclusive of the costs to supply and install the system shown in above block diagram; however, the costs to supply and install a gas turbine generator set to produce electrical power from hydrogen are the same as a LNG gas turbine which are shown in Exhibit 7 and are not included in the capital costs pricing shown in Exhibit 19.

*Equation 2: Electrolyzer Cost Curve*

$$f_{ElecCapCost}(x) = k * LF * \left(\frac{x}{1}\right)^{0.6}$$

Where $x$ = Number of 1MW units required for power gas turbine facility

$k$ = Electrolyzer Cost in U.S. dollars (2021 cost of 1MW electrolyzer unit is $1,300,000)

$LF$ = Location adjustment factor, 1.2

$F_{ElecCapCost}\ (x)$ = Cost to construct electrolyzer unit in U.S. dollars. Note, to convert to $/kW this value should be divided by the kW capacity of the gas turbine facility.

The capital costs shown below includes Equation 2 with the 1.2 location adjustment factor, as well as additional factors of 1.2 greenfield installation factor, and 1.3 EPC and additional balance of plant cost factor for electrolyzers. All costs shown should be considered to be plus or minus 30% accuracy.

*Exhibit 19: Hydrogen Flow Rates and Electrolyzer and Liquid Storage Tank Capital and O&M Estimated Costs for 4 Hours Duration Systems*

| Capital Costs for 4 Hours of Hydrogen | | |
|---|---|---|
| **LNG Fuel Gas Turbine Generator Size Range, kW** | **Hydrogen Flow Rates for 4 Hours Per Day (kg $H_2$/ day)** | **Average Installed Electrolyzer and Liquid Storage Tank Capital Cost (\$/kg $H_2$)** |
| 3,500 to 5,670 | 1,500 - 1,880 | \$9,719 |
| 5,670 to 8,180 | 1,880 - 2,860 | \$8,449 |
| 8,180 to 11,350 | 2,860 - 4,150 | \$7,187 |
| 11,350 to 23,000 | 4,150 - 7,150 | \$5,919 |
| 23,000 to 31,000 | 7,150 - 10,600 | \$4,966 |

| Operations and Maintenance (O&M) Costs for 4 Hours of Hydrogen | | |
|---|---|---|
| **LNG Fuel Gas Turbine Generator Size Range, kW** | **Fixed O&M Costs (\$/kg $H_2$)** | **Variable O&M Costs (\$/kg $H_2$)** |
| 3,500 to 5,670 | \$3.89 | \$3.88 |
| 5,670 to 8,180 | \$2.96 | |
| 8,180 to 11,350 | \$2.18 | |
| 11,350 to 23,000 | \$1.54 | |
| 23,000 to 31,000 | \$1.13 | |

*Exhibit 20: Hydrogen Flow Rates and Electrolyzer and Liquid Storage Tank Capital and O&M Estimated Costs for 12 Hour Duration System*

| Capital Costs for 12 Hours of Hydrogen | | |
|---|---|---|
| **LNG Fuel Gas Turbine Generator Size Range, kW** | **Hydrogen Flow Rates for 12 Hours Per Day (kg $H_2$/ day)** | **Average Installed Electrolyzer and Liquid Storage Tank Capital Cost (\$/kg $H_2$)** |
| 3,500 to 5,670 | 4,500 - 5,640 | \$6,228 |
| 5,670 to 8,180 | 5,640 - 8,580 | \$5,424 |
| 8,180 to 11,350 | 8,580 - 12,450 | \$4,638 |
| 11,350 to 23,000 | 12,450 - 21,450 | \$3,815 |
| 23,000 to 31,000 | 21,450 - 31,800 | \$3,205 |

| Operations and Maintenance (O&M) Costs for 12 Hours of Hydrogen | | |
|---|---|---|
| **LNG Fuel Gas Turbine Generator Size Range, kW** | **Fixed O&M Costs (\$/kg $H_2$)** | **Variable O&M Costs (\$/kg $H_2$)** |
| 3,500 to 5,670 | \$1.67 | \$3.88 |
| 5,670 to 8,180 | \$1.31 | |
| 8,180 to 11,350 | \$1.01 | |
| 11,350 to 23,000 | \$0.74 | |
| 23,000 to 31,000 | \$0.57 | |

The FOM costs shown in  include the following assumptions: annual major maintenance costs are 3% of the capital costs; membrane replacement costs are about 15% of direct capital costs of electrolyzers and electrolyzer membrane stack lifetime is about 9 years; annual labor cost of $1,600,000. The VOM costs depends on the price of water and energy. The electrolyzer system will require about 23 kg of water for every 1 kg of hydrogen produced and about 50 kWh/kg of hydrogen produced. The cost of storage will vary depending on the capacity of the tank, however, an estimate of the capital cost of a liquid tank is $36/kg hydrogen with the location adjustment factor and the energy required to liquify hydrogen is about 10.4 kWh/kg hydrogen. Assuming renewable power costs of $0.064/kWh for the energy required for the electrolyzer system and liquefaction process and water costs of $0.003/gallon of water, the variable O&M is about $3.88/kg of hydrogen.

# VI. Summary of Generation and Storage Costs

Exhibit 21 provides summary level capital costs and O&M costs for generation technologies with the ranges shown that were evaluated in this study. As indicated in the exhibit, the LNG gas turbine generators cost less to install and operate than the ICE generators. However, gas turbines are generally larger in capacity and may not be suitable for the islands with smaller electrical grids and small ICE generators. PV solar electrical generation (without battery storage) has installation costs similar to gas turbine generators plus the added benefit of not requiring fuel. Wind energy systems have installation and FOM costs similar to the 10 MW ICE generators, but availability is intermittent and battery storage may be required.

Exhibit 22 shows a summary of capital and O&M costs for storage technologies. Battery storage for 4 hours costs almost as much as the PV solar to install.  Battery capacity degrades with usage, and it is necessary to replace the batteries over time, which is reflected in the VOM costs. While the cost of producing green hydrogen is high, the cost of electrolyzers is expected to decrease as the technology is developed.  The hydrogen storage VOM costs reflect the water and electricity to convert water to hydrogen and oxygen plus the electricity to liquify the hydrogen.

*Exhibit 21: Summary Generation Technologies and Costs*

| Summary Generation Technologies and Costs | | | | | |
|---|---|---|---|---|---|
| **Generation Technology- Size Range** | **Fuel** | **Cap-Ex ($/kW)** | **FOM ($/kW-year)** | **VOM ($/MWh)** | **Cap-Ex Cost Source** |
| **ICE Generator** | | | | | |
| 150 – 1,750 kW | LNG | $1,800 | $50.63 | $8.19 | Vendor Budgetary Quote |
| Containerized 150 – 1,750 kW | LNG | $2,256 | $50.63 | $8.19 | Vendor Budgetary Quote |
| 2,000 – 7,500 kW | LNG | $1,960 | $42.19 | $6.82 | Vendor Budgetary Quote |
| Containerized 1,750 – 4,400 kW | LNG | $2,210 | $42.19 | $6.82 | Vendor Budgetary Quote |
| 9,300 – 20,000 kW | LNG | $2,172 | $42.19 | $6.82 | EIA 2020 |
| **Gas Turbine Generators** | | | | | |
| 3,500 – 4,600 kW | LNG | $2,047 | $23.47 | $6.77 | GTW 2019 |
| 5,670 – 8,180 kW | LNG | $1,829 | $23.47 | $6.77 | GTW 2019 |
| 8,180 – 11,350 kW | LNG | $1,758 | $23.47 | $6.77 | GTW 2019 |
| 11,350 – 23,000 kW | LNG | $1,580 | $19.56 | $5.64 | GTW 2019 |
| 23,000 – 31,000 kW | LNG | $1,450 | $19.56 | $5.64 | GTW 2019 |
| **Gasification w/ Boiler & STG (1)** | | | | | |
| 5,000 kW (200 tons per day MSW) | MSW | $14,000 | $150.86 | $5.80 | Vendor Budgetary Quote |
| 10,000 kW (400 tons per day MSW) | MSW | $13,000 | $150.86 | $5.80 | Vendor Budgetary Quote |
| 15,000 kW (600 tons per day MSW) | MSW | $11,500 | $150.86 | $5.80 | Vendor Budgetary Quote |
| 20,000 kW (800 tons per day MSW) | MSW | $10,000 | $150.86 | $5.80 | Vendor Budgetary Quote |
| **Geothermal** | | | | | |
| 5,000 kW – 10,000 kW | Geo | $4,800 | $154.25 | $1.39 | EIA 2020 |
| 15,000 kW – 20,000 kW | Geo | $4,500 | $154.25 | $1.39 | EIA 2020 |
| **PV Solar** | | | | | |
| 10,000 kW | Solar | $1,390 | $18.30 | $0.00 | ICF Internal |
| **Onshore Wind** | | | | | |
| 10,000 kW (4 x 2.8 WTG) | Wind | $2,012 | $42.17 | $0.00 | EIA 2020 |
| **Notes:**<br>1) Gasification OEM notes costs are similar for biomass fuel | | | | | |

Exhibit 22 provides summary level capital costs and O&M costs by fuel type for storage technologies with ranges shown that were evaluated in this study.

*Exhibit 22: Summary Storage Technologies and Costs*

| Summary Storage Technologies and Costs | | | | |
|---|---|---|---|---|
| **Generation/Storage Technology-Range** | **Hydrogen Flow Rates for Duration (kg $H_2$/ day)** | **Cap-Ex ($/kg $H_2$ for Hydrogen)** | **Fixed O&M ($/kg $H_2$)** | **VOM ($/kg $H_2$)** |
| **Hydrogen Production and Storage – 4 hours** | | | | |
| 3,500 - 5,670 kW | 1,500 - 1,880 | $9,719 | $3.89 | $3.88 |
| 5,670 - 8,180 kW | 1,880 - 2,860 | $8,449 | $2.96 | |
| 8,180 - 11,350 kW | 2,860 - 4,150 | $7,187 | $2.18 | |
| 11,350 - 23,000 kW | 4,150 - 7,150 | $5,919 | $1.54 | |
| 23,000 - 31,000 kW | 7,150 - 10,600 | $4,966 | $1.13 | |
| **Hydrogen Production and Storage – 12 hours** | | | | |
| 3,500 - 5,670 kW | 4,500 - 5,640 | $6,228 | $1.67 | $3.88 |
| 5,670 - 8,180 kW | 5,640 - 8,580 | $5,424 | $1.31 | |
| 8,180 -11,350 kW | 8,580 - 12,450 | $4,638 | $1.01 | |
| 11,350 - 23,000 kW | 12,450 - 21,450 | $3,815 | $0.74 | |
| 23,000 - 31,000 kW | 21,450 - 31,800 | $3,205 | $0.57 | |
| | | | | |
| **Storage Technology-Range** | | **Cap-Ex ($/kW)** | **Fixed O&M ($/kw-y)** | **VOM ($/MWh-y)** |
| **Battery Energy Storage Systems – 2 hours** | | | | |
| 5,000 – 20,000 kW | - | $660 | $10 to $20 | $135 |
| **Battery Energy Storage Systems – 4 hours** | | | | |
| 5,000 – 20,000 kW | - | $1,120 | $10 to $20 | $135 |

# Sources and Options for Transportation & Storage of Petroleum Products

## I. Introduction

This chapter presents information on possible sources of LNG, propane, and fuel oil that can be imported into the Eastern Caribbean and the methods and costs for transporting and storing those fuels for power generation and other uses. For Antigua and Barbuda, Barbados, St. Lucia, and St. Vincent and the Grenadines which expressed the highest interest in LNG, this chapter also develops fuel costs for specific cases (fuel origin, demand scenario, ship size, and transportation methods) that may be most relevant for evaluating the market potential for LNG and propane.

## II. Sources of Supply: LNG, Propane, and Fuel Oil

### Sources of LNG

Due to the location of the target countries, LNG would primarily be sourced from the U.S. mainland or Trinidad and Tobago. There are 25 large-scale liquefaction export terminals in the United States which could provide LNG to existing markets in the Caribbean, including those in operation as well as various stages of planning, construction, or expansion development. Outside of the United States, Atlantic owns and operates an LNG plant in Trinidad which serves as another option for LNG supply to Caribbean markets. Exhibit 23 below displays these terminals with current statuses and relevant capacities in billion cubic feet (Bcf) per day, where applicable.

*Exhibit 23: LNG Export Terminal Operations with Access to Caribbean Markets*

| Country | State | Company/Name | Capacity (Bcf/d) | Status |
|---|---|---|---|---|
| USA | Sabine, LA | Cheniere - Sabine Pass LNG* | 3.50 | Active |
| USA | Hackberry, LA | Sempra - Cameron LNG* | 2.15 | Active |
| USA | Freeport, TX | Freeport LNG* | 2.13 | Active |
| USA | Corpus Christi, TX | Cheniere - Corpus Christi LNG* | 1.44 | Active |
| USA | Cove Point, MD | Dominion - Cove Point LNG | 0.82 | Active |
| USA | Elba Island, GA | Southern LNG Company - Elba Island LNG | 0.35 | Active |
| Trinidad & Tobago | - | Atlantic LNG | 2.00 | Active |
| USA | Calcasieu Parish, LA | Driftwood LNG | 4.00 | Under Construction |
| USA | Sabine Pass, TX | ExxonMobil - Golden Pass | 2.10 | Under Construction |
| USA | Cameron Parish, LA | Venture Global - Calcasieu Pass | 1.41 | Under Construction |
| USA | Brownsville, TX | Rio Grande LNG | 3.60 | Approved, Not Under Construction |
| USA | Plaquemines Parish, LA | Venture Global LNG | 3.40 | Approved, Not Under Construction |
| USA | Lake Charles, LA | Lake Charles LNG | 2.20 | Approved, Not Under Construction |
| USA | Port Arthur, TX | Port Arthur LNG* | 1.86 | Approved, Not Under Construction |
| USA | Pascagoula, MS | Gulf LNG | 1.50 | Approved, Not Under Construction |
| USA | Lake Charles, LA | Magnolia LNG | 1.19 | Approved, Not Under Construction |
| USA | Brownsville, TX | Annoval LNG Brownsville | 0.90 | Approved, Not Under Construction |
| USA | Brownsville, TX | Texas LNG Brownsville | 0.55 | Approved, Not Under Construction |
| USA | Jacksonville, FL | Eagle LNG | 0.13 | Approved, Not Under Construction |
| USA | Sabine Pass, LA | Sabine Pass Liquefaction | N/A | Approved, Not Under Construction |
| USA | Plaquemines Parish, LA | Delta LNG - Venture Global | 2.76 | Proposed |
| USA | Galveston Bay, TX | Galveston Bay LNG | 1.20 | Proposed |
| USA | Cameron Parish, LA | Commonwealth LNG | 1.18 | Proposed |
| USA | Plaquemines Parish, LA | Pointe LNG | 0.90 | Proposed |
| USA | LaFourche Parish, LA | Port Fourchon LNG | 0.65 | Proposed |

*Sources: Federal Energy Commission (FERC), International Group of Liquefied Natural Gas Importers (GIIGNL)*
**Indicates expansions have either begun construction or have been proposed at this facility. Capacities shown do not include expansions.*

While large scale export terminals can supply significant volumes of LNG, these sources may not always be economic due to the level of demand in the Caribbean markets of interest. However, LNG can also be shipped using smaller ISO-containers on standard containerships. In the U.S., these ISO-containers are currently being shipped in the Atlantic from the American LNG Marketing liquefaction plant in Hialeah, Florida to Barbados (Riviera Newsletters 2017). The Port of Jacksonville has also recently loaded LNG using these containers for delivery to nearby destinations such as Puerto Rico (Crowley 2018).

Outside of the United States, the AES Corporation (AES) operates LNG import terminals in the Dominican Republic and Panama which can provide volumes throughout the region (Dominican Today 2020). The AES Andrés terminal in the Dominican Republic has previously supplied Barbados with LNG ISO-container deliveries and with small bulk carrier deliveries available as an alternative delivery option from the facility (Dominican Today 2017). Providing small volumes from a centrally located, large LNG import terminal represents a “hub and spoke” business model. Hub and spoke can be most effective when supply is needed for regional, low demand markets such as those in the Caribbean where the regional demand is enough to justify larger vessels thereby achieving economies of scale on transportation and storage costs.

In 2019, LNG was only imported by Barbados where 99.1% of the volumes originate from the United States, and the other 0.9% originated from the Dominican Republic, likely from the AES Andrés terminal (Dominican Today 2017, UN Comtrade Database).

## Sources of Propane

Similar to LNG, liquefied petroleum gas (LPG) can be transported by marine vessel either by directly loading into onboard tank storage and shipped via large, capacity vessels or stored in ISO-containers and shipped using a standard containership. In the United States, there have been 12 port areas which have previously shipped LPG exports as shown in Exhibit 24. Two of these locations, Houston and Miami, have provided LPG export volumes to Dominica, Barbados, and Antigua and Barbuda as recently as 2019 (USITC 2019).

*Exhibit 24: Possible U.S. Export Locations to support Caribbean LPG Operations*

| Regional LPG Export Locations | |
|---|---|
| Charlotte, NC | Philadelphia, PA |
| Houston-Galveston, TX | Port Arthur, TX |
| Miami, FL | Portland, ME |
| New Orleans, LA | San Juan, PR |
| New York, NY | Tampa, FL |
| Norfolk, VA | Trinidad and Tobago |
| Ogdensburg, NY | |

Source: U.S. ITC Trade Database

Exhibit 25 displays the proportion of imported LPG supplied by origin country in 2019. Antigua and Barbuda and Saint Lucia both saw minimal volumes of propane, while other countries utilize propane currently primarily for cooking. Currently, almost all volumes of LPG imported to target Caribbean markets originate from Trinidad and Tobago or the United States. Some volumes have been delivered from other markets including China, Saint Lucia, Republic of Korea, and British Virgin Islands, but these volumes have been minimal.

*Exhibit 25: Proportion of 2019 LPG Imports to Target Caribbean Markets by Origin Country*

| Origin Country | Antigua and Barbuda | Barbados | Saint Lucia | Saint Vincent and the Grenadines | Total Across All Four Countries |
|---|---|---|---|---|---|
| Trinidad and Tobago | 0% | 38.2% | 7.4% | 93.2% | 57.5% |
| USA | 78.5% | 61.8% | 89.9% | 6.8% | 42.5% |
| Peru | 21.5% | 0% | 0% | 0% | 0% |
| Barbados | 0% | 0% | 1.3% | 0% | 0% |
| United Kingdom | 0% | 0% | 1.2% | 0% | 0% |
| France | 0% | 0% | 0.2% | 0% | 0% |

Source: UN Comtrade Database

## Sources of Fuel Oil

Fuel oils refer to a group of petroleum products separated during distillation at an oil refinery which can be used for a variety of purposes such as heating, power generation, and as a transportation fuel. Fuel oils consist of distillates and residual fuel oils. Distillates are lighter oils such as diesel fuel, while residual fuel oils are heavier. Residual fuels are primarily used in vessel bunkering but can also be used in various industrial uses. In the Caribbean markets of interest, fuel oils are primarily sourced from Trinidad and Tobago, the United States, and the Netherlands. Distillates have been imported from eight different countries in the last five years across the four island countries. Residual fuel volumes are imported by Barbados from the three primary countries noted above. The country has also recently received smaller volumes from four additional supply countries as shown below. Exhibit 26 and Exhibit 27 give origin countries of both distillate and residual fuels to the four Caribbean markets over the last five years.

*Exhibit 26: Origin Countries for Distillate Imports to Target Caribbean Markets*

| Source Country |
|---|
| Bahamas |
| Japan |
| Netherlands* |
| Saint Lucia |
| Suriname |
| Trinidad and Tobago |
| United States of America |
| Venezuela, Bolivarian Republic of |

Source: International Trade Centre

*May be represented by owned territories such as Aruba, which supports an active oil refinery.

*Exhibit 27: Origin Countries for Residual Fuel Oil Imports to Barbados*

| Source Country |
|---|
| Cayman Islands |
| France |
| Jamaica |
| Netherlands* |
| Suriname |
| Trinidad and Tobago |
| United States of America |

Source: International Trade Centre

*May be represented by owned territories such as Aruba, which supports an active oil refinery.

Within the United States, there were 7 port locations which exported fuel oil to the target Caribbean markets as illustrated in Exhibit 28. All four Caribbean countries considered in this study imported some volume of fuel oils as recently as 2019. (US ITC 2019)

*Exhibit 28: U.S. Export Locations Supporting Caribbean Fuel Oil Operations*

| Source Country |
|---|
| Houston-Galveston, TX |
| Miami, FL |
| New Orleans, LA |
| New York City, NY |
| Port Arthur, TX |
| San Juan, PR |
| U.S. Virgin Islands |

Source: U.S. ITC Trade Database

## Petroleum Product Imports

The following exhibits give the total imported volumes of petroleum products over the last five years to each target Caribbean market. Barbados imports more petroleum products than any other country and is also the only to have imported LNG and residual fuel oils. St. Lucia and St. Vincent and the Grenadines mainly import gasoline and diesel fuels, while Antigua and Barbuda primarily rely on lubricants from international markets.

Exhibit 29 shows the proportion of oil product imports supplied to target Caribbean markets by origin country. In 2019, most product imports originated from three countries: Trinidad and Tobago, the United States, and the Netherlands. Other countries such as Jamaica, Canada, Panama, and Jamaica provide higher volumes proportionally to certain countries, but most imports across all four markets are received from those primary countries. Additional countries that exported minimal volumes to the target countries included Japan, Germany, Dominican Republic, Saint Lucia, Curacao, Grenada, Antigua and Barbuda, and Barbados.

*Exhibit 29: Proportion of 2019 Oil Product Imports to Target Caribbean Markets by Origin Country*

| Origin Country | Antigua and Barbuda | Barbados | Saint Lucia | Saint Vincent and the Grenadines | Total Across All Four Countries |
|---|---|---|---|---|---|
| Trinidad and Tobago | 1.1% | 49.2% | 54.9% | 55.1% | 50.1% |
| USA | 88.5% | 20.5% | 44.9% | 44.2% | 24.5% |
| Netherlands | 0% | 28.0% | 0% | 0% | 23.5% |
| Canada | 0% | 2.1% | 0% | 0% | 1.7% |
| Jamaica | 4.2% | 0% | 0.2% | 0% | 0.1% |
| Other | 7.2% | 0% | 0% | 0.2% | 0% |

Source: UN Comtrade Database; note 0% can indicate small enough volumes to not be significant rather than no volumes

# III. Transportation Options for Imported Petroleum Products

## LNG Transport: Bulk Shipments on LNG Carriers

LNG carriers can be characterized by vessel type, containment system, and propulsion system. LNG carriers typically range from 800-1,000 feet long, 140 feet wide, and have drafts of between 30 to 40 feet (GIIGNL 2020a). Vessel types vary by onboard capacity:

- Conventional –

    - Small (below approximately 50,000 cubic meters ($m^3$))
    - Large (between 50,000 and 165,000 $m^3$)
- Q-Flex – between 165,000 and 216,000 $m^3$
- Q-Max – greater than 216,000 $m^3$

Typically, LNG containment systems are referred to as either Moss or Membrane design. Variations of these systems are usually named after the company which designed them. Moss containment systems consist of multiple (typically 4-5) on-deck spherical tanks. Membrane types vary by containment system design. The most common systems include Technigaz Mark III, GT-96, and GTT CS-1, each of which vary based on related tankage specifications (Marine Insight 2020).

There are approximately 600 LNG carriers currently in operation across the global fleet (GIIGNL 2020b). 139 of these entered or exited a U.S. port in 2018, and of those, 5 were delivering volumes to countries in the Caribbean including Barbados (USACE 2018). These vessels ranged from very small (10,000 $m^3$) to full size (174,000 $m^3$) carriers. Across the fleet, 43 LNG carriers had capacities lower than 50,000 $m^3$ (see Appendix D: Small LNG Carriers). These smaller vessels would be ideal for use in Caribbean markets due to the low demand.

## Propane Transport: Bulk Shipments on LPG Carriers

LPG carriers are classified according to their cargo capacity, as well as the operating temperature and pressure of onboard storage. The smallest LPG carriers are fully pressurized and can range from 100 to nearly 20,000 $m^3$ in capacity. This vessel type offers tanks with design pressures up to 18 barg (Marine Insight 2021). Semi-pressurized, fully refrigerated LPG carriers are also in use, and range from 12,000 to 23,000 $m^3$ with working pressures of 5-7 barg. Midsize and large LPG carriers (MGC/LGC) are the next size classes and are fully refrigerated, with storage capacities ranging from 17,500 to 70,000 $m^3$. Very large gas carriers (VLGC) are the largest vessel type, offering 70,000 to 100,000 $m^3$ of onboard capacity (VesselsValue 2021).

There are nearly 1,400 LPG carriers currently in operation across the global fleet (SIGTTO 2019). Of these, 326 entered or exited a U.S. port in 2018, and of those, 56 were delivering volumes to countries in the Caribbean (USACE 2018). Vessels originating in the United States and delivering to the Caribbean ranged from 3,000 to 53,000 $m^3$ of capacity in size and would be most capable for use in other nearby markets in the region.

## Fuel Oil: Bulk Shipments on Tankers

Fuel oils are shipped in bulk via clean petroleum product tankers. These bulk vessels transport product volumes using storage tanks integrated into the hull of the ship, which can be filled or unloaded from ground storage onsite at port facilities. These tankers range widely in size based on the following approximate capacity ranges (Maritime Connector 2021):

- Handysize: 15,000-30,000 DWT
- Handymax/Supramax: 50,000-60,000 DWT
- Panamax: 60-000-80,000 DWT
- Aframax: 80,000-120,000 DWT
- Suezmax: 120,000-200,000 DWT

The Caribbean fuel oil demand is relatively low when comparing with other markets, so shipments would likely rely on smaller vessels such as those in the Handysize, Handymax, and Panamax ranges. These vessels are widely available for global shipping and would be capable of providing volumes based on demand.

### Land Transport from Ports to Power Plants: Trucks & Pipelines

Transportation to the power plant after arrival at port in each market would depend on the form in which the fuel is shipped. If fuel is shipped in bulk, volumes would first be unloaded from the vessel and stored at tanks onsite at the port. These volumes would then have two available transportation options to arrive at the power plant. Volumes could be sent directly by pipeline, requiring connection to both the port facilities and to the power plant, or by tanker truck. For tanker trucks, fuel volumes would be loaded onsite at port facilities via truck loading racks and driven to the power plant. If the fuel is shipped via ISO container, the tank itself would require transportation. This can be provided via flat-bed truck, where the tank would be loaded onsite at the port and then driven directly to the power plant.

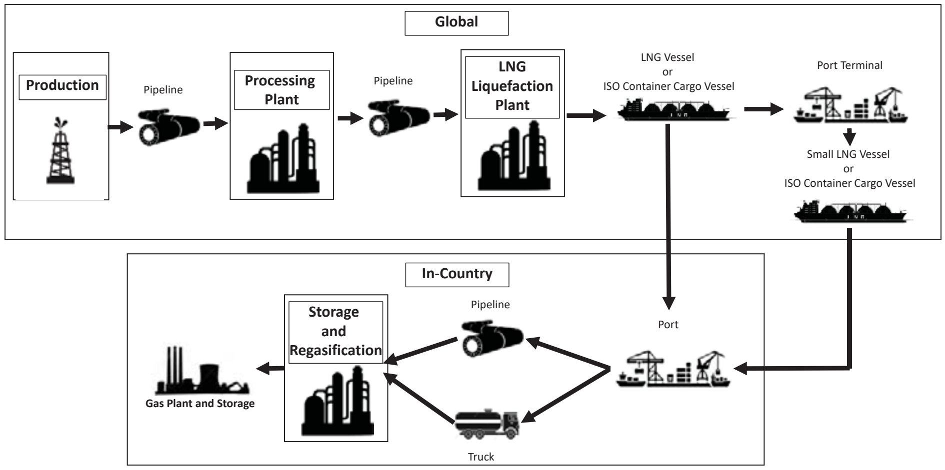
## IV. Transport and Storage Costs

The cost for delivering fuel, whether it be natural gas, propane, diesel, fuel oil, ethanol and hydrogen to the Eastern Caribbean power plants, encompasses costs across the value chain. These costs include production costs, transportation costs (pipelines, vessels and trucking), liquefaction and regasification costs for LNG, port costs, and storage costs. These costs were estimated individually and followed the methodology as outlined in this section to develop the delivered cost for each fuel. Each of these fuels which are produced off-island would be susceptible to the same types of events such as hurricanes impacting the upstream supply chain. Due to the flexibility in procuring fuel from different locations, issues impacting the upstream supply chain oftentimes can be remedied by procuring from a separate location, but nonetheless procurement may be delayed during unexpected events. Hydrogen, an emerging fuel, would have fewer origination locations, and therefore may be more susceptible to events that could impact upstream supply. The most impactful events to supply are those that disrupt the ability to offload product at the port due to damage of equipment or shoaling at the port that prevents ships from docking. These events would require repair of equipment or dredging at the port which can delay all types of fuel deliveries.

### LNG Pathway

Natural gas delivered to the Eastern and Southern Caribbean will follow a pathway as outlined in Exhibit 30. LNG can be shipped to the islands directly on small LNG tankers, on cargo vessels using ISO containers or a combination of these methods where LNG tankers deliver to a centralized storage terminal and then are delivered via a smaller tanker or cargo ship to the various island nations. The added prevalence of ISO containers and additional small LNG vessels has allowed for LNG to be competitive and more accessible to islands without having to rely on regional delivery approaches. Nevertheless, regional approaches utilizing milk runs or centralized terminals would allow larger vessels to supply the region and add economies of scale, reduce storage costs and lowering overall prices. In this section, we modeled various LNG delivery scenarios and chose the most cost-effective solution.

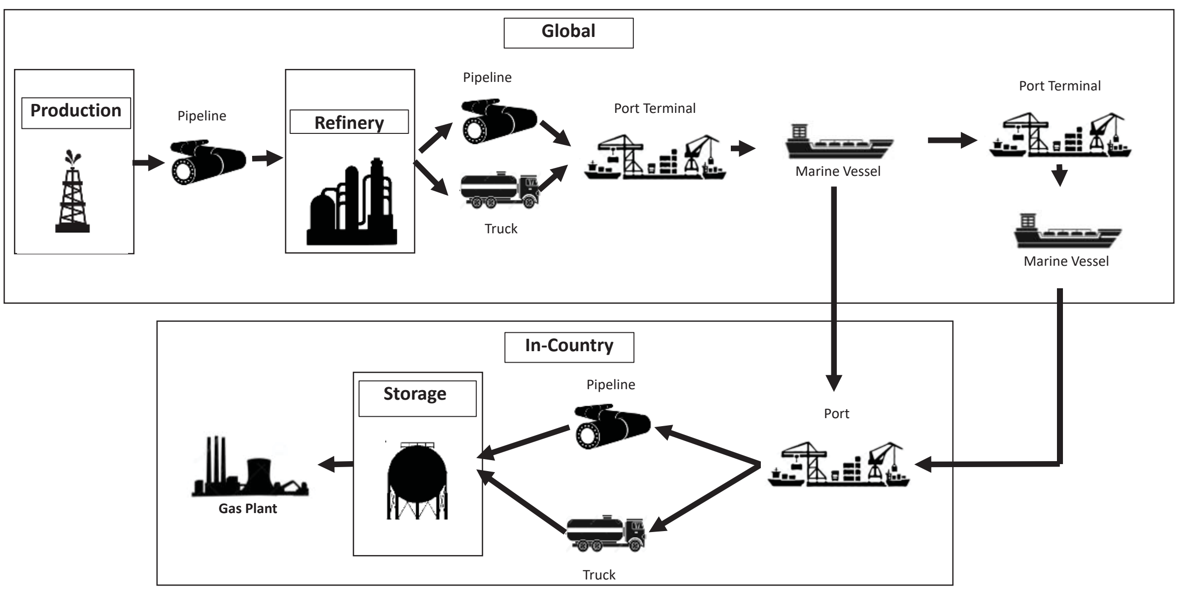
*Exhibit 30: LNG Pathway*




## Petroleum Product Storage Capital and Operating Costs

Petroleum products delivered to the Eastern and Southern Caribbean via small vessels will follow a pathway as outlined in Exhibit 31 with product prices being the primary driver of costs. As done for LNG, we modeled a variety of delivery methods and then let costs dictate the most reasonable solution to deliver to the countries.

*Exhibit 31: Petroleum Product Delivery*




## Methodology for Cost Build-up for All Fuels

In order to compare fuel prices across products, we developed a model that varied the product origination locations, the ship size, and the demand to develop several hundred unique scenarios for each fuel type. These scenarios would then determine the transportation costs, frequency of delivery, storage size, and trucking/pipeline needs. The process was repeated for each fuel, and the most cost-effective pathway was chosen for each country.

### *Product Pricing*

Cost estimates for the various products utilize EIA's Annual Energy Outlook (AEO), taking estimates for Henry Hub natural gas, Brent crude oil, and ethanol wholesale prices between 2023 and 2040 (EIA AEO).

- Natural gas deliveries to Eastern and Southern Caribbean were assumed to originate from nearby markets due to cost competitiveness and proven natural gas reserves. LNG markets evaluated were the United States (Gulf Coast, Jacksonville, and Savannah), Trinidad and Tobago or Guyana/Suriname if natural gas production were to become sufficient for exports.

- Fuel oil, diesel, and ethanol deliveries to Eastern and Southern Caribbean were modeled to originate from nearby markets which included the United States (Houston, New Orleans), Trinidad and Tobago, or Venezuela. Fuel oil and distillate wholesale prices were estimated based on their historical average price in relation to crude oil, while ethanol was based on EIA's AEO.

- Propane was modeled to originate from a variety of U.S. locations including Texas, Louisiana, Florida, North Carolina, Virginia, Pennsylvania, and New York as well as Trinidad and Tobago.

- Hydrogen prices were developed for "blue hydrogen" made from natural gas wherein 90% of the carbon dioxide generated in the steam methane reforming (SMR) process was captured and geologically stored. The cost for natural used in the SMR process was taken from the 2021 EIA AEO projection to represent the feedstock price for blue hydrogen made in the U.S. Gulf Coast area. The hydrogen was then assumed to be liquefied and transported to the islands using specially designed cryogenic ISO containers or on hydrogen carriers. The cost structure for blue hydrogen from other countries was assumed to be the same as in the United States, but shipping costs were adjusted for differences in shipping distances. "Green hydrogen" made from renewable electricity was assumed to also be available, but at a price premium reflecting its lower GHG footprint. This price premium was assumed to exist through 2040 even if technological advances allowed green hydrogen to be produced at a cost below blue hydrogen. This is because the volumes of green hydrogen would not be sufficient to push out all blue hydrogen and establish cheap green hydrogen as the marginal supply source that sets the price.

### *Tanker and Gas Carrier Capital and Operating Costs*

Marine transportation costs are primarily a function of the vessel size and the transit time as these factors dictate the horsepower necessary, the fuel consumption, the time in port vs. underway, and the delivered product volume. The capital costs for each vessel type were determined utilizing recent news releases and articles posting both the vessel sizes and capex costs. This information was then utilized to create a regression to allow us to estimate costs for all sizes. More details on how these costs were estimated can be found in Appendix E: Capital Costs of LNG Tankers.

Operating costs associated with transportation is dictated by the distance traveled and the speed traveled since that will dictate the length of time per ship, the fuel necessary, the time in port vs. underway. Exhibit *32* breaks down the nautical miles from supply locations to destination that were used in conjunction with ship speeds that varied in speed between 13 and 24 knots based on the ship size and type. Due to the proximity, the same vessel traveling from Trinidad and Tobago will yield lower transportation costs than one traveling from the United States.

Exhibit 32: Nautical Miles from Origin to Destination

| Origin Locations | Barbados | Saint Vincent and the Grenadines | Saint Lucia | Antigua and Barbuda |
|---|---|---|---|---|
| Ogdensburg, NY | 2,817 | 2,810 | 2,776 | 2,573 |
| Houston-Galveston, TX | 2,225 | 2,152 | 2,141 | 1,999 |
| Port Arthur, TX | 2,167 | 2,094 | 2,082 | 1,941 |
| U.S. Gulf Coast (Sabine Pass, LA) | 2,157 | 2,084 | 2,072 | 1,931 |
| New Orleans, LA | 2,015 | 1,943 | 1,931 | 1,790 |
| Portland, ME | 1,914 | 1,898 | 1,865 | 1,651 |
| Philadelphia, PA | 1,832 | 1,794 | 1,767 | 1,559 |
| New York, NY | 1,824 | 1,791 | 1,763 | 1,552 |
| Norfolk, VA | 1,696 | 1,652 | 1,628 | 1,422 |
| Tampa, FL | 1,659 | 1,586 | 1,574 | 1,433 |
| Savannah, GA | 1,639 | 1,578 | 1,560 | 1,375 |
| Wilmington, NC | 1,615 | 1,563 | 1,542 | 1,344 |
| Jacksonville, Florida | 1,609 | 1,546 | 1,528 | 1,349 |
| Miami, FL | 1,422 | 1,355 | 1,340 | 1,170 |
| Venezuela, Bolivarian Republic of (port of Cabello) | 516 | 428 | 455 | 536 |
| Port of Georgetown, Guyana | 393 | 420 | 447 | 657 |
| Trinidad and Tobago | 216 | 179 | 217 | 416 |

### *Storage Capital and Operating Costs*

To estimate the capital storage costs, we first estimated the total storage volume and then used regression curves to determine the cost of the storage. The storage volume was calculated to be the larger of either: the vessel that delivered product, increased by a factor of 25% to allow for flexibility in delivery or 15 days of supply of product. Due to size of the vessels and the relatively low demand, this method typically accounted for an excess of 30 days of storage. Due to the size of many of the storage containers, we estimated that there would be at least three storage containers.

For LNG and hydrogen transported to the islands using ISO containers, enough ISO containers would need to be available to have storage onsite, storage coming to and leaving the island, and enough stockpiled at the loading location for filling. This was modeled by taking the total days for a round trip scaled up by 50% plus 15 days of onsite storage multiplied by the number of ISO containers used each day.

### *Pipeline and Trucking Costs*

For modeling purposes, ICF assumed that LNG shipped on a bulk carrier would be transported via pipeline to the facility, while other fuels such as diesel, fuel oil, ethanol, propane, and LNG shipped on ISO containers would travel to the power plant facility location via truck. The cost per unit of fuel was determined by a combination of the capital cost of the trucks, operating and maintenance costs (staffing, insurance, licenses, maintenance), fuel costs, and the distance between the port and power plant, which ranged from 2.5-9 miles one way. Pipeline costs were built up using average cost per mile factors and utilizing the same distances as used for trucking.

### *Liquefication Costs and Regasification Costs*

Liquefaction costs for large natural gas liquefaction locations like those in the Gulf Coast location were assumed to be $2.5/MMBtu while smaller locations like Jacksonville, Florida would have higher liquefaction costs which were assumed to be $3.5/MMBtu. Regasification costs were calculated as $0.1/MMBtu.

### *Demand Scenario*

To evaluate the fuels, ICF examined a “small” and a “large” power generation scenario that represented 25 MW and 50 MW, respectively, of installed capacity for the various fuels. For the purposes of deriving costs for the fuel necessary, these generators were assumed to be utilized for 60% of their time.

# V. Cost Examples for Transport and Storage Options

The resulting product transportation costs to the target Caribbean islands is summarized in Exhibit 33. The results indicated that the small market case for LNG ISO container shipments yielded the lowest cost option, but this is very close to propane and HFO. Some islands are utilizing diesel which, primarily due to the higher product price, was less cost effective than HFO.

*Exhibit 33: Delivered Product Prices to Eastern and Southern Caribbean Islands*

| Fuel | MW Scenario | Product Price ($/MMBtu) | Cost Factor for Gas Used in Liquefaction | Liquefaction Costs ($/MMBtu) | Shipping Transportation Costs ($/MMBtu) | Storage Costs ($/MMBtu) | Regasification Costs ($/MMBtu) | Trucking or Pipeline Costs ($/MMBtu) | Delivered Costs ($/MMBtu) | **Total Cost including Storage Holding Costs ($/MMBtu)** |
|---|---|---|---|---|---|---|---|---|---|---|
| Diesel | 25 | $15.3 | | | $0.4 | $0.1 | | $0.3 | $16.1 | **$16.4** |
| Ethanol | 25 | $16.7 | | | $0.3 | $0.1 | | $0.3 | $17.4 | **$17.5** |
| Heavy Fuel Oil | 25 | $10.8 | | | $0.2 | $0.1 | | $0.3 | $11.3 | **$11.5** |
| Propane | 25 | $9.8 | | | $0.7 | $0.4 | | $0.4 | $11.4 | **$11.4** |
| LNG Container | 25 | $3.3 | $0.5 | $3.5 | $0.75 | $1.9 | $0.1 | $0.5 | $10.5 | **$10.6** |
| LNG Carrier | 25 | $3.3 | $0.5 | $3.5 | $1.5 | $2.9 | $0.1 | $0.3 | $12.1 | **$12.3** |
| Green H2 Container | 25 | $13.7 | $2.1 | $2.5 | $1.7 | $6.3 | $0.2 | $0.8 | $27.3 | **$27.5** |
| Blue H2 Container | 25 | $13.1 | $2.0 | $2.5 | $1.7 | $6.3 | $0.2 | $0.8 | $26.5 | **$26.7** |
| Diesel | 50 | $15.3 | | | $0.4 | $0.1 | | $0.3 | $16.1 | **$16.2** |
| Ethanol | 50 | $16.7 | | | $0.3 | $0.1 | | $0.3 | $17.3 | **$17.4** |
| Heavy Fuel Oil | 50 | $10.8 | | | $0.2 | $0.1 | | $0.3 | $11.3 | **$11.4** |
| Propane | 50 | $9.8 | | | $0.3 | $0.3 | | $0.4 | $10.9 | **$11.1** |
| LNG Carrier | 50 | $3.3 | $0.5 | $3.5 | $1.5 | $1.5 | $0.1 | $0.2 | $10.6 | **$10.7** |
| Green H2 Carrier | 50 | $13.7 | $2.1 | $3.5 | $3.2 | $3.1 | $0.2 | $0.8 | $26.6 | **$26.7** |
| Blue H2 Carrier | 50 | $13.1 | $2.0 | $3.5 | $3.2 | $3.1 | $0.2 | $0.8 | $25.8 | **$25.9** |

As Exhibit 33 illustrates, the costs for product fuels, such as diesel, ethanol, heavy fuel oil and propane, are largely dictated by the price of fuel itself as the high energy content per unit of fuel helps keep transportation and storage costs low on a MMBtu basis. Conversely, LNG costs reflect a relatively low delivery cost, but additional costs for liquefaction, transportation and storage. Additionally, since the smallest ship sizes for bulk LNG shipments are greater than the island's demand, the storage costs are even larger in order to accommodate the ship deliveries. For these reasons, LNG ISO containers can become attractive as these can be stored on normal cargo ship decks, can be transported on freight line routes that are frequently trafficked, and can provide flexibility afforded by smaller storage capacity being housed onsite. LNG ISO containers have some limitations as they can become impractical to utilize for high demand, but as the data shows, it can be cost effective. For this reason, Eagle LNG was able to secure a contract in 2020 to deliver LNG to Barbuda Ocean Club, a private resort and community in Antigua and Barbuda.

# Power Generation Pathways

## I. Introduction

This section discusses how the electricity generation, storage technologies and fuel deliveries discussed in the prior two chapters might be employed over the next 20 years to meet total electricity needs. Presuming a long-term transition from the current fuel mix toward low-carbon sources of electricity, the portion of electricity that will be generated using fossil fuels will decline. The rate of decline will depend on the amount of renewable or other low-carbon generation capacity that is installed, the average generation available from that capacity, whether the capacity is dispatchable, and whether cost-effective short-term and/or long-term electricity storage is available.

This section helps set the stage for decision makers by synthesizing information and stepping through key decision to make informed grid planning decisions. Here the key concepts are pulled together including the total costs, lifecycle GHG emissions, reliability, resiliency, degree of dependence on imported fuels/electricity, and reliance on future technology improvements. The section is structured as follows:

- **Existing Plants:** What is the potential of converting their existing plant to alternative fuel options?
- **New Generation Cost Comparisons:** With aging infrastructure, many facilities will have to retire and build new generation over the next twenty years. This section details how new generation costs may compare.
- **Renewable Penetration:** With low-cost renewables, solar and wind projects are expected to grow in the Eastern and Southern Caribbean. We look at what renewable penetration may look like and the impacts to dispatchable generation.

## II. Economics of Dual Fuel Conversion of Existing Plants

Currently, the Eastern and Southern Caribbean Islands have installed ICE generators that burn HFO or diesel (see Appendices for more details on existing units). For the existing ICE generation, it may be technically possible to enable dual fuel blending via conversion, which would allow the replacement of up to approximately 70% of the diesel or HFO with natural gas in those engines. As this section will illustrate, this conversion is less cost competitive and adds GHG emissions compared to continuing operations or a new build.

To accomplish conversion to dual fuel capabilities, the engine's fuel trains would have to be modified. In addition, infrastructure for LNG off-loading, storage, vaporization, and feeding or propane storage would be required at each of the applicable power stations. The engine modifications would allow LNG or propane to be used as a backup fuel should diesel/HFO be unavailable or a primary fuel if LNG offered a cost advantage. During a transition to dual fuel capability, there would likely be a reduction in available generating capacity depending on how implementation was staged, likely for several months. This would reduce reserve margin on the islands and may introduce too large of a risk for certain islands based on generator size.

Exhibit 34 shows the levelized cost of energy in $/MWh comparing the existing ICE units burning diesel with upgrading those same units to burn more inexpensive fuels like LNG and propane in addition to diesel. The capital cost for conversion assumes that conversion would require engine modifications and new fuel handling facilities at a cost of 10% of a new unit's capital cost. This exhibit shows that even with a modest capital cost assumed, there is not a cost advantage to dual fuel conversion to LNG or propane when comparing against operating the existing units with diesel.

*Exhibit 34: Economics of Conversion of Existing ICE Units from Diesel to Alternative Fuels*

| | LCOE in $/MWh | | | | | GHG kg/MWh | | |
|---|---|---|---|---|---|---|---|---|
| Case | Capital Cost | Fixed O&M | Variable O&M | Fuel Costs | Total Cost (LCOE ex. any SCC) | Fuel LCA GHG kg/MWh | CH4 Slip GHG kg/MWh | Total GHG kg/MWh |
| Existing ICE using Diesel | $0 | $8 | $7 | $136 | $151 | 758 | 0 | 758 |
| Dual-fuel Conversion to LNG | $6 | $8 | $7 | $135 | $156 | 819 | 294 | 1113 |
| Dual-fuel Conversion to Propane | $6 | $8 | $7 | $132 | $153 | 873 | 0 | 873 |
| Replacement Unit: LNG | $42 | $8 | $7 | $87 | $144 | 630 | 0 | 630 |
| Replacement Unit: Propane | $42 | $8 | $7 | $95 | $152 | 692 | 0 | 692 |

Additionally, greenhouse gas emissions are reportedly much higher for the dual fuel units due to lower efficiencies as compared the lean operation of compression-ignition (diesel/HFO) engines (Applied Energy 2017). The lower efficiency of dual fuel engines would also result in higher fuel consumption; the fuel efficiency loss in these calculations is assumed to be 22.6% in switching to dual fuel operation. LNG combustion in the dual fuel units results in unburnt methane, known as methane slip, which was assumed to be 8.6% of the LNG's methane composition in these calculations based on an average of various literature findings (Lindstad 2020, Johnson 2017). The conclusion of the table is that overall GHG emissions go up after conversion when compared to the existing diesel-fueled ICE.

Exhibit 34 also compares the costs of replacing the existing diesel ICE with new LNG or propane ICEs. Although capital costs are much higher, fuel costs are considerably lower for LNG and propane (even when compared to the dual fuel case due to the efficiency differences). Therefore, LNG replacement is cheaper than the existing diesel ICE, and propane replacement is comparable in cost. Both fuels under a complete replacement scenario also have less GHG emissions than the existing ICE diesel unit. From a cost and GHG perspective, it likely will be more advantageous to buy and install a new unit if a change to LNG or propane is desired.

When running this same comparison for HFO fueled generators (results shown in Exhibit 35), the total LCOE for the existing HFO generator is $111/MWh, which is quite a bit lower than the dual fuel and full replacement LNG or propane options. When operating ICE generators with HFO, the most economic option is to extend the life of the existing unit for as long as is possible.

*Exhibit 35: Economics of Conversion of Existing ICE Units from HFO to Alternative Fuels*

| | LCOE in $/MWh | | | | | GHG kg/MWh | | |
|---|---|---|---|---|---|---|---|---|
| Case | Capital Cost | Fixed O&M | Variable O&M | Fuel Costs | Total Cost (LCOE ex. any SCC) | Fuel LCA GHG kg/MWh | CH4 Slip GHG kg/MWh | Total GHG kg/MWh |
| Existing ICE using HFO | $0 | $8 | $7 | $96 | $111 | 812 | 0 | 812 |
| Dual-fuel Conversion to LNG | $6 | $8 | $7 | $119 | $140 | 839 | 294 | 1,132 |
| Dual-fuel Conversion to Propane | $6 | $8 | $7 | $117 | $138 | 893 | 0 | 893 |
| Replacement Unit: LNG | $42 | $8 | $7 | $87 | $144 | 630 | 0 | 630 |
| Replacement Unit: Propane | $42 | $8 | $7 | $95 | $152 | 692 | 0 | 692 |

## III. Generation Cost Comparison of New Generation Units

To compare across the technologies presented in the Generation Technologies- Capital Costs and Viability section, an overall cost per MWh was calculated by adding up the annualized capital costs, the fixed and variable O&M costs, and fuel costs. These costs are shown broken out in Exhibit 36 and how each technology and fuel pairing stacks up against each other. Some assumptions that go into this analysis:

- Capital costs were annualized using a 10% capital recovery factor.
- Capacity utilization rates for all technologies are assumed to be 60%, except for standalone solar and wind which are 32%.
- Fuel costs are based on a 25 MW system size.
- For the two Renewables + Battery Cases: the renewables piece is assumed to be made up of two-thirds and one-third installed capacity of solar and wind, respectively. This is coupled with an 8-hour battery. The storage is sized to take 60% of the renewable generation with the other 40% going directly to the grid. Depending on how the system is configured, and the time of day that peak demand occurs, it might be necessary to add or maintain some dispatchable capacity to make up for the lost contribution to peak when going from a turbine to renewables with batteries. This option is shown as the Renewables + Battery + Backup case in the table.

The LCOE presented here are examples calculated from specific assumptions related to capital, operating and fuel costs and the hourly patterns of electricity demand. Caution should be exercised in applying them to varying locations, circumstances and times.

*Exhibit 36: Economics of New Generating Units in $/MWh*

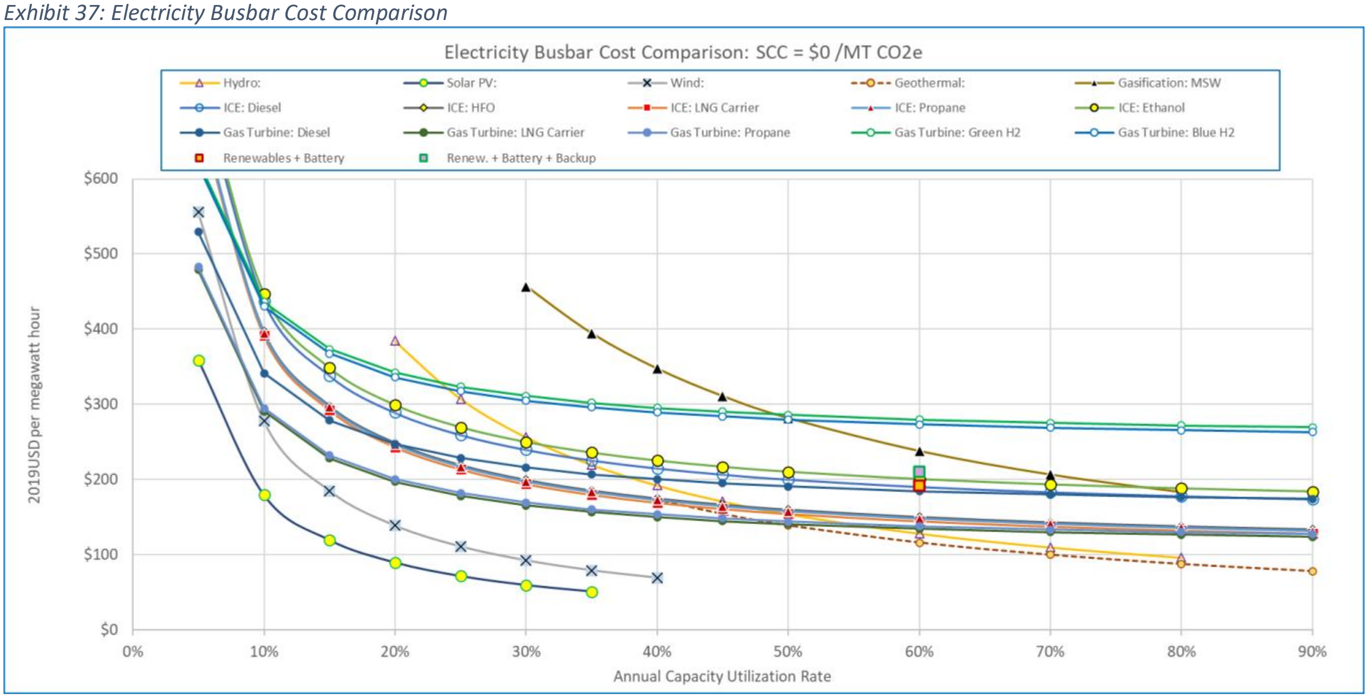
| | **LCOE in $/MWh** | | | | | | |
|---|---|---|---|---|---|---|---|
| Technology & Fuel | Capital Cost | Fixed O&M | Variable O&M | Fuel Costs | Total Cost | Fuel Cost $/MMBtu | Fuel LCA GHG kg/MWH |
| ICE: Diesel | $42 | $8 | $7 | $136 | $193 | $16.40 | 758 |
| ICE: HFO | $42 | $8 | $7 | $96 | $153 | $11.54 | 812 |
| ICE: LNG Carrier | $42 | $8 | $7 | $102 | $159 | $12.29 | 630 |
| ICE: LNG Contain. | $42 | $8 | $7 | $87 | $144 | $10.44 | 630 |
| ICE: Propane | $42 | $8 | $7 | $95 | $152 | $11.47 | 692 |
| Gas Turbine: Diesel | $31 | $4 | $6 | $150 | $190 | $16.40 | 758 |
| Gas Turbine: LNG Carrier | $31 | $4 | $6 | $112 | $152 | $12.29 | 630 |
| Gas Turbine: LNG Contain. | $31 | $4 | $6 | $95 | $135 | $10.44 | 630 |
| Gas Turbine: Propane | $31 | $4 | $6 | $105 | $145 | $11.47 | 692 |
| Gas Turbine: Ethanol | $31 | $4 | $6 | $160 | $200 | $17.56 | 500 |
| Gas Turbine: Blue $H_2$ | $31 | $4 | $6 | $244 | $284 | $26.71 | 104 |
| Gas Turbine: Green $H_2$ | $31 | $4 | $6 | $250 | $290 | $27.38 | 43 |
| Geothermal: Geothermal | $87 | $29 | $1 | $0 | $118 | $0.00 | 39 |
| Gasification: MSW | $194 | $29 | $6 | $13 | $242 | $1.00 | 49 |
| Gasification: Biomass | $194 | $29 | $6 | $40 | $268 | $3.00 | 49 |
| Hydro** | $124 | $7 | $0 | $0 | $130 | $0.00 | 7 |
| Solar PV | $47 | $7 | $0 | $0 | $54 | $0.00 | 55 |
| Wind | $69 | $15 | $0 | $0 | $84 | $0.00 | 15 |
| Renewables + Battery* | $102 | $14 | $78 | $0 | $194 | $0.00 | 74 |
| Renewables + Battery + Backup* | $119 | $16 | $78 | $0 | $213 | $0.00 | 74 |

*Note: Capacity utilization rates for all technologies are assumed to be 60% except for solar and wind which are 32%.*
**The Renewables + Battery cases are based on 67% solar and 33% wind.*
**USAID does not support hydro at >10MW capacity, as per our Clean Energy guidelines, however this was included because some of the target islands have hdyro

On a LCOE basis, renewables (especially solar and wind) have one of the lowest costs among generating technologies and fuels. On islands where there is geothermal potential, building and operating a geothermal plant is an attractive base load option as it has very little GHG emissions and a cheaper LCOE than fossil fuel-based ICE and gas turbines. When selecting a technology for easily dispatchable energy, a gas turbine fueled by bulk LNG delivered by containership was the cheapest option determined by this analysis.

LCOEs were also computed for each of the technologies and fuel type combinations across a range of capacity utilizations in Exhibit 37, which shows that costs per MWh declines with increased capacity utilization for all technologies. The exhibit also illustrates that technologies with higher capital costs and low fuel and variable operating costs like geothermal have much steeper curves on this line and dramatically improve their cost basis at high utilization rates. Solar PV and wind energy are the cheapest options, but because of their intermittent nature, they max out at lower capacity utilization rates.

*Exhibit 37: Electricity Busbar Cost Comparison*




# IV. Illustrating an Example Market

## Renewables Generation Targets

All study countries hope to meet aggressive renewable energy targets and are contemplating options for meeting base load supply requirements until targets are achieved. Renewable energy generation targets in each country are:

- 100% in Barbados by 2030
- 60% in St. Vincent and the Grenadines by 2020
- 35% in St. Lucia by 2035
- 15% in Antigua and Barbuda by 2030

Some of these dates have already passed without the countries achieving their targets. The example created by ICF looks forward to 2040 and represents the likely bounds of what may be achieved across the four islands by modeling various renewable penetration levels.

Once intermittent renewable penetration reaches a level where it exceeds load during any time of the day, ICF assumed that there would be an appropriate amount of energy storage capacity installed to store the excess energy generated. This stored energy would then be discharged during hours when the most dispatchable generation was needed. This was modeled using four-hour (or longer) batteries at the appropriate size to shift the excess generation.

## Projected Needs for Power and Generation Capacity (annual load, peak loads, typical daily patterns, reserve margins)

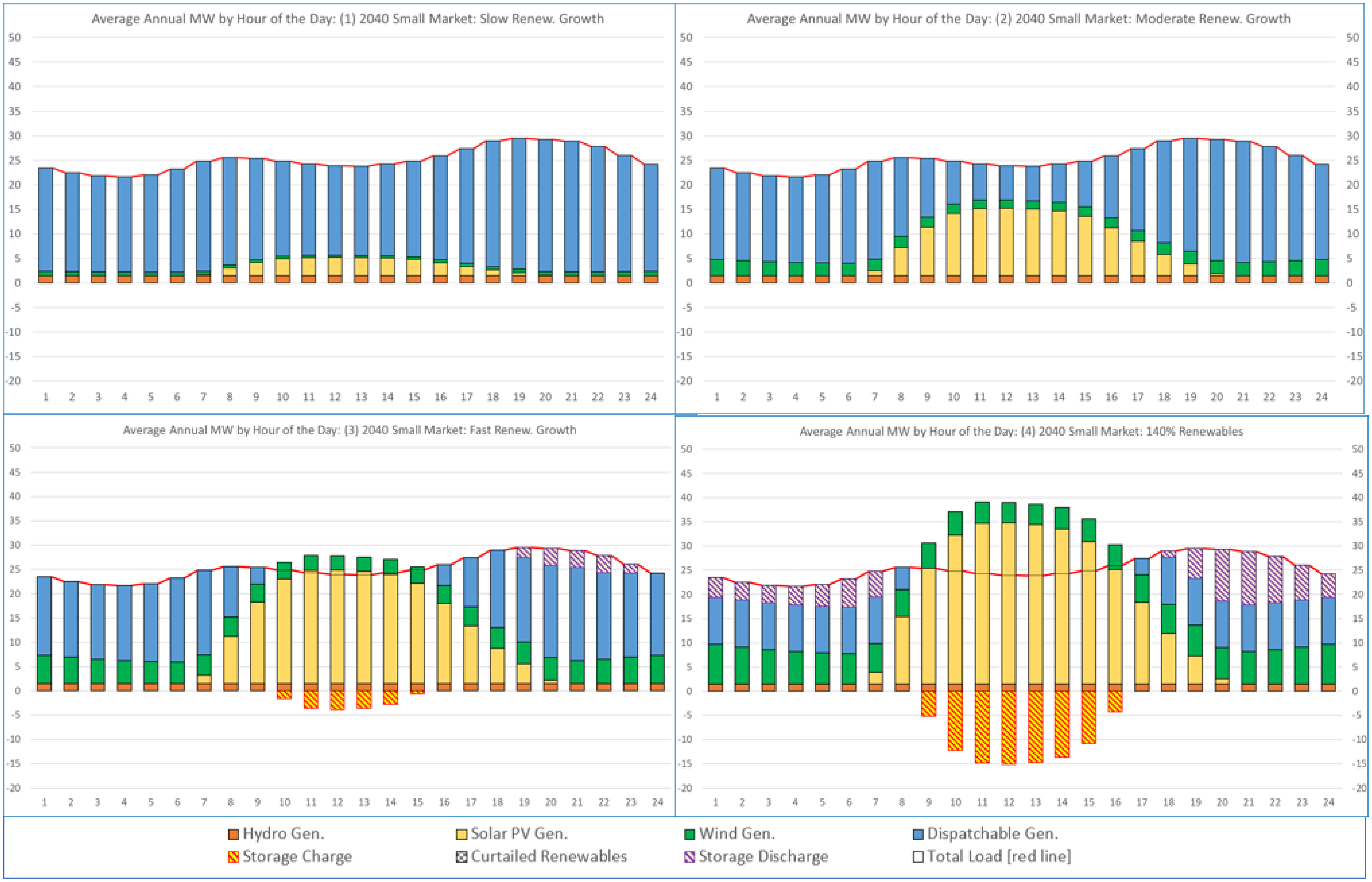
Rather than attempt to model scenarios for all four islands, scenarios were created for a small island market at a current peak load of 25 MW. These peak loads were then projected out to 2040 with a 2.5% annual growth rate of peak electricity demand. The average annual load pattern was modeled based on CAISO's load pattern adjusted by an electricity demand load factor of 0.6 that was assumed for the Caribbean. The pattern for average solar generation by hour was also based on the readily available CAISO solar patterns adjusted for local conditions of hours of daylight per day on average. The reserve margin required for both markets was assumed to be 20%. The share of renewables capacity counted toward the reserve margin are 70% for hydro, 20% for wind and 15% for solar.

Even at high penetration levels of intermittent renewables, there is a need for dispatchable power generation. This is because the hours of maximum generation of intermittent renewable sources (e.g., solar) do not necessarily align with the peak demand time periods of the day. There are two high points of residential demand on a typical day; one in the morning when people wake up to get ready for their day and one in the evening when people come home from their workday. Solar energy, however, is at its highest during the late morning though mid-afternoon hours. This means that for systems where residential demand dominates, dispatchable power is needed, especially to meet the peak demand time periods of the day. Fossil fuel generation or dispatchable renewables such as geothermal and green hydrogen are a good fit for this need as, typically, they can quickly ramp up energy production as the sun sets and the contribution from PV falls.

The slow and moderate renewable growth cases assume lower penetration of intermittent renewable energy generation (combination of hydroelectric, solar photovoltaic, and wind) in comparison to the targets set across the four islands. These were modeled with the assumption that renewable capacity is installed at only 20% and 60% of the 2040 peak load in the slow and moderate growth cases, respectively. In these cases, no electricity storage is employed, because all intermittent power can serve load when it is generated as shown in Exhibit 38.

The fast renewable growth case and the 140% case assume the aggressive targets for penetration of intermittent renewable energy generation (combination of hydroelectric, solar photovoltaic, and wind) are achieved, modeled with the assumption that renewable capacity is installed at 100% and 140% of the peak load in 2040. In this case, electricity storage is employed, as intermittent renewable generation is in excess of load at certain portions of the day as shown in Exhibit 38. It was modeled using a 4-hour (or longer duration) battery. The fast renewable growth case was also evaluated without storage, which required an additional 0.8 MW of dispatchable generation to be installed to meet reserve requirements.

*Exhibit 38: Average Annual Generation by Type, by Hour of the Day in 2040 for Four Renewable Growth Scenarios*

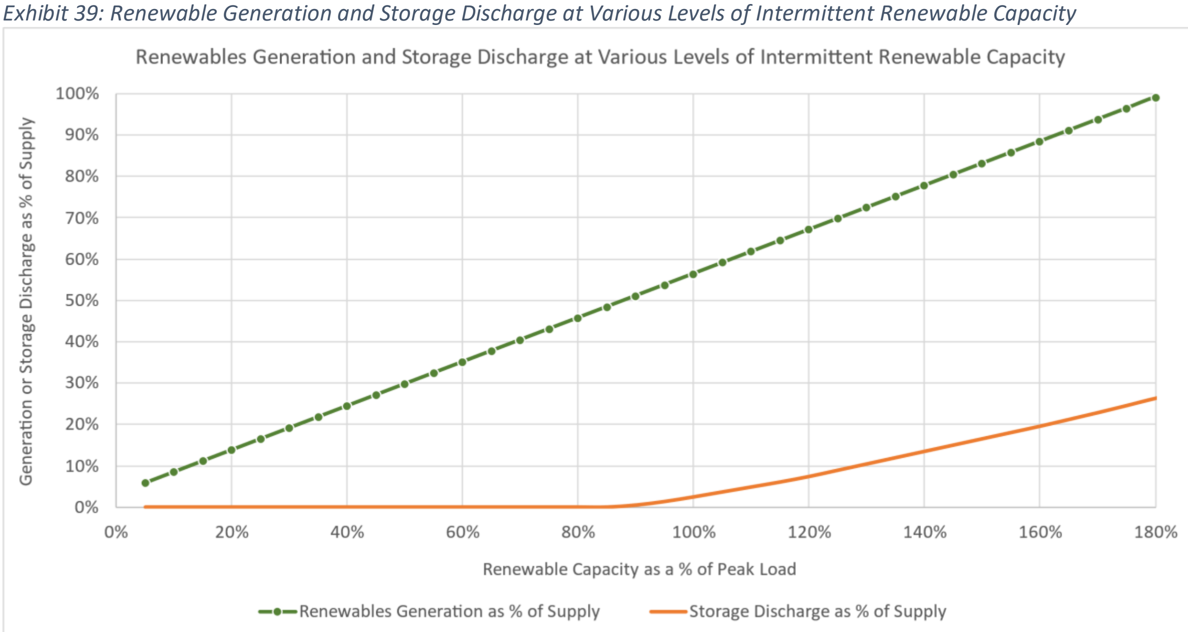


## Example Economics for Different Levels of Renewables

Several scenarios were modeled assuming that renewable development is not constrained on the islands to illustrate how costs change as renewable generation increases. These examples were modeled using intermittent renewables in a combination of two-thirds solar PV and one-third wind. For this analysis, the dispatchable source was modeled as LNG gas turbines supplied by carriers, which is among the least expensive options and is available to all the islands.

Batteries are added when intermittent renewable generation meets all hourly load requirements and any more renewable generation would have to be curtailed. Exhibit 39 shows that storage discharge would begin for this example when renewable capacity hits 90% of peak load. The results of these examples depend on a wide number of assumed conditions that will differ among markets, so the point at which batteries will be needed to avoid curtailment will differ as well. Also, the system might benefit from having utility-scale battery storage to provide ancillary services such voltage regulation.

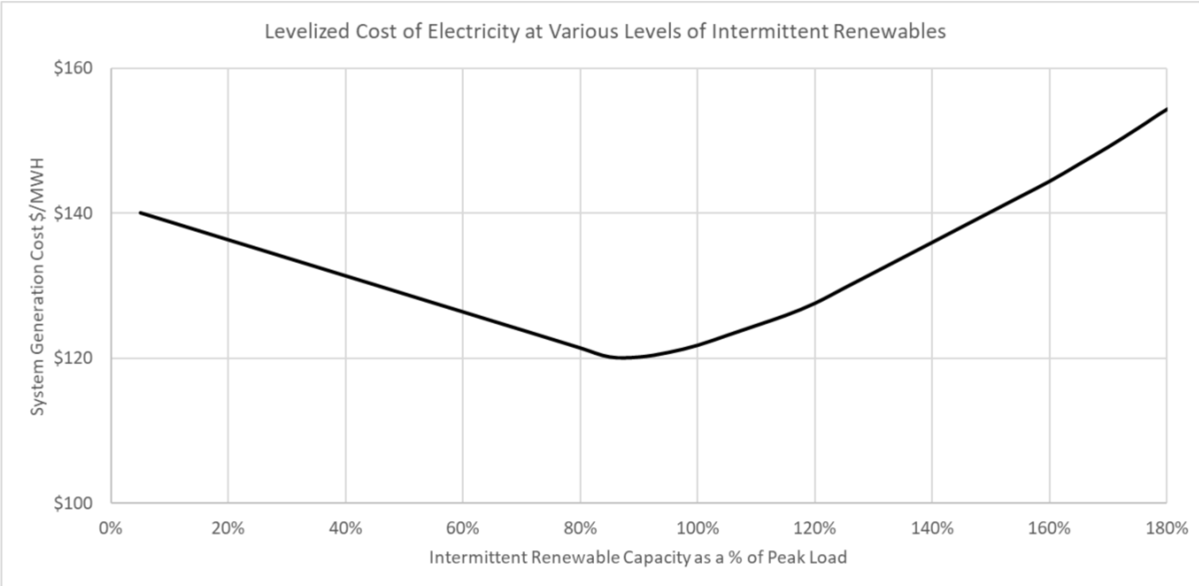
*Exhibit 39: Renewable Generation and Storage Discharge at Various Levels of Intermittent Renewable Capacity*




Assuming few constraints on how much renewable capacity could be built, Exhibit 40 illustrates the effects of increasing levels of renewable penetration ranging from 5% to 180% of peak load on system cost. As intermittent renewables penetration goes up towards 100% of peak demand, total system costs go down as the increase in capital and FOM costs is more than offset by lower fuel costs. The increase in capital costs is rapid, because a substantial amount of dispatchable capacity is required to meet reserve margin requirements, and total installed capacity is much higher than at low renewable penetration even with the same electricity consumption.

Exhibit 40 shows that renewable resources are used immediately to serve load up to the point where renewable capacity is about 90% of peak load. Once the amount of renewable capacity approaches and then exceeds 90% peak demand, there is a growing need to store excess electricity. At this point, total system costs do not decline with higher levels of renewables penetration, but instead, system costs go up as renewables exceed 100% of peak demand. Therefore, in this example the most cost-effective level of installed renewables capacity is around 90% of peak load. As shown in Exhibit 39, at that point renewables are supplying about 50% of generation. A detailed breakout of the data behind this exhibit can be found in Appendix A: Example Detailed Table.

*Exhibit 40: LCOE at Various Levels of Intermittent Renewables for Modeled Example*




## Other Qualitative Factors to Consider

There are other factors that are not incorporated into the cost comparison that may be considered when comparing generation technologies. In Exhibit 41, ICF rated the different technologies evaluated as a part of this report on a favorable (green), neutral (yellow), or unfavorable (red) basis with respect to how they perform along these other dimensions. We examined susceptibility to extreme events or other disruptions, impacts on the local economy, land use requirements, and environmental impacts. These are discussed below.

It is useful to assess the resilience of individual technologies or how susceptible the technology is to external forces, including the potential for fuel supply disruptions or damage from extreme weather events. Having a more diverse energy mix on each island would reduce the overall system's susceptibility to disruption. Another factor that the islands may want to consider is if the generation technology brings local development and jobs to their island. Another factor to consider is if the technology is already proven or relies on technology improvements into the future to be viable. The islands are fairly small, so how much land a generation technology takes up could be a key factor to consider. Additionally, the environmental impact is shown as a rated category with renewables as favorable and bridge fuels like LNG as neutral.

*Exhibit 41: Matrix to Compare Qualitative Factors*

| Technology | Fuel | Susceptibility to Disruptions from External Factors | Local Development and Jobs | Reliance on Future Technology Improv. | Land Use | Environment |
|---|---|---|---|---|---|---|
| ICE | Diesel | Red | Yellow | Green | Green | Red |
| ICE | HFO | Red | Yellow | Green | Green | Red |
| ICE | LNG Carrier | Red | Yellow | Green | Green | Yellow |
| ICE | LNG Contain. | Red | Yellow | Green | Green | Yellow |
| ICE | Propane | Red | Yellow | Green | Green | Yellow |
| ICE | Ethanol | Red | Yellow | Yellow | Green | Yellow |
| Gas Turbine | Diesel | Red | Yellow | Green | Green | Red |
| Gas Turbine | LNG Carrier | Red | Yellow | Green | Green | Yellow |
| Gas Turbine | LNG Contain. | Red | Yellow | Green | Green | Yellow |
| Gas Turbine | Propane | Red | Yellow | Green | Green | Yellow |
| Gas Turbine | Ethanol | Red | Yellow | Yellow | Green | Yellow |
| Gas Turbine | Blue H2 | Red | Yellow | Red | Green | Green |
| Gas Turbine | Green H2 | Red | Yellow | Red | Green | Green |
| Geothermal | Geothermal | Green | Green | Green | Green | Green |
| Gasification | MSW | Yellow | Green | Yellow | Green | Green |
| Gasification | Biomass | Yellow | Green | Yellow | Green | Green |
| PV | Solar | Yellow | Yellow | Green | Red | Green |
| Wind | Wind | Yellow | Yellow | Green | Yellow | Green |
| Green is favorable, yellow is neutral, and red is unfavorable. | | | | | | |

## V. Social Cost of Carbon

The social cost of carbon (SCC) is a measure of the net economic impacts to society associated with adding a small amount of GHG to the atmosphere in a given year. It includes the value of all climate change impacts (e.g., temperature changes, sea level rise). When countries set renewable or carbon neutrality requirements, they can directly set a carbon price to drive change, or they can set the emission limits that then effectively lead to a carbon price. The cost of carbon was utilized in this study to incorporate the net GHG impacts of a given fuel and generation technology into the overall system cost comparison. GHG emissions were calculated for the overall system configuration on a kg $CO_2e$/MWh basis using NREL's Life Cycle Assessment Harmonization values for the different fuel/technology combinations. The U.S. Government estimated social costs of $CO_2$ in the White House's Social Cost of Carbon, Methane, and Nitrous Oxide February 2021 report, and ICF used their intermediate case in 2040 as \$73/metric ton of $CO_2$ and their high case of \$225/metric ton of $CO_2$ to construct their two cases accounting for the cost of carbon (U.S. 2021).

Exhibit *42* shows the same total system LCOE for the different technologies at 60% capacity utilization rates (other than wind and solar at 32%) as Exhibit 36 does but compares across three different levels of social costs of carbon. Exhibit 43 and Exhibit 44 replicate the analysis from Exhibit 37, but they add an additional cost to account for GHG emissions via two different scenarios of carbon costs (\$73 per metric ton $CO_2e$ and \$225 per metric ton $CO_2e$). This increases the costs for any technologies that emit GHG, especially the fossil fuel generators. Adding a social cost of carbon into calculations of system generation costs makes higher levels of intermittent renewables more economically attractive.

*Exhibit 42: Cost Comparison across Different Carbon Costs*

| | LCOE with SCC in $/MWh | | |
|---|---|---|---|
| Technology & Fuel | $/MWh w/ SCC of $0/MT CO2e | $/MWh w/ SCC of $73/MT CO2e | $/MWh w/ SCC of $225/MT CO2e |
| ICE: Diesel | $193 | $248 | $363 |
| ICE: HFO | $153 | $212 | $335 |
| ICE: LNG Carrier | $159 | $205 | $301 |
| ICE: LNG Contain. | $144 | $189 | $285 |
| ICE: Propane | $152 | $203 | $308 |
| Gas Turbine: Diesel | $190 | $245 | $360 |
| Gas Turbine: LNG Carrier | $152 | $198 | $294 |
| Gas Turbine: LNG Contain. | $135 | $181 | $277 |
| Gas Turbine: Propane | $145 | $195 | $300 |
| Gas Turbine: Ethanol | $200 | $237 | $313 |
| Gas Turbine: Blue H2 | $284 | $291 | $307 |
| Gas Turbine: Green H2 | $290 | $293 | $299 |
| Geothermal: Geothermal | $118 | $121 | $127 |
| Gasification: MSW | $242 | $245 | $253 |
| Gasification: Biomass | $268 | $272 | $279 |
| Hydro: None | $130 | $131 | $132 |
| Solar PV: None | $54 | $58 | $66 |
| Wind: None | $84 | $85 | $88 |
| Renewables + Battery | $194 | $199 | $211 |
| Renewables + Battery + Backup | $213 | $218 | $229 |
| Note: Capacity utilization rates for all technologies are assumed to be 60% except for solar and wind which are 32%. The Renewables + Battery cases are based on a mix of 67% solar and 33% wind. | | | |

*Exhibit 43: Electricity Busbar Cost Comparison with a Cost of $73/metric ton of $CO_2e$*

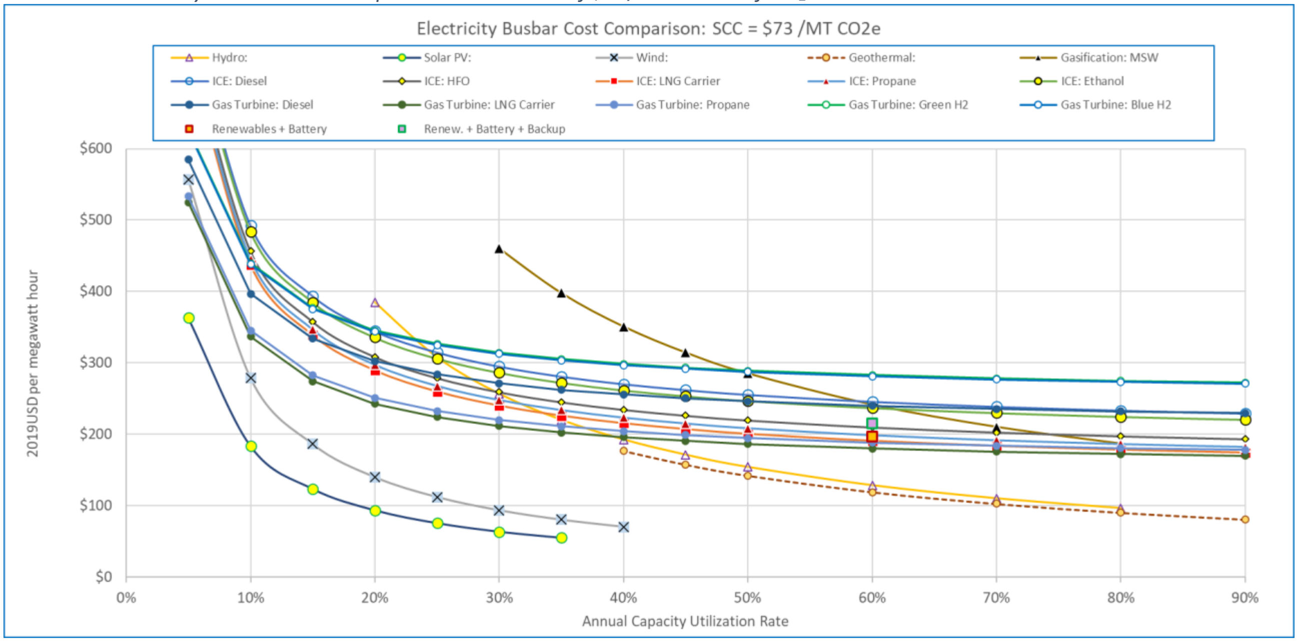



*Exhibit 44: Electricity Busbar Cost Comparison with a Cost of $225/metric ton of $CO_2e$*

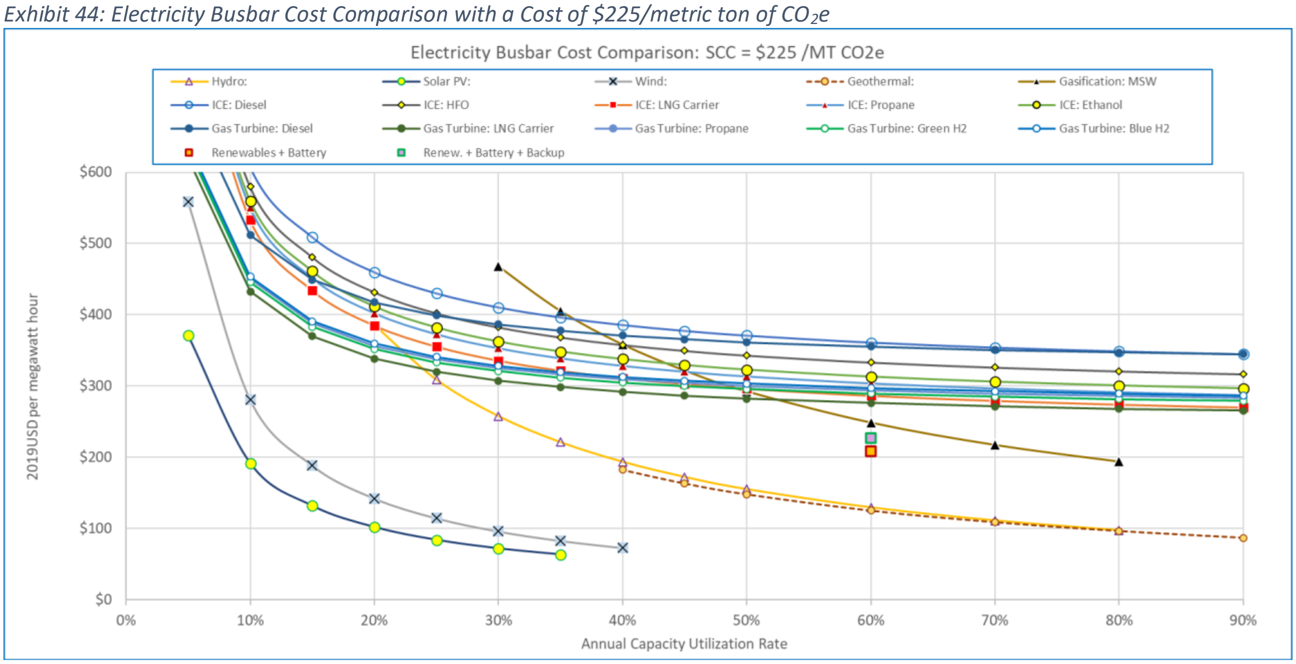


*Exhibit 45: LCOE at Various Levels of Intermittent Renewables across Different Social Costs of Carbon*

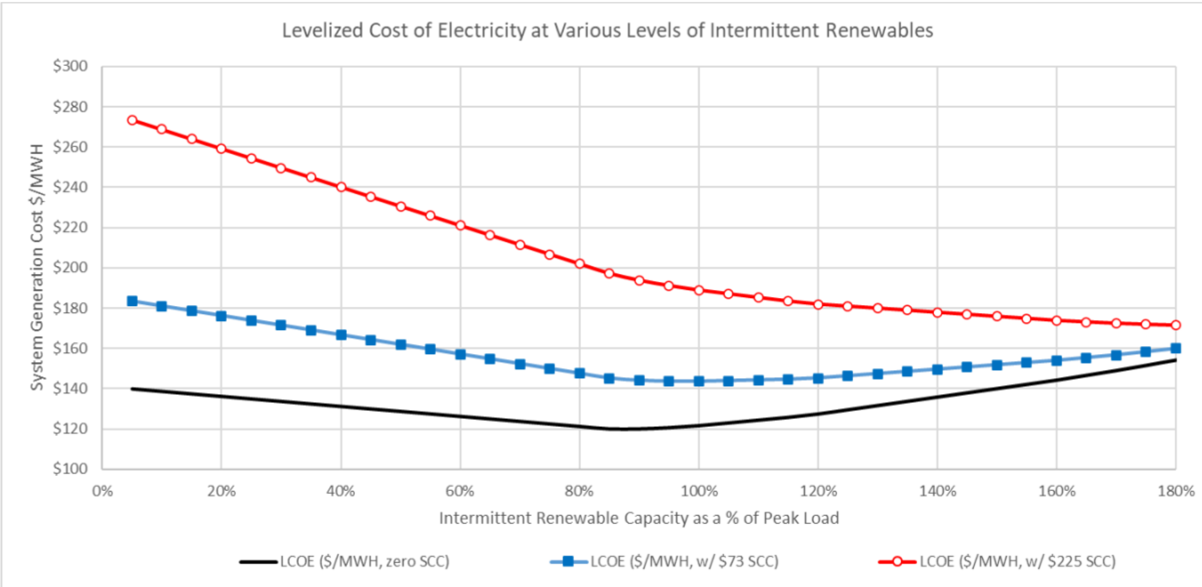



Exhibit 45 shows the optimized system generation cost for the example scenario at the higher social cost of carbon cases. While the optimal renewables capacity fraction is around 90% of peak load for a zero cost of carbon, this shifts to the right with the higher cost of carbon cases, meaning it is economic to keep adding renewable capacity past the 90% of peak load when carbon is valued higher.

# Conclusions

This study concludes that utility scale solar and wind are the most economic option for new generation in terms of lowest LCOE and GHG emissions for the Eastern and Southern Caribbean islands in the years to come. Solar and wind will likely be important pieces of the future grid, but both have limitations given their intermittent nature, with solar only being effective during the day and wind having fluctuations throughout the day. When using solar and/or wind, the least-cost penetration rate is close to 90%-100% of peak demand, so there is a low-cost path to meet fairly aggressive renewable energy targets in terms of average peak hour demand. As the islands adopt more wind and solar, the primary remaining question is how the grid will meet its dispatchable power generation needs during night-time hours, high demand days, or days with low renewable generation. Utilities can evaluate battery storage solutions or easily dispatchable power generation to meet this dispatchable demand. However, batteries are not the most attractive solution with no cost of carbon; LNG power generation may be more attractive as illustrated in this report.

Through this analysis there were various key takeaways on fuels, power generation, other consideration, and these more granular takeaways are outlined here:

## Fossil Fuel Supply and Prices

- The United States and Trinidad and Tobago are the two primary sources of petroleum products, liquefied natural gas, and propane that can supply the future needs of the Eastern Caribbean.
- The commodity prices for oil products and natural gas used in this report are drawn from the 2021 EIA AEO. Delivered prices to the Eastern Caribbean have been computed based on transportation distances and the likely volumes.
- The Eastern Caribbean is disadvantaged in terms of small consumption volumes which make economies of scale in shipping and storage costs hard to obtain.

## Conversion of Existing Power Plants to Natural Gas or Propane

- Although it is technically feasible, the islands would not realize any cost or GHG benefits by converting existing diesel or HFO generators to dual fuel with LNG or propane. It would be better for them to continue to operate their existing generators or just build brand new generation units.

### *Key Considerations for Dual Fuel Conversion*

- GHG emissions increase by converting existing HFO or diesel internal combustion units to dual fuel capability. When LNG is utilized in dual fuel units, unburnt methane is emitted from what is known as methane slip. Methane, which has a greenhouse warming potential of 28 times that of $CO_2$ according to IPCC's Fifth Assessment Report, increases the overall effect of GHG emissions by converting an existing diesel fueled ICE to dual fuel.
- Fuel consumption and greenhouse gases also would increase for the dual fuel units due to lower efficiencies as compared to the lean operation of compression-ignition (diesel/HFO) engines.
- Transition to dual fuel capability would likely require a reduction in the available generating capacity for several months depending on how implementation was staged.
- This study did not find any cost advantage to dual fuel conversion to LNG or propane when comparing against operating the existing units with diesel.

### *Comparing Existing Units to New Units*

- Replacing diesel ICE with new LNG or propane ICE: Although capital costs are much higher, fuel costs are considerably lower for new LNG and propane ICE units. Therefore, LNG replacement is cheaper than the existing diesel ICE, while propane replacement is approximately the same cost as continuing to use diesel in an old unit. Both fuels under a complete replacement scenario also have less GHG emissions than the existing ICE diesel unit. From a cost and GHG perspective, it likely will be more advantageous to buy and install a new unit if a change to LNG or propane is desired.

- When running this same comparison for HFO-fueled generators, the total LCOE for the existing HFO generator is quite a bit lower than the dual fuel and full replacement LNG or propane options. When operating ICE generators with HFO, the most economic option is to run the existing unit for as long as is possible.

## New Power Generation Economics and Technology Highlights

- **Internal Combustion Engines:** Over the long-term countries may consider ethanol (E85/E95) blended fuels as an alternate fuel for ICE generators. The ethanol fraction of E85/E95 is a renewable fuel that, when burned, emits no greenhouse gases on a lifecycle basis, though the gasoline fraction is not a renewable fuel. Technology is now being developed that will replace some or all the diesel/HFO fuel with ethanol, E85, or E95 for existing diesel generators.
- **Gas Turbine Generators:** Gas turbine generators can provide significantly more power generation than ICE generators and should be considered for installation on islands with larger total generation needs. Soon, gas turbines will provide the opportunity to replace the fossil fuel with hydrogen fuel, which is not a GHG nor does it produce GHGs when burned.
- **Gasification:** Converting biomass materials including municipal solid waste into gases that can produce electricity via gas or steam turbines offers dual advantages. It reduces carbon intensity and reduces the volume of municipal solid waste on the islands. This is a developing technology, and costs are expected to decrease as it commercially deployed.
- **Geothermal:** Countries that have adequate geothermal potential may consider implementing geothermal facilities, because it can meet demand throughout the entire day, while reducing GHG emissions at a competitive overall price. Due to the high capital expenditures associated with geothermal, it is important to maximize the facilities expected utilization, and solar and wind penetration may reduce the utilization of the geothermal facility over time making it less economic.
- **Photovoltaic Solar:** Utility-scale solar has low capital costs with small operating and maintenance costs making it the cheapest power generation technology. As companies replace power generation due to retirements of old generators or due to new growth, solar generation provides a low cost, low greenhouse gas solution. Solar, which produces only during daytime hours, cannot be the only source of generation unless it is coupled with a battery solution.
- **Onshore Wind:** Renewable energy from wind is a low-cost option for generating power and should be considered as a method to supplement the power grid. As in solar generation, battery storage may be required as the percentage of wind energy increases. One factor which should be considered when adding large wind farms to the islands is that the structures are highly visible and may not be desirable at tourist destinations.

## New Electricity Storage Economics and Technology Highlights

- **Battery Storage:** Batteries are not currently justifiable by itself as the lowest cost option for powering the grid due to the high capital costs and variable operating and maintenance costs associated with battery replacement. Batteries do provide other benefits such as frequency/voltage regulation, a reserve capacity margin, and the ability to improve the capacity factor of intermittent renewables. Additionally, as more renewables become present in the Caribbean islands, the electricity prices could start to see a Duck Curve impact similar to what is seen in California markets where electricity prices during the day drop with high renewable production while increasing at night when renewable production decreases. Battery storage has allowed operators to arbitrage their renewable production assuming significant price swings occur throughout the day. This price arbitrage which can make batteries more attractive in California markets, may not be as beneficial when there is a single operator trying to minimize overall costs.

- **Hydrogen:** While hydrogen storage is expensive compared to batteries, it could offer advantages for long-term storage durations of more than 5 hours up to days or even weeks. The cost of hydrogen storage is expected to decrease significantly as the technology is developed. The main drawback of green hydrogen storage currently is the low round trip efficiency of converting electricity (plus water) to hydrogen and then back to electricity. This efficiency is expected to increase as the technology is commercialized.

## Optimum Penetration for Renewables

- Based on current cost estimates, as intermittent renewables penetration increases towards 90%-100% of peak demand, total system costs decline as the increase in capital and fixed O&M costs are more than offset by lower fuel costs.
- Once the amount of renewable installed capacity approaches and then exceeds the peak hour demand, excess electricity will need to be stored and then the total system costs would increase with higher levels of renewables penetration due to the high capital and variable costs of batteries.

## Considerations for the Social Cost of Carbon

- The social cost of carbon (SCC) is a measure of the economic impact to society from all climate change impacts associated with adding a small amount of GHG to the atmosphere in a given year. The cost of carbon was used in this study to incorporate the net GHG impacts of a given fuel and generation technology into the overall system cost comparison. Fundamentally, setting renewable targets inherently is implying a social cost of carbon to some degree. The U.S. Government Interagency Working Group estimated the SCC in their February 2021 report.; ICF used the reports' intermediate case in 2040 as $73/metric ton of $CO_2$ and their high case of $225/metric ton of $CO_2$ to construct two cases that account for the social cost of carbon (U.S. 2021).
- Adding SCC into economic calculations increases the LCOE for any technologies that emit GHG, especially the fossil fuel generators. This makes higher levels of intermittent renewables and the required electricity storage more economically attractive as well as low emitting technologies like geothermal. While hydrogen becomes more attractive, based on current cost projections, it is not expected to be the most attractive option over the next twenty years.

# Glossary

**Biomass:** Organic non-fossil-based material of biological origin to be used as a renewable energy source.

**Gas turbine plant:** A gas turbine consists typically of an axial-flow air compressor and one or more combustion chambers where liquid or gaseous fuel is burned, and the hot gases are passed to the turbine where the hot gases expand to drive the generator and are then used to run the compressor.

**Generator capacity:** The maximum output that generating equipment can supply to system load, adjusted for ambient conditions.

**Geothermal plant:** A plant in which the prime mover is a steam turbine driven either by steam produced from hot water or by natural steam that derives its energy from heat found in the Earth.

**Gigawatt (GW):** Measure of electrical power. One billion watts or one thousand megawatts.

**Heat content:** The amount of heat energy available to be released by the transformation or use of a specified physical unit of an energy form (e.g., a ton of coal, a barrel of oil, a kilowatthour of electricity, a cubic foot of natural gas, or a pound of steam). The amount of heat energy is commonly expressed in British thermal units (Btu).

**Internal combustion plant:** An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal types used in electric plants.

**Kilowatt (kW):** Measure of electrical power. One thousand watts.

**Liquefied natural gas (LNG):** Natural gas that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

**Peak demand:** The maximum load during a specified period of time.

**Photo Voltaic Solar:** The radiant energy of the sun, which can be converted into other forms of energy, such as heat or electricity, using an electronic device consisting of layers of semiconductor materials fabricated to form a junction and electrical contacts and being capable of converting incident light directly into direct current electricity.

**Social Cost of Carbon:** The social cost of carbon is the monetary value to the net harm to society associated with adding a given volume of GHG to the atmosphere.

**Wind energy:** Kinetic energy present in wind motion that can be converted to mechanical energy for driving pumps, mills, and electric power generators.

# Appendix A: Example Detailed Table of Generation Costs at Various Renewable Penetration

**Total Generation Costs at Various Level of Renewables: The Modelled Alternative to Renewables is the Dispatchable Technology & Fuel of Gas Turbine / LNG Carrier**

| | | | | Annual Costs | | | | | MWH Supplied per Year | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Renewables Capacity (as % of peak demand) | Renewables Generation as % of Supply | Storage Discharge as % of Supply | Total Capacity Installed (MW) | Capital Costs | Fixed O&M | Variable O&M | Fuel | Total | Hydro | Solar PV | Wind | Storage Charge | Storage Discharge | Curtailed Renewables | Dispatchable Generation: Gas Turbine/ LNG Carrier | Total Supply | GHG kg/MWH | LCOE ($/MWH, zero SCC) | LCOE ($/MWH, w/ $73 SCC) | LCOE ($/MWH, w/ $225 SCC) |
| 5% | 5.8% | 0.0% | 102.0 | $16,864,766 | $2,064,122 | $2,344,244 | $40,543,658 | $61,816,790 | 25,748 | 0 | 0 | - | - | - | 415,646 | 441,394 | 593.23 | $140.05 | $183.35 | $273.53 |
| 10% | 8.5% | 0.0% | 105.5 | $17,434,060 | $2,160,681 | $2,277,858 | $39,395,519 | $61,268,119 | 25,748 | 7,847 | 3,924 | - | - | - | 403,876 | 441,394 | 577.56 | $138.81 | $180.97 | $268.76 |
| 15% | 11.2% | 0.0% | 109.0 | $18,003,354 | $2,257,240 | $2,211,473 | $38,247,380 | $60,719,448 | 25,748 | 15,694 | 7,847 | - | - | - | 392,105 | 441,394 | 561.89 | $137.56 | $178.58 | $263.99 |
| 20% | 13.8% | 0.0% | 112.5 | $18,572,648 | $2,353,800 | $2,145,087 | $37,099,241 | $60,170,777 | 25,748 | 23,541 | 11,771 | - | - | - | 380,335 | 441,394 | 546.22 | $136.32 | $176.19 | $259.22 |
| 25% | 16.5% | 0.0% | 116.0 | $19,141,943 | $2,450,359 | $2,078,701 | $35,951,102 | $59,622,105 | 25,748 | 31,388 | 15,694 | - | - | - | 368,564 | 441,394 | 530.55 | $135.08 | $173.81 | $254.45 |
| 30% | 19.2% | 0.0% | 119.5 | $19,711,237 | $2,546,918 | $2,012,316 | $34,802,963 | $59,073,434 | 25,748 | 39,235 | 19,618 | - | - | - | 356,794 | 441,394 | 514.88 | $133.83 | $171.42 | $249.68 |
| 35% | 21.8% | 0.0% | 123.0 | $20,280,531 | $2,643,477 | $1,945,930 | $33,654,824 | $58,524,763 | 25,748 | 47,082 | 23,541 | - | - | - | 345,023 | 441,394 | 499.22 | $132.59 | $169.03 | $244.91 |
| 40% | 24.5% | 0.0% | 126.5 | $20,849,825 | $2,740,036 | $1,879,544 | $32,506,685 | $57,976,092 | 25,748 | 54,929 | 27,465 | - | - | - | 333,253 | 441,394 | 483.55 | $131.35 | $166.65 | $240.15 |
| 45% | 27.2% | 0.0% | 130.0 | $21,419,120 | $2,836,595 | $1,813,159 | $31,358,546 | $57,427,420 | 25,748 | 62,776 | 31,388 | - | - | - | 321,482 | 441,394 | 467.88 | $130.10 | $164.26 | $235.38 |
| 50% | 29.8% | 0.0% | 133.5 | $21,988,414 | $2,933,155 | $1,746,773 | $30,210,407 | $56,878,749 | 25,748 | 70,623 | 35,312 | - | - | - | 309,712 | 441,394 | 452.21 | $128.86 | $161.87 | $230.61 |
| 55% | 32.5% | 0.0% | 137.0 | $22,557,708 | $3,029,714 | $1,680,387 | $29,062,268 | $56,330,078 | 25,748 | 78,470 | 39,235 | - | - | - | 297,941 | 441,394 | 436.54 | $127.62 | $159.49 | $225.84 |
| 60% | 35.2% | 0.0% | 140.5 | $23,127,003 | $3,126,273 | $1,614,002 | $27,914,129 | $55,781,407 | 25,748 | 86,317 | 43,159 | - | - | - | 286,171 | 441,394 | 420.87 | $126.38 | $157.10 | $221.07 |
| 65% | 37.8% | 0.0% | 144.0 | $23,696,297 | $3,222,832 | $1,547,616 | $26,765,990 | $55,232,735 | 25,748 | 94,164 | 47,082 | - | - | - | 274,400 | 441,394 | 405.20 | $125.13 | $154.71 | $216.30 |
| 70% | 40.5% | 0.0% | 147.5 | $24,265,591 | $3,319,391 | $1,481,230 | $25,617,851 | $54,684,064 | 25,748 | 102,011 | 51,006 | - | - | - | 262,629 | 441,394 | 389.53 | $123.89 | $152.33 | $211.53 |
| 75% | 43.2% | 0.0% | 151.0 | $24,834,885 | $3,415,950 | $1,414,845 | $24,469,712 | $54,135,393 | 25,748 | 109,858 | 54,929 | - | - | - | 250,859 | 441,394 | 373.86 | $122.65 | $149.94 | $206.77 |
| 80% | 45.8% | 0.0% | 154.5 | $25,404,180 | $3,512,510 | $1,348,459 | $23,321,573 | $53,586,722 | 25,748 | 117,705 | 58,853 | - | - | - | 239,088 | 441,394 | 358.19 | $121.40 | $147.55 | $202.00 |
| 85% | 48.5% | 0.0% | 158.0 | $25,973,474 | $3,609,069 | $1,282,073 | $22,173,434 | $53,038,050 | 25,748 | 125,552 | 62,776 | - | - | - | 227,318 | 441,394 | 342.53 | $120.16 | $145.16 | $197.23 |
| 90% | 51.2% | 0.5% | 163.4 | $26,735,521 | $3,742,916 | $1,508,012 | $21,048,656 | $53,035,105 | 25,748 | 133,399 | 66,700 | (2,395) | 2,155 | - | 215,787 | 441,394 | 327.44 | $120.15 | $144.06 | $193.83 |
| 95% | 53.8% | 1.4% | 169.0 | $27,526,158 | $3,882,229 | $1,963,681 | $19,942,235 | $53,314,303 | 25,748 | 141,246 | 70,623 | (6,672) | 6,005 | - | 204,444 | 441,394 | 312.81 | $120.79 | $143.62 | $191.17 |
| 100% | 56.5% | 2.5% | 174.6 | $28,317,815 | $4,021,680 | $2,566,443 | $18,847,569 | $53,753,507 | 25,748 | 149,093 | 74,547 | (12,154) | 10,938 | - | 193,222 | 441,394 | 298.47 | $121.78 | $143.57 | $188.94 |
| 105% | 59.2% | 3.7% | 180.3 | $29,213,330 | $4,161,248 | $3,221,551 | $17,757,086 | $54,353,215 | 25,748 | 156,940 | 78,470 | (18,064) | 16,258 | - | 182,042 | 441,394 | 284.23 | $123.14 | $143.89 | $187.09 |
| 110% | 61.8% | 4.9% | 185.9 | $30,119,444 | $4,300,919 | $3,876,658 | $16,666,603 | $54,963,624 | 25,748 | 164,787 | 82,394 | (23,975) | 21,578 | - | 170,863 | 441,394 | 270.00 | $124.52 | $144.23 | $185.27 |
| 115% | 64.5% | 6.1% | 191.6 | $31,026,216 | $4,440,678 | $4,531,765 | $15,576,120 | $55,574,779 | 25,748 | 172,634 | 86,317 | (29,886) | 26,897 | - | 159,684 | 441,394 | 255.76 | $125.91 | $144.58 | $183.45 |
| 120% | 67.2% | 7.4% | 197.2 | $31,977,833 | $4,580,515 | $5,265,141 | $14,491,891 | $56,315,381 | 25,748 | 180,481 | 90,241 | (36,438) | 32,794 | - | 148,568 | 441,394 | 241.68 | $127.59 | $145.23 | $181.96 |
| 125% | 69.8% | 9.0% | 202.9 | $32,993,757 | $4,720,420 | $6,111,317 | $13,416,677 | $57,242,170 | 25,748 | 188,328 | 94,164 | (43,914) | 39,523 | - | 137,545 | 441,394 | 227.82 | $129.68 | $146.32 | $180.95 |
| 130% | 72.5% | 10.5% | 208.5 | $34,010,128 | $4,860,385 | $6,957,492 | $12,341,462 | $58,169,468 | 25,748 | 196,175 | 98,088 | (51,390) | 46,251 | - | 126,522 | 441,394 | 213.97 | $131.79 | $147.41 | $179.93 |
| 135% | 75.2% | 12.0% | 214.2 | $35,026,897 | $5,000,404 | $7,803,668 | $11,266,248 | $59,097,217 | 25,748 | 204,022 | 102,011 | (58,866) | 52,980 | - | 115,499 | 441,394 | 200.11 | $133.89 | $148.50 | $178.91 |
| 140% | 77.8% | 13.5% | 219.9 | $36,044,021 | $5,140,471 | $8,649,843 | $10,191,033 | $60,025,369 | 25,748 | 211,869 | 105,935 | (66,342) | 59,708 | - | 104,477 | 441,394 | 186.26 | $135.99 | $149.59 | $177.90 |
| 145% | 80.5% | 15.1% | 225.5 | $37,061,464 | $5,280,581 | $9,496,019 | $9,115,819 | $60,953,882 | 25,748 | 219,716 | 109,858 | (73,818) | 66,437 | - | 93,454 | 441,394 | 172.40 | $138.09 | $150.68 | $176.88 |
| 150% | 83.2% | 16.6% | 231.2 | $38,079,193 | $5,420,730 | $10,342,194 | $8,040,604 | $61,882,721 | 25,748 | 227,563 | 113,782 | (81,295) | 73,165 | - | 82,431 | 441,394 | 158.55 | $140.20 | $151.77 | $175.87 |
| 155% | 85.8% | 18.1% | 236.9 | $39,097,182 | $5,560,913 | $11,188,370 | $6,965,390 | $62,811,854 | 25,748 | 235,410 | 117,705 | (88,771) | 79,894 | - | 71,408 | 441,394 | 144.69 | $142.30 | $152.87 | $174.86 |
| 160% | 88.5% | 19.6% | 242.5 | $40,115,405 | $5,701,128 | $12,034,545 | $5,890,175 | $63,741,253 | 25,748 | 243,257 | 121,629 | (96,247) | 86,622 | - | 60,385 | 441,394 | 130.83 | $144.41 | $153.96 | $173.85 |
| 165% | 91.2% | 21.3% | 248.2 | $41,171,746 | $5,841,372 | $12,947,737 | $4,820,316 | $64,781,172 | 25,748 | 251,104 | 125,552 | (104,272) | 93,845 | - | 49,417 | 441,394 | 117.11 | $146.76 | $155.31 | $173.12 |
| 170% | 93.8% | 22.9% | 253.9 | $42,232,412 | $5,981,642 | $13,868,231 | $3,751,041 | $65,833,326 | 25,748 | 258,951 | 129,476 | (112,357) | 101,121 | - | 38,455 | 441,394 | 103.40 | $149.15 | $156.70 | $172.41 |
| 175% | 96.5% | 24.6% | 259.6 | $43,318,565 | $6,121,937 | $14,833,470 | $2,685,341 | $66,959,313 | 25,748 | 266,798 | 133,399 | (120,808) | 108,727 | - | 27,530 | 441,394 | 89.78 | $151.70 | $158.25 | $171.90 |
| 180% | 99.2% | 26.4% | 265.2 | $44,416,041 | $6,262,253 | $15,818,440 | $1,621,218 | $68,117,951 | 25,748 | 274,645 | 137,323 | (129,421) | 116,479 | - | 16,620 | 441,394 | 76.20 | $154.32 | $159.89 | $171.47 |
| 185% | 100.6% | 27.8% | 270.9 | $45,513,666 | $6,402,589 | $16,833,603 | $1,079,280 | $69,829,137 | 25,748 | 282,492 | 141,246 | (138,035) | 124,231 | - | 11,065 | 446,747 | 69.42 | $156.31 | $161.37 | $171.92 |

*Note: The lowest cost option for each Social Cost of Carbon case is highlighted in dark green with white numbers. Options whose cost is within 2.5% of the lowest cost option are shown in light green highlights.*

# Appendix B: Country Overviews

## Barbados

| Barbados – Potential Receptivity to LNG Fuel Supply Options | |
|---|---|
| Moderate-Low | |
| **Energy Profile** | |
| **Peak Energy Demand** | 152 MW |
| **Total Generation Capacity** | 287 MW |
| **Renewable Energy Capacity** | 4% of Installed Capacity |
| **Renewable Energy Target** | 100% by 2030 |

Barbados is an island state of the Lesser Antilles. Due to its location eastward of the other islands of the Lesser Antilles, it is technically classified as an Atlantic island, not a Caribbean island. Barbados has a population of 287,025 people living across 431 square kilometres, making it one of the most densely populated islands in the world. Around 25 percent of Barbados' population lives in the capital Bridgetown with a total urbanization rate of 44 percent (IDB Dossier 2016).

The island's electric utility, The Barbados Light & Power Co. Ltd. (BL&P), established in 1899, was one of the earliest in the Caribbean. It is a vertically integrated monopoly, regulated by the Fair Trading Commission (FTC), and is now totally owned by Emera Inc., a Canadian-based company. BL&P has an installed capacity of 287 MW and supplies electricity to around 130,000 customers. Their existing license, which was gained in 1986, allows BL&P to have the sole franchise to sell electricity in Barbados up to 2028.

### Supply of Petroleum Products

Barbados is the only target island country which produces natural gas and which imports LNG. The country has developed a domestic natural gas network that connects 16,575 residential and 640 commercial customers (Worldwatch Institute 2015).

The Barbados National Oil Company Ltd (BNOCL) produces natural gas sold to the National Petroleum Corporation (NPC). NPC would like to provide more natural gas to customers; however, BNOCL natural gas supply is limited (NPC 2020). The NPC is the state-owned entity which owns the pipeline network and has the responsibility of marketing fuel.

A recent decline in local reserves and growing demand for natural gas has prompted government research on natural gas importation (NPC 2020).

Interamerican Development Bank (IDB) and International Monetary Fund (IMF) staff estimated $190 million for estimated costs of building new capacity of natural-gas-fired power plants (2018-2023); and $129 million investment needs in Barbados for converting existing plants to NG and construction of regasification facilities.

*Exhibit 46: Imports of Petroleum Products to Barbados*

| Product | Unit | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|
| Gasoline/ Light Oil | bbl/d | 2,341 | 2,382 | 2,333 | 2,163 | 2,573 |
| Diesel/ Medium Oils | bbl/d | 1,556 | 1,750 | 1,575 | 3,006 | 1,470 |
| Kerosene/ Jet Fuel | bbl/d | 3,057 | 3,618 | 3,966 | 3,632 | 4,347 |
| Resid/ HFO | bbl/d | 227 | 256 | 198 | 179 | 848 |
| Lubricants | bbl/d | 108 | 44 | 39 | 35 | 35 |
| LNG | kg/d | 71 | 5,286 | 12,782 | 11,338 | 11,660 |
| NGLs/ LPG | bbl/d | 250 | 272 | 263 | 310 | 289 |

Source: International Trade Centre (ITC)

## Port

Barbados offers one significant port in the capital city of Bridgetown. In addition to containers, roll-on/roll-off (RoRo), break bulk, and dry bulk cargo, the Port of Bridgetown handled 617 million tons of petroleum products via 155 tankers in 2019 (Barbados Port 2020a). Available water depths of up to 37 feet in Bridgetown can support receiving full sized LNG or LPG carrier ships (Barbados Port 2020b).

Barbados also receives LNG ISO-containers at the small Woodbourne regasification plant owned by BNOCL. These ISO-containers originate at the 60,000 tonnes per annum American LNG Marketing liquefaction plant in Hialeah, Florida, which receives tanks shipments by truck before loading on container ships for delivery to Barbados.

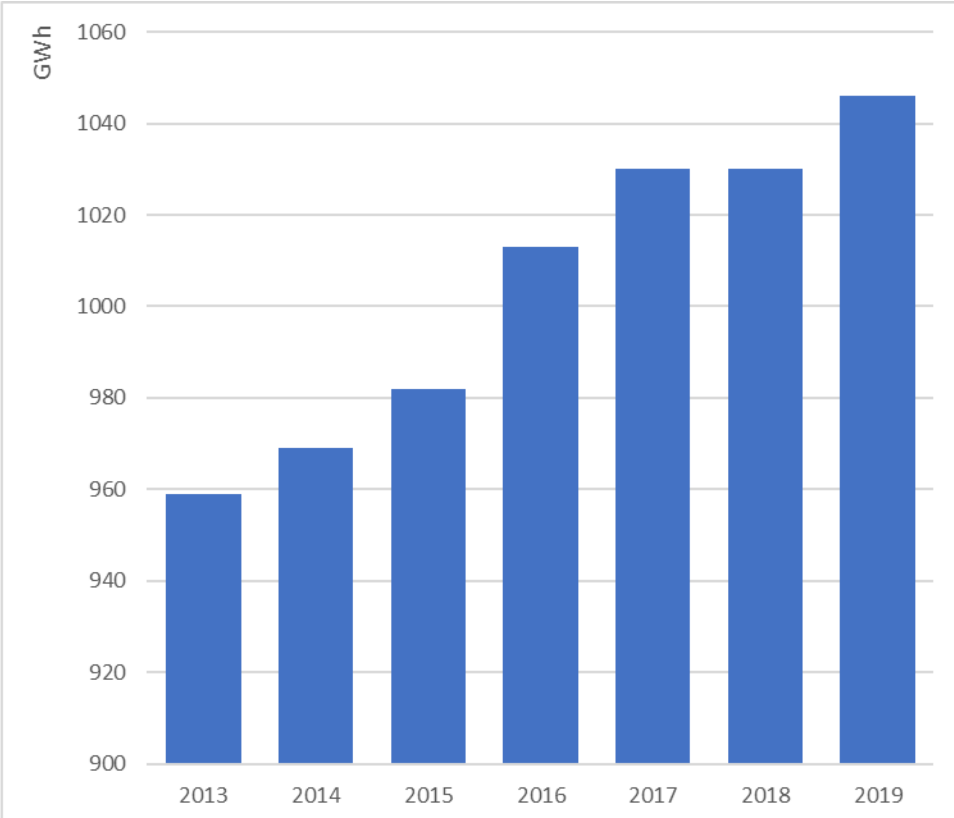
## Electricity Generation

Power on Barbados is generated from three power stations and solar generation. These facilities have a total generation capacity of 287 MW. BL&P is in the final stages of completing their “Clean Energy Bridge” power plant which will add 33 MW medium speed diesel generation and will help ensure the grid is resilient as they transition to renewable power generation (Barbados Advocate 2020). Power from the power plants is brought across the island on 24 kilovolt (kV) transmission lines. The power is then stepped down to 11 kV at one of the 18 substations and power is delivered to customers at 115 volts (V) or 230 V (IDB Dossier 2016).

*Exhibit 47: Unit Power Generation on Barbados*

| Power Station | Fuel | Capacity (MW) | Details |
|---|---|---|---|
| Spring Garden | Diesel | 166 | 3 x 12 MW LSD Engines<br>1 x 12.5 MW LSD Engines<br>2 x 30 MW LSD Engines<br>2 x 20 MW Steam Turbines<br>1 x 17.5 MW Gas Turbine |
| Garrison | Diesel | 13 | 1 x 13 MW Gas Turbine |
| Seawell | Diesel | 73 | 1 x 13 MW Gas Turbine<br>3 x 20 MW Gas Turbines |
| Photo-voltaic Solar Plant | Solar | 10 | |
| Independent Power Producers | | 25 | |
| **Total** | | **287** | |

*Exhibit 48: Electricity Sales on Barbados*




Source: BP Statistical Review of World Energy, Ember

# Saint Vincent and the Grenadines Profile

| St. Vincent and the Grenadines – Potential Receptivity to NG/LNG Fuel Supply Options | |
|---|---|
| Moderate | |
| **Energy Profile** | |
| **Peak Energy Demand** | 28 MW |
| **Total Generation Capacity** | 52 MW |
| **Renewable Energy Capacity** | 17% of Installed Capacity |
| **Renewable Energy Target** | 60% by 2030 |

St. Vincent and the Grenadines is a multi-island state comprised of the main island of St. Vincent as well as seven smaller inhabited islands and about 30 uninhabited islets constituting the Grenadines. The country is located north of Grenada, west of Barbados, and south of St. Lucia. The islands are home to a population of 110,589 people and cover a land area of 389 square kilometers. About 25,000 people live in the country's capital of Kingstown.

St. Vincent Electricity Services Limited (VINLEC) is the sole provider of utility-scale electricity on St. Vincent and four of the Grenadines: Bequia, Union island, Canouan, and Mayreau. The vast majority of the VINLEC's generation capacity, 52 MW, is installed on the island on St. Vincent (U.S. DOE 2020). Some facilities in other islands of the Grenadines have on-site generation for self-use, including the private hotel islands of Palm and Mustique.

## Supply of Petroleum Products

Saint Vincent and the Grenadines have not used any LNG in recent years, but in 2015 had small amounts of LNG delivered to the country.

*Exhibit 49: Imports of Petroleum Products to St Vincent and the Grenadines*

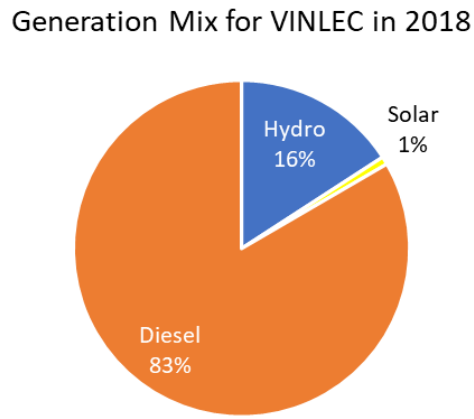
| Product | Unit | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|
| Gasoline/ Light Oil | bbl/d | 497 | 604 | 597 | 686 | 609 |
| Diesel/ Medium Oils | bbl/d | 745 | 1,000 | 519 | 951 | 621 |
| Kerosene/ Jet Fuel | bbl/d | 1 | 1 | 1 | 0 | 0 |
| Resid/ HFO | bbl/d | 0 | 0 | 0 | 0 | 0 |
| Lubricants | bbl/d | 13 | 12 | 13 | 19 | 10 |
| LNG | kg/d | 0 | 0 | 0 | 0 | 0 |
| NGLs/ LPG | bbl/d | 176 | 135 | 116 | 128 | 118 |

Source: International Trade Centre (ITC)

## Port

Port Kingstown on the island of St. Vincent handles both container and break-bulk cargo. However, due to space restrictions, most cargo traffic is handled through the nearby Campden Park Container Port, in nearby Campden Park Bay (SVGPA 2020). Located approximately 2 miles north of Kingstown, this location offers extensive container storage and handling capabilities with water depths up to nearly 40 feet (SVGPA 2020). This area would be easily capable of supporting ISO container movements. One location nearby to this facility in Lowman's Bay also receives tankers to onshore storage (SVGPA 2020). A number of smaller ports are also located across the Grenadines, however these ports are small and primarily serviced by ferry cargo (SVGPA 2020).

## Electricity Generation



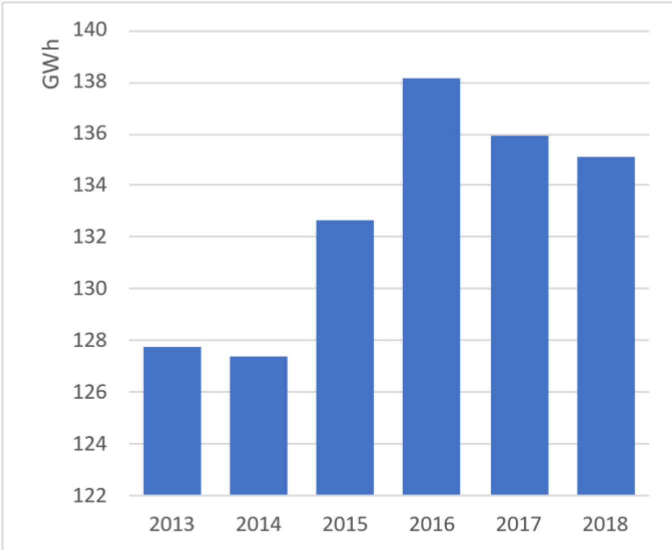

Power on St. Vincent and the Grenadines is generated from nine power stations with a total of 52 MW capacity. These power plants supply St Vincent Electricity Services Ltd. system which delivers electricity along 350 miles of 33 kV, 11 kV, 400 V and 230 V lines (IDB Dossier 2015). In 2018, hydroelectric plants produced 23.8 gigawatthours (GWh) generated (16%), solar facilities produced 1.1 GWh generated by solar (1%), and diesel plants produced 125.0 GWh (83%) of St Vincent Electricity Services Ltd (VINLEC 2018).

Saint Vincent and the Grenadines existing diesel generators are aging, providing an opportunity to increase renewable energy and the efficiency of fossil-fired units (NREL 2015c).

*Exhibit 50: Generation Capacity on Saint Vincent and the Grenadines*

| Island | Power Station | Fuel | Capacity (MW) | Details |
|---|---|---|---|---|
| St. Vincent | Cane Hall | Diesel/ Solar PV | 19.6 | 8 diesel generators<br>PV capacity of 224 kWp |
| St. Vincent | Lowmans Bay | Diesel | 17.4 | 4 Man generators at 4.35 MW |
| St. Vincent | South Rivers | Hydroelectric | 2.3 | 3 Gilkes Turgo generator units-2x0.275MW, 1x0.32MW |
| St. Vincent | Richmond | Hydroelectric | 1.1 | 2 Gilkes Turgo generator units – 0.55MW |
| St. Vincent | Cumberland | Hydroelectric | 3.65 | 5 Neypric Francis Turbine - 2x0.46MW, 2x0.64MW, 1.464MW |
| Bequia | Bequia | Diesel | 4.145 | Caterpillar: 2x0.55MW, 0.64MW, 0.7575MW, 1.28MW<br>Cummins: 0.35MW |
| Canouan | Canouan | Diesel | 4.04 | Caterpillar: 0.2MW, 0.0.22MW<br>Wärtsilä: 2x1.2MW |
| Union Island | Union Island | Diesel/Solar PV | 1.8 | Caterpillar 0.15MW, 0.2MW, 0.35MW, 0.4MW<br>PV system with 0.6 MW installed capacity |
| Mayreau | Mayreau | Diesel | 0.37 | Includes Perkins-3x0.06 MW |
| **Total** | | | **54.4** | |
| Source: VINLEC website<br>Note: U.S. DOE reports 52 MW installed capacity as of 2020 | | | | |

*Exhibit 51: VINLEC Electricity Sales on Annual Basis (GWh)*




Source: VINELEC's 2018 Annual Report

# Saint Lucia Profile

The island of St. Lucia is part of the Lesser Antilles and is located north of St. Vincent and the Grenadines, and northwest of Barbados. The island is 43.5 kilometers long and 22.5 kilometers wide and covers a total land area of 617 square kilometers. It has a population of 182,790, of which more than a third resides in the capital of Castries.

| St. Lucia – Potential Receptivity to NG/LNG Fuel Supply Options | |
|---|---|
| Moderate | |
| **Energy Profile** | |
| **Peak Energy Demand** | 61 MW |
| **Total Generation Capacity** | 92 MW |
| **Renewable Energy Capacity** | 4% of Installed Capacity |
| **Renewable Energy Target** | 35% by 2030 |

St. Lucia Electricity Services, Ltd. (LUCELEC), a privately-owned and vertically-integrated utility, is the sole provider of electricity in St. Lucia and is responsible for the generation, transmission, distribution, and sale of electricity. It holds an exclusive license until 2045, with exceptions for small-scale, self-generated electricity.

## Supply of Petroleum Products

*Exhibit 52: Imports of Petroleum Products to St Lucia*

| Product | Unit | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|
| Gasoline/ Light Oil | bbl/d | 575 | 415 | 457 | 411 | 441 |
| Diesel/ Medium Oils | bbl/d | 331 | 238 | 286 | 258 | 260 |
| Kerosene/ Jet Fuel | bbl/d | 24 | 23 | 24 | 25 | 26 |
| Resid/ HFO | bbl/d | 0 | 0 | 0 | 0 | 0 |
| Lubricants | bbl/d | 25 | 20 | 20 | 24 | 20 |
| LNG | kg/d | 0 | 0 | 0 | 0 | 0 |
| NGLs/ LPG | bbl/d | 0 | 0 | 0 | 0 | 0 |

Source: International Trade Centre (ITC)

## Port

Saint Lucia's largest port is the Port of Castries, found within the capital city. This port offers one terminal, Northern Wharf, which currently receives cargo via container vessels. This terminal has a maximum available depth of 32 feet across two berths (Cox and Company Limited 2020); both of which would be capable of receiving LNG or LPG carriers. Receiving volumes here would likely be close to demand areas. On the most southern tip of the island, Vieux Fort Dock is another port option which could support natural gas or LPG imports. With maximum water depths of 35 feet (Cox and Company Limited 2020), the dock currently supports container traffic and would be capable of receiving carriers or ISO containers with proper infrastructure.

Elsewhere in Saint Lucia, Buckeye operates a crude oil storage and transshipment terminal in Cul-de-Sac Bay. This terminal has the capacity to store 9.3 million barrels of crude oil and 1.0 million barrels of petroleum products (Buckeye 2021). The terminal has two available berths, one of which can receive very large crude carriers, while the other is used to support smaller refined product vessels. Assuming proper supporting infrastructure was constructed, these available depths could provide an alternative site for imported natural gas or LPG receipts.

## Electricity Generation

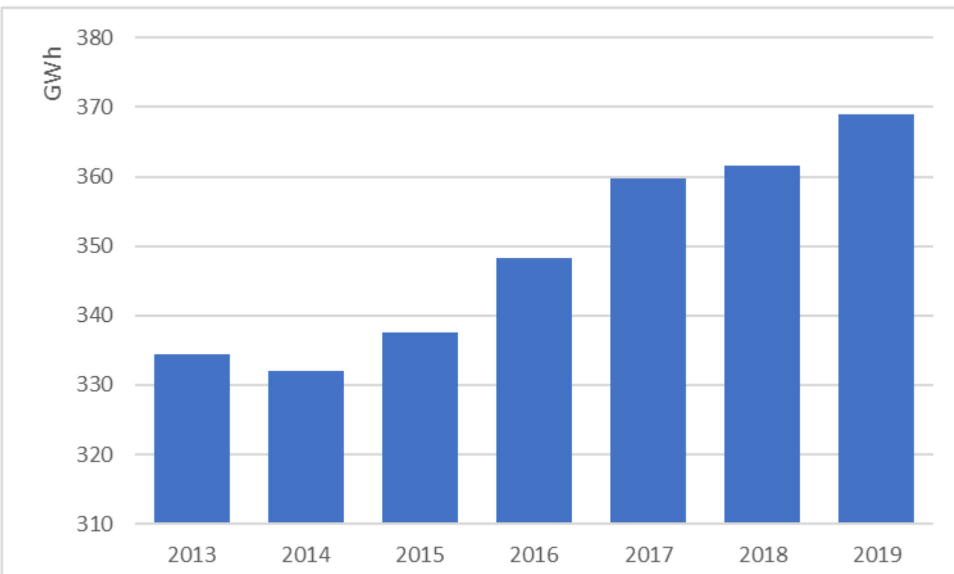
Power on St. Lucia is generated from the Cul-de-Sac Power Station which has an installed capacity of 87.4 MW (LUCELEC 2021a). The LUCELEC transmission network steps up power generated at the Cul-de-Sac Power Station to 66 kV and transports it throughout the island on its 73.32 miles of 66 kV transmission lines where it can be stepped down at any of its other six substations (Castries, Union, Reduit, Soufriere, Vieux Fort, and Praslin). LUCELEC has 2,566 miles of 11 kV transmission lines and then supplies customers on 240V/415V lines. (LUCELEC 2021b).

St. Lucia almost exclusively relies on imported fossil fuel to meet its energy needs, despite large geothermal, wind, and solar resources (NREL 2015b).

*Exhibit 53*: Unit Power Generation on Saint Lucia (LUCELEC 2021a)

| Power Station | Fuel | Capacity | Details |
|---|---|---|---|
| **Cul-de-Sac Power Station** | Diesel | 87.4 MW | 3 MAK engines (6-7 MW)<br>7 Wärtsilä units–4x9.3 MW, 3x10.2 MW |
| **Total** | | **87.4 MW** | |

*Exhibit 54: LUCELEC Electricity Sales on Annual Basis (GWh)*



# Antigua and Barbuda Profile

| Antigua and Barbuda – Potential Receptivity to NG/LNG Fuel Supply Options | |
|---|---|
| Moderate | |
| **Energy Profile** | |
| **Peak Energy Demand** | 50 MW |
| **Total Generation Capacity** | 81 MW |
| **Renewable Energy Capacity** | 11% of Installed Capacity |
| **Renewable Energy Target** | 15% by 2030 |

Antigua and Barbuda is a twin-island state. It is among the wealthiest of the Eastern Caribbean states and has the second highest per capita consumption of electricity. The two islands cover a land area of 443 square kilometres and are home to a population of 97,118 people. Antigua is home to 98 percent of the population, and almost 40 percent reside in the capital city of St. John's (IDB Dossier 2015).

The state-owned Antigua Public Utilities Authority (APUA) is the electric utility. An independent power producer, Antigua Power Company, sells power to APUA. All fuel used in electricity generation is provided by the state-owned West Indies Oil Company.

## Supply of Petroleum Products

*Exhibit 55: Imports of Petroleum Products to Antigua and Barbuda*

| Product | Unit | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|
| Gasoline/ Light Oil | bbl/d | 0.2 | 0.6 | 4.5 | 0.3 | 0.0 |
| Diesel/ Medium Oils | bbl/d | 0.0 | 0.0 | 0.1 | 0.0 | 0.1 |
| Kerosene/ Jet Fuel | bbl/d | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Resid/ HFO | bbl/d | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Lubricants | bbl/d | 15.6 | 16.0 | 17.3 | 20.6 | 18.5 |
| LNG | kg/d | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NGLs/ LPG | bbl/d | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 |

Source: International Trade Centre (ITC)

- On July 1, 2020 the APUA solicited interest for a natural gas power plant with 25 MW-30 MW to be installed on Crabbs peninsula to be located a half kilometer to import facilities (APUA 2020).
- Eagle LNG Partners signed a long-term agreement in October 2020 with Barbuda Ocean Club, a private resort and community on the island, for the use of natural gas for power generation. Eagle LNG Partners will provide U.S.-source natural gas, on-site storage, equipment, and regasification (Hydrocarbons 2020).

## Port

Located on the island of Antigua, Saint John's Harbor is the country's primary port, and one of the largest in the Caribbean (IDB 2013). The construction of the Heritage Quay Dock and the Nevis Pier within this harbor have provided additional dock space to accommodate cruise ships, allowing for more support of cargo in Deep Water Harbor (ABPA 2021). Offering depths of 35 ft, this area can accommodate imported LNG or LPG via full-sized carrier vessels as well as containerships carrying ISO containers. The West Indies Oil Company also operates an oil terminal on Antigua. This terminal, in addition to Deep Water Harbor, currently supports crude oil, oil product, and LPG tanker movements (ABPA 2021).

## Electricity Generation

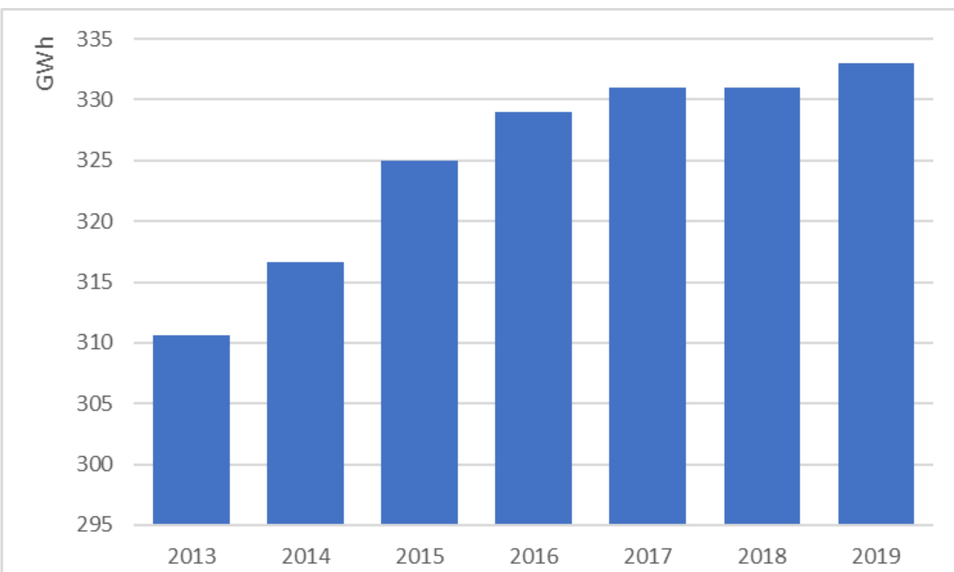
Power on Antigua and Barbuda is generated from two power stations with a total of 77 MW installed capacity. The island is in the process of adding 10 MW of solar by the end of 2020 and another 4.1 MW of wind by the end of 2021. APUA had to shut down its 30 MW Wadadi Power plant (Antigua Observer 2020) due to reliability issues and has requested expression of interests on putting in a 25-30 MW natural gas/LPG plant. Power is supplied around Antigua and Barbuda by stepping up the 11 kV generated power to 69 kV where it is transmitted around the island in a ring configuration to one of seven substations. Power is then stepped down to 11 kV and distributed via one of 25 feeders (APUA 2020).

Antigua and Barbuda is almost entirely reliant on imported fossil fuels (NREL 2015a). The Antigua government owns a 51% share of West Indies Oil Company (WIOC), the sole fuel supplier to the country (NREL 2015a).

*Exhibit 56: Unit Power Generation on Antigua and Barbuda*

| Power Station | Fuel | Capacity | Details |
|---|---|---|---|
| **Blackpine Power Plant** | Diesel | 27 MW | 2x6 MW, 2x7.5MW |
| **IPP** | Diesel | 50 MW | 1x 17 MW, 3x11MW |
| **Total** | | **77 MW** | |

*Exhibit 57: Electricity Sales in Antigua and Barbuda*




*Source:* BP Statistical Review of World Energy, Ember

## Appendix C: Fossil Fuel Generators by Island

| Country Plant | No. | Each Unit MW | Total MW | Type | Manufacturer | Scheduled Decommission Date | Fuel |
|---|---|---|---|---|---|---|---|
| **Barbados** | | | **252** | | | | |
| Spring Garden | | | ***166*** | | | | |
| | 3 | 12 | 36 | LSD Engines | | 2019 | HFO |
| | 1 | 12.5 | 12.5 | LSD Engines | | 2019 | HFO |
| | 2 | 30 | 60 | LSD Engines | | 2036 | HFO |
| | 1 | 17.5 | 17.5 | Gas Turbine | | | |
| | 2 | 20 | 40 | Steam Turbine | | 2017 | HFO |
| Garrison | | | ***13*** | | | | |
| | 1 | 13 | 13 | Gas Turbine | | 2017 | Diesel |
| Seawell | | | ***73*** | | | | |
| | 1 | 13 | 13 | Gas Turbine | | 2022 | Diesel |
| | 3 | 20 | 60 | Gas Turbine | | 2025-2028 | Diesel & Av-Jet |
| **St. Vincent and Grenadine Islands** | | | **49.91** | | | | |
| Cane Hall | | | ***24.06*** | | | | |
| | 1 | 1.13 | 1.13 | Diesel Generator | Allen | 1998 | Diesel |
| | 1 | 1.26 | 1.26 | Diesel Generator | Allen | 1998 | Diesel |
| | 4 | 1.28 | 5.12 | Diesel Generator | Caterpillar | 2026 | Diesel |
| | 1 | 1.47 | 1.47 | Diesel Generator | Caterpillar | 2026 | Diesel |
| | 1 | 3.78 | 3.78 | Diesel Generator | Caterpillar | 2026 | Diesel |
| | 1 | 0.6 | 0.6 | Diesel Generator | Cummings | | Diesel |
| | 2 | 3.25 | 6.5 | Diesel Generator | Wartsila | | Diesel |
| | 1 | 4.2 | 4.2 | Diesel Generator | Wartsila | | Diesel |
| Lowmans Bay | | | ***17.4*** | | | | |
| | 4 | 4.35 | 17.4 | Diesel Generator | Man | 2036 | Diesel & HFO |
| Bequia | | | ***4.13*** | | | | |
| | 2 | 0.55 | 1.10 | Diesel Generator | Caterpillar | 1993 | Diesel |
| | 1 | 0.64 | 0.64 | Diesel Generator | Caterpillar | 1993 | Diesel |
| | 1 | 0.7575 | 0.76 | Diesel Generator | Caterpillar | 1993 | Diesel |
| | 1 | 1.28 | 1.28 | Diesel Generator | Caterpillar | 1993 | Diesel |
| | 1 | 0.35 | 0.35 | Diesel Generator | Cummins | 1993 | Diesel |
| Canouan | | | ***2.82*** | | | | |
| | 1 | 0.2 | 0.2 | Diesel Generator | Caterpillar | 2019 | Diesel |
| | 1 | 0.22 | 0.22 | Diesel Generator | Caterpillar | 2019 | Diesel |
| | 2 | 1.2 | 2.4 | Diesel Generator | Wartsila | | Diesel |
| Union Island | | | ***1.32*** | | | | |
| | 1 | 0.15 | 0.15 | Diesel Generator | Caterpillar | 1999 | Diesel |
| | 1 | 0.2 | 0.2 | Diesel Generator | Caterpillar | 1999 | Diesel |
| | 1 | 2.2 | 0.22 | Diesel Generator | Caterpillar | 1999 | Diesel |
| | 1 | 0.35 | 0.35 | Diesel Generator | Caterpillar | 1999 | Diesel |
| | 1 | 0.4 | 0.4 | Diesel Generator | Caterpillar | 1999 | Diesel |
| Mayreau | | | ***0.18*** | | | | |
| | 3 | 0.06 | 0.18 | Diesel Generator | Perkins | 2028 | Diesel |
| **St. Lucia** | | | **87.3** | | | | |
| Cul de Sac | | | ***87.3*** | | | | |
| | 3 | 6.5 | 19.5 | Diesel Generator | MAK | 2015 | Diesel |
| | 4 | 9.3 | 37.2 | Diesel Generator | Wartsila | 2024 | Diesel |
| | 3 | 10.2 | 30.6 | Diesel Generator | Wartsila | 2032 | Diesel |
| **Antigua and Barbuda** | | | **77** | | | | |
| Blackpine | | | ***27*** | | | | |
| | 2 | 6 | 12 | Diesel Generator | | 2021 | HFO |
| | 2 | 7.5 | 15 | Diesel Generator | | 2029 | HFO |
| IPP | | | ***50*** | | | | |
| | 1 | 17 | 17 | Diesel Generator | | | |
| | 3 | 11 | 33 | Diesel Generator | | | |

Source: The Barbados Light and Power Co. website, Challenges and Opportunities for the Energy Sector in the Eastern Caribbean: Saint Vincent and the Grenadines Energy Dossier, Challenges and Opportunities for the Energy Sector in the Eastern Caribbean: Saint Lucia Energy Dossier, APUA Request for Expression of Interest

# Appendix D: Small LNG Carriers

Small Capacity (less than 50,000 m$^3$) LNG Carriers

| Vessel Name | Capacity (m$^3$) | Containment System |
|---|---|---|
| Seagas | 167 | Other |
| Kayoh Maru | 1,517 | Other |
| Lucia Ambition | 18,928 | Membrane |
| Surya Aki | 19,474 | Moss |
| Aman Sendai | 18,928 | Membrane |
| Pelita Energy | 18,944 | Membrane |
| Triputra | 23,096 | Membrane |
| Shinju Maru No. 1 | 2,513 | Other |
| Pioneer Knutsen | 1,100 | Other |
| North Pioneer | 2,512 | Other |
| Kakurei Maru | 2,536 | Other |
| Shinju Maru No. 2 | 2,536 | Other |
| Coral Methane | 7,500 | Other |
| Oizmendi | 600 | Other |
| Coral Favia | 10,030 | Other |
| Coral Fraseri | 10,030 | Other |
| Akebono Maru | 3,556 | Other |
| Coral Fungia | 10,030 | Other |
| Coral Furcata | 10,030 | Other |
| Unikum Spirit | 12,000 | Other |
| Vision Spirit | 12,022 | Other |
| Coral Energy | 15,600 | Other |
| Coral Anthelia | 6,500 | Other |
| Kakuyu Maru | 2,538 | Other |
| Hai Yang Shi You 301 | 31,043 | Other |
| JS Ineos Ingenuity | 27,566 | Other |
| JS Ineos Insight | 27,566 | Other |
| JS Ineos Intrepid | 27,566 | Other |
| Hua Xiang 8 | 14,000 | Other |
| JS Ineos Innovation | 27,566 | Other |
| JS Ineos Inspiration | 27,566 | Other |
| Cardissa | 6,469 | Other |
| Coralius | 5,737 | Other |
| Engie Zeebrugge | 5,100 | Other |
| JS Ineos Independence | 27,566 | Other |
| JS Ineos Intuition | 27,500 | Other |
| JS Ineos Invention | 27,500 | Other |
| Bunker Breeze | 4,864 | Other |
| Coral Encanto | 30,133 | Other |
| Coral Energice | 18,000 | Other |
| Kairos | 7,500 | Other |
| Saga Dawn | 45,000 | Membrane |
| SM Jeju LNG1 | 7,654 | Membrane |

Source: GIIGNL 2020 Annual Report

# Appendix E: Capital Costs of LNG Tankers

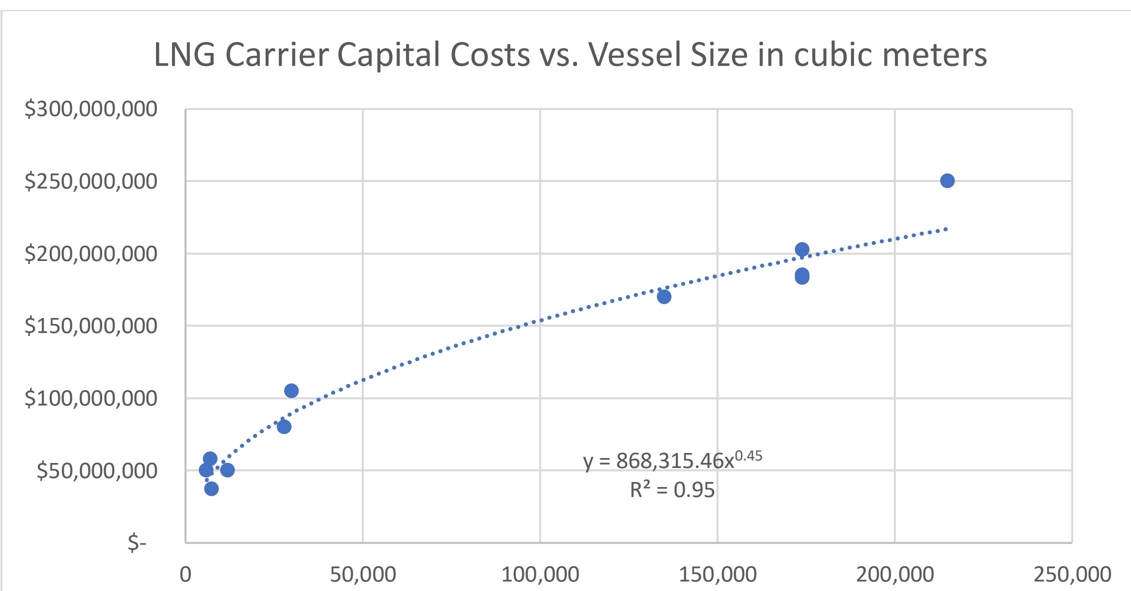
## Vessel Costs

LNG carrier capital costs and the associated sources of information are outlined in Exhibit 58 and the regression resulting from the data is outlined in Exhibit 59. Capital costs for Oil Product tankers and container vessels were derived using power functions that correlated capital expenditures to gross tonnage derived by OECD Directorate.

*Exhibit 58: Recent LNG Tanker Costs by Size*

| Year | Size ($m^3$) | Cost | Source |
|---|---|---|---|
| 2019 | 174,000 | $202,500,000 | https://www.naturalgasintel.com/lng-carrier-market-struggles-to-keep-up-with-liquefaction-capacity-buildout/ |
| 2021 | 174,000 | $183,134,556 | https://www.hellenicshippingnews.com/korean-shipbuilders-benefit-from-increased-demand-for-lng-ships/ |
| 2018 | 174,000 | $185,050,000 | https://www.offshore-energy.biz/south-koreas-dsme-in-1-1-billion-lng-carrier-deal/ |
| 2020 | 7,000 | $58,000,000 | https://marine-offshore.bureauveritas.com/insight/outfitting-world-small-scale-lng-and-bunkering-vessels#:~:text=A%20primary%20point%20of%20hesitation,on%20investment%20(ROI)%20period. |
| 2018 | 215,000 | $250,000,000 | https://www.scitepress.org/Papers/2018/85421/85421.pdf |
| 2018 | 135,000 | $170,000,000 | |
| 2018 | 28,000 | $80,000,000 | |
| 2015 | 6,000 | $50,000,000 | |
| 2014 | 12,000 | $50,000,000 | |
| 2014 | 30,000 | $105,000,000 | |
| 2017 | 7,500 | $37,000,000 | |

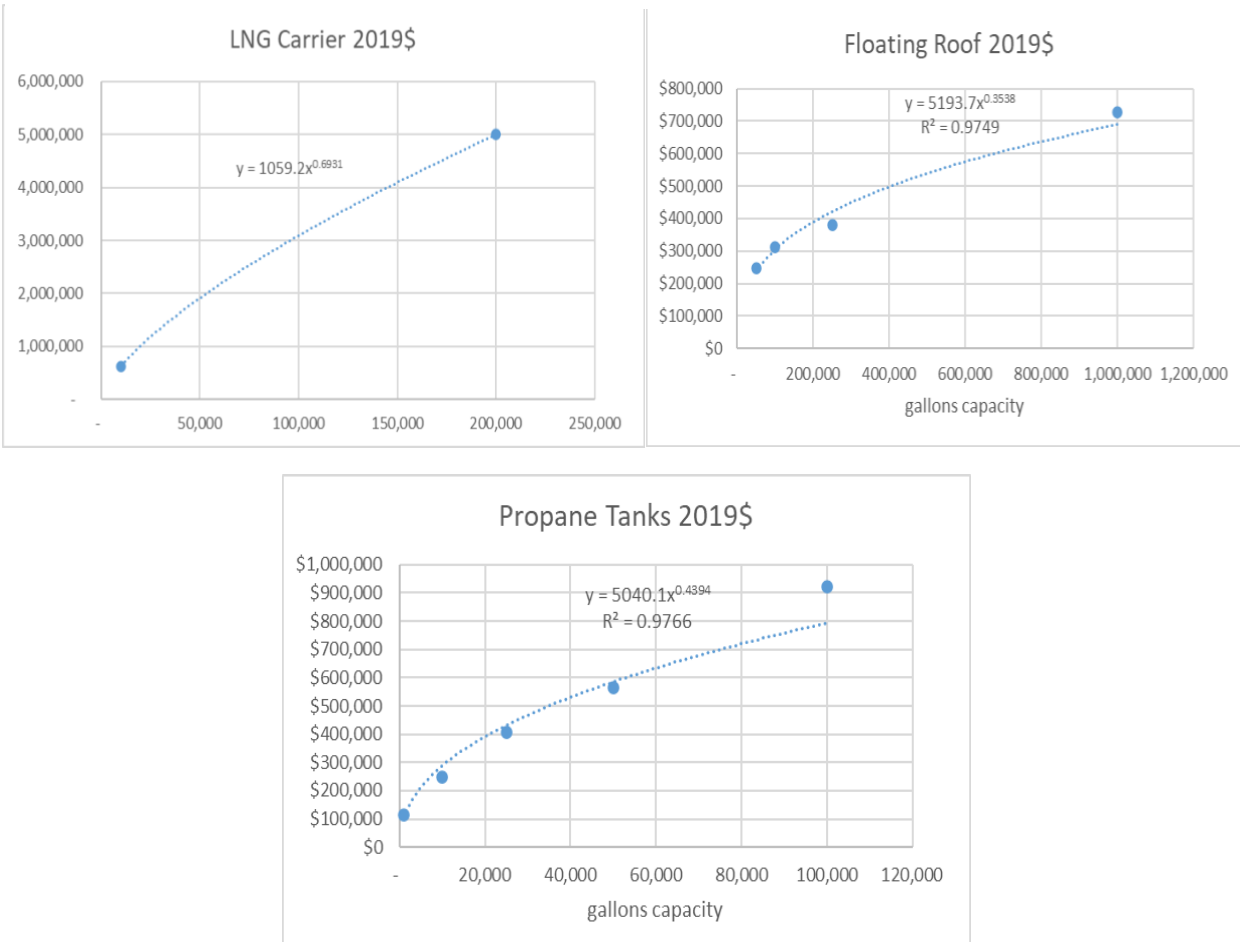
*Exhibit 59: Recent LNG Tanker Costs by Size*



## Storage Costs

Storage costs were estimated based on information from a DOE report on process equipment costs scaled to 2019 dollars and then spot checked against recent storage costs. These regressions are illustrated in Exhibit 60 below. LNG ISO container costs were based on costs reported in a Hawaii Gas filing that listed the ISO container costs. Hydrogen storage costs were calculated as 30% higher than the LNG ISO containers due to increased thickness needs, but these costs also increase because hydrogen has a lower heat content and will need more volume to store the same heat content.

*Exhibit 60: Regressions for Storage Cost*



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