Desk Study of the Options, Cost, Economics, Impacts, and Key Considerations of Transporting and Utilizing Natural Gas from Offshore Guyana for the Generation of Electricity

Revised Final Report

Report to the Government of Guyana

Submitted by Energy Narrative

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1. Executive Summary

Energy Narrative has been engaged to complete a desk study of the options, cost, economics, impacts, and key considerations of transporting and utilizing natural gas from offshore Guyana for the generation of electricity. The primary objective of the study is to determine if offshore natural gas can be used to reduce electricity costs in Guyana. This primary objective is addressed through three broad sub-questions:

- What are the associated technical and operational challenges of using the natural gas?
- What are the associated costs and benefits of producing electricity with natural gas?
- What is the long-term strategic fit between natural gas and renewable energy development?

The analysis to answer these three sub-questions was divided into twelve components, each of which is addressed in this Final Report.

1.1. Technical and operational challenges

Analysis of alternative transportation media shows that **a natural gas pipeline is the preferred transportation technology from offshore to Guyana** given the high capital costs and higher technical risk of floating LNG and seaborne CNG. However, small-scale onshore LNG and CNG may be viable options to distribute natural gas to isolated demand centers once it is landed in Guyana.

More data is needed to assess offshore pipeline technical risks, but process to do so is well established. **Data maturity is low, making only a general interpretation of potential risks possible.** Technical challenges include

- Pipeline technical risks are likely to increase as data maturity increases,
- the small size of the pipeline may present unforeseen design, manufacturing and installation challenges,
- the water depth of the pipeline may complicate the pipeline's deployment and operations, and
- the lack of natural gas storage presents continuity problems which may find their way back to the oil production and gas re-injection wells and facilities. An evaluation of the relevant benefits of the smaller and larger pipeline in the context of natural gas storage should be made.

Ownership, commercial structure, and regulation of the natural gas pipeline are also important strategic decisions. A public-private partnership (PPP) could be a useful option to balance the finance, construction, operational, environmental, social, and competitive complexities of the project. Further analysis is needed to identify potential PPP options and suitable commercial and regulatory structures for the offshore pipeline.

The assessment of the natural gas composition shows that natural gas liquids (mainly propane and butane) account for 12.3% of the natural gas produced. Separating these liquids from **the 30 MMcfd of natural gas supply would provide nearly 890,000 barrels per year of LPG**, more than four times Guyana's current LPG consumption.

This abundant supply could open new opportunities to promote LPG use for transportation, home cooking and water heating, or as a chemical feedstock for new industries.

After removing the LPG, 26.3 MMcfd of dry gas would be available for electricity generation and other uses. The assessment of natural gas demand for electricity generation suggests that **natural gas demand for electricity generation will reach 26.3 MMcfd by 2023**, a year after the natural gas is first available, if the majority of current and all new planned power plants are natural gas fired. The specific timing of investment in natural gas demand (power plant conversions and new power plant additions) should be carefully coordinated with decisions affecting available natural gas supply. This assessment did not include the potential effects of faster economic growth or investment in new energy intensive industries that may result from the availability of natural gas.

In this initial inspection, it was determined that **converting existing generation units to use natural gas as dual fuel generators** would minimize initial capital costs, take advantage of their strategic locations across the current transmission system, and potentially eliminate the need for natural gas storage at the generation sites. Natural gas storage may be advantageous to better match natural gas supply with the electricity load shape, but further detail on Guyana's load shape is required for this more detailed analysis.

New natural gas-fired generation capacity should also be dual fuel. A new power plant should be located at the natural gas landing point, but additional power generation capacity should also be located at the existing generation sites where feasible to optimize the use of onshore natural gas distribution infrastructure.

The dispersed nature of Guyana's existing power plants raised another potential technical challenge. **Distributing the natural gas to each power plant could be challenging** given the dense population and infrastructure in the surrounding area. Installing underground pipelines in urban areas will disrupt traffic and may require extensive planning and rights-of-way negotiations. Transporting the gas as LNG once it is landed could be a more viable option, although it will cost more than the onshore pipeline option. A micro-LNG station and distribution via truck and barge would avoid the potential environmental, economic, and social harm from building pipelines in heavily populated areas. The LNG infrastructure would also be able to reach a wider range of consumers, including hinterland communities, which will create additional natural gas demand uses. Further analysis is needed to better assess the potential costs and benefits of distributing the landed natural gas via LNG.

1.2. Costs and benefits of using natural gas for electricity generation

The offshore pipeline is estimated to cost between US$165 million and US$270 million to build, depending on the size and landing site location. On shore compression and separation of the LPG is estimated to cost between US$43 million and US$114 million. Finally, distributing the natural gas to the various electricity generation location is estimated to cost between US$95 million and $127 million for the various proposed landing sites. **The Clonbrook landing site is the optimal landing site for the 30 MMcfd pipeline**. **This option would cost US$304 million**, including US$165 for the offshore pipeline, US$43.5 million for a compression station and separation plant onshore, and US$95.4 million for onshore pipelines to bring natural gas to power stations in Vreed-en-Hoop, Kinston, Garden of Eden, and Canefield.

The **Clonbrook landing site results in the lowest overall delivered cost of natural gas**. Table 1.1 below compares the delivered cost to each of the power generation sites considered for each natural gas landing site option.

Table 1.1: Estimated natural gas transportation cost by landing site option (US$ per MMBtu)

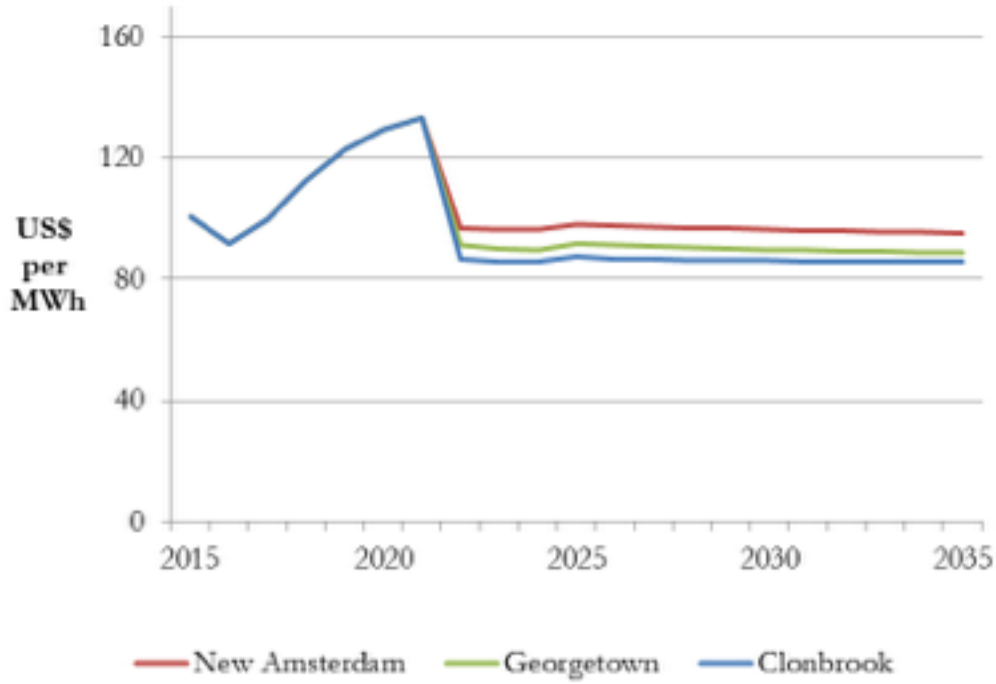
Generation Site	Georgetown	Clonbrook	New Amsterdam
Vreed-en-Hoop	**$3.34**	$3.64	$5.34
Kingston	**$3.25**	$3.54	$5.25
New Sophia	**$3.17**		
Columbia		**$3.09**	
Garden of Eden	$4.31	**$4.23**	$5.79
Canefield	$8.45	$6.69	**$3.50**
Skeldon			**$8.56**

Source: Energy Narrative calculations

As the most central of the three proposed landing sites, Clonbrook balances the costs to deliver natural gas to both ends of the power grid, enabling a more balanced generation system and supporting new capacity additions across the system.

As a result, landing the natural gas in **Clonbrook provides the lowest overall cost of electricity** among the three options (see Figure 1.1 below). The levelized cost of electricity for each option shown below includes a capital component, fixed and variable operations and maintenance costs (O&M), and fuel costs. The capital and O&M costs are identical for each option, such that the variations in electricity price directly reflect differences in the delivered price of natural gas for each option.

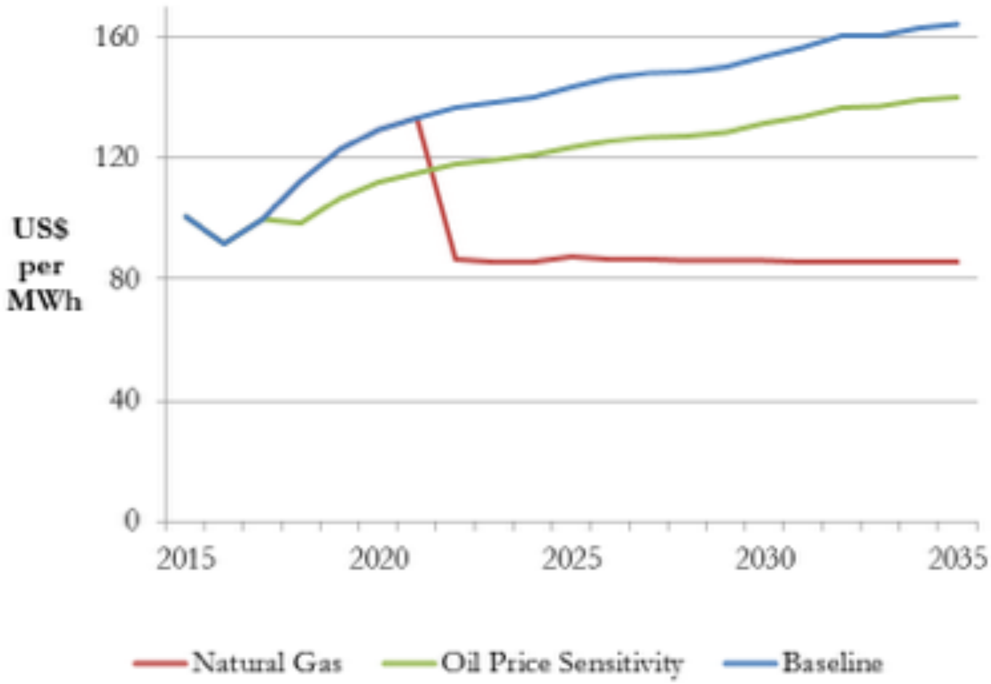
Figure 1.1: Comparison of the average cost of power generation across the three Options (US$ per MWh)



Source: Energy Narrative calculations

The analysis also showed that **natural gas may be significantly cheaper than fuel oil**. Figure 1.2 below compares the average cost of electricity supply in Guyana using natural gas landed at Clonbrook to the outlook for power generation costs based on HFO. As above, the total price of electricity includes the capital, O&M, and fuel costs. The levelized cost of capital is US$43 per MWh for the Baseline case, reflecting an investment of US$342 million through 2035 for new power generation capacity. For the natural gas option, converting GPL's current power plants to use natural gas requires an additional US$13.3 million, or 4% more than the Baseline case. This results in a levelized capital cost of US$44.67 per MWh for the natural gas case. The two options have similar O&M costs, leaving the fuel price as the main differentiator between the two.

Figure 1.2: Average cost of electricity, HFO Baseline and Oil Price Sensitivity Cases vs. Natural Gas (Clonbrook) (US$ per MWh)



Source: Energy Narrative calculations

This analysis (detailed in Section 12 below) **assumes a wellhead price of $0.00 per MMBtu**. As noted below, the actual price per MMBtu for the natural gas molecule will be negotiated between the Government of Guyana and EEPGL, and may be higher or lower than the estimated price used in this analysis.

Rising oil prices and a flat cost for natural gas increases the estimated savings for natural gas fired power generation from US$50 per MWh in 2022 to nearly US$80 per MWh in 2035. Reducing the projected oil price forecast by 20% in the Oil Price Sensitivity case still results in an expected savings of US$31 per MWh in 2022, rising to US$54 per MWh in 2035.

1.3. Strategic fit with renewable energy goals

Guyana relies on imported oil for the majority of its energy needs, including imported fuel oil for power generation. The current strategic plan states that Guyana will move closer towards 100% renewable power supply by 2025, conditional on appropriate support and adequate resources. This aspirational transition includes exploiting the country's considerable hydro power potential. While large-scale hydro power is a significant opportunity in the medium to long term, and other renewable energy sources are available in the interim, **natural gas presents a new transition fuel opportunity** that could reduce electricity costs and promote stronger economic growth. The timing and funding of hydro-electric power is uncertain, whereas the immediate need for a cheaper source of electrical power is now.

Utilizing the **natural gas fits within the proposed regional integration plans,** such as Arco Norte. Although the Arco Norte project is centered on electricity sector integration based on large-scale hydropower development, the project includes other infrastructure improvements, such as roads linking Guyana and northern Brazil and development of the deep water port at New Amsterdam. This infrastructure is complementary to Guyana's potential to develop new industries based on low cost natural gas supplies. In addition, the hydropower envisioned in the Arco Norte project is primarily oriented toward export. Substituting a portion of the forecast power generation capacity additions for natural gas (also for export) could improve the utilization of the transmission lines by smoothing out seasonal variations in hydropower output. This analysis is outside the scope of this project, but merits investigation if natural volumes are confirmed to be the higher range of 145 MMcfd (or more).

Industrial development based on **natural gas also fits within Guyana's strategy to support economic development**. Using natural gas to reduce electricity costs can spur faster economic growth as consumers spend their savings on other goods and businesses are able to lower their operating costs. Natural gas transported via trucks in the form of LNG can also replace diesel for electricity generation and other uses in the hinterland, reducing the cost of electricity and the cost to subsidize fuel deliveries in rural communities. As a low cost fuel, natural gas can also support new industrial development, including adding value to the bauxite and other raw materials currently produced in Guyana. Revenue from oil and gas development can then support investment to improve infrastructure in general, such as roads, port facilities, and utilities. Poor infrastructure was noted as a challenge to faster economic development.

Investing in power plants using **natural gas does not prevent future hydropower and renewable energy development.** Even in the slowest electricity demand growth case, the 30 MMcfd natural gas supply would not be sufficient to meet peak electricity demand. This provides space for alternative energy supply, particularly sources that can follow the demand curve such as hydro power. If the lower cost of electricity allows Guyana's economy and electricity consumption to grow more quickly than currently envisioned, additional sources of clean and low cost electricity will be needed.

2. Introduction

The Government of Guyana would like to determine the feasibility of transporting and utilizing natural gas produced offshore for electricity generation. ExxonMobil's affiliate, Esso Exploration and Production Guyana Limited (EEPGL), has discovered commercial quantities of oil and natural gas in the Stabroek block approximately 120 miles offshore Guyana. EEPGL estimates that between 30-50 million cubic feet per day (MMcfd) of natural gas can be made available for electricity generation in Guyana. Additionally, Guyana Power and Light (GPL), the state-owned electric utility, estimates that Guyana electricity demand will more than double in the coming decade.

The Government of Guyana has engaged Energy Narrative to undertake a desk study on the options, cost, economics, impacts, and key considerations of transporting and utilizing natural gas from offshore Guyana for electricity generation.

This project aims to answer one underlying question: can the natural gas produced offshore Guyana be used to reduce electricity costs? In order to address this question, three related sub-questions must be answered:

- **What are the associated costs and benefits of producing electricity with the natural gas?** The cost of producing electricity using the offshore natural gas must be lower than the current cost of producing electricity in Guyana for it to make sense to transport the natural gas to the shore. There are two key components to determine if this is true: the cost to deliver natural gas relative to the price of alternative liquid fuels (diesel and fuel oil), and the cost to convert current generating equipment to use natural gas or to replace the current capacity with new, gas-fired units.

To ensure that the cost of producing electricity with natural gas will be lower than the current cost of producing electricity, we will need to estimate the cost of transporting the natural gas to the power plants as well as test a range of prices for the natural gas at the wellhead. We will address this in Components 2, 3 and 10.

In addition, the additional cost to convert existing electricity generation equipment to use natural gas and to build new electricity generation capacity must be economically and financially feasible for the project to make sense. We will address this in Component 3, 9, and 10.

- **What are the associated technical and operational challenges?** In order for natural gas to be delivered to Guyana to fuel electricity generation, the selected transportation medium must be technically feasible at the required scale. That is, there must be proven technology for transporting the required volumes of natural gas for the required distance and at the water depths that will be encountered between the producing wells and the mainland. We will address this in Components 2, 4, 7, 8, and 11.

  In addition, the new or converted power plants must be integrated into Guyana's current electricity grid and system operations. We will address this in Components 5, 6, and 9.

- **What is the long-term strategic fit between natural gas and renewable energy and, in particular, hydro, development?** Guyana has committed to moving closer towards 100% renewable power supply by 2025, conditional on appropriate support and adequate resources. Many large hydropower projects, including those related to the Arco Norte integration with Guyana's neighbors, have been proposed as part of this transition. Using the natural gas for power generation could be an effective intermediate solution while longer-term hydropower investment plans are developed. Component 12 will review Guyana's current legal and regulatory structure to highlight potential changes that the introduction of natural gas may require.

This Final Report describes the analysis that Energy Narrative has performed to address the twelve Components of the study in order to answer these questions. The Components included in this report include:

- Component 1: Information gathering (Section 3)
- Component 2: Alternative transportation media (Section 4)
- Component 3: Veracity, cost, and option of using 30-50 MMcfd for power generation (Section 5)
- Component 4: NG pipeline risk assessment and flow analysis (Section 6)
- Component 5: Analyze submitted plans to optimize existing generation units (Section 7)

- Component 6: Analyze framework for including natural gas (Section 8)
- Component 7: Natural gas pipeline conceptual design requirements (Section 9).
- Component 8: Potential sites for proposed transportation media (Section 10)
- Component 9: Analyze power plant performance in light of NG pipeline routing (Section 11)
- Component 10: NG pipeline, Power, and Transmission cost (Section 12)
- Component 11: Pipeline requirement and conditions (Section 13)
- Component 12: Regulatory and institutional framework (Section 14)

Each component is described in detail in the sections below.

3. Component 1: Information gathering

Our first task in this assignment was to confirm our methodology and work plan with the Government of Guyana, and meet with relevant stakeholders to discuss the project objectives and review available data, analysis, and reports. During this initial information gathering trip, Jed Bailey and Jonathan Parry met with the following individuals:

- The Honorable David Patterson, MP, Minister of Public Infrastructure
- The Honorable Raphael Trotman, MP, Minister of Natural Resources
- Dr. Mahender Sharma, CEO, Guyana Energy Agency
- Mr. Renford Homer, CEO, Guyana Power and Light, Inc.
- Mr. Kenneth Jordan, Ministerial Advisor, Ministry of Public Infrastructure
- Mr. Horace Williams, CEO, Hinterland Electrification Company, Inc.
- Ms. Morsha Johnson-Francis, Electricity Regulatory Advisor, Ministry of Public Infrastructure
- Ms. Kiran Mattai, Legal Officer, Guyana Energy Agency
- Mrs. Joanna Homer, Attorney-at-Law, Legal Assistant to the Minister, Ministry of Natural Resources
- Ms. Teresa Gaime, Technical Officer, Ministry of Natural Resources

This initial information gathering ensured that our understanding of the objectives of the assignment is consistent with that of the Government of Guyana and stakeholders, and that all relevant data, analysis, and reports are identified and made available.

A project Inception Meeting was held on April 7, 2017 to set the foundation for a productive working relationship among our team, the Government of Guyana, and key stakeholders. Jed Bailey and Jonathan Parry both attended the Inception Meeting with key stakeholders from the Ministry of Public Infrastructure, as well as a separate meeting with stakeholders from the Ministry of Natural Resources. At these meetings we discussed our approach and methodology, confirmed the output delivery schedule, and discussed project logistics and data availability.

At the same time, the Government of Guyana provided access to recent reports, studies, annual reports, and data that was available and relevant to the study. We reviewed these relevant documents and available data from the Government of Guyana and other stakeholders, and have relied upon them to complete this assignment.

The feedback and insights from the information gathering trip and the Inception Meeting were summarized in a draft Inception report that was delivered to the Ministry of Public Infrastructure on April 14, 2017. The Final Inception Report was accepted by the Ministry of Public Infrastructure on April 26, 2017.

4. Component 2: Alternative transportation media (CNG/LNG)

Transporting natural gas from the production site to the end consumer is traditionally done via pipeline. New technologies, however, including liquefied natural gas (LNG) and compressed natural gas (CNG), are also being developed and deployed. Transporting natural gas via pipeline is a relatively straightforward process and has been successfully employed for decades. The technology to transport natural gas as LNG or CNG, however, continues to evolve. Recent technological advances have helped to improve efficiency and reduce the large investment in processing equipment that is required to liquefy and regasify the LNG, or to compress and de-compress the CNG. The different cost structure and characteristics of each transportation technology option create unique benefits and challenges.

The purpose of Component 2 is to provide background information on the option to use LNG or CNG to transport the natural gas, and to compare the potential benefits or risks of using the alternatives relative to the proposed natural gas pipeline. This analysis is divided into two components: using LNG or CNG to transport the natural gas from the offshore production site to the landing site in Guyana, and using LNG or CNG to transport the natural gas from the landing site to end users, such as power plants and large industrial consumers.

Specific activities and analysis within this Component include:

- reviewing the current state-of-the-art for suitable LNG and CNG technologies,
- examples of current projects at similar scale using each technology,
- identifying known benefits and risks for each technology,
- reviewing the suitability of potential placement of LNG/CNG receiving terminals relative to current and planned electricity infrastructure, and
- comparing each option relative to the proposed natural gas pipeline.

The analysis is based on publicly available data, analysis, and reports, and from Energy Narrative's experience in analyzing similar projects that incorporated alternative natural gas transportation technologies.

4.1. Offshore transportation options

This section reviews the option to use LNG or CNG to transport natural gas from the offshore production site to the Guyana mainland. Each technology brings a unique set of advantages, disadvantages, risks, and opportunities as noted below.

4.1.1. LNG technologies

Liquefied natural gas (LNG) uses cryogenics to cool natural gas to extremely low temperatures until it becomes a liquid. The liquefaction process is energy intensive, consuming as much as 10% of the natural gas to be converted, and the LNG must be kept at cryogenic temperatures to remain in a liquid state. On-shore liquefaction, LNG shipping, and on-shore regasification technologies are all mature, with more than 50 years of operational experience at the global level. Floating storage and regasification units (FSRUs) began to be employed in the past decade and there are now multiple FSRUs in operation worldwide.

Floating liquefaction (FLNG), however, is a much newer technology. According to a recent report by the Oxford Institute for Energy Studies, as of late 2016 there were seven FLNG projects in progress and expected to be completed in the coming year or two.[1] These projects are a range of scales, from the Prelude megaproject offshore Australia (3.4 million tonnes per annum), to an offshore barge proposed for Colombia scaled at 0.5 million tonnes per annum, or roughly 65 MMcfd.

Benefits of using floating LNG include:

- **Moderate flexibility to accommodate changes in scale.** Seaborne LNG can scale up as natural gas volumes increase by employing more ships, larger ships, or both. The liquefaction system's design throughput can be a limiting factor, however, and it represents the largest equipment cost in the delivery system if it needs to be upgraded.
- **High flexibility to accommodate changes in source or destination.** LNG delivery chains can be moved as needed if a particular supply source is depleted or if the natural gas is needed at a different delivery point. This flexibility is virtually unlimited, as LNG ships are a relatively small part of the delivery chain costs and can carry large volumes of natural gas for great distances. While small-scale ships like those that would be used in this application are more expensive per unit of natural gas transported than world scale ships, they are far cheaper per mile than a similar sized CNG ship.

Challenges and risks of floating LNG include:

- **High capital cost.** The capital required for liquefaction and regasification at either end of the delivery chain is high relative to compression costs. These costs do not scale linearly with size, and so smaller-scale facilities generally cost more per unit of natural gas processed than larger facilities. FLNG ship costs are speculative, given the limited number of projects underway, but range between $600-1,000 per tonne per annum of capacity. For the 30-50 MMcfd proposed for Guyana, this translates to a range of $140-380 million. The ship cost is estimated to be 60% of the total capital cost of a project, putting the total for Guyana's application in the range of $230-$600 million.
- **High operating costs.** Operating costs for seaborne LNG are also relatively high. The volume of natural gas lost in liquefaction and regasification can be more than 12%, with additional fuel required to drive the ship. As with capital costs, operating costs are somewhat speculative, but are estimated to be on the order of $1.30 per MMBtu.

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[1] *Floating Liquefaction (FLNG): Potential for Wider Deployment.* Oxford Institute of Energy Studies, November, 2016.

- **Moderate technology risk.** Because FLNG projects are only now being completed, there is limited operational experience and history. As with any new technology, unforeseen challenges may increase costs beyond current estimates.

4.1.2. CNG technologies

Compressed natural gas (CNG) uses high-pressure pumps to reduce the volume of natural gas, while leaving it in a gaseous state. This technology allows greater volumes of natural gas to be stored and shipped than at atmospheric pressure, but without the cost and technical challenges of liquefying it.

Although CNG has been used for decades on land, seaborne CNG has not. Although CNG avoids the large capital costs of liquefaction and regasification, CNG ships are expected to be more expensive (and transport less gas) than similarly sized LNG ships. Because shipping is the most expensive component for CNG, it is best suited for smaller volumes delivered over shorter distances.

Several companies have competing designs for large-scale CNG ships, most of which are essentially floating platforms for coils of high-pressure pipeline. After efforts to develop and promote CNG ships for more than a decade, the first CNG ship to be built was put into commercial operation in late 2016.

This ship was designed to carry CNG from an on-shore production facility to small demand centers within Indonesia, an optimal application for the technology given the small volume of natural gas required and the short distances between islands. However, the project did not require off-shore loading, and so this critical component of the delivery chain remains untested.

As the technology matures, costs will likely come down, but much additional investment and development is required before seaborne CNG will be as readily available as LNG.

Benefits of using floating CNG include:

- **Moderate capital cost.** The capital required for CNG compression and decompression at either end of the delivery chain is moderate relative to liquefaction and regasification. The highest cost in the value chain is the ship which can be scaled to match the required delivery volumes. Although cost estimates are highly speculative given the limited history, shipbuilders suggest a CNG ship of suitable size for Guyana would cost on the order of $210 million. Each ship would hold 3-5 days' worth of natural gas production and would operate as its own storage facility, suggesting at least 2-3 ships would be required to ensure uninterrupted gas supply.
- **Moderate operating costs.** Operating costs for seaborne CNG are expected to be lower than LNG but higher than pipeline operating costs. The volume of natural gas lost in compression and decompression is similar to that of a pipeline, with the additional fuel required to drive the ship.
- **Moderate flexibility to accommodate changes in scale.** Seaborne CNG can scale up as natural gas volumes increase by employing more ships, larger ships, or both. This flexibility comes at a cost, however, as the CNG ships are the highest cost component in the delivery chain. The compressors' design throughput can be a limiting factor, but are a relatively small part of the equipment cost if they need to be upgraded.
- **Moderate flexibility to accommodate changes in source or destination.** CNG delivery chains can be moved as needed if a particular supply source fails

or the natural gas is needed at a different delivery point. This flexibility is limited to a range of a few hundred miles, however, as greater distances would require more ships to accommodate the longer transit times. Distances over 500-700 miles are like to become uneconomic given the high cost of CNG ships relative to the volume of natural gas they can carry.

Challenges and risks of floating CNG include:

- **High technology risk.** With only one CNG ship operating, operational risks and processes remain untested. There is also a limited number of companies able to service the ships, raising the risk of extended disruptions in the event of a technical fault or accident.
- **High cost uncertainty.** The limited number of completed projects also raises uncertainty about the true cost of building and operating CNG ships. Costs for early ships will likely be higher than proposed as shipyards gain experience.

4.1.3. Recommendation

There is very high uncertainty about the capital and operating costs of both the FLNG and CNG options. While the final cost of the pipeline will require additional analysis and detailed design, rough estimates put the total capital cost at between $170-230 million. This is on par with the estimate for a single CNG ship and less than the lowest estimate for FLNG (before including the capital for a regasification terminal), and the true cost for CNG and FLNG could be more than double this lower bound.

Operational costs for a pipeline are also minimal. For most onshore pipelines, the primary operational cost comes from fuel use for compression, but this is not required for the offshore pipeline as the natural gas will enter the pipeline at high pressure already. For CNG, the operating cost will be primarily fuel and crew for the ship, as there is limited additional cost related to offloading the natural gas. For FLNG, operational costs can be significant, adding more than $1 per MMBtu to the delivered cost of the natural gas.

The technical uncertainty and the expected higher cost of FLNG and CNG outweigh the potential benefits of greater flexibility. Therefore, **a pipeline is the recommended option to bring the natural gas to shore**.

Ownership of the natural gas pipeline is an important strategic decision. If the Liza field remains the only hydrocarbon development in Guyana's offshore, pipeline operations will remain closely tied with the field's development. If, however, further hydrocarbon resources are discovered and developed, and if the pipeline is sufficiently scaled to accommodate the additional production volumes, it could become an important midstream asset for multiple producers and downstream consumers. Determining the commercial structure and appropriate guarantees and requirements for the pipeline owner, operator, and users becomes critical.

Public-private partnerships (PPP) have been used in many countries to balance these needs as well as the complexities of financing and environmental and social impact mitigation. PPP projects have many different forms, with private sector involvement ranging from fixed deliverable contracts to long-term concessions and ownership of the assets. PPP projects can be complex, however, and must be tailored to the specific circumstances of the country and project in question. **Further analysis is needed to identify potential PPP options and suitable commercial and regulatory structures for the offshore pipeline**.

4.2. Onshore transportation options

This section reviews the option to use LNG or CNG to transport the natural gas once it has reached the Guyana mainland. On-shore CNG and small-scale LNG—including intermodal "containerized" transportation units that can be carried by ship, rail, or truck—are technically mature. These technologies are deployed worldwide to supply natural gas to isolated demand sites or manage peak demand loads for pipelines operating at full capacity. As such, these technologies could be viable alternatives to distribute natural gas to individual power plants, industrial sites, or other end consumers once the natural gas is landed.

Each technology brings a unique set of advantages, disadvantages, risks, and opportunities as described in greater detail below.

4.2.1. LNG technologies

Liquefied natural gas (LNG) uses cryogenics to cool natural gas to extremely low temperatures until it becomes a liquid. The liquefaction process is energy intensive, consuming as much as 10% of the natural gas to be converted, and the LNG must be kept at cryogenic temperatures to remain in a liquid state. On-shore liquefaction, LNG shipping, and on-shore regasification technologies are all mature, with more than 50 years of operational experience at the global level.

The recent surge of low cost gas supply in the United States, combined with tightening environmental regulations for marine emissions, have boosted investment and interest in LNG for transportation and marine use. In addition, smaller scale liquefaction and regasification plants have been developed in the United States and elsewhere to meet peak demand for natural gas in areas with pipelines operating at maximum capacity or to extend natural gas supply to areas not served by pipelines. Small scale LNG transportation and storage options, including containerized LNG, bullet tanks, and LNG barges, are all increasingly used worldwide.

Benefits of using LNG to transport the natural gas once it is landed include:

- **High flexibility to accommodate changes in scale.** Small scale LNG systems are highly modular, allowing them to be expanded in relatively small increments to meet growing demand. This flexibility reduces the need for very large initial capital commitments and allows the LNG systems to more closely track actual demand growth.
- **High flexibility to accommodate changes in destination.** LNG delivery chains can be moved as needed if a particular supply source is depleted or if the natural gas is needed at a different delivery point. This flexibility is virtually unlimited, as LNG trucks, barges, and ships are a relatively small part of the delivery chain costs.
- **Faster implementation.** LNG facilities are concentrated in single point locations—either the liquefaction facility at the point of supply, or the regasification facility at the point of consumption. This removes a major obstacle and frequent cause of delays in pipeline construction: the need to secure extensive rights-of-ways, relevant construction and environmental permits, and conduct related environmental and social impact studies.

- **Reduced disruption during construction.** The single-point nature of LNG infrastructure also avoids the disruption of traffic or other land uses that often results from pipeline construction along roads or through privately held land.
- **Moderate volume per truck or barge.** A standard 40 foot containerized LNG tank suitable for transportation via truck or rail contains the equivalent of 1,500 cubic feet of natural gas. This is the equivalent of roughly 130 MWh of electricity production from a reciprocating engine similar to those modeled for Guyana's future generation capacity additions. A 200 cubic meter barge would hold sufficient natural gas to provide just over 600 MWh of electricity, while a 1,000 cubic meter barge could fuel just over 3,000 MWh. To put this in perspective, an 11.4 MW power plant (the size expected to be added each year to meet Guyana's incremental electricity needs), would consume the LNG from a tanker truck in 11 hours, a 200 cubic meter barge in 54 hours, and from a 1,000 cubic meter barge in just over 11 days of continuous operation. This makes containerized LNG an attractive option to deliver natural gas to small, remote locations (such as hinterland communities or small commercial and industrial customers), but unsuitable for Guyana's existing main power stations.

Challenges and risks of LNG include:

- **High capital cost.** The capital required for liquefaction and regasification at either end of the delivery chain is high relative to compression costs for CNG and the capital cost of pipelines. These costs do not scale linearly with size, and so smaller-scale facilities generally cost more per unit of natural gas processed than larger facilities. Satellite LNG stations at a suitable scale for Guyana's application are estimated to be on the order of $2,000 per tonne per annum of capacity. For the 30 MMcfd proposed for Guyana, this translates to a cost of $228 million. LNG tanker trucks are estimated to cost US$500,000 each.
- **High operating costs.** Operating costs for LNG are also relatively high. The volume of natural gas lost in liquefaction and regasification can be more than 12%, with additional fuel required to transport the LNG via truck or barge. As with capital costs, operating costs are somewhat speculative, but are estimated to be on the order of 2% of the capital cost for liquefaction, roughly US$0.50 per MMBtu for transportation by truck, and a further US$1.00-$1.30 per MMBtu for regassification.
- **Higher operating complexity.** LNG truck and barge operators, as well as the facility operators at both the supply and consumption ends, must be trained to handle cryogenic liquids such as LNG. In addition, road and sea safety protocols and emergency responses must be implemented to ensure the LNG can be transported safely and the effects of any accident during transportation is mitigated. This is particularly important when transporting LNG in densely populated areas.

4.2.2. CNG technologies

Compressed natural gas (CNG) uses high-pressure pumps to reduce the volume of natural gas, while leaving it in a gaseous state. This technology allows greater volumes of natural gas to be stored and shipped than at atmospheric pressure, but without the cost and technical challenges of liquefying it.

CNG has been used for decades on land and is considered a mature technology. CNG avoids the large capital costs of liquefaction and regasification, but CNG tanker trucks and barges have much smaller capacity than similarly sized LNG trucks and barges.

Benefits of using CNG to transport natural gas onshore include:

- **Moderate capital cost.** The capital required for CNG compression and decompression at either end of the delivery chain is moderate relative to liquefaction and regasification. CNG trucks and barges are of a similar cost to LNG trucks and barges.
- **Moderate operating costs.** Operating costs for land-based CNG are higher than pipeline operating costs, given the greater fuel use and greater number of employees required to move the CNG via truck or barge. The volume of natural gas lost in compression and decompression is similar to that of a pipeline, with the additional fuel required to drive the truck or barge.
- **High flexibility to accommodate changes in scale.** CNG facilities, like LNG facilities noted above, can scale up as natural gas volumes increase.
- **High flexibility to accommodate changes in destination.** CNG delivery chains can be moved as needed if a particular supply source fails or the natural gas is needed at a different delivery point. This flexibility is more limited than LNG, however, as the volume of natural gas carried by each CNG truck or barge is less than a similarly sized LNG transport. As a result, more trucks or vessels are needed to move a similar volume of natural gas, making longer distances less economic.

Challenges and risks of CNG include:

- **Limited volume per truck or barge.** Each CNG truck or barge holds roughly one-third of the natural gas as a similarly sized LNG transport. As noted above, this volume limitation can limit the size of consumer that can be economically served and limits the distance that the CNG can be economically transported. This volume limitation makes CNG trucks unsuitable for power generation except for the very smallest of Guyana's isolated systems. For example, a 0.5 MW generator would require a 40 foot CNG container for every three and a half days. A 5 MW power plant would require one every 8 hours.
- **Moderate operating complexity.** Filling and offloading CNG trucks and barges requires specialized training, although they may be less complex to operate than LNG vessels.

4.2.3. Recommendation

A pipeline is by far the most economical option to transport natural gas onshore, averaging US$1.00-5.00 per MMBtu, assuming no additional costs are required to obtain land or rights-of-way for the pipeline path. It is also the most challenging to implement given the need to negotiate the required rights-of-way, and the potential for construction disruptions and delays.

A satellite LNG liquefaction station, coupled with distribution via truck or barge, could be simpler and faster to implement, but would also be more expensive. As the option to review on-shore LNG was added at the very end of the study period, there was insufficient time to analyze specific costs for such an LNG delivery chain, but global experience and "rule of thumb" numbers suggest a cost on the order of $8-11 per MMBtu to deliver natural gas via small-scale LNG. This cost estimate would need to be assessed in greater detail, but gives an order of magnitude sense of the relative increase in costs to use LNG instead of a pipeline.

CNG would not be to supply the volume of natural gas needed for any except the smallest of Guyana's power plants, and so is not viable for this application. CNG could be used for local applications, including fleet vehicles or industrial uses.

Therefore, **a pipeline is the most technically economic option to transport the natural gas once it is on shore, but also the most difficult to implement**. **LNG barges and trucks are a viable alternative, trading higher cost for simpler and more rapid implementation.** CNG is not viable for larger end users, such as power plants, but may be useful for vehicle fleets or other localized uses.

Further analysis on small-scale LNG to is needed to better ascertain the likely cost to distribute natural gas as LNG to GPL's main power generation facilities and other large consumers. Additional analysis could also identify customers and locations outside of GPL's main generation facilities that could bring additional volumes of viable natural gas demand in Guyana.

5. Component 3: Veracity of using 30-50 MMcfd for power generation

The purpose of Component 3 is to verify that there will be an adequate demand for natural gas for electricity generation to support the project and to ensure that the proposed timing for converting electricity generation equipment to use natural gas or investment in new electricity generation capacity is compatible with the proposed timing of the natural gas supply availability. Specific activities and analysis includes:

- Confirming the available volume of natural gas
- reviewing GPL's current electricity generation assets,
- reviewing GPL forecasts for electricity demand growth,
- reviewing future electricity generation capacity additions and potential to convert existing capacity to use natural gas,

The analysis is based on available data, analysis, and reports on electricity demand growth and future investment projections of new or converted natural-gas-fired electricity generation capacity provided by GPL and the Government of Guyana.

5.1. Available volume of natural gas

The original terms of reference for this report suggested that between 30 and 50 MMcfd of natural gas could be made available for use in Guyana for a period of 15-20 years, starting in 2020. Through our initial data gathering discussions with the Government of Guyana, and in later information provided by EEPGL, the range of potentially available natural gas was suggested to be 30 MMcfd at the lower bound and potentially as much as 145 MMcfd at the upper bound. EEPGL proposed these two volumes for the possible sizes for the natural gas pipeline to shore. This natural gas would be available for power generation January 1, 2022 under EEPGL's latest proposed planning, preparation, and construction schedule.

EEPGL also provided an initial assessment of the composition of the natural gas produced from the Liza Destiny FPSO. As shown in Table 5.1 below, the gas is primarily methane and ethane (86.4% mole fraction), with significant volumes of propane, butane, and heavier condensates (12.4% mole fraction), and only small amounts of CO2 (0.8% mole fraction) and nitrogen (0.4% mole fraction).

Table 5.1: Liza Destiny FPSO natural gas composition

		Component Heat Content	Volume of each Component Produced (MMcfd)		
Component	Mol fraction	(MMBtu/MMcf)	30 MMcfd	50 MMcfd	145 MMcfd
Methane	79.1%	1,011	23.73	39.55	114.70
Ethane	7.3%	1,783	2.19	3.65	10.59
Propane	6.7%	2,572	2.01	3.35	9.72
i-Butane	1.0%	3,259	0.30	0.50	1.45
n-Butane	2.8%	3,262	0.84	1.40	4.06
Condensate (C5+)	1.9%	4,000	0.57	0.95	2.76
Water	0.0%	0	0.00	0.00	0.00
CO2	0.8%	0	0.24	0.40	1.16
H2S	0.0%	672	0.00	0.00	0.00
Nitrogen	0.4%	0	0.12	0.20	0.58
Total	**100.0%**	**1,302**	**30**	**50.00**	**145**
NG stream	**87.6%**	**1,169**	**26.3**	**43.8**	**127.0**
(including Methane, Ethane, CO2 and Nitrogen)					
LPG Stream	**12.4%**	**3,507**	**3.7**	**6.2**	**18.0**
(including Propane, i-Butane, n-Butane, Condensate (C5+))					
	barrels of liquid LPG per day		2,435	4,058	11,767
	barrels of liquid LPG per year		888,636	1,481,060	4,295,073

Source: EEPGL as reported to the Government of Guyana

The gas composition as reported has an average heat content of 1,302 Btu per cubic foot. This is roughly 25% above standard pipeline specifications for natural gas in the United States (where pipeline gas is roughly 1,035 Btu per cubic foot), but still suitable for use in reciprocating engines for power generation (which are generally able to handle a wide range of fuel inputs, including liquid fuels, such as diesel, and LPG) or most industrial applications. The reported levels of CO2 and nitrogen are also within typical ranges for use in power generation, and so no additional treatment is needed to remove impurities from the gas stream.

If the ethane is left in the natural gas stream, but the propane, butanes, and heavier condensates are separated out and sold as LPG once the natural gas reaches the shore, the heat content would be reduced to 1,169 as shown in the "NG stream" line in the table above. This is still roughly 13% higher than is typical for pipeline gas in the U.S., but well within the tolerance range for most end uses.

Separating the LPG stream would reduce the volume of delivered natural gas by 12.4%, such that 30 MMcfd of wet gas delivered to the shore would produce 26.3 MMcfd of dry gas and 3.7 MMcfd of gaseous LPG. At the higher end, a 145 MMcfd supply of wet gas would result in 127 MMcfd of dry gas and 18 MMcfd of gaseous LPG.

Converting the LPG stream to the equivalent in liquid barrels (that is, pressurized until becomes liquid for storage and transportation), results in just over 2,400 barrels of LPG per day, or nearly 890,000 barrels of LPG per year. This is significantly higher than Guyana's current estimated LPG consumption of roughly 200,000 barrels per year, suggesting that the LPG supplied from the natural gas stream could replace all current LPG imports and also support additional new uses. Under the higher natural gas supply range, LPG production could nearly 11,800 barrels per day, or almost 4.3 million barrels per year – more than 20x current consumption levels.

5.2. GPL current power generation assets

GPL provides electricity to the coastal regions where the majority of Guyana's population and economic activity is located. The main demand center outside of the GPL system is Linden which is served by an 18MW power plant owned by the Bosai Bauxite Company (which also uses the plant for its mining operations). Other demand centers are small communities which generally have less than 1 MW of demand. Linden and other communities in the hinterland are served by local power companies that are collectively owned by the Government of Guyana through National Industrial and Commercial Investments Limited.

Table 5.1 below describes GPL's main electricity generation assets that are currently in operation serving the Demerara-Berbice interconnected system (DBIS). All assets listed below are owned by GPL, with the exception of the Skeldon-Guysuco units which are owned and operated by Skeldon Energy Inc. (SEI), also a state-owned company. SEI receives bagasse as fuel for the power station from the Guyana Sugar Company (GuySuCo) and provides electricity to GuySuCo and to GPL under a power purchase agreement.

In addition to the units listed below, GPL also operates smaller isolated reciprocating engines in Guyana's Essequibo region to the west of Georgetown. These units range from 0.3-5.4MW each and serve communities at Anna Regina, Leguan Island, Wakenaam Island, and Bartica that are not connected to the main DBIS.

Table 5.1: GPL current power generation units

	GPL Current Power plants - Demerara-Berbice Interconnect								
Name	**Demerara Power 1**	**Garden of Eden**	**Demerara Power 2**	**Demerara Power 3**	**Vreed-En-Hoop**	**Canefield-Corentyne - 1**	**Canefield-Corentyne - 2**	**Skeldon-Guysuco - 1**	**Skeldon - Guysuco - 2**
Location	East Bank Demerara	East Bank Demerara	Georgetown	Georgetown	West Coast Demerara	Berbice	Berbice	Berbice	Berbice
Available Capacity (MW)	22.0	16.6	22.0	36.3	26.2	4.5	5.6	10.0	30.0
Technology	Wartsilla Generators	Mobile Cat Sets	Wartsilla Generators	Wartsilla Generators	Wartsilla Generators	Mirrlees Blackstone Generators	Mobile Cat Sets	Wartsilla Generators	Gas Turbines
Commissioning Date	1994		1997	2009 / 2011	2014	1976	2011	2007	
Current fuel	HFO	LFO	HFO	HFO	HFO	HFO	LFO	HFO	Bagasse
Fuel Consumption (Gal/MWh)	51.1	61.9	50.1	44.8	50.1	50.3	61.9	50.3	
Calculated Heat Rate (Btu/kWh)	7865	9161	7515	6720	7515	7546	9161	7546	
Reported Heat Rate	9363	10371	9170	8200	8200	9400	10371	9400	
Availability Rate (%)	94%	98%	94%	98%	94%	72%	93%	67%	

Source: Guyana's Power Generation System Expansion Study, 2016.

All of GPL's listed generation units are reciprocating engines, burning either heavy fuel oil (HFO) or light fuel oil (LFO), with the exception of Skeldon-Guysuco 2 which consists of two 15 MW gas turbines fueled by sugarcane bagasse. As such, virtually all of GPL's current installed capacity is suitable to be converted to use natural gas as a fuel.

The current engines are a mix of new installations (within the past 10 years) and much older units ranging from 20-40 years old. While newer units could be adapted to become dual fuel (natural gas and HFO), it is likely more cost effective to replace units that are more than 30 years old.

5.3. GPL forecast electricity demand growth

The amount of natural gas consumed for electricity generation will depend on the amount of current capacity that is converted to use natural gas, the amount of new natural-gas-fired capacity that is added, and the total electricity demand being served. This section reviews the forecast for Guyana's electricity demand growth through 2035.

The 2016 report "Guyana's Power Generation System Expansion Study" performed a detailed econometric study to forecast Guyana's electricity demand growth, reviewed previous demand forecasts to calibrate their results, and examined the potential for lower cost electricity to bring self-generators back to GPL's service.

The study's build-up of the total load to be served by GPL's generators under the Base Case forecast is shown in Table 5.2 below. Annual organic demand growth is forecast to slow from nearly 5% today to 3.6% by 2035. The original study assumed 100% of self-generation load would return to GPL as electricity prices decline. This transition was estimated to occur over four years starting in 2022, with 25% of the total self-generation load switching to GPL per year. For this analysis, a similar conversion was assumed, beginning in 2022 when electricity prices are expected to decline with the arrival of natural gas.

The study also assumed that the Linden system would be integrated into the DBIS by 2022. We have maintained that assumption and also assumed that the Essequibo systems would also be integrated at that time[2]. The study also assumes steady progress in reducing technical and non-technical losses, a share of which are assumed to be converted into sales.

Table 5.2: Guyana Base Case electricity demand forecast

[2] The expansion study removed Essequibo demand from GPL's total reported demand as shown in the table. The study also noted a proposed new transmission line to link the Essequibo region with a new substation at Parika, but the demand from the region was not added into the forecast for DBIS in any of the demand cases. We have included Essequibo demand

	Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Total Electricity Sales	**GWh**	**493.6**	**521.2**	**545.2**	**571.9**	**599.4**	**622.2**	**645.8**	**670.3**	**695.6**	**721.8**	**749.0**	**777.1**	**929.8**	**1108.4**
Rate of Growth	%	3.7%	5.6%	4.6%	4.9%	4.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.7%	3.6%
New Load - Self-Generation	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	57.7	119.7	186.3	257.8	308.5	367.7
Losses converted into Sales	GWh			0.2	2.5	4.7	6.6	6.9	8	9.3	10.6	11.9	13.2	21.8	33.1
Sales from Essequibo region	GWh	-25.9	-28.2	-29.5	-30.9	-32.4	-33.6	-34.9	-36.3	-34.9	-33.5	-32.0	-42.0	-50.2	-59.9
Essequibo Interconnection	GWh									34.875	33.45	32.025	42	50.2	59.9
Total Sales DBIS	**GWh**	**467.7**	**493.0**	**515.9**	**543.5**	**571.7**	**595.2**	**617.8**	**642.0**	**762.6**	**852.2**	**947.2**	**1046.1**	**1260.1**	**1509.2**
Total Losses	**%**	**29.8%**	**28.7%**	**28.6%**	**27.6%**	**26.6%**	**26.1%**	**26.1%**	**25.4%**	**25.4%**	**25.4%**	**25.4%**	**23.1%**	**20.1%**	**17.1%**
Technical	%	14.0%	14.6%	14.6%	14.4%	14.1%	14.1%	14.1%	13.7%	13.7%	13.7%	13.7%	12.4%	10.7%	9.0%
Non Technical	%	15.8%	14.1%	14.0%	13.2%	12.5%	12.0%	12.0%	11.7%	11.7%	11.7%	11.7%	10.7%	9.4%	8.1%
Net Exported Units	**GWh**	**664.3**	**691.5**	**722.6**	**750.7**	**778.9**	**805.4**	**836.0**	**860.6**	**1022.3**	**1142.3**	**1269.7**	**1362.9**	**1577.1**	**1820.5**
Auxiliaries & Self-consumption	GWh	20.8	19.8	20.3	20.1	20.2	20.1	20.1	20.1	21.1	22.1	23.1	20.1	20.1	20.1
Gross Generation	**GWh**	**685.1**	**711.3**	**742.9**	**770.8**	**799.1**	**825.5**	**856.1**	**880.7**	**1043.4**	**1164.4**	**1292.8**	**1383.0**	**1597.2**	**1840.6**
Unserved Energy	GWh	13.0	10.0	10.4	10.8	11.2	11.6	12.0	12.3	14.6	16.3	18.1	19.4	22.4	25.8
Unserved Energy	%	1.9%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
Electricity Demand w/o Linden	GWh	**698.2**	**721.3**	**753.3**	**781.6**	**810.3**	**837.0**	**868.1**	**893.0**	**1058.0**	**1180.7**	**1310.9**	**1402.3**	**1619.6**	**1866.3**
Linden Interconnection	GWh									138.6	139.6	140.6	157.9	176.6	194
Electricity Demand	**GWh**	**698.2**	**721.3**	**753.3**	**781.6**	**810.3**	**837.0**	**868.1**	**893.0**	**1196.6**	**1320.3**	**1451.5**	**1560.2**	**1796.2**	**2060.3**
Load Factor	%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%
Maximum Demand	**MW**		**110.2**	**115.1**	**119.4**	**123.8**	**127.9**	**132.7**	**136.5**	**182.9**	**201.8**	**221.8**	**238.4**	**274.5**	**314.9**

Source: Guyana's Power Generation System Expansion Study, 2016.

The Base Case forecast results in the total load served by GPL rising from just under 700 MWh in 2014 to just over 2,000 MWh in 2035. Peak demand also roughly triples in the period. This strong growth in demand implies a significant need for new power generation capacity over the period, relative to the current installed system.

The Study included High and Low demand cases which are shown in Table 5.3 and 5.4, respectively. The High Case assumes electricity demand growth remains above 4.5% throughout the study period, resulting in total load for GPL reaching 2,400 GWh in 2035, roughly 20% higher than in the Base Case. Peak demand in the High Case reaches nearly 370 MW, roughly 50 MW higher than the Base Case.

Table 5.3: Guyana High Case electricity demand forecast

	Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Total Electricity Sales	**GWh**	**493.6**	**521.2**	**548.9**	**576.3**	**605.7**	**630.5**	**655.8**	**688.5**	**722.6**	**759.0**	**794.7**	**832.7**	**1050.2**	**1317.1**
Rate of Growth	%	3.7%	5.6%	5.3%	5.0%	5.1%	4.1%	4.0%	5.0%	5.0%	4.9%	4.8%	4.8%	4.8%	4.8%
New Load - Self-Generation	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	59.3	124.4	195.7	273.4	344.7	432.4
Losses converted into Sales	GWh			0.2	2.5	4.8	6.7	6.9	8.2	9.7	11.2	12.7	14.2	24.6	39.4
Sales from Essequibo	GWh	-25.9	-28.2	-29.6	-31.1	-32.7	-34	-35.4	-37.2	-36.3	-33.3	-31.4	-45.0	-56.7	-71.2
Essequibo interconnectino										35.25	33.3	31.35	45	56.7	71.2
Total Sales DBIS	**GWh**	**467.7**	**493.0**	**519.5**	**547.7**	**577.8**	**603.2**	**627.3**	**659.5**	**791.6**	**893.7**	**1033.1**	**1120.3**	**1419.5**	**1788.9**
Total Losses	**%**	**29.8%**	**28.7%**	**28.6%**	**27.6%**	**26.6%**	**26.1%**	**26.1%**	**25.4%**	**25.4%**	**25.4%**	**25.4%**	**23.1%**	**20.1%**	**17.1%**
Technical	%	14.0%	14.6%	14.6%	14.4%	14.1%	14.1%	14.1%	13.7%	13.7%	13.7%	13.7%	12.4%	10.7%	9.0%
Non Technical	%	15.8%	14.1%	14.0%	13.2%	12.5%	12.0%	12.0%	11.7%	11.7%	11.7%	11.7%	10.7%	9.4%	8.1%
Net Exported Units	**GWh**	**664.3**	**691.5**	**727.5**	**756.5**	**787.2**	**816.3**	**848.8**	**884.1**	**1061.2**	**1197.9**	**1344.6**	**1456.8**	**1775.6**	**2157.9**
Auxiliaries & Self-consumption	GWh	20.8	19.8	20.3	20.1	20.2	20.1	20.1	20.1	21.1	22.1	23.1	20.1	20.1	20.1
Gross Generation	**GWh**	**685.1**	**711.3**	**747.8**	**776.6**	**807.4**	**836.4**	**868.9**	**904.2**	**1082.3**	**1220.0**	**1367.7**	**1476.9**	**1796.7**	**2178.0**
Unserved Energy	GWh	13.0	10.0	10.5	10.9	11.3	11.7	12.2	12.7	15.2	17.1	19.1	20.7	25.2	30.5
Unserved Energy	%	1.9%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
Electricity Demand w/o Linden	GWh	**698.2**	**721.3**	**758.3**	**787.5**	**818.7**	**848.1**	**881.1**	**916.9**	**1097.4**	**1237.1**	**1386.9**	**1497.6**	**1821.9**	**2208.5**
Linden Interconnection	GWh									138.6	139.6	140.6	157.9	176.6	194
Electricity Demand	**GWh**	**698.2**	**721.3**	**758.3**	**787.5**	**818.7**	**848.1**	**881.1**	**916.9**	**1236.0**	**1376.7**	**1527.5**	**1655.5**	**1998.5**	**2402.5**
Load Factor	%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%
Maximum Demand	**MW**		**110.2**	**115.9**	**120.3**	**125.1**	**129.6**	**134.6**	**140.1**	**188.9**	**210.4**	**233.4**	**253.0**	**305.4**	**367.1**

Source: Guyana's Power Generation System Expansion Study, 2016.

Electricity demand growth in the Low Case slows to 2.5% per year by 2035, resulting in GPL serving a total load of 1,780 GWh by the end of the period, roughly 1,100 GWh higher than in 2014. Peak demand in the Low Case reaches just over 270 MW by 2035.

Table 5.4: Guyana Low Case electricity demand forecast

	Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Total Electricity Sales	GWh	493.6	521.2	541.6	568.1	594.2	615.6	637.8	654.4	671.4	688.7	706.6	724.9	822.1	930.5
Rate of Growth	%	3.7%	5.6%	3.9%	4.9%	4.6%	3.6%	3.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.5%
New Load - Self-Generation	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.2	115.2	177.3	242.5	275.1	311.3
Losses converted into Sales	GWh			0.2	2.5	4.7	6.5	6.8	7.8	8.9	10.1	11.2	12.3	19.3	39.4
Sales from Essequibo region	GWh	-25.9	-28.2	-29.3	-30.7	-32.1	-33.3	-34.4	-36.3	-34.3	-33.4	-32.4	-39.2	-44.4	-50.3
Essequibo interconnection	GWh								36.3	34.325	33.35	32.375	39.2	44.4	50.3
Total Sales DBIS	GWh	467.7	493.0	512.5	539.9	566.8	588.8	610.2	662.2	736.4	814.0	895.1	979.7	1115.5	1281.2
Total Losses	%	29.6%	28.7%	28.6%	27.8%	26.6%	26.1%	26.1%	25.4%	25.4%	25.4%	25.4%	23.1%	20.1%	17.1%
Technical	%	14.0%	14.6%	14.6%	14.4%	14.1%	14.1%	14.1%	13.7%	13.7%	13.7%	13.7%	12.4%	10.7%	9.0%
Non Technical	%	15.6%	14.1%	14.0%	13.2%	12.5%	12.0%	12.0%	11.7%	11.7%	11.7%	11.7%	10.7%	9.4%	8.1%
Net Exported Units	GWh	664.3	691.5	717.7	745.7	772.3	796.8	825.7	887.6	987.2	1091.2	1199.8	1274.0	1397.4	1545.5
Auxiliaries & Self-consumption	GWh	20.8	19.8	20.3	20.1	20.2	20.1	20.1	20.1	21.1	22.1	23.1	20.1	20.1	20.1
Gross Generation	GWh	685.1	711.3	738.0	765.8	792.5	816.9	845.8	907.7	1008.3	1113.3	1222.9	1294.1	1417.5	1565.6
Unserved Energy	GWh	13.0	10.0	10.3	10.7	11.1	11.4	11.8	12.7	14.1	15.6	17.1	18.1	19.8	21.9
Unserved Energy	%	1.9%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
Electricity Demand w/o Linden	GWh	698.2	721.3	748.4	775.5	803.6	828.3	857.6	920.4	1022.4	1128.9	1240.1	1312.3	1437.4	1587.5
Linden Interconnection	GWh									138.6	139.6	140.6	157.9	176.6	194
Electricity Demand	GWh	698.2	721.3	748.4	775.5	803.6	828.3	857.6	920.4	1161.0	1268.5	1380.7	1470.2	1614.0	1781.5
Load Factor	%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%	74.7%
Maximum Demand	MW		110.2	114.4	118.7	122.8	126.6	131.1	140.7	177.4	193.8	211.0	224.7	246.6	272.2

Source: Guyana's Power Generation System Expansion Study, 2016.

5.4. GPL forecast new electricity generation capacity additions

The expansion study examined six alternative combinations of electricity generation technologies for new capacity additions to serve Guyana's growing electricity needs. Of the six, two are presented here: the selected Optimal alternative and Alternative 1, which considered adding only new engines.

Table 5.5 below shows GPL's currently operating units and the proposed new capacity additions and technology choices under the Optimal expansion plan. The plan is centered on a major new hydro plant (estimated to be 150-180 MW, shown as 160 MW here) in 2021. Other renewable energy technologies include wind, solar, biomass (wood residue), and bagasse. Only three new engines are added in this plan: 2x8.7 MW HFO units in 2017, 2x11.4 MW LFO units in 2018, and 3x11.4 natural gas units by 2035.

Table 5.5: Guyana Optimal capacity expansion plan

Capacity	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Demerara Power 1	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Garden of Eden	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Demerara Power 2	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Demerara Power 3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3
Vreed-En-Hoop	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2
Canefield-Corentyne - 1	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Canefield-Corentyne - 2	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Skeldon-Guysuco - 1	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Skeldon-Guysuco - 2	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
New HFO Engine				17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
New Wind				26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
New LFO Engine					22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8
New Solar					3.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
New Wood Residue						0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
New Hydro								160.0	160.0	160.0	160.0	160.0	160.0	160.0
New Bagasse												9.8	9.8	9.8
New Bagasse													5.7	5.7
New NG Engine														34.2
Total Available Capacity	173.2	173.2	173.2	216.6	242.4	246.1	246.1	406.1	406.1	406.1	406.1	415.9	421.6	455.8

Source: Guyana's Power Generation System Expansion Study, 2016.

The Alternative 1 plan is based on adding HFO engines in groups of 2x11.4 MW units as needed to keep pace with electricity demand growth. As shown in Table 5.6 below, engines are added in 2018, 2021, 2022, 2023, 2024, and 2025, with two more sets added between 2025 and 2030 and again between 2030 and 2035. In the expansion study, these engines are assumed to use liquid fuels until natural gas is available in 2031.

Table 5.6: Guyana Alternative 1 capacity expansion plan (engines only)

Capacity	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Demerara Power 1	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Garden of Eden	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Demerara Power 2	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Demerara Power 3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3
Vreed-En-Hoop	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2
Canefield-Corentyne - 1	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Canefield-Corentyne - 2	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Skeldon-Guysuco - 1	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Skeldon-Guysuco - 2	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
New HFO Engine					22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8
New HFO Engine								22.8	22.8	22.8	22.8	22.8	22.8	22.8
New HFO Engine									22.8	22.8	22.8	22.8	22.8	22.8
New HFO Engine										22.8	22.8	22.8	22.8	22.8
New LFO Engine											22.8	22.8	22.8	22.8
New HFO Engine												22.8	22.8	22.8
New HFO Engine													22.8	22.8
New HFO Engine													22.8	22.8
New HFO Engine														22.8
New HFO Engine														22.8
Total Available Capacity	**173.2**	**173.2**	**173.2**	**173.2**	**196.0**	**196.0**	**196.0**	**218.8**	**241.6**	**264.4**	**287.2**	**310.0**	**355.6**	**401.2**

Source: Guyana's Power Generation System Expansion Study, 2016.

The Alternative 1 plan adds less new capacity than the Optimal plan (228 MW added over 2017 levels compared to 282.6 MW of new capacity in the Optimal plan). The Optimal plan includes a higher capacity margin owing to the intermittent availability of wind and solar, and lower availability of hydro power.

5.5. Implications for natural gas demand

The amount of electricity that can be supplied by 26.3 MMcfd of natural gas depends on the efficiency of the power plants that are burning it. Using the 8,000 Btu/kWh heat rate of the theoretical reciprocating engine from the GPL 2016 expansion study, 26.3 MMcfd of natural gas (with heat content of 1,169 Btu per cubic foot as noted in section 5.1 above) would generate 160 MW of continuous electricity supply. This is less than the 182.9 MW peak demand expected in 2022 (when natural gas is first available), but more than the average electricity demand of 136.6 MW (and likely much more than the minimum electricity demand).

This implies that even if 100% of Guyana's electricity supply were able to be generated from natural gas, there would be periods of high electricity demand that would require liquid fuels to supplement the natural gas supply and there would also be periods in which more natural gas was available than was required for electricity generation.

The actual volume of natural gas consumed for electricity generation in Guyana will be determined by the total electricity demand and the total share of installed generation capacity fueled by natural gas. The Optimal plan noted above would result in lower natural gas consumption than the Alternative 1 plan, owing to the addition of significant hydro power capacity and other renewable energy technologies.

In order to establish the maximum potential demand for natural gas for electricity generation, Table 5.7 shows the natural gas required to serve the forecast electricity demand under the three demand cases assuming 100% of electricity supply was fueled by natural gas. The calculated natural gas demand assumes that the hypothetical natural gas burning units have an efficiency rating similar to Guyana's current new engines.

Table 5.7: Guyana theoretical natural gas volumes required to serve entire electricity generation demand (MMscfd)

	2022	2023	2024	2025	2030	2035
Low Demand	23.7	25.9	28.2	30.0	32.9	36.4
Base Case	24.4	27.0	29.6	31.8	36.7	42.1
High Demand	25.2	28.1	31.2	33.8	40.8	49.0

Source: Consultant estimations based on electricity demand forecasts in Guyana's Power Generation System Expansion Study, 2016

The estimated maximum demand for natural gas is 25.2 MMcfd in the first year that the gas would be available. Even under the low demand case, natural gas demand would surpass the minimum available supply of 26.3 MMcfd (based on the 30 MMcfd supply projection after removing the natural gas liquids—see section 5.1 above) by 2024. This clearly demonstrates that there is sufficient demand for natural gas in Guyana's power sector to support the 30 MMcfd pipeline. The maximum natural gas demand under the three cases ranges between 36 and 49 MMcfd by 2035.

It is important to note that this is a theoretical maximum that assumes all electricity is generated with natural gas and natural gas supply can be modulated to match the electricity demand curve (through storage or line pack). The actual conversion of older units may take time and may not reach 100%, depending on the feasibility of suppling natural gas to each location. This could, in turn, delay the pace of natural gas demand growth, reduce the share of electricity generation fired with natural gas, and, ultimately, reduce the total demand for natural gas. This more detailed analysis is covered in section 7 (Optimizing existing generation units), section 8 (Framework for including natural gas), and section 12 (Natural gas pipeline and power costs).

This analysis also assumes there is no additional source for natural gas demand, or new additional electricity demand, as a result of the availability of natural gas. New industrial facilities that are built specifically to take advantage of the available natural gas volumes would add to this total. Higher economic growth and higher electricity consumption as a result of lower electricity costs could also add to this total.

6. Component 4: NG Pipeline Risk Assessment & Flow Analysis

The purpose of Component 4 is to scope out the major risks to the natural gas pipeline. Specific analysis includes:

- defining the high level risks impacting pipeline feasibility,
- identifying the major constraints to the Natural Gas pipeline design, and
- identifying the major risks to pipeline flow.

To complete this deliverable, Energy Narrative utilized their experience in the design and review of major deep water projects worldwide, and conducted a literature survey of similar recent projects in the industry.

6.1. High Level Risks Impacting Pipeline Feasibility

The risks impacting pipeline feasibility are evaluated during pipeline route determination, a process which is iterative with increasing amounts and increasing quality of data. The American Bureau of Shipping (ABS), which certifies the integrity of oil and gas facilities for insurance purposes, defines a process to determine the optimal pipeline.

The evaluation process utilizes a Geophysical Information System (GIS) to define the risks spatially with the optimum pipeline route determined with a least-cost path optimization. The risks considered include geological, geotechnical, ecological and cultural risks, and are interpreted, evaluated, classified and weighted in degree of risk and cost. Constraints are mapped and then combined to create a single Geocost map, which displays a surface of risk and / or cost. An algorithm is then used to select the least cost route between two points resulting in the least risk / cost route (note that this not a risk free route, but the one with the least combination of risk and cost per the algorithm). As information is further refined, the model is updated and the route refined.

It is important to note that at any stage in the iterative process the risk of the pipeline and the uncertainty in defining its final cost and risk may increase due to the acquisition of new data though it is expected that the trend is decreasing risk and cost uncertainty.

6.2. Major Constraints to the Natural Gas Pipeline Design

The major constraints to natural gas pipeline design include geological, geotechnical, ecological and cultural risks. The requirements for data gathering will illustrate the varied methods of defining these risks.

Mechanical and integrity risks are designed out through engineering design, physical properties such as metallurgy / material strength / wall thickness, and operating procedures. Deviations from operating procedures in combination with existing engineering design and operating procedures are a real but manageable risk.

6.3. Major Risks to Pipeline Flow

In addition to the design risks outlined above, operating risks due to upstream and downstream outages, pipeline integrity and intervention of local populations may disrupt pipeline flow.

- **Upstream outage risks.** Compressor downtime and process facility downtime on the FPSO are the most likely upstream operating risks, as gas injection well downtime is mitigated by the number of injection wells. Upstream outages can be mitigated for a short period of time by utilizing line pack in gas pipelines whereby the pipeline pressure falls as gas leaves a pipeline with no flow into it.
- **Downstream outage risks.** Natural gas is a highly-coupled system between supply sources and demand sinks where disruptions in either are mitigated by the use of natural gas storage. The most likely use of natural gas in Guyana is in the substitution of diesel and heavy fuel oil in electricity generators. As the generators are dual-fuel they effectively serve the same role as storage, switching to alternative fuels in the event of a natural gas outage. Any demand that does not have this dual fuel alternative will require natural gas storage to be built, although liquefied and compressed natural gas may be one of the exceptions.

- **Pipeline integrity risks.** Gas conditioning and the metallurgy of the pipeline are important considerations. A cheaper pipeline can be built if sufficient emphasis is placed on maintaining specified oxygen, carbon dioxide, hydrogen sulphide and water levels in the natural gas stream. The level of hydrogen sulphide and water in the natural gas will increase over the life of the project as injected water reaches the producing wells. In periods of financial distress arising from low oil prices, maintenance of these specifications is often the first item to go, potentially leading to future pipeline integrity issues. However, damage that may result from elevated levels of these contaminants is often experienced in the production and injection wells before they impact pipeline integrity.
- **Intervention risks.** Intervention of local populations, including sabotage and theft from the pipeline, are more prevalent when the pipeline path is nearby local populations. Unfortunately, pipelines located away from towns tend to attract people over time. Burial can mitigate this problem, however signs must be placed and the local officials and population educated regarding the location of the pipeline (to avoid accidental damage during construction and excavation) and the contents of the pipeline (natural gas and not oil) to reduce the risk of intentional vandalism for theft.

6.4. Conclusions and recommendations

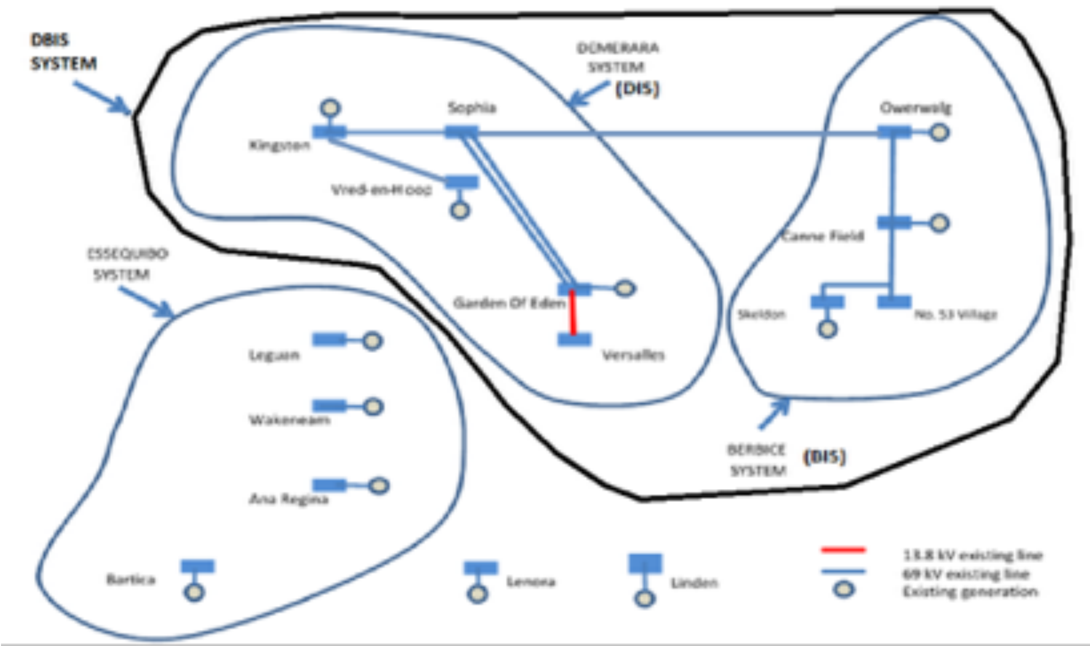
The high-level risks to the natural gas pipeline are discovered during pipeline routing studies where an iterative process using increasing amounts and quality of data is used to define the optimum pipeline route – itself a reflection of a lowest risk / lowest cost approach. The major constraints to natural gas pipeline design include geological, geotechnical, ecological and cultural risks. No information has been provided regarding these risks and how they apply to the EEPGL facilities and proposed routes. These will be further defined as data and studies are procured to define these risks. Operating risks due to upstream and downstream outages, pipeline integrity and intervention of local populations may disrupt pipeline flow. These risks, however, are often designed out and/or mitigated in operating practice. It is important to clearly document what these operating practices are and to maintain their integrity during periods of political and financial distress.

7. Component 5: Optimizing existing generation units

The purpose of Component 5 is to assess the technical feasibility of converting existing power generation equipment and integrating new gas-fired electricity generation equipment. That is, to ensure that the proposed changes and additions to Guyana's electricity generation capacity will be compatible with the electricity transmission grid configuration, capacity, and operations. This analysis is based on data, analysis, and reports provided by GPL and the Government of Guyana.

Guyana's current electricity grid is shown below in Figure 7.1, as presented in the 2016 expansion study. The DBIS includes generation units in six locations, with eight related substations connected via 69kV transmission lines. A ninth substation at Versailles is linked to the Garden of Eden substation through a 13.8kV line. Outside of the DBIS, there are isolated generation units at substations in the Essequibo region at Leguan Island and Wakenaam Island at the mouth of the Essequibo river, Anna Regina, located on the coast to the west of the Essequibo river, and Bartica, located inland at the confluence of the Essequibo and Mazaruni rivers. Other isolated systems include Leonora, located along the coast between the Essequibo and Demerara rivers to the west of Vreed en Hoop, and Linden, located inland along the Demerara river south of the Versailles substation.

Figure 7.1: Guyana current electricity grid (DBIS and other isolated systems)



Source: Guyana's Power Generation System Expansion Study, 2016.

The current generation units are located throughout the DBIS, with the largest units at Kingston and Skeldon, and other important units balancing electricity sources across the grid. No single generation unit accounts for more than 20% of the system total. This distribution of generation assets reduces the load on the transmission grid and helps contribute to system stability.

All existing units, with the exception of the 30 MW gas turbines at Skeldon, are reciprocating engines. Of these, roughly 80 MW are Wartsilla engines and just over 20 MW are mobile Caterpillar gen sets. Both Wartsilla and Caterpillar manufacture dual fuel engines capable of burning liquid fuels and natural gas. Existing single fuel units can also be converted to become dual fuel at an estimated cost of US$100 per kW of capacity.

The main challenges to converting existing units to natural gas will be securing rights-of-way for natural gas pipelines and building the pipelines to link the power generation units to the natural gas landing point. These pipelines will be small diameter as each individual power plant will have a relatively low demand. The anticipated volume of natural gas demand for each power plant is estimated in Component 6 below.

As dual fuel units, the power plants can rely on liquid fuels as a back-up in the event of disruptions to the natural gas supply. Each existing gas power plant already has a storage tank for liquid fuels, removing the need to build additional fuel storage and relieve a potential constraint, given the limited availability of additional space at some locations. Avoiding the need to store natural gas at each power plant site reduces the cost of conversion by reducing the amount of new equipment required and reducing the complexity of the related safety systems (For example, LNG storage tanks in populated areas require full double containment walls as well as the standard surrounding dike to contain the LNG in the event of a rupture, significantly increasing the cost).

New capacity additions noted in the Expansion Plan did not have a specified location. Where space is available, some of the new engines could be co-located with existing units. This would reduce the cost to transport the natural gas by increasing the volume of natural gas transported on each pipeline and by eliminating the need to build additional pipelines to new areas.

A new power plant could also be built at the point of landing for the natural gas. This would allow a share of the natural gas to be consumed immediately at the landing point without requiring additional pipelines. The original EEPGL proposal suggests building a single 200 MW power plant (using 18 individual 11.2 MW reciprocating engines) at the natural gas landing site. As it would be built using 11.2 MW engines, it could be built in stages as new capacity is needed, or built all at once to replace current units (which could be kept as back up or to meet demand growth in the future).

Such a plant would save the roughly $120 million in estimated cost for onshore natural gas pipelines. The downside to a single power plant is the required investment in new transmission capacity to handle the higher power flows from the station to the rest of the grid. Detailed power flow analysis would be needed to accurately size the transmission lines and substation and to estimate the additional investment required. Rough estimates for power transmission lines range from $300,000 to $700,000 per kilometer, plus $70,000 per MVA of transformer capacity (roughly $15-20 million for each transformer of the size needed here).

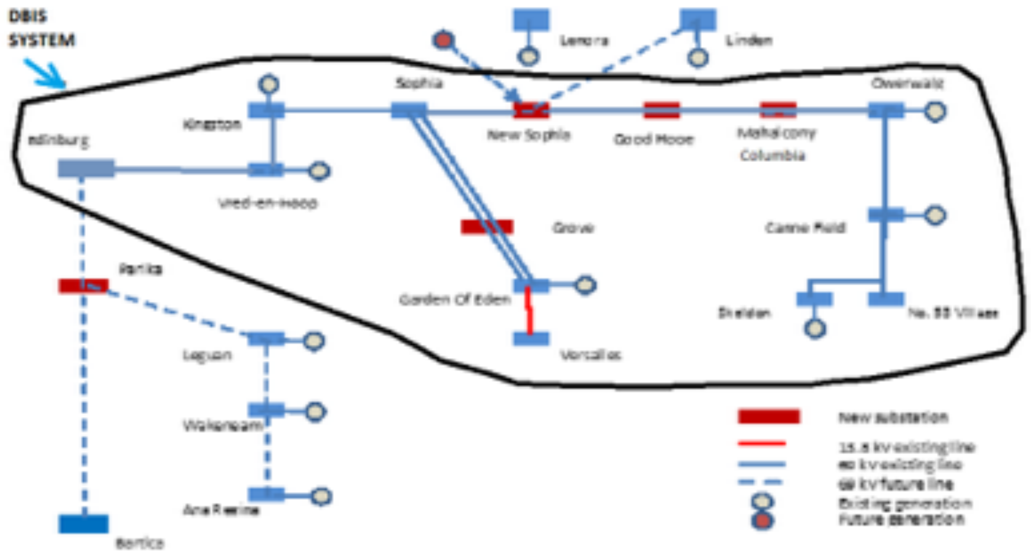
Putting the full power plant in a single location would also put Guyana's electricity grid at greater risk of an outage. A fault at the station itself (mitigated by the fact that it is many smaller engines together, rather than one big turbine), or a downed transmission line between the station and the rest of the system could disrupt electricity supply to the entire grid. Having generation at multiple locations helps mitigate this problem by locating generation nearer to the load. In this way, not all electricity supply is then lost if a transmission line goes down. If the singe 200 MW plant were built, it would be advisable to maintain GPL's current power plants as back-up power in the event of an outage.

In addition, GPLs capacity margin requirements state that the margin must be at least as large as the two largest units in the system. Adding a single large power plant would increase that capacity margin requirement, potentially requiring further investment in smaller plants elsewhere to mitigate its impact on system reliability.

This analysis assumes that new power generation units will be built in a more distributed manner to minimize the need for additional transmission investment.

Figure 7.2 below shows the proposed expansion of Guyana's electricity grid. The planned investments include interconnecting the Linden and Essequibo region isolated systems, adding additional substation capacity in the DBIS, and expanding transmission capacity along the core rights of way between the Sophia substation and Kingston to the west and Good Hope / Columbia to the east.

Figure 7.2: Guyana Planned Electricity Grid Expansion



Source: Guyana's Power Generation System Expansion Study, 2016.

This expansion plan envisions a new power plant at the New Sophia substation, a central point within the main grid and well balanced with other generation assets across the system. This location is also consistent with one of the natural gas landing points proposed by EEPGL (Georgetown).

The other two proposed landing points, Clonbrook and New Amsterdam, are located along the main transmission line linking the Demerara system with Berbice. Clonbrook is located near the proposed Columbia / Mahaicony substation, which could be linked to a new power plant at the site. Although not as central to the main demand centers in Georgetown, the Clonbrook site is reasonably close and does have more space available. This could simplify siting and logistics for a new power plant and the landing of the natural gas pipeline.

The New Amsterdam landing point is located on the Berbice River, near the current Canefield substation. This location is within the smaller Berbice sub-grid, well away from the main demand centers in Georgetown. The Berbice sub-grid has a current installed capacity of roughly 50 MW, with the Skeldon-Guysuco unit accounting for 40 MW, or 80 percent of the total. Placing another large generation unit in this region would require upgrades to the transmission lines linking the region to Georgetown (perhaps in addition to the investment currently envisioned with the New Sophia and related substations). A large power plant could be justified if new industrial demand were attracted to the area. During our discussions with stakeholders, the Ministry of Public Infrastructure noted that space is available for an industrial park in the region. Providing low cost energy in the form of natural gas, and ample electricity supply through a new power plant in the area, could stimulate substantial investment and economic development in the region.

8. Component 6: Framework for including natural gas

This Component extends the analysis in Component 5 to assess the natural gas volumes required for specific individual power plants. To estimate the natural gas needed for electricity generation, the expected utilization of Guyana's current and future electricity generation capacity was modeled. The forecast for individual power plant utilization was based on the Base, High, and Low demand growth cases, and the Optimal and Alternative 1 capacity expansion plans, from the 2016 expansion plan study.

Given the limited data on Guyana's load shape and dispatch methodology, a simplified generation model allocated the system load to be met across each generation unit equally, up to the limit of each unit's known availability. In the Optimal expansion plan, this first-order approximation sets the maximum utilization rate for hydro units to 50%, wind units to 33%, and solar units to 20%.

The resulting unit-level forecast for electricity generation under the Optimal expansion plan and Base Case demand forecast is shown in Table 8.1 below.

Table 8.1: Guyana estimated electricity generation by plant: Optimal expansion plan, Base Case demand forecast (GWh)

Estimated Generation	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Demerara Power 1	92.3	102.7	107.8	89.1	78.7	78.1	89.2	68.5	76.4	84.7	88.1	87.0	100.0	107.8
Garden of Eden	69.6	77.5	81.4	67.2	59.4	59.0	67.3	51.7	57.6	63.9	66.5	65.7	75.5	81.3
Demerara Power 2	92.3	102.7	107.8	89.1	78.7	78.1	89.2	68.5	76.4	84.7	88.1	87.0	100.0	107.8
Demerara Power 3	152.3	169.5	177.9	147.0	129.8	128.9	147.2	113.0	126.0	139.7	145.3	143.6	165.0	177.8
Vreed-En-Hoop	109.9	122.3	128.4	106.1	93.7	93.1	106.3	81.6	90.9	100.8	104.9	103.6	119.1	128.3
Canefield-Corentyne - 1	0.0	0.0	0.0	0.0	15.0	15.3	17.2	13.6	15.0	16.4	17.0	16.9	19.2	20.3
Canefield-Corentyne - 2	23.5	26.1	27.4	22.7	20.0	19.9	22.7	17.4	19.4	21.6	22.4	22.2	25.5	27.4
Skeldon-Guysuco - 1	42.0	46.7	40.0	40.5	35.8	35.5	40.6	31.1	34.7	38.5	40.0	39.6	45.5	40.0
Skeldon-Guysuco - 2	120.9	78.8	78.8	78.8	78.8	102.0	114.8	90.9	100.0	109.6	113.5	112.5	127.8	135.6
New HFO Engine	0.0	0.0	0.0	70.5	62.2	61.8	70.6	54.2	60.4	67.0	69.7	68.8	79.1	86.2
New Wind	0.0	0.0	0.0	75.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2
New LFO Engine	0.0	0.0	0.0	0.0	81.6	81.0	92.5	71.0	79.1	87.8	91.3	90.2	103.6	111.7
New Solar	0.0	0.0	0.0	0.0	5.3	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
New Wood Residue	0.0	0.0	0.0	0.0	0.0	2.5	2.8	2.2	2.4	2.7	2.8	2.8	3.2	3.4
New Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	485.0	533.2	584.3	605.2	600.2	661.7	700.8
New Bagasse	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.8	44.5	48.0
New Bagasse	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.9	27.9
New NG Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	167.5
Total Electricity Demand	**698**	**721**	**753**	**782**	**810**	**837**	**942**	**1,231**	**1,353**	**1,483**	**1,536**	**1,560**	**1,796**	**2,060**

Source: Guyana's Power Generation System Expansion Study, 2016.

Assuming that all engines are converted to use natural gas when it becomes available in 2022, this unit level generation forecasts results in the unit level natural gas consumption show in Table 8.2 below.

Table 8.2: Guyana estimated natural gas consumption by plant: Optimal expansion plan, Base Case demand forecast (MMscfd)

Average Natural Gas Consumption	2022	2023	2024	2025	2030	2035
Demerara Power 1	1.4	1.5	1.7	1.8	2.1	2.2
Garden of Eden	1.2	1.4	1.5	1.6	1.9	2.0
Demerara Power 2	1.3	1.5	1.7	1.8	2.0	2.2
Demerara Power 3	2.0	2.2	2.5	2.6	3.0	3.2
Vreed-En-Hoop	1.6	1.8	2.0	2.1	2.4	2.6
Canefield-Corentyne - 1	0.3	0.3	0.3	0.3	0.4	0.4
Canefield-Corentyne - 2	0.4	0.5	0.5	0.5	0.6	0.7
Skeldon-Guysuco - 1	0.6	0.7	0.8	0.8	0.9	1.0
Skeldon-Guysuco - 2						
New HFO Engine	1.1	1.2	1.3	1.4	1.6	1.8
New Wind						
New LFO Engine	1.4	1.6	1.8	1.9	2.1	2.3
New Solar						
New Wood Residue						
New Hydro						
New Bagasse						
New Bagasse						
New NG Engine	0.0	0.0	0.0	0.0	0.0	3.4
Total Natural Gas Required	**11.3**	**12.6**	**14.1**	**14.8**	**17.0**	**21.8**

Source: Guyana's Power Generation System Expansion Study, 2016.

Total natural gas demand grows from 11 MMcfd in 2022 to just under 22 MMcfd in 2035. Across the generation park, natural gas consumption at individual generation plants ranges from 0.3 MMcfd to 3.4 MMcfd.

Switching to the High demand forecast results in slightly higher generation for each unit, as shown in Table 8.3 below.

Table 8.3: Guyana estimated electricity generation by plant: Optimal expansion plan, High demand forecast (GWh)

Estimated Generation	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Demerara Power 1	92.3	102.7	108.6	86.9	79.7	79.5	90.9	71.9	81.8	92.4	98.0	98.2	122.9	140.8
Garden of Eden	68.6	77.5	82.0	67.8	60.2	60.0	68.6	54.3	61.7	69.7	73.9	74.1	92.8	106.2
Demerara Power 2	92.3	102.7	108.6	86.9	79.7	79.5	90.9	71.9	81.8	92.4	98.0	98.2	122.9	140.8
Demerara Power 3	152.3	169.5	179.3	148.4	131.6	131.2	149.9	118.6	134.9	152.5	161.6	162.0	202.9	232.3
Vreed-En-Hoop	109.9	122.3	129.4	107.1	95.0	94.7	100.2	85.6	97.4	110.1	116.7	116.9	146.4	167.6
Canefield-Corentyne - 1	0.0	0.0	0.0	0.0	15.0	15.3	17.2	13.6	15.0	16.4	17.0	16.9	19.2	20.3
Canefield-Corentyne - 2	23.5	26.1	27.7	22.9	20.3	20.2	23.1	18.3	20.8	23.5	24.9	25.0	31.3	35.8
Skeldon-Guysuco - 1	42.0	46.7	49.4	40.9	36.2	36.1	41.3	32.7	37.2	42.0	44.5	44.6	55.9	64.0
Skeldon-Guysuco - 2	120.9	78.8	78.8	78.8	78.8	102.0	114.8	90.9	100.0	109.6	113.5	112.5	127.8	135.6
New HFO Engine	0.0	0.0	0.0	71.1	63.1	62.9	71.9	56.9	64.7	73.1	77.5	77.6	97.2	111.3
New Wind	0.0	0.0	0.0	75.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2
New LFO Engine	0.0	0.0	0.0	0.0	82.6	82.4	94.2	74.5	84.7	95.8	101.5	101.7	127.4	145.9
New Solar	0.0	0.0	0.0	0.0	5.3	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
New Wood Residue	0.0	0.0	0.0	0.0	0.0	2.5	2.9	2.3	2.6	2.9	3.1	3.1	3.9	4.5
New Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	485.0	533.2	584.3	605.2	600.2	681.7	700.8
New Bagasse	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.7	54.8	62.7
New Bagasse	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.9	36.5
New NG Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	218.8
Total Electricity Demand	**698**	**721**	**758**	**787**	**819**	**848**	**955**	**1,259**	**1,367**	**1,546**	**1,616**	**1,655**	**1,998**	**2,403**

Source: Guyana's Power Generation System Expansion Study, 2016.

This higher generation rate also translates to higher natural gas demand for those units that that are switched in 2022, as shown in Table 8.4 below.

Table 8.4: Guyana estimated natural gas consumption by plant: Optimal expansion plan, High demand forecast (MMcfd)

Average Natural Gas Consumption	2022	2023	2024	2025	2030	2035
Demerara Power 1	1.5	1.7	1.9	2.0	2.5	2.9
Garden of Eden	1.3	1.5	1.7	1.8	2.3	2.6
Demerara Power 2	1.4	1.6	1.9	2.0	2.5	2.8
Demerara Power 3	2.1	2.4	2.7	2.9	3.7	4.2
Vreed-En-Hoop	1.7	2.0	2.2	2.4	3.0	3.4
Canefield-Corentyne - 1	0.3	0.3	0.3	0.3	0.4	0.4
Canefield-Corentyne - 2	0.4	0.5	0.6	0.6	0.8	0.9
Skeldon-Guysuco - 1	0.7	0.7	0.8	0.9	1.1	1.3
Skeldon-Guysuco - 2						
New HFO Engine	1.2	1.3	1.5	1.6	2.0	2.3
New Wind						
New LFO Engine	1.5	1.7	2.0	2.1	2.6	3.0
New Solar						
New Wood Residue						
New Hydro						
New Bagasse						
New Bagasse						
New NG Engine	0.0	0.0	0.0	0.0	0.0	4.5
Total Natural Gas Required	**12.1**	**13.8**	**15.6**	**16.7**	**20.8**	**28.3**

Source: Guyana's Power Generation System Expansion Study, 2016.

Under the High demand case, total natural gas demand reaches just over 28 MMcfd, and natural gas demand in the largest units reaches 4.5 MMcfd.

The Alternative 1 plan, with its sole reliance on reciprocating engines to meet growing demand, provides an example of the upper range of natural gas demand. Table 8.5 below shows the estimated electricity generation by unit under the Base Case demand forecast.

Table 8.5: Guyana estimated electricity generation by plant: Alternative 1 expansion plan, Base Case demand forecast (GWh)

Estimated Generation	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Demerara Power 1	98.2	101.9	107.0	111.5	97.1	97.1	105.7	125.1	124.3	124.4	117.9	110.7	111.1	113.0
Garden of Eden	74.1	76.9	80.7	84.1	73.3	73.3	79.7	94.4	93.8	93.9	89.0	83.5	83.8	85.2
Demerara Power 2	98.2	101.9	107.0	111.5	97.1	97.1	105.7	125.1	124.3	124.4	117.9	110.7	111.1	113.0
Demerara Power 3	162.1	168.1	176.5	183.9	160.2	160.2	174.4	206.4	205.2	205.3	194.5	182.7	183.4	186.4
Vreed-En-Hoop	117.0	121.4	127.4	132.8	115.6	115.6	125.9	149.0	148.1	148.2	140.4	131.9	132.3	134.5
Canefield-Corentyne - 1	0.0	0.0	0.0	0.0	18.6	19.2	21.6	25.3	25.2	25.2	24.1	22.6	22.7	23.1
Canefield-Corentyne - 2	25.0	25.9	27.2	28.4	24.7	24.7	26.9	31.8	31.7	31.7	30.0	28.2	28.3	28.8
Skeldon-Guysuco - 1	44.7	46.3	48.6	50.7	44.1	44.1	48.0	56.9	56.5	56.6	53.6	50.3	50.5	51.4
Skeldon-Guysuco - 2	78.8	78.8	78.8	78.8	78.8	105.1	144.1	157.7	157.7	157.7	157.7	151.0	151.5	154.1
New HFO Engine	0.0	0.0	0.0	0.0	100.6	100.6	109.5	129.7	128.9	128.9	122.2	114.8	115.2	117.1
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	129.7	128.9	128.9	122.2	114.8	115.2	117.1
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	128.9	128.9	122.2	114.8	115.2	117.1
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	128.9	122.2	114.8	115.2	117.1
New LFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	122.2	114.8	115.2	117.1
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	114.8	115.2	117.1
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	115.2	117.1
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	115.2	117.1
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.1
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.1
Total Electricity Demand	**698**	**721**	**753**	**782**	**810**	**837**	**942**	**1,231**	**1,353**	**1,483**	**1,536**	**1,560**	**1,796**	**2,080**

Source: Guyana's Power Generation System Expansion Study, 2016.

Table 8.6 below shows the resulting natural gas demand per unit starting in 2022.

Table 8.6: Guyana estimated natural gas consumption by plant: Alternative 1 expansion plan, Base Case demand forecast (MMscfd)

Average Natural Gas Consumption	2022	2023	2024	2025	2030	2035
Demerara Power 1	2.2	2.3	2.3	2.3	2.3	2.3
Garden of Eden	2.0	2.0	2.1	2.1	2.1	2.1
Demerara Power 2	2.2	2.2	2.2	2.2	2.2	2.3
Demerara Power 3	3.2	3.3	3.3	3.3	3.3	3.4
Vreed-En-Hoop	2.6	2.6	2.7	2.7	2.7	2.7
Canefield-Corentyne - 1	0.5	0.5	0.5	0.5	0.5	0.5
Canefield-Corentyne - 2	0.7	0.7	0.7	0.7	0.7	0.7
Skeldon-Guysuco - 1	1.0	1.0	1.0	1.0	1.0	1.0
Skeldon-Guysuco - 2						
New HFO Engine	2.3	2.3	2.4	2.4	2.4	2.4
New HFO Engine	2.3	2.3	2.4	2.4	2.4	2.4
New HFO Engine	2.3	2.3	2.4	2.4	2.4	2.4
New HFO Engine	0.0	2.3	2.4	2.4	2.4	2.4
New LFO Engine	0.0	0.0	2.4	2.4	2.4	2.4
New HFO Engine	0.0	0.0	0.0	2.4	2.4	2.4
New HFO Engine	0.0	0.0	0.0	0.0	2.4	2.4
New HFO Engine	0.0	0.0	0.0	0.0	2.4	2.4
New HFO Engine	0.0	0.0	0.0	0.0	0.0	2.4
New HFO Engine	0.0	0.0	0.0	0.0	0.0	2.4
Total Natural Gas Required	**21.4**	**24.0**	**26.6**	**28.9**	**33.7**	**39.1**

Source: Guyana's Power Generation System Expansion Study, 2016.

The total natural gas demand is substantially higher in this plan, rising from 21.4 MMcfd in 2022 to nearly 40 MMcfd by 2035. At the unit level, natural gas consumption is relatively stable, ranging between 0.4 MMcfd for the Canefield units to a maximum of 3.4 MMcfd for the Demerara 3 unit. Because the new additions are uniformly 22.8 MW in size, each one has a relatively limited demand (averaging 2.4 MMcfd each).

This limitation in size can be addressed by co-locating future capacity additions at the site of current units, or aggregating several proposed additions into a single site. If all new capacity additions were co-located with the five main existing units (eventually adding a total of 45 MW to each site), natural gas demand at each site would average roughly 7-8 MMcfd in 2035.

Table 8.7 below shows the Alternative 1 plan generation outlook at the unit level under the High demand case. The 20% increase in total generation is shared equally across all generation units.

Table 8.7: Guyana estimated electricity generation by plant: Alternative 1 expansion plan, High demand forecast (GWh)

Estimated Generation	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Demerara Power 1	98.2	101.9	107.8	112.4	98.3	98.6	107.5	128.4	129.0	130.4	124.9	118.3	125.0	133.5
Garden of Eden	74.1	76.9	81.3	84.8	74.1	74.4	81.1	96.9	97.3	98.4	94.2	89.3	94.3	100.7
Demerara Power 2	98.2	101.9	107.8	112.4	98.3	98.6	107.5	128.4	129.0	130.4	124.9	118.3	125.0	133.5
Demerara Power 3	162.1	168.1	177.8	185.5	162.1	162.7	177.4	211.9	212.8	215.2	206.0	195.2	206.2	220.3
Vreed-En-Hoop	117.0	121.4	128.4	133.9	117.0	117.4	128.0	152.9	153.6	155.3	148.7	140.9	148.8	159.0
Canefield-Corentyne - 1	0.0	0.0	0.0	0.0	18.6	19.2	21.6	25.3	25.2	25.2	24.1	22.6	22.7	23.1
Canefield-Corentyne - 2	25.0	25.9	27.4	28.5	25.0	25.1	27.4	32.7	32.8	33.2	31.8	30.1	31.8	34.0
Skeldon-Guysuco - 1	44.7	46.3	49.0	51.1	44.7	44.8	48.9	58.4	58.6	59.3	56.8	53.8	56.8	60.7
Skeldon-Guysuco - 2	78.8	78.8	78.8	78.8	78.8	105.1	144.1	157.7	157.7	157.7	157.7	151.0	151.5	154.1
New HFO Engine	0.0	0.0	0.0	0.0	101.8	102.2	111.4	133.1	133.7	135.2	129.4	122.6	129.5	138.4
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	133.1	133.7	135.2	129.4	122.6	129.5	138.4
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	133.7	135.2	129.4	122.6	129.5	138.4
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	135.2	129.4	122.6	129.5	138.4
New LFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	129.4	122.6	129.5	138.4
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	122.6	129.5	138.4
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	129.5	138.4
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	129.5	138.4
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	138.4
New HFO Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	138.4
Total Electricity Demand	**698**	**721**	**758**	**787**	**819**	**848**	**955**	**1,259**	**1,367**	**1,546**	**1,616**	**1,655**	**1,998**	**2,403**

Source: Guyana's Power Generation System Expansion Study, 2016.

The resulting natural gas demand starting in 2022 is shown in Table 8.8 below. Total natural gas demand increases to over 45 MMcfd by 2035, and individual unit consumption reaches 2.8 MMcfd. As noted above, if all new engines were co-located with the five largest current units, each site would see roughly 8-10 MMcfd of natural gas demand by 2035 in this case.

Table 8.8: Guyana estimated natural gas consumption by plant: Alternative 1 expansion plan, High demand forecast (MMscfd)

Average Natural Gas Consumption	2022	2023	2024	2025	2030	2035
Demerara Power 1	2.3	2.4	2.4	2.4	2.6	2.7
Garden of Eden	2.1	2.1	2.2	2.2	2.3	2.5
Demerara Power 2	2.3	2.3	2.4	2.4	2.5	2.7
Demerara Power 3	3.4	3.4	3.5	3.5	3.7	4.0
Vreed-En-Hoop	2.7	2.8	2.8	2.8	3.0	3.2
Canefield-Corentyne - 1	0.5	0.5	0.5	0.5	0.5	0.5
Canefield-Corentyne - 2	0.7	0.7	0.7	0.7	0.8	0.8
Skeldon-Guysuco - 1	1.0	1.1	1.1	1.1	1.2	1.2
Skeldon-Guysuco - 2						
New HFO Engine	2.4	2.5	2.5	2.5	2.7	2.8
New HFO Engine	2.4	2.5	2.5	2.5	2.7	2.8
New HFO Engine	2.4	2.5	2.5	2.5	2.7	2.8
New HFO Engine	0.0	2.5	2.5	2.5	2.7	2.8
New LFO Engine	0.0	0.0	2.5	2.5	2.7	2.8
New HFO Engine	0.0	0.0	0.0	2.5	2.7	2.8
New HFO Engine	0.0	0.0	0.0	0.0	2.7	2.8
New HFO Engine	0.0	0.0	0.0	0.0	2.7	2.8
New HFO Engine	0.0	0.0	0.0	0.0	0.0	2.8
New HFO Engine	0.0	0.0	0.0	0.0	0.0	2.8
Total Natural Gas Required	**22.2**	**25.1**	**28.2**	**30.8**	**37.9**	**46.1**

Source: Guyana's Power Generation System Expansion Study, 2016.

This analysis suggests that for Guyana to consume the full 26.3 MMcfd of natural gas available for electricity generation, all current units that use liquid fuels should be converted to natural gas and all future capacity additions should be natural gas fired.

The analysis also suggests that the natural gas supply will be most cost effective if new generation units are co-located with the existing units that are converted to natural gas. Based on these observations, the analysis of specific locations, natural gas demand, and cost in Section 12 assumes that Guyana follows the Alternative 1 expansion plan (all dual-fuel reciprocating engines) and that new generation capacity is added at or near the current generation plants.

9. Component 7: Natural Gas Pipeline Functional Requirements

The purpose of Component 7 is to scope out the functional requirements of the natural gas pipeline. To complete this deliverable, Energy Narrative interviewed key stakeholders, conducted a literature survey of key conceptual requirements for natural gas pipeline design, and defined key sources of information within Guyana.

9.1. Summary of dialogue with key stakeholders

A visit to Guyana was made between Monday, 3rd April and Saturday, 8th of April. The following key stakeholders were interviewed:

- The Honorable Raphael Trotman, Minister of Natural Resources.
- Horace Williams, CEO of Hinterland Electrification Company, Inc.
- The Honorable David Patterson, Minister of Public Infrastructure.
- Dr. Mahender Sharma, CEO of Guyana Energy Agency.

It was universally agreed that the discovery of oil and gas offshore Guyana presents a disruptive change in the opportunities available to Guyana energy policy. The availability of natural gas, as a byproduct of oil production, in quantities in excess of the local energy market presents both opportunities and challenges. The opportunity to reduce electricity costs is significant and its impact on providing the foundations for economic development substantial. The challenges initially center around the prudent development of a natural gas market which matches available excess supply, and the current commitments to renewable sources of energy, including major hydroelectric projects.

Guyana was the first country in the world to ratify the Paris Accord dealing with greenhouse gasses emissions mitigation, adaption and finance, committing Guyana to a green economy. In 2009, the Government of Guyana signed a memorandum of understanding with Norway whereby they would receive between $120 million and $250 million in carbon credits in return for reducing their carbon footprint and maintaining their forest canopy. The stated aim is to move closer towards 100% renewable power supply by 2025, conditional on appropriate support and adequate resources. .

The current energy policy aims to transition from reliance on imported heavy oil to power diesel generators to developing hydropower in the context of a regional electricity market (the Arco Norte project). Specific hydroelectric development projects that have been promoted include:

- Arco-Norte: A massive hydroelectric project producing between 1,500 and 4,500 MW of power expected in 2027 or later.
- Amaila: A smaller hydroelectric plant producing between 150 and 180 MW of power expected in 2024 or later.

Various option for economic development were discussed, some of which had some level of dependency on energy policy. Specific projects included:

- A deep-water port to allow imports and exports of consumer and semi-finished goods. This port would be located at New Amsterdam at the mouth of the Berbice River.
- A road to Northern Brazil with the objective of increasing trade with Brazil, dependent on a deep-water port in Georgetown. This project is included in the master plan for the Arco Norte project.
- An Aluminum plant with the objective to create the demand for hydroelectric power while moving up the value chain in Bauxite mining.
- An Industrial / Free-trade Park near New Amsterdam to use the natural gas in refineries, chemical plants, and other manufacturing facilities.

- Various hydroelectric power projects providing a regional solution to electric power and transmission. These projects are collectively included within the Arco Norte project.

9.2. Conceptual design of natural gas pipeline

All stakeholders agree that natural gas should be landed in a quantity that will provide cheap electrical power to Guyana. There was disagreement on whether natural gas should be used for other uses. Further, the impact on current renewables commitments was not well understood.

9.3. Guyana data sources for natural gas pipeline conceptual design

The major constraints to natural gas pipeline design include geological, geotechnical, ecological and cultural risks. In order to evaluate these risks, geophysical data, geological investigations, and geological studies are required.

- **Geophysical Data**. This includes detailed information of the physical characteristics of the pipeline path. Data gathering options include:
    - **3D Seismic** identifying faults, landslides, mass transport deposits, fluid expulsion systems, buried faults and folds, buried stratigraphy, and buried free-phase gas or gas hydrates.
    - **High Resolution or Ultra High Resolution 2D Seismic reflection** identifying shallow seafloor features, buried structures (faults and folds), buried stratigraphy, and buried free-phase gas or gas hydrates.
    - **Sub-Bottom Profiler** identifying man-made objects, faults, fluid expulsion features, shallow buried faults and folds, and shallow buried stratigraphy.
    - **Multibeam Echo-sounder** identifying faults, landslides, mass transport deposits, fluid expulsion features, and channel systems at the seafloor.
    - **Side Scan Sonar** identifying man-made objects, fluid expulsion features, and channel systems at the seafloor.
- **Geological Investigations**. Geotechnical cores and in-situ tests are used to obtain design-level information once a preliminary route has been determined to provide an early indication of soil conditions that may be necessary for conceptual design.
- **Geological Studies**. These studies are conducted on either a regional scale using generalized data, on a project-specific scale using more localized high-resolution data, or specifically along a proposed pipeline route with high-resolution geophysical data, geotechnical data, and geological cores.

The primary source of these data and their interpretation is Esso Exploration and Production Guyana, their partners, Hess Guyana Exploration and CNOOC Nexen Petroleum Guyana, and oilfield service and data companies such as Schlumberger, Halliburton and Core Labs.

Mechanical and integrity risks are designed out through engineering design, physical properties such as metallurgy, material strength, and wall thickness, and operating procedures. A third party review of the design and engineering documents accompanied by a third-party certification and inspection program during construction from companies such as the American Bureau of Shipping should satisfy this requirement.

10. Component 8: Potential sites for the natural gas landing

The purpose of Component 8 is to assess the relative benefits and constraints to different proposed natural gas landing sites. The proposed landing sites are evaluated based on the recommendation to use a subsea pipeline to transport the natural gas to land, the topographical constraints at each potential site, and the proposed uses for the natural gas.

This assessment draws upon GPL's expansion plan, alternative proposals for the use of the natural gas, and a literature search of technical and safety requirements for various transportation and storage technologies.

There are three locations currently under discussion for the landing site of the proposed pipeline:

- **Georgetown.** This location is being considered because of the location of the Sophia substation (and the proposed New Sophia substation as noted in the 2016 GPL Expansion Study).
- **Clonbrook.** This location is near Georgetown, located to the east of the main city along the Atlantic coast. It is being considered as an alternative to Georgetown as it is less busy and potentially has more space for development. The location is estimated to be near the Columbia substation.
- **New Amsterdam.** This location is being considered owing to its location along the Berbice River and the potential to develop a new industrial site and deep water port to support new energy-intensive industries. Its location is estimated to be near the Canefield substation.

Table 10.1 below reviews and ranks each option across a variety of criteria related to the undersea pipeline route, the immediate surrounds of the landing site, and its relation to the GPL electricity system. The selection criteria were grouped around three broad areas:

- **Undersea pipeline route** including the pipeline distance and route to each landing site option.
- **Pipeline landing site** including the availability of space for related development, population density, and related infrastructure
- **Power sector considerations** including the distance to existing substations, generation sites, and demand centers.

Table 10.1: Natural gas pipeline landing site benefits and challenges comparison

		Location (Sub station)			
	Criteria	Georgetown (New Sophia)	Clonbrook (Columbia)	New Amsterdam (Canefield)	Notes
Undersea Pipeline Route	Distance from production site	0	1	-1	Vairation in pipeline length along the proposed routes is less than 15% (180km - 205km).
	Estimated pipeline cost	0	1	-1	Like the distance, the range in cost estimates varies by less than 15% across the three options, well within the overall cost uncertainty range.
	Complexity of pipeline route	0	0	0	No information available to suggest any variation in complexity for the proposed routes.
	Environmentally sensitive areas along pipeline route	0	0	0	No information available to suggest any variation in environmental sensitivity for the proposed routes.
Pipeline Landing Site	Space available for required natural gas facilities	1	1	1	Minimal infrastructure needed for pipeline landing site.
	Space available for new electricty generation station	0	1	1	Additional capacity could be added to existing stations in Georgetown, difficult to build a new generation site there.
	space available for new electricty sub-station	0	1	1	Proposed New Sophia sub station could be expanded to accommodate new generation capacity, but limited space for a separate new substation.
	Space available for new energy intensive industry	-1	0	1	Georgetown is heavily developed with little space available for new industry.
	Local population density	-1	1	1	Georgetown is very densely populated.
	Local port suitable for seaborne NG distribution	1	0	1	Georgetown and New Amsterdam can manage barges and light ships. No known port at Clonbrook, but a jetty or small port could be developed if needed.
	Local deepwater port to export energy intestive industry products	-1	-1	1	New Amsterdam is the only location suitable for a deep water port.
Power Sector Considerations	Proximity to main GPL generation facilities	1	0	-1	GPL's main facilities at Kingston and Georgetown are close to New Sophia. Clonbrook is farther away. New Amsterdam is near small units at Canefield, but
	Proximity to current GPL sub-station facilities	1	0	0	Clonbrook and New Amsterdam are near their respective substations (Columbia and Canefield) but not co-located
	Proximity to GPL main demand centers	1	0	-1	Georgetown is the main demand center. Demand and New Amsterdam is small relative to Georgetown region.
	Local sub-station / transmission lines able to support new generation facility	1	0	0	Proposed New Sophia sub station could support new generation. Uncertain if Clonbrook and New Amsterdam are sufficient.
	Net Ranking	0.20	0.33	0.20	**Clonbrook is the top choice, followed by Georgetown and New Amsterdam**

Source: Energy Narrative estimates

An unweighted simple average of the rankings suggests that Clonbrook is the best choice for the landing site, given the greater flexibility of the space while still being within a short distance of the main electricity generation stations and demand centers. The Georgetown option was downgraded for the dense population and limited space for new electricity generation stations or industrial demand. The New Amsterdam site was downgraded for its extreme distance from the current electricity generation assets and demand centers, as well as the slightly higher cost for the undersea pipeline owing to the longer distance.

The conclusion that the Clonbrook site is the most suitable assumes that the natural gas volumes will be 30 MMcfd. Should the volumes be the higher estimate (145 MMcfd), or if even higher natural gas volumes become available, the New Amsterdam site, or the potential for two separate pipelines, should be re-examined. As shown in Section 5 (Component 3) above, Guyana's projected electricity demand is insufficient to absorb 145 MMcfd of natural gas. Therefore, new energy intensive industries (consuming either natural-gas fired electricity or using the natural gas directly for process heat or as a feed-stock) would be needed to develop sufficient demand. These industries would need additional development space. In addition, they could produce energy intensive products for export, putting greater value on the deep water port in New Amsterdam.

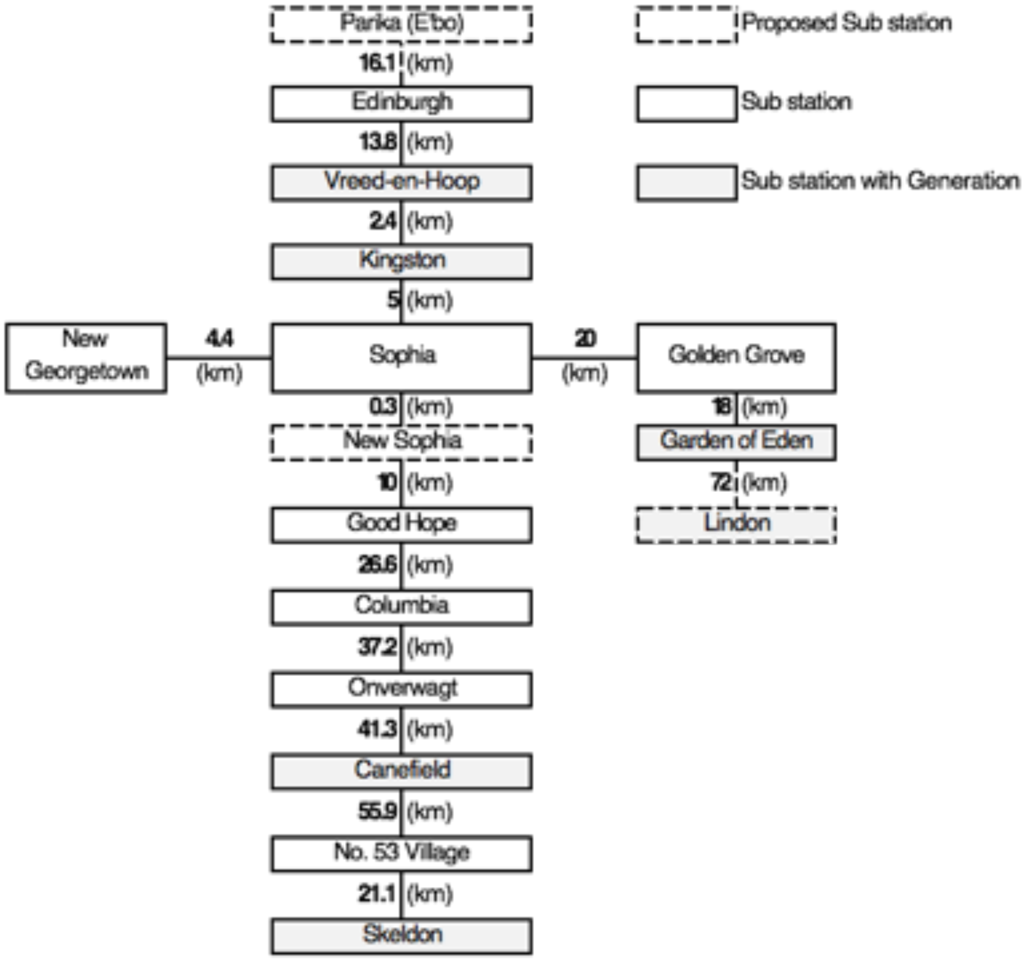
11. Component 9: Analyze power plant performance in light of natural gas pipeline routing

The purpose of Component 9 is to build upon the analysis in Component 8 to analyze the impact of the assessed pipeline landing sites on power sector logistics, infrastructure, and T&D network expansion and operations. The analysis is based on the GPL expansion plan and Energy Narrative analysis.

Figure 11.1 below presents a line diagram of the DBIS interconnected power grid highlighting the major substations as reported in the 2016 Generation Expansion Study. The reported distance between each substation is noted in the diagram, along with the location of the main generation assets.

As can be seen in the diagram, GPL's electricity generation stations are distributed across the system, with the majority located near the main demand loads in Georgetown (comprising the Kingston, Sophia, New Sophia, and New Georgetown substations). Additional generation units are located to the west (Vreed-en-Hoop), south (Garden of Eden), and east (Canefield and Skeldon) of the main demand center. This distribution of generation assets helps to balance power flows across the system, limiting the need for additional transmission capacity as electricity demand increases. As a single-line system (that is, one that does not have multiple transmission paths between each demand and supply point), this distribution of generation assets is also important to minimize the system's dependence on supply from any one region and to reduce the impact of a transmission outage.

Figure 11.1: DBIS system diagram

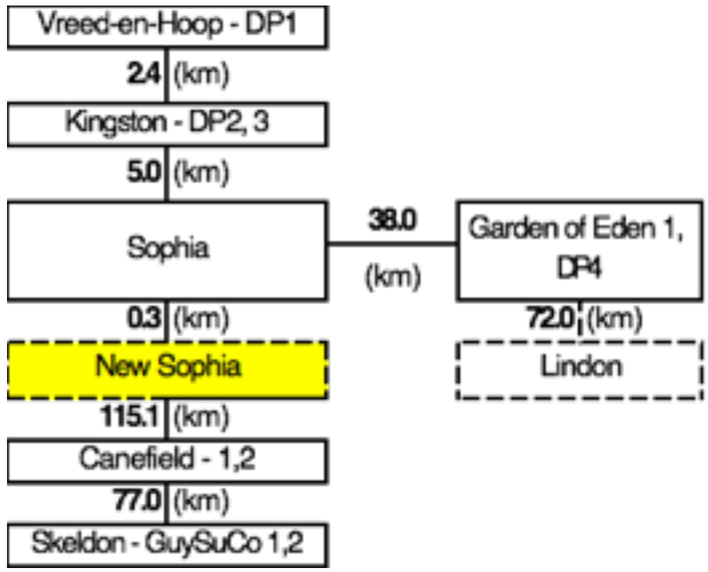


Source: Energy Narrative based on data from 2016 Generation Expansion Study

The reported distances between each substation were used as proxies for the estimated pipeline length to deliver natural gas to the currently existing power generation units.

Figure 11.2 below shows a simplified version of the above schematic, highlighting only those substations that are located near generation assets. The proposed New Sophia substation is included and highlighted.

Figure 11.2: DBIS generation assets



Source: Energy Narrative based on data from 2016 Generation Expansion Study

As shown in the figure, the generation assets at Vreed-en-Hoop and Kingston are less than 8 km from the Sophia substation at the heart of the transmission system. Units at Garden of Eden are roughly 40 km to the south, with the currently isolated Linden system a further 70 km south. The DBIS transmission system stretches 115 km along the coast to the west of Georgetown, passing through three substations before reaching Canefield near New Amsterdam at the Berbice River where two small generation units are located. The GuySuCo generation assets are another 77 km to the west at the far end of the transmission system.

Given the distributed nature of the current generation system, and the single-line characteristics of the transmission grid, it is advisable for future generation capacity additions to also be distributed along the grid. The most cost effective option is to add new capacity at the same location as current units, if there is space available.

These two criteria suggest that any new power plants built to use the available natural gas should not be too large relative to the power grid (in order to avoid the need for higher reserve margins, and also to reduce the need for additional transmission strengthening). Because the initial estimate for natural gas demand assumed all existing thermal power plants would be converted, it is also desirable to locate new gas fired capacity at those locations that are converted to natural gas to minimize the cost of building pipelines to distribute the natural gas.

These considerations guided the assessment of new generation capacity additions and conversions noted in Section 10 below.

12. Component 10: Natural Gas Pipeline and Power Costs

The purpose of Component 10 is to scope out the cost of the natural gas pipeline, power stations, and power generation. To complete this deliverable, Energy Narrative reviewed published industry data on offshore natural gas pipelines and calculated the reduction in electricity generation costs and their impact on electricity tariffs if savings are fully passed through.

This analysis was carried out for each of the natural gas landing site options covering a range of input cost for the natural gas. The analysis is based on available data, analysis, and reports provided by the Government of Guyana, and from discussing the underlying assumptions with key personnel within the Government of Guyana.

12.1. Natural gas pricing methodologies

The price to be charged for the natural gas at the point of production (the wellhead) is either set by market conditions (in countries with a competitive natural gas market), by regulation, or by contract with the producer. As Guyana does not yet have a natural gas market, and there are no other suppliers to date, the price will most likely be the result of negotiation between the Government of Guyana and EEPGL.

Three price setting methodologies can provide some guidance on the potential range for the negotiated price: Cost-Plus, Opportunity Cost, and Substitution Cost. Each is described below.

12.1.1. Cost Plus

As the name suggests, the cost-plus price setting methodology uses the calculated cost to produce the natural gas, including a reasonable return on investment, to determine the price of the delivered natural gas. The determination of what costs to include and the level of return on investment are the main negotiating points between the seller and the buyer. In theory, the Cost-Plus approach sets a floor for the potential price, as no seller would accept a price that is lower than their cost of production. In practice, however, the approach can be complicated for associated gas production, as production costs must be allocated to both the natural gas and oil that are produced—a process that is not always straightforward. In addition, if the natural gas must be disposed of in order to enable production of the more valuable oil, the associated gas may be priced well below cost—or even set at a negative price—in order to ensure the oil is produced.

This approach requires detailed data on the capital and operating costs associated with EEPGL's natural gas production which are not currently available. Therefore it is not used in this analysis.

12.1.2. Opportunity Cost

An opportunity-cost pricing system explicitly links the price for the delivered natural gas to the price that could have been received if the natural gas was sold into a different market. Because Guyana does not currently have a natural gas market, the opportunity cost would be calculated as the netback price that would have been received if the gas was exported (in the form of LNG) to another natural gas market. Table 12.1 below shows the calculation for the netbacked natural gas price in Guyana based on the IMF's current outlook for natural gas prices in Europe and Japan (the most likely markets for LNG exports), current rates for LNG shipping, and estimated liquefaction and regasification costs.

Table 12.1: Europe and Japan natural gas netback price estimates (US$ per MMBtu)

	Europe	Japan
Local Price	$5.63	$7.50
- Regas cost	$0.60	$0.60
-LNG shipping cost	$0.50	$1.40
-Liquefaction cost	$3.00	$3.00
Netback to Guyana	$1.53	$2.50

Source: Energy Narrative calculations

This analysis suggests that the price of natural gas in Guyana (including the upstream production cost and the cost to transport it to the shore) should be priced between US$1.50 and US$2.50 per MMBtu to be at parity with the price that producers could receive by exporting it to Europe or Japan. This price is extremely low, driven down by the excess of LNG supply in global markets and the low price of natural gas in the United States. Indeed, as shown in section 12.2 below, the cost to transport the natural gas to shore is estimated to be between US$0.76 per MMBtu (145 MMcfd to Clonbrook) and US$3.49 per MMBtu (30 MMcfd to New Amsterdam). For the smaller pipeline, the calculated netback price is less than the cost to transport natural gas to shore in Guyana, resulting in a negative price for the natural gas at the wellhead (-$0.99 for Japan, -$1.96 for Europe).

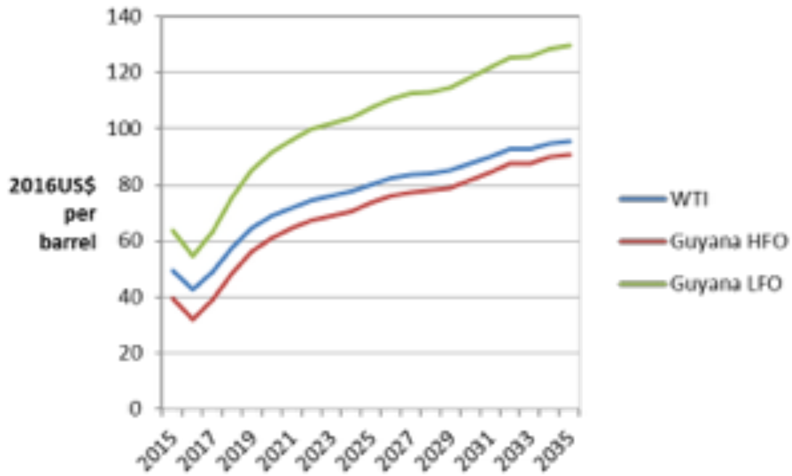
While the analysis gives a range of potential prices, the current volumes of natural gas proposed are insufficient to justify investment in a liquefaction facility for LNG exports. Therefore, this is a purely theoretical value unless additional natural gas supply becomes available.

12.1.3. Substitution Cost

The substitution cost approach links the natural gas price to the fuel that it is replacing, generally at a discount that can be fixed or adjustable, depending on the formula being used. For Guyana, the natural gas will substitute fuel oil for power generation. Therefore, the natural gas price would be discounted from the fuel oil parity on an equivalent price per unit of energy basis. The relative discount from fuel oil parity can be set at any value negotiated between the seller and buyer. In this way, fuel oil parity sets a price cap—no buyer would agree to pay a price higher than the price of the fuel they are currently using.

Figure 12.1 shows the forecast fuel oil price in Guyana based on the price formula used in the 2016 Expansion Plan study linking Guyana fuel prices with WTI and the latest WTI outlook from the US EIA (the Reference Case from the 2017 Annual Energy Outlook).

Figure 12.1: Liquid fuels price outlook (2016US$ per barrel)



Source: Energy Narrative calculations based on EIA AEO 2017 WTI Reference Case price and formula for Guyana fuel oil prices from 2016 Expansion study.

Figure 12.2 below shows the Guyana price for HFO in US$ per MMBtu in order to more easily compare it with the cost of natural gas.

Figure 12.2: HFO price outlook (2016US$ per MMBtu)

Source: Energy Narrative calculations based on EIA AEO 2017 WTI Reference Case price and formula for Guyana fuel oil prices from 2016 Expansion study.

For natural gas deliveries starting in 2022, the substitution cost approach suggests that any the delivered cost of natural gas should be less than US$10 per MMBtu, rising to more than US$14 per MMBtu by 2035. The 2016 expansion study provides a single HFO price for Guyana and does not report the cost to deliver HFO to each individual power plant. For this analysis, we compare the cost of natural gas as delivered to the individual power plants with this country-wide average HFO price, which likely underestimates the actual discount to delivered HFO.

12.1.4. Natural gas supply cost used in this analysis

The above options to calculate the price for natural gas supply at the wellhead provide guidance on the possible range of natural gas prices in Guyana. The opportunity cost analysis suggests that the wellhead cost could be as little as –US$1.96 (opportunity cost floor) or as high as US$9.00 (substitution ceiling with a 10% discount). The actual price will be determined through negotiations between the Government of Guyana and EEPGL.

For this cost analysis, a wellhead cost of zero (US$0.00) was assumed. This allows the analysis to highlight the variations in transportation cost among the various configurations. As negotiations on the actual wellhead price advance, the revised price can be added to the transportation costs used in this report to calculate the resulting total delivered price of natural gas.

12.2. Offshore pipeline cost

There are three hypothetical locations where the pipeline may be routed: 1) Georgetown, 2) Clonbrook, and 3) New Amsterdam. The cost to install and 8-in pipeline (30 MMcfd) and a 12-in pipeline (145 MMcfd) was estimated for each proposed route. The estimation of the offshore pipeline cost for the 8-in is out of the bounds of normal practice in deep water as the pipeline diameter is much smaller than usually installed offshore. Table 12.2 below shows examples of recent offshore pipelines for comparison.

Table 12.2: Example offshore natural gas pipeline projects

Name	Date Completed	Location	Water depth (meters)	Undersea Length (km)	# of Pipes	Pipe Diameter (inches)	PipeWall thickness (inches)	Total Volume (MMcfd)	Offshore Cost (US$ million)	Capital Cost per Pipe	Cost per km (US$ million per km)	Cost per km-inch (US$ per km-inch)
Keathley Canyon Connector	2015	US Gulf of Mexico	2,215	344	1	20	2	400	600	600	1.74	87,209
Trans-Med (2 pipes)	1983–1997	Mediterranean Sea	610	155	2	20	0.79	2,922	1,500	750	4.84	241,935
Blue Stream	2002	Black Sea	2100	396	1	24	1.26	1,548	1,700	1,700	4.29	178,872
Medgaz	2010	Mediterranean Sea	N/A	210	1	24	1.10	774	882	882	4.20	175,000
South Stream (3 pipes)	Not built	Black Sea	2100	925	3	32	1.54	6,095	13,000	4,333	4.68	146,396
Nord Stream (2 pipes)	2012	Baltic Sea	200	1,224	2	48	1.32	5,321	11,440	5,720	4.67	97,358
Nord Stream 2 (2 pipes)	2019	Baltic Sea	200	1,224	2	48	1.32	5,321	10,500	5,250	4.29	89,369
Average				**542**	**1.7**	**28**	**1.30**	**2,843**	**5,660**	**2,301**	**4.07**	**154,462**

Source: Energy Narrative based on data from Oil & Gas Journal; Nord Stream; MIT study on Natural Gas Monetization Pathways for Cyprus

This selection of recent projects suggests that the average cost per kilometer for an undersea pipeline is roughly US$4 million. As each of these pipelines is significantly larger than the pipeline proposed for Guyana, a more relevant measure could be the cost per kilometer of length and inch of pipeline diameter (a composite measure noted as km-inches). The average cost reported for the above projects per kilometer-inch is roughly US$154,500. It is important to note that all projects listed above (with the exception of the Keathley Canyon Connector project) are located in Europe, which may affect the average cost per project relative to other regions of the world.

By comparison, the INGAA Foundation (the public information and advocacy arm of the Interstate Natural Gas Association of America, an industry association for long distance natural gas pipeline developers and operators) estimated that the average cost for offshore pipelines built in the United States in 2015 was US$96,875 per kilometer-inch. This study did not distinguish between deep water pipelines or shallow water pipelines, and so likely underestimates the cost for deep water pipelines that require thicker walls and more expensive installation. The specific case of the Keathley Canyon Connector pipeline that was completed in 2015 was reported to require roughly US$1 million per mile for pipeline materials alone. The reported day rate for the J-lay and S-lay installation rigs ranged between US$750,000 and US$1.5 million per day. These rigs were able to lay pipe at roughly 2 km per day, suggested a total installation cost of US$1 million to US$1.375 million per km. This is comparable to the reported total cost for the project of $600 million, or US$1.74 million per km.

An approximation to the installed cost of an offshore pipeline has been made below by considering the installed cost for the materials required to build a 12-in pipeline and substituting a lower material cost for the 8-in pipeline by scaling by the relative cross-sectional areas.

The cost of the offshore pipeline was estimated by using industry practices in estimating, the methodology was as follows: 1) the cross sectional area of the pipeline was calculated, 2) the weight of the pipeline in kg/m was calculated, 3) the cost of the pipeline in $/m was calculated in 2013 prices, 4) the 2013 prices were adjusted to process today using a market index for steel, 5) the coating cost of 15% of the uncoated pipe was calculated, 6) the installed cost was calculated as 2.5 times the total pipe cost per m, and 7) the final cost for the pipeline segment was calculated. Table 12.3 below shows the total estimated installed cost for each pipeline route and size combination based on this methodology.

Table 12.3: Estimated pipeline cost for offshore natural gas pipeline options

Landing	Length (km)	Installed Cost (8-in)	Installed Cost (12-in)
Georgetown	185	$170MM	$235MM
Clonbrook	180	$165MM	$230MM
New Amsterdam	205	$190MM	$260MM

Source: Energy Narrative estimates

It is estimated that one compressor station at the landing site for the offshore natural gas pipeline will be required. Onshore, gas compression facilities will need to be built to ensure pipeline pressure is maintained. The offshore pipeline acts as a conduit and a reservoir for the gas. In times when there is less than planned throughput into the pipeline due to well maintenance, well availability or facility downtime, the offshore pipeline pressure will fall, requiring a boost from the onshore compressor station. Onshore compressor stations are priced at US$ 25 million each for site works, buildings and equipment not directly related to gas compression equipment. Compressors and associated equipment (drivers, coolers, and ancillaries) are priced at US$ 1,500 per demand horsepower. While hydraulic studies by ExxonMobil are in process, it is estimated that the compressor station cost will be $27.5MM for the 8-in pipeline and $37.5MM for the 12-in pipeline.

In addition to compression, the natural gas liquids present in the wet gas that is transported in the pipeline can be separated and sold as LPG. The INGAA Foundation estimated the average cost of a natural gas separation plant in the United States to be US$525,000 per MMcfd of natural gas processed (not included the required compression, which is captured in the analysis above). This results in an estimated cost of US$15.75 million for a separator plant for 30 MMcfd and US$76.125 for a 145 MMcfd capacity separator. Table 12.4 below shows the total estimated cost for the compression and liquids separation plant.

Table 12.4: Estimated cost for natural gas compressors

Item	8-in Pipeline	12-in Pipeline
Compressor Station	$25.0MM	$25.0MM
Compression	$2.5MM	$12.5MM
Total Compressor Station Cost	$27.5MM	$37.5MM
Gas Separation Plant	$16MM	$76MM
Total Cost	**$43.5MM**	**$114MM**

Source: Energy Narrative estimates

Table 12.5 below shows the total estimated cost for the pipeline after adding in the cost of compression and liquids separation to the estimated cost for each variation in pipeline size and length.

Table 12.5: Estimated all-in cost for offshore natural gas pipeline options

Landing	Length (km)	Installed Cost (8-in)	Installed Cost (12-in)
Georgetown	185	$213.5MM	$349MM
Clonbrook	180	$208.5MM	$344MM
New Amsterdam	205	$233.5MM	$374MM

Source: Energy Narrative estimates

Table 12.6 below compares the estimated cost for the offshore pipeline based on the multiple calculation and comparison methodologies described above. The low range is based on the 30 MMcfd pipeline using the lowest cost combination of variables for each methodology, while the high range is based on the 145 MMcfd pipeline using the highest cost combination of variables.

Table 12.6: Offshore cost estimates, including liquids separation

	(US$ million)	
Source	Low	High
INGAA average offshore	183	364
Energy Narrative estimate	**208**	**374**
Keathley Canyon per unit material and installation cost	223	463
Offshore projects average (cost per km-inch)	258	498
EEPGL estimate	**400**	**500**
Offshore projects average (cost per km)	730	934

Source: Energy Narrative based on analysis and data sources detailed above.

It is important to note that the cost estimates developed in the analysis above do not provide for contingencies or country-specific costs that may affect the overall cost of the pipeline. These additional costs can significantly increase the cost of the pipeline development and are highly specific to each individual project.

12.3. Onshore pipeline cost

Once the natural gas reaches the shore it must be delivered to the power plants where it will be consumed. The onshore pipelines linking the landing site with power generation sites are assumed to carry up to 10-20 MMcfd each and are sized as 4-in pipelines. A similar methodology to the offshore pipeline cost analysis was used with a multiple of five used to calculates the installation cost. The onshore cost of a 4-in diameter, 1-in thick pipeline is estimated to be $410 per meter.

Based on the above cost analysis, we estimated the transportation tariff for each potential route based on 30 MMcfd average volumes for the 8-in pipeline, and 145 MMcfd average volumes for the 12-in pipeline. The estimated tariff assumed the project was financed with 20% equity (at a real cost of capital of 12%) and 80% debt (at a real interest rate of 8%). Annual O&M costs were estimated to be 2% of the project's capital cost. The project was assumed to have a 20 year depreciation life and taxes were not included in the cost assessment.

It was assumed that there was no need for natural gas storage at the landing site or the individual power plants. The new and converted power plants are expected to be dual fuel, and existing power plants already have liquid fuel storage tanks. This will allow them to use liquid fuels in the event of a disruption in natural gas supply.

This analysis resulted in the levelized tariffs for the various pipeline route options shown in Table 12.7 below. Note that the analysis below assumes that the cost of the natural gas separation plant is borne by the LPG stream that is generated by the plant, and so is not included in the estimated costs for natural gas transportation.

Table 12.7: Levelized natural gas transportation tariffs, offshore pipeline options

	Landing Point		
	Georgetown	Clonbrook	New Amsterdam
		8-in (30 MMcfd)	
Without Compression	2.72	2.64	3.05
With Compression	3.17	3.09	3.49
		12-in (145 MMcfd)	
Without Compression	0.78	0.76	0.86
With Compression	0.9	0.89	0.99

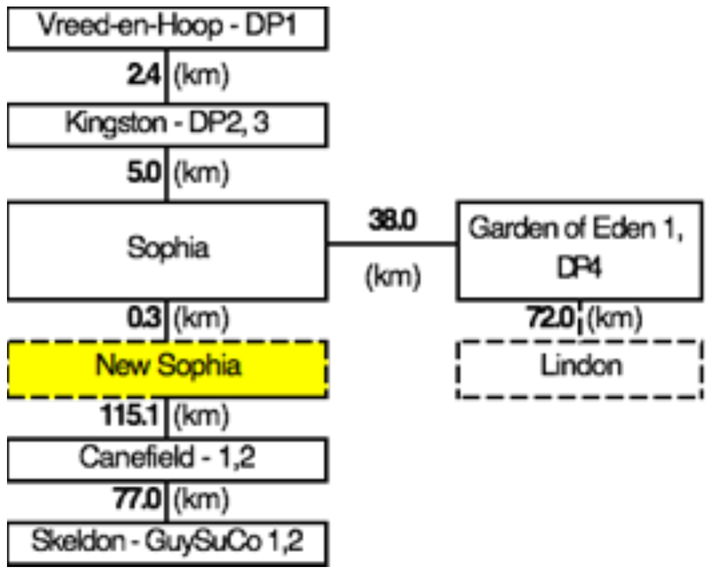
Source: Energy Narrative calculations

The onshore transportation cost analysis used in the calculations for each landing site option below assumed that a 30 MMcfd pipeline would be built and compression would be needed to ensure pipeline pressure and flow was maintained. This, along with the above assumption of zero cost at the wellhead, resulted in a landed price of US$3.17 per MMBtu in Georgetown, US$3.09 per MMBtu in Clonbrook, and US$3.49 per MMBtu in New Amsterdam.

12.4. Option 1: Georgetown (New Sophia substation)

This option assumes that the offshore pipeline is landed at or near at the New Sophia substation. This location is near Georgetown, but is assumed to have sufficient space for compression station and generation facilities at the substation. Figure 12.3 below highlights where the pipeline would land relative to the main generation facilities and substations in the GPL system.

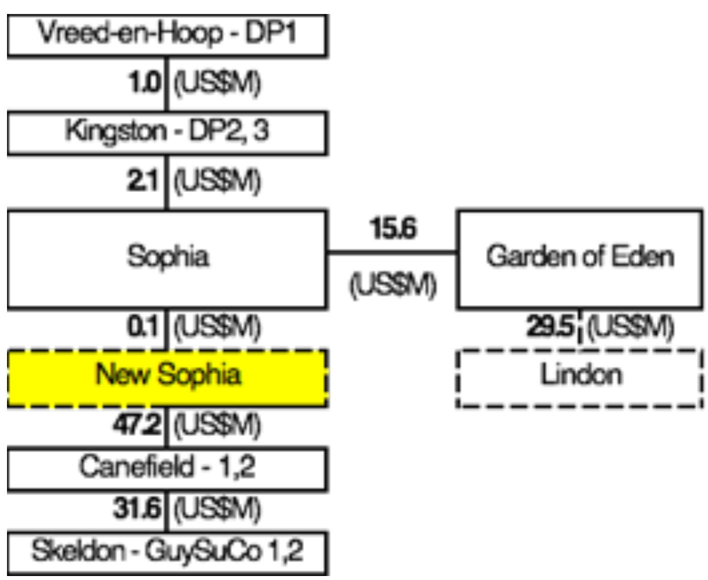
Figure 12.3: New Sophia landing site distance from other GPL generation units



Source: Energy Narrative calculations

Based on the above distances, the cost to develop onshore natural gas pipelines to reach the main generation centers was calculated (see Figure 12.4 below). The total cost was based on the pipeline length and the estimated cost of US$410 per meter noted in section 12.2 above.

Figure 12.4: New Sophia landing site pipeline development costs



Source: Energy Narrative calculations

Building natural gas pipelines to all current generation locations (not including Lindon), would require US$127 million.

Translating these investment costs into a price per unit of natural gas delivered requires an assessment of the volume of natural gas that will be transported by each pipeline. To do this, we first assigned a location to each new power generation plant listed in the 2016 Expansion Plan "Alternative 1". The expansion study does not give the location for each new unit. For the Georgetown Option, we assumed that the two units to be built in 2021 and 2022 are co-located at the natural gas landing site, and are built in a single year (2021) in order to provide an anchor demand for the pipeline. Other new units that are included in the expansion study were allocated to existing generation locations to maintain the current balance of generation across the transmission grid. This allocation minimizes the need to upgrade transmission capacity and reduces the risk of disruption from a transmission outage, assuming that electricity demand growth is similar across all regions of the system.

Table 12.8 shows the proposed generation capacity additions and their location, based on the Alternative 1 expansion case.

Table 12.8: DBIS generation capacity and new additions, Alternative 1 Case (MW)

Capacity	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Garden of Eden - DP 1	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Garden of Eden	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Kingston - DP 2	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Kingston - DP 3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3
Vreed-En-Hoop	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2
Canefield-Corentyne - 1	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Canefield-Corentyne - 2	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Skeldon-Guysuco - 1	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Skeldon-Guysuco - 2	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
V-en-H New Convt Engine					11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Canefeild New Convrt Engine					11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
New Sophie New Engine								22.8	22.8	22.8	22.8	22.8	22.8	22.8
New Sophie New Engine								22.8	22.8	22.8	22.8	22.8	22.8	22.8
Kingston New Engine										22.8	22.8	22.8	22.8	22.8
Garden of Eden New Engine											22.8	22.8	22.8	22.8
Canefield New Engine												22.8	22.8	22.8
New Sophie New Engine													22.8	22.8
V-en-H New Engine													22.8	22.8
New Sophia New Engine														22.8
Garden of Eden New Engine														22.8
Total Available Capacity	173.2	173.2	173.2	173.2	196.0	196.0	196.0	241.6	241.6	264.4	287.2	310.0	355.6	401.2

Source: Energy Narrative calculations

The capacity utilization was assumed to be constant across all units, given the lack of a competitive power system and the need for all units to operate to balance the demand across the grid. Table 12.9 below shows the expected generation per unit under the expansion plan's Base Case demand outlook from the 2016 Expansion plan.

Table 12.9: DBIS generation by unit, Alternative 1 and Base Demand Cases (GWh)

Estimated Generation	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Garden of Eden - DP 1	98.2	101.9	107.0	111.5	97.1	97.1	105.7	112.1	124.3	124.4	117.9	110.7	111.1	113.0
Garden of Eden	74.1	76.9	80.7	84.1	73.3	73.3	79.7	84.6	93.8	93.9	89.0	83.5	83.8	85.2
Kingston - DP 2	98.2	101.9	107.0	111.5	97.1	97.1	105.7	112.1	124.3	124.4	117.9	110.7	111.1	113.0
Kingston - DP 3	162.1	168.1	176.5	183.9	160.2	160.2	174.4	185.0	205.2	205.3	194.5	182.7	183.4	186.4
Vreed-En-Hoop	117.0	121.4	127.4	132.8	115.6	115.6	125.9	133.5	148.1	148.2	140.4	131.9	132.3	134.5
Canefield-Corentyne - 1	0.0	0.0	0.0	0.0	18.6	19.2	21.6	22.9	25.2	25.2	24.1	22.6	22.7	23.1
Canefield-Corentyne - 2	25.0	25.9	27.2	28.4	24.7	24.7	26.9	28.5	31.7	31.7	30.0	28.2	28.3	28.8
Skeldon-Guysuco - 1	44.7	46.3	48.6	50.7	44.1	44.1	48.0	51.0	56.5	56.6	53.6	50.3	50.5	51.4
Skeldon-Guysuco - 2	78.8	78.8	78.8	78.8	78.8	105.1	144.1	152.9	157.7	157.7	157.7	151.0	151.5	154.1
V-en-H New Convt Engine	0.0	0.0	0.0	0.0	47.1	48.7	54.8	58.1	63.9	63.9	61.0	57.4	57.6	58.5
Canefield New Convt Engine	0.0	0.0	0.0	0.0	47.1	48.7	54.8	58.1	63.9	63.9	61.0	57.4	57.6	58.5
New Sophie New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	116.2	128.9	128.9	122.2	114.8	115.2	117.1
New Sophie New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	116.2	128.9	128.9	122.2	114.8	115.2	117.1
Kingston New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	128.9	122.2	114.8	115.2	117.1
Garden of Eden New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	122.2	114.8	115.2	117.1
Canefield New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	114.8	115.2	117.1
New Sophie New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	115.2	117.1
V-en-H New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	115.2	117.1
New Sophia New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.1
Garden of Eden New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.1
Total Electricity Demand	**698**	**721**	**753**	**782**	**810**	**837**	**942**	**1,231**	**1,353**	**1,480**	**1,536**	**1,560**	**1,796**	**2,060**

Source: Energy Narrative calculations

Based on this generation outlook, we assumed that natural gas pipelines would be built between the offshore natural gas landing site at New Sophia and the generation units at Vreed-en-Hoop, Kingston, Garden of Eden, and Canefield. A pipeline was not built to Lindon or Skeldon under this Option given the long distance and limited natural gas demand expected at each location. Removing the pipeline to Skeldon reduces the total investment in onshore natural gas pipelines from US$127 million to US$95.4 million.

The total amount of electricity generation capacity that is able to use natural gas at each location is shown in Table 12.10 below.

Table 12.10: Total DBIS natural gas fired generation capacity by location, Alternative 1 Case (MW)

NG fired Capacity by Location	2022	2023	2024	2025	2030	2035
Vreed-en-Hoop	37.6	37.6	37.6	37.6	60.4	60.4
Kingston	58.3	81.1	81.1	81.1	81.1	81.1
New Sophia	45.6	45.6	45.6	45.6	68.4	91.2
Garden of Eden	38.6	38.6	61.4	61.4	61.4	84.2
Canefield	21.5	21.5	21.5	44.3	44.3	44.3

Source: Energy Narrative calculations

The installed capacity represents the maximum electricity that could be generated at each location. For the units to be fueled by natural gas, the supplying pipeline needs to be sized to be able to provide for this maximum demand, even though the average throughput on the pipeline will be less. Table 12.11 below shows the maximum potential natural gas demand at each location, based on each region's installed capacity and the average efficiency of the installed units.

Table 12.11: Maximum potential natural gas demand for electricity generation by location, Alternative 1 Case (MMcfd)

Peak Natural Gas Consumption	2022	2023	2024	2025	2030	2035
Vreed-en-Hoop	6.7	6.7	6.7	6.7	10.8	10.8
Kingston	9.6	13.7	13.7	13.7	13.7	13.7
New Sophia	8.2	8.2	8.2	8.2	12.3	16.4
Garden of Eden	7.5	7.5	11.7	11.7	11.7	15.8
Canefield	4.1	4.1	4.1	8.2	8.2	8.2

Source: Energy Narrative calculations

The electricity that will actually be generated by the natural gas fired units to meet the system's electricity demand is shown in Table 12.12 below.

Table 12.12: Total DBIS electricity generated by location, Alternative 1 and Base Demand Case (GWh)

Estimated Generation	2022	2023	2024	2025	2030	2035
Vreed-en-Hoop	186.2	187.8	190.0	189.2	305.1	310.2
Kingston	288.7	405.0	409.9	408.2	409.6	416.5
New Sophia	225.8	227.7	230.5	229.5	345.5	468.3
Garden of Eden	191.2	192.8	310.3	309.0	310.1	432.4
Canefield	106.5	107.4	108.7	223.0	223.8	227.5

Source: Energy Narrative calculations

Based on the efficiency of each power plant, this translated into the total actual natural gas demand at each location shown in Table 12.13 below.

Table 12.13: Estimated natural gas demand for electricity generation by location, Alternative 1 and Base Demand Cases (MMcfd)

Average Natural Gas Consumption	2022	2023	2024	2025	2030	2035
Vreed-en-Hoop	3.8	3.8	3.9	3.8	6.2	6.3
Kingston	5.4	7.8	7.9	7.9	7.9	8.1
New Sophia	4.6	4.7	4.7	4.7	7.1	9.6
Garden of Eden	4.3	4.3	6.7	6.7	6.7	9.2
Canefield	2.3	2.3	2.3	4.7	4.7	4.8
Total NG Consumption	**20.4**	**23.0**	**25.6**	**27.9**	**32.7**	**38.1**

Source: Energy Narrative calculations

The levelized transportation tariff to deliver natural gas to each location was calculated based on the distance, the estimated cost per meter to install the natural gas pipeline, and the average demand at each location over the life of the pipeline. The same financial and accounting assumptions were made for the onshore pipelines as were made for the undersea pipeline (see Section 12.2 above). These calculations resulted in the following costs per pipeline segment shown in Table 12.14 below.

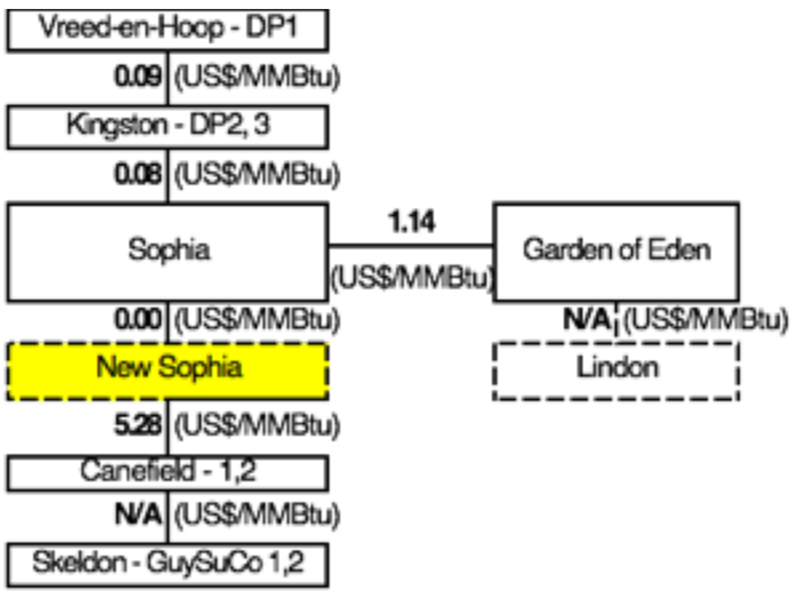
Table 12.14: Estimated natural gas transportation cost by segment

NG Pipeline Segment	Volume (MMcfd) Average	Peak	(US$ M) Cost	(US$/MMBtu) Unit Cost
New Sophia - Sophia	19.3	33.1	0.123	0.003
Sophia - Kingston	12.6	21.7	2.05	0.075
Kingston - Vreed-en-Hoop	5.1	8.7	0.984	0.093
Sophia - Garden of Eden	6.6	11.4	15.58	1.135
New Sophia - Canefield	4.3	7.4	47.191	5.276

Source: Energy Narrative calculations

The resulting transportation tariffs per segment are shown in Figure 12.5 below.

Figure 12.5: Estimated natural gas transportation tariffs by segment, Alternative 1 and Base Demand Cases (US$ per MMBtu)



Source: Energy Narrative calculations

The total cost to deliver natural gas to each location is shown in Table 12.15 below. As noted in section 12.1.4 above, this cost assumes the wellhead price for the natural gas is zero, so there is no additional cost for the natural gas molecule itself.

Table 12.15: Estimated natural gas transportation cost by segment

Total NG Trans $	Transportation (US$/MMBtu) Undersea	Compression	On shore	Total
Vreed-en-Hoop	2.72	0.45	0.17	**3.34**
Kingston	2.72	0.45	0.08	**3.25**
New Sophia	2.72	0.45	0.00	**3.17**
Garden of Eden	2.72	0.45	1.14	**4.31**
Canefield	2.72	0.45	5.28	**8.45**

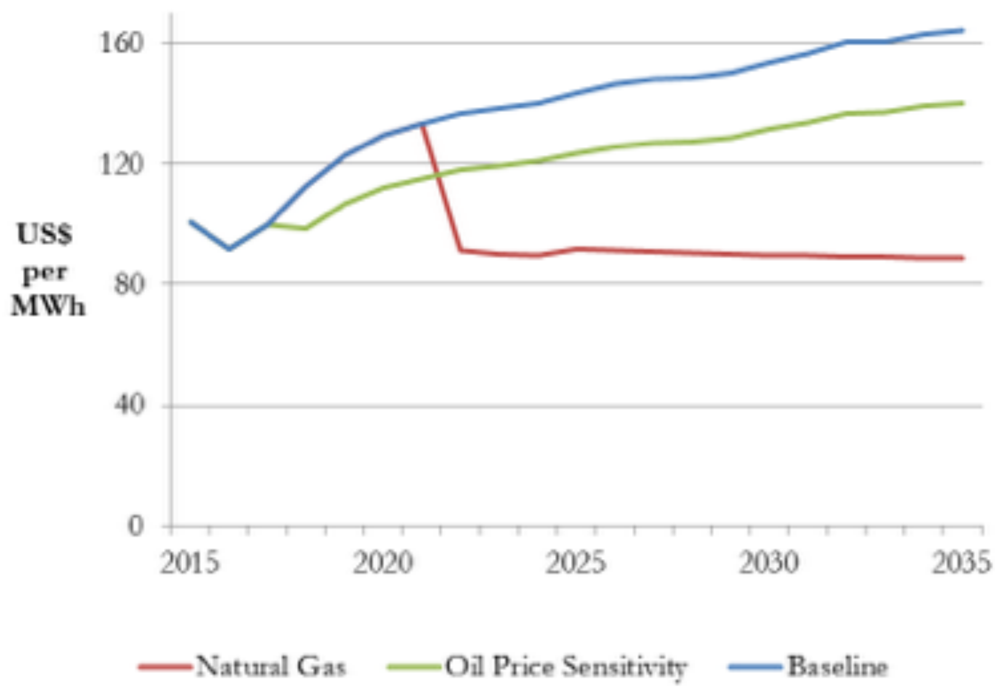
Source: Energy Narrative calculations

The average cost to transport natural gas to the generator is similar across the major generator sites near Georgetown, including New Sophia, Kingston, and Vreed-en-Hoop.

Delivered natural gas is roughly US$1 per MMBtu more expensive in Garden of Eden owing to the smaller volume and longer distance. The cost to deliver gas to Canefield is far more expensive, estimated to be almost double the next most expensive area (Garden of Eden). The extreme pipeline length relative to the volume of natural gas required makes this pipeline of questionable value. Unless additional natural gas demand (such as for industrial uses) were located at the Canefield region, this pipeline may be uneconomic.

Figure 12.6 below compares the impact on power prices from switching to natural gas. The cost per MWh shown includes the levelized capital and fixed operations and maintenance (O&M) costs, as well as the price of fuel and other variable O&M expenses. In addition to the Baseline case, an oil price sensitivity case is included to test the impact of reducing the oil price forecast by 20%.

Figure 12.6: Average cost of power generation, HFO vs. Option 1 (Georgetown) (US$ per MWh)



Source: Energy Narrative calculations

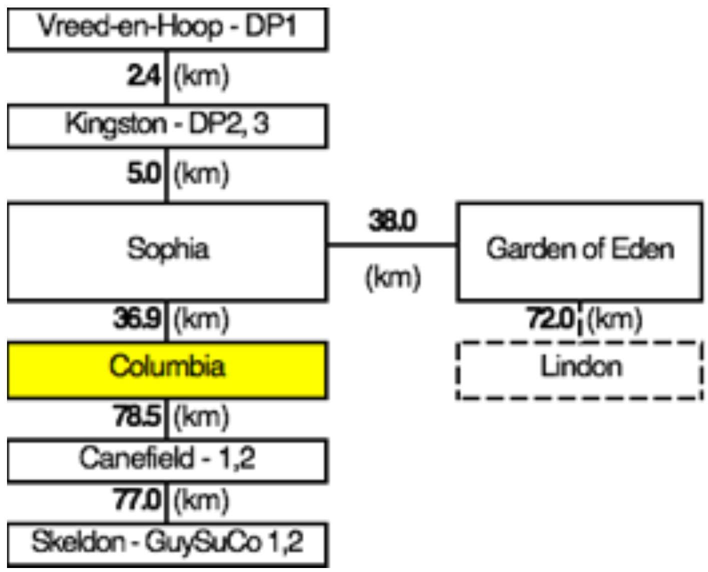
The much lower delivered cost of natural gas results in significant savings from the baseline HFO-fired projection. In this projection, natural gas prices are fixed (being based on the levelized cost of the pipelines and a zero wellhead price), and so the gap between natural gas and HFO fired electricity widens in future years. The size of the gap suggests there is ample room for negotiation to arrive at a wellhead price that is greater than zero but would still provide substantial savings in electricity prices. Even after reducing the forecast oil price by 20%, the cost of electricity from natural gas averages more than US$40 per MWh cheaper.

It is important to note that this analysis does not include the cost of any transmission and substation upgrades that may be required to accommodate the new power generation facilities or growing electricity demand. A detailed power flow analysis is required to determine the electricity grid's changing requirements and the expected investment needed to meet those requirements.

12.5. Option 2: Clonbrook (Columbia substation)

This option assumes that the offshore pipeline is landed at Clonbrook which is estimated to be near the Columbia substation. This location is roughly 35 km east of Georgetown, and is selected because it has more readily available space for a compression station and generation facilities at the substation. Figure 12.7 below highlights where the pipeline would land relative to the main generation facilities and substations in the GPL system.

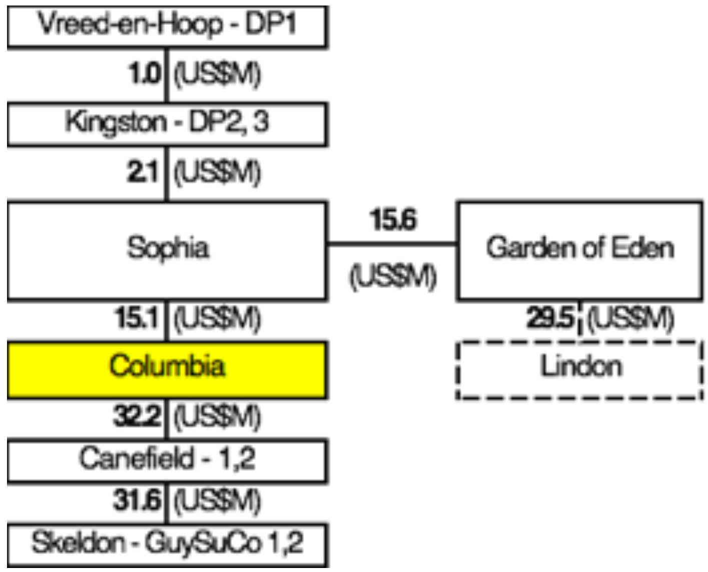
Figure 12.7: Columbia landing site distance from other GPL generation units



Source: Energy Narrative calculations

Based on the above distances, the cost to develop onshore natural gas pipelines to reach the main generation centers was calculated (see Figure 12.8 below). The total cost was based on the pipeline length and the estimated cost of US$410 per meter noted in section 12.2 above.

Figure 12.8: Columbia landing site pipeline development cost



Source: Energy Narrative calculations

Building natural gas pipelines to all current generation locations (not including Lindon), would require US$127 million.

Translating these investment costs into a price per unit of natural gas delivered requires an assessment of the volume of natural gas that will be transported by each pipeline. To do this, we first assigned a location to each new power generation plant listed in the 2016 Expansion Plan "Alternative 1". The expansion study does not give the location for each new unit. For this Option, we assumed that the two units to be built in 2021 and 2022 are co-located at the natural gas landing site, and are built in a single year (2021) in order to provide an anchor demand for the pipeline. Other new units that are included in the expansion study were allocated to existing generation locations to maintain the current balance of generation across the transmission grid. This allocation minimizes the need to upgrade transmission capacity and reduces the risk of disruption from a transmission outage, assuming that electricity demand growth is similar across all regions of the system.

Table 12.16 shows the proposed generation capacity additions and their location, based on the Alternative 1 expansion case.

Table 12.16: DBIS generation capacity and new additions, Alternative 1 Case (MW)

Capacity	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Garden of Eden - DP 1	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Garden of Eden	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Kingston - DP 2	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Kingston - DP 3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3
Vreed-En-Hoop	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2
Canefield-Corentyne - 1	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Canefield-Corentyne - 2	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Skeldon-Guysuco - 1	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Skeldon-Guysuco - 2	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
V-en-H New Convt Engine					11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Canefield New Convrt Engine					11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
New Columbia New Engine								22.8	22.8	22.8	22.8	22.8	22.8	22.8
New Columbia New Engine								22.8	22.8	22.8	22.8	22.8	22.8	22.8
Kingston New Engine										22.8	22.8	22.8	22.8	22.8
Garden of Eden New Engine											22.8	22.8	22.8	22.8
Canefield New Engine												22.8	22.8	22.8
New Columbia New Engine													22.8	22.8
V-en-H New Engine													22.8	22.8
New Columbia New Engine														22.8
Garden of Eden New Engine														22.8
Total Available Capacity	**173.2**	**173.2**	**173.2**	**173.2**	**196.0**	**196.0**	**196.0**	**241.6**	**241.6**	**264.4**	**287.2**	**310.0**	**355.6**	**401.2**

Source: Energy Narrative calculations

The capacity utilization was assumed to be constant across all units, given the lack of a competitive power system and the need for all units to operate to balance the demand across the grid. Table 12.17 below shows the expected generation per unit under the expansion plan's Base Case demand outlook from the 2016 Expansion plan.

Table 12.17: DBIS generation by unit, Alternative 1 and Base Demand Cases (GWh)

Estimated Generation	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Garden of Eden - DP 1	98.2	101.9	107.0	111.5	97.1	97.1	105.7	112.1	124.3	124.4	117.9	110.7	111.1	113.0
Garden of Eden	74.1	76.9	80.7	84.1	73.3	73.3	79.7	84.6	93.8	93.9	89.0	83.5	83.8	85.2
Kingston - DP 2	98.2	101.9	107.0	111.5	97.1	97.1	105.7	112.1	124.3	124.4	117.9	110.7	111.1	113.0
Kingston - DP 3	162.1	168.1	176.5	183.9	160.2	160.2	174.4	185.0	205.2	205.3	194.5	182.7	183.4	186.4
Vreed-En-Hoop	117.0	121.4	127.4	132.8	115.6	115.6	125.9	133.5	148.1	148.2	140.4	131.9	132.3	134.5
Canefield-Corentyne - 1	0.0	0.0	0.0	0.0	18.6	19.2	21.6	22.9	25.2	25.2	24.1	22.6	22.7	23.1
Canefield-Corentyne - 2	25.0	25.9	27.2	28.4	24.7	24.7	26.9	28.5	31.7	31.7	30.0	28.2	28.3	28.8
Skeldon-Guysuco - 1	44.7	46.3	48.6	50.7	44.1	44.1	48.0	51.0	56.5	56.6	53.6	50.3	50.5	51.4
Skeldon-Guysuco - 2	78.8	78.8	78.8	78.8	78.8	105.1	144.1	152.9	157.7	157.7	157.7	151.0	151.5	154.1
V-en-H New Convt Engine	0.0	0.0	0.0	0.0	47.1	48.7	54.8	58.1	63.9	63.9	61.0	57.4	57.6	58.5
Canefield New Convrt Engine	0.0	0.0	0.0	0.0	47.1	48.7	54.8	58.1	63.9	63.9	61.0	57.4	57.6	58.5
New Columbia New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	116.2	128.9	128.9	122.2	114.8	115.2	117.1
New Columbia New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	116.2	128.9	128.9	122.2	114.8	115.2	117.1
Kingston New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	128.9	122.2	114.8	115.2	117.1
Garden of Eden New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	122.2	114.8	115.2	117.1
Canefield New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	114.8	115.2	117.1
New Columbia New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	115.2	117.1
V-en-H New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	115.2	117.1
New Columbia New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.1
Garden of Eden New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.1
Total Electricity Demand	**698**	**721**	**753**	**792**	**810**	**837**	**942**	**1,231**	**1,363**	**1,483**	**1,536**	**1,590**	**1,796**	**2,060**

Source: Energy Narrative calculations

Based on this generation outlook, we assumed that natural gas pipelines would be built between the offshore natural gas landing site at Columbia and the generation units at Vreed-en-Hoop, Kingston, Garden of Eden, and Canefield. A pipeline was not built to Lindon or Skeldon under this Option given the long distance and limited natural gas demand expected at each location. Removing the pipeline to Skeldon reduces the total investment in onshore natural gas pipelines from US$127 million to US$95.4 million.

The total amount of electricity generation capacity that is able to use natural gas at each location is shown in Table 12.18 below.

Table 12.18: Total DBIS natural gas fired generation capacity by location, Alternative 1 Case (MW)

Capacity by Location	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2036
Vreed-en-Hoop	37.6	37.6	37.6	37.6	37.6	37.6	60.4	60.4	60.4	60.4	60.4	60.4	60.4	60.4
Kingston	58.3	81.1	81.1	81.1	81.1	81.1	81.1	81.1	81.1	81.1	81.1	81.1	81.1	81.1
Columbia	45.6	45.6	45.6	45.6	68.4	68.4	68.4	68.4	68.4	91.2	91.2	91.2	91.2	91.2
Garden of Eden	38.6	38.6	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	84.2	84.2	84.2
Canefield	21.5	21.5	21.5	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3

Source: Energy Narrative calculations

The installed capacity represents the maximum electricity that could be generated at each location. For the units to be fueled by natural gas, the supplying pipeline needs to be sized to be able to provide for this maximum demand, even though the average throughput on the pipeline will be less. Table 12.19 below shows the maximum potential natural gas demand at each location, based on each region's installed capacity and the average efficiency of the installed units.

Table 12.19: Maximum potential natural gas demand for electricity generation by location, Alternative 1 Case (MMcfd)

Peak Natural Gas Consumption	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2036
Vreed-en-Hoop	6.7	6.7	6.7	6.7	6.7	6.7	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Kingston	9.6	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
Columbia	8.2	8.2	8.2	8.2	12.3	12.3	12.3	12.3	12.3	16.4	16.4	16.4	16.4	16.4
Garden of Eden	7.5	7.5	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	15.8	15.8	15.8
Canefield	4.1	4.1	4.1	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2

Source: Energy Narrative calculations

The electricity that will actually be generated by the natural gas fired units to meet the system's electricity demand is shown in Table 12.20 below.

Table 12.20: Total DBIS electricity generated with natural gas by location, Alternative 1 and Base Demand Case (GWh)

Estimated Generation	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2036
Vreed-en-Hoop	211.9	212.1	201.4	189.2	181.6	186.9	289.1	297.1	305.1	296.1	303.6	294.3	302.2	310.2
Kingston	329.5	458.6	434.6	408.2	391.7	403.2	388.1	388.9	408.6	396.3	407.6	395.1	405.8	416.5
Columbia	257.7	257.9	244.4	229.5	330.4	340.1	327.3	336.4	345.5	445.6	458.4	444.3	456.3	468.3
Garden of Eden	218.2	218.3	329.0	309.0	296.6	305.3	293.8	302.0	310.1	300.0	308.6	410.2	421.3	432.4
Canefield	120.7	120.9	115.0	223.0	214.0	220.2	212.0	217.9	223.8	216.6	222.7	215.8	221.7	227.6

Source: Energy Narrative calculations

Based on the efficiency of each power plant, this translated into the total natural gas demand at each location shown in Table 12.21 below.

Table 12.21: Estimated natural gas demand for electricity generation by location, Alternative 1 and Base Demand Cases (MMcfd)

Average Natural Gas Consumption	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2036
Vreed-en-Hoop	4.3	4.3	4.1	3.8	3.7	3.8	5.9	6.1	6.2	6.0	6.2	6.0	6.2	6.3
Kingston	6.2	8.9	8.4	7.9	7.6	7.8	7.5	7.7	7.9	7.7	7.9	7.6	7.8	8.1
Columbia	5.3	5.3	5.0	4.7	6.8	7.0	6.7	6.9	7.1	9.2	9.4	9.1	9.4	9.6
Garden of Eden	4.9	4.9	7.1	6.7	6.4	6.6	6.4	6.5	6.7	6.5	6.7	8.8	9.0	9.2
Canefield	2.6	2.6	2.5	4.7	4.5	4.6	4.5	4.6	4.7	4.6	4.7	4.5	4.7	4.8
Total NG Consumption	**23.3**	**26.0**	**27.1**	**27.9**	**29.0**	**29.9**	**31.0**	**31.8**	**32.7**	**33.9**	**34.9**	**36.1**	**37.1**	**38.1**

Source: Energy Narrative calculations

The levelized transportation tariff to deliver natural gas to each location was calculated based on the distance, the estimated cost per meter to install the natural gas pipeline, and the average demand at each location over the life of the pipeline. The same financial and accounting assumptions were made for the onshore pipelines as were made for the undersea pipeline (see Section 12.2 above). These calculations resulted in the following costs per pipeline segment shown in Table 12.22 below.

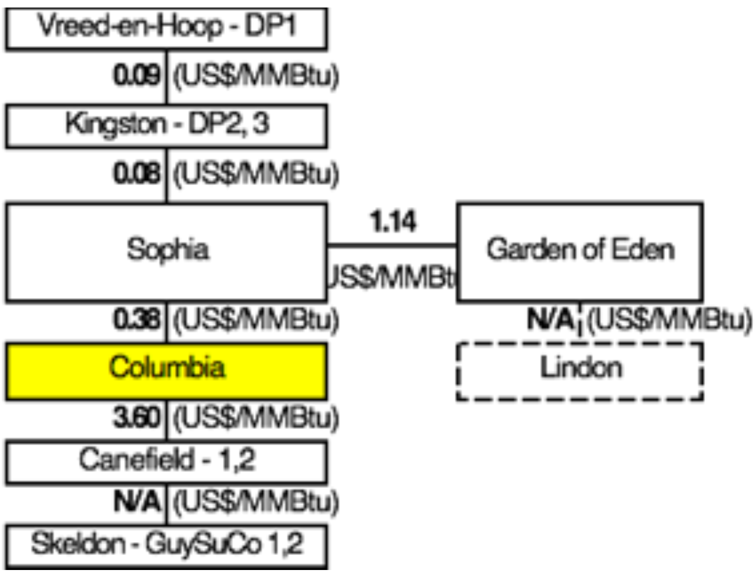
Table 12.22: Estimated natural gas transportation cost by segment

NG Pipeline Segment	Volume (MMcfd) Average	Peak	(US$) Cost	(US$/MMBtu) Unit Cost
Columbia - Sophia	19.3	33.1	15.129	0.377
Sophia - Kingston	12.6	21.7	2.05	0.075
Kingston - Vreed-en-Hoop	5.1	8.7	0.984	0.093
Sophia - Garden of Eden	6.6	11.4	15.58	1.135
Columbia - Canefield	4.3	7.4	32.185	3.599

Source: Energy Narrative calculations

The resulting transportation tariffs per segment are shown in Figure 12.9 below.

Figure 12.9: Estimated natural gas transportation tariffs by segment, Alternative 1 and Base Demand Cases (US$ per MMBtu)



Source: Energy Narrative calculations

The total cost to deliver natural gas to each location is shown in Table 12.23 below. As noted in section 12.1.4 above, this cost assumes the wellhead price for the natural gas is zero, so there is no additional cost for the natural gas molecule itself.

Table 12.23: Estimated natural gas transportation cost by segment

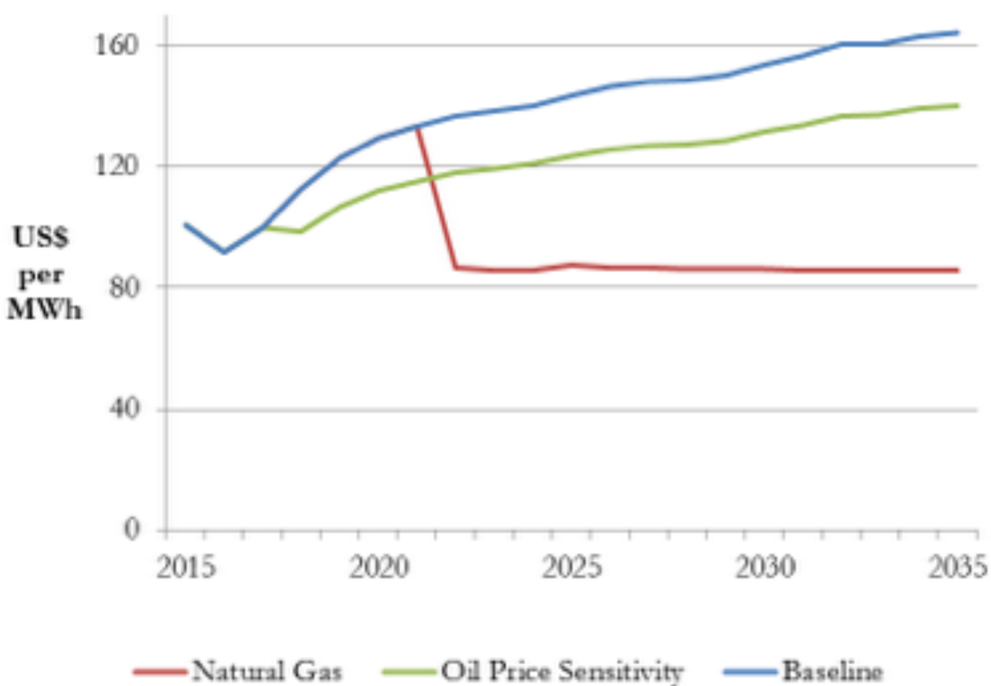
Total NG Trans $	Transportation (US$/MMBtu) Undersea	Compression	On shore	Total
Vreed-en-Hoop	2.64	0.45	0.55	3.64
Kingston	2.64	0.45	0.45	3.54
Columbia	2.64	0.45	0.00	3.09
Garden of Eden	2.64	0.45	1.14	4.23
Canefield	2.64	0.45	3.60	6.69

Source: Energy Narrative calculations

The average cost to transport natural gas to the generator is similar across the major generator sites near Georgetown, including Kingston and Vreed-en-Hoop. Delivered natural gas at Columbia is roughly US$0.50 per MMBtu cheaper while natural gas delivered to Garden of Eden is roughly US$0.60 more expensive than Georgetown owing to the smaller volume and longer distance. The cost to deliver gas to Canefield is also more expensive, estimated to be almost US$2.50 more than the next most expensive area (Garden of Eden). The extreme pipeline length relative to the volume of natural gas required (despite Columbia being closer than New Sophia in Option 1) makes this pipeline the most expensive in the system.

Figure 12.10 below compares the impact on power prices from switching to natural gas. The cost per MWh shown includes the levelized capital and fixed operations and maintenance (O&M) costs, as well as the price of fuel and other variable O&M expenses. In addition to the Baseline case, an oil price sensitivity case is included to test the impact of reducing the oil price forecast by 20%.

Figure 12.10: Average cost of power generation, HFO vs. Option 2 (Clonbrook) (US$ per MWh)



Source: Energy Narrative calculations

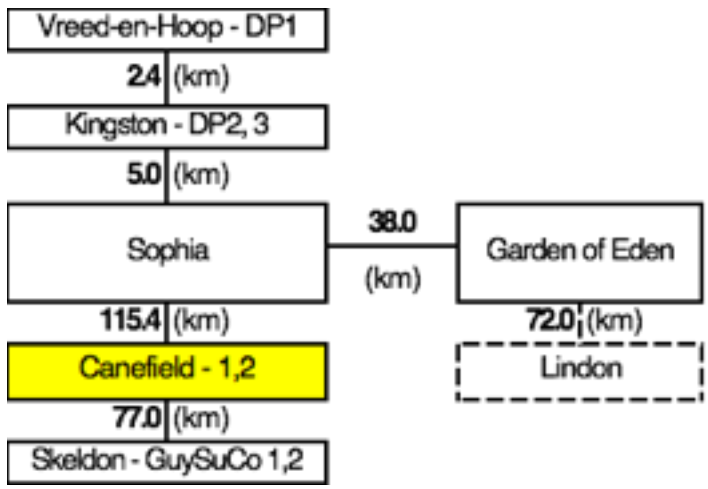
The much lower delivered cost of natural gas results in significant savings from the baseline HFO-fired projection. In this projection, natural gas prices are fixed (being based on the levelized cost of the pipelines and a zero wellhead price), and so the gap between natural gas and HFO fired electricity widens in future years. The size of the gap suggests there is ample room for negotiation to arrive at a wellhead price that is greater than zero but would still provide substantial savings in electricity prices. Even after reducing the forecast oil price by 20%, the cost of electricity from natural gas averages roughly US$40 per MWh cheaper.

It is important to note that this analysis does not include the cost of any transmission and substation upgrades that may be required to accommodate the new power generation facilities or growing electricity demand. A detailed power flow analysis is required to determine the electricity grid's changing requirements and the expected investment needed to meet those requirements.

12.6. Option 3: New Amsterdam (Canefield substation)

This option assumes that the offshore pipeline is landed at New Amsterdam, near the Canefield substation. This location is near Guyana's only deep water port and has ample space for a compression station and generation facilities at the substation, as well as additional industrial development if required. Figure 12.11 below highlights where the pipeline would land relative to the main generation facilities and substations in the GPL system.

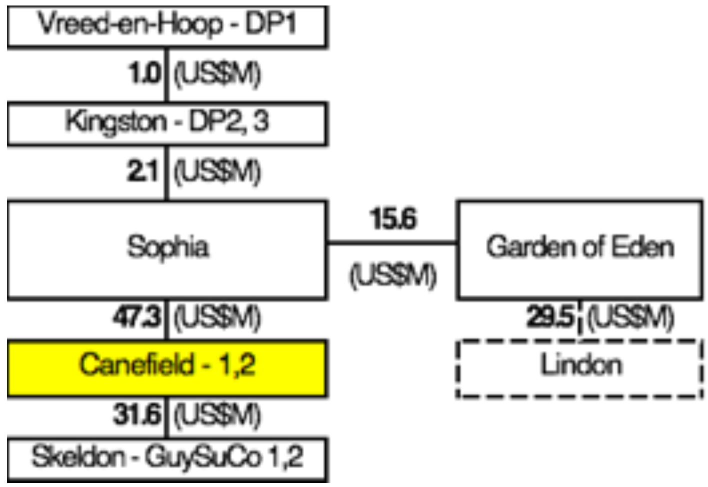
Figure 12.11: Canefield landing site distance from other GPL generation units



Source: Energy Narrative calculations

Based on the above distances, the cost to develop onshore natural gas pipelines to reach the main generation centers was calculated (see Figure 12.12 below). The total cost was based on the pipeline length and the estimated cost of US$410 per meter noted in section 12.2 above.

Figure 12.12: Canefield landing site pipeline development costs



Source: Energy Narrative calculations

Building natural gas pipelines to all current generation locations (not including Lindon), would require US$127 million.

Translating these investment costs into a price per unit of natural gas delivered requires an assessment of the volume of natural gas that will be transported by each pipeline. To do this, we first assigned a location to each new power generation plant listed in the 2016 Expansion Plan "Alternative 1". The Expansion study does not give the location for each new unit. For this Option, we assumed that the two units to be built in 2021 and 2022 are co-located at the natural gas landing site, and are built in a single year (2021) in order to provide an anchor demand for the pipeline. Other new units that are included in the expansion study were allocated to existing generation locations to maintain the current balance of generation across the transmission grid. This allocation minimizes the need to upgrade transmission capacity and reduces the risk of disruption from a transmission outage, assuming that electricity demand growth is similar across all regions of the system.

Table 12.24 shows the proposed generation capacity additions and their location, based on the Alternative 1 expansion case. The location of new generation units is shifted more toward Canefield and Skeldon in this Option. This is based on the assumption that new industrial demand will be located near the port once natural gas is available and so demand growth is more skewed toward this region than in the other two Options.

Table 12.24: DBIS generation capacity and new additions, Alternative 1 Case (MW)

Capacity	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Garden of Eden - DP 1	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Garden of Eden	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Kingston - DP 2	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Kingston - DP 3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3
Vreed-En-Hoop	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2
Canefield-Corentyne - 1	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Canefield-Corentyne - 2	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Skeldon-Guysuco - 1	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Skeldon-Guysuco - 2	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
V-en-H New Convt Engine					11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Canefield New Convrt Engine					11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
New Amsterdam New Engine								22.8	22.8	22.8	22.8	22.8	22.8	22.8
New Amsterdam New Engine								22.8	22.8	22.8	22.8	22.8	22.8	22.8
Kingston New Engine										22.8	22.8	22.8	22.8	22.8
Garden of Eden New Engine											22.8	22.8	22.8	22.8
Skeldon New Engine												22.8	22.8	22.8
New Amsterdam New Engine													22.8	22.8
V-en-H New Engine													22.8	22.8
Kingston New Engine														22.8
Canefield New Engine														22.8
Total Available Capacity	**173.2**	**173.2**	**173.2**	**173.2**	**196.0**	**196.0**	**196.0**	**241.6**	**241.6**	**264.4**	**287.2**	**310.0**	**355.6**	**401.2**

Source: Energy Narrative calculations

The capacity utilization was assumed to be constant across all units, given the lack of a competitive power system and the need for all units to operate to balance the demand across the grid. Table 12.25 below shows the expected generation per unit under the expansion plan's Base Case demand outlook from the 2016 Expansion plan.

Table 12.25: DBIS generation by unit, Alternative 1 and Base Demand Cases (GWh)

Estimated Generation	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Garden of Eden - DP 1	98.2	101.9	107.0	111.5	97.1	97.1	105.7	112.1	124.3	124.4	117.9	110.7	111.1	113.0
Garden of Eden	74.1	76.9	80.7	84.1	73.3	73.3	79.7	84.6	93.8	93.9	89.0	83.5	83.8	85.2
Kingston - DP 2	98.2	101.9	107.0	111.5	97.1	97.1	105.7	112.1	124.3	124.4	117.9	110.7	111.1	113.0
Kingston - DP 3	162.1	168.1	176.5	183.9	160.2	160.2	174.4	185.0	205.2	205.3	194.5	182.7	183.4	186.4
Vreed-En-Hoop	117.0	121.4	127.4	132.8	115.6	115.6	125.9	133.5	148.1	148.2	140.4	131.9	132.3	134.5
Canefield-Corentyne - 1	0.0	0.0	0.0	0.0	18.6	19.2	21.6	22.9	25.2	25.2	24.1	22.6	22.7	23.1
Canefield-Corentyne - 2	25.0	25.9	27.2	28.4	24.7	24.7	26.9	28.5	31.7	31.7	30.0	28.2	28.3	28.8
Skeldon-Guysuco - 1	44.7	46.3	48.6	50.7	44.1	44.1	48.0	51.0	56.5	56.6	53.6	50.3	50.5	51.4
Skeldon-Guysuco - 2	78.8	78.8	78.8	78.8	78.8	105.1	144.1	152.9	157.7	157.7	157.7	151.0	151.5	154.1
V-en-H New Convt Engine	0.0	0.0	0.0	0.0	47.1	48.7	54.8	58.1	63.9	63.9	61.0	57.4	57.6	58.5
Canefield New Convrt Engine	0.0	0.0	0.0	0.0	47.1	48.7	54.8	58.1	63.9	63.9	61.0	57.4	57.6	58.5
New Amsterdam New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	116.2	128.9	128.9	122.2	114.8	115.2	117.1
New Amsterdam New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	116.2	128.9	128.9	122.2	114.8	115.2	117.1
Kingston New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	128.9	122.2	114.8	115.2	117.1
Garden of Eden New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	122.2	114.8	115.2	117.1
Skeldon New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	114.8	115.2	117.1
New Amsterdam New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	115.2	117.1
V-en-H New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	115.2	117.1
Kingston New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.1
Canefield New Engine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.1
Total Electricity Demand	**698**	**721**	**753**	**782**	**810**	**837**	**942**	**1,231**	**1,353**	**1,460**	**1,536**	**1,560**	**1,796**	**2,060**

Source: Energy Narrative calculations

Based on this generation outlook, we assumed that natural gas pipelines would be built between the offshore natural gas landing site at Canefield and the generation units at Vreed-en-Hoop, Kingston, Garden of Eden, and Skeldon. A pipeline was not built to Lindon under this Option given the long distance and limited natural gas demand expected at the location.

The total amount of electricity generation capacity that is able to use natural gas at each location is shown in Table 12.26 below.

Table 12.26: Total DBIS natural gas fired generation capacity by location, Alternative 1 Case (MW)

Capacity by Location	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Vreed-en-Hoop	26.2	26.2	26.2	26.2	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	60.4	60.4
Kingston	58.3	58.3	58.3	58.3	58.3	58.3	58.3	58.3	58.3	81.1	81.1	81.1	81.1	103.9
Canefield	10.1	10.1	10.1	10.1	21.5	21.5	21.5	67.1	67.1	67.1	67.1	67.1	89.9	112.7
Garden of Eden	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	61.4	61.4	61.4	61.4
Skeldon	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	62.8	62.8	62.8

Source: Energy Narrative calculations

The installed capacity represents the maximum electricity that could be generated at each location. For the units to be fueled by natural gas, the supplying pipeline needs to be sized to be able to provide for this maximum demand, even though the average throughput on the pipeline will be less. Table 12.27 below shows the maximum potential natural gas demand at each location, based on each region's installed capacity and the average efficiency of the installed units.

Table 12.27: Maximum potential natural gas demand for electricity generation by location, Alternative 1 Case (MMcfd)

Peak Natural Gas Consumption	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Vreed-en-Hoop	0.0	0.0	0.0	0.0	0.0	0.0	6.7	6.7	6.7	6.7	6.7	6.7	10.8	10.8
Kingston	0.0	0.0	0.0	0.0	0.0	0.0	9.6	9.6	9.6	13.7	13.7	13.7	13.7	17.9
Canefield	0.0	0.0	0.0	0.0	0.0	0.0	4.1	12.3	12.3	12.3	12.3	12.3	16.4	20.5
Garden of Eden	0.0	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	11.7	11.7	11.7	11.7
Skeldon	0.0	0.0	0.0	0.0	0.0	0.0	1.8	1.8	1.8	1.8	1.8	5.9	5.9	5.9

Source: Energy Narrative calculations

The electricity that will actually be generated by the natural gas fired units to meet the system's electricity demand is shown in Table 12.28 below.

Table 12.28: Total DBIS electricity generated with natural gas by location, Alternative 1 and Base Demand Case (GWh)

Estimated Generation	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Vreed-en-Hoop	117.0	121.4	127.4	132.8	162.8	164.3	180.6	191.6	211.9	212.1	201.4	189.2	305.1	310.2
Kingston	260.3	270.0	283.5	295.4	257.3	257.3	280.1	297.1	329.5	458.6	434.6	408.2	409.6	533.6
Canefield	25.0	25.9	27.2	28.4	90.4	92.6	103.3	341.9	378.4	378.7	359.4	337.7	454.1	578.8
Garden of Eden	172.4	178.8	187.7	195.6	170.4	170.3	185.4	196.7	218.2	218.3	329.0	309.0	310.1	315.3
Skeldon	123.5	125.2	127.5	129.5	123.0	149.2	192.2	203.8	214.2	214.2	211.3	316.1	317.2	322.5

Source: Energy Narrative calculations

Based on the efficiency of each power plant, this translated into the total natural gas demand at each location shown in Table 12.29 below.

Table 12.29: Estimated natural gas demand for electricity generation by location, Alternative 1 and Base Demand Cases (MMcfd)

Average Natural Gas Consumption	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Vreed-en-Hoop	0.0	0.0	0.0	0.0	0.0	0.0	3.7	3.9	4.3	4.3	4.1	3.8	6.2	6.3
Kingston	0.0	0.0	0.0	0.0	0.0	0.0	5.3	5.6	6.2	6.9	8.4	7.9	7.9	10.5
Canefield	0.0	0.0	0.0	0.0	0.0	0.0	2.2	7.1	7.9	7.9	7.5	7.1	9.5	12.0
Garden of Eden	0.0	0.0	0.0	0.0	0.0	0.0	4.1	4.4	4.9	4.9	7.1	6.7	6.7	6.8
Skeldon	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.1	1.1	1.1	3.4	3.4	3.5
Total NG Consumption	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**16.3**	**22.1**	**24.4**	**27.1**	**28.2**	**28.9**	**33.7**	**39.1**

Source: Energy Narrative calculations

The levelized transportation tariff to deliver natural gas to each location was calculated based on the distance, the estimated cost per meter to install the natural gas pipeline, and the average demand at each location over the life of the pipeline. The same financial and accounting assumptions were made for the onshore pipelines as were made for the undersea pipeline (see Section 12.2 above). These calculations resulted in the following costs per pipeline segment shown in Table 12.30 below.

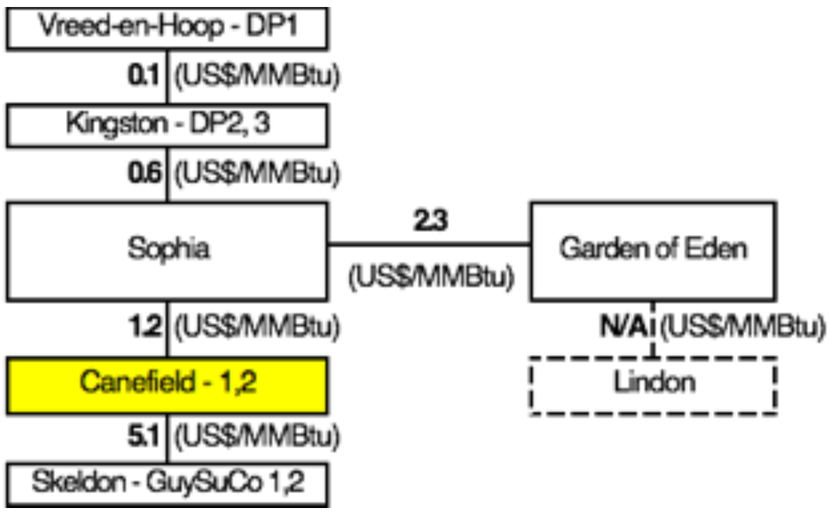
Table 12.30: Estimated natural gas transportation cost by segment

	Volume (MMcfd)		(US$)	(US$/MMB
NG Pipeline Segment	Average	Peak	Cost	Unit Cos
Canefield - Sophia	19.3	33.1	47.314	1.179
Sophia - Kingston	13.1	22.5	15.58	0.572
Kingston - Vreed-en-Hoop	5.1	8.7	0.984	0.093
Sophia - Garden of Eden	6.2	10.6	29.52	2.289
Canefield - Skeldon	3.0	5.1	31.57	5.059

Source: Energy Narrative calculations

The resulting transportation tariffs per segment are shown in Figure 12.13 below.

Figure 12.13: Estimated natural gas transportation tariffs by segment, Alternative 1 and Base Demand Cases (US$ per MMBtu)



Source: Energy Narrative calculations

The total cost to deliver natural gas to each location is shown in Table 12.31 below. As noted in section 12.1.4 above, this cost assumes the wellhead price for the natural gas is zero, so there is no additional cost for the natural gas molecule itself.

Table 12.31: Estimated natural gas transportation cost by segment

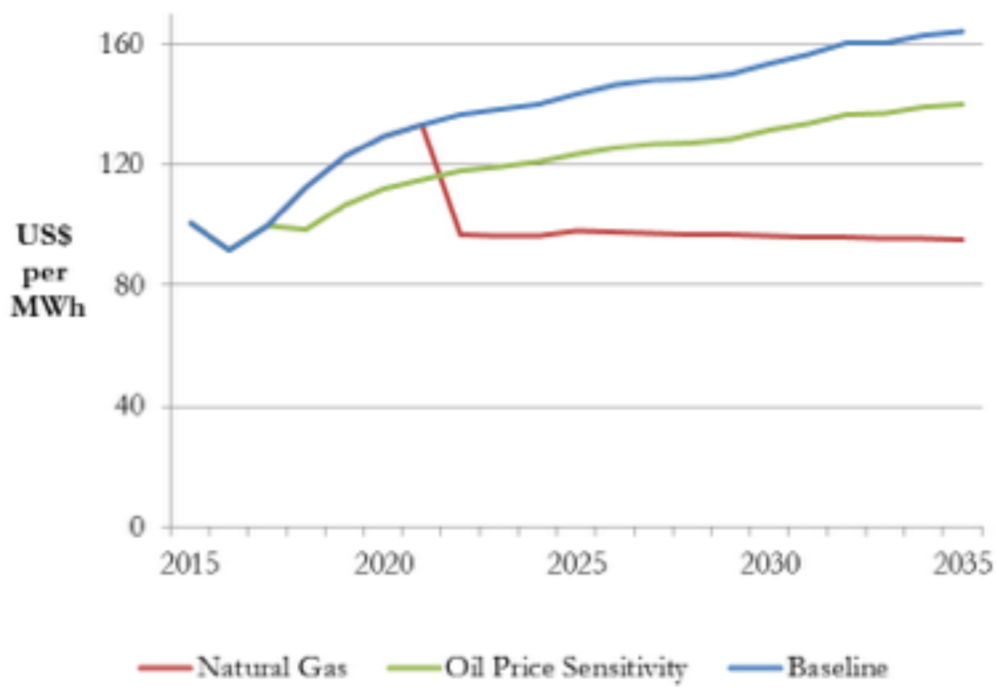
	Transportation (US$/MMBtu)			
Total NG Trans $	Undersea	Compression	On shore	Total
Vreed-en-Hoop	3.05	0.45	1.84	5.34
Kingston	3.05	0.45	1.75	5.25
Canefield	3.05	0.45	0.00	3.50
Garden of Eden	3.05	0.45	2.29	5.79
Skeldon	3.05	0.45	5.06	8.56

Source: Energy Narrative calculations

The average cost to transport natural gas to the generator is similar across the major generator sites near Georgetown, including Kingston and Vreed-en-Hoop, and only roughly US$0.50 per MMBtu more expensive in Garden of Eden. The cost to deliver gas to Skeldon is far more expensive, estimated to be US$2.80 per MMBtu more than the next most expensive area (Garden of Eden). The extreme pipeline length relative to the volume of natural gas required makes this pipeline of questionable value. Unless additional natural gas demand (such as for industrial uses) were located at the Skeldon region, this pipeline may be uneconomic.

Figure 12.14 below compares the impact on power prices from switching to natural gas. The cost per MWh shown includes the levelized capital and fixed operations and maintenance (O&M) costs, as well as the price of fuel and other variable O&M expenses. In addition to the Baseline case, an oil price sensitivity case is included to test the impact of reducing the oil price forecast by 20%.

Figure 12.14: Average cost of power generation, HFO vs. Option 3 (New Amsterdam) (US$ per MWh)



Source: Energy Narrative calculations

The much lower delivered cost of natural gas results in significant savings from the baseline HFO-fired projection. In this projection, natural gas prices are fixed (being based on the levelized cost of the pipelines and a zero wellhead price), and so the gap between natural gas and HFO fired electricity widens in future years. The size of the gap suggests there is ample room for negotiation to arrive at a wellhead price that is greater than zero but would still provide substantial savings in electricity prices. Even after reducing the forecast oil price by 20%, the cost of electricity from natural gas averages close to US$40 per MWh cheaper.

It is important to note that this analysis does not include the cost of any transmission and substation upgrades that may be required to accommodate the new power generation facilities or growing electricity demand. A detailed power flow analysis is required to determine the electricity grid's changing requirements and the expected investment needed to meet those requirements.

12.7. Conclusions and recommendations

The above analysis calculates the estimated cost to deliver natural gas to each proposed generation site under the three landing site options and the resulting impact on electricity generation prices. Table 12.32 below compares how the different landing options affect the delivered natural gas price at the different generation points, highlighting the lowest cost option for each location.

Table 12.32: Estimated natural gas transportation cost by landing site option (US$ per MMBtu)

Generation Site	Georgetown	Clonbrook	New Amsterdam
Vreed-en-Hoop	**$3.34**	$3.64	$5.34
Kingston	**$3.25**	$3.54	$5.25
New Sophia	**$3.17**		
Columbia		**$3.09**	
Garden of Eden	$4.31	**$4.23**	$5.79
Canefield	$8.45	$6.69	**$3.50**
Skeldon			**$8.56**

Source: Energy Narrative calculations

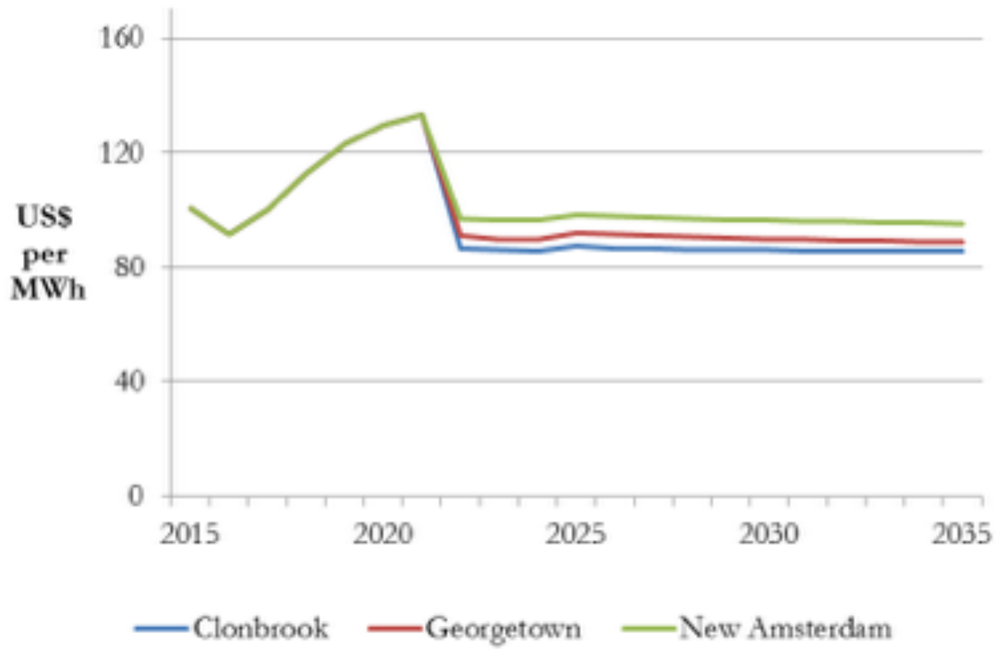
Not surprisingly, the Georgetown option provides the least cost natural gas for locations in the western region of the grid, the Clonbrook option is the lowest cost for the more central demand points, and the New Amsterdam option is the least cost option for natural gas in the eastern part of the grid.

The price difference across the system is more pronounced for the Georgetown option than for the New Amsterdam option because of the greater volume of natural gas demand in the Georgetown region. Transporting a higher volume from east to west (New Amsterdam option to Kingston) results in a lower average tariff than shipping a smaller volume from west to east (Georgetown option to Canefield), even though the distance and investment costs are the same.

Even so, the more central location of the Clonbrook landing site minimizes the price extremes at either end of the grid, and results in the lowest overall price of delivered natural gas.

The above analysis also suggests that any of the three landing options could significantly reduce the cost of electricity generation in Guyana. As shown in Figure 12.15 below, both Option 1 (Georgetown) and Option 2 (Clonbrook) average just below US$40 per MWh, while Option 3 (New Amsterdam) averages just below US$45 per MWh.

Figure 12.15: Comparison of the average cost of power generation across the three Options (US$ per MWh)



Source: Energy Narrative calculations

The minimal difference in costs between Option 1 and Option 2 suggests that factors other than cost that may affect the site selection should also be taken into consideration. As shown in Section 10 (Component 8) above, the more qualitative considerations also suggest that Clonbrook is the best choice for the landing site, given the greater flexibility of the space while still being within a short distance of the main electricity generation stations and demand centers. The Georgetown option was downgraded for the dense population and limited space for new electricity generation stations or industrial demand. The New Amsterdam site was downgraded for its extreme distance from the current electricity generation assets and demand centers, as well as the slightly higher cost for the undersea pipeline owing to the longer distance.

Therefore, **Clonbrook is the recommended natural gas landing point.** This location has the best balance of natural gas prices across the grid, availability of space for the natural gas infrastructure, and space for related power generation and, potentially, industrial development.

The recommendation to land the natural gas at Clonbrook assumes that the natural gas volumes will be 30 MMcfd. Should the volumes be the higher estimate (145 MMcfd), or if even higher natural gas volumes become available, the New Amsterdam site, or the potential for two separate pipelines, should be re-examined. As shown in the detailed analysis of each Option above, Guyana's projected electricity demand is insufficient to absorb 145 MMcfd of natural gas. Therefore, new energy intensive industries (consuming either natural-gas fired electricity or using the natural gas directly for process heat or as a feedstock) would be needed to develop sufficient demand. These industries would need additional development space. In addition, they could produce energy intensive products for export, putting greater value on the deep water port in New Amsterdam.

13. Component 11: Pipeline requirements and conditions

The purpose of Component 11 is to scope out the practical considerations for offshore natural gas pipeline construction. To complete this component, Energy Narrative conducted a literature survey.

13.1. Requirements for natural gas pipeline construction

This pipeline is unusual in its small size, placing it outside of normal construction and installation practice in deep-water. Preliminary engineering by ExxonMobil indicates that the depth of the water combined with the internal pressure of the gas leads to a minimum wall thickness of 1-in.

Based on the water depths encountered, 1,800m / 5,900-ft water depth to shore, J-lay / S-lay / barge may all be required for installation of the offshore pipeline. The deep water installation methods, J-lay and S-lay, typically use larger diameter and wall thickness pipe. The installation methods and equipment therefore may need to be modified to accommodate the smaller pipeline diameter, especially concerning bending and fatigue during installation. Manufacturing considerations regarding the minimum wall thickness of 1-in are less important.

13.2. Data requirements for gas transmission estimates

ExxonMobil currently plans either an 8-in pipeline delivering 30MMscfd, or a 12-in pipeline delivering 145MMscfd of natural gas to onshore Guyana. In order to assure the suitability of the gas transmission estimates:

- the reserves behind the offshore Lisa field need to be certified by a third-party reserve certification agency,
- the field development plan needs to be approved by the same third party certification agency, and
- the primary engineering of the pipeline itself needs to be approved.

The authors of this study have not received or reviewed these certifications, but have been assured that the primary engineering analysis consisting of 1) hydraulic analysis and flow assurance concerning gas components / pressure / liquid management, and 2) installation concerning burst / collapse / stability are suitable.

14. Component 12: Regulatory and institutional framework

The purpose of Component 12 is to review Guyana's current legal and regulatory framework related to natural gas and electricity generation, assess any gaps within the current framework that may create uncertainty or potential risks to the project implementation and operations, and recommend any additional analysis that may be required to address the identified gaps.

This preliminary summary assessment includes a review of Guyana's regulations as they apply to the construction and operation of natural gas transportation infrastructure, and the use of natural gas in electricity generation.

The analysis is based on available data, analysis, and reports provided by the Government of Guyana, and from discussing the current legal and regulatory framework with key personnel within the Government of Guyana. The documents reviewed include:

- Guyana's draft Energy Policy
- Guyana's Energy Transition Roadmap
- Petroleum and Petroleum Products Regulations, 2014
- Electricity Sector Reform Act, 1999 and Amendments, 2010
- GPL License

14.1. Draft Energy Policy

The Draft National Energy Policy of Guyana – Report 2 – Green Paper (DNEP), completed on February 20, 2017, presents the suggested national policy objectives for Guyana as well as the specific policies for energy supply, energy demand, and the attendant cross cutting issues. For the special case of electricity, the policies are intended to move Guyana towards a goal of 100 percent renewable energy by the year 2025.

The document draws upon the Guyana Power Generation Expansion Study, 2016; the Green Development Strategy (GDS), 2016; the Assessment of Fiscal and Regulatory Barriers to Deployment of Energy Efficiency and Renewable Energy Technologies in Guyana, 2014; the Low Carbon Development Strategy (LCDS), 2009 and revised in 2010 and 2013; and the National Development Strategy, 2001 to 2010.

Each of these studies were completed before the potential supply of offshore natural gas was known, and so do not incorporate the use of natural gas in the suggested policy guidelines. Even so, the potential for using natural gas in Guyana's energy sector is explicitly mentioned in the draft policy document. Although the draft policy notes that the goal is to transition toward 100% renewable energy in the electricity sector by 2025, Section 3.1.1 notes that GPL's capacity expansion will include thermal power plants fueled with Light fuel oil (LFO) and Heavy Fuel Oil (HFO) in the short term and thermal reciprocating plants fired with natural gas in the long term. It also notes that GPL will investigate the feasibility of establishing a liquefied natural gas re-gasification plant at a suitable location for supply to power stations, industrial users, and residential users. Natural gas is intended to serve as the bridge fuel to a full 100 percent renewable energy scenario should this prove to be necessary. While the discovery of natural gas resources in Guyana will remove the necessity to import natural gas via LNG, the inclusion of natural gas as a potential transition fuel opens room in the national energy policy to use the domestic resource for electricity generation.

The DNEP also states that a new regulatory oversight body will be established "to balance multiple competing interests of public and private entities, and enable growth of the sector while supporting the efficient, safe and orderly development of energy resources while minimizing the environmental footprint of the sector. This agency will be established after it has been demonstrated that significant long term exploitable oil and gas reserves have been verified. This will serve as the single credible body to monitor and regulate all aspects of the sector;" (Section 3.2)

The DNEP also notes that in respect to upstream and midstream oil and gas, it is the intent of Government to:

1. Develop an overall intuitional and regulatory framework for the oil and gas sector that includes the Ministry of Infrastructure, the Guyana Energy Agency, the Audit Office of Guyana (AOG), Guyana Revenue Authority (GRA), and the Ministry of Finance;

2. Establish a new institution to regulate the oil and gas sector;

3. Create a new directorate for petroleum in the Ministry of Public Infrastructure to provide policy guidance and licensing for the upstream, midstream and downstream aspects of the petroleum value chain;

4. Evaluate the requirements for a petroleum refinery based on the results of the current off-shore oil and gas exploration;

5. Evaluate the requirements for off-shore gas transmission pipelines and on an on-shore gas distribution network based on the results of the current off-shore oil and gas exploration;

6. Evaluate the requirements of oil and gas storage facilities based on the current off-shore oil and gas exploration;

7. Establish the legal and regulatory framework for the upstream and midstream petroleum sectors. This may include Acts for: Petroleum exploration, development and production; and petroleum refining, conversion, transmission and midstream storage;

8. Provide training and capacity building for officials in oil and gas related disciplines, including petroleum geoscience, law, audit, taxation and management;

9. Introduce artisanal and technical skills training at certificate and diploma levels at the University of Guyana and local technical institutes; and

10. Develop a Licensing Strategy and Plan. This will include model contracts for multi-client seismic survey; a procedure for international bidding and open licensing for producers; a promotional campaign; establishment of a data facility and procedures; and procedures for sales of data packages.

14.2. Energy Transition Roadmap

An Energy Transition Roadmap, dated March 10, 2017, was developed by the same consultant that produced the DNEP noted above. As stated in the report, "this Roadmap points the way towards the aspirational goal of 100 percent renewable energy in the power sector. The existing Guyana generation expansion plan would not achieve this goal as it considers only a single mid-scale hydro plant and the introduction of natural gas as a transitional energy source (albeit natural gas being a cleaner energy source). [The Roadmap] therefore reviews the peak load forecast for GPL, the indicative cost and benefits of renewable energy, and the policy commitments that guide this transition road map. A series of actions are also identified to guide the orderly development of the transition and to identify the financial requirements that would be necessary."

Like the DNEP, the Roadmap is based upon existing documents, and so does not integrate the potential for domestically sourced natural gas in power generation. There is discussion of using revenue from upstream oil and gas development to fund various projects, including the development of medium scale hydro power plants, but there is no direct discussion of using natural gas for electricity generation before the dates proposed in the original GPL expansion plan from June, 2016.

14.3. Petroleum and Petroleum Products Regulations 2014

These regulations direct the GEA's authority and actions to license and oversee the transportation, storage, wholesale and retail sale, import, and export of petroleum and petroleum products. As written, the regulations clearly give the GEA the authority to regulate and oversee natural gas activities and infrastructure. The regulations define "petroleum and petroleum products" as "petrol, diesel, bunker-C, and any other heavy oils, liquefied natural gas, liquefied petroleum gas, aviation fuel, kerosene, and any other hydrocarbon-based fuel source or product of the petroleum refining process, whether in liquid of gaseous form". In addition, "gas" is defined as "liquid of non-liquid gas which can be used as fuel for the operation of a spark ignition engine or flame or heat generating appliance". Both definitions clearly cover natural gas.

In general, the Regulations are appropriate for natural gas as they provide broad guidelines for overseeing the technical, operational, health, safety, and environmental parameters for related infrastructure and installations. While the broad requirements are sufficient, the specific parameters referenced in the regulations would need to be developed for natural gas installations and businesses.

One gap in the Regulations is the lack of any mention of pipelines. The regulations for storage and bulk transportation both touch on aspects of the regulations that would be required to oversee natural gas pipelines and distribution systems, but as currently written both are inadequate. The storage regulations assume a contained facility held entirely within land that the operator either owns or has permission to use – this would not necessarily be true for pipelines built under public or private lands along rights-of-way easements. The bulk carrier regulations touch on many requirements for transporting natural gas safely, but "bulk transportation carrier" is clearly defined as "a vehicle capable of transporting 2000 liters or more of petroleum and petroleum products." This covers both land and water based transportation, but excludes pipelines.

14.4. Electricity Sector Reform Act of 1999 and the Electricity Sector Reform (Amendment) Act of 2010

The ESRA, as amended in 2010, created the Guyana Power and Light Company and established the conditions for its license, its duties to supply electricity, parameters for purchasing power from IPPs, the mechanism used to set retail electricity tariff rates, and penalties for non-compliance. The ESRA does not describe specific technologies for the generation of electricity, with the exception of promoting sustainable technologies where appropriate.

The tariff setting mechanism does include provisions for adjustments related to fuel prices and foreign exchange rates, allowing GPL to pass through reductions in the cost of fuel to the consumer.

The ESRA does not directly address fuel supply for electricity generation, or proscribe any manner in which the fuel should be purchased or stored. As such, there is no restriction within the law from GPL acquiring fuel directly from importers or domestic producers, or maintaining its own fuel supplies.

The ESRA does state that GPL is only allowed to break up streets and otherwise affect public or private lands for works related to electricity lines. This would prohibit GPL from breaking up roads for the purpose of installing natural gas pipelines without special approval.

14.5. GPL License

GPL was granted a license to supply electricity to the coastal regions of Guyana in 1999, concurrent with the ESRA which created it. This License, as amended in 2010, limits GPLs activities to:

- the generation of electricity (except hydropower);
- the transmission, distribution, storage, furnishing and sale of electricity;
- the purchase of electricity through PPAs with IPPs
- the installation, operation, and maintenance of meters, electric lines and other electric apparatuses, installations, and facilities necessary to carry out its activities.

The provision of fuels for electricity generation is not listed among the authorized activities, although section 28 does provide authorization for GPL to "act and to perform such other activities and services as may be necessary for the purposes of exercising its rights, fulfilling its obligations and performing the activities and services authorized under this License." This broad language could provide sufficient authorization for GPL to build and operate natural gas pipelines and other delivery services if they were deemed necessary. Amending GPL's License or enacting separate legislation that explicitly grants or prohibits GPL from owning and operating natural gas distribution facilities would remove any ambiguity.