Feasibility Study for Guyana's Offshore Natural Gas Pipeline, NGL separation and LPG production plant, and Related Electricity Infrastructure

Draft Final Report

Report to the Government of Guyana

and

the Inter-American Development Bank

Submitted by Energy Narrative

August 22, 2018

1. Table of Contents

List of Figures and Tables

Abbreviations

EEPGL	Esso Exploration and Production Guyana Limited
CO2	carbon dioxide
CNG	compressed natural gas
CBA	cost-benefit analysis
ESRA	Electricity Sector Reform Act
EU	European Union
FPSO	floating production, storage, and offloading
G$	Guyana dollar
GPL	Guyana Power & Light
HFO	heavy fuel oil
IPP	independent power producer
IDB	Inter-American Development Bank
IRR	internal rate of return
kWh	kilowatt-hour
LNG	liquefied natural gas
LPG	liquid petroleum gas
MWh	megawatt-hour
MMBtu	million British thermal units
MMscf	million standard cubic feet
MMscfd	million standard cubic feet per day
NGL	natural gas liquids
NPV	net present value
PPP	public-private partnership
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
US$	United States dollar
WHO	World Health Organization

1. Executive Summary

Esso Exploration and Production Guyana Limited (EEPGL), an affiliate of ExxonMobil, has recently discovered commercial oil and natural gas reserves in the Stabroek block approximately 120 miles offshore Guyana. EEPGL estimates that 30 to 50 million cubic feet per day (MMscfd) of natural gas could be available for electricity generation in Guyana. Using the available natural gas for electricity generation would reduce Guyana's reliance on imported liquid fuels for electricity generation, thereby allowing for the diversification of Guyana's energy matrix. Utilizing the natural gas in this way would require investment in an offshore natural gas pipeline to bring the natural gas to the Guyanese mainland, a natural gas liquids (NGL) separation plant and LPG production facility, and new natural-gas-fired electricity generation capacity.

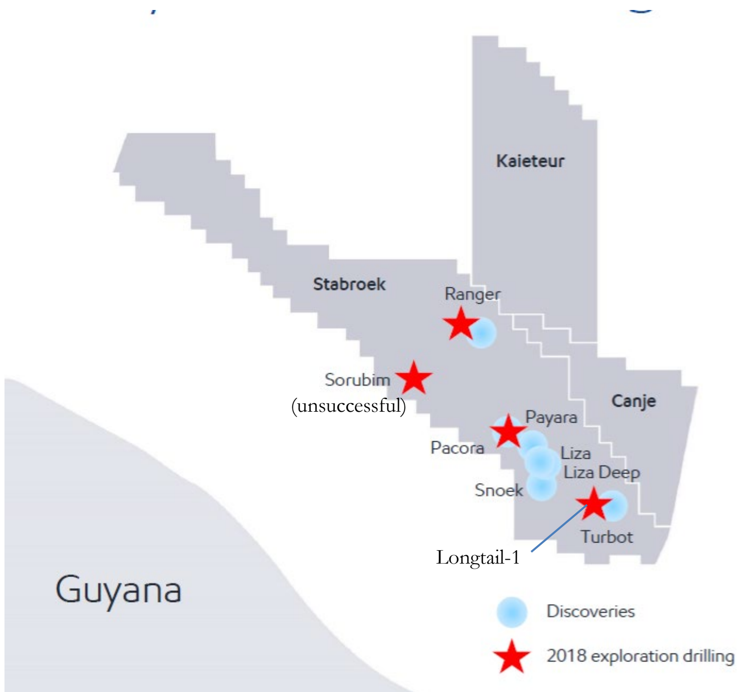
The Government of Guyana has partnered with the Inter-American Development Bank (IDB) to commission Energy Narrative to conduct a feasibility study of the planned offshore natural gas pipeline, the NGL separation and LPG production facility, and the natural gas-fired generation plant and related electricity infrastructure. The primary objective of the study is to determine the overall feasibility of transporting natural gas from offshore Guyana, building an NGL separation and LPG production plant to market the liquids from the natural gas stream, and building a new electricity generation station to use the remaining dry natural gas.

1.1. Project Overview

The proposed natural gas offshore pipeline, NGL separation and LPG production plant, and natural-gas-fired power plant that comprise the project will exploit natural gas that will be made available for commercial uses from the Liza-1 deepwater project. Liza-1 is located in the Stabroek block roughly 180 kilometers offshore of Guyana in more than 2,000 meters of water.

Liza-1 is the first of eight hydrocarbon discoveries made by EEPGL in the Stabroek block since 2015. The most recent discoveries are still being appraised, but ExxonMobil's most recent estimate, released on July 23, 2018, estimated more than 4 billion barrels of recoverage oil-equivalent hydrocarbons. This was a significant increase from the previous 3.2 billion barrel of oil equivalent estimate. Figure 1-1 shows the location of EEPGL's finds and planned drilling program for 2018.

Figure 1-1: EEPGL Stabroek block discoveries and planned drilling activity (2018)



Source: ExxonMobil Analyst Meeting, March 2018, updates added by Energy Narrative

Of these discoveries, only the first phase of development of the Liza discovery has been given a final investment decision. Liza phase 2 is under development and Liza phase 3, which would also produce oil from the Payara discovery, is being developed with an estimated start date in 2023.

EEPGL's latest gas production profile information for Liza-1 confirmed the availability of ~50 MMscfd of natural gas for commercial sale over a 15-20 year period. This supply profile, as well as potential future natural gas production from other nearby discoveries, has led the proposed pipeline to bring the natural gas onshore to be tentatively sized at 12" diameter. This pipeline size would be sufficient to transport 145 MMscfd of natural gas.

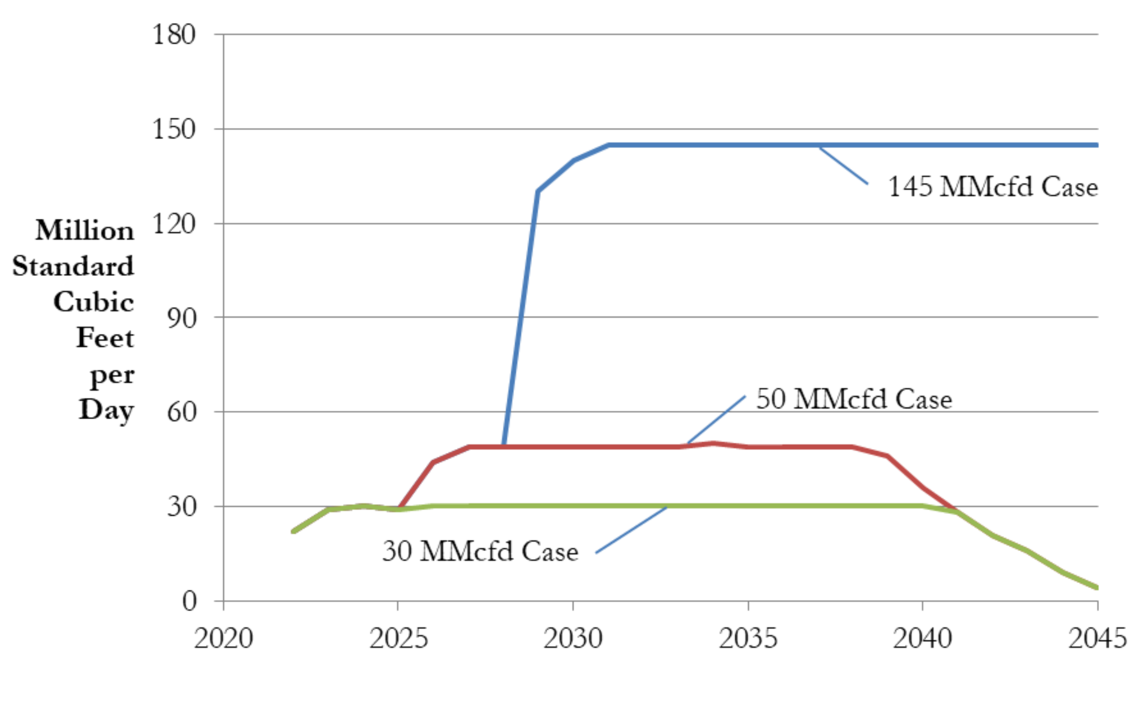
The offshore natural gas pipeline is planned to land at Woodlands on the Guyana coast roughly 30 kilometers east of Georgetown. This site was selected after an extensive site selection process, led by a cross-agency team including representatives from the Guyana Energy Agency, Guyana Power & Light, the Ministry of Natural Resources, the Ministry of Business, the Ministry of Public Infrastructure, the Guyana Lands & Surveys Commission, and the Maritime Administration Department. The Woodlands site has the benefit of sufficient area (roughly 476 acres) for the planned natural-gas-fired power plant, the NGL separation and LPG production plant, and a potential industrial park. The site is not located near a port, however, and will require extensive site development work owing to the poor soil conditions at the location.

1.1.1. Expected natural gas volume

The feasibility analysis assumes two natural gas supply cases based on the most recent supply profile and natural gas composition data provided by EEPGL: a lower case averaging 30 MMscfd from 2022 until 2041, and a higher case averaging 50 MMscfd for the bulk of the study period, including a ramp up period at the beginning and a ramp down period at the end (see Figure 1-2 below).

In addition to these two main supply cases, a third case was considered to highlight the potential impact of future additional natural gas availability. Although the currently modeled natural gas supply from Liza is capped at 50 MMscfd, the potential for additional natural gas supply from future developments has led EEPGL to size the offshore pipeline to transport a maximum of 145 MMscfd. The natural gas supply modeled in this third case assumes that the additional volumes begin to come online in 2028, six years after Liza-1's initial production. The supply curve rapidly increases to the full 145 MMscfd and then maintains that volume throughout the study period. It should be stressed that this is a purely conjectural case—the proposed supply curve and duration are not based on any supply or reservoir data currently available. As a result, the analysis based on this theoretical 145 MMscfd supply case is presented separately from the two main supply cases noted above.

Figure 1-2: Modeled natural gas supply profiles



Source: Energy Narrative

The theoretical 145 MMscfd natural gas supply case highlights the economic and financial implications of operating the pipeline at maximum capacity. Although Guyana's power sector is not large enough to absorb this volume of natural gas, the gas could be used as a feedstock and to support other industrial development. Most importantly, the capital cost of the offshore pipeline will be spread across a greater volume of natural gas supply, thereby reducing the cost of gas to the power plant and other users. Because the pipeline was intentionally oversized to accommodate the potential for additional volumes of natural gas, this analysis is included to quantify the economic and financial benefits of operating the pipeline at full capacity.

These two main natural gas supply cases, matched with the two options for new natural-gas-fired electricity generation capacity developed in the GPL 2018 Expansion Plan, were used for the economic and financial analysis, and related sensitivity analyses of each of the project components as described below.

1.2. Offshore natural gas pipeline feasibility

The offshore natural gas pipeline's economic and financial feasibility were calculated separately, using a common set of physical, operational, and financial assumptions.

1.2.1. Economic feasibility

The offshore natural gas pipeline's economic feasibility was determined by comparing the economic costs of building and operating the infrastructure to produce, prepare, and transport the natural gas to shore with the economic benefits that the natural gas will bring. The upstream natural gas production and offshore pipeline's economic costs include the capital cost of the additional equipment required to produce the natural gas and the capital cost to build the pipeline, the annual cost to produce the natural gas and operate the pipeline, and any environmental costs associated with the pipeline's operations. The offshore pipeline's economic benefits include the avoided costs that would have been incurred if the offshore natural gas pipeline had not been built. The natural gas delivered by the offshore pipeline will primarily replace heavy fuel oil (HFO) that is currently being imported for electricity generation. The economic benefits from building the offshore natural gas pipeline therefore include the avoided cost of importing HFO and the avoided economic cost of carbon dioxide (CO_2) emissions that would result from burning the HFO for electricity generation. This analysis does not include any economic benefits from increased job creation (both directly from the construction and operation of the project and indirectly from the greater economic activity associated with the pipeline). While the pipeline will clearly bring some job creation benefits, this value was not quantified for this analysis.

This economic cost-benefit analysis (CBA) finds that the offshore natural gas pipeline has an aggregate net present value (NPV) of approximately US$782 million and an economic rate of return of 30% percent under the project's Base Case assumptions. This indicates that the offshore natural gas pipeline is economically viable.

A sensitivity analysis was performed to estimate how changes in key variables would impact the offshore natural gas pipeline's economic feasibility. Three independent variables were included in the sensitivity analysis: the volume of natural gas shipped by the pipeline, the cost to produce the natural gas and build and operate the pipeline, and the price of HFO that the natural gas will displace. These variables were selected based on the likelihood that they could change and their potential to have a material impact on the offshore natural gas pipeline's economic feasibility.

Table 1-1 presents the results of changing the three input variables individually as well as a "worst case" scenario that combined high project costs with a low oil price outlook.

Table 1-1: Natural gas pipeline economic feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics				
NG Flow Volume	Capital & Operating Costs	HFO and LPG Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	Base	Base	$1,312	($531)	$782	30%	2.47
30	High	Base	$1,312	($608)	$704	26%	2.16
30	Low	Base	$1,312	($454)	$859	36%	2.89
30	Base	High	$2,396	($531)	$1,865	48%	4.51
30	Base	Low	$630	($531)	$99	13%	1.19
30	High	Low	$630	($608)	$22	11%	1.04
50	Base	Base	$1,827	($586)	$1,241	35%	3.12
50	High	Base	$1,827	($663)	$1,164	31%	2.76
50	Low	Base	$1,827	($509)	$1,318	40%	3.59
50	Base	High	$3,352	($586)	$2,766	52%	5.72
50	Base	Low	$874	($586)	$289	18%	1.49
50	High	Low	$874	($663)	$212	15%	1.32
145	Base	Base	$3,798	($790)	$3,008	41%	4.81

Source: Energy Narrative analysis

The table shows that the offshore natural gas pipeline remains economically feasible under each individual sensitivity case. Under the "worst case" combination of both high project costs and a low oil price outlook, the project is marginally feasible, showing a US$22 million economic gain over 20 years and an economic rate of return of 11%--just above the 10% hurdle rate. The pipeline shows the highest economic return under the 50 MMscf per day of natural gas volumes and the high oil price case, reaching nearly US$2.8 billion in net present value and a 52% economic rate of return.

If natural gas supply were increased to the theoretical 145 MMscfd case, the offshore natural gas pipeline would have an economic net present value of just over US$3 billion and an economic rate of return of 41%.

1.2.2. Financial feasibility

The project's financial feasibility will be determined by the price of natural gas that will be negotiated between the Government of Guyana and EEPGL In this negotiation, EEPGL's priority will be to secure a price for the natural gas and LPG that will provide the greatest return on investment. At the same time, the Government of Guyana's priority is to minimize the cost of electricity generated with the supplied natural gas.

The financial feasibility analysis used two price setting approaches to reflect these different priorities: a Cost+ approach which added a fixed return to the project costs and then calculated the resulting electricity price, and a Net Back approach which fixed an average electricity price for the project timeframe and then calculated the natural gas price and resulting returns on investment that would be required to provide electricity at the chosen price. In each methodology, the natural gas price is assumed to be fixed throughout the project timeframe.

For each price setting approaches a high and low value were selected in order to examine the range of possible outcomes for the natural gas price negotiations. Under the Cost+ approach, both a 10% internal rate of return (IRR) and a 16% IRR were modeled. Under the Net Back approach, an electricity price of US$0.09 per kWh and US$0.06 per kWh were modeled.

The financial feasibility analysis for the offshore natural gas pipeline divided the project component into two parts: the upstream natural gas supply, including the additional investment and equipment added to the FPSO to allow natural gas to be produced for sale onshore, and the offshore natural gas pipeline that then transports the produced natural gas to the landing site on the Guyana mainland.

1.2.2.1. Upstream natural gas production financial feasibility

The financial analysis of the upstream segment finds that under the Cost+ approach the produced wet gas natural gas would be priced at US$1.01 per MMBtu to have a net present value (NPV) of zero and an internal rate of return of 10% under the Base Case assumptions. Achieving a 16% IRR would require a price of US$1.48 per MMBtu for the natural gas supply, resulting in a US$40 million NPV for the upstream investments.

Under the Net Back approach, delivering an average electricity price of US$0.09 per kWh under the Base Case assumptions would require an upstream gas price of US$1.03 per MMBtu, resulting in an NPV of approximately US$2 million and an internal rate of return of 10% percent. That is, the upstream natural gas production would be profitable under this pricing option. An electricity price of US$0.06 per kWh is not possible at this volume of natural gas production, however, as this electricity price would require the produced natural gas to be priced at US$0.64 per MMBtu, resulting in a 4% IRR and a US$32 million loss in net present value terms.

A sensitivity analysis was performed to estimate how changes in key variables would impact the upstream natural gas production's financial feasibility under both the Cost+ and Net Back pricing options. The sensitivity analysis used two of the independent variables that were included in the economic sensitivity analysis: the volume of natural gas produced, and the cost to produce the natural gas. Under the Cost+ pricing option, adjusting the variables only affected the natural gas sales price and net present value, as the internal rate of return was held fixed at 10% and 16%. For the Net Back pricing option, adjusting the variables affected only the net present value and the internal rate of return, as the natural gas price was held fixed. The summary results of the sensitivity analysis are presented in Table 1-2 below.

Table 1-2: Natural gas upstream financial feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics		
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	NG Wellhead Price (US$/MMBtu)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$1.01	$0	10%
30	Base	IRR-16%	$1.48	$40	16%
30	Base	Elec - 6 cent	$0.64	($32)	4%
30	Base	Elec - 9 cent	$1.03	$2	10%
30	Low	IRR-10%	$0.81	$0	10%
30	Low	IRR-16%	$1.18	$32	16%
30	Low	Elec - 6 cent	$0.64	($14)	7%
30	Low	Elec - 9 cent	$1.03	$19	14%
30	High	IRR-10%	$1.22	$0	10%
30	High	IRR-16%	$1.78	$48	16%
30	High	Elec - 6 cent	$0.64	($50)	2%
30	High	Elec - 9 cent	$1.03	($16)	8%
50	Base	IRR-10%	$0.74	$0	10%
50	Base	IRR-16%	$1.12	$45	16%
50	Base	Elec - 6 cent	$0.50	($27)	5%
50	Base	Elec - 9 cent	$0.84	$12	12%
50	Low	IRR-10%	$0.59	$0	10%
50	Low	IRR-16%	$0.89	$36	16%
50	Low	Elec - 6 cent	$0.51	($10)	8%
50	Low	Elec - 9 cent	$0.84	$30	15%
50	High	IRR-10%	$0.88	$0	10%
50	High	IRR-16%	$1.34	$54	16%
50	High	Elec - 6 cent	$0.50	($45)	3%
50	High	Elec - 9 cent	$0.84	($5)	9%
145	Base	IRR-10%	$0.36	$0	10%
145	Base	IRR-16%	$0.62	$62	16%
145	Base	Elec - 6 cent	$0.39	$5	11%
145	Base	Elec - 9 cent	$0.61	$59	16%

Source: Energy Narrative analysis

The table shows that the upstream natural gas production remains financially feasible under every Cost+ sensitivity case for both the assumed 10% IRR and 16% IRR. The resulting natural gas price ranges from US$0.59 per MMBtu for the 10% IRR under the 50 MMscfd Low Cost Case to US$1.78 per MMBtu for the 16% IRR under the 30 MMscfd High Cost Case.

Under the Net Back approach, the upstream natural gas production is financially feasible under the 9 cent electricity level in all sensitivities except the 50 MMscfd High Cost Case where it has a 9% IRR and a US$5 million loss over the project's 20 year life. The upstream natural gas production is not feasible under the 6 cent electricity level for any of the sensitivity cases, suggesting that this average price for electricity is unobtainable without higher natural gas volumes or subsidization.

If the natural gas production were increased to the theoretical 145 MMscfd supply case, the natural gas wellhead price could fall as low as US$0.36 per MMBtu under the Cost+ price setting mechanism and a 10% IRR. Increasing the IRR to 16% would result in a price of US$0.62 per MMBtu. Under the Net Back price setting methodology, the natural gas wellhead price for 9 cent electricity and 6 cent electricity both fall within the range set by the Cost+ price setting methodology. That is, at this volume of natural gas, setting the natural gas price to produce electricity at an average price of 6 cents per kWh is financially feasible, resulting in a US$5 million NPV and 11% IRR. Increasing the electricity price to 9 cents per kWh results in an NPV of US$59 million and an IRR of 16%.

1.2.2.2. Natural gas pipeline financial feasibility

The financial analysis for the offshore natural gas pipeline finds that the pipeline tariff under the Cost+ approach would be priced at US$3.91 per MMBtu for the pipeline to have a net present value (NPV) of zero and an internal rate of return of 10%. Achieving a 16% IRR for the pipeline would require a tariff of US$5.71 per MMBtu, resulting in a US$155 million NPV.

Under the Net Back approach, delivering an average electricity price of US$0.09 per kWh under the Base Case assumptions would require a pipeline tariff of US$3.99 per MMBtu, resulting in an NPV of approximately US$7 million and an internal rate of return of 10% percent. That is, the offshore natural gas pipeline would be profitable under this option. An electricity price of US$0.06 per kWh is not possible at this natural gas volume, however, as this electricity price would require the produced natural gas to be priced at US$2.48 per MMBtu, resulting in a 4% IRR and a US$123 million loss in net present value terms.

A sensitivity analysis was performed to estimate how changes in key variables would impact the offshore natural gas pipeline's financial feasibility under both the Cost+ and Net Back pricing options. The sensitivity analysis used the independent variables that were included in the upstream natural gas production financial sensitivity analysis. The summary results of the sensitivity analysis are presented in Table 1-3 below.

Table 1-3: Natural gas pipeline financial feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics		
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	NG Pipeline Tariff (US$/MMBtu)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$3.91	$0	10%
30	Base	IRR-16%	$5.71	$155	16%
30	Base	Elec - 6 cent	$2.48	($123)	4%
30	Base	Elec - 9 cent	$3.99	$7	10%
30	Low	IRR-10%	$3.13	$0	10%
30	Low	IRR-16%	$4.57	$124	16%
30	Low	Elec - 6 cent	$2.48	($56)	7%
30	Low	Elec - 9 cent	$3.99	$74	14%
30	High	IRR-10%	$4.69	$0	10%
30	High	IRR-16%	$6.85	$186	16%
30	High	Elec - 6 cent	$2.47	($191)	2%
30	High	Elec - 9 cent	$3.98	($61)	8%
50	Base	IRR-10%	$2.84	$0	10%
50	Base	IRR-16%	$4.31	$175	16%
50	Base	Elec - 6 cent	$1.95	($105)	5%
50	Base	Elec - 9 cent	$3.24	$48	12%
50	Low	IRR-10%	$2.27	$0	10%
50	Low	IRR-16%	$3.45	$140	16%
50	Low	Elec - 6 cent	$1.95	($37)	8%
50	Low	Elec - 9 cent	$3.25	$116	15%
50	High	IRR-10%	$3.40	$0	10%
50	High	IRR-16%	$5.17	$210	16%
50	High	Elec - 6 cent	$1.94	($174)	3%
50	High	Elec - 9 cent	$3.24	($20)	9%
145	Base	IRR-10%	$1.40	$0	10%
145	Base	IRR-16%	$2.41	$240	16%
145	Base	Elec - 6 cent	$1.50	$22	11%
145	Base	Elec - 9 cent	$2.37	$232	16%

Source: Energy Narrative analysis

The table shows that the natural gas pipeline remains financially feasible under every Cost+ sensitivity case for both the assumed 10% IRR and 16% IRR. The resulting natural gas transportation tariffs range from US$2.27 per MMBtu for the 10% IRR under 50 MMscfd Low Cost Case to US$6.85 per MMBtu for the 16% IRR under 30 MMscfd and High Cost Case.

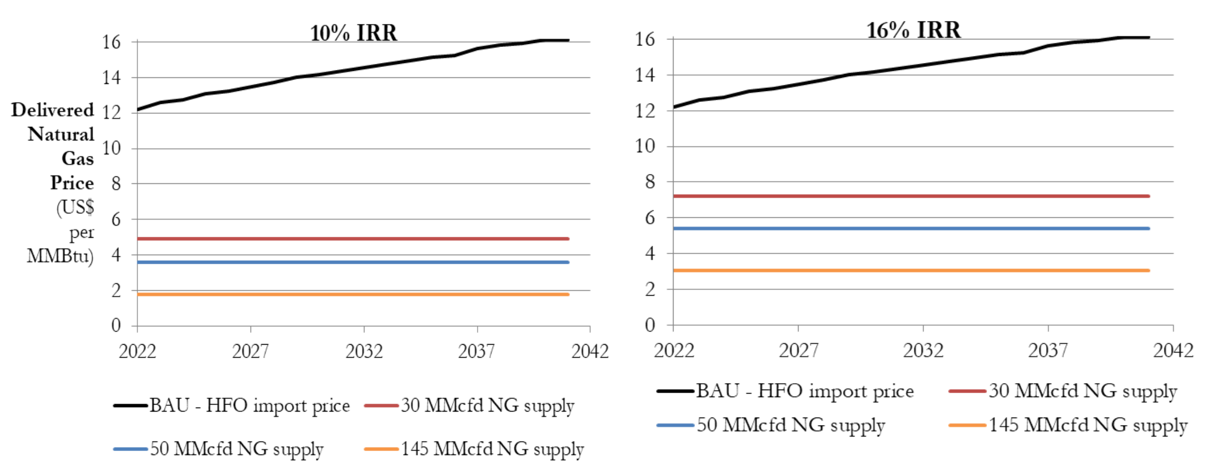
Under the Net Back approach, the natural gas pipeline is financially feasible under the 9 cent electricity level in all sensitivities except the 50 MMscfd High Cost Case where it has a 9% IRR and a US$20 million loss over the project's 20 year life. The natural gas pipeline is not feasible under the 6 cent electricity level for any of the sensitivity cases, suggesting that this average price for electricity is unobtainable without higher natural gas volumes or subsidization.

If the natural gas production were increased to the theoretical 145 MMscfd supply case, the pipeline transportation tariff could fall as low as US$1.40 per MMBtu under the Cost+ price setting mechanism and a 10% IRR. Increasing the IRR to 16% would result in a price of US$2.41 per MMBtu. Under the Net Back price setting methodology, the natural gas wellhead price for 9 cent electricity and 6 cent electricity both fall within the range set by the Cost+ price setting methodology. That is, at this volume of natural gas, setting the natural gas price to produce electricity at an average price of 6 cents per kWh is financially feasible, resulting in a US$22 million NPV and 11% IRR. Increasing the electricity price to 9 cents per kWh results in an NPV of US$232 million and an IRR of 16%.

1.2.3. Natural gas delivered price

The price of the natural gas delivered to the Guyana mainland is the sum of the upstream price of the produced natural gas and the pipeline tariff to transport it to the shore. Figure 1-3 below compares the delivered price of natural gas under the different natural gas volumes under the Cost+ price setting methodology for both a 10% IRR and 16% IRR. In both cases, the natural gas price is compared to a "business as usual" price for the imported HFO that the natural gas replaces.

Figure 1-3: Price of delivered natural gas to achieve a 10% and 16% IRR (2017 US$ per MMBtu)



Source: Energy Narrative analysis

Under the 30 MMscfd natural gas supply case, a delivered natural gas price of US$4.92 per MMBtu provides a 10% IRR, rising to US$7.19 per MMBtu for a 16% IRR. Increasing the natural gas volume to the 50 MMscfd supply case lowers the delivered price to US$3.57 per MMBtu for a 10% IRR and US$5.42 per MMBtu for a 16% return. If the 145 MMscfd natural gas supply profile is achieved and the pipeline was fully utilized, the delivered price of natural gas could fall to just US$1.77 per MMBtu for a 10% return and US$3.03 per MMBtu for a 16% return.

Under all pricing options and natural gas volume cases, the delivered price of natural gas is well below the projected import parity price for HFO. Under the Base Case price forecast, the HFO price is expected to increase from roughly US$12 per MMBtu in 2022 to over US$16 per MMBtu in 2041 (in real 2017 US$), averaging US$14.49 per MMBtu throughout the period. This is more than double the highest cost natural gas option (16% return on 30 MMscfd supply) and more than eight times the price of the lowest cost option (10% return on 145 MMscfd supply).

1.3. NGL separation and LPG production plant feasibility

The NGL separation and LPG production plant's economic and financial feasibility are calculated separately below, using a common set of physical, operational, and financial assumptions.

1.3.1. Economic feasibility

The NGL separation and LPG production plant's economic feasibility was determined by comparing the economic costs of building and operating the plant with the economic benefits that it will bring. The plant's economic costs include the capital cost to build the facility, including equipment to separate the raw NGLs from the natural gas stream, fractionate the NGLs into LPG and other end products, and prepare the separate products for wholesale or retail sale; the ongoing costs to operate the plant, and any environmental costs associated with the plant's operations.

The NGL separation and LPG production plant's economic benefits include the avoided costs that would have been incurred if the plant had not been built. The LPG delivered by the plant will replace LPG that is currently being imported for domestic use, with additional volumes available to support new LPG demand or for export. The economic benefit of the plant was therefore modeled as the avoided cost of importing LPG for the volume of expected LPG demand and the economic benefit of exporting the LPG for the remaining volumes.

This analysis does not include any economic benefits from increased job creation (both directly from the construction and operation of the plant and indirectly from the greater economic activity associated with it). While the plant will clearly bring some job creation benefits, this value was not quantified for this analysis.

This economic cost benefit analysis (CBA) finds that the NGL separation and LPG production plant has an aggregate net present value (NPV) of approximately US$373 million and an economic rate of return of 48% percent under the project's Base Case assumptions. This indicates that the plant is economically viable.

A sensitivity analysis was performed to estimate how changes in key variables would impact the NGL separation and LPG production plant's economic feasibility using the same three independent variables as for the natural gas pipeline.

Table 1-4 presents the results of changing the input variables individually as well as a "worst case" scenario that combined high project costs with a low oil price outlook.

Table 1-4: NGL separation and LPG production plant economic feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics				
NG Flow Volume	Capital & Operating Costs	HFO and LPG Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	Base	Base	$461	($88)	$373	48%	5.23
30	High	Base	$461	($106)	$355	42%	4.36
30	Low	Base	$461	($71)	$390	57%	6.53
30	Base	High	$796	($88)	$708	69%	9.03
30	Base	Low	$249	($88)	$161	30%	2.83
30	High	Low	$249	($106)	$144	26%	2.36
50	Base	Base	$634	($104)	$531	48%	6.12
50	High	Base	$634	($124)	$510	42%	5.10
50	Low	Base	$634	($83)	$551	55%	7.65
50	Base	High	$1,107	($104)	$1,003	67%	10.67
50	Base	Low	$339	($104)	$236	31%	3.27
50	High	Low	$339	($124)	$215	27%	2.73
145	Base	Base	$1,298	($178)	$1,121	41%	4.81

Source: Energy Narrative analysis

The table shows that the NGL separation and LPG production plant remains economically feasible under each individual sensitivity case. Even under the "worst case" combination of high project costs and a low oil price outlook, the project is feasible, showing a US$144 million economic net present value over the project's 20-year lifespan and an economic rate of return of 26% under the 30 MMscfd volume Case. The plant shows the highest economic return under the case with 50 MMscf per day of natural gas and high oil prices, reaching US$1 billion in net present value and a 67% economic rate of return.

If natural gas supply were increased to the theoretical 145 MMscfd case, the NGL separation and LPG production plant would have an economic net present value of roughly US$1.1 billion and an economic rate of return of 41%.

1.3.2. Financial feasibility

The NGL separation and LPG production plant's financial feasibility was calculated using the Cost+ pricing approach that was used in the offshore natural gas pipeline financial feasibility analysis. Because the price of LPG does not affect the price of electricity, the Net Back pricing option was not used for the plant's financial feasibility analysis.

The financial analysis finds that the LPG produced by the plant would be priced at US$6.72 per MMBtu to have a net present value (NPV) of zero and an internal rate of return of 10%. The LPG would have to be priced at US$9.74 per MMBtu to achieve a 16% IRR, resulting in a US$18 million NPV. This indicates that the NGL separation and LPG production plant is financially viable under this pricing option.

A sensitivity analysis was performed to estimate how changes in key variables would impact the NGL separation and LPG production plant's financial feasibility under the Cost+ pricing options. The sensitivity analysis used the natural gas volume and cost variables that were included in the economic sensitivity analysis. Under the Cost+ pricing option, adjusting the variables only affected the LPG sales price and the net present value as the internal rate of return was held fixed at 10% and 106%, respectively.

The summary results of the sensitivity analysis are presented in Table 1-5 below.

Table 1-5: NGL separation and LPG production plant financial feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics		
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	LPG Price (US$/MMBtu)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$6.72	$0	10%
30	Base	IRR-16%	$9.74	$18	16%
30	Base	Elec - 6 cent	$4.26	($16)	3%
30	Base	Elec - 9 cent	$6.85	$1	10%
30	Low	IRR-10%	$5.38	$0	10%
30	Low	IRR-16%	$7.79	$15	16%
30	Low	Elec - 6 cent	$4.27	($7)	7%
30	Low	Elec - 9 cent	$6.86	$10	14%
30	High	IRR-10%	$8.07	$0	10%
30	High	IRR-16%	$11.69	$22	16%
30	High	Elec - 6 cent	$4.25	($25)	1%
30	High	Elec - 9 cent	$6.84	($8)	7%
50	Base	IRR-10%	$5.38	$0	10%
50	Base	IRR-16%	$8.09	$29	16%
50	Base	Elec - 6 cent	$3.70	($19)	5%
50	Base	Elec - 9 cent	$6.15	$9	12%
50	Low	IRR-10%	$4.30	$0	10%
50	Low	IRR-16%	$6.47	$23	16%
50	Low	Elec - 6 cent	$3.71	($7)	8%
50	Low	Elec - 9 cent	$6.16	$21	16%
50	High	IRR-10%	$6.46	$0	10%
50	High	IRR-16%	$9.70	$35	16%
50	High	Elec - 6 cent	$3.69	($32)	3%
50	High	Elec - 9 cent	$6.14	($4)	9%
145	Base	IRR-10%	$3.85	$0	10%
145	Base	IRR-16%	$6.49	$94	16%
145	Base	Elec - 6 cent	$4.12	$11	11%
145	Base	Elec - 9 cent	$6.52	$100	16%

Source: Energy Narrative analysis

The table shows that the NGL separation and LPG production plant remains financially feasible for every individual sensitivity case under the Cost+ pricing approach. The resulting LPG price ranges from US$4.30 per MMBtu for the 10% IRR under 50 MMscfd Low Cost Case to US$11.69 per MMBtu for the 16% IRR under 30 MMscfd High Cost Case.

Under the Net Back approach, delivering an average electricity price of US$0.09 per kWh and holding the NGL separation and LPG production plant to the same return as other project components under the Base Case assumptions would result in an LPG price of US$6.85 per MMBtu, resulting in an NPV of approximately US$1 million and an internal rate of return of 10% percent. That is, the plant would be profitable under this option. An electricity price of US$0.06 per kWh is not possible at this natural gas volume, however, as this electricity price would require the LPG to be priced at US$4.26 per MMBtu, resulting in a 3% IRR and a US$16 million loss in net present value terms.

If the natural gas production were increased to the theoretical 145 MMscfd supply case, the LPG price could fall as low as US$3.85 per MMBtu under the Cost+ price setting mechanism and a 10% IRR. Increasing the IRR to 16% would result in a price of US$6.49 per MMBtu. Under the Net Back price setting methodology, the natural gas wellhead price for 9 cent electricity and 6 cent electricity both fall within the range set by the Cost+ price setting methodology. That is, at this volume of natural gas, setting the natural gas price to produce electricity at an average price of 6 cents per kWh is financially feasible, resulting in a US$11 million NPV and 11% IRR. Increasing the electricity price to 9 cents per kWh results in an NPV of US$100 million and an IRR of 16%.

1.4. Power plant feasibility

The natural gas power plant's economic and financial feasibility are calculated separately below, using a common set of physical, operational, and financial assumptions.

1.4.1. Economic feasibility

The natural-gas-fired power plant's economic feasibility was determined by comparing the economic costs of building and operating the power plant with the economic benefits that it will bring. The power plant's economic costs include the capital cost to build the power plant, the annual cost to operate the power plant, and any environmental costs associated with the power plant's operations. The power plant's economic benefits include the avoided costs that would have been incurred if the power plant had not been built. The proposed natural-gas-fired power plant will replace similar power plants using heavy fuel oil that is currently being imported for electricity generation. The economic benefit of the power plant therefore includes the avoided cost of importing heavy fuel oil and the avoided economic cost of CO_2 emissions that would result from burning the HFO for electricity generation.

This analysis does not include any economic benefits from increased job creation (both directly from the construction and operation of the plant and indirectly from the greater economic activity associated with it). While the plant will clearly bring some job creation benefits, this value was not quantified for this analysis.

The economic cost benefit analysis (CBA) finds that the power plant has an aggregate net present value (NPV) of approximately US$532 million and an economic rate of return of 24% percent under the project's Base Case assumptions. This indicates that the power plant is economically viable.

A sensitivity analysis was performed to estimate how changes in key variables would impact the power plant's economic feasibility using the same three independent variables as the natural gas pipeline.

Table 1-6 presents the results of changing the three input variables individually as well as a "worst case" scenario that combined high project costs with a low oil price outlook. For each combination of natural gas volume, project cost, and HFO price, the table presents the calculated present value of the project benefits, costs, and economic net present value, the economic rate of return, and the economic benefit/cost ratio of the power plant.

Table 1-6: Power plant economic feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics				
NG Flow Volume	Capital & Operating Costs	HFO and LPG Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	Base	Base	$1,192	($661)	$532	24%	1.80
30	High	Base	$1,224	($765)	$459	21%	1.60
30	Low	Base	$1,160	($556)	$604	29%	2.09
30	Base	High	$1,963	($661)	$1,303	37%	2.97
30	Base	Low	$709	($661)	$49	12%	1.07
30	High	Low	$742	($765)	($23)	9%	0.97
50	Base	Base	$1,613	($766)	$847	27%	2.11
50	High	Base	$1,657	($882)	$775	24%	1.88
50	Low	Base	$1,569	($650)	$919	31%	2.41
50	Base	High	$2,671	($766)	$1,905	39%	3.49
50	Base	Low	$958	($766)	$192	15%	1.25
50	High	Low	$1,002	($882)	$119	13%	1.14
145	Base	Base	$1,746	($771)	$975	28%	2.26

Source: Energy Narrative analysis

The table shows that the power plant remains economically feasible under each individual sensitivity case. Under the "worst case" combination of both high project costs and a low oil price outlook and the 30 MMscfd natural gas volume, the project is marginally unfeasible, showing a US$23 million economic loss over 20 years and an economic rate of return of 9%--just below the 10% hurdle rate. The power plant shows the highest economic return under the 50 MMscf per day of natural gas volumes and the high oil price case, reaching US$1.9 billion in net present value and a 39% economic rate of return.

If natural gas supply were increased to the theoretical 145 MMscfd case, the power plant would have an economic net present value of US$975 million and an economic rate of return of 28%.

1.4.2. Financial feasibility

The natural-gas-fired power plant's financial feasibility was calculated using the same two pricing options—Cost+ and Net Back—that were used in the offshore natural gas pipeline financial feasibility analysis.

The financial analysis described below finds that the electricity generated by the natural-gas-fired power plant would be priced at US$88 per MWh (8.8 cents per kWh) if the natural gas is priced using the Cost+ methodology and 10% IRR under the Base Case assumptions. Setting the IRR to 16% would result in an average electricity price of US$126 per MWh (12.6 cents per kWh).

A sensitivity analysis was performed to estimate how changes in key variables would impact the power plant's financial feasibility under both the Cost+ and Net Back natural gas pricing options. The sensitivity analysis used the same independent variables that were included in the natural gas pipeline financial sensitivity analysis. The summary results of the sensitivity analysis are presented in Table 1-7 below.

Table 1-7: Power plant financial feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics		
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	Electricity Price (US$/MWh)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$88.49	$0	10%
30	Base	IRR-16%	$125.53	$88	16%
30	Base	Elec - 6 cent	$60.00	($65)	5%
30	Base	Elec - 9 cent	$90.00	$3	10%
30	Low	IRR-10%	$74.30	$0	10%
30	Low	IRR-16%	$104.67	$74	16%
30	Low	Elec - 6 cent	$60.00	($36)	7%
30	Low	Elec - 9 cent	$90.00	$32	13%
30	High	IRR-10%	$102.68	$0	10%
30	High	IRR-16%	$146.41	$101	16%
30	High	Elec - 6 cent	$60.00	($93)	3%
30	High	Elec - 9 cent	$90.00	($25)	8%
50	Base	IRR-10%	$79.95	$0	10%
50	Base	IRR-16%	$110.12	$98	16%
50	Base	Elec - 6 cent	$60.00	($71)	5%
50	Base	Elec - 9 cent	$90.00	$39	13%
50	Low	IRR-10%	$67.73	$0	10%
50	Low	IRR-16%	$92.13	$81	16%
50	Low	Elec - 6 cent	$60.00	($30)	7%
50	Low	Elec - 9 cent	$90.00	$80	16%
50	High	IRR-10%	$92.17	$0	10%
50	High	IRR-16%	$128.08	$116	16%
50	High	Elec - 6 cent	$60.00	($113)	2%
50	High	Elec - 9 cent	$90.00	($3)	10%
145	Base	IRR-10%	$56.72	$0	10%
145	Base	IRR-16%	$83.09	$107	16%
145	Base	Elec - 6 cent	$60.00	$16	11%
145	Base	Elec - 9 cent	$90.00	$157	19%

Source: Energy Narrative analysis

The table shows that the power plant remains financially feasible under every Cost+ sensitivity case for both the assumed 10% IRR and 16% IRR. The resulting average cost of electricity generated range from US$68 per MWh (6.8 cents per kWh) for the 10% IRR under the 50 MMscfd Low Cost Case to US$128 per MWh (12.8 cents per kWh) for the 16% IRR under the 30 MMscfd High Cost Case.

Under the Net Back pricing approach, it is financially feasible for the power plant to sell electricity for 9 cents per kWh under the Base Cases and Low Cost Cases for both natural gas volumes. It is not financially feasible under the High Cost Cases for either natural gas volume level, with a US$25 million loss in net present value terms for the 30 MMscfd natural gas volume and a US$3 million NPV loss for the 50 MMscfd natural gas volume. It is not feasible for the power plant to sell electricity for 6 cents per kWh under any of the sensitivity cases, suggesting that this average price for electricity is unobtainable without subsidization.

If the natural gas production were increased to the theoretical 145 MMscfd supply case, the average electricity price could fall as low as US$56.72 per MWh under the Cost+ price setting mechanism and a 10% IRR. Increasing the IRR to 16% would result in an average electricity price of US$83.09 per MWh. Under the Net Back price setting methodology, the natural gas wellhead price for 9 cent electricity and 6 cent electricity both fall within the range set by the Cost+ price setting methodology. That is, at this volume of natural gas, setting the natural gas price to produce electricity at an average price of 6 cents per kWh is financially feasible, resulting in a US$16 million NPV and 11% IRR. Increasing the electricity price to 9 cents per kWh results in an NPV of US$157 million and an IRR of 16%.

1.5. Overall project feasibility

The overall project's economic and financial feasibility are calculated separately below, based on the previous analysis of the project components.

1.5.1. Economic feasibility

The overall project's economic feasibility was determined by comparing the sum of the economic costs of the project components with the sum of the component's economic benefits. The overall project's economic costs include the capital cost to build each of the project components, the annual cost to operate each of the project components, and any environmental costs associated with each component's operations. The overall project's economic benefits include the avoided costs that would have been incurred if the overall project had not been built. These include the avoided costs of importing heavy fuel oil and LPG, and the avoided economic cost of CO_2 emissions that would result from burning the HFO for electricity generation.

This analysis does not include any economic benefits from increased job creation (both directly from the construction and operation of the project components and indirectly from the greater economic activity associated with it). While the project will clearly bring some job creation benefits, this value was not quantified for this analysis.

The economic cost benefit analysis found that the overall project has an aggregate economic net present value (NPV) of approximately US$918 million and an economic rate of return of 30% percent under the project's Base Case assumptions. This indicates that the overall project is economically viable.

Table 1-8 below summarizes the aggregate results under each of the sensitivity variations calculated for each of the project components. Because the same variables were changed for each of the component sensitivity analyses (capital costs, oil price, and natural gas volume), the sensitivity analysis for each component can be directly combined to find the impact of changing each sensitivity variable on the project as a whole.

Table 1-8: Overall project economic feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics				
NG Flow Volume	Capital & Operating Costs	HFO and LPG Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	Base	Base	$1,715	($798)	$918	30%	2.15
30	High	Base	$1,747	($928)	$820	26%	1.88
30	Low	Base	$1,683	($667)	$1,016	36%	2.52
30	Base	High	$2,867	($798)	$2,070	47%	3.59
30	Base	Low	$990	($798)	$192	16%	1.24
30	High	Low	$1,022	($928)	$94	13%	1.10
50	Base	Base	$2,367	($925)	$1,442	34%	2.56
50	High	Base	$2,411	($1,070)	$1,341	30%	2.25
50	Low	Base	$2,323	($780)	$1,543	40%	2.98
50	Base	High	$3,988	($925)	$3,063	50%	4.31
50	Base	Low	$1,356	($925)	$431	20%	1.47
50	High	Low	$1,400	($1,070)	$330	17%	1.31
145	Base	Base	$4,536	($1,141)	$3,394	38%	3.97

Source: Energy Narrative analysis

The table shows that the overall project remains economically feasible under each individual sensitivity case. Even under the "worst case" combination of both high project costs and a low oil price outlook with 30 MMscf per day of natural gas volume the project is feasible, showing a US$94 million economic net present value over 20 years and an economic rate of return of 13%. The overall project shows the highest economic return under the 50 MMscf per day of natural gas volumes and the high oil price case, reaching just over US$3 billion in net present value and a 50% economic rate of return.

If natural gas supply were increased to the theoretical 145 MMscfd case, the overall project would have an economic net present value of nearly US$3.4 billion and an economic rate of return of 38%.

1.5.2. Financial feasibility

The overall project's financial feasibility was determined by subtracting the sum of the costs of the project components from the sum of the component's income. The overall project's costs include the capital cost to build each of the project components and the annual cost to operate each of the project components, interest expense for any debt that is issued to finance the project, and any corporate income taxes assessed on the project component's profits. The overall project's income is the sum of income from each project component based on the volume of natural gas, LPG, and electricity that is sold, and the price for which each is sold under both the Cost+ and Net Back price setting methodologies.

The financial analysis finds that the natural gas would be delivered to the shore for US$4.92 per MMBtu, the LPG would be priced at US$7.58 per MMBtu, and the electricity generated by the natural-gas-fired power plant would be priced at US$88 per MWh (8.8 cents per kWh) if the natural gas is priced using the Cost+ methodology and setting the return at each component to 10%. Increasing the internal rate of return to 16% would increase the delivered natural gas price to US$7.19 per MMBtu, the LPG price to US$9.74 per MMBtu, and the electricity generation cost to US$125 per MWh (12.5 cents per kWh).

Pricing the natural gas to achieve an average electricity price of 9 cents per kWh would result in an average delivered natural gas price of US$5.02, and an LPG price of US$6.85 per MMBtu. Under this pricing option, the overall project has a net present value (NPV) of approximately US$11 million and an internal rate of return of 10% percent under the project's Base Case assumptions. It is not feasible to set the electricity price to 6 cents per kWh as this pricing leads to a US$215 million loss in net present value terms under the Base Case assumptions.

Table 1-9 below summarizes the aggregate results under each of the sensitivity variations calculated for each of the project components. Because the same variables were changed for each of the component sensitivity analyses (costs, natural gas volume, rate of return and electricity price), the sensitivity analysis for each component can be combined to find the impact of changing each sensitivity variable on the project's financial feasibility as a whole.

Table 1-9: Overall project financial feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics						
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	NG Wellhead Price (US$/MMBtu)	NG Pipeline Tariff (US$/MMBtu)	NG Delivered Price (US$/MMBtu)	LPG Price (US$/MMBtu)	Electricity Price (US$/MWh)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$1.01	$3.91	$4.92	$6.72	$88.49	$0	10%
30	Base	IRR-16%	$1.48	$5.71	$7.19	$9.74	$125.53	$274	16%
30	Base	Elec - 6 cent	$0.64	$2.48	$3.12	$4.26	$60.00	($215)	4%
30	Base	Elec - 9 cent	$1.03	$3.99	$5.02	$6.85	$90.00	$11	10%
30	Low	IRR-10%	$0.81	$3.13	$3.94	$5.38	$74.30	$0	10%
30	Low	IRR-16%	$1.18	$4.57	$5.75	$7.79	$104.67	$223	16%
30	Low	Elec - 6 cent	$0.64	$2.48	$3.13	$4.27	$60.00	($103)	7%
30	Low	Elec - 9 cent	$1.03	$3.99	$5.03	$6.86	$90.00	$123	13%
30	High	IRR-10%	$1.22	$4.69	$5.91	$8.07	$102.68	$0	10%
30	High	IRR-16%	$1.78	$6.85	$8.63	$11.69	$146.41	$326	16%
30	High	Elec - 6 cent	$0.64	$2.47	$3.11	$4.25	$60.00	($326)	2%
30	High	Elec - 9 cent	$1.03	$3.98	$5.01	$6.84	$90.00	($100)	8%
50	Base	IRR-10%	$0.74	$2.84	$3.57	$5.38	$79.95	$0	10%
50	Base	IRR-16%	$1.12	$4.31	$5.42	$8.09	$110.12	$316	16%
50	Base	Elec - 6 cent	$0.50	$1.95	$2.45	$3.70	$60.00	($203)	5%
50	Base	Elec - 9 cent	$0.84	$3.24	$4.08	$6.15	$90.00	$98	12%
50	Low	IRR-10%	$0.59	$2.27	$2.86	$4.30	$67.73	$0	10%
50	Low	IRR-16%	$0.89	$3.45	$4.34	$6.47	$92.13	$254	16%
50	Low	Elec - 6 cent	$0.51	$1.95	$2.46	$3.71	$60.00	($76)	8%
50	Low	Elec - 9 cent	$0.84	$3.25	$4.09	$6.16	$90.00	$225	15%
50	High	IRR-10%	$0.88	$3.40	$4.29	$6.46	$92.17	$0	10%
50	High	IRR-16%	$1.34	$5.17	$6.51	$9.70	$128.08	$377	16%
50	High	Elec - 6 cent	$0.50	$1.94	$2.45	$3.69	$60.00	($330)	3%
50	High	Elec - 9 cent	$0.84	$3.24	$4.08	$6.14	$90.00	($28)	9%
145	Base	IRR-10%	$0.36	$1.40	$1.77	$3.85	$56.72	$0	10%
145	Base	IRR-16%	$0.62	$2.41	$3.03	$6.49	$83.09	$458	16%
145	Base	Elec - 6 cent	$0.39	$1.50	$1.88	$4.12	$60.00	$49	11%
145	Base	Elec - 9 cent	$0.61	$2.37	$2.98	$6.52	$90.00	$498	16%

Source: Energy Narrative analysis

The table shows that the overall project is financially feasible under all sensitivity cases using the Cost+ price setting methodology. The most profitable case is the High Cost Case under the 50 MMscf per day of natural gas supply and 16% IRR. In this case, the overall project has a net present value of over US$377 million.

Under the Net Back pricing approach, the project as a whole is financially feasible when the generated electricity is sold for 9 cents per kWh under the Base Cases and Low Cost Cases for both natural gas volumes. It is not financially feasible under the High Cost Cases for either natural gas volume level, with a US$100 million loss in net present value terms for the 30 MMscfd natural gas volume and a US$28 million NPV loss for the 50 MMscfd natural gas volume. It is not feasible for the power plant to sell electricity for 6 cents per kWh under any of the sensitivity cases, suggesting that this average price for electricity is unobtainable without subsidization.

If the natural gas production were increased to the theoretical 145 MMscfd supply case, the overall project would be financially feasible under all price setting methodologies under the Base Case. Because this level of natural gas production is only theoretical with the currently available data, detailed sensitivities were not performed for this supply case.

1.6. Commercial structure framework

The purpose of the commercial structure framework is to identify potential commercial structures and risk allocation for the project as a whole and implications for each project segment (natural gas pipeline, NGL separation and LPG production plant, and electricity generation plant).

A review of similar projects delivering offshore natural gas for power generation suggests that the most common commercial structure for similar offshore natural gas pipeline and power generation projects integrates the natural gas infrastructure facilities with the upstream natural gas producing entities while the power plant is owned separately. This structure fits well within Guyana's institutional structure, as EEPGL and its partners are well positioned to build and operate the offshore pipeline and GPL is well positioned to own and operate the power plant, or manage the IPP contract for an independent company to build and operate it.

This structure simplifies the contracting arrangements as there is a single gas sales agreement (between the natural gas infrastructure company and the power plant), as well as risk mitigation and coordination of operations along the natural gas value chain. Avoiding the need to attract a separate company to build the natural gas pipeline and NGL separation and LPG production plant also avoids potential project development delays, an important consideration given the tight timeframe before expected first gas production. Furthermore, the income derived from the LPG sales could be used to reduce the cost of the natural gas sold to the power plant, helping to reduce electricity generation costs. This can be achieved by allocating a greater share of the upstream and pipeline costs to the LPG stream, or through direct cross-subsidization.

Although placing all of the natural gas and LPG assets within a single company could limit competition and market access should other upstream producers wish to use the natural gas pipeline to bring additional natural gas volumes to Guyana, this can be handled by setting terms and timing for future open access in the gas contract or in a newly established gas regulatory regime. The LPG plant would also be a de facto monopoly, as it is large enough to provide for all of Guyana's current domestic LPG needs, and so managing its interaction with the current LPG providers will be important.

2. Introduction

Guyana is expected to experience a significant growth in electricity demand, with Guyana Power and Light (GPL) estimating that Guyana electricity demand will more than double in the coming decade. The high and volatile cost of electricity supply is an important issue for Guyana. The country's reliance on expensive imported liquid fuels, primarily fuel oil and diesel, for electricity generation also places a heavy burden on Guyana's balance of payments. GPL is therefore faced with the challenge to produce, distribute and commercialize the necessary energy to supply that demand under adequate quality standards and economic conditions, with a further objective of reducing electricity rates, as prices in Guyana are the third highest in the Caribbean.

Following the recent commercial oil and natural gas discoveries by ExxonMobil's affiliate, Esso Exploration and Production Guyana Limited (EEPGL), in the Stabroek block approximately 120 miles offshore Guyana, EEPGL estimates that between 30-50 million cubic feet per day (MMscfd) of natural gas could be available for electricity generation in Guyana, thereby diversifying the energy matrix in Guyana. Currently, the Government of Guyana has commissioned an update of the Study on System Expansion of the Generation and Transmission System of Guyana which aims to consider the option of natural gas fired power generation facilities utilizing indigenous gas resources as part of this mix. Using domestically produced natural gas for electricity generation could offer substantial benefits as lower cost natural gas could reduce the cost of electricity generation, minimize local environmental impacts of burning liquid fuels, and reduce GHG emissions.

Bearing these factors in mind in the context of the commercial natural gas discoveries, in 2017 the Government of Guyana undertook a Desk Study on the options, cost, economics, impacts, and key considerations of transporting and utilizing natural gas from offshore Guyana for electricity generation. The objective of the study was to determine the feasibility of transporting and utilizing natural gas produced offshore for electricity generation including the technical and operational challenges of using natural gas, the costs and benefits of producing electricity with natural gas, and natural gas' strategic fit with Guyana's renewable energy goals.

The Desk Study's analysis of alternative transportation media showed 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. The Desk Study noted that more data is needed to assess offshore pipeline technical risks, but process to do so is well established and potential technical risks will be identified and addressed as data is gathered on the proposed pipeline pathway and landing site. The Desk Study also noted that 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. The Desk Study suggested that further analysis is needed to identify potential PPP options and suitable commercial and regulatory structures for the offshore pipeline.

For the proposed new electricity generation capacity, the Desk Study suggested that the new capacity should be dual fuel, and at least part of the new capacity additions should be located at the pipeline landing site as it noted that distributing the natural gas to each existing power plant could be challenging given the dense population and infrastructure in the surrounding area.

The Desk Study analyzed the costs and benefits of using natural gas for electricity generation and suggested that the Clonbrook region was the optimal landing site when compared to alternative proposed sites at Georgetown and New Amsterdam. The analysis also showed that natural gas may be significantly cheaper than fuel oil.

In addition, the Desk Study noted that natural gas presents a new transition fuel opportunity that could reduce electricity costs and promote stronger economic growth. Because the timing and funding of hydro-electric power is uncertain, natural gas could provide a more immediate cheaper and cleaner source of electrical power. The Desk Study also concluded that 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 MMscfd natural gas supply would not be sufficient to meet peak electricity demand.

With new data available on Guyana's offshore hydrocarbon resources, the potential path and landing site for the proposed offshore natural gas pipeline, and an updated electricity generation expansion plan, there is a need to update and expand upon the Desk Study's analysis and conclusions.

The Government of Guyana has partnered with the Inter-American Development Bank (IDB) to commission Energy Narrative to conduct a feasibility study of the offshore natural gas pipeline, the LPG separation facility, and the natural gas-fired generation plant and related electricity infrastructure. This feasibility study updates and expands upon the previous desk study, taking into account the new information and data that is now available. The primary objective of the study is to determine the overall feasibility of transporting natural gas from offshore Guyana, building an NGL separation and LPG production plant to market the liquids from the natural gas stream, and building a new electricity generation station to use the remaining dry natural gas. The feasibility analysis will emphasize the economic and financial feasibility of the project as a whole and provide guidance for more detailed studies of the individual project components.

This Final Report describes the analysis that Energy Narrative performed in order to determine the project's overall economic and financial feasibility, including complementary analysis of the project's environmental and social impacts. The analysis is based on the three project components—offshore natural gas pipeline, NGL separation and LPG production plant, and power plant—and is organized as follows:

- **Section 3** describes the feasibility study objectives and underlying key questions;
- **Section 4** provides an overview of the project and related upstream oil and gas activity;
- **Section 5** describes the offshore natural gas pipeline economic and financial feasibility;
- **Section 6** describes the NGL separation and LPG production plant economic and financial feasibility;
- **Section 7** describes the natural-gas-fired power plant economic and financial feasibility;

- **Section 8** describes the total project economic and financial feasibility;
- **Section 9** describes potential commercial structure frameworks for the project components; and,
- **Section 10** describes the complementary analysis of the project's environmental and social impact.

In addition to these main report sections, six Appendices provide further detail on the economic and financial feasibility analysis. Appendix A lists the reference and data sources used in the analysis. Appendix B (attached to this report) provides details on the methodologies used to estimate the offshore natural gas pipeline capital costs. The remaining Appendices (C – F) are in Volume II of this report and contain tables detailing the annual cost and benefit calculations of each sensitivity variation that was performed.

3. Study Objectives

The objective of this study is: (i) to determine the feasibility of transporting natural gas from offshore Guyana, building an NGL separation and LPG production plant to market the liquids from the natural gas stream, and building a new electricity generation station to use the remaining dry natural gas; and, (ii) provide an economic and financial feasibility assessment of the project as a whole and of the individual project components (natural gas pipeline, LPG separation facility, and electric power plant).

Key elements of the feasibility study

We provide a broad review of the project's overall economic and financial feasibility by analyzing the three project components (natural gas upstream and offshore pipeline, NGL separation and LPG production plant, and electricity generation infrastructure) as described below:

- **Upstream natural gas and offshore pipeline feasibility.** The natural gas production and the offshore pipeline to bring the natural gas to the Guyana mainland must be economically feasible to justify the required investment and financially feasible to benefit investors and other stakeholders. For this project component, the economic feasibility assessment reviews natural gas supply, demand, and related market factors affecting its economic feasibility; reviews the conceptual pipeline design and proposed project site; and calculates the relevant costs and benefits accruing to the production of natural gas for sale and the offshore pipeline. This analysis is described in section 5.1 below.

  The pipeline must also be financially feasible to ensure that the resulting revenues are sufficient to cover debt payment obligations and expected returns on investment. For this project component, the financial feasibility assessment reviews income, costs, and the expected net present value and internal rate of return based on the price paid for natural gas delivered by the pipeline. This analysis is described in section 5.2 below.

- **NGL separation and LPG production plant feasibility.** The NGL separation and LPG production plant must be economically feasible to justify the required investment and financially feasible to benefit investors and other stakeholders. For this project component, the economic feasibility assessment reviews the cost to deliver natural gas, LPG demand, and related market factors affecting its economic feasibility; reviews the conceptual separation plant design and proposed project site; and calculates the relevant costs and benefits accruing to the NGL separation and LPG production plant. This analysis is described in section 6.1 below.

  The NGL separation and LPG production plant must also be financially feasible to ensure that the resulting revenues are sufficient to cover debt payment obligations and expected returns on investment. For this project component, the financial feasibility assessment reviews income, costs, and the expected net present value and internal rate of return based on the price paid for LPG produced by the separation plant. This analysis is described in section 6.2 below.

- **Power plant feasibility.** The power plant must be economically feasible to justify the required investment and financially feasible to benefit investors and other stakeholders. In addition, the power plant aims to reduce the cost of electricity to Guyana's electricity consumers. For this project component, the economic feasibility assessment reviews new power generation capacity additions, power plant operational parameters, the delivered price of natural gas, and the price of HFO; and calculates the relevant costs and benefits accruing to the power plant. This analysis is described in section 7.1 below.

The power plant must also be financially feasible to ensure that the resulting revenues are sufficient to cover debt payment obligations and expected returns on investment. For this project component, the financial feasibility assessment reviews income, costs based on the price paid for natural gas delivered to the power plant, and set the expected internal rate of return to 10% in order to calculate the resulting cost of electricity generated. This analysis is described in section 7.2 below.

- **Overall project feasibility.** The overall project must be economically feasible to justify the required investment and financially feasible to benefit investors and other stakeholders. This section combines the feasibility assessments for each of the three project components to determine the overall project feasibility. This analysis is described in section 8 below.
- **Commercial structure framework**. This section provides an initial assessment of potential commercial structures and risk allocation for the entire project and implications for each of the three project components. This analysis is described in section 9 below.
- **Complementary Analysis**. The project must also meet Guyana's environmental and social laws and regulations. This analysis includes a review of potential environmental and social impacts of building and operating the natural gas pipeline, NGL separation and LPG production plant, and natural gas-fired power plant, identifying potential factors to be considered during the EIA process for each project component. This analysis is described in section 10 below.

The above analysis ultimately arrives at a set of recommendations regarding the overall feasibility of transporting and utilizing gas from offshore Guyana to supply LPG and generate electricity.

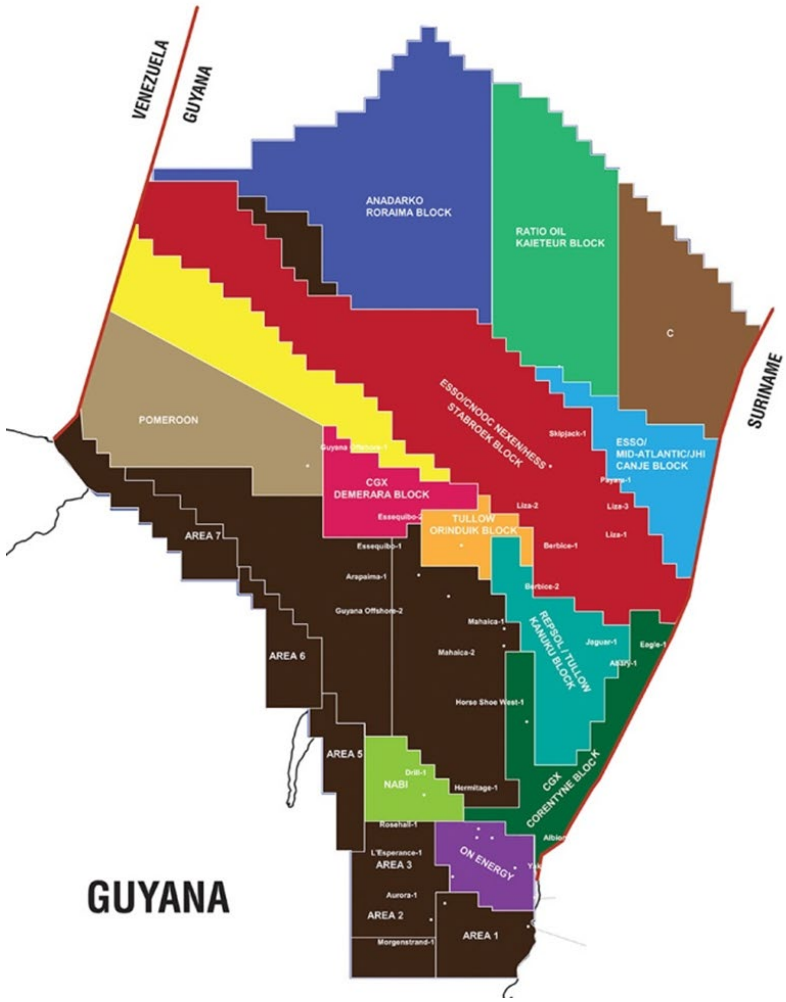
2. Project Overview

The proposed natural gas offshore pipeline, NGL separation and LPG production plant, and natural-gas-fired power plant that comprise the project are being developed to exploit natural gas available for commercials uses from the Liza-1 deepwater project, located in the Stabroek block roughly 180 kilometers offshore of Guyana in more than 2,000 meters of water.

The Stabroek block concession license was awarded to Esso Exploration and Production Guyana Limited (EEPGL), a local affiliate of ExxonMobil, in consortia with Hess and CNOOC Nexen. EEPGL is the operator and holds a 45% interest in the block, while Hess holds a 30% interest and CNOOC Nexen holds the remaining 25%. The Stabroek block, covering 6.6 million acres (26,800 square kilometers), is among the largest of the nearly dozen offshore blocks that have been awarded by the Government of Guyana to stimulate offshore oil and gas exploration and production.

EEPGL is also the operator of two additional blocks: the Canje block located east of the Stabroek block (with a 35% interest and in partnership with JHI (40%) and Mid-Atlantic (25%), and the Kaieteur block to the north and adjacent to the Stabroek and Canje blocks (with a 50% interest in partnership with Ratio Energy (50% through two holding companies). Other companies currently exploring in offshore Guyana include Anadarko (Roraima block), CGX (Corentyne and Demerara blocks), and Repsol and Tullow Oil (jointly exploring the Kanuku block (see Figure 4-1)

Figure 4-1: Guyana offshore exploration blocks



Source:

Liza-1 is the first of eight hydrocarbon discoveries made in the Stabroek block since 2015. Indeed, EEPGL's drilling record in the block has been an almost uninterrupted string of significant discoveries. Major wells that were drilled include:

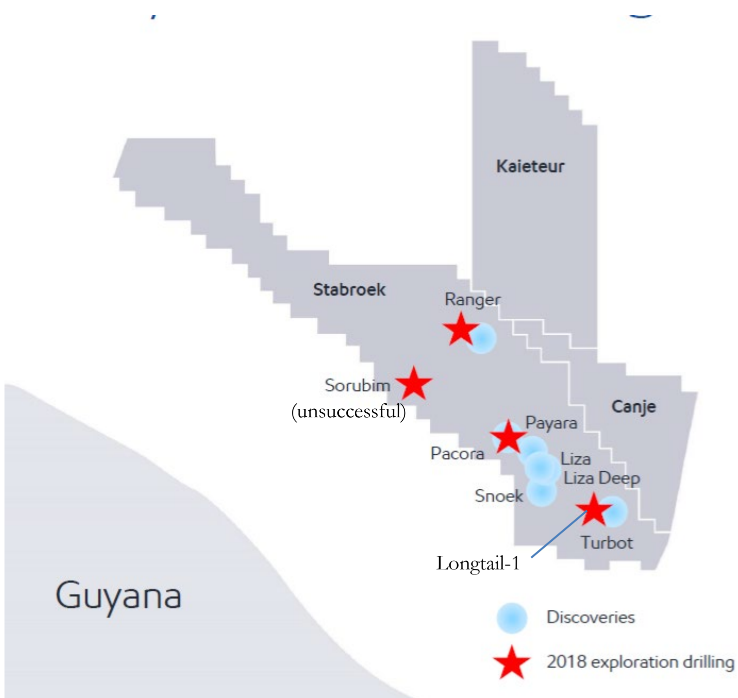
- May 2015: Liza-1 well, **Liza reservoir** discovered
- July 2016: Liza-2 well drilled and tested
- September 2016: Skipjack-1 drilled, no commercial quantities of hydrocarbons
- October 2016: Liza-3 well confirming a world-class resource discovery in excess of 1 billion boe
- Appraisal drilling at Liza 3 identified **Liza Deep,** an additional high quality reservoir directly below the Liza field, estimated to contain 100-150 million boe
- January 2017: Payara-1 well, **Payara reservoir** discovered with more than 95 feet of high quality, oil bearing sandstone.

- March 2017: Liza-4 well encountered more than 197 feet of high-quality, oil-bearing sandstone, which will underpin a potential Liza Phase 2 development
- March 2017: Snoek-1 well discovers **Snoek reservoir** with 82 feet of high-quality, oil-bearing sandstone.
- July 2017: Payara-2 well encountered 59 feet of high-quality, oil-bearing sandstone. Payara discovery estimated at approximately 500 million boe.
- October 2017: Turbot-1 well discovers **Turbot reservoir** with approximately 75 feet of high-quality, oil-bearing sandstone.
- January 2018: Ranger-1 well discovers **Ranger reservoir** encountering approximately 230 feet of high-quality, oil-bearing carbonate.
- February 2018: Pacora-1 well discovers **Pacora reservoir** encountering approximately 65 feet of high-quality, oil-bearing sandstone.
- April 2018: Sorubim-1 well drilled, no commercial quantities of hydrocarbons
- June 2018: Longtail-1 well discovers **Longtail reservoir** encountering approximately 256 feet of high-quality, oil-bearing sandstone in close proximity to the previous Turbot discovery.

To date, EEPGL and its partners have found eight commercial oil and gas reservoirs in the Stabroek block. The most recent discoveries are still being appraised, but EEPGL increased its estimate of total recoverable hydrocarbons from 3.2 billion oil-equivalent barrels to more than 4 billion oil-equivalent barrels in July, 2018.

EEPGL plans to continue drilling highly prospective areas of the block, and has recently added a third drill ship in order to speed up its operations. Figure 4-2 shows the location of ExxonMobil's finds and planned drilling program for 2018.

Figure 4-2: ExxonMobil Stabroek block discoveries and planned drilling activity (2018)



Source: ExxonMobil Analyst Meeting, March 2018, updates added by Energy Narrative

5. Offshore natural gas pipeline feasibility

The purpose of this section is to determine whether the production of natural gas for sale and the undersea natural gas pipeline that is proposed to deliver the natural gas from EEPGL's offshore platform to onshore Guyana is both economically and financially feasible. The upstream natural gas production and offshore natural gas pipeline will be economically feasible if the net present value of the economic benefits of the project outweigh the net present value of the economic costs. It will be financially feasible if the net present value of the pipeline's annual cash flows (income minus costs) is positive.

The upstream natural gas production and offshore natural gas pipeline economic and financial feasibility are calculated separately below, using a common set of physical, operational, and financial assumptions.

5.1. Natural gas pipeline economic feasibility

The upstream natural gas production and offshore pipeline's economic feasibility was determined by comparing the economic costs of building and operating the upstream infrastructure and offshore natural gas pipeline with the economic benefits that they will bring. The economic costs include the capital cost to add the natural gas production infrastructure to the offshore facility and build the pipeline, the annual cost to operate the natural gas production and pipeline, and any environmental costs associated with the production and pipeline operations. The economic benefits include the avoided costs that would have been incurred if the natural gas were not produced and the offshore natural gas pipeline was not built. These benefits are primarily from avoided imports of heavy fuel oil and avoided CO2 emissions from burning heavy fuel oil. The natural gas delivered by the offshore pipeline will primarily replace heavy fuel oil that is currently being imported for electricity generation. The economic benefit of the offshore natural gas pipeline therefore includes the avoided cost of importing heavy fuel oil and the avoided economic cost of CO_2 emissions that would result from burning the HFO for electricity generation.

The economic cost benefit analysis (CBA) described below finds that the offshore natural gas pipeline has an aggregate net present value (NPV) of approximately US$782 million and an economic rate of return of 30% percent under the project's Base Case assumptions. This indicates that the upstream natural gas production and offshore natural gas pipeline are economically viable.

The analysis to calculate the net present value of the upstream natural gas production and offshore pipeline is presented as follows:

- Verification of the projected natural gas supply and composition and timing of natural gas demand for power generation;
- Assessment and review of the landing site;
- Validation of the pipeline operational and functional characteristics;
- Methodology and assumptions to calculate the pipeline capital and operating costs;
- Methodology and assumptions to calculate the pipeline economic benefits;
- Economic feasibility analysis; and,
- Sensitivity analysis.

5.1.1. Verification of projected natural gas supply and composition and timing of natural as demand for power generation

This analysis verifies the projected supply and composition of natural gas from EEPGL and estimates the natural gas required for electric power generation requirements by GPL. The aim is to ensure that the expecting timing and profile of natural gas production is compatible with the proposed timing and profile of natural gas demand from Guyana's electricity sector. This analysis was completed under Energy Narrative's previous Desk Study, and has been updated and expanded to reflect new or additional information that has become available after the completion of that report.

Specific components of the analysis includes:

- Confirming the volume of natural gas available for electric power generation and the timing of its availability;
- reviewing GPL forecasts for electricity demand growth;
- reviewing GPL's proposed capacity and timing of natural gas-fired electricity generation assets;
- estimating GPL's natural gas consumption; and,
- comparing the available natural gas supply and estimated demand.

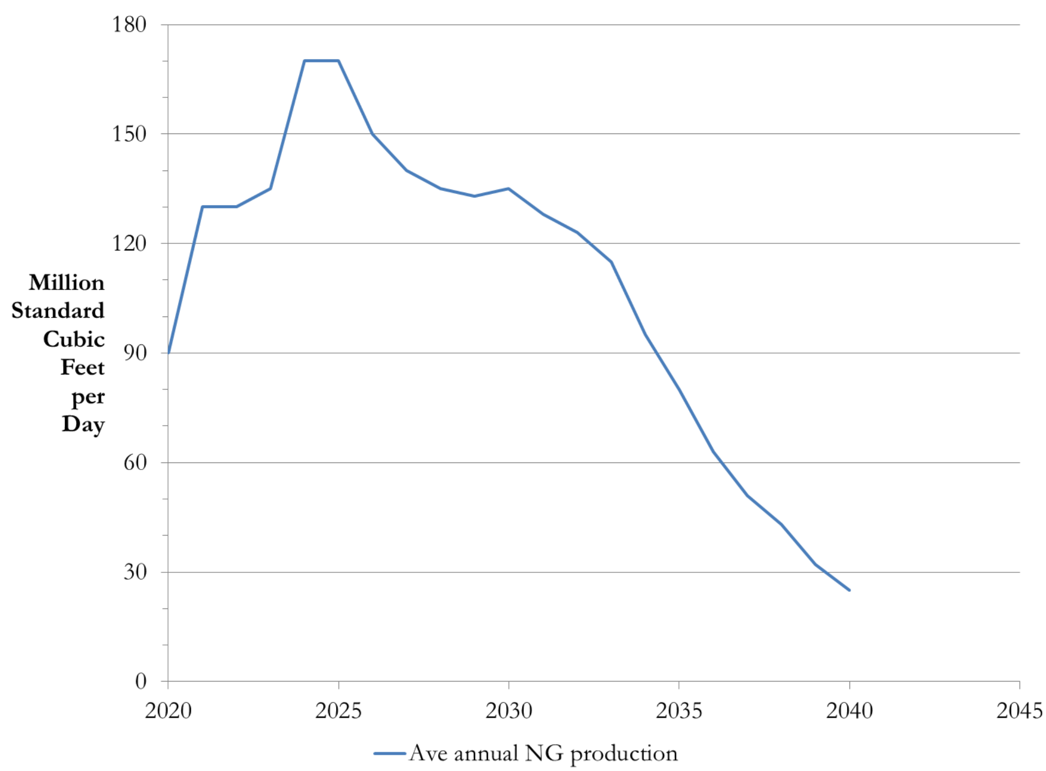
The analysis is based on natural gas production and composition data provided by EEPGL and electricity demand growth and future investment projections of new or converted natural-gas-fired electricity generation capacity provided by GPL and the Government of Guyana.

Projected supply and composition of natural gas

EEPGL's latest gas production profile information, provided through a presentation prepared for August, 2018, confirmed the availability of ~50 MMscf per day for gas sales for approximately 13 years (2027 to 2039) and the availability of ~30 MMscf per day for approximately 20 years (2022-2041). EEPGL also noted that it was continuing to model the reservoir and production facilities to evaluate the availability of 50 MMscfd for a longer period as well as the potential to make larger volumes of natural gas available for commercial sale.

The overall gas production profile for Liza Phase 1 (final investment decision basis) is shown in Figure 5-1 below. The production profile includes natural gas that will be reinjected to support oil production and natural gas required for FPSO operations, in addition to any volumes that will be made available for sale.

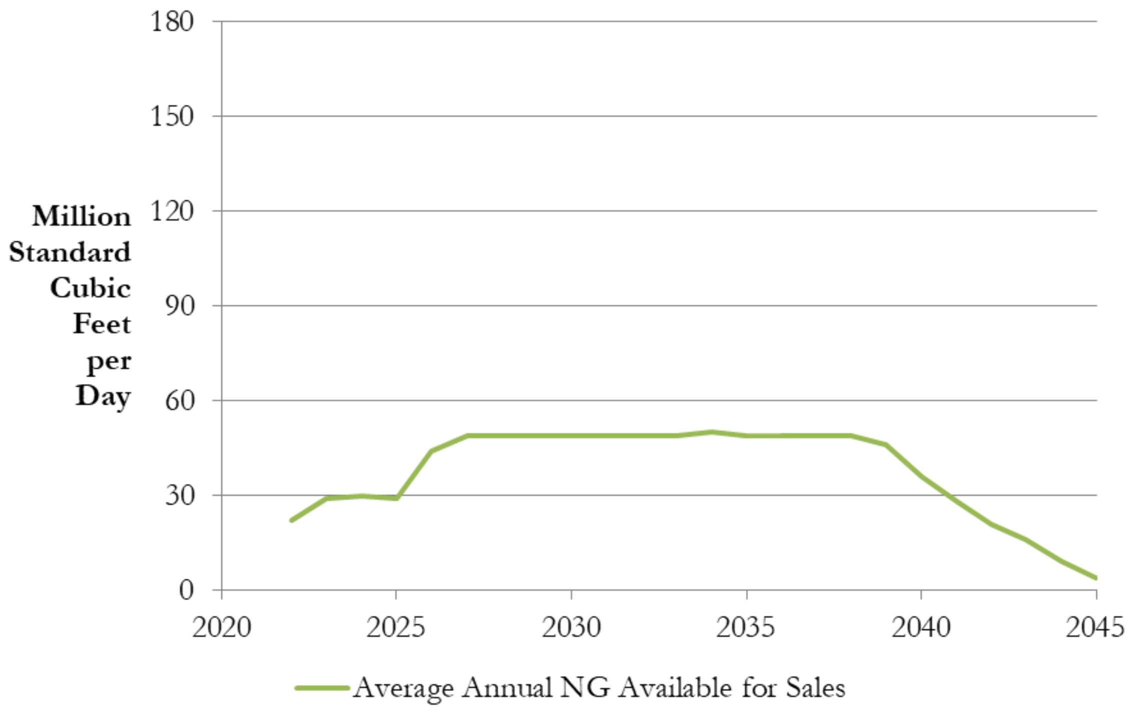
Figure 5-1: Liza-1 natural gas production profile, final investment decision basis



Source: Based on data from EEPG Presentation January 28, 2018 "Liza Phase 1 Gas Production Profile Final Investment Decision Basis"

Figure 5-2 below shows the latest estimate of natural gas volumes available for sale, based on a presentation prepared by EEPGL in August, 2018. The profile suggests an initial production level of roughly 30 MMscfd available from 2022 until 2025 (including a ramp up period in the first year), followed by production maintained at roughly 50 MMscfd between 2026 and 2039, and then a steady decline in production from 2039, falling below 30 MMscfd in 2041 and reaching zero in 2046.

Figure 5-2: Liza-1 natural gas available for sales, August 2018 estimate

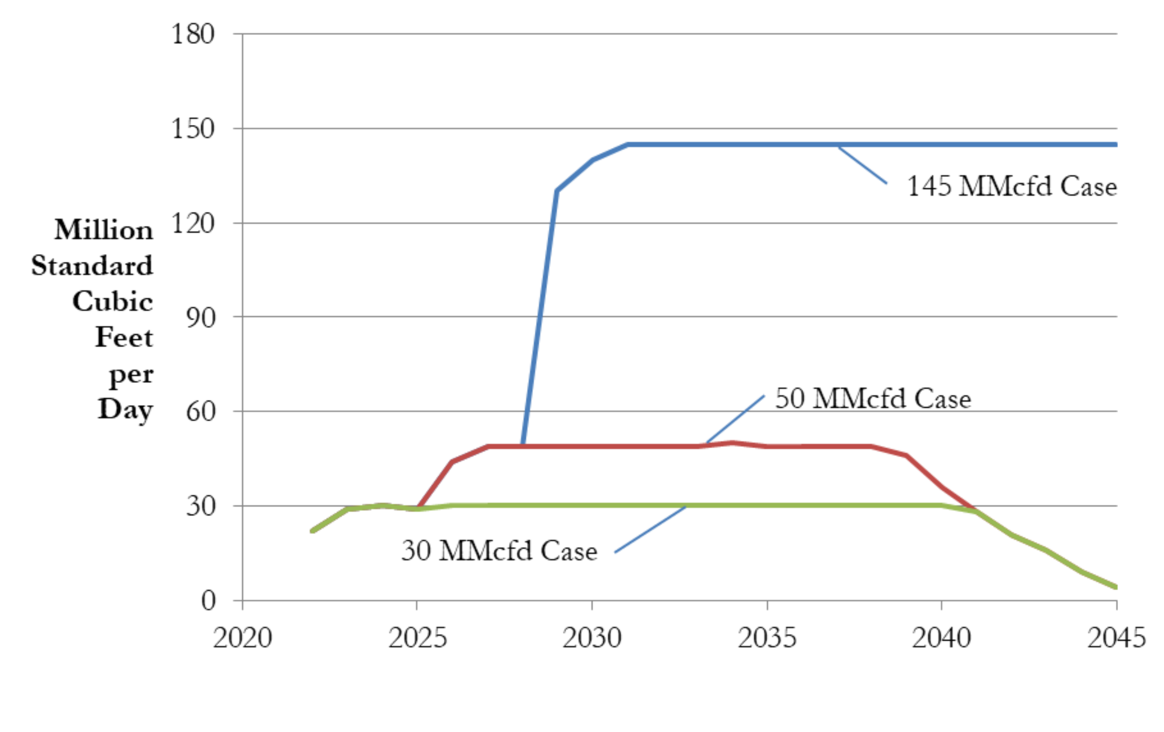


Source: Based on data from EEPG Presentation January 28, 2018 "Liza Phase 1 Gas Production Profile Final Investment Decision Basis"

This base production profile was used to create two natural gas supply cases for the economic and financial analysis: a lower case averaging 30 MMscfd from 2022 until 2041, and a higher case averaging 50 MMscfd for the bulk of the study period, including a ramp up period at the beginning and a ramp down period at the end (see Figure 5-3). These two natural gas supply cases, matched with the two options for new natural-gas-fired electricity generation capacity developed in the GPL 2018 Expansion Plan, were used for the economic and financial analysis, and related sensitivity analyses.

In addition to these two main supply cases, a third case was considered to highlight the potential impact of future additional natural gas availability. Although the currently modeled natural gas supply from Liza is capped at 50 MMscfd, the potential for additional natural gas supply from future developments has led EEPGL to size the offshore pipeline to transport a maximum of 145 MMscfd. This third natural gas supply case highlights the economic and financial implications of operating the pipeline at maximum capacity. The natural gas supply modeled in this third case assumes that the additional volumes begin to come online in 2028, six years after Liza-1's initial production. The supply curve rapidly increases to the full 145 MMscfd and then maintains that volume throughout the study period. It should be stressed that this is a purely conjectural case—the proposed supply curve and duration are not based on any supply or reservoir data currently available. As a result, the analysis based on this theoretical 145 MMscfd supply case will be presented separately from the two main supply cases noted above.

Figure 5-3: Modeled natural gas supply profiles



Source: Energy Narrative

Composition of the produced natural gas

On June 2, 2017 EEPGL provided an assessment of the composition of the natural gas that will be produced from the Liza Destiny FPSO for the 2017 Desk Study. 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 Phase 1 FPSO natural gas composition and resulting NGL streams

Liza Destiny FPSO gas composition

Component	Mol fraction	Component Heat Content (MMBtu/MMcf)	Volume of each Component Produced (MMcfd) 30 MMcfd	50 MMcfd	145 MMcfd	Gallons per Mcf (GPM)
Methane	79.1%	1,011	23.73	39.55	114.70	
Ethane	7.3%	1,783	2.19	3.65	10.59	1.95
Propane	6.7%	2,572	2.01	3.35	9.72	1.84
i-Butane	1.0%	3,259	0.30	0.50	1.45	0.33
n-Butane	2.8%	3,262	0.84	1.40	4.06	0.88
Condensate (C5+)	1.9%	4,000	0.57	0.95	2.76	0.70
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**	**5.70**
NG stream	**87.6%**	**1,061**	**26.3**	**43.8**	**127.0**	
(including Methane, Ethane, CO2 and Nitrogen)						
NGL Stream	**12.4%**	**3,002**	**3.7**	**6.2**	**18.0**	**3.75**
(including Propane, i-Butane, n-Butane, Condensate (C5+))						
		barrels of liquid NGL per day	2,678	4,463	12,942	
		barrels of liquid NGL per year	977,366	1,628,943	4,723,934	
LPG Stream	**10.5%**	**2,821**	**3.2**	**5.3**	**15.2**	**3.05**
(including Propane, i-Butane, n-Butane)						
		barrels of liquid LPG per day	2,180	3,633	10,535	
		barrels of liquid LPG per year	795,570	1,325,949	3,845,253	
Condensate Stream	**1.9%**	**4,000**	**0.6**	**1.0**	**2.8**	**0.70**
(Condensate (C5+) only)						
		barrels of liquid Condensate per day	498	830	2,407	
		barrels of liquid Condensate per year	181,796	302,993	878,681	

Source: Energy Narrative calculations based on data from EEPGL

In industry terms, the Liza Phase I gas is rich (high in liquid content) and sweet (low sulfur). The gas composition as reported has an average heat content of 1,302 Btu per standard 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 standard cubic foot), but still suitable for use in reciprocating engines[1] 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 once the natural gas reaches the shore, the heat content of the remaining dry gas would

[1] Reciprocating engines were determined to be the preferred technology for new thermal capacity in the GPL 2018 Expansion Study

be reduced to 1,061 as shown in the "NG stream" line in the table above. This is slightly higher than is typical for pipeline gas in the U.S., but well within the tolerance range for most end uses.

Separating the natural gas liquids (NGLs) from the natural gas would reduce the volume of delivered natural gas by 12.4%, such that 30 MMscfd of wet gas delivered to the shore would produce 26.3 MMscfd of dry gas and 3.7 MMscfd of NGLs. This NGL stream is equivalent to just under 2,700 barrels of NGLs per day, or nearly 980,000 barrels of NGLs per year. At the higher end, a 145 MMscfd supply of wet gas would result in 127 MMscfd of dry gas and 18 MMscfd of NGLs, equivalent to nearly 13,000 barrels of NGLs per day or 4.7 million barrels per year.

Fractioning the NGL stream into LPG (propane and butanes) and condensate (the remaining C5+) would produce 3.2 MMscfd of LPG and 0.6 MMscfd of condensate from the 30 MMscfd wet gas volume. This LPG stream is equivalent to just under 2,200 barrels of LPG per day, or nearly 800,000 barrels of LPG per year. At the higher end, a 145 MMscfd supply of wet gas would result in 15.2 MMscfd of LPG and 2.8 MMscfd of condensate, equivalent to 10,500 barrels of LPG per day or 3.8 million barrels per year.

Even the lowest proposed volume of LPG production is significantly higher than Guyana's current estimated LPG consumption of roughly 220,000 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 or exports. Under the higher natural gas supply range, LPG production could be more than 17x current consumption levels.

GPL forecasts for electricity demand growth

Guyana's future electricity consumption determines the amount of power generation capacity is needed and the volume of electricity that is produced by that capacity. Table 5-2 below shows the base case electricity demand outlook from GPL's 2018 Expansion Study.

Table 5-2: Guyana electricity demand outlook, Base Case

Base Case Forecast		(actual)				(forecast from 2018 on)									
	Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Total Electricity Sales	**GWh**	**493.6**	**518.9**	**550.9**	**555.3**	**581.4**	**607.1**	**884.3**	**1168.5**	**1204.4**	**1220.8**	**1237.5**	**1254.4**	**1357.4**	**1451.5**
Rate of Growth	%	3.7%	5.1%	6.2%	0.8%	4.7%	4.4%	45.7%	32.1%	3.1%	1.4%	1.4%	1.4%	1.6%	1.4%
New Load - Self-Generation	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	64.3	308.0	367.3
Losses converted into Sales	GWh					1.2	3.3	4.8	8.6	11.3	13.8	16.5	19.1	34.1	50.7
Sales from Essequibo region	GWh	-25.9	-39.5	-41.6	-41.7	-43.6	-45.6	-66.4	-87.7	-90.4	-91.6	-92.9	-94.2	-101.9	-108.9
Essequibo Interconnection	GWh														
Total Sales DBIS	**GWh**	**467.7**	**479.4**	**509.3**	**513.6**	**539.0**	**564.8**	**822.7**	**1089.4**	**1125.3**	**1143.0**	**1161.1**	**1243.6**	**1597.6**	**1760.6**
Total Losses	**%**	**29.6%**	**29.2%**	**29.2%**	**29.6%**	**28.7%**	**28.1%**	**28.1%**	**27.3%**	**26.6%**	**25.9%**	**25.1%**	**24.4%**	**20.7%**	**17.1%**
Technical	%	14.0%	14.9%	14.5%	14.5%	14.1%	14.1%	14.1%	13.7%	13.4%	13.0%	12.7%	12.4%	10.6%	9.0%
Non Technical	%	15.6%	14.3%	14.7%	15.1%	14.7%	14.0%	14.0%	13.6%	13.2%	12.8%	12.4%	12.0%	10.1%	8.1%
Net Exported Units	**GWh**	**663.9**	**676.7**	**719.1**	**729.9**	**756.3**	**785.1**	**1143.6**	**1499.1**	**1533.1**	**1541.8**	**1551.0**	**1645.2**	**2015.6**	**2123.5**
Auxiliaries & Self-consumption	GWh	20.8	20	21.8	21.1	21.5	21.2	21.3	21.3	21.2	21.3	21.3	21.3	21.3	21.3
Gross Generation	**GWh**	**684.7**	**696.7**	**740.9**	**750.9**	**777.7**	**806.3**	**1164.9**	**1520.4**	**1554.3**	**1563.2**	**1572.3**	**1666.6**	**2037.0**	**2144.8**
Unserved Energy	GWh	**13.9**	**10.6**	**11.2**	**11.3**	**10.5**	**10.9**	**15.9**	**20.8**	**21.3**	**21.4**	**21.6**	**22.9**	**28.0**	**29.5**
Unserved Energy	%	2.0%	1.5%	1.5%	1.5%	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	**698.6**	**707.3**	**752.1**	**762.2**	**788.2**	**817.2**	**1180.8**	**1541.2**	**1575.6**	**1584.6**	**1593.9**	**1689.5**	**2065.0**	**2174.3**
Linden Interconnection	GWh											168.9	172.2	188.2	202.8
DBIS Electricity Demand before EE	**GWh**	**698.6**	**707.3**	**752.1**	**762.2**	**788.2**	**817.2**	**1180.8**	**1541.2**	**1575.6**	**1584.6**	**1762.8**	**1861.7**	**2253.2**	**2377.1**
EE measures	GWh					12.8	17.6	22.9	31.5	39.8	48.5	61.8	74.9	137.2	203.7
DBIS Electricity Demand after EE	**GWh**	**698.6**	**707.3**	**752.1**	**762.2**	**775.4**	**799.6**	**1157.9**	**1509.7**	**1535.8**	**1536.1**	**1701.0**	**1786.8**	**2116.0**	**2173.4**
Electric Vehicles	GWh					0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.6	6.0	10.8
DBIS Electricity Demand	**GWh**	**698.6**	**707.3**	**752.1**	**762.2**	**775.4**	**799.6**	**1157.9**	**1509.7**	**1535.8**	**1536.1**	**1701.8**	**1788.4**	**2122.0**	**2184.2**
Load Factor	GWh		73.2%	74.0%	75.5%	75.5%	75.4%	75.4%	75.5%	75.5%	75.5%	75.4%	75.5%	75.5%	75.5%
Maximum Demand	**MW**		**110.3**	**116.1**	**115.3**	**117.3**	**121.0**	**175.2**	**228.4**	**232.2**	**232.4**	**257.5**	**270.5**	**321.0**	**330.4**

Source: GPL 2018 Expansion Study

The study expects electricity demand to grow rapidly in 2020 and 2021 as Guyana's offshore oil production comes on line. Total electricity consumption is expected to grow from 775 GWh in 2018 to nearly 2,200 GWh in 2035, while peak demand increases from 117 MW to 330 MW in the same period.

The 2017 Expansion Study also considered two demand growth alternatives: a High Demand Case, in which long-term electricity demand remains above 4% per year, driven by faster economic growth; and a Low Demand Case, in which the expected boost from oil development does not materialize and long-term demand growth remains below 2%. Table 5-3 below shows the electricity demand outlook for the High Demand Case.

Table 5-3: Guyana electricity demand outlook, High Demand Case

High Case Forecast			(actual)			(forecast from 2018 on)									
	Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Total Electricity Sales	**GWh**	**493.6**	**518.9**	**550.9**	**555.3**	**584.2**	**609.9**	**888.2**	**1173.6**	**1245.7**	**1296.6**	**1349.5**	**1404.3**	**1766.2**	**2146.2**
Rate of Growth	%	3.7%	5.1%	6.2%	0.8%	5.2%	4.4%	45.6%	32.1%	6.1%	4.1%	4.1%	4.1%	4.7%	4.0%
New Load - Self-Generation	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	64.3	308.0	367.3
Losses converted into Sales	GWh					1.2	3.3	4.8	8.7	11.7	14.7	17.9	21.4	44.3	75
Sales from Essequibo	GWh	-25.9	-39.5	-41.6	-41.7	-43.9	-45.8	-66.7	-88.1	-93.5	-97.3	-101.3	-105.4	-132.6	-161.1
Essequibo interconnectino															
Total Sales DBIS	**GWh**	**467.7**	**479.4**	**509.3**	**513.6**	**541.5**	**567.4**	**826.3**	**1094.2**	**1163.9**	**1214.0**	**1266.1**	**1384.6**	**1985.9**	**2427.4**
Total Losses	**%**	**29.6%**	**29.2%**	**29.2%**	**29.6%**	**28.7%**	**28.1%**	**28.1%**	**27.3%**	**26.6%**	**25.9%**	**25.1%**	**24.4%**	**20.7%**	**17.1%**
Technical	%	14.0%	14.9%	14.5%	14.5%	14.1%	14.1%	14.1%	13.7%	13.4%	13.0%	12.7%	12.4%	10.6%	9.0%
Non Technical	%	15.6%	14.3%	14.7%	15.1%	14.7%	14.0%	14.0%	13.6%	13.2%	12.8%	12.4%	12.0%	10.1%	8.1%
Net Exported Units	**GWh**	**663.9**	**676.7**	**719.1**	**729.9**	**759.8**	**788.7**	**1148.6**	**1505.7**	**1585.7**	**1637.7**	**1691.3**	**1831.7**	**2505.5**	**2927.8**
Auxiliaries & Self-consumption	GWh	20.8	20	21.8	21.1	21.5	21.2	21.3	21.3	21.2	21.3	21.3	21.3	21.3	21.3
Gross Generation	**GWh**	**684.7**	**696.7**	**740.9**	**750.9**	**781.2**	**809.9**	**1169.9**	**1527.0**	**1606.9**	**1659.0**	**1712.6**	**1853.1**	**2526.8**	**2949.1**
Unserved Energy	GWh	**13.9**	**10.6**	**11.2**	**11.3**	**10.9**	**11.3**	**16.4**	**21.4**	**22.5**	**23.2**	**24.0**	**25.9**	**35.4**	**41.3**
Unserved Energy	%	2.0%	1.5%	1.5%	1.5%	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	**698.6**	**707.3**	**752.1**	**762.2**	**792.1**	**821.2**	**1186.3**	**1548.4**	**1629.4**	**1682.3**	**1736.6**	**1879.0**	**2562.2**	**2990.4**
Linden Interconnection	GWh											168.9	172.2	188.2	202.8
DBIS Electricity Demand before EE	**GWh**	**698.6**	**707.3**	**752.1**	**762.2**	**792.1**	**821.2**	**1186.3**	**1548.4**	**1629.4**	**1682.3**	**1905.5**	**2051.2**	**2750.4**	**3193.2**
EE measures	GWh					12.8	17.6	22.9	31.5	39.8	48.5	61.8	74.9	137.2	203.7
DBIS Electricity Demand after EE	**GWh**	**698.6**	**707.3**	**752.1**	**762.2**	**779.3**	**803.6**	**1163.4**	**1516.9**	**1589.6**	**1633.8**	**1843.7**	**1976.3**	**2613.2**	**2989.5**
Electric Vehicles	GWh					0.0	0.0	0.0	0.0	0.0	0.0	2.5	5.1	18.8	34.2
DBIS Electricity Demand	**GWh**	**698.6**	**707.3**	**752.1**	**762.2**	**779.3**	**803.6**	**1163.4**	**1516.9**	**1589.6**	**1633.8**	**1846.2**	**1981.4**	**2632.0**	**3023.7**
Load Factor	GWh		73.2%	74.0%	75.5%	75.5%	75.4%	75.5%	75.5%	75.5%	75.5%	75.5%	75.5%	75.5%	75.5%
Maximum Demand	**MW**		**110.3**	**116.1**	**115.3**	**117.9**	**121.6**	**176.0**	**229.5**	**240.4**	**247.1**	**279.3**	**299.7**	**398.2**	**457.4**

Source: GPL 2018 Expansion Study

Under this Case, electricity consumption is expected to reach more than 3,000 GWh in 2035, while peak demand increases to almost 460 MW in the same period.

Table 5-4 shows the outlook for electricity demand under the Low Demand Case.

Table 5-4: Guyana electricity demand outlook, Low Demand Case

Low Case Forecast			(actual)			(forecast from 2018 on)									
	Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Total Electricity Sales	**GWh**	**493.6**	**518.9**	**550.9**	**555.3**	**578.1**	**603.6**	**630.1**	**659.1**	**689.4**	**699.4**	**709.5**	**719.7**	**782.3**	**839.8**
Rate of Growth	%	3.7%	5.1%	6.2%	0.8%	4.1%	4.4%	4.4%	4.6%	4.6%	1.5%	1.5%	1.4%	1.7%	1.4%
New Load - Self-Generation	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	64.3	308.0	367.3
Losses converted into Sales	GWh					1.2	3.3	3.4	4.9	6.5	7.9	9.4	11	19.6	29.3
Sales from Essequibo region	GWh	-25.9	-39.5	-41.6	-41.7	-43.4	-45.3	-47.3	-49.5	-51.7	-52.5	-53.3	-54.0	-58.7	-63
Essequibo interconnection	GWh														
Total Sales DBIS	**GWh**	**467.7**	**479.4**	**509.3**	**513.6**	**535.9**	**561.6**	**586.2**	**614.5**	**644.2**	**654.8**	**665.6**	**741.0**	**1051.2**	**1173.4**
Total Losses	**%**	**29.6%**	**29.2%**	**29.2%**	**29.6%**	**28.7%**	**28.1%**	**28.1%**	**27.3%**	**26.6%**	**25.9%**	**25.1%**	**24.4%**	**20.7%**	**17.1%**
Technical	%	14.0%	14.9%	14.5%	14.5%	14.1%	14.1%	14.1%	13.7%	13.4%	13.0%	12.7%	12.4%	10.6%	9.0%
Non Technical	%	15.6%	14.3%	14.7%	15.1%	14.7%	14.0%	14.0%	13.6%	13.2%	12.8%	12.4%	12.0%	10.1%	8.1%
Net Exported Units	**GWh**	**663.9**	**676.7**	**719.1**	**729.9**	**751.9**	**780.6**	**814.9**	**845.6**	**877.6**	**883.3**	**889.2**	**980.3**	**1326.2**	**1415.3**
Auxiliaries & Self-consumption	GWh	20.8	20	21.8	21.1	21.5	21.2	21.3	21.3	21.2	21.3	21.3	21.3	21.3	21.3
Gross Generation	**GWh**	**684.7**	**696.7**	**740.9**	**750.9**	**773.3**	**801.8**	**836.2**	**866.9**	**898.9**	**904.6**	**910.5**	**1001.7**	**1347.6**	**1436.6**
Unserved Energy	GWh	**13.9**	**10.6**	**11.2**	**11.3**	10.8	11.2	11.7	12.1	12.6	12.7	12.7	14.0	18.9	20.1
Unserved Energy	%	2.0%	1.5%	1.5%	1.5%	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	**698.6**	**707.3**	**752.1**	**762.2**	**784.2**	**813.0**	**847.9**	**879.0**	**911.5**	**917.3**	**923.2**	**1015.7**	**1366.4**	**1456.7**
Linden Interconnection	GWh											168.9	172.2	188.2	202.8
DBIS Electricity Demand before EE	**GWh**	**698.6**	**707.3**	**752.1**	**762.2**	**784.2**	**813.0**	**847.9**	**879.0**	**911.5**	**917.3**	**1092.1**	**1187.9**	**1554.6**	**1659.5**
EE measures	GWh					12.8	17.6	22.9	31.5	39.8	48.5	61.8	74.9	137.2	203.7
DBIS Electricity Demand after EE	**GWh**	**698.6**	**707.3**	**752.1**	**762.2**	**771.4**	**795.4**	**825.0**	**847.5**	**871.7**	**868.8**	**1030.3**	**1113.0**	**1417.4**	**1455.8**
Electric Vehicles	GWh					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DBIS Electricity Demand	**GWh**	**698.6**	**707.3**	**752.1**	**762.2**	**771.4**	**795.4**	**825.0**	**847.5**	**871.7**	**868.8**	**1030.3**	**1113.0**	**1417.4**	**1455.8**
Load Factor	GWh		73.2%	74.0%	75.5%	75.5%	75.5%	75.5%	75.5%	75.5%	75.5%	75.4%	75.4%	75.4%	75.5%
Maximum Demand	**MW**		**110.3**	**116.1**	**115.3**	**116.7**	**120.3**	**124.8**	**128.2**	**131.8**	**131.4**	**155.9**	**168.4**	**214.5**	**220.2**

Source: GPL 2018 Expansion Study

Under this Case, electricity consumption is expected to reach just under 1,500 GWh in 2035, while peak demand increases to 220 MW in the same period.

GPL's proposed capacity and timing of natural gas-fired electricity generation assets

Using the Base Case electricity demand forecast, the 2018 Expansion Study created for outlooks for new electricity generation capacity additions: a "Business as Usual" case without natural gas and using HFO as the main fuel, one based on 30 MMscf per day of natural gas supply, one based on 50 MMscf per day of natural gas, and one "Green" scenario without natural gas and using hydropower and other renewable energy sources for the main electricity supply. Tables 5-5 and 5-6 below show the proposed schedule for new dual-fuel engines under the two natural gas Cases.

Table 5-5: GPL forecast new electricity generation capacity additions, 30 MMscf per day natural gas supply Case

Year	Capacity Added (MW)	Technology	Fuel
2019	17.4	Engine	Dual
2021	34	Engine	Dual
2023	85	Engine	Dual
2024	34	Engine	Dual
2025	17	Engine	Dual
Total	**187.4**		

Source: GPL 2018 Expansion Study

Table 5-6: GPL forecast new electricity generation capacity additions, 50 MMscf per day natural gas supply Case

Year	Capacity Added (MW)	Technology	Fuel
2019	8.7	Engine	Dual
2021	34	Engine	Dual
2023	68	Engine	Dual
2024	34	Engine	Dual
2025	34	Engine	Dual
2026	34	Engine	Dual
2027	34	Engine	Dual
2028	34	Engine	Dual
Total	**280.7**		

Source: GPL 2018 Expansion Study

The total amount of new dual-fuel capacity in each Case is set to maximize the use of available natural gas, while the pace of new capacity additions is determined by the pace of electricity demand growth under the Base Case. For both tables, the engines added in 2019 and 2021 are assumed to run on HFO until natural gas become available in 2022.

Estimated natural gas consumption for power generation

The volume of natural gas consumed for power generation is determined by the amount of electricity that is generated from natural gas and the efficiency at which that electricity is generated (that is, the amount of natural gas consumed per unit of electricity produced. The amount of electricity generated with natural gas is the product of the available natural gas fired electricity generation capacity and the utilization rate of that capacity.

Table 5-7 below shows the assumed availability and heat rate for each type of power plant technology added in the various GPL 2018 Expansion Study cases. The availability sets the maximum utilization rate for a particular power generation technology, taking into account required down time for maintenance. The actual utilization rate for any particular unit can be lower than this maximum, depending on the system's electricity consumption and load shape, the total amount of generation capacity that is available, and the relative efficiency of the unit in question.

Table 5-7: Power plant operational assumptions

Estimated Availability by plant type

Technology	Unit	Value
Gas Turbine, LFO	%	90%
Engine, HFO	%	90%
Engine, NG	%	90%

Heat rate by plant type

Technology	Unit	Value
Gas Turbine, LFO	Btu/kWh	10,200
Engine, HFO	Btu/kWh	9,000
Engine, NG	Btu/kWh	8,500

Source: GPL 2018 Expansion Study

As shown in the Table, engines running on natural gas are expected to be more efficient than engines running on HFO (the lower heat rate indicates less fuel consumed per unit of electricity produced). As a result, an engine using natural gas would produce less expensive electricity than an engine using HFO even if the price of the two fuels on a US$ per MMBtu basis was the same.

Estimated natural gas demand and available excess supply

GPL's 2018 Expansion Study calculated the amount of natural gas required for electricity generation under the two natural gas scenarios based on the previously described parameters. In addition, the table shows the potential available excess natural gas supply under a 145 MMscfd production profile and the 50 MMscfd power plant expansion plan. As shown in Table 5-8, both main natural gas volume cases assume that virtually all of the available natural gas is used for power generation once all of the planned dual fuel engines are built. The 145 MMscfd supply case has substantial volumes of natural gas available for non-power generation uses as the proposed electricity generation capacity additions under the 50 MMscfd supply case are sufficient to provide virtually all of Guyana's electricity needs.

Table 5-8: Natural gas availability in excess of requirements for electricity generation (MMscf per day)

30 MMcf per day Supply and Expansion Plan	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
NG Pipeline capacity	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
NG Flow rate	22	29	30	29	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	28
Utilization Rate	15%	20%	21%	20%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	19%
LPG stream	2.3	3.0	3.2	3.0	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	2.9
Condensate stream	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5
Dry gas stream	19.3	25.4	26.3	25.4	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	24.5
Dry gas consumption for electricity generation	6.7	20.9	26.3	25.4	26.3	26.3	26.3	26.3	25.8	25.8	26.1	26.1	26.3	26.3	26.3	26.3	26.3	26.3	26.3	24.5
Available excess dry gas	**12.5**	**4.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.5**	**0.5**	**0.2**	**0.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

50 MMcf per day Supply and Expansion Plan	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
NG Pipeline capacity	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
NG Flow rate	22	29	30	29	44	49	49	49	49	49	49	49	50	49	49	49	49	46	36	28
Utilization Rate	15%	20%	21%	20%	30%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	32%	25%	19%
LPG stream	2.3	3.0	3.2	3.0	4.6	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.3	5.1	5.1	5.1	5.1	4.8	3.8	2.9
Condensate stream	0.4	0.6	0.6	0.6	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	0.9	0.9	0.9	0.9	0.9	0.7	0.5
Dry gas stream	19.3	25.4	26.3	25.4	38.5	42.9	42.9	42.9	42.9	42.9	42.9	42.9	43.8	42.9	42.9	42.9	42.9	40.3	31.5	24.5
Dry gas consumption for electricity generation	2.5	17.7	23.1	25.4	33.1	38.4	42.9	42.9	42.9	42.9	42.9	42.9	43.7	42.9	42.9	42.9	42.9	40.3	31.5	24.5
Available excess dry gas	**16.7**	**7.7**	**3.2**	**0.0**	**5.4**	**4.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

145 MMcf per day Supply and 50 MMcf per day Expansion Plan	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
NG Pipeline capacity	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
NG Flow rate	22	29	30	29	44	49	49	130	140	145	145	145	145	145	145	145	145	145	145	145
Utilization Rate	15%	20%	21%	20%	30%	34%	34%	90%	97%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
LPG stream	2.3	3.0	3.2	3.0	4.6	5.1	5.1	13.7	14.7	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2
Condensate stream	0.4	0.6	0.6	0.6	0.8	0.9	0.9	2.5	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Dry gas stream	19.3	25.4	26.3	25.4	38.5	42.9	42.9	113.9	122.6	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0
Dry gas consumption for electricity generation	2.5	17.7	23.1	25.4	33.1	38.4	42.9	44.2	44.2	44.2	44.2	43.7	43.7	43.2	43.2	43.2	43.2	43.2	43.2	43.2
Available excess dry gas	**16.7**	**7.7**	**3.2**	**0.0**	**5.4**	**4.5**	**0.0**	**69.6**	**78.4**	**82.8**	**82.8**	**83.3**	**83.3**	**83.9**	**83.9**	**83.9**	**83.9**	**83.9**	**83.9**	**83.9**

Source: Energy Narrative analysis

In the 30 MMscfd case, just over 12 MMscfd of excess gas is available in 2022, the first year of the pipeline's operations, but this excess is cut to just 4.5 MMscfd in 2023. After 2023 all available natural gas is absorbed by the power sector (assuming the wet gas NGLs are removed and dry gas is provided to the power plant). In this case only 21% of the pipeline's capacity is used during the peak period from 2023 to 2040.

In the 50 MMscfd case, over 16 MMscfd is available during the pipeline's first year of operation, falling to 7.7 MMscfd in 2023 and 3.2 MMscfd the following year. There is a short period with excess gas volume 2026 and 2027, but otherwise all natural gas is used for power generation for the rest of the study period. In this case, 34% of the pipeline's capacity is used during the peak period from 2027 to 2038.

In the 145 MMscfd case, natural gas demand for power generation is the same as the 50 MMscfd case, allowing for a substantial amount of excess natural gas to be available for other uses once the additional supply volumes come on line in 2029. Between 2022 and 2028 the supply profile and availability of excess gas is the same as the 50 MMscfd case. In 2029 nearly 70 MMscfd of excess supply is available, ramping up to roughly 83 MMscfd by 2031, a volume of excess supply that is then maintained through 2041. In this case, the pipeline reaches full capacity in 2031 and is fully utilized for the following decade.

5.1.2. Assessment and review of landing site

The purpose of this section is to review the physical characteristics of the selected landing site and industrial development location (Woodlands) and validate the findings of the site selection committee.

Site selection

The Woodlands site was selected after an extensive site selection process, led by cross-agency team including representatives from the Guyana Energy Agency, Guyana Power & Light, the Ministry of Natural Resources, the Ministry of Business, the Ministry of Public Infrastructure, the Guyana Lands & Surveys Commission, and the Maritime Administration Department.

The selection process had seven stages:

- **Stage 1: Identification of Criteria**. Ten sites were initially identified based on five criteria: land size (minimum 200 acres for future expansion and an industrial park; site development cost; accessibility to utilities, infrastructure, and port; distance and accessibility to the FPSO; and, socio-economic and environmental impact.

- **Stage 2**: **Evaluation of Sites.** The five criteria were given even weighting and rated on a scale of 0-20 with 0 being unacceptable and 20 denoting excellent conditions. This ranking evaluation resulted in three shortlisted sites for further consideration: Crab Island, Right Bank Berbice River; Woodlands, Right Bank Mahaica River, East Coast Demerara; and, Patentia, West Bank Demerara.

- **Stage 3**: **Further Review and Consideration.** After further consideration, Crab Island was dropped from consideration owing to possible conflicting interests at the location, and Vreed en Hoop was added as a possible location for power generation in conjunction with an industrial park in Patentia (both on the West Bank, Demerara).

- **Stage 4**: **EEPGL technical pre-screening report.** EEPGL conducted a preliminary environmental scoping report for both the Woodlands and Vreed-en-Hoop locations using basic geospatial analysis for four potential constraints: surrounding land use, biodiversity, social/cultural, and technical. This assessment led to a firm preference for the Woodlands site owing to lower technical issues with the pipeline landing; better ground elevation and lower overall impact on surround communities; and, potential challenges landing a high pressure natural gas pipeline in Vreed-en-Hoop owing to higher population density and the active river waterway.

- **Stage 5**: **Internal Validation of Findings (GoG entities).** The Site Selection Team conducted its own review of the two proposed sites and validated the preference for Woodlands based on specific considerations evaluated by GPL, MARAD, GL&SC, WSG and other members of the selection committee.

- **Stage 6**: **Field Assessments (EEPGL).** EEPGL also conducted physical field assessments of both sites to affirm the pre-screening report. This physical assessment found the Vreed-en-Hoop location had greater constraints to the proposed development than the Woodlands site, particularly related to surrounding land use.

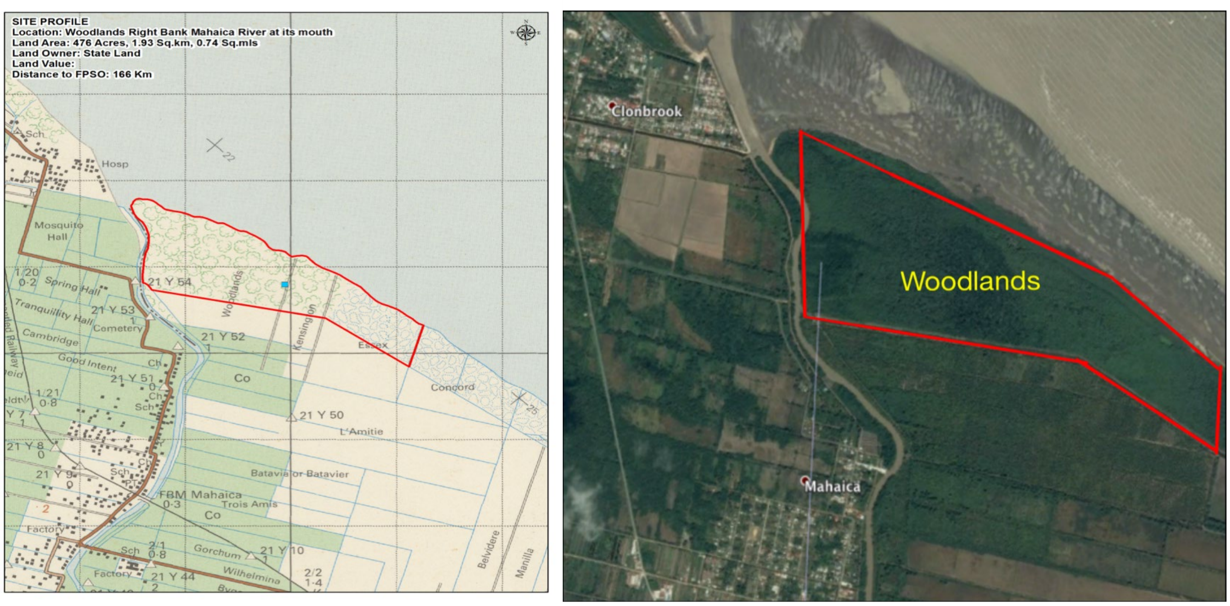
- **Stage 7**: **Evaluation of Site Capital Cost Comparisons.** An initial estimation of pipeline capital costs for the two proposed sites suggested that offshore pipeline to Vreed-en-Hoop would cost roughly US$12 million more than the pipeline, and the Vreed-en-Hoop location would also incur the additional cost of a US$60 million onshore pipeline to connect the power plant location with the industrial park location. This additional cost of US$72 million implied that the Vreed-en-Hoop location would be roughly 15% more expensive than the Woodlands location.

Based on this analysis, the Woodlands location was deemed the recommended landing site for the offshore natural gas pipeline and the development of the natural-gas-fired power plant with associated industries.

Landing site characteristics

The Woodlands landing site is located along the Atlantic coast, east of Georgetown in a relatively sparsely populated region. Figure 5-4 shows the proposed site on a regional map and satellite view.

Figure 5-4: Woodlands landing site map and satellite view



Source: NG presentation to Cabinet, March 20, 2018

The site selection group noted the pros and cons of the Woodlands landing site across five criteria: the available land size, cost to develop the site, accessibility to utilities, infrastructure and port, distance and accessibility to the FPSO, and socio-economic and environmental impact. These characteristics are described in Table 5-9.

Table 5-9: Woodlands characteristics

Criteria	Pros	Cons
Land size, future expansion	1. 476 Acres of land available for development. 2. Adequate size and allows for future expansions and development.	1. Nil
Site Development Cost **(soil characteristics and conditions, topography and vulnerabilities to natural disasters)**	In close proximity to the Mahaica River on the west and facade drainage canal to the South. 2. Internal drainage from facility can be discharged into the Mahaica River.	1. Poor soil conditions – soft saturated clays necessitating extensive foundation and soil stabilization works. 2. Low site elevation, area prone to soil erosion and flooding – flood protection infrastructure works would require (US$3,500 – US$4,500/m.) 3. Filling of site to achieve acceptable elevation and ground stability – retaining structures may be required.
Accessibility to utilities, infrastructure, and port.	1. Easy integration with GPL's Infrastructure at Sophia, Berbice and in proximity of plant. 2. Operating and maintaining Overhead Transmission Lines are easier. 3. Greater flexibility (2 load centers being powered directly) and more efficient dispatch of power by way of higher primary voltage transmission (230kv standard). 4. Access to major roadway. 5. Possibility of use of access through port Georgetown.	1. Longer Transmission Lines required to connect to Sophia. 2. More costly to interconnect Regions 2,3,7 & 10 to the DBIS. 3. Greater dependability on SCADA for ensuring efficient operation of network during power interruptions. 4. Acquiring easements would be challenging. 5. No natural channel large shipping vessels making the development of a port difficult.
Distance and Accessibility to FPSO	1. Shorter distance to FPSO (approx. 166 km) 2.Away from major shipping lanes and natural channels. 3. Reduction in cost – build and maintain port	1. Onshore pipeline transmission required. 2. Delays in accessing nearby port facility. 3. Increase operation cost to provide and maintain storage of gas and other products at site.
Socio-economic and environmental impact	1. Environmental impact of facility will be at a minimum, since surrounding area mainly comprises of farmlands.	1. Some cattle–farmers may be displaced. 2. Mangroves as the natural protection for shoreline would be disturbed.

Source: NG presentation to Cabinet, March 20, 2018

The Woodlands site as described has sufficient area to accommodate the planned power plant, NGL plant, and supporting infrastructure. Natural-gas-fired power plants have a relatively small footprint, averaging 20-40 acres in the United States. The NGL separation and LPG production plant will also have a relatively small footprint, estimated to be similar in size to the power plant, or roughly 20-30 acres depending on the volume of on-site storage that is required. The main potential constraint on the available space at the site will be the size of the required shoreline buffer. A large buffer zone will greatly reduce the space available for industrial development as the site stretches along the coast.

The lack of a local port will require the construction of a jetty or buoy system to allow seaborne deliveries of HFO as a backup fuel for the power plant. This same infrastructure could potentially also be used to load LPG carriers to export the LPG product if desired, or other liquids that are produced in the industrial park. Other solid products, such as urea, must be transported by road. This requirement could put additional pressure on regional road infrastructure from increased heavy truck traffic.

5.1.3. Validation of the pipeline operational and functional characteristics

The proposed pipeline is unusual in its small size, placing it outside of typical 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.

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.

5.1.4. Methodology and assumptions to calculate the upstream natural gas and offshore pipeline economic costs

The purpose of this section is to estimate the economic costs related to the proposed upstream natural gas production and offshore pipeline. The economic costs include the capital cost to add the infrastructure required to produce the natural gas for sale and to build the pipeline, the ongoing costs to produce the natural gas and operate the pipeline, and any environmental costs associated with the pipeline's operations.

The capital cost of modifying the FPSO to produce natural gas and of building and installing the pipeline is a major contributor to the cost of delivering natural gas from the offshore production platform to Guyana. EEPGL has provided an initial rough estimate of the associated capital costs.

The estimated costs from EEPGL were validated using three different comparison methodologies: reported costs from a sample of comparable projects, industry reported average pipeline costs, and an estimated built up from materials and services costs. Each of these methodologies are inexact given this project's unique circumstances, but can provide valuable context to the initial cost estimates provided by ExxonMobil.

The detailed capital cost comparison analysis can be found in Appendix B. Table 5-10 below summarizes the offshore natural gas pipeline estimated capital costs under each of the three methodologies with a 20% contingency added to each and compares the results with the reported figure from ExxonMobil.

Table 5-10: Estimated capital cost to install a 180 km, 12-inch pipeline offshore Guyana with a 20% contingency added

Cost estimation basis	Unit Cost (US$ per km-in)	Total Cost (US$ million)
Comparable Projects	$159,600	$344
Indusry Average	$171,240	$370
Materials cost	$162,840	$352
Average Estimate	**$164,560**	**$355**
ExxonMobil Estimate	$184,700	$399

Source: ExxonMobil, Energy Narrative estimates and calculations

Based on this analysis, a capital cost of US$355 million for the offshore natural gas pipeline was used in the economic and financial models. This amount was added to the US$92 million required to produce the natural gas for export from the FPSO as reported by ExxonMobil. The total capital cost to deliver the natural gas to shore is therefore US$447 million. This capital cost is the figure used to calculate the economic feasibility of the pipeline project.

Operational costs

Operational costs include ongoing operations and maintenance to ensure the natural gas production facility and pipeline operate in an efficient and safe manner and the cost of fuel and other consumables used when producing and transporting the natural gas. These operational costs are related to the size and length of the pipeline, and so can be linked to the capital cost required to build the pipeline. While these costs can vary substantially for different geographies and operational characteristics, industry standard estimates place the annual operational costs at roughly 2% of the pipeline's capital cost.

Given the lack of detailed operational data for natural gas pipelines in Guyana, this general industry value was used to estimate the annual operating costs for the offshore natural gas pipeline. Because the operational cost is linked to the pipeline capital cost, changing the pipeline's assumed capital cost will also change the assumed operational cost. In this way, sensitivity variations for the pipeline capital cost will also capture a range of sensitivities for the pipeline operational costs.

Based on this methodology, the estimated annual operating cost is US$7.1 million. The annual operating cost per volume of natural gas that is transported is then calculated as the total annual operating cost divided by the volume of transported natural gas.

Environmental costs

The main ongoing environmental cost from operating the offshore natural gas pipeline is the potential impact from CO2 emissions from the use of the natural gas that is transported. The economic cost of CO_2 emissions from natural gas consumption is calculated as the product of the expected CO_2 emissions and the social cost of CO_2 emissions. The expected CO_2 emissions is the product of the CO_2 emissions per unit of natural gas consumed and the volume of natural gas transported through the pipeline. The social cost of CO_2 emissions is assumed to be US$30 per ton. This value was used in order to align the economic analysis of the offshore pipeline with the economic analysis of Guyana's electric power sector that was conducted in the GPL 2018 Expansion Study.

5.1.5. Methodology and assumptions to calculate the upstream natural gas and pipeline economic benefits;

The purpose of this section is to calculate the economic benefits that will accrue from producing natural gas for sale and building and operating the offshore natural gas pipeline. The economic benefits include the savings that are obtained by reducing imports of liquid fuels (in particular, heavy fuel oil for electricity generation) and from avoided CO_2 emissions from burning HFO for electricity generation.

This analysis does not include any economic benefits from increased job creation (both directly from the construction and operation of the upstream production facility and indirectly from the greater economic activity associated with it). While the project will clearly bring some job creation benefits, this value was not quantified for this analysis.

Avoided fuel import costs

The value of the fuel imports that are avoided by producing the natural gas and building the offshore natural gas pipeline is the product of the volume of heavy fuel oil imports that are avoided and the imported heavy fuel oil's unit value. The heavy fuel oil that will be displaced by the natural gas will be primarily used for electricity generation. However, only the cost of HFO and displaced volume are included in the cost analysis for this segment of the overall project. Avoided costs related to building and operating HFO power plants is captured in the natural-gas-fired power plant economic feasibility analysis in section 7.

Even so, the volume of avoided heavy fuel oil imports is not equal to the volume of natural gas transported via the pipeline, even on an equivalent MMBtu basis. This is because the operational efficiency (as measured by the power plant's heat rate) of HFO-fired engines is less than the efficiency of natural-gas-fired engines. This difference is shown in Table 5-11 below, using the assumed heat rate values presented in the GPL 2018 Expansion Study.

Table 5-11: Power plant efficiency assumptions by technology and fuel

Heat rate by plant type

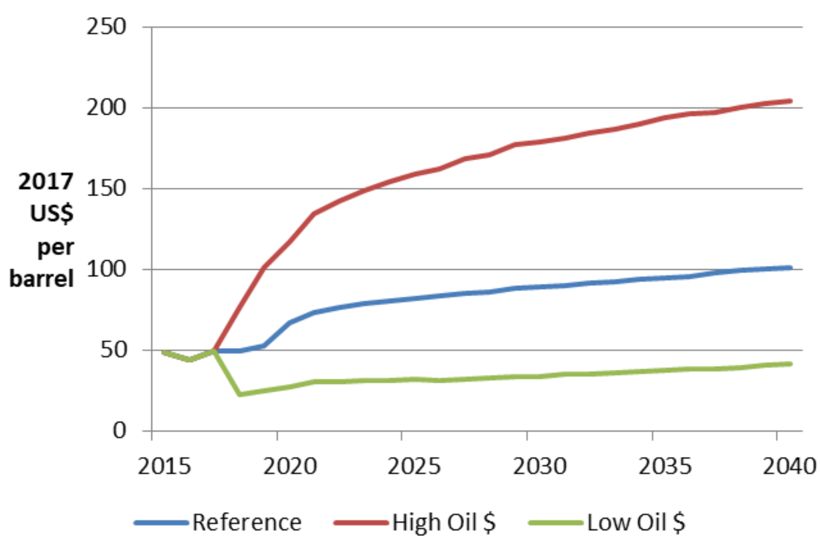
Technology	Unit	Value
Gas Turbine, LFO	Btu/kWh	10,200
Engine, HFO	Btu/kWh	9,000
Engine, NG	Btu/kWh	8,500

Source: GPL 2018 Expansion Study

As a result, the energy volume of avoided HFO imports in MMBtu per year will be 9/8.5 or roughly 5.9% higher than the energy volume of natural gas transported by the pipeline, also reported in MMBtu per year.

The value of the avoided heavy fuel oil imports was calculated using the same methodology that was used in the GPL 2018 Expansion Study. In this methodology, the historical price of HFO imports in Guyana was linked to the historical price of the West Texas Intermediate (WTI) crude oil index using a linear regression. This linear equation was then applied to the forecast WTI price reported in the EIA Annual Energy Outlook Reference Case (in real 2017 US dollars). Figure 5-5 below shows the forecast price for WTI under the Reference Case as well as two sensitivity cases: High Oil Price and Low Oil Price. These sensitivities were used to calculate high and low HFO price outlooks for the sensitivity analysis of the economic feasibility assessment as described in section 5.1.7.

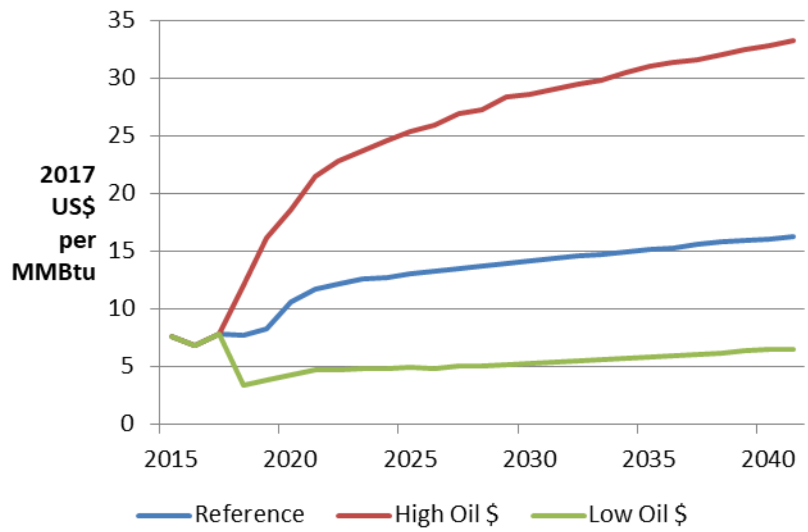
Figure 5-5: WTI price forecast under three scenarios (2017 US$ per barrel)



Source: Energy Narrative based on EIA 2018 Annual Energy Outlook data

Using the linear relationship between WTI and Guyana's price for imported HFO, the future price for Guyana's HFO imports was calculated under the three price scenarios. These outlooks are shown in Figure 5-6 below.

Figure 5-6: Guyana HFO price forecast under three scenarios (2017 US$ per MMBtu)



Source: Energy Narrative

The economic benefit of avoided HFO imports for each year of the forecast period was then calculated as the product of the forecast HFO price per MMBtu in that year and the calculated volume of HFO that would have been consumed under the Business as Usual Case for the same year. The sum of the future annual economic benefits from avoided HFO imports was then discounted to a present value in 2018 using a 10% real discount rate.

Avoided environmental costs

The main avoided environmental cost from operating the offshore natural gas pipeline is the potential impact from CO_2 emissions from the use of HFO for electricity generation. The economic cost of CO_2 emissions from HFO-fired electricity generation is calculated as the product of the expected CO_2 emissions and the social cost of CO_2 emissions. The expected CO_2 emissions is the product of the CO_2 emissions per unit of HFO consumed and the volume of HFO consumed each year. The social cost of CO_2 emissions is assumed to be US$30 per ton. This value was used in order to align the economic analysis of the offshore pipeline with the economic analysis of Guyana's electric power sector that was conducted in the GPL 2018 Expansion Study.

5.1.6. Economic feasibility analysis

The economic costs and benefits described above were calculated for each year between 2018 and 2041. This timeframe is based on EEPGL's project development timeline projecting first gas availability in 2022 and a 20-year period of natural gas availability from the Liza-1 development. The annual results were then discounted to 2018 using a 10% real discount rate in order to determine the economic net present value. Based on this analysis, the upstream natural gas production and offshore natural gas pipeline have an aggregate economic net present value (NPV) of approximately US$782 million and an economic rate of return of 30% percent under the project's Base Case assumptions. This indicates that the offshore natural gas pipeline is economically viable. The summary results of the economic feasibility analysis are presented in Table 5-12 below.

Table 5-12: Natural gas pipeline economic feasibility analysis results

Sensitivity Variable Settings			Key Results Metrics				
NG Flow Volume	Capital & Operating Costs	HFO and LPG Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	Base	Base	$1,312	($531)	$782	30%	2.47

Source: Energy Narrative analysis

A detailed schedule of the annual economic benefits and costs for the offshore natural gas pipeline is included in Appendix C.

5.1.7. Sensitivity analysis

A sensitivity analysis was performed to estimate how changes in key variables would impact the offshore natural gas pipeline's economic feasibility. Three independent variables were included in the sensitivity analysis: the volume of natural gas shipped by the pipeline, the capital cost to build the pipeline, and the price of HFO that the natural gas will displace. These variables were selected based on the likelihood that they could change and their potential to have a material impact on the offshore natural gas pipeline's economic feasibility.

Other variables that could potentially affect the economic feasibility include the discount rate and the price of CO2. The base real discount rate was set at 10% to match the discount rate used in GPL's 2018 Expansion Study, although many institutions use a 12% discount rate.

Table 5-13 below shows the impact on the natural gas pipeline economic feasibility by increasing the discount rate to 12%.

Table 5-13: Offshore natural gas pipeline economic feasibility sensitivity to discount rate

Sensitivity Variable Settings		Key Results Metrics				
NG Flow Volume	Discount Rate	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	10%	$1,312	($531)	$782	30%	2.47
30	12%	$1,061	($476)	$584	30%	2.23

Source: Energy Narrative calculations

Increasing the discount rate to 12% reduces the net present value of both the economic benefits and costs of the offshore natural gas pipeline. Because the costs tend to be front-weighted and the benefits more spread over time, the benefits are more affected by the change in discount rate than the costs, resulting in a lower economic net present value. The economic rate of return was unaffected (as it is well above the discount rate) and the economic benefit/cost ratio was only marginally affected.

Because the economic rate of return metric is unaffected by the change in discount rate, it was deemed to be less important as a sensitivity variable than other factors.

In addition to the discount rate, the value of the reduction in CO2 emissions could also be a factor for the sensitivity analysis. Although natural gas does produce CO2 when it is burned for electricity generation, it produces much less CO2 than burning HFO. Each MMBtu of natural gas produces roughly 117 pounds of CO2 when burned, while each MMBtu of HFO produces 174 pounds of CO2, or roughly 49% more CO2 than natural gas. In addition, a natural-gas-fired power plant is more fuel efficient than a similar HFO-fired one (see Table 7-1). This means that more electricity is produced per unit of natural gas consumed than per unit of HFO, further reducing CO2 emissions per unit of electricity produced.

Table 5-14 below shows the impact on the natural gas pipeline economic feasibility by reducing the value of CO2 emission to zero.

Table 5-14: Offshore natural gas pipeline economic feasibility sensitivity to CO2 price

Sensitivity Variable Settings		Key Results Metrics				
NG Flow Volume	CO2 Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	$30	$1,312	($531)	$782	30%	2.47
30	$0	$891	($358)	$533	29%	2.49

Source: Energy Narrative calculations

Removing the economic cost of CO2 reduces both the project benefits (accruing from the avoided CO2 emissions from burning HFO) and the project costs (accruing from the CO2 emissions from burning the natural gas). Because natural gas emits less CO2 per unit of energy than HFO, the economic benefits were more affected by removing the value of CO2 emissions than the project costs. This reduced the offshore natural gas pipeline's economic net present value, but had a minimal effect on the economic rate of return and actually increased the economic benefit/cost ratio slightly. Because removing the value of CO2 had a minimal effect on these metrics, the CO2 price was deemed to be less important as a sensitivity variable than other factors.

Each of the three selected sensitivity variables was adjusted as follows:

- **Natural gas volume.** The Base Case analysis assumes that 30 MMscf per day of natural gas will be made available for transportation to the shore from Liza-1 production. However, the most recent information from EEPGL confirmed that 50 MMscf per day could be made available for much of the 20-year period. This sensitivity analysis examined the effect of increasing the natural gas volume to 50 MMscf per day.

- **Pipeline cost.** As noted above, there is a high degree of uncertainty in the actual cost to build the proposed pipeline owing to the limited number of similar projects worldwide and the frontier nature of Guyana's hydrocarbon industry. Although a 20% contingency factor was added to the Base Case capital cost estimate, it is plausible that costs could be substantially higher. In order to capture this uncertainty, the sensitivity analysis considered capital costs that were 20% higher and 20% lower than the Base Case. Because operating costs are calculated as a percentage of capital costs, changing the capital cost for each sensitivity case also changes the operating costs by +/- 20%.

- **HFO price.** The main economic benefit from developing the natural gas pipeline project is displacing high cost HFO imports with the domestically produced natural gas. Therefore, the value of the displaced HFO has a direct impact on the economic feasibility of the project. The sensitivity analysis used the forecast WTI price under the EIA's High Oil Price and Low Oil Price scenarios (from the 2018 Annual Energy Outlook) to adjust the calculated price for Guyana's imported HFO.

Table 5-15 presents the results of changing the three input variables individually as well as a "worst case" scenario that combined high project costs with a low oil price outlook. For each combination of natural gas volume, project cost, and HFO price, the table presents the calculated present value of the project benefits, costs, and economic net present value, the economic rate of return, and the economic benefit/cost ratio of the offshore natural gas pipeline.

Table 5-15: Natural gas pipeline economic feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics				
NG Flow Volume	Capital & Operating Costs	HFO and LPG Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	Base	Base	$1,312	($531)	$782	30%	2.47
30	High	Base	$1,312	($608)	$704	26%	2.16
30	Low	Base	$1,312	($454)	$859	36%	2.89
30	Base	High	$2,396	($531)	$1,865	48%	4.51
30	Base	Low	$630	($531)	$99	13%	1.19
30	High	Low	$630	($608)	$22	11%	1.04
50	Base	Base	$1,827	($586)	$1,241	35%	3.12
50	High	Base	$1,827	($663)	$1,164	31%	2.76
50	Low	Base	$1,827	($509)	$1,318	40%	3.59
50	Base	High	$3,352	($586)	$2,766	52%	5.72
50	Base	Low	$874	($586)	$289	18%	1.49
50	High	Low	$874	($663)	$212	15%	1.32
145	Base	Base	$3,798	($790)	$3,008	41%	4.81

Source: Energy Narrative analysis

The table shows that the offshore natural gas pipeline remains economically feasible under each individual sensitivity case. Under the "worst case" combination of both high project costs and a low oil price outlook, the project remains economically feasible, showing a US$22 million economic gain over 20 years and an economic rate of return of 11%--just above the 10% hurdle rate. The pipeline shows the highest economic return under the 50 MMscf per day of natural gas volumes and the high oil price case, reaching nearly US$2.8 billion in net present value and a 52% economic rate of return.

If natural gas supply were increased to the theoretical 145 MMscfd case, the offshore natural gas pipeline would have an economic net present value of just over US$3 billion and an economic rate of return of 41%.

A detailed schedule of the annual economic benefits and costs for each of the sensitivity analysis noted above is included in Appendix C.

5.2. Natural gas upstream financial feasibility

The purpose of this section is to determine whether it is financially feasible to produce the natural gas for delivery to onshore Guyana. It will be financially feasible if the net present value of the annual cash flows (income minus costs) from selling the natural gas at the wellhead (that is, at the delivery point on the FPSO linked to the offshore pipeline) is positive. The upstream financial analysis is separated from the offshore pipeline analysis to highlight the range of prices for natural gas delivered to the pipeline in the event the ownership of the offshore pipeline is different from the upstream consortium operating the FPSO.

The financial costs to produce the natural gas include the capital cost to build the additions to the FPSO to produce the gas for sale, the annual cost to produce the natural gas, interest expense for any debt that is issued to finance the project, and any corporate income taxes assessed on the profits. The upstream gas income is calculated from the volume of natural gas sold at the wellhead and the price paid for the natural gas. Because there is currently no market for natural gas in Guyana, the price paid for the natural gas will be negotiated between the Government of Guyana and EEPGL. In this negotiation, EEPGL's priority will be to secure a price for the natural gas and LPG that will provide the greatest return on investment. At the same time, the Government of Guyana's priority is to minimize the cost of electricity generated with the supplied natural gas.

The financial feasibility analysis used two price setting approaches to reflect these different priorities: a Cost+ approach which added a fixed return to the project costs and then calculated the resulting electricity price, and a Net Back approach which fixed an average electricity price for the project timeframe and then calculated the natural gas price and resulting returns on investment that would be required to provide electricity at the chosen price.

For each price setting approaches a high and low value were selected in order to examine the range of possible outcomes for the natural gas price negotiations. Under the Cost+ approach, both a 10% internal rate of return (IRR) and a 16% IRR were modeled. Under the Net Back approach, an electricity price of US$0.09 per kWh and US$0.06 per kWh were modeled.

The upstream natural gas production's financial feasibility was calculated using both pricing mechanisms. The actual price for the natural gas will be negotiated between EEPGL and the Government of Guyana or other buyers. This approach establishes the financial feasibility under a range of preferred outcomes for each negotiating party, effectively placing bookends around the likely band for any negotiated natural gas price.

The financial analysis described below finds that the natural gas delivered by the offshore natural gas pipeline would be priced at US$1.01 per MMBtu to have a net present value (NPV) of zero and an IRR of 10%. Pricing the natural gas to achieve a 16% IRR would result in a natural gas price of US$1.48 per MMBtu, and a net present value of approximately US$40 million. That is, the offshore natural gas pipeline would be profitable under the range of pricing levels using the Cost+ methodology.

Pricing the natural gas to achieve an electricity price of 9 US cents per kWh would result in a natural gas price of US$1.03 per MMBtu, a net present value of approximately US$2 million and an IRR of 10% percent. Pricing the natural gas to achieve an electricity price of 6 US cents per kWh would result in a natural gas price of US$0.64 per MMBtu, a loss of approximately US$32 million in NPV terms and an IRR of 4% percent. That is, the offshore natural gas pipeline would be profitable for an average electricity price of 9 cents per kWh, but would not be profitable for an electricity price of 6 cents per kWh at the assumed volume of natural gas production.

The analysis to calculate the financial feasibility of the natural gas pipeline is presented as follows:

- Financial analysis assumptions
- Financial feasibility analysis
- Sensitivity analysis

5.2.1. Financial analysis assumptions

Key financial assumptions include the project component's taxation rate, depreciation period and calculation methodology, the share of debt and equity financing used and the interest rate and loan tenor for the debt component.

Table 5-16 shows the specific assumptions that were used in the financial analysis. The upstream natural gas producer is assumed to pay no income tax on its profits as it is considered part of the production-related investments incurred by EEPGL under its petroleum production license. Capital depreciation is assumed to be 20 years to match the project lifespan and is calculated as a straight line. The natural gas production is also assumed to be equity financed (no project debt). This assumption is in line with the financial assumptions made for Guyana's power sector in the 2018 Expansion Study.

Table 5-16: Upstream Natural Gas Financial Analysis Assumptions

Financial variables	Unit	Base Case	Notes
Upstream Tax rate	%	0%	Assumed no income tax per EEPGL production license agreement
Upstream Depreciation period (straight line)	years	20	20 year project lifespan based on natural gas supply availability
Upstream Debt % of total capital cost	%	0%	Set to match assumptions in GPL 2018 Expansion Plan Update

Source: Energy Narrative

These factors were applied to calculate the natural gas production's earnings and net cash flow for each of the 20 years included in the analysis. This series of future cash flows was discounted to the present value using a 10% discount rate to calculate the natural gas production's NPV and the internal rate of return (IRR).

5.2.2. Financial feasibility analysis

The natural gas production income and expenditures described above were calculated for each year between 2018 and 2041. This timeframe is based on EEPGL's project development timeline projecting first gas availability in 2022 and a 20-year period of natural gas availability from the Liza-1 development. The annual results were then discounted to 2018 using a 10% real discount rate in order to determine the natural gas production's net present value, internal rate of return, and the average price of natural gas at the wellhead under each of the natural gas pricing options.

Based on this analysis, natural gas could be priced at the wellhead for US$1.01 per MMBtu under the Cost+ pricing option to achieve a 10% IRR or for US$1.48 per MMBtu to achieve a 16% IRR and a US$40 million NPV. Under the Net Back pricing option, the upstream natural gas production has a net present value (NPV) of approximately US$2 million and an internal rate of return of 10% under the project's Base Case assumptions for electricity priced at 9 cents per kWh. This indicates that the offshore natural gas pipeline is financially viable under this pricing option. However, the natural gas production is not financially feasible for electricity priced at 6 cents per kWh as this price level (US$0.64 per MMBtu for the natural gas delivered to the pipeline) results in a US$32 million loss and a 4% IRR. The summary results of the financial feasibility analysis are presented in Table 5-17 below.

Table 5-17: Upstream natural gas financial feasibility analysis results

Sensitivity Variable Settings			Key Results Metrics		
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	NG Wellhead Price (US$/MMBtu)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$1.01	$0	10%
30	Base	IRR-16%	$1.48	$40	16%
30	Base	Elec - 6 cent	$0.64	($32)	4%
30	Base	Elec - 9 cent	$1.03	$2	10%

Source: Energy Narrative analysis

A detailed schedule of the annual cash flows for the offshore natural gas pipeline is included in Appendix C.

5.2.3. Sensitivity analysis

A sensitivity analysis was performed to estimate how changes in key variables would impact the natural gas production's financial feasibility under both the Cost+ and Net Back pricing options. The sensitivity analysis used the same independent variables that were included in the economic sensitivity analysis: the volume of natural gas shipped by the pipeline, and the capital and operating cost to produce the natural gas. These variables were selected based on the likelihood that they could change and their potential to have a material impact on the financial feasibility. The summary results of the sensitivity analysis are presented in Table 5-18 below.

Table 5-18: Natural gas pipeline financial feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics		
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	NG Wellhead Price (US$/MMBtu)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$1.01	$0	10%
30	Base	IRR-16%	$1.48	$40	16%
30	Base	Elec - 6 cent	$0.64	($32)	4%
30	Base	Elec - 9 cent	$1.03	$2	10%
30	Low	IRR-10%	$0.81	$0	10%
30	Low	IRR-16%	$1.18	$32	16%
30	Low	Elec - 6 cent	$0.64	($14)	7%
30	Low	Elec - 9 cent	$1.03	$19	14%
30	High	IRR-10%	$1.22	$0	10%
30	High	IRR-16%	$1.78	$48	16%
30	High	Elec - 6 cent	$0.64	($50)	2%
30	High	Elec - 9 cent	$1.03	($16)	8%
50	Base	IRR-10%	$0.74	$0	10%
50	Base	IRR-16%	$1.12	$45	16%
50	Base	Elec - 6 cent	$0.50	($27)	5%
50	Base	Elec - 9 cent	$0.84	$12	12%
50	Low	IRR-10%	$0.59	$0	10%
50	Low	IRR-16%	$0.89	$36	16%
50	Low	Elec - 6 cent	$0.51	($10)	8%
50	Low	Elec - 9 cent	$0.84	$30	15%
50	High	IRR-10%	$0.88	$0	10%
50	High	IRR-16%	$1.34	$54	16%
50	High	Elec - 6 cent	$0.50	($45)	3%
50	High	Elec - 9 cent	$0.84	($5)	9%
145	Base	IRR-10%	$0.36	$0	10%
145	Base	IRR-16%	$0.62	$62	16%
145	Base	Elec - 6 cent	$0.39	$5	11%
145	Base	Elec - 9 cent	$0.61	$59	16%

Source: Energy Narrative analysis

The table shows that the upstream natural gas production remains financially feasible under every Cost+ sensitivity case for both the assumed 10% IRR and 16% IRR. The resulting natural gas price ranges from US$0.59 per MMBtu for the 10% IRR under the 50 MMscfd Low Cost Case to US$1.78 per MMBtu for the 16% IRR under the 30 MMscfd High Cost Case.

Under the Net Back approach, the upstream natural gas production is financially feasible under the 9 cent electricity level in all sensitivities except the 50 MMscfd High Cost Case where it has a 9% IRR and a US$5 million loss over the project's 20 year life. The upstream natural gas production is not feasible under the 6 cent electricity level for any of the sensitivity cases, suggesting that this average price for electricity is unobtainable without subsidization.

If the natural gas production were increased to the theoretical 145 MMscfd supply case, the natural gas wellhead price could fall as low as US$0.36 per MMBtu under the Cost+ price setting mechanism and a 10% IRR. Increasing the IRR to 16% would result in a price of US$0.62 per MMBtu. Under the Net Back price setting methodology, the natural gas wellhead price for 9 cent electricity and 6 cent electricity both fall within the range set by the Cost+ price setting methodology. That is, at this volume of natural gas, setting the natural gas price to produce electricity at an average price of 6 cents per kWh is financially feasible, resulting in a US$5 million NPV and 11% IRR. Increasing the electricity price to 9 cents per kWh results in an NPV of US$59 million and an IRR of 16%.

A detailed schedule of the annual cash flows for the upstream natural gas production is included in Appendix C.

5.3. Natural gas pipeline financial feasibility

The purpose of this section is to determine whether the undersea natural gas pipeline used to deliver natural gas from EEPGL's offshore platform to onshore Guyana is financially feasible. It will be financially feasible if the net present value of the offshore natural gas pipeline's annual cash flows (income minus costs) is positive. The upstream financial analysis is separated from the offshore pipeline analysis to highlight the range of pipeline tariffs separate from the price of the natural gas molecule in the event the ownership of the offshore pipeline is different from the upstream consortium operating the FPSO.

The financial feasibility analysis used two price setting approaches to reflect these different priorities: a Cost+ approach which added a fixed return to the project costs and then calculated the resulting electricity price, and a Net Back approach which fixed an average electricity price for the project timeframe and then calculated the natural gas price and resulting returns on investment that would be required to provide electricity at the chosen price.

For each price setting approaches a high and low value were selected in order to examine the range of possible outcomes for the natural gas price negotiations. Under the Cost+ approach, both a 10% internal rate of return (IRR) and a 16% IRR were modeled. Under the Net Back approach, an electricity price of US$0.09 per kWh and US$0.06 per kWh were modeled.

The financial analysis described below finds that the offshore natural gas pipeline tariff would be priced at US$3.91 per MMBtu to have a net present value (NPV) of zero and an internal rate of return of 10% under the 30 MMscfd volume case. Pricing the natural gas to achieve a 16% rate of return would result in a pipeline tariff price of US$5.71 per MMBtu, and a net present value of approximately US$155 million. That is, the offshore natural gas pipeline would be profitable under the range of tariff levels using this methodology.

Pricing the natural gas to achieve an electricity price of 9 US cents per kWh would result in a pipeline tariff of US$3.99 per MMBtu, a net present value of approximately US$7 million and an internal rate of return of 10% percent. That is, the offshore natural gas pipeline would be profitable under the range of pricing levels using this methodology as well. Pricing the natural gas to achieve an electricity price of 6 US cents per kWh, however, would result in a pipeline tariff of US$2.48 per MMBtu, a loss of US$123 million in net present value terms and IRR of 4% percent. The pipeline would not be feasible at this tariff rate, suggesting that a 6 cent per kWh electricity price cannot be achieved without higher natural gas volumes or subsidies.

The analysis to calculate the financial feasibility of the natural gas pipeline is presented as follows:

- Financial analysis assumptions
- Financial feasibility analysis
- Sensitivity analysis

5.3.1. Financial analysis assumptions

Key financial assumptions include the project component's taxation rate, depreciation period and calculation methodology, the share of debt and equity financing used and the interest rate and loan tenor for the debt component.

Table 5-19 shows the specific assumptions that were used in the natural gas pipeline financial analysis. The natural gas pipeline is assumed to pay no income tax on its profits as it is considered part of the production related investments incurred by EEPGL under its petroleum production license. Capital depreciation is assumed to be 20 years to match the project lifespan and is calculated as a straight line. The pipeline is also assumed to be equity financed (no project debt). This assumption is in line with the financial assumptions made for Guyana's power sector in the 2018 Expansion Study.

Table 5-19: Offshore Natural Gas Pipeline Financial Analysis Assumptions

Financial variables	Unit	Base Case	Notes
Pipeline Tax rate	%	0%	Assumed no income tax per EEPGL production license agreement
Pipeline Depreciation period (straight line)	years	20	20 year project lifespan based on natural gas supply availability
Pipeline Debt % of total capital cost	%	0%	Set to match assumptions in GPL 2018 Expansion Plan Update

Source: Energy Narrative

These factors were applied to calculate the natural gas pipeline's earnings and net cash flow for each of the 20 years included in the analysis. This series of future cash flows was discounted to the present value using a 10% discount rate to calculate the natural gas pipeline's NPV and the internal rate of return (IRR).

5.3.2. Financial feasibility analysis

The natural gas pipeline income and expenditures described above were calculated for each year between 2018 and 2041. This timeframe is based on EEPGL's project development timeline projecting first gas availability in 2022 and a 20-year period of natural gas availability from the Liza-1 development. The annual results were then discounted to 2018 using a 10% real discount rate in order to determine the offshore natural gas pipeline's net present value, internal rate of return, and the average pipeline tariff under each of the natural gas pricing options.

Based on this analysis, the pipeline tariff of US$3.91 per MMBtu natural gas would allow a 10% IRR under the 30 MMscfd supply case under the Cost+ pricing option. Increasing the IRR to 16% results in a pipeline tariff of US$5.71 per MMBtu. Under the Net Back pricing option for 9 cent per kWh electricity, the offshore natural gas pipeline tariff would be US$3.99, resulting in a net present value (NPV) of approximately US$7 million and an IRR of 10% percent. The summary results of the financial feasibility analysis are presented in Table 5-20 below.

Table 5-20: Natural gas pipeline financial feasibility analysis results

Sensitivity Variable Settings			Key Results Metrics		
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	NG Pipeline Tariff (US$/MMBtu)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$3.91	$0	10%
30	Base	IRR-16%	$5.71	$155	16%
30	Base	Elec - 6 cent	$2.48	($123)	4%
30	Base	Elec - 9 cent	$3.99	$7	10%

Source: Energy Narrative analysis

A detailed schedule of the annual cash flows for the offshore natural gas pipeline is included in Appendix C.

5.3.3. Sensitivity analysis

A sensitivity analysis was performed to estimate how changes in key variables would impact the offshore natural gas pipeline's financial feasibility under both the Cost+ and Net Back pricing options. The sensitivity analysis used the same independent variables that were included in the economic sensitivity analysis: the volume of natural gas shipped by the pipeline and the capital cost to build the pipeline. These variables were selected based on the likelihood that they could change and their potential to have a material impact on the offshore natural gas pipeline's financial feasibility. The summary results of the sensitivity analysis are presented in Table 5-21 below.

Table 5-21: Natural gas pipeline financial feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics		
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	NG Pipeline Tariff (US$/MMBtu)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$3.91	$0	10%
30	Base	IRR-16%	$5.71	$155	16%
30	Base	Elec - 6 cent	$2.48	($123)	4%
30	Base	Elec - 9 cent	$3.99	$7	10%
30	Low	IRR-10%	$3.13	$0	10%
30	Low	IRR-16%	$4.57	$124	16%
30	Low	Elec - 6 cent	$2.48	($56)	7%
30	Low	Elec - 9 cent	$3.99	$74	14%
30	High	IRR-10%	$4.69	$0	10%
30	High	IRR-16%	$6.85	$186	16%
30	High	Elec - 6 cent	$2.47	($191)	2%
30	High	Elec - 9 cent	$3.98	($61)	8%
50	Base	IRR-10%	$2.84	$0	10%
50	Base	IRR-16%	$4.31	$175	16%
50	Base	Elec - 6 cent	$1.95	($105)	5%
50	Base	Elec - 9 cent	$3.24	$48	12%
50	Low	IRR-10%	$2.27	$0	10%
50	Low	IRR-16%	$3.45	$140	16%
50	Low	Elec - 6 cent	$1.95	($37)	8%
50	Low	Elec - 9 cent	$3.25	$116	15%
50	High	IRR-10%	$3.40	$0	10%
50	High	IRR-16%	$5.17	$210	16%
50	High	Elec - 6 cent	$1.94	($174)	3%
50	High	Elec - 9 cent	$3.24	($20)	9%
145	Base	IRR-10%	$1.40	$0	10%
145	Base	IRR-16%	$2.41	$240	16%
145	Base	Elec - 6 cent	$1.50	$22	11%
145	Base	Elec - 9 cent	$2.37	$232	16%

Source: Energy Narrative analysis

The table shows that the natural gas pipeline remains financially feasible under every Cost+ sensitivity case for both the assumed 10% IRR and 16% IRR. The resulting natural gas transportation tariffs range from US$2.27 per MMBtu for the 10% IRR under 50 MMscfd Low Cost Case to US$6.85 per MMBtu for the 16% IRR under 30 MMscfd and High Cost Case.

Under the Net Back approach, the natural gas pipeline is financially feasible under the 9 cent electricity level in all sensitivities except the 50 MMscfd High Cost Case where it has a 9% IRR and a US$20 million loss over the project's 20 year life. The natural gas pipeline is not feasible under the 6 cent electricity level for any of the sensitivity cases, suggesting that this average price for electricity is unobtainable without higher natural gas volumes or subsidization.

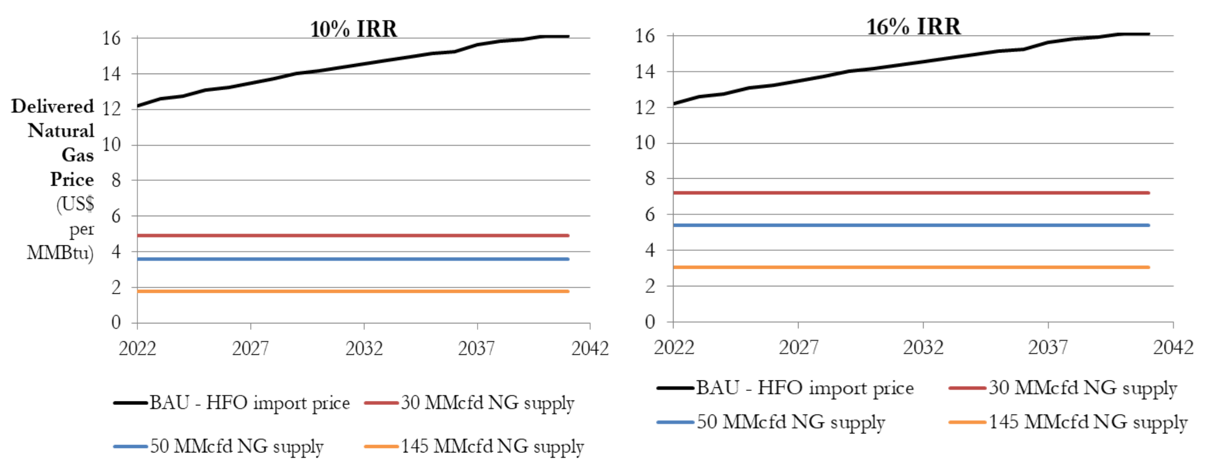
If the natural gas production were increased to the theoretical 145 MMscfd supply case, the pipeline transportation tariff could fall as low as US$1.40 per MMBtu under the Cost+ price setting mechanism and a 10% IRR. Increasing the IRR to 16% would result in a price of US$2.41 per MMBtu. Under the Net Back price setting methodology, the natural gas wellhead price for 9 cent electricity and 6 cent electricity both fall within the range set by the Cost+ price setting methodology. That is, at this volume of natural gas, setting the natural gas price to produce electricity at an average price of 6 cents per kWh is financially feasible, resulting in a US$22 million NPV and 11% IRR. Increasing the electricity price to 9 cents per kWh results in an NPV of US$232 million and an IRR of 16%.

A detailed schedule of the annual cash flows for the offshore natural gas pipeline is included in Appendix C.

5.4. Natural gas delivered price

The price of the natural gas delivered to the Guayana mainland is the sum of the upstream price of the produced natural gas and the pipeline tariff to transport it to the shore. Figure 5-7 below compares the delivered price of natural gas under the different natural gas volumes under the Cost+ price setting methodology for both a 10% IRR and 16% IRR. In both cases, the natural gas price is compared to a "business as usual" price for the imported HFO that the natural gas replaces.

Figure 5-7: Price of delivered natural gas to achieve a 10% and 16% IRR (2017 US$ per MMBtu)



Source: Energy Narrative analysis

Under the 30 MMscfd natural gas supply case, a delivered natural gas price of US$4.92 per MMBtu provides a 10% IRR, rising to US$7.19 per MMBtu for a 16% IRR. Increasing the natural gas volume to the 50 MMscfd supply case lowers the delivered price to US$3.57 per MMBtu for a 10% IRR and US$5.42 per MMBtu for a 16% return. If the 145 MMscfd natural gas supply profile is achieved and the pipeline was fully utilized, the delivered price of natural gas could fall to just US$1.77 per MMBtu for a 10% return and US$3.03 per MMBtu for a 16% return.

Under all pricing options and natural gas volume cases, the delivered price of natural gas is well below the projected import parity price for HFO. Under the Base Case price forecast, the HFO price is expected to increase from roughly US$12 per MMBtu in 2022 to over US$16 per MMBtu in 2041 (in real 2017 US$), averaging US$14.49 per MMBtu throughout the period. This is more than double the highest cost natural gas option (16% return on 30 MMscfd supply) and more than eight times the price of the lowest cost option (10% return on 145 MMscfd supply).

In addition, setting the natural gas to a fixed price removes the risk of price volatility that could come from linking the natural gas price to international oil prices. Figure 5-3 demonstrates the very wide range of potential future oil prices. Switching to domestically produced natural gas therefore has the additional benefit of removing the potential economic costs and dislocations from rapidly changing international oil prices.

6. NGL separation and LPG production plant feasibility

The purpose of this section is to determine whether the NGL separation and LPG production plant that is proposed to remove and monetize the natural gas liquids from the natural gas from EEPGL's offshore production is both economically and financially feasible. The NGL separation and LPG production plant will be economically feasible if the net present value of the economic benefits of the project outweigh the net present value of the economic costs. It will be financially feasible if the net present value of the NGL separation and LPG production plant's annual cash flows (income minus costs) is positive.

The NGL separation and LPG production plant's economic and financial feasibility are calculated separately below, using a common set of physical, operational, and financial assumptions.

6.1. NGL separation and LPG production plant economic feasibility

The purpose of this section is to estimate the economic feasibility of the proposed NGL separation and LPG production plant. The NGL separation and LPG production plant's economic feasibility was determined by comparing the economic costs of building and operating the NGL separation and LPG production plant with the economic benefits that it will bring.

The NGL separation and LPG production plant's economic costs include the capital cost to build the facility, including equipment to separate the raw NGLs from the natural gas stream, fractionate the NGLs into LPG and other end products, and prepare the separate products for wholesale or retail sale; the ongoing costs to operate the NGL separation and LPG production plant, and any environmental costs associated with the NGL separation and LPG production plant's operations.

The NGL separation and LPG production plant's economic benefits include the avoided costs that would have been incurred if the NGL separation and LPG production plant had not been built. The LPG delivered by the NGL separation and LPG production plant will primarily replace LPG that is currently being imported for domestic use. The economic benefit of the NGL separation and LPG production plant is therefore the avoided cost of importing LPG. Because the domestically produced LPG would generate the same CO_2 emissions as imported LPG, there is no additional environmental benefit or cost from building the NGL separation and LPG production plant.

The economic cost benefit analysis (CBA) described below finds that the NGL separation and LPG production plant has an aggregate net present value (NPV) of approximately US$373 million and an economic rate of return of 48% percent under the project's Base Case assumptions. This indicates that the NGL separation and LPG production plant is economically viable.

The analysis to calculate the net present value of the NGL separation and LPG production plant is presented as follows:

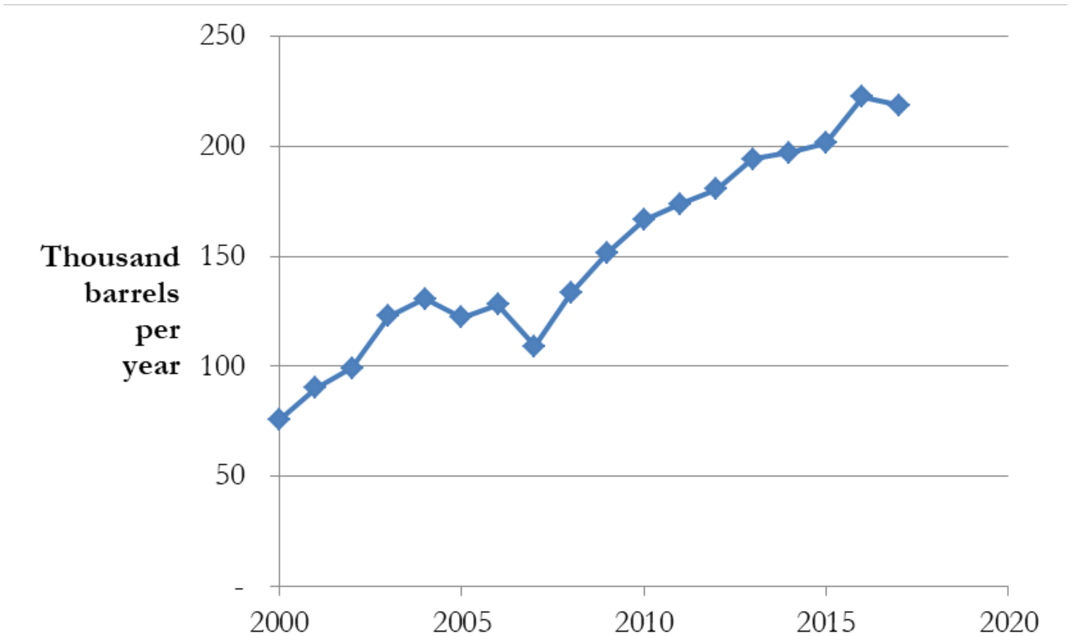
- Verification of LPG supply and potential demand
- Conceptual design parameters.

- Methodology and assumptions to calculate the NGL separation and LPG production plant capital and operating costs;
- Methodology and assumptions to calculate the LPG plant economic benefits;
- Economic feasibility analysis; and,
- Sensitivity analysis.

6.1.1. Verification of LPG supply and potential demand

As shown in the natural gas composition analysis in section 5.1.1, the production of 30 MMscfd of wet gas could provide up to 795,570 barrels per year of LPG, or roughly 2,200 barrels per day. This volume is far in excess of Guyana's current LPG consumption of roughly 220,000 barrels per year. Figure 6-1 below shows Guyana's historical LPG consumption.

Figure 6-1: Guyana historical LPG demand (thousand barrels per year)



Source: Energy Narrative based on data from GEA

Roughly 90% of Guyana's LPG consumption is sold to residential consumers, primarily for cooking in the form of small cylinders. Industrial customers account for half of the remaining demand, and commercial and public sector consumers the rest. Table 6-1 shows the share of annual demand for each sector.

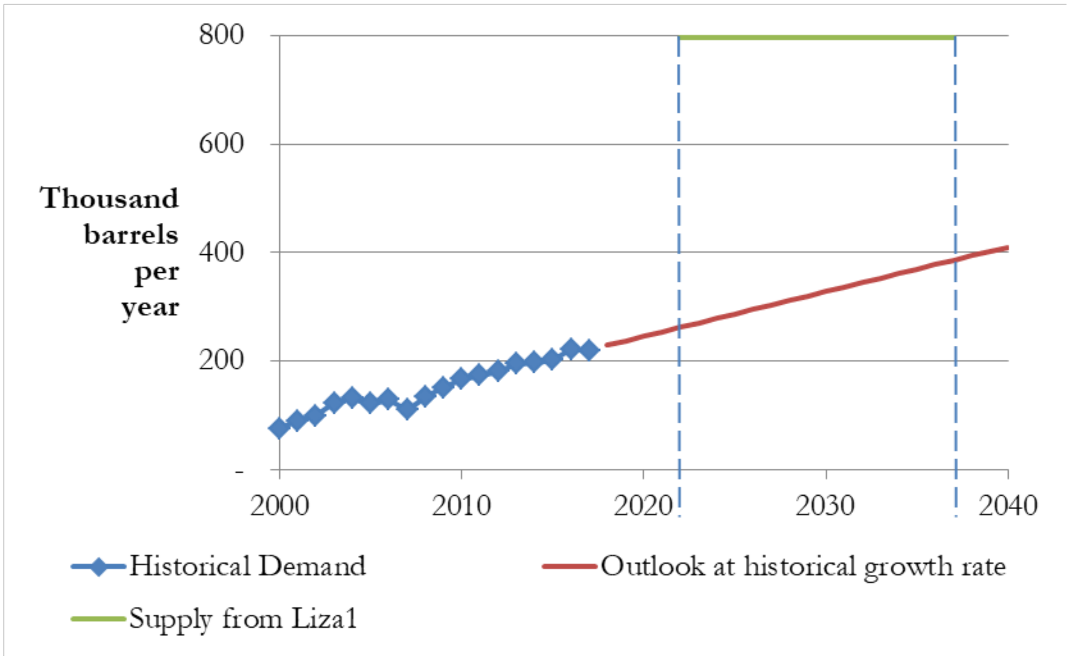
Table 6-1: Guyana historical LPG demand by sector (thousand barrels per year)

	Industrial	Residential	Commercial, services, public	Total
2000	3.39	68.45	3.86	75.70
2001	4.81	81.22	3.98	90.00
2002	3.98	90.26	5.06	99.30
2003	5.89	110.31	6.50	122.70
2004	6.10	117.84	6.66	130.60
2005	5.88	110.00	6.23	122.10
2006	6.54	115.30	6.26	128.10
2007	4.73	98.90	5.57	109.20
2008	6.51	120.06	6.80	133.37
2009	7.14	136.73	7.73	151.60
2010	7.89	149.67	9.04	166.60
2011	8.01	156.99	8.87	173.87
2012	8.30	164.82	7.44	180.56
2013	9.46	174.92	9.91	194.30
2014	9.47	177.60	10.05	197.12
2015	9.37	180.81	11.27	201.45
2016	9.94	201.18	11.35	222.47
2017	9.77	198.25	10.65	218.67

Source: GEA

If the average historical growth rate was maintained until 2040, Guyana's LPG demand would reach roughly 410,000 barrels per year. This is still just over half of the LPG volume available from the Liza-1 natural gas stream, and shown in Figure 6-2 below.

Figure 6-2: Guyana LPG demand outlook and potential domestic supply (thousand barrels per year)



Source: Energy Narrative

This large volume of excess supply suggests Guyana could develop new industries to take advantage of the available LPG volumes. Alternatively, the LPG could be exported to neighboring consumers via small scale LPG vessels.

6.1.2. Conceptual design parameters

The functional requirements of the NGL separation and LPG production plant include removing the NGLs from the wet gas stream, converting them into useable products, and bringing those products to market. At the conceptual level, these functions require:

- an NGL separation unit to remove the NGLs from the wet gas stream,
- an LPG fractionation unit to separate the component liquids and make them available as individual end products,
- a storage facility to store the produce LPG and other products
- an offloading facility to move them from the separation plant to the end market.

Each of these steps is described below.

NGL separation unit

The NGL separation unit will be scaled to process 30 MMscf per day of natural gas under the Base Case. There were just under 500 operating natural gas processing plants in the United States in 2012, the latest available plant level data from the US Energy Information Agency. These processing plants ranged in size from 1 MMscf per day of capacity to 2,100 MMscf per day (the Aux Sable plant owned by Enbridge in Grundy county, Illinois). Table 6-2 below shows the variation in average processing plant size, actual throughput (in 2012) and utilization rate for different size categories of processing plant.

Table 6-2: United States operating natural gas processing plants by size, 2012

Range (MMcfd capacity)	Count	Average Capacity (MMcfd)	Average Processed (MMcfd)	Utilization Rate (%)
0-9	93	4	2	52%
10-29	91	17	10	58%
30-99	134	55	38	68%
100-299	124	163	127	77%
300-999	43	513	322	62%
1,000-2,999	8	1254	937	66%
Total	**493**	**127**	**88**	**65%**

Source: US EIA, Energy Narrative calculations

The proposed scale for the Guyana separation plant (30-50 MMscfd) is in the mid-range of existing units in the United States.

Current NGL extraction technologies typically separate the liquids by rapidly lowering the natural gas stream temperature to cause the NGLs to come out of phase and liquefy. This can be accomplished using various technologies, such as external refrigeration, Joule-Thompson expansion valves (J-T expansion), or turbo expanders. Refrigeration tends to have lower capital costs but higher operational costs and has lower recovery rates for the lighter hydrocarbons, particular ethane. J-T expansion and turbo expanders both use rapid expansion of the gas to cause it cool rapidly. J-T expanders use a specialized nozzle shape to create the expansion, while turbo expanders force the expansion process much like a compressor operating in reverse. Although they have higher capital and operating costs, turbo expanders obtain the highest NGL recovery rates, reaching essentially 100% recovery of the propane and heavier liquids and more than 95% of the ethane.

The high exit pressure that is expected in the proposed natural gas pipeline can be exploited through a J-T expander, or to reduce the compression costs for a turbo expander, potentially resulting in lower capital and operational costs than the assumed industry averages used in this analysis.

In addition, the flexible nature of the dual fuel power generation engines, and the need to maintain sufficient energy content in the dry gas stream suggests the majority of the ethane can be left in the stream. This also simplifies the plant design by removing the need for a de-ethanizer in the fractionation stage as well as ethane storage and handling infrastructure. Table 6-3 presents the assumed recovery rates for the NGL separation and LPG production plant to achieve the required energy content for the dry gas stream while maximizing the potential value of the separated LPG.

Table 6-3: Assumed NGL recovery rates from NGL separation and LPG production plant

Ethane recovery rate (C2)	0%
Propane recovery rate (C3)	100%
Butane recovery rate (C4)	100%
Condensate recovery rate (C5+)	100%

Source: Energy Narrative calculated based on EEPGL gas composition data and estimated NGL recovery rates

LPG fractionation unit

Once the liquids are removed from the natural gas stream, they must be separated from each other to produce useable products. This process generally uses a series of boilers, known as trays, which heat the NGL stream to the respective boiling points of each successively higher hydrocarbon. Since the ethane is expected to be left in the natural gas stream, the NGLs would first pass through a depropanizer to remove the propane followed by a debutanizer to remove the butanes. The propane and butane streams would then be combined as LPG, and the remaining NGLs (C5+ condensates) would be left as a separate product.

The energy content of each resulting stream can be calculated from the heat content of each component hydrocarbon and that hydrocarbon's share of the total stream. Table 6-4 shows the standard energy content

Table 6-4: Hydrocarbon energy content

Fuel characteristics	Unit	Value
Calorific Value HFO	MMBTU/BBL	6.287
Calorific Value Diesel	MMBTU/BBL	5.551
Calorific Value C1	BTU/scf	1,011
Calorific Value C2	BTU/scf	1,783
Calorific Value C3	BTU/scf	2,572
Calorific Value C4	BTU/scf	3,260
Calorific Value C5+	BTU/scf	4,000

Source: United States Energy Information Agency

Multiplying these values by the percent share of each hydrocarbon in the various streams results in the energy content for each stream shown in Table 6-5.

Table 6-5: Estimated energy content of produced natural gas and processed outputs

Fuel characteristics	Unit	Value
Calorific Value wet NG (source)	BTU/scf	1,302
Calorific Value dry NG (to power plant)	BTU/scf	1,061
Calorific Value NGL (raw from separation plant)	BTU/scf	3,002
Calorific Value LPG (post fractionation)	BTU/scf	2,821
Calorific Value Condensate (post fractionation)	BTU/scf	4,000

Source: Energy Narrative calculated based on EEPGL gas composition data and estimated NGL recovery rates

These values are used to calculate the capital and operational costs of the various process stages (which are scaled based on the volume of BTUs that are processed).

Storage facility

The separation plant must also store the LPG products that are produced before they are sent on to the market. There are two general types of LPG storage tank:

- **Spherical storage tanks.** This style of LPG storage tank typically range from 10,000-75,000 barrels in size. Their spherical shape reduces the footprint required for storage, but their greater size requires each tank to be constructed on site. These tanks are generally used for large scale storage, particularly at refineries and other major LPG production centers.
- **Cylindrical "bullet" tanks.** This style of LPG storage tank can range in size from a few hundred gallons to up to 120,000 gallons (2,860 barrels). Their smaller size means a larger volume of steel is needed relative to the volume of LPG stored, but also allows them to be manufactured at a facility rather than on site and installed in a modular fashion. These tanks tend to be used for onsite storage for large LPG users or for smaller production facilities, often with multiple tanks connected to achieve the required total storage volume.

The proposed NGL separation and LPG production plant's storage requirements would depend on the markets it served. If additional large scale LPG consumption centers were developed near the NGL separation and LPG production plant, relatively limited storage would be needed at the plant itself. If the majority of the current excess LPG were exported, the storage capacity would have to be slightly larger than the size of the vessel used for export.

Offloading facility

Finally, the LPG that is produced must be sent from the production facility to the market. For domestic use, this will mostly likely be a truck loading facility to send bulk LPG to Guyana's existing LPG bottling facilities to package it for residential consumption or to deliver it directly in bulk to industrial and commercial customers. Alternatively, the LPG plant could include its own LPG bottling facility and sell the LPG directly to residential consumers, or to an LPG distribution company to manage the final delivery.

For export, an offshore buoy and supply line would be required to load the LPG onto small scale gas carriers (generally 3,500-20,000 cubic meters, or 22,000 to 125,000 barrels in capacity). For example, all of the LPG produced in excess of domestic demand (580,000 barrels per year in 2023, falling to 390,000 barrels per year by 2037) could be exported with a 7,500 cubic meter ship (roughly 50,000 barrels) receiving roughly one cargo per month. This arrangement could potentially use the same buoy structure as the HFO imports for back up fuel for the power plant, with a separate fuel line dedicated to the LPG plant. The cost for this export infrastructure was not included in the LPG plant cost estimations.

6.1.3. Methodology and assumptions to calculate the NGL separation and LPG production plant economic costs

The purpose of this section is to estimate the economic costs related to the proposed NGL separation and LPG production plant. The NGL separation and LPG production plant's economic costs include the capital cost to build the facility, including equipment to separate the raw NGLs from the natural gas stream, fractionate the NGLs into LPG and other end products, and prepare the separate products for wholesale or retail sale; the ongoing costs to operate the NGL separation and LPG production plant, and any environmental costs associated with the NGL separation and LPG production plant's operations.

NGL separation and LPG production plant capital costs

The capital cost of building and installing NGL separation and LPG production plant is much lower than the cost of delivering natural gas from the offshore production platform to Guyana. ExxonMobil has provided an initial rough estimate of the NGL separation and LPG production plant capital cost as part of the total cost to deliver dry gas to a power plant on shore Guyana.

This analysis validates the estimated costs from ExxonMobil using an industry reported average LPG separation costs for each of three major components included in the NGL separation and LPG production plant: the initial NGL separation, fractionation into the separation LPG products, and an LPG bottling/send out facility. The capital cost estimate for each of these components is inexact given this project's unique circumstances, but can provide valuable context to the initial cost estimate provided by ExxonMobil.

Table 6-6: Estimated capital cost for LPG plant components

LPG plant component	Unit	Value	Notes
NGL separation plant unit capital cost	US$ per Mscf per day capacity	945	Based on INGAA US national average
NGL fractionation plant unit capital cost	US$ per MMBtu per day capacity	1,086	Based on INGAA US national average
LPG bottling facility unit capital cost	US$ per MMBtu per day capacity	1,800	Estimated based on sample facility bottling 250,000 barrels per year

Source: Energy Narrative calculations based on INGAA data, industry news

As noted in the 2017 Desk Study, the INGAA Foundation estimated that the average cost for natural gas separation plant in the United States in 2015 was US$525,000 per MMscfd of natural gas processed (not included the required compression). Compression cost averaged US$3,000 per horsepower in 2015, also with substantial regional variations as with pipeline costs. Regional cost variations in 2015 ranged from 34% above the national average in the Midwest region to 20% below the national average in the Western region.

A 2018 update to the INGAA study reported natural gas separation plant costs that were significantly higher than the 2015 data reported in the previous 2016 study. The latest average US natural gas separation plant cost estimate was US$635,000 per MMscf per day of natural gas processed. Compression costs were slightly higher, averaging US$3,100 per horsepower in 2017, also with substantial regional variations. The cost of compression was highest in the California region 84% above the national average, while the Central/Mountain region was the lowest at 9% below the national average. In both studies, an estimated 100 HP of compression was required for each MMscf per day of natural gas processed in a natural gas separation plant. This implies an all in cost of US$945,000 per MMscf per day of natural gas processing capacity, including the natural gas separation plant and compression.

This methodology therefore estimates the natural gas separation plant cost at US$945,000 per MMscf per day of capacity. For the proposed 30 MMscf per day natural gas flow, the estimated cost using this methodology is US$28.35 million, not including any project contingencies or additions to reflect the frontier nature of the Guyana project.

The INGAA foundation also estimates the US national average cost to build NGL fractionation plants at US$1,086 per MMBtu per day of NGLs separated. For the proposed 30 MMscf per day natural gas flow, the estimated cost using this methodology is US$16.25 million. The estimated capital cost for the LPG bottling plant is based on a similar industry average estimate of US$1,800 per MMBtu per day of capacity. This assumption results in a cost of US$12.1 million for a plant scaled to manage the expected volume from the natural gas pipeline.

The combined capital cost of the three components is therefore US$56.7 million for the plant scaled to separate, fractionate, and bottle the liquids from the 30 MMscf per day natural gas stream. The modular nature of the NGL separation and LPG production facilities makes it relatively straightforward to increase the required capacity to match any increase in natural gas supply.

6.1.4. Methodology and assumptions to calculate the LPG plant economic benefits

The purpose of this section is to calculate the economic benefits that will accrue from building and operating the NGL separation and LPG production plant. The NGL separation and LPG production plant's economic benefits include the avoided costs that would have been incurred if the plant had not been built. The LPG delivered by the plant will replace LPG that is currently being imported for domestic use, with additional volumes available to support new LPG demand or for export. The economic benefit of the plant was therefore modeled as the avoided cost of importing LPG for the volume of expected LPG demand and the economic benefit of exporting the LPG for the remaining volumes. Because the domestically produced LPG would generate the same CO_2 emissions as imported LPG, there is no additional environmental benefit or cost from building the NGL separation and LPG production plant.

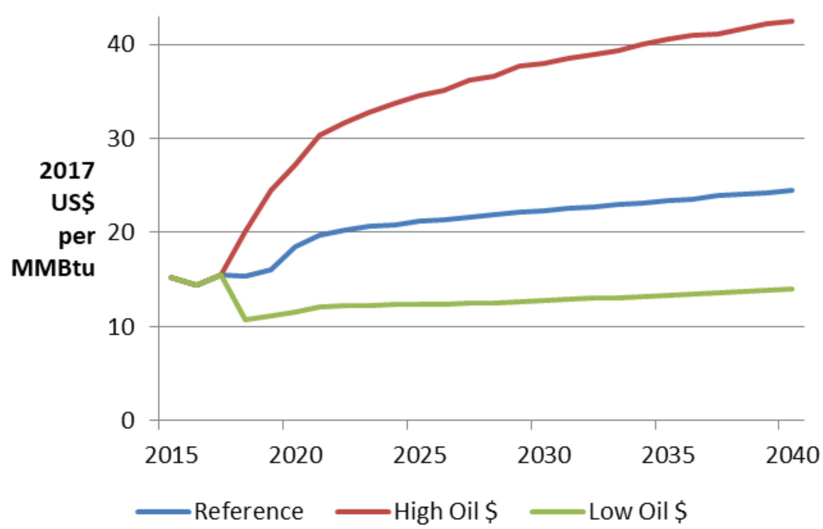
This analysis does not include any economic benefits from increased job creation (both directly from the construction and operation of the plant and indirectly from the greater economic activity associated with it). While the plant will clearly bring some job creation benefits, this value was not quantified for this analysis.

Avoided fuel import costs

The value of the fuel imports that are avoided by building the NGL separation and LPG production plant is the product of the volume of LPG imports that are avoided and the imported LPG's unit value.

The unit value of the avoided LPG imports was calculated using the same methodology that was used to calculate the value of avoided HFO imports for the offshore pipeline. In this methodology, the historical price of LPG imports in Guyana was linked to the historical price of the West Texas Intermediate (WTI) crude oil index using a linear regression. This linear equation was then applied to the forecast WTI price reported in the EIA Annual Energy Outlook Reference Case (in real 2017 US dollars). Figure 6-3 below shows the resulting Guyana LPG price forecast price under the three EIA oil price cases.

Figure 6-3: Guyana LPG price forecast under three scenarios (2017 US$ per MMBtu)



Source: Energy Narrative

The economic benefit of avoided LPG imports for each year of the forecast period was then calculated as the product of the forecast LPG price per MMBtu in that year and the calculated volume of LPG that is produced in the NGL separation and LPG production plant for the same year. The sum of the future annual economic benefits from avoided LPG imports was then discounted to a present value in 2018 using a 10% real discount rate.

Additional LPG export benefit

The LPG that is produced in excess of the domestic demand was modeled as if it was exported. This approach was used as the definition of additional LPG demand, and the expected costs and timeframe to develop industries to provide that demand is outside the scope of this project. The value of the remaining LPG is the product of the volume of LPG available for export and the exported LPG's unit value.

The unit value of the exported LPG imports was calculated using an export parity price in which the cost to transport the LPG from Guyana is subtracted from the LPG price at a price setting market. This methodology used the calculated link between LPG prices in Guyana and the price of the West Texas Intermediate (WTI) crude oil index described above, minus twice the estimated cost to ship the LPG between Guyana and the US Gulf Coast (once to account for the shipping cost embedded in the import parity calculation, and once to calculate the export parity price). This resulted in an export parity price that is US$2.53 per MMBtu below the import parity price for each year of the forecast period.

The economic benefit of avoided LPG imports for each year of the forecast period was then calculated as the product of the forecast LPG export price per MMBtu in that year and the calculated volume of LPG that is produced in the NGL separation and LPG production plant in excess of domestic demand for the same year. The sum of the future annual economic benefits from avoided LPG imports was then discounted to a present value in 2018 using a 10% real discount rate.

6.1.5. Economic feasibility analysis

The economic costs and benefits described above were calculated for each year between 2018 and 2041. This timeframe is based on EEPGL's project development timeline projecting first gas availability in 2022 and a 20-year period of natural gas availability from the Liza-1 development. The annual results were then discounted to 2018 using a 10% real discount rate in order to determine the NGL separation and LPG production plant's economic net present value. Based on this analysis, the NGL separation and LPG production plant has an aggregate economic net present value (NPV) of approximately US$373 million and an economic rate of return of 48% percent under the project's Base Case assumptions. This indicates that the NGL separation and LPG production plant is economically viable. The summary results of the economic feasibility analysis are presented in Table 6-7 below.

Table 6-7: NGL separation and LPG production plant economic feasibility analysis results

Sensitivity Variable Settings			Key Results Metrics				
NG Flow Volume	Capital & Operating Costs	HFO and LPG Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	Base	Base	$461	($88)	$373	48%	5.23

Source: Energy Narrative analysis

A detailed schedule of the annual economic benefits and costs for the NGL separation and LPG production plant is included in Appendix D.

6.1.6. Sensitivity analysis

A sensitivity analysis was performed to estimate how changes in key variables would impact the NGL separation and LPG production plant's economic feasibility. Three independent variables were included in the sensitivity analysis: to volume of natural gas processed by the NGL separation and LPG production plant, the capital cost to build the separation plant's share of the natural gas pipeline, the capital cost to build the NGL separation and LPG production plant, and the price of LPG that the separation plant will displace. These variables were selected based on the likelihood that they could change and their potential to have a material impact on the NGL separation and LPG production plant's economic feasibility. Each of these variables was adjusted as follows:

- **Natural gas volume.** The Base Case analysis assumes that 30 MMscf per day of natural gas will be made available for transportation to the shore from Liza-1 production. However, given the additional discoveries noted in section 4 that were made after Liza, there is the potential for additional volumes of natural gas to be made available. This is the rationale for scaling the pipeline to a 12" diameter rather than 8" that would be sufficient to transport 30 MMscf per day. This sensitivity analysis examined the effect of increasing the natural gas volume to 50 MMscf per day. This volume was chosen to match the 50 MMscf per day scenario in the GPL 2018 Expansion Study.

- **Pipeline cost.** As noted above, there is a high degree of uncertainty in the actual cost to build the proposed offshore natural gas pipeline, owing to the limited number of similar projects worldwide and the frontier nature of Guyana's hydrocarbon industry. The sensitivity analysis considered pipeline capital and operational costs that were 20% higher and 20% lower than the Base Case. As in the Base Case economic analysis, the share of pipeline costs that were accrued to the NGL separation and LPG production plant were calculated based on the share of natural gas liquids within the wet gas stream delivered by the pipeline.

- **NGL separation and LPG production plant cost.** As with the offshore pipeline, there is a degree of uncertainty regarding the true cost to build the proposed NGL separation and LPG production plant owing to the frontier nature of Guyana's hydrocarbon industry. In order to capture this uncertainty, the sensitivity analysis considered capital costs that were 20% higher and 20% lower than the Base Case. Because the NGL separation and LPG production plant's operating costs are calculated as a percentage of capital costs, changing the capital cost for each sensitivity case also changes the operating costs by +/- 20%.

- **LPG price.** The main economic benefit from developing the natural gas pipeline project is displacing imported LPG with the domestically produced LPG. Therefore, the value of the displaced LPG has a direct impact on the economic feasibility of the project. The sensitivity analysis used the forecast WTI price under the EIA's High Oil Price and Low Oil Price scenarios (from the 2018 Annual Energy Outlook) to adjust the calculated price for Guyana's imported LPG.

Table 6-8 presents the results of changing the four input variables individually as well as a "worst case" scenario that combined high project costs with a low oil price outlook. For each combination of natural gas volume, project cost, and LPG price, the table presents the calculated present value of the project benefits, costs, and economic net present value, the economic rate of return, and the economic benefit/cost ratio of the NGL separation and LPG production plant.

Table 6-8: NGL separation and LPG production plant economic feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics				
NG Flow Volume	Capital & Operating Costs	HFO and LPG Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	Base	Base	$461	($88)	$373	48%	5.23
30	High	Base	$461	($106)	$355	42%	4.36
30	Low	Base	$461	($71)	$390	57%	6.53
30	Base	High	$796	($88)	$708	69%	9.03
30	Base	Low	$249	($88)	$161	30%	2.83
30	High	Low	$249	($106)	$144	26%	2.36
50	Base	Base	$634	($104)	$531	48%	6.12
50	High	Base	$634	($124)	$510	42%	5.10
50	Low	Base	$634	($83)	$551	55%	7.65
50	Base	High	$1,107	($104)	$1,003	67%	10.67
50	Base	Low	$339	($104)	$236	31%	3.27
50	High	Low	$339	($124)	$215	27%	2.73
145	Base	Base	$1,298	($178)	$1,121	41%	4.81

Source: Energy Narrative analysis

The table shows that the NGL separation and LPG production plant remains economically feasible under each individual sensitivity case. Even under the "worst case" combination of high project costs and a low oil price outlook, the project is feasible, showing a US$144 million economic net present value over the project's 20-year lifespan and an economic rate of return of 26%. The NGL separation and LPG production plant shows the highest economic return under the case with 50 MMscf per day of natural gas and high oil prices, reaching just over US$1 billion in net present value and a 67% economic rate of return.

If natural gas supply were increased to the theoretical 145 MMscfd case, the NGL separation and LPG production plant would have an economic net present value of roughly US$1.1 billion and an economic rate of return of 41%.

A detailed schedule of the annual economic benefits and costs for each of the sensitivity cases is included in Appendix D.

6.2. NGL separation and LPG production plant financial feasibility

The purpose of this section is to determine whether the NGL separation and LPG production plant is financially feasible. It will be financially feasible if the net present value of the NGL separation and LPG production plant's annual cash flows (income minus costs) is positive. The NGL separation and LPG production plant's financial costs include the capital cost to build the NGL separation and LPG production plant, the annual cost to operate the NGL separation and LPG production plant including the cost of the raw natural gas that is processed, interest expense for any debt that is issued to finance the project, and any corporate income taxes assessed on the NGL separation and LPG production plant's profits. The NGL separation and LPG production plant's income is calculated from the volume of LPG sold and the price paid for the LPG.

The NGL separation and LPG production plant's financial feasibility was calculated using the same two approaches as used in the natural gas upstream and offshore pipeline financial feasibility analysis: a Cost+ pricing approach which added a fixed return to the project costs and then calculated the resulting LPG price, and a Net Back approach which fixed an average electricity price for the project timeframe and then calculated the natural gas price and resulting returns on investment that would be required to provide electricity at the chosen price. This natural gas price was then used as the input to calculate the LPG price.

Under the Net Back price setting approach, the NGL separation and LPG production plant was assumed to have the same IRR as the other project components. This assumption was made in order to avoid cross subsidies from the NGL separation and LPG production plant to the other project components. Because the price of LPG is not connected to the price of electricity, the LPG could conceivably be sold at any price below the import parity price. Revenue from a higher LPG price could offset losses in other components, potentially supporting a lower electricity price will still maintaining overall project profitability. However, because the project ownership structure is not determined (that is, the ownership of the NGL separation and LPG production plant could be different from the upstream natural gas production and offshore pipeline ownership), this potential cross-subsidization was not modeled for this analysis.

For each price setting approaches a high and low value were selected in order to examine the range of possible outcomes for the natural gas price negotiations. Under the Cost+ approach, both a 10% internal rate of return (IRR) and a 16% IRR were modeled. Under the Net Back approach, an electricity price of US$0.09 per kWh and US$0.06 per kWh were modeled.

The financial analysis described below finds that the LPG produced by the NGL separation and LPG production plant would be priced at US$6.72 per MMBtu to have a net present value (NPV) of zero and an internal rate of return of 10%. Pricing the LPG to achieve a 16% IRR would result in an LPG price of US$9.74 per MMBtu, a net present value of approximately US$18 million under the Base Case assumptions. That is, the NGL separation and LPG production plant would be profitable under this price setting methodology.

Pricing the natural gas to achieve an electricity price of 9 US cents per kWh and setting the NGL separation and LPG production plant's IRR the same as other project components would result in an

LPG price of US$6.85 per MMBtu, a net present value of approximately US$1 million and an internal rate of return of 10% percent. That is, the plant would be profitable. Pricing the natural gas to achieve an electricity price of 6 US cents per kWh, however, would result in an LPG price of US$4.26 per MMBtu, a loss of US$16 million in net present value terms and an IRR of 3% percent. The plant would not be feasible at this price, suggesting that higher natural gas volumes, cross-subsidies through a higher LPG price, or direct subsidies would be needed to support a 6 cent per kWh electricity price.

The analysis to calculate the financial feasibility of the NGL separation and LPG production plant is presented as follows:

- Financial analysis assumptions
- Financial feasibility analysis
- Sensitivity analysis

6.2.1. Financial analysis assumptions

Key financial assumptions include the project component's taxation rate, depreciation period and calculation methodology, the share of debt and equity financing used and the interest rate and loan tenor for the debt component.

Table 6-9 shows the specific assumptions that were used in the NGL separation and LPG production plant financial analysis. The NGL separation and LPG production plant is assumed to pay no corporate income taxes as it is considered to be part of the production related investments incurred by EEPGL under its petroleum production license. Capital depreciation is assumed to be 20 years to match the project lifespan and is calculated as a straight line. The NGL separation and LPG production plant is also assumed to be equity financed (no project debt). This assumption is in line with the financial assumptions made for Guyana's power sector in the 2018 Expansion Study.

Table 6-9: NGL separation and LPG production plant Financial Analysis Assumptions

Financial variables	Unit	Base Case	Notes
LPG plant Tax rate	%	0%	Assumed no income tax per EEPGL production license agreement
LPG plant Depreciation period (straight line)	years	20	20 year project lifespan based on natural gas supply availability
LPG plant Debt % of total capital cost	%	0%	Set to match assumptions in GPL 2018 Expansion Plan Update

Source: Energy Narrative

These factors were applied to calculate the NGL separation and LPG production plant's earnings and net cash flow for each of the 20 years included in the analysis. This series of future cash flows was discounted to the present value using a 10% discount rate to calculate the NGL separation and LPG production plant's NPV and the internal rate of return (IRR).

6.2.2. Financial feasibility analysis

The NGL separation and LPG production plant income and expenditures described above were calculated for each year between 2018 and 2041. This timeframe is based on EEPGL's project development timeline projecting first gas availability in 2022 and a 20-year period of natural gas availability from the Liza-1 development. The annual results were then discounted to 2018 using a 10% real discount rate in order to determine the NGL separation and LPG production plant's net present value, internal rate of return, and the average price of the delivered natural gas under each of the natural gas pricing options.

Based on this analysis, LPG could be produced for US$6.72 per MMBtu under the Cost+ pricing option at a 10% IRR or for US$9.74 per MMBtu at a 16% IRR. Under the second pricing option, the NGL separation and LPG production plant has a net present value (NPV) of approximately US$18 million under the project's Base Case assumptions. This indicates that the NGL separation and LPG production plant is financially viable under this price setting option.

Pricing the natural gas to achieve an electricity price of 9 US cents per kWh and setting the NGL separation and LPG production plant's IRR the same as other project components would result in an LPG price of US$6.85 per MMBtu, a net present value of approximately US$1 million and an internal rate of return of 10% percent. That is, the plant would be profitable. Pricing the natural gas to achieve an electricity price of 6 US cents per kWh, however, would result in an LPG price of US$4.26 per MMBtu, a loss of US$16 million in net present value terms and an IRR of 3% percent. The plant would not be feasible at this price, suggesting that higher natural gas volumes, cross-subsidies through a higher LPG price, or direct subsidies would be needed to support a 6 cent per kWh electricity price.

The summary results of the financial feasibility analysis are presented in Table 6-10 below.

Table 6-10: NGL separation and LPG production plant financial feasibility analysis results

Sensitivity Variable Settings			Key Results Metrics		
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	LPG Price (US$/MMBtu)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$6.72	$0	10%
30	Base	IRR-16%	$9.74	$18	16%
30	Base	Elec - 6 cent	$4.26	($16)	3%
30	Base	Elec - 9 cent	$6.85	$1	10%

Source: Energy Narrative analysis

A detailed schedule of the annual cash flows for the NGL separation and LPG production plant is included in Appendix D.

6.2.3. Sensitivity analysis

A sensitivity analysis was performed to estimate how changes in key variables would impact the NGL separation and LPG production plant's financial feasibility under both the Cost+ and Oil Discount pricing options. The sensitivity analysis used the same independent variables that were included in the economic sensitivity analysis: the volume of natural gas shipped by the pipeline, a share of the capital cost to build the pipeline, the capital cost to build the NGL separation and LPG production plant, and the price of LPG imports that the natural gas pipeline will displace. These variables were selected based on the likelihood that they could change and their potential to have a material impact on the NGL separation and LPG production plant's financial feasibility. The summary results of the sensitivity analysis are presented in Table 6-11 below.

Table 6-11: NGL separation and LPG production plant financial feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics		
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	LPG Price (US$/MMBtu)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$6.72	$0	10%
30	Base	IRR-16%	$9.74	$18	16%
30	Base	Elec - 6 cent	$4.26	($16)	3%
30	Base	Elec - 9 cent	$6.85	$1	10%
30	Low	IRR-10%	$5.38	$0	10%
30	Low	IRR-16%	$7.79	$15	16%
30	Low	Elec - 6 cent	$4.27	($7)	7%
30	Low	Elec - 9 cent	$6.86	$10	14%
30	High	IRR-10%	$8.07	$0	10%
30	High	IRR-16%	$11.69	$22	16%
30	High	Elec - 6 cent	$4.25	($25)	1%
30	High	Elec - 9 cent	$6.84	($8)	7%
50	Base	IRR-10%	$5.38	$0	10%
50	Base	IRR-16%	$8.09	$29	16%
50	Base	Elec - 6 cent	$3.70	($19)	5%
50	Base	Elec - 9 cent	$6.15	$9	12%
50	Low	IRR-10%	$4.30	$0	10%
50	Low	IRR-16%	$6.47	$23	16%
50	Low	Elec - 6 cent	$3.71	($7)	8%
50	Low	Elec - 9 cent	$6.16	$21	16%
50	High	IRR-10%	$6.46	$0	10%
50	High	IRR-16%	$9.70	$35	16%
50	High	Elec - 6 cent	$3.69	($32)	3%
50	High	Elec - 9 cent	$6.14	($4)	9%
145	Base	IRR-10%	$3.85	$0	10%
145	Base	IRR-16%	$6.49	$94	16%
145	Base	Elec - 6 cent	$4.12	$11	11%
145	Base	Elec - 9 cent	$6.52	$100	16%

Source: Energy Narrative analysis

The table shows that the NGL separation and LPG production plant remains financially feasible under every individual sensitivity case for the Cost+ price setting methodology for both the assumed 10% IRR and 16% IRR. The resulting LPG prices range from US$4.30 per MMBtu for the 10% IRR under 50 MMscfd Low Cost Case to US$11.69 per MMBtu for the 16% IRR under 30 MMscfd and High Cost Case.

Under the Net Back approach, the NGL separation and LPG production plant is financially feasible under the 9 cent electricity level in all sensitivities except the High Cost Cases where it has a 7% IRR and a US$8 million loss under the 30 MMscfd supply case and a 9% IRR and a US$4 million loss under the 50 MMscfd supply case. The plant is not feasible under the 6 cent electricity level for any of the sensitivity cases, suggesting that this average price for electricity is unobtainable without higher natural gas volumes, cross-subsidies, or direct subsidization.

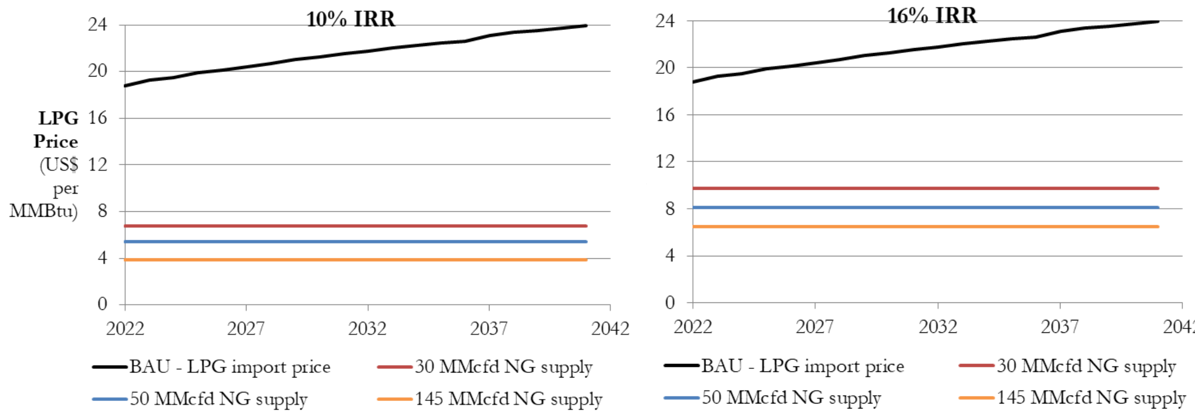
If the natural gas production were increased to the theoretical 145 MMscfd supply case, the LPG price could fall as low as US$3.85 per MMBtu under the Cost+ price setting mechanism and a 10% IRR. Increasing the IRR to 16% would result in a price of US$6.49 per MMBtu. Under the Net Back price setting methodology, the natural gas wellhead price for 9 cent electricity and 6 cent electricity both fall within the range set by the Cost+ price setting methodology. That is, at this volume of natural gas, setting the natural gas price to produce electricity at an average price of 6 cents per kWh is financially feasible, resulting in a US$11 million NPV and 11% IRR. Increasing the electricity price to 9 cents per kWh results in an NPV of US$100 million and an IRR of 16%.

A detailed schedule of the annual cash flows for the NGL separation and LPG production plant is included in Appendix D.

6.3. Impact of natural gas volumes on LPG price

The price of the wet gas provided to the NGL separation and LPG production plant has a direct impact on the price of LPG using the Cost+ pricing methodology. As a result, the volume of natural gas that is produced and processed also has a direct impact on the LPG price. Figure 6-4 compares the price of LPG under the two IRR levels for each natural gas supply profile, including the theoretical 145 MMscfd case, to a "business as usual" case based on the LPG import parity price.

Figure 6-4: Price of LPG to achieve a 10% and 16% IRR (2017 US$ per MMBtu)



Source: Energy Narrative analysis

Under the 30 MMscfd natural gas supply case, an LPG price of US$6.72 per MMBtu provides a 10% IRR, rising to US$9.74 per MMBtu for a 16% IRR. Increasing the natural gas volume to the 50 MMscfd supply case lowers the LPG price to US$5.38 per MMBtu for a 10% IRR and US$8.09 per MMBtu for a 16% return. If the 145 MMscfd natural gas supply profile is achieved and the pipeline was fully utilized, the LPG price could fall to just US$3.85 per MMBtu for a 10% return and US$6.49 per MMBtu for a 16% return.

Under all pricing options and natural gas volume cases, the LPG price is well below the projected LPG import parity price. Under the Base Case price forecast, the price of imported LPG is expected to increase from US$18.76 per MMBtu in 2022 to nearly US$24 per MMBtu in 2041 (in real 2017 US$), averaging US$21.55 per MMBtu throughout the period. This is more than double the highest LPG price option (16% return on 30 MMscfd supply) and more than five times the price of the lowest cost option (10% return on 145 MMscfd supply).

In addition, setting the LPG to a fixed price removes the risk of price volatility that could come from linking the LPG price to international oil prices. Figure 6-3 demonstrates the very wide range of potential future international LPG prices. Switching to domestically produced LPG therefore has the additional benefit of removing the potential economic costs and dislocations from rapidly changing international LPG prices.

7. Natural gas power plant feasibility

The purpose of this section is to determine whether the natural-gas-fired power plant that is proposed to use the natural gas from EEPGL's offshore platform is both economically and financially feasible. The natural gas power plant will be economically feasible if the net present value of the economic benefits of the project outweigh the net present value of the economic costs. It will be financially feasible if the net present value of the power plant's annual cash flows (income minus costs) is positive.

The natural gas power plant's economic and financial feasibility are calculated separately below, using a common set of physical, operational, and financial assumptions.

7.1. Natural gas power plant economic feasibility

The natural-gas-fired power plant's economic feasibility was determined by comparing the economic costs of building and operating the power plant with the economic benefits that it will bring. The power plant's economic costs include the capital cost to build the power plant, the annual cost to operate the power plant, and any environmental costs associated with the power plant's operations. The power plant's economic benefits include the avoided costs that would have been incurred if the power plant had not been built. The proposed natural-gas-fired power plant will replace similar power plants using heavy fuel oil that is currently being imported for electricity generation. The economic benefit of the power plant therefore includes the avoided cost of importing heavy fuel oil and the avoided economic cost of CO_2 emissions that would result from burning the HFO for electricity generation.

The economic cost benefit analysis (CBA) described below finds that the power plant has an aggregate net present value (NPV) of approximately US$532 million and an economic rate of return of 24% percent under the project's Base Case assumptions. This indicates that the power plant is economically viable.

The analysis to calculate the net present value of the offshore pipeline is presented as follows:

- Methodology and assumptions to calculate the power plant capital and operating costs;
- Methodology and assumptions to calculate the power plant economic benefits;
- Economic feasibility analysis; and,
- Sensitivity analysis of key cost and benefit assumptions.

7.1.1. Methodology and assumptions to calculate the power plant economic costs;

The purpose of this section is to estimate the economic costs related to the proposed natural-gas-fired power plant. The power plant's economic costs include the capital cost to build the facility; the ongoing costs to operate the power plant, and any environmental costs associated with the power plant's operations.

Power plant capital and operational costs

This analysis used the assumptions from the 2018 Expansion Study to set the capital cost for the proposed new dual fuel engines. That Study assumed the dual fuel engines would cost US$1,413 per kW of capacity. The total capital cost was then calculated as the product of the unit capital cost and the total kW of capacity added in each year based on the Expansion Study schedule for new capacity additions to meet Guyana's electricity demand growth.

In addition to the power plant capital costs, the Expansion Study calculated that new transmission lines and substations to connect the new power plant to GPL's transmission grid would cost US$25.1 million.

Power plant operational costs were also based on the cost estimates in the 2018 Expansion Plan, including power plant heat rates and fixed and variable operations and maintenance (O&M) as shown in Table 7-1.

Table 7-1: Power plant capital and operational cost assumptions

Heat rate by plant type

Technology	Unit	Value
Gas Turbine, LFO	Btu/kWh	10,200
Engine, HFO	Btu/kWh	9,000
Engine, NG	Btu/kWh	8,500

O&M Cost (Fixed) by plant type

Technology	Unit	Value
Gas Turbine, LFO	US$/kW/year	18.0
Engine, HFO	US$/kW/year	45.0
Engine, NG	US$/kW/year	7.3

O&M Cost (Variable) by plant type

Technology	Unit	Value
Gas Turbine, LFO	US$/MWh	3.5
Engine, HFO	US$/MWh	9.8
Engine, NG	US$/MWh	6.2

Source: 2018 Expansion Study

In addition to the power plant operational costs, the annual transmission line operational costs were estimated to be 2.5% of the capital cost.

7.1.2. Methodology and assumptions to calculate the power plant economic benefits;

The purpose of this section is to calculate the economic benefits that will accrue from building and operating the natural-gas-fired power plant. The power plant's economic benefits include the savings that are obtained by reducing imports of heavy fuel oil for electricity generation, from avoided investment in new HFO burning engines, and from avoided CO_2 emissions from burning HFO for electricity generation.

This analysis does not include any economic benefits from increased job creation (both directly from the construction and operation of the plant and indirectly from the greater economic activity associated with it). While the plant will clearly bring some job creation benefits, this value was not quantified for this analysis.

Avoided fuel import costs

The value of the fuel imports that are avoided by building the natural-gas-fired power plant is the product of the volume of heavy fuel oil imports that are avoided and the imported heavy fuel oil's unit value. As noted in the natural gas pipeline economic analysis, the volume of avoided heavy fuel oil imports is not equal to the volume of natural gas transported via the pipeline, even on an equivalent MMBtu basis. This is because the operational efficiency (as measured by the power plant's heat rate) of HFO fired engines is less than the efficiency of natural gas fired engines. This difference is shown in Table 5-12 in section 5.1.5, using the assumed heat rate values presented in the GPL 2018 Expansion Study. The methodology to calculate the value of the avoided heavy fuel oil imports is also shown in section 5.1.5.

Avoided investment in HFO engines

The 2018 Expansion Study Business as Usual Case projects the new electricity generation capacity required to meet Guyana's future electricity demand. The difference in capital cost to build the proposed HFO engines under this scenario and the cost to build the dual fuel engines in the natural gas scenarios is also an economic cost that the natural-gas-fired power plants avoid. Table 7-2 shows the schedule for new capacity under the Business as Usual case.

Table 7-2: GPL forecast new electricity generation capacity additions, Business As Usual Case (no natural gas)

Year	Capacity Added (MW)	Technology	Fuel
2019	17.4	Engine	HFO
2021	20	Gas Turbine	LFO
2023	34	Engine	HFO
2024	20	Gas Turbine	LFO
2024	17	Engine	HFO
2025	34	Engine	HFO
2026	20	Gas Turbine	LFO
2026	17	Engine	HFO
2027	51	Engine	HFO
2028	34	Engine	HFO
Total	**264.4**		

Source: GPL 2018 Expansion Study

The 2018 Expansion Study to set the unit capital cost for the HFO engines equal to the dual fuel engines at US$1,413 per kW of capacity. The total avoided capital cost was then calculated as the product of the unit capital cost and the total kW of HFO capacity that would have been added in each year based on the Expansion Study schedule for new capacity additions to meet Guyana's electricity demand growth in the Business as Usual case.

Avoided HFO power plant operational costs were also based on the cost estimates in the 2018 Expansion Plan, including power plant heat rates and fixed and variable operations and maintenance (O&M) as shown in Table 7-1 above.

Avoided environmental costs

The main avoided environmental cost from operating the natural-gas-fired power plant is the potential impact from CO_2 emissions from the use of HFO for electricity generation. The economic cost of CO_2 emissions from HFO-fired electricity generation is calculated as the product of the expected CO_2 emissions and the social cost of CO_2 emissions. The expected CO_2 emissions is the product of the CO_2 emissions per unit of HFO consumed and the volume of HFO consumed each year. The social cost of CO_2 emissions is assumed to be US$30 per ton. This value was used in order to align the economic analysis of the offshore pipeline with the economic analysis of Guyana's electric power sector that was conducted in the GPL 2018 Expansion Study.

7.1.3. Economic feasibility analysis

The economic costs and benefits described above were calculated for each year between 2018 and 2041. This timeframe is based on EEPGL's project development timeline projecting first gas availability in 2022 and a 20-year period of natural gas availability from the Liza-1 development. The annual results were then discounted to 2018 using a 10% real discount rate in order to determine the power plant's economic net present value. Based on this analysis, the power plant has an aggregate economic net present value (NPV) of approximately US$532 million and an economic rate of return of 24% percent under the project's Base Case assumptions. This indicates that the power plant is economically feasible. The summary results of the economic feasibility analysis are presented in Table 7-3 below.

Table 7-3: Power plant economic feasibility analysis results

Sensitivity Variable Settings			Key Results Metrics				
NG Flow Volume	Capital & Operating Costs	HFO and LPG Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	Base	Base	$1,192	($661)	$532	24%	1.80

Source: Energy Narrative analysis

A detailed schedule of the annual economic benefits and costs for the natural gas power plant is included in Appendix E.

7.1.4. Sensitivity analysis

A sensitivity analysis was performed to estimate how changes in key variables would impact the power plant's economic feasibility. Three independent variables were included in the sensitivity analysis: to volume of natural gas shipped by the pipeline, the capital cost to build the pipeline and related electricity infrastructure, and the cost to generate electricity using HFO that the natural-gas-fired power plant will displace. These variables were selected based on the likelihood that they could change and their potential to have a material impact on the power plant's economic feasibility. Each of these variables was adjusted as follows:

- **Natural gas volume.** The Base Case analysis assumes that 30 MMscf per day of natural gas will be made available for transportation to the shore from Liza-1 production. However, given the additional discoveries noted in section 4 that were made after Liza, there is the potential for additional volumes of natural gas to be made available. This is the rationale for scaling the pipeline to a 12” diameter rather than 8” that would be sufficient to transport 30 MMscf per day. This sensitivity analysis examined the effect of increasing the natural gas volume to 50 MMscf per day. This volume was chosen to match the 50 MMscf per day scenario in the GPL 2018 Expansion Study.

- **Pipeline cost.** As noted above, there is a high degree of uncertainty in the actual cost to build the proposed offshore natural gas pipeline, owing to the limited number of similar projects worldwide and the frontier nature of Guyana’s hydrocarbon industry. The sensitivity analysis considered pipeline capital and operational costs that were 20% higher and 20% lower than the Base Case. As in the Base Case economic analysis, the share of pipeline costs that were accrued to the power plant were calculated based on the share of dry natural gas delivered to the power plant as a percentage of the wet gas stream delivered by the pipeline to the NGL separation and LPG production plant.

- **Power plant cost.** As with the offshore pipeline, there is a degree of uncertainty regarding the true cost to build the proposed natural-gas-fired power plant. In order to capture this uncertainty, the sensitivity analysis considered capital costs that were 20% higher and 20% lower than the Base Case. In addition, the power plant’s assumed fixed and variable operating costs were also adjusted +/- 20% for the High and Low Cost sensitivity cases.

- **HFO price.** The main economic benefit from developing the natural-gas-fired power plant is displacing higher cost electricity generated from imported HFO with electricity generated from the domestically produced natural gas. Therefore, the value of the displaced HFO has a direct impact on the economic feasibility of the project. The sensitivity analysis used the forecast WTI price under the EIA’s High Oil Price and Low Oil Price scenarios (from the 2018 Annual Energy Outlook) to adjust the calculated price for Guyana’s imported HFO. The adjusted HFO fuel prices where then used to calculate the cost to generate an amount of electricity with HFO equal to the volume of electricity generated with natural gas delivered by the pipeline.

Table 7-4 presents the results of changing the three input variables individually as well as a “worst case” scenario that combined high project costs with a low oil price outlook. For each combination of natural gas volume, project cost, and HFO price, the table presents the calculated present value of the project benefits, costs, and economic net present value, the economic rate of return, and the economic benefit/cost ratio of the power plant.

Table 7-4: Power plant economic feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics				
NG Flow Volume	Capital & Operating Costs	HFO and LPG Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	Base	Base	$1,192	($661)	$532	24%	1.80
30	High	Base	$1,224	($765)	$459	21%	1.60
30	Low	Base	$1,160	($556)	$604	29%	2.09
30	Base	High	$1,963	($661)	$1,303	37%	2.97
30	Base	Low	$709	($661)	$49	12%	1.07
30	High	Low	$742	($765)	($23)	9%	0.97
50	Base	Base	$1,613	($766)	$847	27%	2.11
50	High	Base	$1,657	($882)	$775	24%	1.88
50	Low	Base	$1,569	($650)	$919	31%	2.41
50	Base	High	$2,671	($766)	$1,905	39%	3.49
50	Base	Low	$958	($766)	$192	15%	1.25
50	High	Low	$1,002	($882)	$119	13%	1.14
145	Base	Base	$1,746	($771)	$975	28%	2.26

Source: Energy Narrative analysis

The table shows that the power plant remains economically feasible under each individual sensitivity case. Under the "worst case" combination of both high project costs and a low oil price outlook, the project is marginally unfeasible, showing a US$23 million economic loss over 20 years and an economic rate of return of 9%--just below the 10% hurdle rate. The power plant shows the highest economic return under the 50 MMscf per day of natural gas volumes and the high oil price case, reaching US$1.9 billion in net present value and a 39% economic rate of return.

If natural gas supply were increased to the theoretical 145 MMscfd case, the power plant would have an economic net present value of US$975 million and an economic rate of return of 28%.

A detailed schedule of the annual economic benefits and costs for each sensitivity case is included in Appendix E.

7.2. Natural gas power plant financial feasibility

The purpose of this section is to determine whether the natural-gas-fired power plant is financially feasible. It will be financially feasible if the net present value of the power plant's annual cash flows (income minus costs) is positive. The power plant's financial costs include the capital cost to build the power plant, the annual cost to operate the power plant including the cost of the natural gas, interest expense for any debt that is issued to finance the project, and any corporate income taxes assessed on the power plant's profits. The power plant's income is calculated from the volume of electricity sold and the price paid for the electricity.

The analysis was performed using the two natural gas prices derived from the natural gas pricing options—Cost+ and Net Back—that were used in the offshore natural gas pipeline financial feasibility analysis above.

The financial analysis described below finds that the electricity generated by the natural-gas-fired power plant would be priced at an average US$88.49 per MWh (8.8 cents per kWh) if the natural gas is priced using the Cost+ methodology at a 10% IRR. Pricing the natural gas for a 16% IRR would result in an average electricity price of US$125.53 per MWh (12.5 cents per kWh). That is, the power plant would be profitable under the range of tariff levels using this methodology.

Setting the electricity price to 9 US cents per kWh under the Net Back pricing methodology would result in a net present value of approximately US$3 million and an internal rate of return of 10% percent. That is, the power plant would be profitable using this methodology as well. Reducing the electricity price to 6 US cents per kWh, however, would result in a loss of US$65 million in net present value terms and IRR of 5% percent. This suggests that a 6 cent per kWh electricity price cannot be achieved without higher natural gas volumes or subsidies.

The analysis to calculate the financial feasibility of the power plant is presented as follows:

- Financial analysis assumptions
- Financial feasibility analysis
- Sensitivity analysis

7.2.1. Financial analysis assumptions

Key financial assumptions include the project component's taxation rate, depreciation period and calculation methodology, the share of debt and equity financing used and the interest rate and loan tenor for the debt component.

Table 7-5 shows the specific assumptions that were used in the power plant financial analysis. The power plant is assumed to pay Guyana's corporate income tax of 27.5% as GPL is treated as a taxable entity under Guyana's tax laws. Capital depreciation is assumed to be 20 years to match the lifespan of the power generation engines and is calculated as a straight line. The power plant is also assumed to be equity financed (no project debt). This assumption is in line with the financial assumptions made for Guyana's power sector in the 2018 Expansion Study.

Table 7-5: Power plant Financial Analysis Assumptions

Financial variables	Unit	Base Case	Notes
Power plant Tax rate	%	27.5%	Based on Guyana corporate tax rate
Power plant Depreciation period (straight line)	years	20	20 year project lifespan assuming will switch to HFO once NG supply is depleted
Power plant Debt % of total capital cost	%	0%	Set to match assumptions in GPL 2018 Expansion Plan Update

Source: Energy Narrative

These factors were applied to calculate the power plant's earnings and net cash flow for each of the 20 years included in the analysis. This series of future cash flows was discounted to the present value using a 10% discount rate to calculate the power plant's NPV and the internal rate of return (IRR).

7.2.2. Financial feasibility analysis

The natural gas power plant's income and expenditures described above were calculated for each year between 2018 and 2041. This timeframe is based on EEPGL's project development timeline projecting first gas availability in 2022 and a 20-year period of natural gas availability from the Liza-1 development. The annual results were then discounted to 2018 using a 10% real discount rate in order to determine the power plant's net present value, internal rate of return, and the average price of the generated electric power under each of the natural gas pricing options.

Based on this analysis, electricity could be produced by the natural-gas-fired power plant for an average price of US$88.49 per MWh (8.8 cents per kWh) under the Cost+ natural gas pricing option and 10% IRR or for an average price of US$125.53 per MWh (12.5 cents per kWh) at a 16% IRR. The summary results of the financial feasibility analysis are presented in Table 7-6 below.

Table 7-6: Power plant financial feasibility analysis results

Sensitivity Variable Settings			Key Results Metrics		
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	Electricity Price (US$/MWh)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$88.49	$0	10%
30	Base	IRR-16%	$125.53	$88	16%
30	Base	Elec - 6 cent	$60.00	($65)	5%
30	Base	Elec - 9 cent	$90.00	$3	10%

Source: Energy Narrative analysis

A detailed schedule of the annual cash flows for the natural gas power plant is included in Appendix E.

7.2.3. Sensitivity analysis

A sensitivity analysis was performed to estimate how changes in key variables would impact the power plant's financial feasibility under both the Cost+ and Oil Price Discount natural gas pricing options. The sensitivity analysis used the same independent variables that were included in the economic sensitivity analysis: the volume of natural gas shipped by the pipeline, a share of the capital cost to build the pipeline accrued to the power plant, the capital cost to build the power plant, and the price of HFO that the natural gas will displace. These variables were selected based on the likelihood that they could change and their potential to have a material impact on the power plant's financial feasibility. The summary results of the sensitivity analysis are presented in Table 7-7 below.

Table 7-7: Power plant financial feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics		
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	Electricity Price (US$/MWh)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$88.49	$0	10%
30	Base	IRR-16%	$125.53	$88	16%
30	Base	Elec - 6 cent	$60.00	($65)	5%
30	Base	Elec - 9 cent	$90.00	$3	10%
30	Low	IRR-10%	$74.30	$0	10%
30	Low	IRR-16%	$104.67	$74	16%
30	Low	Elec - 6 cent	$60.00	($36)	7%
30	Low	Elec - 9 cent	$90.00	$32	13%
30	High	IRR-10%	$102.68	$0	10%
30	High	IRR-16%	$146.41	$101	16%
30	High	Elec - 6 cent	$60.00	($93)	3%
30	High	Elec - 9 cent	$90.00	($25)	8%
50	Base	IRR-10%	$79.95	$0	10%
50	Base	IRR-16%	$110.12	$98	16%
50	Base	Elec - 6 cent	$60.00	($71)	5%
50	Base	Elec - 9 cent	$90.00	$39	13%
50	Low	IRR-10%	$67.73	$0	10%
50	Low	IRR-16%	$92.13	$81	16%
50	Low	Elec - 6 cent	$60.00	($30)	7%
50	Low	Elec - 9 cent	$90.00	$80	16%
50	High	IRR-10%	$92.17	$0	10%
50	High	IRR-16%	$128.08	$116	16%
50	High	Elec - 6 cent	$60.00	($113)	2%
50	High	Elec - 9 cent	$90.00	($3)	10%
145	Base	IRR-10%	$56.72	$0	10%
145	Base	IRR-16%	$83.09	$107	16%
145	Base	Elec - 6 cent	$60.00	$16	11%
145	Base	Elec - 9 cent	$90.00	$157	19%

Source: Energy Narrative analysis

The table shows that the natural-gas-fired power plant remains financially feasible under every individual sensitivity case for the Cost+ price setting methodology for both the assumed 10% IRR and 16% IRR. The resulting electricity prices range from US$67.73 per MWh for the 10% IRR under the 50 MMscfd Low Cost Case to US$146.41 per MWh for the 16% IRR under 30 MMscfd and High Cost Case.

Under the Net Back approach, the power plant is financially feasible under the 9 cent electricity level in all sensitivities except the High Cost Cases where it has an 8% IRR and a US$25 million loss under the 30 MMscfd supply case and a 10% IRR and a US$3 million loss under the 50 MMscfd supply case. The plant is not feasible under the 6 cent electricity level for any of the sensitivity cases, suggesting that this average price for electricity is unobtainable without higher natural gas volumes, cross-subsidies, or direct subsidization.

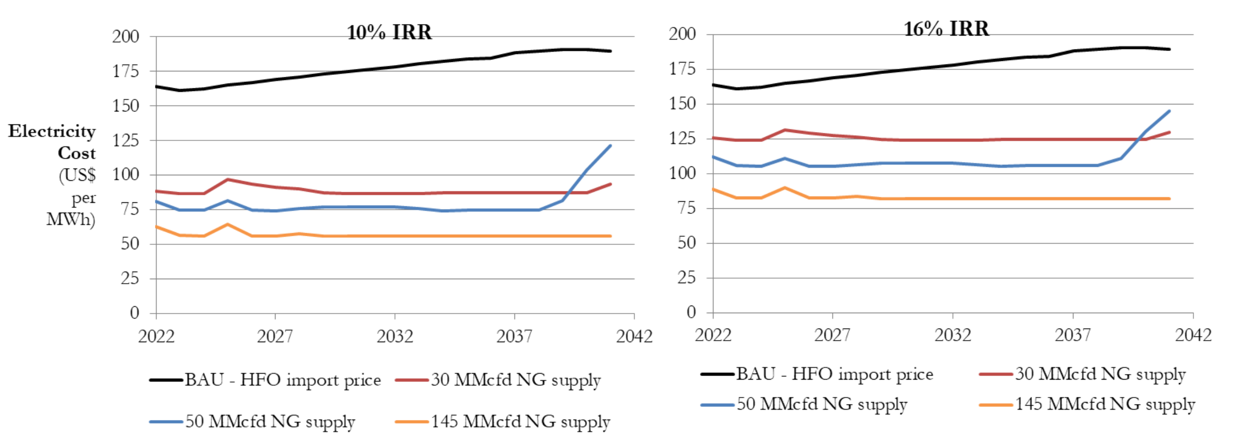
If the natural gas production were increased to the theoretical 145 MMscfd supply case, the average electricity price could fall as low as US$56.72 per MWh under the Cost+ price setting mechanism and a 10% IRR. Increasing the IRR to 16% would result in an average electricity price of US$83.09 per MWh. Under the Net Back price setting methodology, the natural gas wellhead price for 9 cent electricity and 6 cent electricity both fall within the range set by the Cost+ price setting methodology. That is, at this volume of natural gas, setting the natural gas price to produce electricity at an average price of 6 cents per kWh is financially feasible, resulting in a US$16 million NPV and 11% IRR. Increasing the electricity price to 9 cents per kWh results in an NPV of US$157 million and an IRR of 16%.

A detailed schedule of the annual cash flows for each sensitivity case is included in Appendix E.

7.3. Impact of natural gas volumes on the price of electricity generated

The price of the natural gas provided to the power plant has a direct impact on the price of electricity using the Cost+ pricing methodology. As a result, the volume of natural gas that is produced and transported via the pipeline also has a direct impact on the electricity generation price. Figure 7-1 compares the cost of electricity generated under the two IRR levels for each natural gas supply case, including the theoretical 145 MMscfd case, to a "business as usual" electricity price based on HFO.

Figure 7-1: Price of electricity to achieve a 10% and 16% IRR (2017 US$ per MWh)



Source: Energy Narrative analysis

The price of natural gas delivered to the power plant is fixed, but the price of electricity varies slightly each year according to the share of electricity generated with back up HFO. This is particularly notable in the later years of the 50 MMscfd supply option, when natural gas supply begins to decline and a growing share of the natural-gas-fired capacity switches back to HFO.

Under the 30 MMscfd natural gas supply case, an average electricity price of US$88.49 per MWh provides a 10% IRR, rising to US$125.53 per MWh for a 16% IRR. Increasing the natural gas volume to the 50 MMscfd supply case lowers the electricity price to US$79.95 per MWh for a 10% IRR and US$110.12 per MWh for a 16% return. If the 145 MMscfd natural gas supply profile is achieved and the pipeline was fully utilized, the electricity price could fall to just US$56.72 per MWh for a 10% return and US$83.09 per MWh for a 16% return.

Under all pricing options and natural gas volume cases, the electricity price is well below the "business as usual" price using imported HFO. Under the Base Case price forecast, the price of electricity generated from HFO is expected to increase from US$163.82 per MWh in 2022 to US$189.61per MWh in 2041 (in real 2017 US$), averaging US$176.93 per MWh throughout the period. This is more than 30% higher than the highest natural-gas-fired electricity price option (16% return on 30 MMscfd supply) and more than three times the price of the lowest cost option (10% return on 145 MMscfd supply).

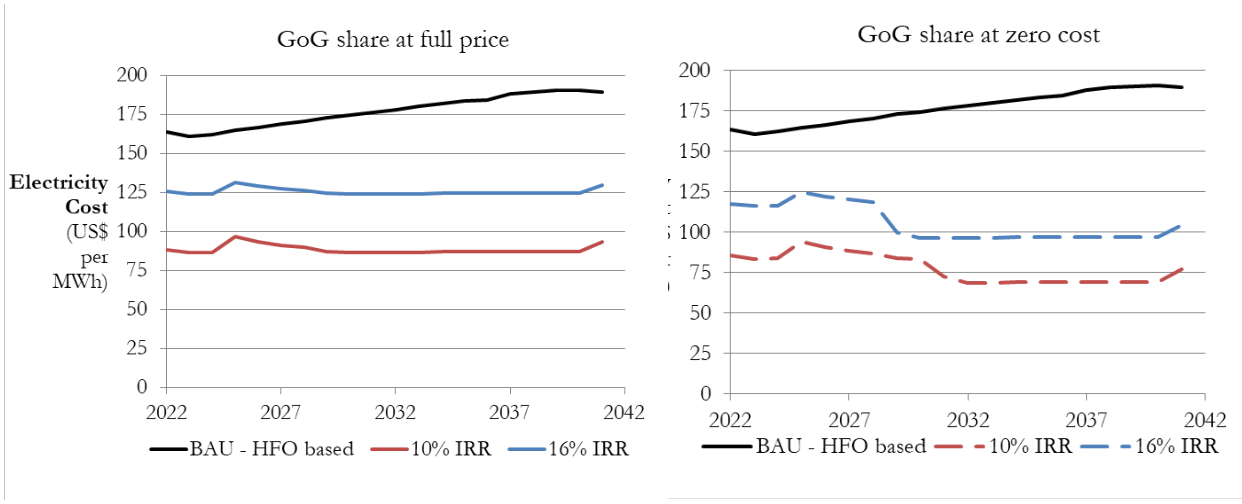
In addition, setting the natural gas to a fixed price removes the risk of price volatility that could come from linking the natural gas price to international oil prices. Figure 5-3 demonstrates the very wide range of potential future oil prices. Switching to domestically produced natural gas therefore has the additional benefit of removing the potential economic costs and dislocations that rapidly changing international oil prices could have on Guyana's electricity prices.

7.4. Impact of reducing the price for the Government of Guyana's natural gas share on the price of electricity generated

The price of the natural gas provided to the power plant has a direct impact on the price of electricity using the Cost+ pricing methodology. In addition, the terms of EEPGL's production agreement state that profits (income minus capital recovery and operating costs) from oil and natural gas sales will be shared equally between EEPGL and the Government of Guyana. If the Government of Guyana were willing to charge the power plant a lower price for its share of profit gas (that is, accept a lower rate of return on the gas sales), the price of the generated electricity would be correspondingly lower.

Figure 7-2 compares the cost of electricity generated under the 30 MMscfd natural gas supply case for the Government of Guyana's share of profit gas provided at full price and provided at zero cost.

Figure 7-2: Price of electricity at 30 MMscfd natural gas volume (2017 US$ per MWh)

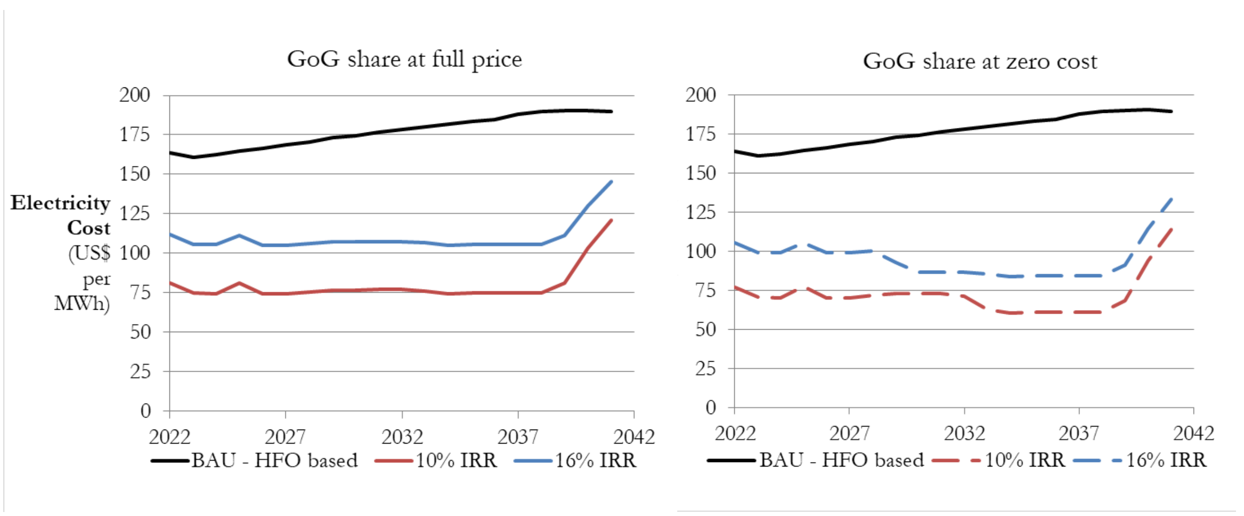


Source: Energy Narrative analysis

Under the 30 MMscfd natural gas supply case, an average electricity price of US$88.49 per MWh provides a 10% IRR, rising to US$125.53 per MWh for a 16% IRR. By providing its share of natural gas at zero cost under the 10% IRR case, the Government of Guyana would reduce the cost of electricity to as low as US$68.61 MWh and provide an average electricity cost of US$77.68 per MWh over the life of the project. Increasing the IRR to 16% raises the minimum electricity price to US$96.51 per MWh and the average electricity cost over the project lifetime to US$105.30 per MWh.

Figure 7-3 shows the same analysis under the 50 MMscfd natural gas volume case.

Figure 7-3: Price of electricity at 50 MMscfd natural gas volume (2017 US$ per MWh)



Source: Energy Narrative analysis

Increasing the natural gas volume to the 50 MMscfd supply case lowers the electricity price to US$79.95 per MWh for a 10% IRR and US$110.12 per MWh for a 16% return. By providing its share of natural gas at zero cost under the 10% IRR case, the Government of Guyana would reduce the cost of electricity to as low as US$60.69 MWh and provide an average electricity cost of US$72.19 per MWh over the life of the project. Increasing the IRR to 16% raises the minimum electricity price to US$83.85 per MWh and the average electricity cost over the project lifetime to US$95.48 per MWh.

7.5. Impact on retail electricity tariffs

Reducing the cost of electricity generated by using natural gas to substitute fuel oil will reduce the cost of electricity to GPL's end consumer as the cost of generation is a major component of the total cost of electricity. For large consumers at the proposed industrial park next to the natural-gas-fired power plant, the calculated cost of electricity generated is essentially the full cost of the delivered electricity. For other electricity consumers, the cost of transmission and distribution (T&D) must be added to the electricity cost to estimate the final retail price to the consumer.

The average T&D cost in Guyana was estimated from reported costs in GPL's Annual Reports from 2009-2012. Table 7-8 below shows the total costs to produce and deliver electricity as reported by GPL, the share attributed to generation costs, and the remainder (noted as "Other" in the table). These costs were spread across the total gross electricity generated and the billed sales reported for each year to get two estimates for the average cost of generation and the average T&D cost.

Table 7-8: GPL reported electricity costs

	Original Data - Guyana Dollars						Calculated - US Dollars					
	Unit	2012	2011	2010	2009	2008	Unit	2012	2011	2010	2009	2008
Total Costs	G$million	33,682	32,138	25,620	21,053	25,876	US$ million	168	157	125	107	131
Generation	G$million	27,078	25,873	19,899	15,971	20,978	US$ million	135	127	97	81	106
Other	G$million	6,604	6,265	5,720	5,082	4,898	US$ million	33	31	28	26	25
Gross Generation	GWh	690	653	626	586	564	GWh	690	653	626	586	564
Billed Sales	GWh	455	430	415	370	356	GWh	455	430	415	370	356
% Costs - Generation	%	80%	81%	78%	76%	81%	%	80%	81%	78%	76%	81%
% Costs - Other	%	20%	19%	22%	24%	19%	%	20%	19%	22%	24%	19%
	Gross Generation						Gross Generation					
Total Unit Cost	G$/kWh	48.81	49.22	40.93	35.93	45.88	US$/kWh	0.243	0.241	0.200	0.183	0.232
Unit Cost - Generation	G$/kWh	39.24	39.62	31.79	27.25	37.19	US$/kWh	0.195	0.194	0.155	0.139	0.188
Unit Cost - Other	G$/kWh	9.57	9.59	9.14	8.67	8.68	US$/kWh	0.048	0.047	0.045	0.044	0.044
Billed Sales	Billed Sales						Billed Sales					
Total Unit Cost	G$/kWh	74.03	74.74	61.73	56.90	72.69	US$/kWh	0.369	0.366	0.302	0.289	0.367
Unit Cost - Generation	G$/kWh	59.51	60.17	47.95	43.17	58.93	US$/kWh	0.296	0.294	0.235	0.220	0.298
Unit Cost - Other	G$/kWh	14.51	14.57	13.78	13.74	13.76	US$/kWh	0.072	0.071	0.067	0.070	0.070

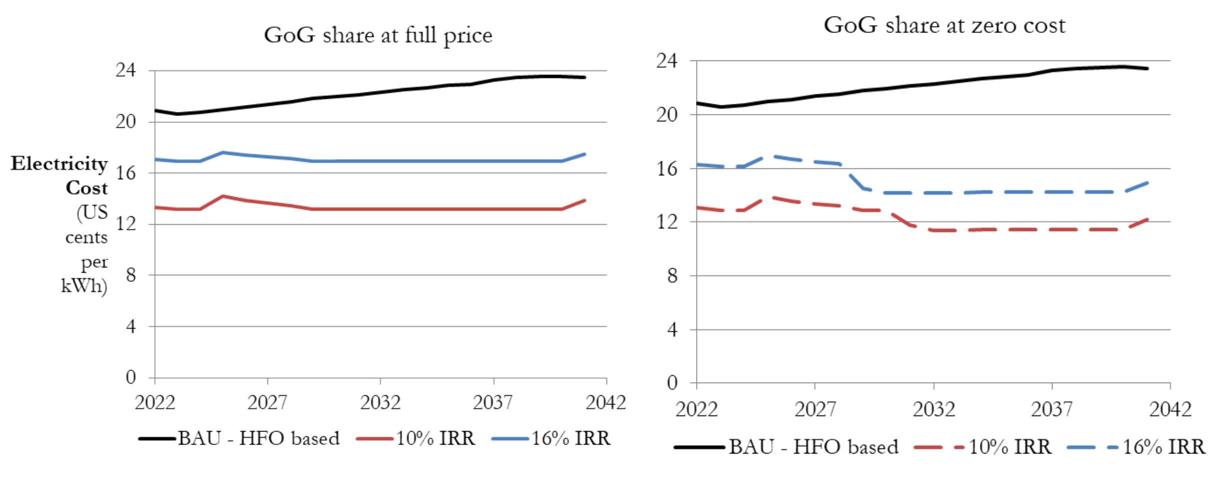
Source: GPL annual reports, Energy Narrative calculations

Based on this analysis, an estimated US$45 per MWh average cost for transmission and distribution was added to the projected cost of electricity generated as calculated in the natural-gas-fired power plant financial feasibility analysis and sensitivities. This value is based on the average value of "Other" costs spread over the total gross electricity generated from 2008-2012. The average value over gross generation was chosen based on the methodology used in the GPL 2018 Expansion

Study to calculate future demand and cost per MWh. This approach assumes that GPL will absorb the cost of providing unbilled electricity (non-technical losses), or that the non-technical losses will be resolved. As such, it underestimates the true cost of T&D services in Guyana if they were covered only through billed sales of electricity.

Figure 7-4 compares the average retail electricity price under the 30 MMscfd natural gas supply case for the Government of Guyana's share of profit gas provided at full price and provided at zero cost.

Figure 7-4: Price of electricity at 30 MMscfd natural gas volume (2017 US$ per MWh)

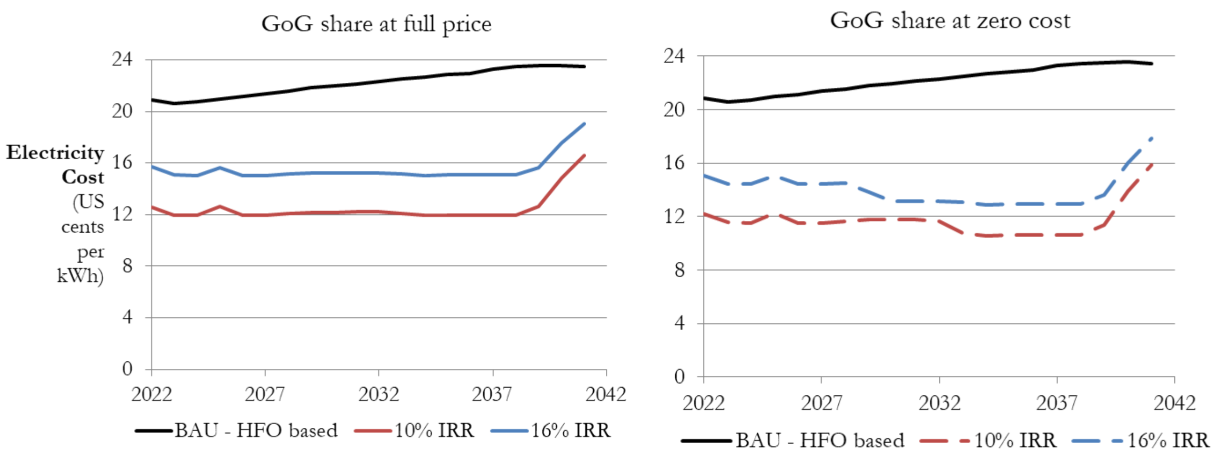


Source: Energy Narrative analysis

Under the 30 MMscfd natural gas supply case, an average retail electricity price of 13 US cents per kWh provides a 10% IRR, rising to 17 US cents per kWh for a 16% IRR. By providing its share of natural gas at zero cost under the 10% IRR case, the Government of Guyana would reduce the cost of electricity to as low as 11 US cents per kWh and provide an average electricity cost of 12 US cents per kWh over the life of the project. Increasing the IRR to 16% raises the minimum electricity price to 14 US cents per kWh and the average electricity cost over the project lifetime to 15 US cents per kWh. In all cases, this is well below the average 22 US cents per kWh expected under the "business as usual" case using imported HFO for electricity generation.

Figure 7-5 shows the same analysis under the 50 MMscfd natural gas volume case.

Figure 7-5: Price of electricity at 50 MMscfd natural gas volume (2017 US$ per MWh)



Source: Energy Narrative analysis

Increasing the natural gas volume to the 50 MMscfd supply case lowers the electricity price to 12.5 US cents per kWh for a 10% IRR and 15.5 US cents per kWh for a 16% return. By providing its share of natural gas at zero cost under the 10% IRR case, the Government of Guyana would reduce the cost of electricity to as low as 10 US cents per kWh and provide an average electricity cost of 11.7 US cents per kWh over the life of the project. Increasing the IRR to 16% raises the minimum electricity price to 14 US cents per kWh and the average electricity cost over the project lifetime to 22 US cents per kWh.

It is important to note that these retail tariff projections are indicative of the retail price for the electricity generated by the natural-gas-fired power plant. They do not represent the overall cost of electricity supplied by GPL as GPL operates additional electricity generation facilities, including existing HFO fired units (which will remain available as back up supply and for system balancing), PV and wind capacity, and potentially new hydro capacity (as proposed under the 30 MMscfd natural gas supply case expansion plan). The calculation of the system's overall retail cost, or the specific tariff for each consumer class, is beyond the scope of this analysis.

8. Overall Project Feasibility

The purpose of this section is to determine whether the overall proposed project, including the offshore natural gas pipeline, NGL separation and LPG production plant, and natural-gas-fired power plant, is both economically and financially feasible. The overall project will be economically feasible if the net present value of the economic benefits of the overall project outweigh the net present value of the economic costs. It will be financially feasible if the net present value of the overall project's annual cash flows (income minus costs) is positive.

The overall project's economic and financial feasibility are calculated separately below, based on the previous analysis of the three project components.

8.1. Overall project economic feasibility

The overall project's economic feasibility was determined by comparing the sum of the economic costs of the three project components with the sum of the three component's economic benefits. The overall project's economic costs include the capital cost to build each of the project components, the annual cost to operate each of the project components, and any environmental costs associated with each component's operations. The overall project's economic benefits include the avoided costs that would have been incurred if the overall project had not been built. These include the avoided costs of importing heavy fuel oil and LPG, and the avoided economic cost of CO_2 emissions that would result from burning the HFO for electricity generation.

This analysis does not include any economic benefits from increased job creation (both directly from the construction and operation of the project components and indirectly from the greater economic activity associated with it). While the project will clearly bring some job creation benefits, this value was not quantified for this analysis.

The economic cost benefit analysis found that the overall project has an aggregate economic net present value (NPV) of approximately US$918 million and an economic rate of return of 30% percent under the project's Base Case assumptions. This indicates that the overall project is economically viable. The summary results of the overall project economic feasibility analysis are presented in Table 8-1 below.

Table 8-1: Overall project economic feasibility analysis results

Sensitivity Variable Settings			Key Results Metrics				
NG Flow Volume	Capital & Operating Costs	HFO and LPG Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	Base	Base	$1,715	($798)	$918	30%	2.15

Source: Energy Narrative analysis

A detailed schedule of the annual economic benefits and costs for the total project is included in Appendix F.

8.1.1. Sensitivity Analysis

Table 8-2 below summarizes the aggregate results of the total project present economic value, present economic costs, economic net present value, economic rate of return, and the economic cost/benefit ratio under each of the sensitivity variations calculated for each of the project components. Because the same variables were changed for each of the component sensitivity analyses (capital costs, oil price, and natural gas volume), the sensitivity analysis for each component can be directly added together to find the impact of changing each sensitivity variable on the project as a whole.

Table 8-2: Overall project economic feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics				
NG Flow Volume	Capital & Operating Costs	HFO and LPG Price	Present Value of Economic Benefits (US$ million)	Present Value of Economic Costs (US$ million)	Economic Net Present Value (US$ million)	Economic Rate of Return (%)	Economic Benefit / Cost Ratio
30	Base	Base	$1,715	($798)	$918	30%	2.15
30	High	Base	$1,747	($928)	$820	26%	1.88
30	Low	Base	$1,683	($667)	$1,016	36%	2.52
30	Base	High	$2,867	($798)	$2,070	47%	3.59
30	Base	Low	$990	($798)	$192	16%	1.24
30	High	Low	$1,022	($928)	$94	13%	1.10
50	Base	Base	$2,367	($925)	$1,442	34%	2.56
50	High	Base	$2,411	($1,070)	$1,341	30%	2.25
50	Low	Base	$2,323	($780)	$1,543	40%	2.98
50	Base	High	$3,988	($925)	$3,063	50%	4.31
50	Base	Low	$1,356	($925)	$431	20%	1.47
50	High	Low	$1,400	($1,070)	$330	17%	1.31
145	Base	Base	$4,536	($1,141)	$3,394	38%	3.97

Source: Energy Narrative analysis

The table shows that the overall project remains economically feasible under each individual sensitivity case. Even under the “worst case” combination of both high project costs and a low oil price outlook with 30 MMscf per day of natural gas volume the project is feasible, showing a US$94 million economic net present value over 20 years and an economic rate of return of 13%. The overall project shows the highest economic return under the 50 MMscf per day of natural gas volumes and the high oil price case, reaching just over US$3 billion in net present value and a 50% economic rate of return.

If natural gas supply were increased to the theoretical 145 MMscfd case, the overall project would have an economic net present value of nearly US$3.4 billion and an economic rate of return of 38%.

A detailed schedule of the annual economic benefits and costs for each sensitivity analysis of the total project is included in Appendix F.

8.2. Overall project financial feasibility

The overall project's financial feasibility was determined by subtracting the sum of the costs of the three project components from the sum of the three component's income. The overall project's economic costs include the capital cost to build each of the project components and the annual cost to operate each of the project components, interest expense for any debt that is issued to finance the project, and any corporate income taxes assessed on the project component's profits. The overall project's income is the sum of income from each project component based on the volume of natural gas, LPG, and electricity that is sold, and the price for which each is sold under both the Cost+ and Net Back price setting methodologies.

The financial analysis results shown in Table 8-3 below finds that the natural gas would be delivered to the landing site for US$4.92 per MMBtu, the LPG would be priced at US$6.72 per MMBtu and the electricity generated by the natural-gas-fired power plant would be priced at US$88 per MWh (8.8 cents per kWh) using the Cost+ methodology at a 10% IRR. Increasing the IRR to 16% would raise the price of the delivered natural gas to US$7.19 per MMBtu, the LPG price to US$9.74 per MMBtu, and the average electricity price to US$126 per MWh (12.6 cents per kWh). At these price levels, the overall project would have an NPV of US$274 million.

Under the Net Back price setting option, setting the average electricity price to 9 US cents per kWh would result in a net present value (NPV) of approximately US$11 million and an internal rate of return of 10% percent for the project as a whole under the project's Base Case assumptions. Setting the electricity price to 6 cents per kWh, however, would result in an overall US$215 million loss and a 4% IRR under the Base Case assumptions. This suggests that a 6 cent per kWh price for electricity is unobtainable without higher natural gas volumes, cross-subsidies, or direct subsidization.

Table 8-3: Overall project financial feasibility analysis results

Sensitivity Variable Settings			Key Results Metrics						
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	NG Wellhead Price (US$/MMBtu)	NG Pipeline Tariff (US$/MMBtu)	NG Delivered Price (US$/MMBtu)	LPG Price (US$/MMBtu)	Electricity Price (US$/MWh)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$1.01	$3.91	$4.92	$6.72	$88.49	$0	10%
30	Base	IRR-16%	$1.48	$5.71	$7.19	$9.74	$125.53	$274	16%
30	Base	Elec - 6 cent	$0.64	$2.48	$3.12	$4.26	$60.00	($215)	4%
30	Base	Elec - 9 cent	$1.03	$3.99	$5.02	$6.85	$90.00	$11	10%

Source: Energy Narrative analysis

A detailed schedule of the annual cash flows for the entire project is included in Appendix F.

8.2.1. Sensitivity analysis

Table 8-4 below summarizes the aggregate results under each of the sensitivity variations calculated for each of the project components. Because the same variables were changed for each of the component sensitivity analyses, the sensitivity analysis for each component can be combined to find the impact of changing each sensitivity variable on the project's financial feasibility as a whole.

Table 8-4: Overall project financial feasibility sensitivity analysis results

Sensitivity Variable Settings			Key Results Metrics						
NG Flow Volume	Capital & Operating Costs	Pricing Mechanism	NG Wellhead Price (US$/MMBtu)	NG Pipeline Tariff (US$/MMBtu)	NG Delivered Price (US$/MMBtu)	LPG Price (US$/MMBtu)	Electricity Price (US$/MWh)	Net Present Value (US$ million)	Internal Rate of Return (%)
30	Base	IRR-10%	$1.01	$3.91	$4.92	$6.72	$88.49	$0	10%
30	Base	IRR-16%	$1.48	$5.71	$7.19	$9.74	$125.53	$274	16%
30	Base	Elec - 6 cent	$0.64	$2.48	$3.12	$4.26	$60.00	($215)	4%
30	Base	Elec - 9 cent	$1.03	$3.99	$5.02	$6.85	$90.00	$11	10%
30	Low	IRR-10%	$0.81	$3.13	$3.94	$5.38	$74.30	$0	10%
30	Low	IRR-16%	$1.18	$4.57	$5.75	$7.79	$104.67	$223	16%
30	Low	Elec - 6 cent	$0.64	$2.48	$3.13	$4.27	$60.00	($103)	7%
30	Low	Elec - 9 cent	$1.03	$3.99	$5.03	$6.86	$90.00	$123	13%
30	High	IRR-10%	$1.22	$4.69	$5.91	$8.07	$102.68	$0	10%
30	High	IRR-16%	$1.78	$6.85	$8.63	$11.69	$146.41	$326	16%
30	High	Elec - 6 cent	$0.64	$2.47	$3.11	$4.25	$60.00	($326)	2%
30	High	Elec - 9 cent	$1.03	$3.98	$5.01	$6.84	$90.00	($100)	8%
50	Base	IRR-10%	$0.74	$2.84	$3.57	$5.38	$79.95	$0	10%
50	Base	IRR-16%	$1.12	$4.31	$5.42	$8.09	$110.12	$316	16%
50	Base	Elec - 6 cent	$0.50	$1.95	$2.45	$3.70	$60.00	($203)	5%
50	Base	Elec - 9 cent	$0.84	$3.24	$4.08	$6.15	$90.00	$98	12%
50	Low	IRR-10%	$0.59	$2.27	$2.86	$4.30	$67.73	$0	10%
50	Low	IRR-16%	$0.89	$3.45	$4.34	$6.47	$92.13	$254	16%
50	Low	Elec - 6 cent	$0.51	$1.95	$2.46	$3.71	$60.00	($76)	8%
50	Low	Elec - 9 cent	$0.84	$3.25	$4.09	$6.16	$90.00	$225	15%
50	High	IRR-10%	$0.88	$3.40	$4.29	$6.46	$92.17	$0	10%
50	High	IRR-16%	$1.34	$5.17	$6.51	$9.70	$128.08	$377	16%
50	High	Elec - 6 cent	$0.50	$1.94	$2.45	$3.69	$60.00	($330)	3%
50	High	Elec - 9 cent	$0.84	$3.24	$4.08	$6.14	$90.00	($28)	9%
145	Base	IRR-10%	$0.36	$1.40	$1.77	$3.85	$56.72	$0	10%
145	Base	IRR-16%	$0.62	$2.41	$3.03	$6.49	$83.09	$458	16%
145	Base	Elec - 6 cent	$0.39	$1.50	$1.88	$4.12	$60.00	$49	11%
145	Base	Elec - 9 cent	$0.61	$2.37	$2.98	$6.52	$90.00	$498	16%

Source: Energy Narrative analysis

The table shows that the overall project is financially feasible under all sensitivity cases for the Cost+ price setting methodology for both the assumed 10% and 16% IRR. Under the 16% IRR option, the overall project's NPV ranges from US$223 million under the 30 MMscfd Low Cost Case to US$377 million under the 50 MMscfd High Cost Case.

Under the Net Back price setting methodology, the overall project is financially feasible under the 9 cent electricity price level in all sensitivities except the High Cost Cases where it has an 8% IRR and a US$100 million loss under the 30 MMscfd supply case and a 9% IRR and a US$28 million loss under the 50 MMscfd supply case. The overall project is not feasible under the 6 cent electricity price for any of the sensitivity cases, suggesting that this average price for electricity is unobtainable without higher natural gas volumes, cross-subsidies, or direct subsidization.

The table also shows a wide range of prices for delivered natural gas, LPG, and electricity. The lowest price for delivered natural gas among the financially feasible sensitivities is US$2.86 per MMBtu, under the 50 MMscfd Low Cost scenario with the natural gas priced using the Cost+ methodology and 10% IRR. The highest delivered natural gas price is US$8.63 per MMBtu under the 30 MMscfd High Cost scenario using the Cost+ methodology and 16% IRR.

The lowest price for LPG is just under US$4.30 per MMBtu, under the 50 MMscfd Low Cost scenario with the LPG priced using the Cost+ methodology and 10% IRR. The highest average LPG price is US$11.69 per MMBtu under the 30 MMscfd High Cost scenario with the LPG priced using the Cost+ methodology and 16% IRR.

The lowest price for electricity is just under US$68 per MWh (6.8 cents per kWh), under the Low Cost and 50 MMscf per day natural gas volume scenario if the natural gas is priced using the Cost+ methodology and a 10% IRR. The highest average electricity price is the 30 MMscf per day natural gas volume scenario with High Cost under the Cost+ price setting methodology and 16% IRR. This case results in an average electricity price of US$146 per MWh (14.6 cents per kWh), or more than double the price in the lowest scenario.

If the natural gas production were increased to the theoretical 145 MMscfd supply case, the overall project would be financially feasible under all price setting methodologies under the Base Case. Because this level of natural gas production is only theoretical with the currently available data, detailed sensitivities were not performed for this supply case.

A detailed schedule of the annual cash flows for each sensitivity case for the entire project is included in Appendix F.

9. Commercial structure framework

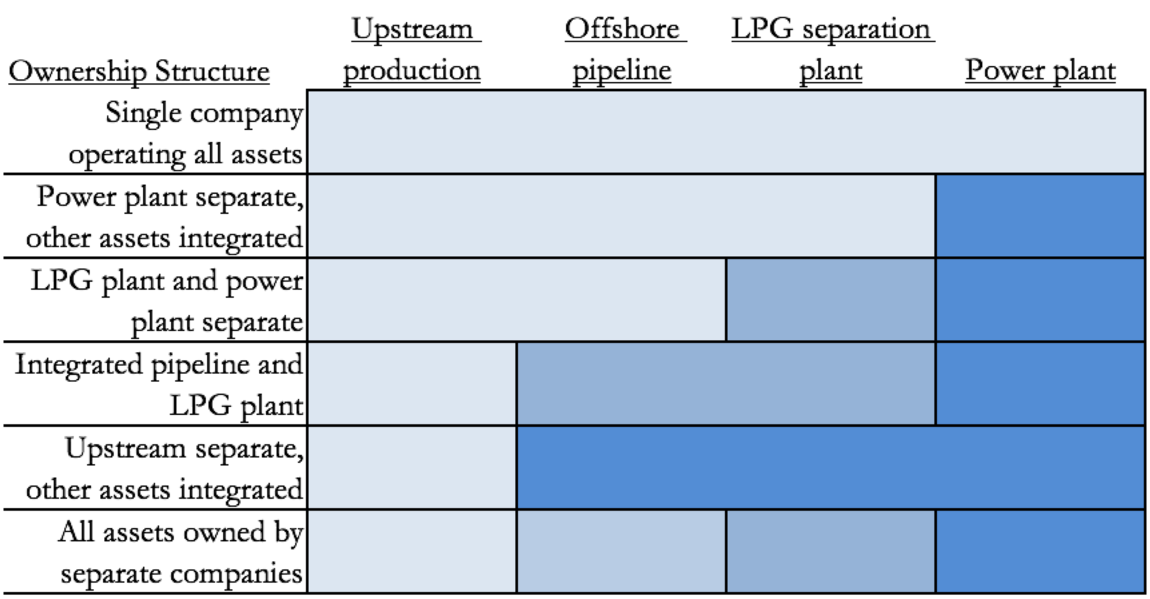
The purpose of the commercial structure framework is to identify potential commercial structures and risk allocation for the project as a whole and implications for each project segment (natural gas pipeline, NGL separation and LPG production plant, and electricity generation plant). The analysis examines the broad spectrum of commercial structures that may be applied to the Project, including ownership, contracting modalities, and public-private partnerships. We then assess the benefits, risks, and constraints for each organizational and contractual structure in Guyana.

This analysis provides a framework for assessing proposed commercial structures and guides future studies that will assess specific options in detail.

9.1. Potential commercial structures

Table 9-1 below shows six potential ownership options for the project's four component parts.

Table 9-1: Potential commercial structures



Source: Energy Narrative

Each optional structure is described below.

9.1.1. Single company owns all assets

In this commercial structure, a single entity owns all four project components. The same entity could operate all four project components, or could contract an outside company to maintain and operate individual components. Ownership of the natural gas is retained within the company through processing in the LPG plant and use in the power plant. The LPG produced in the NGL separation and LPG production plant is sold to other LPG retailers or directly to LPG consumers. The electric power produced in the power plant is sold to the electric utility or large consumers through a power purchase agreement.

For the Guyana project, EEPGL and its upstream partners are already the owners of the upstream production assets. Therefore, this structure would entail the same group building and owning the offshore pipeline, NGL separation and LPG production plant, and power plant.

This structure has the simplest contracting arrangements as there is no need for gas sales agreements among the project component pieces, and risk mitigation and coordination of operations (such as managing FPSO down time) is handled within the company rather than through contractual arrangements. This could help to speed the project development time and reduce downtime in the event of an accident or other contingency. It has the potential to simplify project financing as well, as there are fewer entities involved, although by concentrating the investment burden onto a single company it also requires the company to have a strong balance sheet and investment credit rating.

From a policy perspective, placing all assets within a single company could limit competition and market access should other upstream producers wish to use the natural gas pipeline to bring additional natural gas volumes to Guyana. The LPG plant and power plant would also be de facto monopolies in their respective sectors, as each is large enough to provide for all of Guyana's current domestic LPG and electricity needs.

9.1.2. Power plant separate, other assets integrated

In this commercial structure, a single entity owns the upstream, offshore pipeline, and NGL separation and LPG production plant project components, while a separate entity owns the power plant. The power plant owner could be the electric utility or an independent power producer. The two entities could operate their respective project components, or could contract an outside company to maintain and operate them. Ownership of the natural gas is retained within the upstream company through processing in the LPG plant. The dry gas that is produced after LPG separation is then sold to the power plant through a gas sales agreement. The LPG produced in the NGL separation and LPG production plant is sold to other LPG retailers or directly to LPG consumers. The power plant purchases the natural gas and, if it is an IPP, sells the electricity that is produced to the electric utility or large customers through a power purchase agreement.

For the Guyana project, EEPGL and its upstream partners are already the owners of the upstream production assets. Therefore, this structure would entail the same group building and owning the offshore pipeline and the NGL separation and LPG production plant. The power plant could be owned by GPL or another entity operating as an IPP.

This structure has relatively simple contracting arrangements as there is a single gas sales agreement (between the natural gas company and the power plant), and gas production, transportation, and processing are contained within the same company. This can simplify risk mitigation and coordination of operations (such as managing FPSO down time) along the natural gas value chain. This could help to speed the project development time and reduce natural gas supply downtime in the event of an accident or other contingency. It also has the advantage of separating power generation from the natural gas segments, thereby allowing EEPGL and its partners to focus on oil and gas operations and leave the electricity component to another entity.

From a policy perspective, placing all of the natural gas and LPG assets within a single company could limit competition and market access should other upstream producers wish to use the natural gas pipeline to bring additional natural gas volumes to Guyana. The LPG plant would also be a de facto monopoly, as it is large enough to provide for all of Guyana's current domestic LPG needs. If the power plant operated as an IPP, it would be the primary (if not the sole) generator supply GPL.

9.1.3. LPG plant and power plant separate

In this commercial structure, a single entity owns the upstream production and offshore pipeline, while separate entities own the NGL separation and LPG production plant and power plant components. The LPG plant owner could be a private or public entity. The power plant owner could be the electric utility or an independent power producer. The three entities could operate their respective project components, or could contract an outside company to maintain and operate them. Ownership of the natural gas could be transferred to the LPG plant operator through a gas sales agreement, or it could be held by the upstream company until it is sold to the power plant with the LPG plant providing separation services for a fee. The dry gas that is produced after LPG separation is then sold to the power plant through a gas sales agreement. The LPG produced in the NGL separation and LPG production plant is sold to other LPG retailers or directly to LPG consumers. The power plant purchases the natural gas and, if it is an IPP, sells the electricity that is produced to the electric utility or large customers through a power purchase agreement.

For the Guyana project, EEPGL and its upstream partners are already the owners of the upstream production assets. Therefore, this structure would entail the same group building and owning the offshore pipeline. The NGL separation and LPG production plant could be owned by a different private sector entity or consortia, or could be owned by the Government of Guyana. The power plant could be owned by GPL or another entity operating as an IPP.

This structure has more complex contracting arrangements as there multiple options for structuring the gas sales agreement (between the natural gas company and the power plant) and the commercial arrangements between the pipeline owner/operator and the LPG plant (such as a gas sales agreement, a tolling "fee for service" arrangement). This structure requires contracts between the separate entities to address a greater degree of the risk mitigation measures and coordination of operations (such as managing FPSO down time). This additional complexity could slow project development time. It has the advantage of increasing the transparency of the price for natural gas sold to the LPG plant and power plant.

From a policy perspective, separating the natural gas upstream and pipeline from the LPG assets could support competition and market access should other upstream producers wish to build new natural gas pipelines to bring additional natural gas volumes to Guyana. The LPG plant and power plant would also have to compete for the natural gas supply, allowing other consumers to potentially enter the market.

9.1.4. Integrated pipeline and LPG plant

In this commercial structure, a single entity owns the offshore pipeline and NGL separation and LPG production plant separate from the upstream and power plant components. The offshore pipeline and LPG plant owner could be a private or public entity. The power plant owner could be the electric utility or an independent power producer. The three entities could operate their respective project components, or could contract an outside company to maintain and operate them. Ownership of the natural gas could be transferred to the pipeline and LPG plant operator at the FPSO through a gas sales agreement, or it could be held by the upstream company until it is sold to the power plant with the pipeline and LPG plant operator providing transportation and separation services for a fee. The dry gas that is produced after LPG separation is then sold to the power plant through a gas sales agreement. The LPG produced in the NGL separation and LPG production plant is sold to other LPG retailers or directly to LPG consumers. The power plant purchases the natural gas and, if it is an IPP, sells the electricity that is produced to the electric utility or large customers through a power purchase agreement.

For the Guyana project, EEPGL and its upstream partners are already the owners of the upstream production assets. This structure would allow a separate entity or consortia, including private companies or the Government of Guyana, to build and own the offshore pipeline and NGL separation and LPG production plant. The power plant could be owned by GPL or another entity operating as an IPP.

This structure has more complex contracting arrangements as there multiple options for structuring the gas sales agreement (between the natural gas producers and the pipeline/LPG plant or the power plant) and the commercial arrangements between the pipeline and LPG plant owner/operator (such as a gas sales agreement at the FPSO, a tolling "fee for service" arrangement). This structure requires contracts between the separate entities to address a greater degree of the risk mitigation measures and coordination of operations (such as managing FPSO down time). This additional complexity could slow project development time. It has the advantage of increasing the transparency of the price for natural gas transportation and the price of the natural gas sold to the power plant. In addition, the pipeline/LPG plant owner could use revenue from the LPG plant to cover a greater share of the pipeline costs, thereby reducing the price of natural gas to the power plant.

From a policy perspective, separating the natural gas upstream from the pipeline and LPG assets could support competition and market access should other upstream producers wish to sell natural gas into the existing pipeline to bring additional natural gas volumes to Guyana.

9.1.5. Upstream separate, other assets integrated

In this commercial structure, a single entity owns the upstream production, while the offshore pipeline, the NGL separation and LPG production plant, and the power plant components are owned by a single entity. This entity could private or public, or a consortium. The downstream entity could operate the respective project components, or could contract an outside company to maintain and operate them. Ownership of the natural gas would be transferred to the downstream entity through a gas sales agreement at the FPSO. The LPG produced in the NGL separation and LPG production plant is then sold to other LPG retailers or directly to LPG consumers. The power plant sells the electricity that is produced to the electric utility or large customers through a power purchase agreement.

For the Guyana project, EEPGL and its upstream partners are already the owners of the upstream production assets. Therefore, this structure would entail a new entity building and owning the offshore pipeline, the NGL separation and LPG production plant, and the power plant. The new entity could be a private sector entity or consortia, or could be owned by the Government of Guyana. The power plant would operate as an IPP.

This structure has relatively simple contracting arrangements as there is a single gas sales agreement between the natural gas producing company and the downstream entity. This structure requires some degree of coordination of operations to manage FPSO down time.

From a policy perspective, separating the natural gas upstream from the downstream assets could support competition and market access should other upstream producers wish to connect additional natural gas supply to the offshore pipeline.

9.1.6. All assets owned by separate companies

In this commercial structure, separate entities own each of the project components. Each of the four entities could be private or public, or could be a consortium. The power plant owner could be the electric utility or an independent power producer. Each entity could operate their respective project components, or could contract an outside company to maintain and operate them. Ownership of the natural gas could be transferred to the pipeline owner through a gas sales agreement, or it could be held by the upstream company until it is sold to the LPG plant and/or power plant owners with the LPG plant providing separation services for a fee. The dry gas that is produced after LPG separation is then sold to the power plant through a gas sales agreement. The LPG produced in the NGL separation and LPG production plant is sold to other LPG retailers or directly to LPG consumers. The power plant purchases the natural gas and, if it is an IPP, sells the electricity that is produced to the electric utility or large customers through a power purchase agreement.

For the Guyana project, EEPGL and its upstream partners are already the owners of the upstream production assets. A separate entity would build and own the offshore pipeline. The NGL separation and LPG production plant could be owned by a different private sector entity or consortia, or could be owned by the Government of Guyana. The power plant could be owned by GPL or another entity operating as an IPP.

This structure has the most complex contracting arrangements of the various options presented as there multiple options for structuring the gas sales agreement (among the natural gas producers, the pipeline company, the NGL separation and LPG production plant company, and the power plant) and the commercial arrangements with the pipeline owner/operator and the LPG plant could also include a tolling "fee for service" arrangement). This structure requires contracts between the separate entities, increasing the potential for overlaps or gaps between contracting arrangements to create operational or financial risks. The greater number of contracts and entities also increases the complexity and importance of coordinating operations (such as managing FPSO down time). This additional complexity could slow project development time and complicate project financing. It has the advantage of increasing the transparency of the price for natural gas at each point of the value chain, spreading the investment burden and risks across a wider number of entities, and increasing the potential for competition or to accommodate new entrants at each stage of the value chain.

From a policy perspective, separating each project component could support the creation of a competitive natural gas market with multiple suppliers, consumers, and intermediary companies.

9.2. Example commercial structures

Table 9-2 below describes six projects that use offshore natural gas to fuel power plants that can provide proxy examples of commercial structure options for the Guyana project.

Table 9-2: Examples of recent offshore natural gas to power projects

Project / NG field	Location	Distance to shore (km)	NG Reserves (Tcf)	Start of Production	Power Plant Size (MW)
Tamar NG Field	Israel	90	10	2013	835
Banda Gas Field	Mauritania	55	1	2016	300
Ca Voi Xanh	Vietnam	80	5.3	2023	3,000
Sankofa Gas Project	Ghana	60	1.45	2018	1,000
Malampaya Gas Field	Philippines	80 (504 km pipeline)	2.7	2001	2,700
Songo Songo Gas Field	Tanzania	15	0.5	2004	190

Source: World Bank, industry and news publications

Most projects have been recently completed or still pending. All except the Songo Songo field are much larger than the Liza-1 proposed natural gas supply, and therefore are able to support much larger gas-fired power plants. All also have a shorter distance between the offshore natural gas production and the shore, although the Malampaya gas field includes a 500 km pipeline in order to reach the large population centers on a more distant island.

Table 9-3 shows the commercial structure for each of the projects, highlighting the ownership at each segment.[2]

Table 9-3: Commercial structure of recent offshore natural gas to power projects

[2] A blank square indicates ownership data was not available

Project / NG field	Upstream production	Offshore pipeline	Gas processing/ separation	Onshore pipeline	Power plant(s)
Tamar NG Field	Noble Energy + partners	Noble Energy + partners	Noble Energy + partners	Israel NG Lines Ltd	Dalia Power Energies, Israel Electric Corp.
Banda Gas Field	Tullow + partners	Tullow + partners	Tullow + partners	Tullow + partners	SPEG
Ca Voi Xanh	ExxonMobil, PetroVietnam	ExxonMobil, PetroVietnam			PetroVietnam
Sankofa Gas Project	ENI, Vitol, GNPC	ENI, Vitol, GNPC	ENI, Vitol, GNPC	GNGC (GNPC subsidiary)	VRA, IPPs
Malampaya Gas Field	Shell, Chevron, PNOC	Shell, Chevron, PNOC	Shell, Chevron, PNOC		First Gen, KEPCO
Songo Songo Gas Field	Orca Exploration Group	Songas Ltd	Songas Ltd	Songas Ltd	AES Siroco

Source: World Bank, industry and news publications

In all projects, ownership of the gas-fired power plant was separate from ownership of the natural gas infrastructure, although in the Ca Voi Xanh project the power plant owner (PetroVietnam) was also a partner in the natural gas segments.

In every project except the Songo Songo field, the consortium producing the natural gas also owned the offshore pipeline and gas processing infrastructure. In the Songo Songo project, all pipeline and processing infrastructure is owned by a single company contracted to take the produced natural gas at the offshore production platform. This is also the project that is closest to the shore (including some wells listed as being onshore).

Those projects that had a separate owner for the onshore pipeline infrastructure operate in countries with an established natural gas transmission pipeline system (Israel and Ghana). In these cases, the new pipeline from the offshore production linked to the existing onshore pipeline system, which was used to transmit the gas to the final consumer. However, data on the onshore pipeline ownership could not be found for two of the examples.

9.3. Commercial structure recommendations

The above analysis suggests that the most common commercial structure for similar offshore natural gas pipeline and power generation projects integrates the natural gas infrastructure facilities with the upstream natural gas producing entities while the power plant is owned separately. This structure fits well within Guyana's institutional structure, as EEPGL and its partners are well positioned to build and operate the offshore pipeline and GPL is well positioned to own and operate the power plant, or manage the IPP contract for an independent company to build and operate it.

This structure simplifies the contracting arrangements as there is a single gas sales agreement (between the natural gas infrastructure company and the power plant), as well as risk mitigation and coordination of operations along the natural gas value chain. Avoiding the need to attract a separate company to build the natural gas pipeline and NGL separation and LPG production plant also avoids potential project development delays, an important consideration given the tight timeframe before expected first gas production. Furthermore, the income derived from the LPG sales could be used to reduce the cost of the natural gas sold to the power plant, helping to reduce electricity generation costs. This can be achieved by allocating a greater share of the upstream and pipeline costs to the LPG stream, or through direct cross-subsidization.

Although placing all of the natural gas and LPG assets within a single company could limit competition and market access should other upstream producers wish to use the natural gas pipeline to bring additional natural gas volumes to Guyana, this can be handled by setting terms and timing for future open access in the gas contract or in a newly established gas regulatory regime. The LPG plant would also be a de facto monopoly, as it is large enough to provide for all of Guyana's current domestic LPG needs, and so managing its interaction with the current LPG providers will be important.

10. Complementary Analysis

The purpose of the complementary analysis is to review potential environmental and social impacts of building and operating the natural gas pipeline, NGL separation and LPG production plant and natural-gas-fired power plant. This analysis aims to identify factors that should be considered when conducting the environmental and social impact assessments for each segment of the project. It does provide such assessments of the project components themselves, but rather provides guidance for preparing and evaluating the environmental impact assessments.

The complementary analysis is divided into three sections: an overview of Guyana's current environmental legislation and participation in international environmental treaties, a review of international practices in developing environmental and social impact assessments for energy projects, and a review of international air and water emissions standards.

10.1. Guyana environmental laws and participation in international environmental treaties

Guyana has established a number of laws and regulations that are relevant to environmental and social issues in energy development. A selection of these laws and regulations include:

- **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, including natural gas and LPG. The Regulations provide broad guidelines for overseeing the technical, operational, health, safety, and environmental parameters for related infrastructure and installations.
- **Petroleum (Exploration and Production) Act and related Regulations.** This Act sets the basic terms and conditions for awarding petroleum exploration and production permits, including requirements for environmental assessment and mitigation.
- **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.
- **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, confirms GPL's ability to generation of electricity (except hydropower) and to purchase electricity through PPAs with IPPs.
- **Guyana Shipping Act 1998.** This Act regulates maritime activity in Guyanese waters, including environmental, health, and safety aspects of marine operations.

In addition, Guyana is party to many international environmental treaties. Table 10-1 below lists major international treaties and Guyana's current status for each.

Table 10-1: Guyana participation in international environmental treaties

Treaty	Status
Basel Convention on the Control of Transboundary Movements fo Hazardous Wastes and Their Disposal (1992)	Ratified
Convention on **Biodiversity** (1993)	Ratified
Convention on **Wetlands of International Importance** Especially as Waterfowl Haibtat (Ramsar) (1975)	Not a Party
Convention on **Long-Range Transboundary Air Pollution** (1983)	Not a Party
Convention on the **Prevention of Marine Pollution** by Dumping Wastes and Other Matter (London Convention) (1975)	Not a Party
Convention on **Fishing** and Conservation of Living Resources of the High Seas (1966)	Not a Party
International **Tropical Timber** Agreement (1983)	Ratified
International **Tropical Timber** Agreement (1994)	Ratified
Montreal Protocol on Substances that Deplete the Ozone Layer (1989)	Ratified
Protocol of 1978 Related to the International Convention for the **Prevention fo Pollution From Ships**, 1973 (MARPOL) (1983)	Ratified
United Nations Convention on the **Law of the Sea** (1994)	Ratified
United Nations **Convention to Combat Desertification** in Those Countries Experiencing Serious Drought and/or Desertification, Particularly in Africa (1996)	Ratified
United Nations **Framework Convention on Climate Change** (UNFCCC) (1994)	Ratified
Kyoto Protocol to the UNFCCC (2005)	Ratified
Paris Agreement (2016)	Ratified

Source CIA World Fact Book

10.2. International practices in developing Environmental and Social Impact Assessments

The purpose of this section is to review potential environmental impacts of building and operating a natural gas pipeline, NGL separation and LPG production plant and natural-gas-fired power plant, based on international practices for developing environmental impact assessments.

According to the US EPA and Agency for International Development[3], an environmental impact assessment should aim to:

- Identify applicable environmental standards, norms, and requirements set forth at the international, national, regional and/or local levels including those designed to meet the objectives of resource management and/or land use plans that may be in effect in and around the

[3] From "EIA Technical Review Guidelines Energy Generation and Transmission" Regional Document prepared under the CAFTA DR Environmental Cooperation Program to Strengthen Environmental Impact Assessment (EIA) Review, 2011

jurisdiction(s) in which a proposed project is to be developed or in which it might have a potential impact.

- Identify any public or stakeholder concerns related to impacts in and around the proposed project and alternatives, at least for stakeholders within the geographic scope of potential impact.
- Describe all relevant plans related to the proposed energy project, including engineering and site preparation plans, operations and decommissioning/closure, environmental management, and mitigation in whatever form these may take.
- Cover all phases of the project, from feasibility studies to site preparation to operations to closure/decommissioning. The analysis should also include plans to expand capacity at the current or adjacent sites.
- Consider alternative approaches to meeting the purpose and need for the proposed energy project, including alternative fuels (including renewable fuels), siting, designing, constructing, operating and closing the project. These alternatives should be considered to avoid and prevent, or (if that is not possible), to reduce or minimize adverse environmental or socioeconomic impacts. Alternatives that also increase or extend potential beneficial impacts can also be considered. The alternatives to the project must include a "no action" alternative, indicating what would happen in the absence of the proposed project.
- Quantify direct, indirect and cumulative impacts and their significance level.
- Highlight uncertainty and how that uncertainty will be addressed through monitoring and contingency plans as may be needed to reduce risk of adverse impacts in the future.
- Establish specific commitments, including who is responsible, what will be done, when and how it will be monitored, reported and audited to confirm that commitments are met.

In order to achieve these aims, environmental impact assessments generally contain the following components:

- General Information
- Project and Alternatives Description
- Environmental Setting
- Assessment of Impacts to resources described in the Environmental Setting
- Mitigation and Monitoring Measures
- Environmental Management Plan

Each of these components is described below in the context of offshore natural gas pipelines, NGL separation and LPG production plants, and thermal power generators.

10.2.1. General Information

This section introduces the energy infrastructure project and the environmental assessment process. It typically includes information about the energy infrastructure project's objectives and why it is important in relation to the current energy landscape; the companies and entities involved in the infrastructure project; the country's relevant legal and regulatory framework, including any permits and authorizations that are required, and, the team the developed the environmental impact assessment itself;

10.2.2. Project and Alternatives Description

This section describes the proposed energy infrastructure project in detail, any alternatives to the proposed approach that were considered, and why the proposed approach is superior to the alternatives. An alternative in which the project is not implemented is generally included among the alternative options in order to highlight the project's beneficial or adverse impacts relative to a baseline "business as usual" case. The following project details that are typically included in the description:

- Project facilities, including
  - Project location and site access
  - Project facilities, with detail on the technologies used and any fuel requirements including fuel delivery, storage, and handling infrastructure
  - Project operations
  - Design and engineering features for each major component of the project
  - Onsight support facilities such as housing, offices, fuel stations, repair shops, sanitary facilities, water supply, waste handling, etc.
- Project access, including
  - New and existing roads details such as traffic volume, construction plans, stream and animal crossings, erosion prevention, dust control, and maintenance.
  - Other transport systems as required, including rail and waterways
- Construction phase and timetable, including
  - Schedule and critical path management
  - Equipment, labor and materials requirements
  - Any temporary structures, water supply, waste handling, or power supply during construction
- Operation phase, including
  - Pre-operation inspections and evaluation
  - Operational information for equipment, machinery, labor and materials that are required

- Closure and decommissioning plan, including
  - Closure process and anticipated timeline
  - Restoration and remedial measures

10.2.3. Environmental Setting

This section describes the environment in the project area and in areas that could be impacted by the project development and operations. It is developed through field studies and data gathering as well as public outreach meetings and other stakeholder engagement. The environmental setting including physical, biological, and socio-economic or cultural conditions present before the project is development. Areas of interest in the physical environment can include:

- Geologic resources and hazards
- Soil resources
- Water resources
- Air and climate
- Noise and vibration
- Aesthetic resources

Biological environmental considerations can include:

- Vegetation/flora
- Aquatic and terrestrial wildlife/fauna, including birdlife
- Terrestrial, wetlands, aquatic, or marine ecosystems
- Specific endangered or threatened species and habitats
- Designated protected areas

Socio-economic and cultural factors can include:

- Socio-economic conditions
- Infrastructure, including transportation, public health, communications, and energy
- Cultural, archeological, Ceremonial, and historic resources, including indigenous people
- Land use, including population centers, agriculture, forest, and tourism.

10.2.4. Assessment of Impacts to resources described in the Environmental Setting

This section brings together the project description and the environmental setting to describe how each component of the infrastructure project may impact each of the identified environmental aspects. The assessment generally includes the expected magnitude, frequency and potential significance of the identified impacts using standardized predictive models and historical data where available. The impact assessment helps to identify and prioritize areas of greatest concern.

10.2.5. Mitigation and Monitoring Measures

This section identifies measures to mitigate any potential adverse impacts that were identified and prioritized in the previous section. Mitigation measures typically emphasize avoiding or preventing the potential adverse impact. If that is not possible, the measures then focus on reducing the impact or offsetting it by improving a similar environmental feature in another location (for example, planting mangroves in another section of the shoreline to replace mangroves that are removed for a natural gas import facility). Mitigation measures can also include compensation to affected individuals or communities if the expected impacts cannot be removed and the project is deemed to be sufficiently beneficial to the country as a whole to justify the impact on a particular region or community.

Monitoring measures are also identified to ensure that the project's actual impacts are in line with the expected impacts described in the environmental assessment. These measures are identified for each stage of the infrastructure project's life and should include specific measureable metrics for each environmental aspect that is identified. The measures often also identify contingency options that can be implemented should the project's environmental performance not remain within the predicted range.

10.2.6. Environmental Management Plan

This section applies the mitigation and monitoring measures that are identified in the previous section and applies them to an Environmental Management Plan. This Plan details the specific actions that will be taken to monitor and address the project's environmental impacts. It is usually divided into two sections: the first detailing specific mitigation actions that will be taken before and during project construction and operations; the second describing the project's ongoing monitoring activities and contingency actions that will be taken in the event the project's environmental performance deteriorates. This Plan is often accompanies by a signed and legally binding commitment statement establishing legal liability for each aspect of the project's environmental impact.

10.3. Potential impacts specific to the project

The proposed offshore natural gas pipeline, LPG processing plant, and power plant each bring potential environmental and social impacts. While the exact impacts must be identified and analyzed through the environmental impact assessment process noted above, the World Bank's IFC has outlined impacts that are comment to offshore oil and gas development, onshore oil and gas development, and thermal power plants. These potential impacts are described in the IFCs Environmental, Health, and Safety Guidelines for each industry segment, and are summarized here.

10.3.1. Air emissions

Air emissions generally come from combustion for power (to operate compressors along the pipeline and within the LPG separation facility and in the thermal power plant) and for process heat (for LPG separation and fractionation); from support and supply vessels, including trucks, ships and helicopters (for offshore operations); and direct emissions from flaring, venting, or fugitive emissions of natural gas throughout its transportation, processing, and use.

Typical emissions from these activities include sulfur oxides, nitrogen oxides, carbon monoxide, and particulates. Carbon dioxide is also produced in great quantity through combustion, and other greenhouse gases such as methane can also be released through fugitive emissions or venting. Other air emissions can include hydrogen sulfide, volatile organic compounds, other hydrocarbons such as benzene, toluene, and xylenes; glycols and polycyclic aromatic hydrocarbons.

Table 10-2 below compares the permissible ambient air quality levels for major air pollutants (including sulfur dioxide, nitrogen dioxide, and particulate matter) from the World Health Organization, the United States, the European Union, and Canada.

Table 10-2: Ambient air quality guidelines and standards (WHO, US, EU, and Canada)

Pollutant	World Health Organization (WHO) Ambient Air Quality Guidelines		United States National Ambient Air Quality Standards				European Commission Air Quality Standards			Canada National Ambient Air Quality Objectives & Guidelines			
			Primary Standards		Secondary Standards								
	Averaging Period	Guideline Value (µg/m^3)	Averaging Period	Level	Averaging Period	Level	Averaging Period	Concentration	Permitted Exceedences Per Year	Averaging Time	Maximum Desirable Level	Maximum Acceptable Level	Maximum Tolerable Level
Sulfur Dioxide (SO_2)	24 hour	125 (interim target 1) 50 (interim target 2) 20 (guideline)	24 hour	0.14 ppm	3 hour	0.5 ppm	1 hour	350 µg/m^3	24	1 hour	172 ppb	334ppb	N/A
	10 minute	500 (guideline)	1 year	0.030 ppm			24 hour	125 µg/m^3	3	24 hour	57 ppb	115 ppb	306 ppb
										1 year	11 ppb	23ppb	N/A
Nitrogen Dioxide (NO2)	1 year	40 (guideline)	1 year	53 ppb (100 µg/m3)	1 year	0.053 ppm (100 µg/m^3)	1 year	200 µg/m^3	N/A	1 year	32 ppb	53ppb	N/A
	1 hour	200 (guideline)	1 hour	100 ppb	N/A	N/A	1 hour	40 µg/m^3	18	24?hour	N/A	106 ppb	160 ppb
										1?hour	N/A	213 ppb	532 ppb
Total Suspended Particulate (TSP)							1 year	N/A	120 µg/m^3	400 µg/m^3			
							24 hour	60 µg/m^3	70 µg/m^3	N/A			
Particulate Matter (PM10)	1 year	70 (interim target 1) 50 (interim target 2) 30 (interim target 3) 20 (guideline)	24 hour	150 µg/m^3	24 hour	150 µg/m^3	24 hour	50 µg/m^3	35				
	24 hour	150 (interim target 1) 100 (interim target 2) 75 (interim target 3) 50 (guideline)					1 year	40 µg/m^3	N/A				
Particulate Matter (PM2.5)	1?year	35 (interime target 1) 25 (interim target 2) 15 (interim target 3) 10 (guideline)	1?year	15.0 µg/m^3	1?year	15.0 µg/m^3	1?year	25 µg/m^3	N/A				
	24?hour	75 (interim target 1) 50 (interim target 2) 37.5 (interim target 3) 25 (guideline)	24?hour	35 µg/m^3	24?hour	35 µg/m^3							
Ozone	8hour	160 (interim target 1) 100 (guideline)	1 hour**	0.12 ppm (235 µg/m^3)	1 hour**	0.12 ppm (235 µg/m^3)	8 hour	120 µg/m^3	25 days averaged over 3 years	1 year	N/A	15 ppb	N/A
			8 hour	0.075 ppm	8 hour	0.075 ppm				24 hour	15 ppb	25ppb	N/A
										1 hour	51 ppb	82ppb	153 ppb
Lead (Pb)	N/A	N/A	3 month	0.15 µg/m^3	3 month	0.15 µg/m^3	1 year	0.5 µg/m^3	N/A				
Carbon Monoxide (CO)	N/A	N/A	1 hour	35 ppm (40 mg/m^3)			8 hour	10 mg/m^3	N/A	1 hour	13 ppm	31 ppm	N/A
			8 hour	9 ppm (10 mg/m^3)						8 hour	5 ppm	13 ppm	17 ppm
Benzene							1 year	5 µg/m^3	N/A				
Arsenic (As)							1 year	6 ng/m^3	N/A				
Cadmium (Cd)							1 year	5 ng/m^3	N/A				
Nickel (Ni)							1 year	20 ng/m^3	N/A				
Polycyclic Aromatic Hydrocarbons							1?year	1 ng/m^3 (expressed as a concentration of Benzo(a)pyrene)	N/A				

* Target value enters into force 1.1.2012

** The 1 hour U.S. Ozone standard was revoked beginning on June 15, 2005, and is being replaced by the 8 hour standard.

Source: USAID EIA Technical Review Guidelines, Energy Generation and Transmission

10.3.2. Wastewater and effluent discharges

Wastewater is generally associated with oil and gas production at the wellhead, but hydrostatic testing of equipment and pipelines can also create wastewater as chemical additives may be added to prevent corrosion and identify leaks. For power generation, steam turbines have the greatest impact on water resources, but other technologies can also use water for cooling. Other waste waters include sewage from facility offices, drainage and storm waters from the operations sites, potential tank bottom waters from any storage tanks with roof leaks, firewater from testing fire prevention equipment, and wash waters from ongoing machinery maintenance.

10.3.3. Terrestrial impacts and project footprint

The project footprint includes the land occupied by the project itself as well as roadways and other access, rights of way for pipelines and transmission lines, communication facilities (such as antennas) and temporary land use during construction or decommissioning. Terrestrial impacts can include habitat loss and the creation of barriers for migrating wildlife; loss of, or changes to, natural water drainage; soil erosion; disturbance of water bodies, including sedimentation; establishment of non-native invasive species; and visual disturbances.

10.3.4. Noise

Building and decommissioning the project components will generate noise. In addition, normal operation of the power plant reciprocating engines and the pipeline and NGL separation and LPG production plant compressors generates substantial noise levels. Traffic associated with the projects, including personal vehicles, trucks, marine vessels, and helicopters also create noise.

10.3.5. Spills

Spills can occur from pipeline, storage and equipment leaks; equipment failure; as well as accidents and human error. Natural gas and LPG facilities pose reduced risk of spills (although an increased risk of air emissions in the event of a similar leak or failure. However, the power plant is planned to be dual fuel to enable it to continue operating when natural gas is not available (for example, during scheduled maintenance of the FPSO). This will require the power plant to have HFO receiving, handling, and storage, any of which could be subject to a spill.

10.3.6. Social impacts

Each of the project components can also create adverse social impacts, including potential risks to occupational health and safety and community health and safety. Occupational health and safety issues include air quality in the working environment, noise levels, and fire and accident prevention. Community health and safety concerns include impacts on nearby industries and economic activity (fishing, shipping, agriculture); physical hazards from spills, explosions or fires; and traffic safety from increased volume of heavy truck traffic, including trucks carrying LPG or other potentially hazardous materials.

11. Appendix A: References

AIS Environment Limited. (2017). *Malta-Italy Gas Pipeline Interconnection - Phase 1: Project Description Statement*. Fgura, Malta: AIS Environment Limited.

American Chemistry Council, Economics & Statistics Department. (2017). *The Potential Economic Benefits of an Appalachian Petrochemical Industry*. Washington, D.C.: American Chemistry Council. Retrieved from https://www.americanchemistry.com/Appalachian-Petrochem-Study/

ARPEL (Regional Association of Oil and Natural Gas companies in Latin America and the Caribean). (2010). *Guidelines for an Environmental Impact Assessment (EIA) Process*. Montevideo, Uruguay: ARPEL. Retrieved from https://arpel.org/media/apps/library/63/files/GUIDELINE%2010.pdf

Bar-Eli. A. (2017). Flow of Natural Gas, Used to Generate Half of Israel's Electrical Power, Halted Following Pipeline Fault. *Haaretz*. Retrieved from https://www.haaretz.com/israel-news/business/israel-s-supply-of-natural-gas-halted-after-pipeline-crack-discovered-1.5453093

Bayar, T. (2017). PetroVietnam and ExxonMobil to Develop Vietnamese Gas Project. *Power Engineering International (PEi)*. Retrieved from https://www.powerengineeringint.com/articles/2017/01/petrovietnam-and-exxonmobil-to-develop-vietnamese-gas-project.html

Brugman SAS. (2018). *Government of the Cooperative Republic of Guyana: Update of the Study on System Expansion of the Generation System Final Draft Report – Confidential*. Bogota, Colombia: Brugman SAS.

Bullin, K. (2000). *Optimization of Natural Gas Processing Plants Including Business Aspects*. Bryan, Texas: Bryan Research and Engineering, Inc.

Eni. (2017). Eni Starts Production from the OCTP Integrated Oil & Gas Development Project, in Ghana's Offshore, Ahead of Schedule and with a Record Time-to-Market. Retrieved from https://www.eni.com/en_IT/media/2017/05/eni-starts-production-from-the-octp-integrated-oilgas-development-project-in-ghanas-offshore-ahead-of-schedule-and-with-a-record-time-to-market

Environmental Resources Management (ERM). (2016). *Environmental Impact Assessment Report for a Gas-Fired Independent Power Plant to Support Saldanha Steel and Other Industries in Saldanha Bay*. Cape Town, South Africa: Environmental Resources Management. Retrieved from https://www.erm.com/contentassets/e0a5be1d1528420596a08ad35381ada6/deir/draft-eia-report-for-ccgt-independent-power-plant-to-support-saldanha-steel-and-other-industries-in-saldanha-bay_22-july-2016.pdf

Environmental Resources Management (ERM). (2016). *Leviathan Project: Supplemental Lender Information Package – Overarching Environmental and Social Assessment Document*. Washington, D.C.: Environmental Resources Management. Retrieved from https://www3.opic.gov/Environment/EIA/nobleenergy/Supplementary_Lender_Package.pdf

ERM Iberia S.A. (2004). *MEDGAZ Natural Gas Transportation System: Environmental Impact Assessment*. Barcelona, Spain: ERM Iberia. Retrieved from https://www.medgaz.com/medgaz/doc/EIA_internacional.pdf

Federal Energy Regulatory Commission (FERC). (2016). *Final Environmental Impact Statement Volume I: NEXUS Gas Transmission Project and Texas Eastern Appalachian Lease Project*. Washington, D.C.: FERC. Retrieved from https://www.ferc.gov/industries/gas/enviro/eis/2016/07-08-16-eis/volume-I.pdf

Federal Energy Regulatory Commission (FERC). (2017). *Guidance Manual for Environmental Report Preparation: For Applications Filed Under the Natural Gas Act*. Washington, D.C.: FERC. Retrieved from https://www.ferc.gov/industries/gas/enviro/guidelines/guidance-manual-volume-1.pdf

Ford. N. (2017). Ghana: Sankofa Gas Project Secures $300M Funding. *African Business*. Retrieved from https://africanbusinessmagazine.com/sectors/energy/ghana-sankofa-gas-project-secures-300m-funding/

Government of Guyana Site Selection Team. (2018). *Final Report: Identification of Suitable Site(s) for the Installation of a 200 MW Dual Fuel (Natural Gas and Heavy Fuel Oil) Generation Plant Along with Associated Substation, Liquid Fuel Storage and Related Facilities*. Georgetown, Guyana: Government of Guyana.

Government of Guyana Site Selection Team. (2018). *Preliminary REPORT: Site Development Progress*. Georgetown, Guyana: Government of Guyana.

Guyana-ExxonMobil. (2018). Guyana. Retrieved from https://corporate.exxonmobil.com/en/company/worldwide-operations/locations/guyana#About

Guyana-ExxonMobil. (2018). Guyana Project Overview. Retrieved from https://corporate.exxonmobil.com/en/company/worldwide-operations/locations/guyana/about-us/project-overview

Hartree Partners LP. (2017). *Guyana Refinery Study: Presentation to the Ministry of Natural Resources of Guyana*. New York, New York.

HDR Engineering, Inc. (2015). *Environmental Assessment and Routing Study for the 138 kV Zenith-Franz Project Harris County, Texas*. Houston, Texas. Retrieved from https://www.centerpointenergy.com/en-us/Corp/Documents/Zenith-Franz%20Transmission%20Project/Att%201_Envir%20Assess.pdf

Herdiyanti, J. (2013). *Comparisons Study of S-Lay and J-Lay Methods for Pipeline Installation in Ultra Deep Water* (Master's Thesis). Retrieved from https://brage.bibsys.no/xmlui/bitstream/handle/11250/183162/Herdiyanti%2C%20Jihan.pdf?sequence=1

ICF International. (2016). *North American Midstream Infrastructure Through 2035: Leaning into the Headwinds*. Fairfax, Virginia: The Interstate Natural Gas Association of America (INGAA). Retrieved from http://www.ingaa.org/File.aspx?id=27961&v=db4fb0ca

ICF International. (2018). *North American Midstream Infrastructure Through 2035: Significant Development Continues*. Fairfax, Virginia: The Interstate Natural Gas Association of America (INGAA). Retrieved from http://www.ingaa.org/File.aspx?id=34658

International Association for Impact Assessment (IAIA). (2015). *Social Impact Assessment: Guidance for Assessing and Managing the Social Impacts of Projects*. Fargo, North Dakota: IAIA. Retrieved from https://www.iaia.org/uploads/pdf/SIA_Guidance_Document_IAIA.pdf

International Energy Agency (IEA) - Organization for Economic Co-Operation and Development. (2018). *World Energy Outlook*. Paris, France: IEA.

International Finance Corporation (IFC) - World Bank Group. (2007). *Environmental, Health and Safety Guidelines for Natural Gas Distribution*. Washington, D.C.: World Bank Group. Retrieved from http://www.ifc.org/ehsguidelines

International Finance Corporation - World Bank Group. (2015). *Environmental, Health and Safety Guidelines for Offshore Oil and Gas Development*. Washington, D.C.: World Bank Group. Retrieved from http://www.ifc.org/ehsguidelines

International Finance Corporation - World Bank Group. (2008). *Environmental, Health and Safety Guidelines for Thermal Power Plants*. Washington, D.C.: World Bank Group. Retrieved from http://www.ifc.org/ehsguidelines

International Finance Corporation - World Bank Group. (2017). *Environmental, Health and Safety Guidelines for Thermal Power Plants; DRAFT for Second Public Consultation*. Washington, D.C.: World Bank Group. Retrieved from https://www.ifc.org/wps/wcm/connect/topics_ext_content/ifc_external_corporate_site/sustainability-at-ifc/policies-standards/ehs-guidelines/thermalpower_phase2_secondconsultation

International Finance Corporation - World Bank Group. (2012). *Guidance Note 1: Assessment and Management of Environmental and Social Risks and Impacts*. Washington, D.C.: World Bank Group. Retrieved from https://www.ifc.org/wps/wcm/connect/b29a4600498009cfa7fcf7336b93d75f/Updated_GN1-2012.pdf?MOD=AJPERES

International Finance Corporation - World Bank Group. (2012). *Performance Standards on Environmental and Social Sustainability*. Washington, D.C.: World Bank Group. Retrieved from https://www.ifc.org/wps/wcm/connect/c8f524004a73daeca09afdf998895a12/IFC_Performance_Standards.pdf?MOD=AJPEREShttps://www.ifc.org/wps/wcm/connect/b29a4600498009cfa7fcf7336b93d75f/Updated_GN1-2012.pdf?MOD=AJPERES

International Petroleum Industry Environmental Conservation Association (IPIECA). (2013). *Integrating Human Rights into Environmental, Social and Health Impact Assessments: A Practical Guide for the Oil and Gas Industry*. London, United Kingdom: IPIECA. Retrieved from https://www.humanrights.dk/files/media/dokumenter/tools/integrating_hr_into_eshia.pdf

Jechura, J. (2018). *Overview: Gas & NGL Processingn* (PowerPoint slides). Colorado School of Mines.

Keller, A. (2012). *NGL 101 – The Basics* [PowerPoint slides]. Retrieved from https://www.eia.gov/conference/ngl_virtual/eia-ngl_workshop-anne-keller.pdf

Khabibullin, E., Febrianti, F., Sheng, J., Banbyopadhyay, S. (2010). *Process Design and Economic Investigation of LPG Production from Natural Gas Liquids (NGL)* (Project). Retrieved from folk.ntnu.no/skoge/diplom/prosjekt10/LPG-project/.../LPG_Plant_Report.doc

Kidnay, A., & Parrish, W. (2006). *Fundamental of Natural Gas Processing.* Boca Raton, Florida: Taylor and Francis Group, LLC.

KLM Technology Group. (2013). *LPG Unit: Engineering Design Guideline.* Johor Bahru, Malaysia: KLM Technology Group. Retrieved from http://kolmetz.com/pdf/EDG/ENGINEERING%20DESIGN%20GUIDELINE-LPG%20Rev%2001%20web.pdf

Langelandsvik, L., Postvoll, W., Aarhus, B., & Kaste, K. (2009). *Accurate Calculation of Pipeline Transport Capacity.*

Ministry of Energy and Water Management. (2018). *Malta-Italy Gas Pipeline Interconnection Non-Technical Summary.* Ħal, Luqa, Malta: The Energy & Water Agency. Retrieved from https://www.energywateragency.gov.mt/wp-content/uploads/2018/03/Non-tech-summary-v12-English-final.pdf

Ministry of Legal Affairs of Guyana. (2012). *Laws of Guyana: Corporation Tax Act - Chapter 81:03.* Georgetown, Guyana: Ministry of Legal Affairs: Guyana.

Ministry of Legal Affairs of Guyana. (1008). *Laws of Guyana: Petroleum (Exploration and Production) – Chapter 65:10.* Georgetown, Guyana: Ministry of Legal Affairs: Guyana.

Ministry of Natural Resources of Guyana. (2016). *Petroleum Agreement Between: The Government of the Cooperative Republic of Guyana and Esso Exploration and Production Guyana Limited, CNOOC Nexen Petroleum Guyana, Hess Guyana Exploration Limited.* Georgetown, Guyana.

Offshore Energy Today. (2018). Total Enters Prolific Guyana Basin. Buys Two Offshore Blocks. Retrieved from https://www.offshoreenergytoday.com/total-enters-prolific-guyana-basin-buys-two-offshore-blocks/

Offshore Technology. (Date Not Known). Banda Gas Field Development. Retrieved from https://www.offshore-technology.com/projects/banda-gas-field-development/

Offshore Technology. (Date Not Known). Malampaya Gas Field Project, South China Sea. Retrieved from https://www.offshore-technology.com/projects/malampaya/

Offshore Technology. (Date Not Known). Sankofa Gas Project, Tano Basin. Retrieved from https://www.offshore-technology.com/projects/sankofa-gas-project-tano-basin/

Offshore Technology. (Date Not Known). Tamar Natural Gas Field. Retrieved from https://www.offshore-technology.com/projects/tamar-field/

Oil & Gas Journal. (2018). Nobel Energy Begins Tamar Sell-Down. Retrieved from https://www.ogj.com/articles/2018/01/noble-energy-begins-tamar-sell-down.html

Oil & Gas Journal. (2015). Williams, DCP Start Gas Flow from Keathley Canyon Connector. Retrieved from https://www.ogj.com/articles/2015/02/williams-dcp-start-gas-flow-from-keathley-canyon-connector.html

Oil Now. (2018). Who's Who in the Oil and Gas Sector in Guyana. Retrieved from http://oilnow.gy/profiles/companies/whos-who-in-the-oil-and-gas-sector-in-guyana/

Oueidat, D., Guarnieri, F., Garbolino, E., Rigaud, E. (2015). Evaluating the Safety Operations Procedures of an LPG Storage and Distribution Plant with STAMP. Pr*ocedia Engineering 128 (2015) 83-92. https://doi.org/10.1016/j.proeng.2015.11.507*

Parliament of Guyana. (1999). *Laws of Guyana: ACT No. 11 of 1999 Electricity Sector Reform Act 1999*. Georgetown, Guyana: Guyana Government Printing Office.

Parliament of Guyana. (2010). *Laws of Guyana: ACT No. 17 of 2010 Electricity Sector Reform (Amendment) Act 2010*. Georgetown, Guyana: Guyana Government Printing Office.

Parliament of Guyana. (1997). *Laws of Guyana: ACT No. 31 of 1997 Guyana Energy Agency Act 1997*. Georgetown, Guyana: Guyana Government Printing Office.

Prime Minister of Guyana. (2010). *Amendment to the Licence to Supply Electricity for Public Purposes Granted to Guyana Power & Light Inc. Under Sections 4 and 42 (3) (c) of the Electricity Sector Reform Act 1999 (No. 11 of 1999).* Georgetown, Guyana. Guyana Government Printing Office.

Pulsinelli, O. (2018). Nobel Energy Inks Multibillion-Dollar Deal to Export Natural Gas from Israel to Egypt. *Houston Business Journal*. Retrieved from https://www.bizjournals.com/houston/news/2018/02/21/noble-energy-inks-multibillion-dollar-deal-to.html

Shell. (Dante Not Known). Malampaya Phases 2 & 3. Retrieved from https://www.shell.com/about-us/major-projects/malampaya-phases-two-and-three.html

Smith, C. (2016). Near-Term Pipeline Construction Strong. *Oil & Gas Journal*. Retrieved from https://www.ogj.com/articles/print/volume-114/issue-2/transportation/near-term-pipeline-construction-strong.html

Smith, C. (2018). Subsea Pipeline Projects Advance in 2018. *Oil & Gas Journal*. Retrieved from https://www.ogj.com/articles/print/volume-116/issue-4/special-report-offshore-operations/subsea-pipeline-projects-advance-in-2018.html

Strata Policy. (2017). *The Footprint of Energy: Land Use of U.S. Electricity Production*. Logan, Utah: Strata Policy. Retrieved from https://www.strata.org/footprints/

Super Gas. (2015). *Prefeasibility Report for Proposed LPG Bottling Plant Capacity - 21000 MTA*. SHV Energy Private Limited: Atkiabd Industrial Area.

Szczetnikowicz, S. (2018). Financing Options in the Oil and Gas Industry. *Milbank, Tweed, Hadley & McCloy LLP*. Retrieved from https://www.milbank.com/images/content/9/7/v2/97930/Financing-options-in-the-oil-and-gas-industry.pdf

U.S. Energy Information Administration. (May 2018). *EIA - Natural Gas Pipeline Projects*. Washington, D.C.: U.S. Energy Information Administration. Retrieved from https://www.google.com/search?q=EIA+-+Natural+Gas+Pipeline+Projects&rlz=1C1KMZB_enUS511US518&oq=EIA+-+Natural+Gas+Pipeline+Projects&aqs=chrome..69i57j0j69i64.1348j0j4&sourceid=chrome&ie=UTF-8

U.S. Environmental Protection Agency (EPA). (2011). *EIA Technical Review Guidelines: Energy Generation and Transmission - Volume I*. Washington, D.C.: EPA. Retrieved from https://www.epa.gov/international-cooperation/eia-technical-review-guidelines-energy-sector

U.S. Environmental Protection Agency (EPA). (2011). *EIA Technical Review Guidelines: Energy Generation and Transmission - Volume I Part 2 Example EIA Terms of Reference*. Washington, D.C.: EPA. Retrieved from https://www.epa.gov/international-cooperation/eia-technical-review-guidelines-energy-sector

U.S. Environmental Protection Agency (EPA). (2011). *EIA Technical Review Guidelines: Energy Generation and Transmission - Volume II Appendices*. Washington, D.C.: EPA. Retrieved from https://www.epa.gov/international-cooperation/eia-technical-review-guidelines-energy-sector

Upstream. (Date Not Known). Ca Voi Xanh Vietnam Gas Development is "Approaching FEED" Stage. Retrieved from http://www.upstreamonline.com/hardcopy/1452435/ca-voi-xanh-vietnam-gas-development-is-approaching-feed-stage

Vanclay, F., Esteves, A.M., Aucamp, I. & Franks, D. (2015). *Social Impact Assessment: Guidance for Assessing and Managing the Social Impacts of Projects*. Fargo, North Dakota: International Association for Impact Assessment (IAIA). Retrieved from https://www.iaia.org/uploads/pdf/SIA_Guidance_Document_IAIA.pdf

Vitol. (2017). Production Commences on the OCTP Sankofa Oil and Gas Project in Ghana. Retrieved from https://www.vitol.com/press-release-production-commences-octp-sankofa-oil-gas-project-ghana/

World Bank. (2014). Banda Gas to Power Guarantee. Retrieved from http://projects.worldbank.org/P145664?lang=en

World Bank. (2015). What is the Sankofa Gas Project? Retrieved from http://www.worldbank.org/en/country/ghana/brief/what-is-the-sankofa-gas-project

World LPG Association (WLPGA). (Date Not Known). Applications. Retrieved from https://www.wlpga.org/about-lpg/applications/

12. Appendix B: Offshore pipeline capital cost analysis

The capital cost of building and installing the pipeline is a major contributor to the cost of delivering natural gas from the offshore production platform to Guyana. ExxonMobil has provided an initial rough estimate of the pipeline capital cost, including modifications that would be required to the FPSO, the cost of the pipeline materials, the cost to install the pipeline, and related onshore facilities in July, 2017. In March, 2018, ExxonMobil provided and updated estimate as part of the site selection analysis. This updated analysis incorporates the company's increased knowledge of the potential pipeline route, but still includes a large contingency factor as a detailed FEED study and specific route selection have not yet been completed. Table B-1 shows the breakdown of these estimated costs for a 12" pipeline as reported by ExxonMobil in July 2017 and March 2018.

Table B-1: ExxonMobil estimated capital cost to install a 180 km, 12-inch pipeline offshore Guyana, July 2017 and March 2018 (US$ million)

Cost component	July 2017 Estimate	March 2018 Base Estimate	March 2018 Estimate with Contingency	March 2018 Estimate including withholding tax
FPSO additions	$36	$12	$17	$18
Riser	$56	$38	$54	$58
Pipeline materials	$143	$93	$133	$144
Pipeline installation	$256	$166	$237	$257
Onshore facilities	$35			
Total Upstream cost	**$92**	**$49**	**$71**	**$77**
Total Pipeline cost	**$399**	**$259**	**$370**	**$401**
Total Upstream and Pipeline cost	**$526**	**$308**	**$441**	**$478**

Source: ExxonMobil

The most recent ExxonMobil cost estimate including contingency and withholding taxes is roughly 10% lower than the original cost estimate, mainly owing to reduced upstream cost estimates. This is not surprising as the preparations for the FPSO are moving forward rapidly in preparation for first oil production in 2020, while the pipeline development is still in very early stages.

This analysis validates the estimated costs from ExxonMobil using three different comparison methodologies: reported costs from a sample of comparable projects, industry reported average pipeline costs, and an estimated built up from materials and services costs. Each of these methodologies are inexact given this project's unique circumstances, but can provide valuable context to the initial cost estimates provided by ExxonMobil.

Comparable subsea natural gas pipeline projects

Under this methodology, the reported capital cost of other undersea pipelines is used as a proxy for the projects potential capital cost. Table B-2 below shows the total capital cost and the unit capital cost per km and per inch-km for 14 undersea natural gas pipelines.

Table B-2: Example offshore natural gas pipeline projects

Name	Date Completed	Location	Water depth (meters)	Undersea Length (km)	# of Pipes	Pipe Diameter (inches)	Pipe wall 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)
Equinor Johan Sverdrup	Late 2019	North Sea	120	156	1	18			104	104	0.67	37,209
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	0.8	2,922	1,500	750	4.84	241,935
Malta-Italy	2024	Mediterranean Sea	155	159	1	22		200	386	386	2.43	110,463
Blue Stream	2002	Black Sea	2,100	396	1	24	1.3	1,548	1,700	1,700	4.29	178,872
Medgaz	2010	Mediterranean Sea		210	1	24	1.1	774	882	882	4.20	175,000
TurkStream (2 pipes)	2019	Black Sea	2,200	930	2	32		3,048	8,600	4,300	4.62	144,489
South Stream (3 pipes)	Not built	Black Sea	2,100	925	3	32	1.5	6,095	13,000	4,333	4.68	146,396
Polarled	2015	Norwegian Sea	1,260	482	1	36		2,472	1,946	1,946	4.04	112,122
Trans Adriatic Pipeline (TAP)	2020	Mediterranean Sea	820	115	1	36		968	708	708	6.16	171,131
Sur de Tejas-Tuxpan	Late 2018	Gulf of Mexico	100	795	1	42		2,600	3,100	3,100	3.90	92,819
Nord Stream (2 pipes)	2012	Baltic Sea	200	1,224	2	48	1.3	5,321	11,440	5,720	4.67	97,358
Nord Stream 2 (2 pipes)	2019	Baltic Sea	200	1,224	2	48	1.3	5,321	10,500	5,250	4.29	89,359
Average			**1,007**	**491**	**1.4**	**29.5**	**1.3**	**2,395**	**3,664**	**2,044**	**3.85**	**132,917**

Source: Energy Narrative based on data from Oil & Gas Journal; Nord Stream; Equinor; 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$3.7 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 per 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$133,000. This is 14% below the US$154,500 per km-in reported in the 2017 Desk Study owing to the addition of projects with lower than average costs, including the Polarled pipeline completed in 2015, the Sur de Tejas-Tuxpan pipeline expected to come on line in late 2018, Equinor's Johan Sverdrup pipeline expected to be completed in late 2019, and the proposed Malta-Italy pipeline that is slated to enter service in 2024.

It is important to note that all projects listed above (with the exception of the Keathley Canyon Connector project and the Sur de Tejas-Tuxpan pipeline) are located in Europe, which may affect the average cost per project relative to other regions of the world. In addition, all projects are located in well-established oil and gas production areas (Gulf of Mexico and North Sea) or areas with substantial supporting infrastructure (Mediterranean and Black Sea). As the Guyana development will be the first pipeline built in a country with no established oil and gas industry, unit project costs will likely be higher.

This methodology therefore estimates the project cost at US$133,000 per km-inch. For the proposed 180 km, 12-inch pipeline linking the offshore production to the Woodland landing site, the estimated cost using this methodology is US$287 million, not including any project contingencies or additions to reflect the frontier nature of the Guyana project.

Industry reported average natural gas pipeline costs

As noted in the 2017 Desk Study, 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 figure was slightly lower than the nation-wide average natural gas pipeline cost of US$98,137 per kilometer-inch. The study also noted that natural gas pipeline costs showed significant regional variations across the United States, reflecting cost differences for labor and land as well as differences in the permitting process and regulatory requirements for natural gas pipelines. Regional cost variations in 2015 ranged from 61% above the national average in the Northeast region to 21% below the national average in the Southwest region.

A 2018 update to the INGAA study reported pipeline construction costs that were significantly higher than the 2015 data reported in the previous 2016 study. These cost increases were driven in part by higher investment in pipelines and greater overall utilization of midstream oil and gas construction capacity supported by higher oil prices in 2016 and 2017. The latest average US natural gas pipeline cost estimate was US$142,729 per kilometer-inch. As in the previous study, there were significant regional differences in the new estimated costs. The Northeast region was the highest cost at 187% above the national average while the Central/Mountain region was the lowest at 40% below the national average. The updated report did not separate offshore costs from other regional costs. For this analysis we assumed that offshore costs remained in line with the reported national average, or US$142,730 per kilometer-inch.

This methodology therefore estimates the project cost at US$142,700 per km-inch. For the proposed 180 km, 12-inch pipeline linking the offshore production to the Woodland landing site, the estimated cost using this methodology is US$308 million, not including any project contingencies or additions to reflect the frontier nature of the Guyana project.

Estimated cost based on materials and services

The capital cost to build the pipeline can also be estimated as a sum of the cost of the materials and processes required to build it. The primary cost components for natural gas pipelines is high grade steel (typically API 5L standard), coatings to smooth the inner surface and related corrosion protection, and costs related to pipeline installation.

In May, 2017 ICF provided a detailed analysis of average U.S. oil and gas pipeline installation costs in a report for INGAA and other industry associations titled "Feasibility and Impacts of Domestic Content Requirements for U.S. Oil and Gas Pipelines." This analysis estimated average pipeline costs to be US$1,578 per metric tonne for the raw steel and US$3,485 per metric tonne including coatings, corrosion protection, and ancillary production costs (adjusted to 2017 dollars).

The cost of the offshore pipeline materials was estimated by using these industry average costs and the calculated volume of steel required for the pipeline. The volume of steel required per meter of pipeline length was calculated from the cross sectional area of a standard 12" nominal pipe size (NPS) with 1" thick walls and standard weight of carbon steel in kg per cubic meter. The resulting material cost per meter was then multiplied by the pipeline's 180 km length, resulting in a total material cost of US$117 million.

The day rates for the specialized ships used for J-lay and S-lay pipeline installation are negotiated at the time that the ships are contracted, and vary according to market conditions. The reported day rate for the Keathley Canyon project's 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 Keathley Canyon project of $600 million, or US$1.74 million per km.

For the Guyana project, ExxonMobil estimated that roughly 40 km of the pipeline route would require J-lay (deep water), 70 km of the route would require S-lay (intermediate water depth), and the remaining 70 km would be suitable for barge laying (shallow water). Table B-3 below shows the distance, speed, and required time for each of these pipeline laying options.

Table B-3: Pipeline laying systems for the Guyana offshore natural gas pipeline

Offshore pipe laying system	Distance Employed (km)	Laying Speed (km per day)	Laying Time (days)
J-Lay	40	1.5	26.7
S-Lay	70	2.6	26.9
Barge	70	2.0	35.0
Total	**180**	**2.0**	**88.6**

Source: ExxonMobil, Energy Narrative calculations

Using the three laying methods in sequence results in a total construction period of roughly 3 months to install the offshore pipeline at an average rate of 2 km per day, in line with reported industry averages as noted above.

The combined cost to lay the pipeline using these three methods was estimated to be 1.5 times the pipe material cost, following the estimation methodology used in the 2017 Desk Study. This estimate uses changes in the cost of materials as a rough proxy for changes in the day rate for pipe laying ships as both are affected by changes in industry activity and the relative supply and demand for materials and services supporting major oil and gas projects.

Table B-4 below applies this cost per metric tonne estimate to the calculated volume of steel required to build the proposed 12" pipeline.

Table B-4: Materials and services costs to manufacture and install a 180 km, 12-inch pipeline

Cost component	Value	Unit
INGAA 2017 Pipe cost (steel + coating)	$3.49	US$ per kg
Steel required (12" NPS pipe, 1" walls)	186.9	kg per meter
Materials unit cost	$651	US$ per meter
Total pipeline material costs	**$117**	**US$ million**
Installation unit cost (1.5x materials)	$977	US$ per meter
Total pipeline installation cost	**$176**	**US$ million**
Total Pipeline cost	**$293**	**US$ million**

Source: INGAA, Energy Narrative estimates and calculations

This methodology therefore estimates the project cost at US$135,700 per km-inch. For the proposed 180 km, 12-inch pipeline linking the offshore production to the Woodland landing site, the estimated cost using this methodology is US$293 million, not including any project contingencies or additions to reflect the frontier nature of the Guyana project.

Estimated capital cost for the economic feasibility analysis

Table B-5 compares the estimated capital cost provided by ExxonMobil with the estimated capital cost using each of the methodologies described above.

Table B-5: Estimated capital cost to install a 180 km, 12-inch pipeline offshore Guyana

Cost estimation basis	Unit Cost (US$ per km-in)	Total Cost (US$ million)
Comparable Projects	$133,000	$287
Indusry Average	$142,700	$308
Materials cost	$135,700	$293
Average Estimate	**$137,133**	**$296**
ExxonMobil Estimate	$184,700	$399

Source: ExxonMobil, Energy Narrative estimates and calculations

The average capital cost across the three estimation methodologies is roughly 26% below ExxonMobil's estimated $399 million. 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. For example, although the comparable projects and industry average actual costs should capture the likely contingency costs, they are aggregated from the United States and Europe, with well-established upstream industries and readily available input materials and skilled labor. The materials cost methodology does not include a contingency, and so is lower.

It is therefore reasonable to add a 20% contingency factor to the cost estimates in order to account for these different factors in Guyana. Table B-6 compares the resulting capital cost estimates with the 20% contingency added.

Table B-6: Estimated capital cost to install a 180 km, 12-inch pipeline offshore Guyana with a 20% contingency added

Cost estimation basis	Unit Cost (US$ per km-in)	Total Cost (US$ million)
Comparable Projects	$159,600	$344
Indusry Average	$171,240	$370
Materials cost	$162,840	$352
Average Estimate	**$164,560**	**$355**
ExxonMobil Estimate	$184,700	$399

Source: ExxonMobil, Energy Narrative estimates and calculations

The estimated costs are still below the estimate provided by ExxonMobil, but are now much closer. Based on this analysis, we used a capital cost of US$355 million for the offshore natural gas pipeline. This amount was added to the US$92 million required to produce the natural gas for export from the FPSO as reported by ExxonMobil. The total capital cost to deliver the natural gas to shore is therefore US$447 million. This capital cost is the figure used to calculate the economic feasibility of the pipeline project.

1. Appendix C: Offshore Natural Gas Pipeline Economic and Financial Feasibility Sensitivity Analysis

The tables in this section show how the offshore natural gas pipeline's annual economic and financial costs and benefits were calculated under each sensitivity case. This Appendix can be found in Final Report Volume II: Detailed Results Tables.

2. Appendix D: NGL separation and LPG production plant Economic and Financial Feasibility Sensitivity Analysis

The tables in this section show how the NGL separation and LPG production plant's annual economic and financial costs and benefits were calculated under each sensitivity case. This Appendix can be found in Final Report Volume II: Detailed Results Tables.

3. Appendix E: Power Plant Economic and Financial Feasibility Sensitivity Analysis

The tables in this section show how the power plant's annual economic and financial costs and benefits were calculated under each sensitivity case. This Appendix can be found in Final Report Volume II: Detailed Results Tables.

4. Appendix F: Total Project Economic and Financial Feasibility Sensitivity Analysis

The tables in this section summarize the total project's annual economic and financial costs and benefits under each sensitivity case. This Appendix can be found in Final Report Volume II: Detailed Results Tables.