GUYANA POWER & LIGHT INC.

DEVELOPMENT AND EXPANSION PROGRAMME

2021 – 2025

Updated on March 17, 2021

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1.2 Introduction

The Guyana Power and Light (GPL) has a critical role to play in the development of the country's economy and by extension, the livelihood of the nation. International recognition of Guyana as an emerging oil-producer has placed the country on the radar of the international community (countries and companies) desirous of seeking related commercial opportunities.

The Development and Expansion Programme is a 5-year expansion plan to satisfy the anticipated growth in the demand for electric services and also to support the demand from increased economic activities and opportunities stemming from the emerging Oil and Gas Industry. It supports Government short to long-term vision, which is guided by the Low Carbon Development Strategy (LCDS), National Energy Priorities and other Government initiatives, which informs the detailed plans to ensure adequate generation, transmission, and distribution of electricity consistent with the demand forecasts. The Programme includes targets such as reducing tariff, supporting global climate change commitment, implementing demand side management and operational efficiency strategies.

The present customer-centric programme is intended to guide the Company's efforts to deliver reliable and affordable electric services, inclusive of the development of a Smart Grid and further sustained reductions in system losses.

In view of the above, GPL has defined the following planning targets, which guided the development of this expansion programme:

- Generation: Loss of Load Probability (LOLP) less than 0.27% per annum, or Loss of Load Expectation (LOLE) less than 1 day per year;
- Transmission: N-1 compliant on transmission circuits and substation equipment; and
- Distribution: reduce length of circuits and thermal loading by 50%.

The programme considers all areas of the Company's operations and is intended to present the strategies and projected capital investments required to successfully position the Company to support the projected rate of economic and other forms of national developments.

1.3 Current Status of GPL's Electric Power Systems

1.3.1 Demerara Berbice Interconnected System's Generation

GPL's new GOE II 46.5 MW power plant at GOE, expected to be in commercial operation by Q2 2021 will mean GPL's aggregated electric power system will have 15 power plants totalling 222.9 MW of available capacity. The aggregated available capacity includes the 11 power plants or generating sites in the DBIS and the total of 4 in the Essequibo Islands and Bartica.

A breakdown by fuel type indicates that HFO generator units account for 85% and LFO 15% of the total available capacity in the DBIS. For the Isolated Systems, 25% capacity is HFO and 75%, LFO. See Table 1 for further details.

Table 1: Breakdown of available generation capacity by fuel type

Fuel Type	Demerara	Berbice	Total DBIS	Anna Regina	Wakenaam	Leguan	Bartica	Total Isolated	Total GPL
MWs of HFO	155.9	18.2	174.1	4.8	-	-	-	4.8	178.9
MWs of LFO	10.8	19.2	30	7.2	1.1	0.8	5.0	14.0	44
Total Available Capacity (MW)	166.7	37.4	204.1	12.0	1.1	0.8	5.0	18.8	222.9
Fuel Type	**Demerara**	**Berbice**	**Total DBIS**	**Anna Regina**	**Wakenaam**	**Leguan**	**Bartica**	**Total Isolated**	**Total GPL**
% of HFO	94%	49%	85%	40%	0%	0%	0%	25%	80%
% of LFO	6%	51%	15%	60%	100%	100%	100%	75%	20%

With scheduled maintenance and efficient operation, generator units generally have a maximum operational life of 25 years, although, in most instances, their economic life is taken as 20 years, after which these units are classified as Cold Reserve Capacity. To date, a total of 57.6 MW of available capacity in the DBIS has surpassed the economic lifespan threshold of 20 years. The specifics of these generator units are shown in Table 2.

Table 2: Aged generator units in the DBIS

Generator Units	Commissioned Dates	Age to Date (yrs.)	Installed Capacity (MW)	Available Capacity (MW)
Garden of Eden - Niigata	**Subtotal**		**11.00**	**6.00**
# 5 Niigata	1991	30	5.50	3.00
# 6 Niigata	1996	25	5.50	3.00
Garden of Eden - DP1	**Subtotal**		**22.00**	**22.00**
# 1 Wartsila	1996	25	5.50	5.50
# 2 Wartsila	1996	25	5.50	5.50
# 3 Wartsila	1996	25	5.50	5.50
# 4 Wartsila	1996	25	5.50	5.50
Kingston I - DP2	**Subtotal**		**22.00**	**22.00**
# 1 Wartsila	1997	24	5.50	5.50
#2 Wartsila	1997	24	5.50	5.50
# 3 Wartsila	1997	24	5.50	5.50
# 4 Wartsila	1997	24	5.50	5.50
Canefield	**Subtotal**		**5.50**	**3.00**
#3DA - Mirrlees	1996	25	5.50	3.00
Onverwagt	**Subtotal**		**5.00**	**4.60**
#5 GM	1981	40	2.50	2.30
#7 GM	1981	40	2.50	2.30
Grand Total			**65.50**	**57.60**

Even though these older engines have been and continue to be well maintained and deliver availability above 95%, their continued use as baseload units is accompanied by an elevated risk of major mechanical failure resulting from the failure of components that are not renewed for the life of the engine, e.g., counterweight bolts. One engine was destroyed, suspected to result from of failed counterweight bolts, precipitating a series of other mechanical failures.

In addition to the aged engines, 46.8 MW of relatively new HFO fired generator units at Kingston and Vreed En Hoop is considered suspect capacities. This is due to technical issues encountered by the alternators at the 26.1 MW power plant at Vreed en Hoop and three units at Kingston II power plant totalling 20.7 MW. As a priority, GPL is currently working ardently to address these matters incrementally.

Combining the age of generator units and engine and/or alternator issues, Table 3 shows the annual Total Available Capacity, Reliable Capacity, Unreliable / Suspect Capacity, and Cold Reserve Capacity in MWs.

Table 3: Summary of power generation profile: 2021-2025 (DBIS Only)

Demerara Berbice Interconnected System	Year	2021	2022	2023	2024	2025
Demerara	Total Available Capacity (MW)	166.7	144.7	116.7	111.9	111.9
	Reliable Capacity (MW)	63.6	63.6	63.6	63.6	63.6
	Unreliable Capacity (MW)	103.1	81.1	53.1	48.3	48.3
	Cold Reserve Capacity (MW)	-	22.0	28.0	4.8	-
	Accumulated Cold Reserve (MW)	-	22.0	50.0	54.8	54.8
Berbice	Total Available Capacity (MW)	37.4	37.4	20.0	15.2	15.2
	Reliable Capacity (MW)	9.7	9.7	9.7	9.7	9.7
	Unreliable Capacity (MW)	27.7	27.7	10.3	5.5	5.5
	Cold Reserve Capacity (MW)	-	-	17.4	4.8	-
	Accumulated Cold Reserve (MW)	-	-	17.4	22.2	22.2
DBIS Total	Total Available Capacity (MW)	204.1	182.1	136.7	127.1	127.1
	Reliable Capacity (MW)	73.3	73.3	73.3	73.3	73.3
	Unreliable Capacity (MW)	130.8	108.8	63.4	53.8	53.8
	Cold Reserve Capacity (MW)	-	22.0	45.4	9.6	-
	Accumulated Cold Reserve (MW)	-	22.0	67.4	77.0	77.0

In view of the demand forecast (see section 2 on page 16 for further details) and the current fleet of generator units in the DBIS, capacity reserve margin, which excludes cold reserve capacity, will become negative and significant LOLP violation by 2022, as shown in Table 4.

Table 4: Capacity reserve margin and LOLP profile for No Additional Firm Capacity

Year	Unit	2021	2022	2023	2024	2025
Peak Demand (MW)	MW	160.77	210.63	283.14	340.98	414.28
Annual Peak Demand Growth Rate (%)	*%*	27.3%	31.0%	34.4%	20.4%	21.5%
Required Reserve Capacity Margin (MW)	MW	42.7	46.9	82.4	166.5	141.7
Stochastic Capacity Reserve Margin (%) for LOLP Target	***%***	26.6%	22.2%	29.1%	48.8%	34.2%

Year	Unit	2021	2022	2023	2024	2025
No Additional Firm Capacity						
Available Generation Capacity	MW	204.1	182.1	136.7	127.1	127.1
Capacity Reserve	MW	43.33	- 28.53	- 46.44	-213.88	-287.18
Capacity Reserve Margin (CRM)	%	26.95%	**-13.55%**	**-51.72%**	**-62.72%**	**-69.32%**
Loss of Load Probability (LOLP)	%	0.7%	**10.2%**	**86.2%**	**92.1%**	**95.3%**

1.3.2 Isolated Systems' Generation

For the CAT LFO units in the Isolated Power Systems, GPL has realised over the years that it is considered cost-effective to replace highspeed generator units with brand-new units than to perform a major overhaul.

Major overhaul of a highspeed generator unit is usually carried out each 24,000 hours, which approximates to 3 calendar years. The total cost of a major overhaul is approximately 80% of the price of a brand-new generator unit.

After a major overhaul, returning a highspeed generator unit's performance to its original state has been a challenge. The balance 20% cost in lieu can compensate for the loss in performance and reliably justify the need to support improved efficiencies with a new generator unit.

The above concept does not apply to the Cummins generator units at Bartica because the cost of a major overhaul is approximately 50% of the price of a brand-new Cummins generator unit.

Combining the age of generator units and engine and/or alternator issues, Table 5 shows the annual Total Available Capacity, Reliable Capacity, Unreliable / Suspect Capacity, and Cold Reserve Capacity in MWs.

Table 5: Summary of power generation profile: 2021-2025 (Isolated Systems Only)

Isolated Systems	Year	*2021*	*2022*	*2023*	*2024*	*2025*
Anna Regina	**Total Available Capacity (MW)**	12.0	12.0	12.0	4.8	4.8
	Reliable Capacity (MW)	4.8	4.8	4.8	4.8	4.8
	Unreliable Capacity (MW)	7.2	7.2	7.2	-	-
	Cold Reserve Capacity (MW)	**-**	**-**	**-**	**7.2**	**-**
	Accumulated Cold Reserve (MW)	**-**	**-**	**-**	**7.2**	**7.2**
Wakenaam	**Total Available Capacity (MW)**	1.06	1.06	0.41	-	-
	Reliable Capacity (MW)	0.41	0.41	0.41	-	-
	Unreliable Capacity (MW)	0.65	0.65	-	-	-
	Cold Reserve Capacity (MW)	**-**	**-**	**0.65**	**0.41**	**-**
	Accumulated Cold Reserve (MW)	**-**	**-**	**0.65**	**1.06**	**1.06**
Leguan	**Total Available Capacity (MW)**	0.82	0.82	0.82	-	-
	Reliable Capacity (MW)	0.82	0.82	0.82	-	-
	Unreliable Capacity (MW)	-	-	-	-	-
	Cold Reserve Capacity (MW)	**-**	**-**	**-**	**0.82**	**-**
	Accumulated Cold Reserve (MW)	**-**	**-**	**-**	**0.82**	**0.82**

Isolated Systems	Year	*2021*	*2022*	*2023*	*2024*	*2025*
Bartica	**Total Available Capacity (MW)**	5.0	5.0	5.0	3.4	3.4
	Reliable Capacity (MW)	-	-	-	-	-
	Unreliable Capacity (MW)	1.6	1.6	1.6	-	-
	Cold Reserve Capacity (MW)	**-**	**-**	**-**	**1.6**	**-**
	Accumulated Cold Reserve (MW)	**-**	**-**	**-**	**1.60**	**1.60**
Isolated System	**Total Available Capacity (MW)**	18.8	18.8	18.2	8.2	8.2
	Reliable Capacity (MW)	6.0	6.0	6.0	4.8	4.8
	Unreliable Capacity (MW)	9.5	9.5	8.8	-	-
	Cold Reserve Capacity (MW)	**-**	**-**	**0.65**	**10.0**	**-**
	Accumulated Cold Reserve (MW)	**-**	**-**	**0.65**	**10.68**	**10.68**

1.3.3 Transmission and Distribution

The Transmission and Distribution section of GPL's electric power system comprises three main volage levels; 69 kV for bulk power transfer, 13.8 kV for primary power distribution and lower utilisation voltage for customer-specific applications.

GPL's present transmission and distribution network provides electricity supply coverage of approximately 81% on the Coastland and comprises the following:

1. The transmission voltage level of 69 kV is only present in the DBIS and has a total length of 276 km;
2. The total estimated length of primary distribution circuits in the DBIS is 784 km; and
3. The total estimated length of primary distribution circuits in the Isolated Systems is 143.56 km. A breakdown of the Isolated Systems is as follow:
    a. Anna Regina – 75.97 km;
    b. Wakenaam – 21.19 km;
    c. Leguan – 28.8 km; and
    d. Bartica – 17.6 km.

Within the total GPL power system, the majority of network-related challenges are currently experienced in the DBIS. A summary of the critical issues presently experienced are:

1. The reduced life span of pole structures due to poor quality of poles and cross-arms;
2. Impassable accesses to pole structures in remote terrains; mainly for the transmission lines;
3. Frequent line trips due to vegetation encroachments on open conductors;
4. High voltage drops due to long feeder lengths, high electricity demands, and low power factor presented by maximum demand customers;
5. Widespread outages due to fault clearing by protection relay scheme at substation level;

6. A large number of and duration of outages to facilitate line maintenance and emergency switching; and
7. Poor operation visibility and remote control of primary distribution feeders result in a high dependency on customer fault reports.

1.4 Demand Forecasts and Customer Growth Projection

The Company has forecasted energy demand growth of 1,876 GWh for all GPL Systems that represents a significant increase of 208%. The DBIS which accounts for about 95% of GPL's system demand has forecasted energy demand growth by 1,806.39 GWh or 211% in the same period, as presented in Table 6.

Table 6: Energy Demand and Peak Power Forecasts for all GPL systems

System	Description	Unit	2020	2021	2022	2023	2024	2025
All GPL	**Electricity Demand**	**GWh**	902.6	1,143.1	1,422.9	1,902.3	2,397.8	2,778.5
All GPL	**Peak Power**	**MW**	134.5	170.4	222.5	298.4	358.8	435.3
DBIS	**Electricity Demand**	**GWh**	855.3	1,086.3	1,355.2	1,816.7	2,294.2	2,661.6
DBIS	**Peak Power**	**MW**	126.3	160.8	210.6	283.1	341.0	414.3
Anna Regina	**Electricity Demand**	**GWh**	31.6	38.4	46.1	58.9	72.1	82.3
Anna Regina	**Peak Power**	**MW**	5.6	6.7	8.3	10.7	12.6	15.0
Bartica	**Electricity Demand**	**GWh**	12.3	14.4	16.9	20.8	24.4	26.6
Bartica	**Peak Power**	**MW**	1.9	2.3	2.7	3.4	3.8	4.3
Leguan	**Electricity Demand**	**GWh**	1.7	2.0	2.4	3.0	3.6	4.0
Leguan	**Peak Power**	**MW**	0.4	0.4	0.5	0.6	0.7	0.9
Wakenaam	**Electricity Demand**	**GWh**	1.7	2.0	2.4	2.9	3.5	3.9
Wakenaam	**Peak Power**	**MW**	0.3	0.4	0.4	0.5	0.6	0.7

This projection is based on the expected significant stimulation in the economy that the emerging Oil and Gas Industry will provide. The Company projects an increase in its customer base from 205,814 in 2020 to potentially 265,667 by the end of 2025 (Table 7). The projected increase in the customer base is primarily due to the increased economic activities, which are expected to result from 1) population growth, 2) increased business activities and 3) providing services to all existing un-served areas.

Table 7: Customer growth

Year	2020	2021	2022	2023	2024	2025
No. of Customers	205,814	218,278	232,861	240,930	255,505	265,667

1.5 Meeting Energy Demand and Peak Power Forecasts

The availability of reliable generation capacity and T&D infrastructure to satisfy the growing electricity demand is pivotal to providing the required electric energy security to support economic activities and economic growth.

Guyana is rich in renewable and sustainable energy sources (hydro, wind and solar). These generation sources have gained international recognition and embraced for their contribution to the reduction of carbon emissions and green-house-gases.

The legal and regulatory framework to guide compensation to Grid-Tie customers is expected to be completed during 2021 and will support establishing an appropriate tariff for current and future grid-tie customers.

Whilst GPL embraces the benefits expected to be realized from distributed generation, the Company will aggressively monitor the electricity exported to the grid to ensure the stability of the DBIS.

Significant generation from renewable energy resources, therefore, whilst attractive, will not entirely displace the larger volumes of the firm and the dispatchable fossil-fired generation that is required to satisfy the current and projected baseload demand during the life of this programme. Additionally, the intermittent nature of these resources with significant penetration levels would present considerable challenges to the stability of the grid in its current state. The Company will incrementally introduce and integrate generation from these renewable resources into the GPL system to ensure that system stability and service reliability are not adversely affected.

Electricity generation from hydro and biomass are potential sources of generation for GPL. However, these require lengthy studies before progressing to Expressions of Interest and ultimately power facility construction and commissioning and would not be realized during this programme's life. It, however, remains GPL's intention to continue to work closely with the Government of Guyana and with private investors in this regard.

The midterm potential of a mid-sized Hydropower facility of approximately 165 megawatts remains the Government's focus, as reflected in the Draft National Energy Policy 2016[1]. It is consistent with the Inter-American Development Bank's (IDB's) sponsored Update of the Study on System Expansion of the Generation System 2018[2]. The Company will continue to monitor its available generation capacity prudently and continue its close collaboration with the Government of Guyana on developing the first mid-sized Hydropower facility during and beyond the life of this plan.

1.5.1 Generation (Firm and Non-Firm Capacities)

1.5.1.1 Demerara Berbice Interconnected System (DBIS)

GPL has been exploring electricity generation from solar and intends to integrate a total of 29 MW of Solar PV generation capacity into the generation portfolio by 2025, as presented in Table 8 for the DBIS.

In the case of Linden, the 15 MWp Solar PV project is expected to be in service by 2023. However, given that it is planned for Linden to be interconnected with the DBIS by 2024, the

[1] Draft National Energy Policy 2016 https://doe.gov.gy/published/document/5af72892dc677720ccdc33b8
[2] Update of Study on System Expansion of the Generation System 2018, Brugman SAS 2018

Solar PV capacity is represented in Table 8 accordingly. Only the Linden Solar PV system will include a total of 15 MWh of Battery Energy Storage System.

In view of the generation planning target and need to guarantee grid stability, GPL's recommended generation expansion plan for the DBIS is presented in Table 8.

Table 8: Proposed Generation Expansion Plan – DBIS

Name of Location	Type	Installed Capacity (MW)				
		2021	2022	2023	2024	2025
Garden of Eden - Phase 1	Firm Capacity	46.5				
Garden of Eden - Phase 2	Firm Capacity		54.0			
250 MW NG Plant - Phase 1	Firm Capacity			108.0		
250 MW NG Plant - Phase 2	Firm Capacity				142.0	
Crab Island	Firm Capacity					54.0
Berbice Solar PV	Non-Firm Capacity			10.0		
Linden Solar PV	Non-Firm Capacity				15.0	
Naarstigheid Solar PV	Non-Firm Capacity					4.0
Total New Additions		**46.5**	**54.0**	**118.0**	**157.0**	**58.0**
Total Accumulated Additions			**100.5**	**218.5**	**375.5**	**433.5**
Annual Non-Firm Capacity		**-**	**-**	**10.0**	**15.0**	**4.0**
Annual Firm Capacity		**46.5**	**54.0**	**108.0**	**142.0**	**54.0**
Total Accumulated Firm Capacity		**46.5**	**100.5**	**208.5**	**350.5**	**404.5**
Existing Firm Capacity		**157.6**	**154.6**	**134.2**	**125.5**	**125.5**
Grand Total Firm Capacity		**204.1**	**255.1**	**342.7**	**476**	**530.0**

1.5.1.2 Natural Gas

The emerging Oil and Gas sector has presented an opportunity for the Company's transition to natural gas for power generation. Whilst natural gas is not a renewable energy source, it is a cleaner source of energy than GPL's current energy source and offers the potential of a lower cost of generation and reduced electricity tariffs. Natural gas exploitation for electricity generation forms part of a broader national initiative, further determining the Company's immediate to medium term generation strategies.

Given the confirmed availability of excess natural gas from Guyana's offshore oil production wells and the Government's intention to direct the excess gas to shore, GPL has commenced preparatory works in transition to using this cheaper and cleaner form of generation.

The Company expects to commission 46.5 megawatts of new and additional dual-fuel generation by Q2 2021, thus positioning the Company to initially transition 21.9% of its generation capacity to natural gas-fired generation. Careful consideration will be given to converting 106 MW of existing HFO fired baseload capacity to natural gas-fired generation.

The Government of Guyana has commenced a 'Gas to Power' initiative, which is expected to deliver natural gas to shore before 2024 in sufficient volumes for residential, commercial and industrial use. This gas to shore initiative is expected to realize approximately two hundred and fifty megawatts of natural gas-fired generation for export to the national grid and further boosting the Company's generating capacity.

1.5.1.3 Possibility of Converting Existing HFO Plants to Dual Fuel Plants

GPL can convert Garden of Eden Wärtsilä (DP1), Kingston I (DP2), Kingston II (DP3) and Vreed-en-Hoop (DP4) plants to consume natural gas as the primary fuel and HFO as the contingency fuel.

The conversion of these power plants will result in significant reduction of their present operating costs and extension of their economic operational life by 12 to 15 years for DP1 and DP2, and 20 years for DP3 and DP4, as show in Table 9.

Table 9: Summary of Variation of key operating paraments after conversion to natural gas

Key Parameters	DP2	DP3 - W16V	DP3 - W18V	DP4
Output (kW)	-0.02%	-3.74%	-4.55%	-8.56%
Heat rate (BTU/kWh) - 100% Loading	-8.63%	0.11%	0.24%	4.94%
FO&M[3] ($/kW/yr)	-33.50%	-66.29%	-66.29%	-42.93%
VO&M[4] ($/kWh)	-59.25%	-65.86%	-68.79%	-64.35%
Maintenance Rate	-13.04%	-13.04%	-13.04%	-13.04%
Mean Time to Repair – Top Overhaul	1.19%	1.19%	1.19%	1.19%
Mean Time to Repair – Major Overhaul	-45.44%	-45.44%	-45.44%	-45.44%
Mean Time to Repair - FOR	-71.43%	-71.43%	-71.43%	-71.43%
FOR	-49.15%	-3.23%	-3.23%	-18.92%

The duration to ultimately convert a single HFO engine to natural gas would be 52 business days (almost 2 months). Given the need to ensure generation reliability is maintained, plant conversion can be executed sequentially, commencing with the engines at DP1 – Garden of Eden. As such, at any given time, only a single engine will be out of service for 2 months, after which works would commence on another engine in sequential order, moving from one completely converted plant to another. Three years is the estimated duration to convert the four existing power plants.

[3] Fixed Operation and Maintenance Cost
[4] Variable Operation and Maintenance Cost

With recommended additional generation capacity, coupled with the total available and cold reserve capacity, the DBIS will have sufficient firm generation contingency capacity as shown in Table 10 for the present planning period.

Table 10: Generation Contingency Capacity Forecast with Recommended Additions - DBIS

Existing and New Power Generators	**Type**	**2021**	**2022**	**2023**	**2024**	**2025**
DEMERARA						
Garden of Eden Power Station	Firm Capacity	6.0	6.0	**6.0**	**6.0**	**6.0**
Demerara Power (Kingston 1)	Firm Capacity	22.0	22.0	**22.0**	**22.0**	**22.0**
Demerara Power, (Kingston 11)	Firm Capacity	36.3	36.3	36.3	36.3	36.3
Demerara Power 1 (GoE)	Firm Capacity	22.0	**22.0**	**22.0**	**22.0**	**22.0**
Vreed En Hoop Power Station	Firm Capacity	26.1	26.1	26.1	26.1	26.1
Old Sophia	Firm Capacity	4.8	4.8	4.8	**4.8**	**4.8**
MCG - Giftland	Firm Capacity	3.0	3.0	3.0	3.0	3.0
ADDITION 10MW-4hr BESS (New Sophia)	Firm Capacity	-	10.0	10.0	10.0	10.0
ADDITION (Garden of Eden - Phase 1)	Firm Capacity	46.5	46.5	46.5	46.5	46.5
ADDITION (Garden of Eden - Phase 2)	Firm Capacity	-	54.0	54.0	54.0	54.0
ADDITION (250MW NG Plant - Phase 1)	Firm Capacity	-	-	108.0	108.0	108.0
ADDITION (250MW NG Plant - Phase 2)	Firm Capacity	-	-	-	142.0	142.0
ADDITION (Crab Island)	Firm Capacity	-	-	-	-	54.0
ADDITION (Linden Solar PV)	Non-Firm Capacity	-	-	-	15.0	15.0
Total Installation Generation (MW)		**166.7**	**230.7**	**338.7**	**495.7**	**549.7**
Total Firm Generation Capacity (MW)		**166.7**	**230.7**	**338.7**	**480.7**	**534.7**
Total Non-Firm Generation Capacity (MW)		**-**	**-**	**-**	**15.0**	**15.0**
Total Cold Reserve Capacity (MW)		**-**	**22.0**	**50.0**	**54.8**	**54.8**
BERBICE						
Canefield						
Hyundai	Firm Capacity	5.5	5.5	5.5	5.5	5.5
No. 4 Mirrlees Blackstone	Firm Capacity	3.0	3.0	**3.0**	**3.0**	**3.0**
Mobile Sets	Firm Capacity	7.8	7.8	**7.8**	**7.8**	**7.8**
Onverwagt						

No. 5 General Motor	Firm Capacity	2.3	2.3	**2.3**	**2.3**	**2.3**
No. 7 General Motor	Firm Capacity	2.3	2.3	**2.3**	**2.3**	**2.3**
Mobile Sets	Firm Capacity	6.8	6.8	**6.8**	**6.8**	**6.8**
ADDITION (10MWp Solar PV)	Non-Firm Capacity	-	-	10.0	10.0	10.0
ADDITION (Naarstigheid Solar PV)	Non-Firm Capacity	-	-	-	-	4.0
Skeldon						
SEI	Firm Capacity	9.7	9.7	9.7	9.7	9.7
Total Installation Generation (MW)		**37.4**	**37.4**	**47.4**	**47.4**	**51.4**
Total Firm Generation Capacity (MW)		**37.4**	**37.4**	**37.4**	**37.4**	**37.4**
Total Non-Firm Generation Capacity (MW)		**-**	**-**	**10.0**	**10.0**	**14.0**
Total Cold Reserve Capacity (MW)		**-**	**-**	**17.4**	**22.2**	**22.2**
DBIS Accumulated Firm Generation Capacity (MW)		**204.1**	**268.1**	**376.1**	**518.1**	**572.1**
DBIS Accumulated Non-Firm Generation Capacity (MW)		**-**	**-**	**10.0**	**25.0**	**29.0**
DBIS Min Required Spinning Reserve (MW)		**14.0**	**27.0**	**30.0**	**34.5**	**35.7**
DBIS Net Capacity (MW)		**190.2**	**241.1**	**346.1**	**483.6**	**536.4**
DBIS Forecast Peak Demand (MW)		**160.8**	**210.6**	**283.1**	**341.0**	**414.3**
Contingency Capacity (MW)		**29.4**	**30.5**	**63.0**	**142.6**	**122.1**

Legend for Table 9	
Font	Units/Plant as Cold Reserve Capacity
Font	Part of Plant's as Cold Reserve Capacity

1.5.1.4 Isolated Systems (Anna Regina, Bartica, Leguan & Wakenaam)

For the Isolated systems, GPL plans to have a total of 8 MWp Solar PV capacity and 8 MWh Battery Energy Storage System for the Anna Regina Power System in commercial operation by 2023.

With debt funding from the IaDB and execution by the GEA, GPL plans to have a 1.5 MW Solar PV farm with BESS in commercial operation in Bartica by 2023.

Regarding the other isolated systems, through grant funding from the United Arab Emirates, 750 kW Solar PV farm with BESS will be in commercial operation before the end of 2021 in Wakenaam. For Leguan, a 600 kW Solar PV farm is planned to be in commercial operation in Leguan by 2022.

With the need to ensure grid stability and electricity supply security, GPL also plans to install firm power generation capacities in each Isolated Systems. See Table 11 for further details.

Table 11: Proposed Expansion Plan – Essequibo Isolated Systems

Isolated System Locations	**Planned Addition Capacity (MW)**				
Anna Regina	**2021**	**2022**	**2023**	**2024**	**2025**
Total Non-Firm Capacity	**-**	**-**	**8.0**	**-**	**-**
Total Firm Capacity	**2.5**	**2.5**	**1.8**	**5.0**	**-**
Total Accumulated Firm Capacity	**2.5**	**5.0**	**6.8**	**11.8**	**11.8**
Existing Firm Capacity	**12.0**	**12.0**	**12.0**	**12.0**	**12.0**
Grand Total Firm Capacity	**14.5**	**17.0**	**18.8**	**23.8**	**23.8**
Bartica	**2021**	**2022**	**2023**	**2024**	**2025**
Total Non-Firm Capacity	**-**	**-**	**1.5**	**-**	**-**
Total Firm Capacity	**1.1**	**-**	**4.0**	**-**	**-**
Total Accumulated Firm Capacity	**1.1**	**1.1**	**5.1**	**5.1**	**5.1**
Existing Firm Capacity	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**
Grand Total Firm Capacity	**6.1**	**6.1**	**10.1**	**10.1**	**10.1**
Leguan	**2021**	**2022**	**2023**	**2024**	**2025**
Total Non-Firm Capacity	**-**	**0.6**	**-**	**-**	**-**
Total Firm Capacity	**-**	**-**	**0.8**	**-**	**0.8**
Total Accumulated Firm Capacity	**-**	**-**	**0.8**	**0.8**	**0.8**
Existing Firm Capacity	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**
Grand Total Firm Capacity	**0.8**	**0.8**	**1.6**	**1.6**	**2.5**
Wakenaam	**2021**	**2022**	**2023**	**2024**	**2025**
Total Non-Firm Capacity	**0.75**				
Total Firm Capacity	**0.8**	**0.4**	**-**	**0.4**	**-**
Total Accumulated Firm Capacity	**0.8**	**1.2**	**1.2**	**1.6**	**1.6**
Existing Firm Capacity	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**
Grand Total Firm Capacity	**1.9**	**2.3**	**2.3**	**2.7**	**2.7**

1.5.1.5 Summary of Power Generation Expansion – DBIS and Isolated Systems

Given that power plants have an economic operation lifespan of 20 years, GPL has ensured that the currently planned capital investment in generation expansion is well aligned with the 20 years demand forecast. The recommended generation expansion plans for the 2021-2025 planning period are summarised in Table 10 for the DBIS and Table 11 for the Isolated Systems. Each table also shows the projected energy mix of the power systems by 2025, respectively.

Table 10: GPL 5 Year Generation Expansion Plan and Energy Mix- DBIS

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
2021	Multifuel	46.5	Garden of Eden - Phase 1	GPL
2022	Multifuel	54.0	Garden of Eden - Phase 2	GPL
2023	NG	108.0	250 MW NG Plant - Phase 1	GPL
	Solar PV	10.0	Berbice Solar PV	GPL
	Solar PV	4.0	Naarstigheid	GPL
2024	NG	142.0	250 MW NG Plant - Phase 2	GPL
	Solar PV	15.0	Linden	GPL
2025	NG	54.0	Crab Island	GPL
Existing Capacity (MW) (Excludes GOE II 46.5 MW)	HFO	127.6	DBIS	GPL
Existing Capacity (MW)	LFO	30.0	DBIS	GPL
Total Existing Firm Capacity (MW) - Excludes GOE II 46.5 MW)		157.60	157.6	GPL
Total Additional Firm Capacity by 2025 (MW)		404.50		
Total Additional Non-Firm Capacity by 2025 (MW)		29.00		
Total Additional Capacity by 2025 (MW)		433.50		
Total Firm Capacity by 2025 (MW)		562.10		
Total Non-Firm Capacity by 2025 (MW)		29.00		
Total Capacity by 2025 (MW)		591.10		
Total HFO Capacity by 2025 (MW)		282.10		
Total LFO Capacity by 2025 (MW)		30.00		
Total Solar PV Capacity by 2025 (MW)		29.00		
Total NG Capacity by 2025 (MW)		250.00		
DBIS HFO % Share		47.7%	DBIS	
DBIS LFO % Share		5.1%	DBIS	
DBIS NG % Share		42.3%	DBIS	
DBIS Solar PV % Share		4.9%	DBIS	

Table 12: GPL 5 Year Generation Expansion Plan and Energy Mix- Isolated Systems

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
2021	HFO	2.5	Anna Regina	GPL
	LFO	1.1	Bartica	GPL
	Solar PV	0.75	Wakenaam	GPL
2022	HFO	2.5	Anna Regina	GPL
	LFO	0.41	Wakenaam	
	Solar PV	0.6	Leguan	GPL
2023	HFO	1.8	Anna Regina	GPL
	Solar PV	8	Anna Regina	GPL
	Solar PV	1.5	Bartica	GPL
	LFO	0.82	Leguan	GPL
	LFO	4	Bartica	GPL
2024	LFO	0.41	Wakenaam	
	HFO	5	Anna Regina	GPL
2025	LFO	0.82	Leguan	GPL
Existing Capacity	HFO	4.8	Isolated Systems	GPL
	LFO	14.04	Isolated Systems	GPL
Total Existing Capacity		18.84	Isolated Systems	GPL
Total Additional Firm Capacity by 2025 (MW)		19.36	Isolated Systems	GPL
Total Additional Non-Firm Capacity by 2025 (MW)		10.85	Isolated Systems	GPL
Total Additional Capacity by 2025 (MW)		30.21	Isolated Systems	GPL
Total Firm Capacity by 2025 (MW)		38.2	Isolated Systems	GPL
Total Non-Firm Capacity by 2025 (MW)		10.85	Isolated Systems	GPL
Total Capacity by 2025 (MW)		49.05	Isolated Systems	GPL
Total HFO Capacity by 2025 (MW)		16.6	Isolated Systems	GPL
Total LFO Capacity by 2025 (MW)		21.6		
Total Solar PV Capacity by 2025 (MW)		10.85	Isolated Systems	GPL
Isolated System HFO % Share		33.8%	Isolated Systems	GPL
Isolated System LFO % Share		44.0%	Isolated Systems	GPL
Isolated System Solar PV % Share		22.1%	Isolated Systems	GPL

1.5.2 Transmission and Distribution (T&D)

The reliable delivery of electricity service from the generation stations to customers requires a robust and resilient Transmission and Distribution network. With the combined progressive expansion of the T&D System and the Company's extensive planned and executed maintenance activities, the networks are still prone to defects due to the aged sections of the network. These defects contribute to service disruptions that negatively impact the Company's ability to serve its customers and reducing technical losses reliably.

The network was partially improved in 2014, which was as a result of the construction of seven (7) new substations, one hundred and thirty-seven kilometres (137 km) of transmission lines and the interconnection of two systems: Berbice and Demerara Power Systems into the Demerara Berbice Interconnected System (DBIS). These network improvements positively and progressively improved the reliability and quality of electricity service to our customers and contributed towards the Company's technical loss reduction efforts.

In 2020, GPL continued to build on the 2014 network improvements that included:

- Constructing 9.8 km of express medium voltage feeders;
- Laying a 13.8 kV submarine cable as partial redundancy to the 69 kV submarine cable from West to East Demerara; and
- Replacement of 48 Single Wire Earth Return Transformers (JICA Grant Fund).

In view of the Transmission and Distribution planning targets and demand forecasts, a summary of improvements expected to be realized during the life of this Programme, specifically at the transmission level, include:

1. Installing 2 x 5 MVAr Reactive Power compensators in West Coast Berbice (JICA Grant Fund);
2. 329.5 km of new 69 kV transmission circuits to accommodate new substations and parallel lines;
3. 64.3 km of conductor upgrade to existing 69 kV transmission circuits;
4. 11 new 69/13.8 kV distribution substations (load centres);
5. 13-69/13.8 kV substations upgrades/expansions to accommodate additional transmission lines and primary distribution feeders; and
6. Installation of a total of 55 MVAr of Reactive Power compensators at the 69 kV level (IaDB Loan funded).

Interventions for improving the distribution systems' reliability, resiliency, and capacity to manage increased power flow and to deliver quality electricity supply service to customers are:

1. Upgrade of existing SCADA – expanding remote control and supervision reach into power generation and primary distribution levels, respectively;
2. Reinforce vegetation management;

3. Use of concrete poles and either concrete or fibreglass crossarms to improve the integrity of structures in primary distribution circuits;
4. Use of covered conductors in primary distribution circuits in areas of dense vegetation;
5. Installation and commissioning of 99 Auto-Reclosers;
6. Installation and commissioning of a total of 3,000 kVAr (4 banks) of Automatic Power Factor Correction Capacitor Banks on Onverwagt F2 (JICA Grant Fund);
7. Installation and commissioning of a total of 12,000 kVAr (23 banks) of Automatic Power Factor Correction Capacitor Banks on 30 primary distribution feeders;
8. Upgrading of 55.52 km of primary distribution circuits;
9. Upgrading 371 km of medium voltage conductors (JICA Grant Fund and GPL)
10. Construction of 46 new primary distribution circuits (for new and existing substations in the DBIS and Anna Regina); and
11. SCADA integration of Auto-Reclosers and Automation of Distribution Networks.

1.6 Metering (Technical and Non-Technical Losses)

The progressive and sustained reduction in Total System Losses remains a corporate priority, despite the notable reduction from thirty-seven percent (37%) in 2006, to twenty-six-point five percent (26.5%) as of December 2020.

The major contributors to the Company's non-technical losses are:

- Unmetered supplies;
- Defective meters;
- Street lighting; and
- Electricity theft.

The major contributors to the Company's technical losses are:

- Aged and lengthy conductors (medium and low voltage);
- Inefficient transformers; and
- Insufficient reactive power compensation.

The Company's Loss Reduction effort has been bolstered by an aggregated investment of US$43 million in debt and grant funding from the Inter-American Development Bank (IaDB) and the European Union (EU), respectively. This investment is in addition to the Company's self-funded efforts. The IaDB/EU funding targets upgrading 830 kilometres of low voltage conductors, including distribution transformer right-sizing, meter replacements and service installation upgrades.

Further reductions in system losses will improve revenue and reduce operating costs. In 2018, GPL commenced Phase II of its meter upgrade program to AMI compatible meters (smart meters), to position the Company to expand its Advanced Metering Infrastructure (AMI) coverage and strengthen its ability to track losses from substation to customer and inform corrective actions. This will positively impact efforts to lower tariffs for all consumers and improve the financial strength of GPL.

As such, through the Power Utility Upgrade Programme (PUUP), GPL plans to upgrade:

1. 20,000 meters to AMI in 2021;
2. 7,000 meters to AMI in 2022; and
3. 7,000 meters to AMI in 2023.

With the combined application of SCADA at the transmissions and primary distribution levels, and power generation, coupled with the continued implementation of AMI meters at the customer level, the Company plans to transform the power system into a smart grid in a phased manner.

In view of the benefits of having a smart grid together with the above-mentioned projects, which will reduce technical and non-technical losses, the Company's loss projection profile indicates that by 2025, technical losses should be reduced from 9.4% to 8.6%, and non-technical from 17.1% to approximately 13.6% (Figure 1). Consequently, a total loss reduction from twenty-six-point five percent (26.5%) in 2020 to twenty-two-point five percent (22.5%) by 2025.

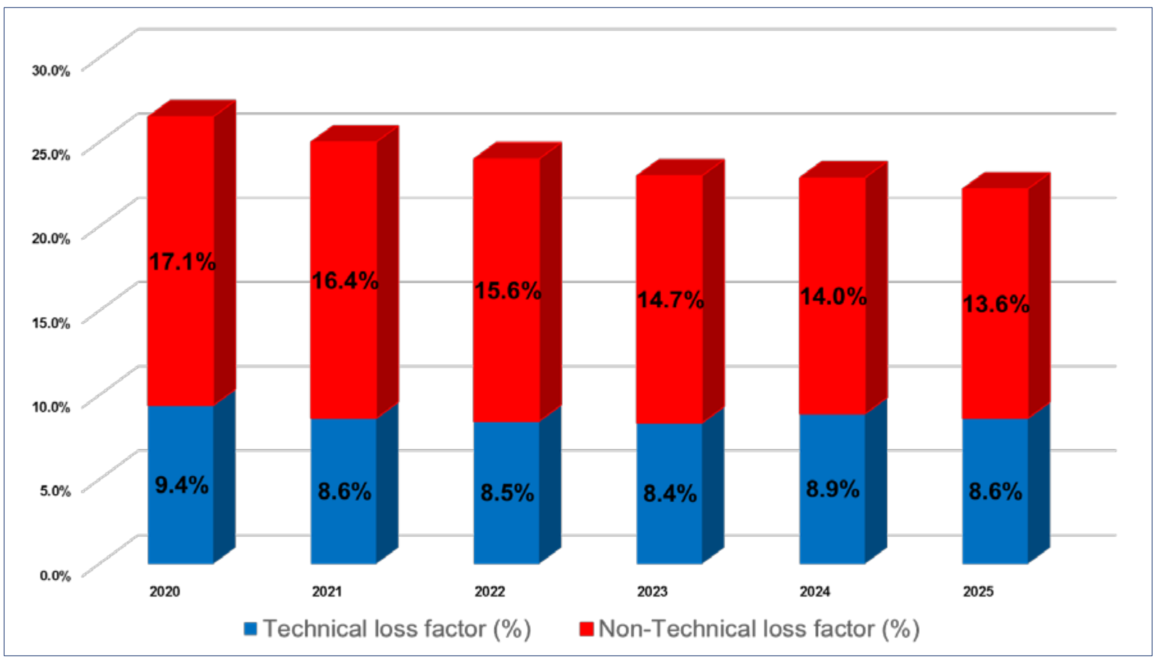

Figure 1: Loss Reduction Projections

1.7 Sales and Revenue Collection

Sales growth from 2020 to 2025 is projected to increase by 234% from 635 GWh to 2,121 for the total GPL Power Systems (Figure 2) This projection is premised on the details mentioned in section 1.4, page 16, and the projected percentage loss reduction by 2025.

The active campaign to improve Receivables will continue and GPL will maintain a cash collection rate of 99.5% (cash collections as a percentage of sales).

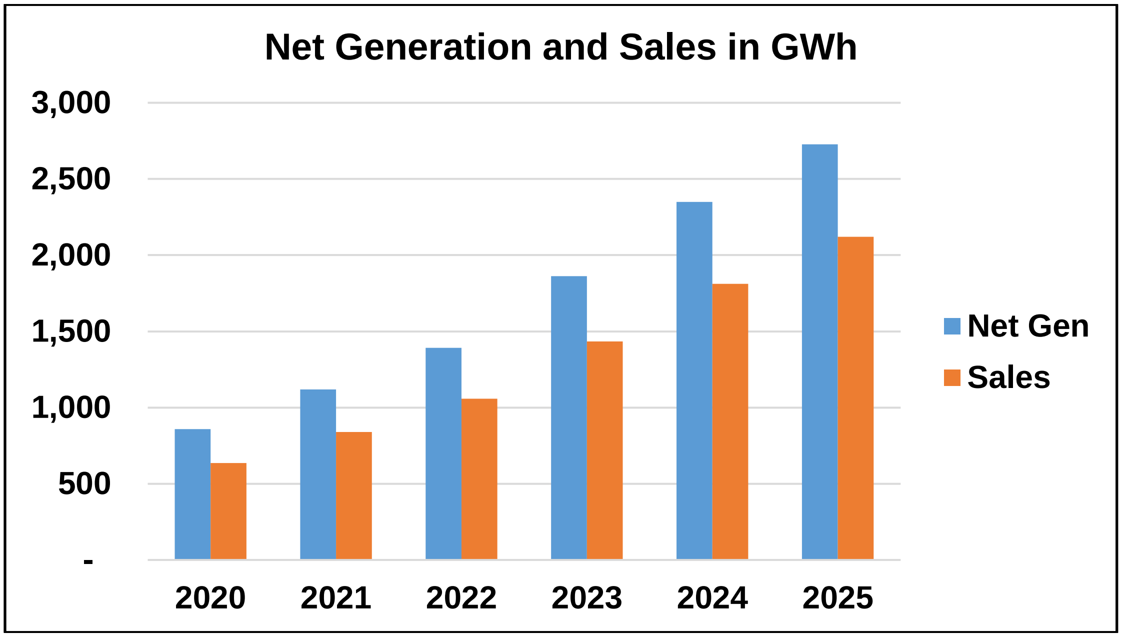

Figure 2: Net generation & Sales (GWh)

1.8 Tariffs

The reduction of tariffs remains a priority to the Company and is consistent with the corporate vision. Whilst the Company's operating license provides a tariff mechanism to adjust rates to ensure profitability and self-sustainability, GPL will continue to adopt prudent operating practices in its efforts to sustain lowered tariffs to all customers.

During 2015 and 2016, when world market fuel prices declined considerably, the Company applied a fuel rebate of five percent (5%) and ten percent (10%) respectively. In addition, tariffs were reduced by five percent (5%) in year 2016. The aggregated effect was a twenty percent (20%) reduction in tariffs over year 2014.

Despite increases in world market fuel prices by approximately thirty-one percent (31%) in ensuing years (2017 – 2020), the Company has not applied any fuel surcharge or tariff increases as provided for under its license.

Whilst lowered and sustained tariffs are among the Company's primary objectives, GPL remains challenged to fund network and generation improvement projects without debt financing and grants from multi-lateral concessional lending agencies.

The Financial projections are instructive as to the measures that could be taken to facilitate a reduction in Tariffs. The key assumptions used in the projections are detailed in Table 13.

Table 13: Financial Projections – Facilitating Tariff Reduction

		Year 2020	Year 2025	Change
NET TARIFFS	US cents/kWh	**23**	**18**	22%
SALES DEMAND	GWh	667	2121	
LOSSES	%	26.0%	22.2%	3.8%
FUEL PRICES				
Natural Gas Price delivered to the engines	US$/MMBTU	NA	6	
HFO CIF Price	US$/barrel	50	50	
LFO CIF Price	US$/barrel	70	70	
LOAN STOCK				
GPL Loans Debt burden	G$' billion	52	147	183%
Interest Payment 4%	G$' billion	2.08	5.88	183%
Principal Payments (15 years amortization)	G$' billion	3.47	9.80	183%
Debt Service Total	G$' billion	**5.55**	**15.68**	**183%**

These factors have a major influence on GPL's ability to lower Tariffs from the current level of approximately US 23 cents per kWh. A review of the projected financial performance for the period to Year 2025 highlights the following:

i) Growth in Sales Demand

The significant growth in demand (increase of approximately 218%) over the five (5) year period is projected to have a favourable impact on the generation of profits and operating cash flows. The projections have included a tariff reduction to US 21 cents per kWh at the beginning of year 2024, and a further reduction to US 18 cents per kWh at the start of year 2025.

ii) Losses (Technical and Commercial losses)

Losses are projected to decline from 26.0% to 22.2%. Further reductions in losses will have a positive impact on the Financial performance and would improve the ability of the company to lower tariffs even further. As an example, an additional reduction in losses of 5% would allow for a reduction in Tariffs by about US 1 cent per kWh at the projected costs of generation.

iii) Cost of Generation

By year 2023, generation using natural gas is projected to provide more than 95% of the required generation. The price at which gas is delivered to the engines is therefore extremely important and will have the most impact on the ability of the company to lower tariffs by the 2025 as shown below:

Price of Gas:

- US$ 6 per MMBtu - Tariff reduced by 22% to US 18 cents/kWh
- US$ 5 per MMBtu - Tariff reduced by 30% to US 17 cents/kWh
- US$ 4 per MMBtu - Tariff reduced by 43% to US 16 cents/kWh
- US$ 3 per MMBtu - Tariff reduced by 52% to US 15 cents/kWh

iv) GPL's Debt Burden

The projections indicate that by the end of 2025, GPL's Loans to the Government of Guyana would increase from G$52 billion to more than G$147 billion. This will require approximately G$16 billion in annual debt service obligations.

GPL is currently in the process of negotiating with the Ministry of Finance, the extension of the moratorium on all debt service until Year 2026.

Converting this debt to equity, would allow for a further reduction of about US 2 cents after year 2025.

1.9 Capital Programmes, Investments and Financial Projections: 2021 – 2025.

Table 14: Planned Capital Programmes and Investments: 2021-2025

CAPITAL WORK PROGRAM YEARS 2021-2025						
	TOTAL USD	Yr 2021 USD	Yr 2022 USD	Yr 2023 USD	Yr 2024 USD	Yr 2025 USD
Generation	$ 752,826,383	$ 52,329,293	$ 103,748,448	$ 253,217,617	$ 326,383,025	$ 17,148,000
Transmission Lines	$ 199,748,849	$ 11,485,544	$ 42,996,268	$ 78,823,803	$ 42,451,394	$ 23,991,840
Sub-Stations	$ 252,685,193	$ 41,525,143	$ 100,443,143	$ 75,983,550	$ 17,757,000	$ 16,976,357
Non Technical Loss Reduction	$ 36,009,225	$ 12,434,997	$ 12,978,561	$ 3,531,889	$ 3,531,889	$ 3,531,889
Technical Loss Reduction Distribution upgrades	$ 65,672,200	$ 8,072,200	$ 13,680,000	$ 11,480,000	$ 20,200,000	$ 12,240,000
Electrification (unserved areas)	$ 3,390,561	510,829	1,686,022	64,459	843,161	286,091
New Services	$ 15,125,000	$ 2,750,000	$ 2,887,500	$ 3,025,000	$ 3,162,500	$ 3,300,000
Buildings	$ 7,011,084	$ 1,971,405	$ 1,647,689	$ 1,055,330	$ 1,400,830	$ 935,830
Capacity Building	$ 56,669,732	$ 24,188,995	$ 13,541,700	$ 8,302,033	$ 5,664,068	$ 4,972,937
Information Technology	$ 2,500,929	$ 1,863,929	$ 287,000	$ 40,000	$ 95,000	$ 215,000
Reactive Power Compensation	$ 21,840,000	$ 6,328,000	$ 6,552,000	$ 5,488,000	$ 3,472,000	$ -
GRAND TOTAL	$ 1,413,479,156	$ 163,460,334	$ 300,448,330	$ 441,011,681	$ 424,960,867	$ 83,597,944
FINANCED BY						
THIRD PARTY FINANCED						
- INDEPENDENT POWER PRODUCERS (IPP)	$ 561,200,000	$ -	$ -	$ 226,848,000	$ 320,912,000	$ 13,440,000
Note - Not coded to GPL Fixed Assets	$ 561,200,000	$ -	$ -	$ 226,848,000	$ 320,912,000	$ 13,440,000
GPL FINANCING SOURCES						
- LOANS	$ 435,673,789	$ 81,999,087	$ 174,056,259	$ 125,040,892	$ 29,258,794	$ 25,318,757
- GRANT AID	$ 99,748,239	$ 26,513,808	$ 50,990,823	$ 16,063,608	$ 2,472,000	$ 3,708,000
- EQUITY	$ -	$ -	$ -	$ -	$ -	$ -
- INTERNAL FUNDS	$ 316,857,128	$ 54,947,439	$ 75,401,248	$ 73,059,181	$ 72,318,073	$ 41,131,186
Note - Coded to GPL Fixed Assets	$ 852,279,156	$ 163,460,334	$ 300,448,330	$ 214,163,681	$ 104,048,867	$ 70,157,944
TOTAL FINANCING	$ 1,413,479,156	$ 163,460,334	$ 300,448,330	$ 441,011,681	$ 424,960,867	$ 83,597,944

Table 15: Profit & Loss Account

	2020	Yr 2021	Yr 2022	Yr 2023	Yr 2024	Yr 2025
	Unaudited	Proj	Proj	Proj	Proj	Proj
	$'M	$'M	$'M	$'M	$'M	$'M
REVENUE						
Turnover	37,469	41,579	52,405	70,971	81,919	82,184
Rebate	(4,738)					
NET REVENUE	**32,731**	**41,579**	**52,405**	**70,971**	**81,919**	**82,184**
GENERATION COSTS						
Fuel & Freight	15,352	17,098	21,419	15,495	6,047	11,555
Operation & Maintenance Contract	2,777	5,745	7,411	5,353	2,024	3,964
Repairs & Maintenance - Generation Facility	482	500	500	500	500	500
Purchased Power (IPP costs)	2,213	2,137	1,293	16,994	37,649	37,950
Rental of Equipment	308	250	250	250	250	250
Fuel Agency Fee						
	21,132	**25,730**	**30,872**	**38,593**	**46,471**	**54,218**
GROSS INCOME	**11,599**	**15,849**	**21,532**	**32,378**	**35,448**	**27,966**
EXPENSES						
Employment Costs	4,663	5,129	5,642	6,206	6,827	7,510
Repairs & Maintenance T&D	758	1,956	4,225	6,235	6,902	7,063
Depreciation	3,333	3,396	6,480	10,288	13,500	15,155
Administrative Expenses	2,300	2,484	2,683	2,897	3,129	3,379
Rates & Taxes	50	54	58	63	68	73
Loss On Exchange	-	-	-	-	-	-
Bad Debts Provision	437	624	786	1,065	1,229	1,233
Puc Assessment & Licence	50	75	75	75	100	100
	11,591	**13,718**	**19,949**	**26,829**	**31,755**	**34,514**
NET (LOSS)/PROFIT FROM OPERATIONS	**8**	**2,131**	**1,583**	**5,548**	**3,693**	**(6,547)**
INTEREST EXPENSE	1,326	2,835	4,334	5,410	5,662	5,880
	(1,318)	**(704)**	**(2,751)**	**138**	**(1,970)**	**(12,428)**
OTHER INCOME	809	1,559	1,965	2,661	3,072	3,082
	(509)	**855**	**(786)**	**2,799**	**1,102**	**(9,346)**
TAXATION	64	128	(118)	420	165	(1,402)
NET (LOSS)/PROFIT FOR THE YEAR	**(573)**	**727**	**(668)**	**2,379**	**937**	**(7,944)**

In accordance with GPL's Licence, the Shareholder is entitled to a target rate of return on equity of 8% per annum.

Table 16: Cash Flow Statement

Guyana Power & Light	Yr 2020	Yr 2021	Yr 2022	Yr 2023	Yr 2024	Yr 2025	5 Year
Cash flow Statement for the year ended	**Unaudited**	**Proj**	**Proj**	**Proj**	**Proj**	**Proj**	**Summary**
December 31st	**$'m**	**$'m**	**$'m**	**$'m**	**$'m**	**$'m**	**$'m**
OPERATING ACTIVITIES							
Profit/(Loss) before Taxation	**(509)**	**855**	**(786)**	**2,799**	**1,102**	**(9,346)**	**(5,375)**
Adjustments for:							
Depreciation	3,333	3,396	6,480	10,288	13,500	15,155	48,819
Deferred Income	106	15	40	69	41	1	166
Deferred Tax Asset	0	102	(94)	333	131	(1,112)	(640)
Interest Expense	1,326	2,835	4,334	5,410	5,662	5,880	24,122
Amortization of Customer Projects							
Operating (loss)/profit before WC changes	**4,256**	**7,203**	**9,975**	**18,900**	**20,436**	**10,579**	**67,093**
Working Capital (WC) Changes							
Change in Inventories	(515)	1,579	(2,629)	(1,516)	120	(619)	(2,542)
Change in receivables and prepayments	(3,704)	6,625	(1,804)	(3,094)	(1,825)	(44)	(8,834)
Change in payables and accruals	2,017	16,656	(1,882)	(5,016)	(13,921)	(3,770)	943
Change in related parties	(162)	2,835	4,334	5,410	5,662	5,880	26,134
Taxes paid	(64)	(132)	67	(253)	(266)	780	195
Net Cash (Outflow)/Inflow - Operating Activities	**1,828**	**34,766**	**8,061**	**14,430**	**10,206**	**12,806**	**82,989**
INVESTING ACTIVITIES							
Acquisition of Property, plant and equipment	(12,590)	(47,930)	(53,696)	(42,641)	(21,864)	(14,303)	(180,434)
Acquisition of Intangible assets	0	(166)	(200)	(240)	(288)	(345)	(1,238)
Increase in WIP	0	(8,642)	2,310	5,660	14,578	4,415	18,321
Acquisition of treasury bills	0	0	0	0	0	0	0
Increase in deposit	437	0	0	0	0	0	0
Net Cash Outflow - Investing Activities	**(12,153)**	**(56,738)**	**(51,585)**	**(37,221)**	**(7,574)**	**(10,233)**	**(163,351)**
FINANCING ACTIVITIES							
Movement in non current related parties	12,161	29,877	37,466	26,915	6,298	5,450	106,005
Deposit on Shares	0	0	0	0	0	0	0
Interest paid	(1,326)	(2,835)	(4,334)	(5,410)	(5,662)	(5,880)	(24,122)
Customer deposits	305	391	1,031	1,768	1,043	25	4,258
Increase in advances customer financed projects	(639)	248	654	1,122	662	16	2,702
Decrease in advances customer financed projects							
Net Cash (Outflow)/Inflow - Financing Activities	**10,501**	**27,681**	**34,817**	**24,394**	**2,340**	**(389)**	**88,843**
NET MOVEMENT IN CASH AND CASH EQUIVALENTS	**176**	**5,709**	**(8,708)**	**1,603**	**4,972**	**2,184**	**8,481**
CASH AND CASH EQUIVALENTS AS AT BEGINNING OF YEAR	3,155	3,331	9,040	333	1,936	6,908	3,331
CASH AND CASH EQUIVALENTS AS AT END OF YEAR	**3,331**	**9,040**	**333**	**1,936**	**6,908**	**9,092**	**11,812**
Represented By:							
Cash on Hand and at Bank	**3,331**	**9,040**	**333**	**1,936**	**6,908**	**9,092**	**9,092**

Table 17: Balance Sheet

Guyana Power & Light	Yr 2020	Yr 2021	Yr 2022	Yr 2023	Yr 2024	Yr 2025
Statement of Financial Position	**Unaudited**	**Proj**	**Proj**	**Proj**	**Proj**	**Proj**
As at December 31st	**$'M**	**$'M**	**$'M**	**$'M**	**$'M**	**$'M**
ASSETS						
Non Current Assets						
Property, plant and equipment	29,384	73,918	121,133	153,487	161,851	160,999
Intangible assets	832	998	1,198	1,438	1,725	2,070
Work in progress	18,321	26,963	24,653	18,993	4,415	-
Deferred tax assets	5,623	5,521	5,615	5,282	5,150	6,263
	54,160	**107,400**	**152,599**	**179,199**	**173,142**	**169,332**
Current Assets						
Inventories	4,960	3,381	6,010	7,527	7,406	8,026
Receivables & Prepayments	13,555	6,930	8,734	11,828	13,653	13,697
Deposits	588	588	588	588	588	588
Related parties	5,646	5,646	5,646	5,646	5,646	5,646
Investments	828	828	828	828	828	828
Cash resources	3,331	9,040	333	1,936	6,908	9,092
	28,908	**26,414**	**22,139**	**28,353**	**35,029**	**37,876**
Total Assets	**83,068**	**133,814**	**174,738**	**207,552**	**208,172**	**207,209**
EQUITY & LIABILITIES						
Share Capital	23,118	23,118	23,118	23,118	23,118	23,118
Accumulated deficit	(14,575)	(13,848)	(14,516)	(12,137)	(11,200)	(19,144)
	8,543	**9,270**	**8,602**	**10,981**	**11,918**	**3,974**
Non Current Liabilities						
Related Parties	41,005	70,882	108,347	135,262	141,560	147,010
Advances customer financed project	1,545	1,714	2,161	2,926	3,378	3,389
Provision for decommissioning	243	243	243	243	243	243
Customer deposits	3,568	3,959	4,990	6,758	7,801	7,826
Defined benefit liability	851	851	851	851	851	851
Deferred tax liability	947	947	947	947	947	947
	48,159	**78,597**	**117,540**	**146,988**	**154,780**	**160,266**
Current liabilities						
Related parties	13,002	15,837	20,171	25,582	31,244	37,124
Deferred Income	139	154	194	263	304	305
Advances customer financed project	719	798	1,006	1,362	1,572	1,577
Payables and accruals	12,451	29,107	27,225	22,209	8,288	4,518
Taxation	55	51	-	167	66	- 556
	26,366	**45,947**	**48,597**	**49,583**	**41,473**	**42,968**
Total Equity and Liabilities	**83,068**	**133,814**	**174,738**	**207,552**	**208,172**	**207,209**

2. Introduction

2.1 General

The Guyana Power and Light (GPL) plays a critical role in the developing the country's economy, consistent with its mandate. This mandate requires the Company's firm commitments to provide and sustain efficient and available generation capacity to meet the forecasted demand within the industrial, commercial, and residential sectors.

The Company currently does not have sufficient reliable generation capacity to meet the forecasted peak demand, and this is further exacerbated by the lack of redundant circuits in the transmission and distribution networks. The situation will worsen with the expected increases in electricity demand and the dependency on the ageing network infrastructure.

Forty-seven megawatts (47 MW) of the Company's Heavy Fuel Oil fired baseload generator units (powered by Wärtsilä[5] and Mireles Blackstone[6] engines) within the Demerara Berbice Interconnected System (DBIS) have has surpassed the economic lifespan threshold of 20 years. Additionally, 11.53 MW of LFO fired have also exceeded the 20 years limit.

Although these older engines have been and continue to be well maintained and deliver a notable reliability level, they have become prone to mechanical and electrical failures due to exhaustive years of continuous operation.

In addition to LFO generator units, there is currently a total of 14.6 MW of LFO fired, high-speed generator units in Berbice. Although these generator units are designed and built for emergency operation, there are occasions when they are required to operate for longer hours because of system exigencies. These longer operation hours further expose the units to the risks of mechanical and electrical failures.

Combining the age of generator units and engine and/or alternator issues, the total unreliable power generation capacity in the DBIS (LFO and HFO fired generation) is 130.8 MW, and in the Isolated System, a total of 9.5 MW. Consequently, the Company is presented with the challenge of aged and unreliable generation capacity that is not consistent with the Company's desire to satisfy the growing demand with reliable generation.

The Government of Guyana remains cognizant of the importance of reliable generation and has provided debt financing to GPL to facilitate the construction of GPL's first single and largest power generation facility in the Country – 46.5 MW. This project is located at Garden of Eden and is expected to be commissioned within the first half of 2021.

Whilst the 46.5 MW at Garden of Eden will assist in improving generation reliability and supporting GPL to satisfy the immediate and short-term demand, against the backdrop of the forecasted demand, the DBIS will still require significant additional firm generation capacity. Similarly, the Isolated Systems will also require additional firm generation capacity.

[5] DP1 is 24 years old and totals 22MW, while and DP2 is 23 years old and totals 22MW. As such, a grand total of 44MW of Wartsila Engines.

[6] Canefield Mireles Blackstone Generator unit is 24 years old and totals 3MW of available capacity.

Should GPL be confronted with protracted delays in its power generation expansion plans, then the reliable supply-demand gap will dramatically widen and negatively impact Guyana's significant economic development, which is anticipated from the emerging Oil and Gas sector.

2.2 Positioning the 2021 – 2025 Development and Expansion Plan

GPL is cognizant of the changing, and evolving energy landscape as electricity generation from renewable resources is becoming more affordable and more attractive for self-generation. In addition, affordable and reliable electricity has become increasingly critical to national economic and socio-economic developments.

As the leading supplier of electricity services, the Company has comprehensively reviewed its role within this context and has revised its core objectives and critical issues, which form the 'pillars' of this Development and Expansion Programme. The core objectives and critical issues are presented below**: Corporate Objectives:**

2.1.1 Customer Service

- Provide Customer Centred Quality, Reliable and Timely Products and Services. This is integral to improving the Company's public image and ensuring the long-term viability of GPL. and
- Build the Market: The demand for electricity services continues to increase while renewable energy self-generation technologies are becoming more affordable. The Company recognizes the importance of lower tariffs and improved service reliability to sustain and influence growth in its customer base.

2.1.2 Employee Learning and Growth

- Ensure our employees possess the skills and competencies required to improve the quality of our products and services continuously; and
- Stimulate, develop, and retain a highly engaged workforce.

2.1.3 Financials

- Ensure that there are sufficient financial resources to sustain the Company's operations; and
- Mitigate against financial disruptions associated with the various risks facing the Company, e.g., fuel prices and currency exchange rates.

2.1.4 Core Operations

- Provide a cost-effective electricity service: Electricity is critical to national economic and socio-economic developments. This crucial positioning of the product dictates stakeholders' expected delivery of service in addition to competitive and affordable tariffs, and
- Provide a reliable electricity service: The Company intends to aggressively improve its reliability of service through investments in increasing its firm generation capacity,

upgrade and construct new distribution feeders and deploy technologies to manage better, supervise and support the distribution system remotely. These investments will improve generation reliability, mitigate transmission contingencies, improve SIAFI and SAIDI and provide aid in reducing technical losses.

2.1.5 Critical Issues

The Company continues to focus on four (4) critical issues that it intends to address in order to achieve operational excellence and achieve its strategic objectives. These critical issues are:

1. Improve the Quality of Products and Services;
2. Strengthen Management;
3. Optimize GPL as a System; and
4. Reduce Losses.

To address these issues, the Company will optimally develop and operate its generation, transmission, and distribution systems, while improving customer service and developing its human resources capacity.

2.3 Outline of Development and Expansion Programme

Section 3 (page 37) outlines the technical operation details of the Company;

Section 4 (page 99) summarises the non-technical components of the Company;

Section 5 (page 109) defines the Corporate Key Performance Indicators and Targets of GPL;

Section 6 (page 113) presents the summary of annual expansion, upgrades, and service work plan;

Sections 7 (page 121), 8 (page 122), and 9 (page 123) outlines GPL's financial position; and

Sections 10 (page 126) and 11 (page 126) highlights risks and mitigation measures.

3. Technical Operations

3.1 Generation

Before 2019, the previous planning studies have not been based on achieving key reliability targets. In 2019, GPL moved to change this approach by procuring PLEXOS and PSS Sincal and developing the internal capability to prepare development plans that are directly geared towards achieving reliability targets in the form of Loss of Load Probability (LOLP) or Loss of Load Expectation (LOLE). This is a critical step towards becoming a world-class utility.

GPL recognizes the importance and urgent need for new power generation capacity within the DBIS, to reliably satisfy the projected growth in electricity demand of over 500 megawatts of peak demand during the life of this development and expansion plan. The Company also anticipates that the projected electricity demand will rise above traditional levels as Guyana realizes the anticipated economic benefits associated with commercial crude oil production commencement in 2020.

3.2 Renewable Energy Resources

Whilst the abundance of renewable energy from resources such as wind and solar appear as attractive sources of generation that will have a mitigating effect on imported fossil fuel, price volatility and reduce carbon emissions, the intermittent nature of these resources concomitant with significant levels of penetration would present considerable challenges to the stability of the grid at this infant stage.

Generation from wind and solar, whilst attractive, will therefore not entirely displace the firm and dispatchable generation that is required to satisfy the current and projected baseload peak demand during the life of this development and expansion plan. Therefore, the Company plans to incrementally introduce and integrate generation from these renewable resources to ensure that electricity service delivery and system stability are not adversely affected. Firm and dispatchable generation from hydropower and biomass resources are attractive options to the Company. However, given the estimated project lead time of these resources, potential generation from hydropower and biomass is considered to be long-term options.

The immediate need for new dispatchable generation does not negate the Company's endorsement or alignment with Guyana's Energy Policy, Low Carbon Development Strategy and other Government related initiatives that seek to reduce the national carbon footprint and the electricity tariff. GPL intends to implement a total of 39.85 MWp of utility-scale Solar PV energy systems over the next five years.

3.3 Natural Gas

The emerging Oil and Gas sector has presented an opportunity for the Company's exploration of natural gas for electricity generation. Whilst natural gas is not a renewable source of energy, it is a cheaper, cleaner, green, and indigenous source of energy for the generation of electricity than GPL's current supply and offers the potential of a lower cost of generation and reduced electricity tariffs.

Natural gas consists typically of 70%-90% of methane, is the cleanest of all fossil fuels. It produces lower emissions of CO2, NO_x and SO_x and particulate matter than HFO and LFO. Natural gas is well suited to complement solar, wind and other RE sources in the power generation mix.

A desktop review on the feasibility of tapping gas from the Liza 1 indicated that this well could produce an estimated 30-50 MMBTU of natural gas per day and without impacting oil production. Additionally, this study also showed that a more substantial volume of gas would be expected at the end of the field life (resulting from gas reinjection).

Between the commencement date of the Liza-1 well, September 2015 and June 2020, ExxonMobil flared more than 9 billion cubic feet of gas[7], which is equivalent to no less than 1.591 million barrel of oil equivalents8 or 9,225,011 MMBtu. This amounted to approximately

[7] https://www.kaieteurnewsonline.com/2020/06/07/exxonmobils-flaring-in-guyana-it-releases-more-than-1-kilo-of-carbon-dioxide-for-every-man-woman-and-child-daily/

[8] Based on $1ft^3$ = 5658.3 cfng/boe: $1ft^3$ = 5.5mmBtu/boe

995.06 GWh or 113% of GPL’s 2019 total gross generation (DBIS + Essequibo Isolated power systems).

The flaring of natural gas will threaten the country’s global carbon footprint limit and impose a direct limit on the forest-based production activities. The Brugman Expansion Study indicated that Liza1 has a gas reserve of 0.2 Tcf. As such, a flow of 50 MMcf/d can power a 250-300 MW plant for approximately 11 years (K&M Gas to Power Study).

Several studies have concluded that the natural gas from Liza1 and others can be used to develop a sustainable energy sector that provides secure, reliable, environmentally friendly, and affordable energy services that are especially crucial to poverty reduction and align with the United Nations Sustainable Development Goal (SDG) No. 7.

The potential of natural gas from this emerging sector for electricity generation, therefore, forms part of a wider national initiative, which will further assist in determining the Company’s immediate to medium term generation strategy.

The Government of Guyana highlighted that the landing site for the pipeline and location for the committed gas to power project should be finalised by the end of 2021 to commence ‘Gas to Shore’ developmental activities by 2023.

The Company is currently constructing a 45.6 multifuel power plant at Garden of Eden that it expects to commission within the first half of 2021. The 46.5 MW Wärtsilä power plant can consume Natural Gas as the primary fuel and HFO or LFO as contingency fuels.

The Company expects the advent of an abundance of gas to replace liquid fossil fuels as energy resource electricity generation. This energy resource migration will propel the country towards the realising of the national objective of energy security from cleaner and cheaper sources for climate change, generation availability and reliability and the delivery of affordable electric services.

3.4 Transmission and Distribution

The reliable delivery of service from the generation stations to customers requires a robust and resilient Transmission and Distribution network. The Company’s current transmission and distribution network has evolved from a distribution network that is more than forty years and has been progressively expanded to deliver electricity to unserved areas along the coast of Guyana.

This progressive expansion, despite the Company’s extensive planned and executed maintenance activities, is still prone to defects on the aged sections of the network. These defects contribute to service disruptions that negatively impact the Company’s ability to reliably serve its customers and reduce unacceptable levels of technical losses.

The network was partially improved in 2014, having benefitted from the construction of seven (7) new substations, one hundred and thirty-seven (137) kilometres of transmission lines and the interconnection of two systems: Demerara and Berbice Power Systems. These network improvements positively influenced the service reliability to our customers and contributed towards the Company's technical loss reduction efforts. In order to continue improving the service reliability to meet the expectations of our customers, continued investment in the refurbishment and expansion of the network is required. The current high customer tariffs limit GPL's ability to leverage rate increases to fund the necessary investment in its system. GPL will continue to pursue alternative sources of funding to maintain its momentum of network improvements and expansion. This Development and Expansion Programme details the system improvements planned for the next 5 years.

3.5 System Losses

The progressive and sustained reduction in System Losses remains a corporate priority. This is underpinned by the notable reduction from twenty-six-point five percent (26.5%) in 2020 to a projected twenty-two decimal two percent (22.2%) in 2025. Further reductions in system losses will improve revenues and reduce operating costs. This will positively impact the Company's efforts and desire to lower tariffs for all consumers and improve the financial strength of GPL.

The major contributors identified to the Company's non-technical losses are:

- Unmetered supplies,
- Defective meters,
- Street lighting and
- Electricity theft.

The major contributors to the Company's technical losses are:

1. Aged and lengthy conductors (medium and low voltage),
2. Inefficient transformers and
3. Insufficient reactive power compensation.

The Company intends to reduce total losses to 22.2% by December 2025 from investments in feeder upgrades, transformer right-sizing, meter replacements, reactive power compensation at both transmission and primary distribution levels, and service installation upgrades. Additional low voltage rehabilitative efforts will require a significant capital investment that continues to present a challenge to the Company's self-financing efforts. The Company will prudently pursue concessional funding sources to intensify its loss reduction efforts and progressively lower production costs and tariffs.

3.6 Tariffs

The reduction of tariffs remains a priority to the Company and is consistent with the corporate vision. The Company will ensure that its generation strategies support and sustain reduced tariffs to all customers.

During 2015 and 2016, when world market fuel prices declined considerably, the Company applied a fuel rebate of five percent (5%) and ten percent (10%), respectively. Also, tariffs were reduced by five percent (5%) in year 2016. The aggregated effect was a twenty percent (20%) reduction in tariffs over year 2014.

Despite increases in world market fuel prices by approximately thirty-one percent (31%) in the ensuing years (2017 – 2020), the Company has not applied any fuel surcharge or tariff increases as provided for under its license.

Whilst lowered and sustained tariffs are among the Company's primary objectives, GPL remains challenged to fund network and generation improvement projects without debt financing and grants from multi-lateral concessional lending agencies.

The Financial projections are instructive as to the measures that could be taken to facilitate a reduction in Tariffs.

The key assumptions used in the projections are detailed in Table 1.

Table 1: Financial Projections – Facilitating Tariff Reduction

		Year 2020	Year 2025	Change
NET TARIFFS	US cents/kWh	**23**	**18**	22%
SALES DEMAND	GWh	667	2,121	218%
LOSSES (Technical and Commercial)	%	26.0%	22.2%	3.8%
FUEL PRICES				
Natural Gas Price delivered to the engin	US$/MMBTU	6	6	
HFO CIF Price	US$/barrel	55	55	
LFO CIF Price	US$/barrel	70	70	
LOAN STOCK				
GPL Loan Debt burden	G$' billion	52	121	133%
Interest Payments (4%)	G$' billion	2.08	4.84	133%
Principal Payments (15 Years amortizat	G$' billion	3.47	8.07	133%
Debt Servicing Total	G$' billion	**5.55**	**12.91**	133%

These factors have a significant influence on GPL's ability to lower Tariffs from the current level of approximately US 23 cents per kWh. A review of the projected financial performance for the period to 2025 highlights the following:

i) Growth in Sales Demand:

The significant growth in demand (an increase of approximately 234%) over the five (5) year period is projected to have a favourable impact on the generation of profits and operating cash flows. The projections have included a tariff reduction to US 21 cents per kWh at the beginning of 2024, and a further reduction to US 18 cents per kWh at the start of 2025.

ii) Losses (Technical and Commercial losses):

Losses are projected to decline from 26.5% to 22.2%. Further reductions in losses will have a positive impact on the Financial performance and improve the Company's ability to lower tariffs even further. As an example, an additional reduction in losses of 5% would allow for a reduction in Tariffs by about US 1 cent per kWh at the projected costs of generation.

iii) Cost of Generation

By 2025, generation using natural gas is projected to provide more than 42% of the required generation. The price at which gas is delivered to the engines is extremely important and will have the most significant impact on the ability of the Company to lower tariffs by 2025 as shown below:

Price of Gas:

- US$ 6 per MMBtu - Tariff reduced by 22% to US 18 cents/kWh
- US$ 5 per MMBtu - Tariff reduced by 30% to US 17 cents/kWh
- US$ 4 per MMBtu - Tariff reduced by 43% to US 16 cents/kWh
- US$ 3 per MMBtu - Tariff reduced by 52% to US 15 cents/kWh

iv) GPL's Debt Burden:

The projections indicate that by the end of 2025, GPL's Loans to the Government of Guyana would increase from G$52 billion to more than G$147 billion. This will require approximately G$16 billion in annual debt service obligations.

GPL is currently in the process of negotiating with the Ministry of Finance, the extension of the moratorium on all debt service until Year 2026.

Converting this debt to equity would allow for a further reduction of about US 2 cents after 2025.

3.7 Planning Criteria, Inputs and Assumptions

One of the essential cornerstones for economic and socio-economic developments is reliable electric service. As such, GPL planes to expand the power systems to satisfy the growing electricity demand and to ensure there is sufficient generation contingency capacity.

The Company seeks to expand and develop in tandem with the vision of National Energy Priorities, Low Carbon Development Strategy, and other related national energy priorities and strategies to improve the quality and reliability of service to customers and provide support to sustaining and fostering national developments. As such, the Company has a menu of programmes geared towards improvements in sustainable efficiencies. (see section 6 on page 113 for further details).

GPL has identified the two significant planning constraints to power system development and expansion: system reliability (generation availability) and capital investments availability.

Although capacity reserve margin provides a practical indication of the health status of the power generation system, probability-based power generation reliability metrics such as Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE) provide more accurate details on the ability of the power system to satisfy the current and future electricity demands.

The LOLP is essentially the probability of the total available generation capacity unable to satisfy the total peak demand. Within the period of a year (365 days), the LOLE indicates the number of days that the total available generation capacity is expected not to satisfy power demand. Consequently, there will be a certain amount of Expected Energy Not Served (EENS). Additionally, the Unserved Served Energy (USE) indicates load that could not be met due to a shortage in generation and/or transmission capacity.

The targeted generation reliability indices vary globally and depends on the country's economic status quo and projections. As such, in USA, Australia and Jamaica, the LOLE is 0.1 day/year, Republic of Ireland and New Zealand 8 hours/year (0.33 days/year), the Netherlands' 4 hours/year (0.167 days/year), Barbados 0.8 days/year.

The transmission system is also subject to contingency metrics. These are detailed in the Planning Code of the National Grid Code.

Given the above and the aim of GPL becoming a world-class utility, the Company has defined the following planning criteria for generation and T&D expansions:

1. LOLP of less than 0.27% per annum (LOLE of less than one (1) day per annum),
2. N-1 compliant on the transmission system, and
3. Reduce feeder thermal loading and total backbone length by at least 50%, respectively.

From an operation perspective, GPL adopted the rule of thumb used by NYISO[9] and PJM[10], which states that spinning reserve shall be 150% of the single largest contingency. In the case of the DBIS, the single largest contingency is presently equivalent to an N-G-1. As such, the required spinning reserve before the commissioning of the 46.5 MW plant is 13.05 MW, and after, 13.95 MW. As firm power generation expansion continues using larger units, the required spinning will increase accordingly.

3.8 Recent Achievements

3.8.1 Generation

In 2018, GPL commissioned key power generation expansion projects at Canefield, Anna Regina and Bartica. In 2020, GPL commenced constructing a 46.5 MW of multifuel power generation capacity at Garden of Eden.

3.8.1.1 Garden of Eden

Commencement of the construction of the 46.5 MW multifuel power plant at Garden of Eden. Given the 2021 forecasted peak demand, this power plant is expected to boost the capacity reserve margin by 28.92% (based on the peak demand forecast of 160.8 MW and total available generation capacity of 204.1 MW in 2021).

[9] http://www.caiso.com/Documents/AddendumDraftFinalProposal-ContingencyModelingEnhancements.pdf
[10] https://www.nrel.gov/docs/fy11osti/51978.pdf

3.8.1.2 Wakenaam

The company procured two 410 kW diesel-fired generators to augment the planned installation of 0.75 MW solar PV system with BESS. The Solar PV system with storage is funded via grant funding from the United Arab Emirates. GPL intends to realize hybrid generation capacity on the island.

3.8.1.3 Canefield

At Canefield, East Berbice Corentyne, GPL commissioned a 5.5 MW HFO fired power plant in March 2019. This power plant boosted the capacity reserve margin by 40% in 2018 and supported the Company's objective of reliably satisfying the growing demand in the DBIS.

In 2020, power generation capacity at Canefield was increased by 4.8 MW – 3 Mobile 1.6 MW Mobile CAT units.

3.8.1.4 Sophia

In 2020, 4.8 MW (3 x1.4MW Mobile CAT units) of LFO fired power generation capacity was added to the DBIS at Sophia.

3.8.1.5 Anna Regina

In April 2019, GPL commissioned a 5.4 MW HFO fired power plant at Anna Regina. This power plant replaced the aged, unreliable and derated 4 MW HFO fired power plant. This new power plant has resulted in significant improvement in generation reliability relative to the demand. The power plant has been designed for expansion for additional generation to meet the projected growth in demand.

3.8.1.6 Bartica

A 3.3 MW LFO fired plant was commissioned in the first quarter of 2020. With the assistance from Cummins, GPL performed workshop training sessions and included planted ancillaries to mitigate contingencies, thus ensuring the new power plant operates at a high percentage availability and reliability indices.

The 3.3 MW LFO fired plant replaces aged, unreliable and derated LFO fired units, which included containerised CAT units. This new 3.3 MW plant resulted in significant improvement in power generation reliability and efficiency, inclusive of firm reserve capacity for short to medium term load growth.

3.8.2 Transmission and Distribution (T&D)

GPL's 2020 distribution network work programme achieved:

1. Installation of additional 891 km of conductors for the extension of electricity service into unserved areas,
2. Upgraded a total of 98 km conductors on existing network,
3. Replaced 12.1 km of service line to customers, and

4. Installation of 235 additional transformers on the primary distribution network (13.8 kV).

For 2020, the T&D maintenance programme was developed to address known defects (from field inspections). Table 2 shows further and specific details of T&D achievements across the networks of GPL's coverage along the coastal plain of Guyana.

Table 2: T&D Achievements – Year to date 2020

T & D Achievements - Year to Date 2020					
TARGET INDICATORS			**TOTAL OVERALL (2020)**		
			AMOUNT		
ITEMS			**Plan**	**Ach**	**% Ach**
Pole replacement	**1**	PRIM.	1637	1511	92
		SEC.	2306	1977	86
Pole plumbing	**2**	PRIM.	812	651	80
		SEC.	894	685	77
Pole treatment	**3**	PRIM.	5636	2531	45
		SEC.	8899	2063	23
Old pole removal	**4**	PRIM.	1365	865	63
		SEC.	1521	1399	92
Pole stubbing	**5**	PRIM.	354	173	49
		SEC.	307	122	40
Anchor block replacement.	**6**	PRIM.	349	136	39
		SEC.	407	200	49
Guy replacement	**7**	PRIM.	356	316	89
		SEC.	492	429	87
Replacement defective cross arms	**8**	PRIM.	1844	1921	104
Insulator replacement	**9**	PRIM.	2338	2417	103
		SEC.	2045	1847	90
Line/hardware transfer	**10**	PRIM.	1374	1140	83
		SEC.	2526	2128	84
Line extension (km)	**11**	PRIM.	359	366	102
		SEC.	153	525	344
Line upgrade (km)	**12**	PRIM.	129	7	5
		SEC.	71	91	128
Line retention (km)	**13**	PRIM.	418	92	22
		SEC.	346	258	74
Service line replacement (meter)	**14**		19829	12054	61
Installation/replacement (GAB)	**15**	PRIM.	198	11	6
Installation/replacement (SPD)	**16**	PRIM.	136	63	46
Installation/replacement (RCO)	**17**	PRIM.	658	572	87

T & D Achievements - Year to Date 2020					
TARGET INDICATORS			TOTAL OVERALL (2020)		
			AMOUNT		
Installation/replacement (PMCO)	**18**		710	43	6
Transformer maintenance	**19**	SEC.	1116	1787	160
Installation of additional transformers	**20**	SEC.	363	235	65
Maintenance of capacitor banks	**21**		54	42	78
Jumper servicing/replacement	**22**	PRIM.	1020	2670	262
		SEC.	1755	4293	245
Service connection @ consumer	**23**		8454	11873	140
Installation of additional earths	**24**		2314	615	27
Route clearing (km)	**25**	PRIM.	408	371	91
		SEC.	222	199	90
Line inspection (km)	**26**	PRIM.	1285	1863	145
		SEC.	1592	1099	69
C.e.o.f cards	**27**	SEC.	742	1559	210
Total manhours					

3.9 Demand Analysis and Forecast

A historical analysis of GPL power systems (DBIS & Essequibo Isolated Systems) shows that for the period 2014 - 2019, total energy demand, by the proxy of gross generation, increased by an annual average of 3.8%, moving from 717GWh to 876GWh.

In the same period, the associated non-coincidental Peak Demand (Peak Load) from all systems increased by an annual average of 2.8%, moving from 115.7MW to 133.0MW. The slower growth in peak demand, when compared with the total energy consumed, explains the improvement in the power system load factor from 70.78% to 75.25%.

The load factor (discussed in a later subsection) is used to prepare the peak demand forecast, which is a critical component in the generation expansion planning process that seeks to achieve a specific generation reliability target.

Note that the load factor measures the overall average hourly energy divided by peak power. In other words, higher load factors indicate a relative lowering of the difference between power demand at its highest peak and its lowest trough.

The current 30-year base-case forecast is driven by robust economic growth projections arising from Guyana's nascent Oil and Gas sector while incorporating the most realistic and likely impacts of covid-19 that were expected as of the end of 2020. However, GPL continues to monitor the impacts of covid-19 and will make appropriate updates should this become necessary in order to maintain the statistical significance of the energy demand forecast.

The base-case forecast shows the combined gross demand for electrical energy growing by the following annual averages for the respective 5-year periods: by 26.4% from 2020 to 2025

(903GWh to 2,913GWh); by 11.7% from 2026 to 2030 (up to 5,059GWh), and 8.0% from 2031 to 2035 (up to 7,423GWh). For the 15 years from 2036 to 2050, the gross energy demand is forecasted to grow by an annual average of 5.4% reaching 16,417GWh.

Base case forecasted growth of peak demand for the 30 indicative years are as follows: by 21.5% from 2020 to 2025 (141MW to 456MW); by 13.0% from 2026 to 2030 (up to 761MW); and by 8.3% from 2031 to 2035 (up to 1,097MW). For the 15 years from 2036 to 2050, peak demand is forecasted to grow by an annual average of 5.3% reaching 2,375MW.

The current forecast (as of September 7, 2020) was built on, and to some extent, incorporated elements of work previously done in preparing the energy demand projections; (1) the Generation Expansion Study 2018[1] referred to as the "Brugman Study", and (2) The Demand Forecast Capacity Building Consultancy by ETS consultants (2019-2020). Reference is also made to forecasts prepared under the Gas to Power Feasibility Assessment in Guyana by K&M Advisors in 2019 mainly for comparison. A summary of the forecasts from these projects is provided in Appendix 1, page 137.

3.9.1 Disaggregated Forecast

The disaggregated forecast in this document is broken down into:

1. Gross Generation;
2. Net Generation;
3. Electricity Sales (per tariff and self-generation):
    a. Residential;
    b. Commercial;
    c. Industrial;
4. Unserved Electricity;
5. Energy Efficiency Measure

See Table 3, Table 4, Table 5 and Table 6 for details of the disaggregated demand forecast of GPL. Power systems

With regards to self-generated customers, in the Brugman's Study, it was assumed for these customers to become grid connected by 2025. In this report, GPL endorse this assumption against the backdrop of recent amendments to its license to purchase power from self-generated customers.

Table 3: Disaggregated Electricity and Peak Demand Forecast 2020-2025

GWh values unless stated otherwise	2020	2021	2022	2023	2024	2025
Gross Gen (No New EE Measures)	**902.63**	**1,173.75**	**1,468.12**	**1,970.97**	**2,500.30**	**2,912.60**
Energy Not served Factor (%)	*1.4%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Estimated Energy Not served	12.33	0.01	0.00	0.00	0.01	0.07
Energy Efficiency factor (% of Total Demand)	*2.4%*	*2.6%*	*3.1%*	*3.5%*	*4.1%*	*4.7%*
Potential Impact of EE measures	(21.90)	(30.65)	(45.26)	(68.64)	(103.35)	(135.73)
Potential Demand Post-EE	**880.73**	**1,143.10**	**1,422.86**	**1,902.33**	**2,396.95**	**2,776.87**
EVs consumption (DBIS only)	-	-	-	-	0.80	1.60
New Gross Gen. with EE &Evs	**880.73**	**1,143.10**	**1,422.86**	**1,902.33**	**2,397.75**	**2,778.47**
Auxiliaries & Self-Consumption	(22.25)	(23.28)	(30.07)	(40.60)	(47.65)	(51.35)
Net Energy Exported to Grid	**858.48**	**1,119.81**	**1,392.79**	**1,861.73**	**2,350.10**	**2,727.12**
Technical loss factor (%)	8.9%	8.6%	8.5%	8.4%	8.9%	8.6%
Non-Technical loss factor (%)	17.1%	16.4%	15.6%	14.7%	14.0%	13.6%
Technical & Non-technical losses	(223.20)	(279.95)	(334.27)	(428.20)	(537.84)	(605.97)
Total Sales	**635.27**	**839.86**	**1,058.52**	**1,433.53**	**1,812.26**	**2,121.15**
of which Commercial	*214.09*	*224.24*	*285.80*	*397.09*	*509.24*	*613.01*
Residential	*141.03*	*206.61*	*260.40*	*349.78*	*433.13*	*500.59*
Industrial	*280.16*	*409.01*	*512.32*	*686.66*	*869.88*	*1,007.55*
Demand category factors (%)						
Commercial	33.7%	26.7%	27.0%	27.7%	28.1%	28.9%
Residential	22.2%	24.6%	24.6%	24.4%	23.9%	23.6%
Industrial	44.1%	48.7%	48.4%	47.9%	48.0%	47.5%
Load Factor (%)	**76.633%**	**76.57%**	**73%**	**73%**	**76%**	**73%**
Peak MW (with EV's & En. Efficiency)	**131.20**	**170.41**	**222.55**	**298.37**	**358.83**	**435.26**
Peak MW (without EV's & En. Efficiency)	**134.46**	**174.98**	**229.62**	**309.14**	**374.18**	**456.28**

Table 4:Disaggregated Electricity and Peak Demand Forecast 2026-2030

GWh values unless stated otherwise	2026	2027	2028	2029	2030
Gross Gen (No New EE Measures)	**3,331.92**	**3,695.12**	**4,098.40**	**4,555.34**	**5,059.42**
Energy Not served Factor (%)	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Estimated Energy Not served	0.07	0.08	0.08	0.08	0.08
Energy Efficiency factor (% of Total Demand)	*4.9%*	*5.1%*	*5.3%*	*5.6%*	*5.8%*
Potential Impact of EE measures	(162.38)	(188.63)	(218.93)	(254.09)	(294.90)
Potential Demand Post-EE	**3,169.54**	**3,506.48**	**3,879.46**	**4,301.25**	**4,764.52**
EVs consumption (DBIS only)	2.08	2.71	3.54	4.61	6.00
New Gross Gen. with EE &Evs	**3,171.62**	**3,509.20**	**3,883.00**	**4,305.86**	**4,770.52**
Auxiliaries & Self-Consumption	(54.28)	(55.72)	(57.13)	(58.59)	(60.07)
Net Energy Exported to Grid	**3,117.34**	**3,453.48**	**3,825.87**	**4,247.27**	**4,710.45**
Technical loss factor (%)	8.5%	8.4%	8.3%	8.2%	8.1%
Non-Technical loss factor (%)	13.2%	12.8%	12.4%	12.0%	11.6%
Technical & Non-technical losses	(674.90)	(730.41)	(791.57)	(858.09)	(929.06)
Total Sales	**2,442.44**	**2,723.07**	**3,034.30**	**3,389.18**	**3,781.39**
of which Commercial	*721.98*	*822.91*	*936.99*	*1,068.95*	*1,217.61*
Residential	*571.04*	*630.66*	*696.07*	*770.02*	*850.81*
Industrial	*1,149.41*	*1,269.49*	*1,401.24*	*1,550.21*	*1,712.97*
Demand category factors (%)					
Commercial	29.6%	30.2%	30.9%	31.5%	32.2%
Residential	23.4%	23.2%	22.9%	22.7%	22.5%
Industrial	47.1%	46.6%	46.2%	45.7%	45.3%
Load Factor (%)	**75%**	**75%**	**75%**	**76%**	**76%**
Peak MW (with EV's & En. Efficiency)	**482.16**	**531.27**	**588.77**	**649.97**	**717.66**
Peak MW (without EV's & En. Efficiency)	**506.53**	**559.42**	**621.43**	**687.63**	**761.12**

Table 5: Disaggregated Electricity and Peak Demand Forecast 2031-2035

GWh values unless stated otherwise	2031	2032	2033	2034	2035
Gross Gen (No New EE Measures)	**5,475.99**	**5,944.96**	**6,425.81**	**6,918.53**	**7,423.13**
Energy Not served Factor (%)	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Estimated Energy Not served	0.08	0.08	0.09	0.09	0.09
Energy Efficiency factor (% of Total Demand)	*6.0%*	*6.1%*	*6.2%*	*6.3%*	*6.5%*
Potential Impact of EE measures	(327.50)	(361.50)	(398.08)	(437.47)	(479.95)
Potential Demand Post-EE	**5,148.48**	**5,583.46**	**6,027.73**	**6,481.06**	**6,943.18**
EVs consumption (DBIS only)	6.75	7.59	8.54	9.60	10.80
New Gross Gen. with EE &Evs	**5,155.23**	**5,591.05**	**6,036.27**	**6,490.66**	**6,953.98**
Auxiliaries & Self-Consumption	(61.53)	(62.68)	(63.68)	(63.20)	(63.96)
Net Energy Exported to Grid	**5,093.70**	**5,528.37**	**5,972.59**	**6,427.46**	**6,890.02**
Technical loss factor (%)	8.0%	8.0%	7.9%	7.8%	7.7%
Non-Technical loss factor (%)	11.2%	10.8%	10.4%	10.0%	9.6%
Technical & Non-technical losses	(980.20)	(1,037.31)	(1,091.99)	(1,144.30)	(1,193.58)
Total Sales	**4,113.50**	**4,491.07**	**4,880.60**	**5,283.16**	**5,696.44**
of which Commercial	*1,355.81*	*1,514.39*	*1,682.83*	*1,861.78*	*2,050.72*
Residential	*915.67*	*988.93*	*1,062.99*	*1,137.99*	*1,213.34*
Industrial	*1,842.03*	*1,987.75*	*2,134.77*	*2,283.38*	*2,432.38*
Demand category factors (%)					
Commercial	33.0%	33.7%	34.5%	35.2%	36.0%
Residential	22.3%	22.0%	21.8%	21.5%	21.3%
Industrial	44.8%	44.3%	43.7%	43.2%	42.7%
Load Factor (%)	**76%**	**76%**	**76%**	**76%**	**76%**
Peak MW (with EV's & En. Efficiency)	**775.84**	**840.56**	**906.51**	**973.69**	**1,042.06**
Peak MW (without EV's & En. Efficiency)	**824.11**	**893.77**	**965.01**	**1,037.87**	**1,112.36**

Table 6:Disaggregated Electricity and Peak Demand Forecast 2036-2040

GWh values unless stated otherwise	2036	2037	2038	2039	2040
Gross Gen (No New EE Measures)	**7,939.61**	**8,467.96**	**9,008.19**	**9,560.30**	**10,124.28**
Energy Not served Factor (%)	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Estimated Energy Not served	0.09	0.09	0.09	0.09	0.09
Energy Efficiency factor (% of Total Demand)	*6.6%*	*6.8%*	*7.0%*	*7.2%*	*7.4%*
Potential Impact of EE measures	(525.78)	(575.26)	(628.70)	(686.46)	(748.90)
Potential Demand Post-EE	**7,413.83**	**7,892.71**	**8,379.49**	**8,873.84**	**9,375.38**
EVs consumption (DBIS only)	12.15	13.66	15.37	17.28	19.44
New Gross Gen. with EE &Evs	**7,425.98**	**7,906.37**	**8,394.86**	**8,891.12**	**9,394.82**
Auxiliaries & Self-Consumption	(68.41)	(72.97)	(77.62)	(82.38)	(87.24)
Net Energy Exported to Grid	**7,357.56**	**7,833.40**	**8,317.23**	**8,808.74**	**9,307.58**
Technical loss factor (%)	7.6%	7.6%	7.5%	7.4%	7.4%
Non-Technical loss factor (%)	9.2%	8.8%	8.4%	8.0%	8.0%
Technical & Non-technical losses	(1,239.26)	(1,281.81)	(1,321.05)	(1,356.84)	(1,433.68)
Total Sales	**6,118.30**	**6,551.60**	**6,996.18**	**7,451.90**	**7,873.90**
of which Commercial	*2,202.59*	*2,358.57*	*2,518.62*	*2,682.69*	*2,834.61*
Residential	*1,303.20*	*1,395.49*	*1,490.19*	*1,587.26*	*1,677.14*
Industrial	*2,612.52*	*2,797.53*	*2,987.37*	*3,181.96*	*3,362.16*
Demand category factors (%)					
Commercial	36.0%	36.0%	36.0%	36.0%	36.0%
Residential	21.3%	21.3%	21.3%	21.3%	21.3%
Industrial	42.7%	42.7%	42.7%	42.7%	42.7%
Load Factor (%)	**76%**	**76%**	**76%**	**76%**	**77%**
Peak MW (with EV's & En. Efficiency)	**1,111.61**	**1,182.34**	**1,254.22**	**1,327.25**	**1,401.43**
Peak MW (without EV's & En. Efficiency)	**1,188.50**	**1,266.32**	**1,345.86**	**1,427.15**	**1,510.25**

3.9.2 Electricity Demand – Essequibo Isolated Power Systems

The forecasts for Essequibo, which includes Anna Regina, Bartica, Wakenaam and Leguan, indicate that electricity and peak demand in these areas will continue to grow at a significant rate (Table 7 to Table 10). With these projections and the need to improve on generation reliability and quality of electricity service to customers, the Company plans to boost its firm generation capacity in these areas.

Table 7: Disaggregated Forecast for Essequibo: 2020-2025

	GWh values unless stated otherwise	2020	2021	2022	2023	2024	2025
Anna Regina	Gross Generation (GWh)	31.61	39.39	47.55	61.06	75.20	86.32
	Rate of Growth (%)						
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.03	0.04	0.05	0.06	0.08	0.09
	Anna Regina Electricity Demand (GWh)	31.65	39.43	47.60	61.12	75.28	86.41
	Peak Demand (MW)	5.57	6.90	8.59	11.08	13.15	15.69
	Rate of Growth (%)						
	Load Factor	0.65	0.65	0.63	0.63	0.65	0.63
Bartica	Gross Generation (GWh)	12.28	14.82	17.41	21.54	25.42	27.87
	Rate of Growth (%)						
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.01	0.01	0.02	0.02	0.03	0.03
	Anna Regina Electricity Demand (GWh)	12.29	14.83	17.43	21.56	25.45	27.90
	Peak Demand (MW)	1.94	2.33	2.81	3.49	3.99	4.51
	Rate of Growth (%)						
	Load Factor	0.72	0.73	0.71	0.71	0.73	0.71
Leguan	Gross Generation (GWh)	1.74	2.08	2.46	3.08	3.73	4.23
	Rate of Growth (%)						
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.00	0.00	0.00	0.00	0.00	0.00
	Anna Regina Electricity Demand (GWh)	1.74	2.09	2.46	3.08	3.74	4.23
	Peak Demand (MW)	0.36	0.43	0.52	0.66	0.77	0.90
	Rate of Growth (%)						
	Load Factor	0.55	0.55	0.54	0.54	0.55	0.54
Wakenaam	Gross Generation (GWh)	1.72	2.08	2.44	3.04	3.66	4.12
	Rate of Growth (%)						
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.00	0.00	0.00	0.00	0.00	0.00
	Anna Regina Electricity Demand (GWh)	1.72	2.08	2.45	3.05	3.66	4.13
	Peak Demand (MW)	0.31	0.37	0.45	0.56	0.65	0.76
	Rate of Growth (%)						
	Load Factor	0.64	0.64	0.62	0.62	0.64	0.62

Table 8: Disaggregated Forecast for Essequibo: 2026-2030

	GWh values unless stated otherwise	2026	2027	2028	2029	2030
Anna Regina	Gross Generation (GWh)	97.76	108.13	119.92	133.53	149.18
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.10	0.11	0.12	0.13	0.15
	Anna Regina Electricity Demand (GWh)	97.86	108.24	120.04	133.66	149.33
	Peak Demand (MW)	17.30	19.10	21.21	23.52	26.24
	Rate of Growth (%)					
	Load Factor	0.65	0.65	0.65	0.65	0.65
Bartica	Gross Generation (GWh)	30.03	31.58	33.13	34.68	36.23
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.03	0.03	0.03	0.03	0.04
	Anna Regina Electricity Demand (GWh)	30.06	31.61	33.16	34.72	36.27
	Peak Demand (MW)	4.75	4.99	5.23	5.45	5.69
	Rate of Growth (%)					
	Load Factor	0.72	0.72	0.72	0.73	0.73
Leguan	Gross Generation (GWh)	4.69	5.04	5.38	5.70	6.01
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.00	0.01	0.01	0.01	0.01
	Anna Regina Electricity Demand (GWh)	4.69	5.04	5.39	5.71	6.01
	Peak Demand (MW)	0.98	1.05	1.12	1.18	1.24
	Rate of Growth (%)					
	Load Factor	0.55	0.55	0.55	0.55	0.55
Wakenaam	Gross Generation (GWh)	4.57	4.93	5.30	5.68	6.07
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.00	0.00	0.01	0.01	0.01
	Anna Regina Electricity Demand (GWh)	4.57	4.93	5.30	5.69	6.08
	Peak Demand (MW)	0.82	0.88	0.95	1.02	1.08
	Rate of Growth (%)					
	Load Factor	0.64	0.64	0.64	0.64	0.64

Table 9: Disaggregated Forecast for Essequibo: 2031-2035

	GWh values unless stated otherwise	2031	2032	2033	2034	2035
Anna Regina	Gross Generation (GWh)	166.31	185.54	207.28	232.00	260.21
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.17	0.19	0.21	0.23	0.26
	Anna Regina Electricity Demand (GWh)	166.48	185.72	207.49	232.23	260.47
	Peak Demand (MW)	29.35	32.74	36.58	40.94	45.91
	Rate of Growth (%)					
	Load Factor	0.65	0.65	0.65	0.65	0.65
Bartica	Gross Generation (GWh)	37.74	39.13	40.45	41.72	42.94
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.04	0.04	0.04	0.04	0.04
	Anna Regina Electricity Demand (GWh)	37.78	39.17	40.49	41.76	42.98
	Peak Demand (MW)	5.99	6.21	6.42	6.62	6.81
	Rate of Growth (%)					
	Load Factor	0.72	0.72	0.72	0.72	0.72
Leguan	Gross Generation (GWh)	6.30	6.54	6.75	6.92	7.06
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.01	0.01	0.01	0.01	0.01
	Anna Regina Electricity Demand (GWh)	6.31	6.55	6.76	6.93	7.06
	Peak Demand (MW)	1.31	1.36	1.41	1.44	1.47
	Rate of Growth (%)					
	Load Factor	0.55	0.55	0.55	0.55	0.55
Wakenaam	Gross Generation (GWh)	6.47	6.84	7.21	7.56	7.89
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.01	0.01	0.01	0.01	0.01
	Anna Regina Electricity Demand (GWh)	6.48	6.85	7.21	7.56	7.90
	Peak Demand (MW)	1.16	1.23	1.30	1.36	1.42
	Rate of Growth (%)					
	Load Factor	0.63	0.63	0.63	0.63	0.63

Table 10: Disaggregated Forecast for Essequibo: 2036-2040

	GWh values unless stated otherwise	2036	2037	2038	2039	2040
Anna Regina	Gross Generation (GWh)	278.31	296.84	315.78	335.13	354.90
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.28	0.30	0.32	0.34	0.35
	Anna Regina Electricity Demand (GWh)	278.59	297.13	316.09	335.47	355.26
	Peak Demand (MW)	49.11	52.38	55.72	59.14	62.62
	Rate of Growth (%)					
	Load Factor	0.65	0.65	0.65	0.65	0.65
Bartica	Gross Generation (GWh)	45.38	47.89	50.45	53.07	55.75
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.05	0.05	0.05	0.05	0.06
	Anna Regina Electricity Demand (GWh)	45.43	47.93	50.50	53.12	55.81
	Peak Demand (MW)	7.20	7.60	8.01	8.42	8.85
	Rate of Growth (%)					
	Load Factor	0.72	0.72	0.72	0.72	0.72
Leguan	Gross Generation (GWh)	7.48	7.91	8.36	8.81	9.27
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.01	0.01	0.01	0.01	0.01
	Anna Regina Electricity Demand (GWh)	7.49	7.92	8.37	8.82	9.28
	Peak Demand (MW)	1.56	1.65	1.74	1.84	1.93
	Rate of Growth (%)					
	Load Factor	0.55	0.55	0.55	0.55	0.55
Wakenaam	Gross Generation (GWh)	8.38	8.89	9.40	9.93	10.46
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.01	0.01	0.01	0.01	0.01
	Anna Regina Electricity Demand (GWh)	8.39	8.90	9.41	9.94	10.47
	Peak Demand (MW)	1.51	1.60	1.69	1.79	1.88
	Rate of Growth (%)					
	Load Factor	0.63	0.63	0.63	0.63	0.63

3.10 Current Status of Power Generation

3.10.1 Demerara Berbice Interconnected System (DBIS)

GPL's new GOE II 46.5 MW power plant at GOE, expected to be in commercial operation by Q2 2021 will mean GPL's aggregated electric power system will have 15 power plants totalling 222.9 MW of available capacity. The aggregated available capacity includes the 11 power plants or generating sites in the DBIS and the total of 4 in the Essequibo Islands and Bartica. A breakdown by fuel type indicates that HFO generator units account for 85% and LFO 15% of the total available capacity in the DBIS. For the Isolated Systems, 25% capacity is HFO and 75%, LFO. See Table 11 for further details.

Table 11: Breakdown of available generation capacity by fuel type

Fuel Type	Demerara	Berbice	Total DBIS	Anna Regina	Wakenaam	Leguan	Bartica	Total Isolated	Total GPL
MWs of HFO	155.9	18.2	174.1	4.8	-	-	-	4.8	178.9
MWs of LFO	10.8	19.2	30	7.2	1.1	0.8	5.0	14.0	44
Total Available Capacity (MW)	166.7	37.4	204.1	12.0	1.1	0.8	5.0	18.8	222.9

Fuel Type	Demerara	Berbice	Total DBIS	Anna Regina	Wakenaam	Leguan	Bartica	Total Isolated	Total GPL
% of HFO	94%	49%	85%	40%	0%	0%	0%	25%	80%
% of LFO	6%	51%	15%	60%	100%	100%	100%	75%	20%

With scheduled maintenance and efficient operation, generator units generally have a maximum operational life of 25 years although in most instances their economic life is taken as 20 years after which these units are classified as Cold Reserve Capacity. To date, a grand total of 57.6 MW of available capacity in the DBIS has surpassed the economic lifespan threshold of 20 years. The specifics of these generator units are shown in Table 12.

Table 12: Aged generator units in the DBIS

Generator Units	Commissioned Dates	Age to Date (yrs.)	Installed Capacity (MW)	Available Capacity (MW)
Garden of Eden - Niigata	**Subtotal**		**11.00**	**6.00**
# 5 Niigata	1991	30	5.50	3.00
# 6 Niigata	1996	25	5.50	3.00
Garden of Eden - DP1	**Subtotal**		**22.00**	**22.00**
# 1 Wartsila	1996	25	5.50	5.50
# 2 Wartsila	1996	25	5.50	5.50
# 3 Wartsila	1996	25	5.50	5.50
# 4 Wartsila	1996	25	5.50	5.50
Kingston I - DP2	**Subtotal**		**22.00**	**22.00**
# 1 Wartsila	1997	24	5.50	5.50
#2 Wartsila	1997	24	5.50	5.50
# 3 Wartsila	1997	24	5.50	5.50
# 4 Wartsila	1997	24	5.50	5.50
Canefield	**Subtotal**		**5.50**	**3.00**
#3DA - Mirrlees	1996	25	5.50	3.00
Onverwagt	**Subtotal**		**5.00**	**4.60**
#5 GM	1981	40	2.50	2.30
#7 GM	1981	40	2.50	2.30
Grand Total			**65.50**	**57.60**

Even though these older engines have been and continue to be well maintained and deliver availability above 95%, their continued use as baseload units is accompanied by an elevated risk of major mechanical failure resulting from the failure of components that are not renewed for the life of the engine, e.g., counterweight bolts. One engine was destroyed; suspected to be the result of failed counterweight bolts, precipitating a series of other mechanical failures.

In addition to the aged engines, 46.8 MW of relatively new HFO fired capacity at Kingston and Vreed En Hoop are considered to be suspect capacities. This is due to technical issues encountered by the alternators at the 26.1 MW power plant at Vreed en Hoop, and three units at Kingston II power plant totalling 20.7 MW. As a priority, GPL is currently working ardently to address these matters incrementally.

For the CAT LFO units in the Isolated Power Systems, GPL has realised over the years that it is considered cost-effective to replace a highspeed generator units with a brand-new unit than to perform a major overhaul. Major overhauls are usually done each 24,000 hours, and which approximates to 3 calendar years, and the total cost is approximately 80% of the cost of a brand-new generator unit. After major overhauls, it has been a challenge to return a highspeed generator unit's performance to its original state. As such, the balance 20% cost is in lieu can compensate for loss in performance and reliably justify the need to support improved efficiencies.

Combining the age of generator units and engine and/or alternator issues, Table 13 shows the annual Total Available Capacity, Reliable Capacity, Unreliable / Suspect Capacity, and Cold Reserve Capacity in MWs.

Table 13: Summary of power generation profile: 2021-2025 (DBIS)

GPL Power Systems	Year	2021	2022	2023	2024	2025
Demerara	Total Available Capacity (MW)	166.7	144.7	116.7	111.9	111.9
	Reliable Capacity (MW)	63.6	63.6	63.6	63.6	63.6
	Unreliable Capacity (MW)	103.1	81.1	53.1	48.3	48.3
	Cold Reserve Capacity (MW)	-	22.0	28.0	4.8	-
	Accumulated Cold Reserve (MW)	-	22.0	50.0	54.8	54.8
Berbice	Total Available Capacity (MW)	37.4	37.4	20.0	15.2	15.2
	Reliable Capacity (MW)	9.7	9.7	9.7	9.7	9.7
	Unreliable Capacity (MW)	27.7	27.7	10.3	5.5	5.5
	Cold Reserve Capacity (MW)	-	-	17.4	4.8	-
	Accumulated Cold Reserve (MW)	-	-	17.4	22.2	22.2
DBIS Total	Total Available Capacity (MW)	204.1	182.1	136.7	127.1	127.1
	Reliable Capacity (MW)	73.3	73.3	73.3	73.3	73.3
	Unreliable Capacity (MW)	130.8	108.8	63.4	53.8	53.8
	Cold Reserve Capacity (MW)	-	22.0	45.4	9.6	-
	Accumulated Cold Reserve (MW)	-	22.0	67.4	77.0	77.0

In view of the demand forecast (see section 1.4 on page 16 for further details) and the current fleet of generator units in the DBIS, capacity reserve margin, which excludes cold reserve capacity, will become negative and significant LOLP violation by 2022 (Table 14).

Table 14: Capacity reserve margin and LOLP profile for No Additional Firm Capacity

Year	Unit	2021	2022	2023	2024	2025
Peak Demand (MW)	MW	160.77	210.63	283.14	340.98	414.28
Annual Peak Demand Growth Rate (%)	*%*	27.3%	31.0%	34.4%	20.4%	21.5%
Required Reserve Capacity Margin (MW)	MW	43.2	47.5	83.0	167.1	147.8
Stochastic Capacity Reserve Margin (%) for LOLP Target	***%***	26.9	22.5	29.3	49.0	35.7
No Additional Firm Capacity						
Available Generation Capacity	MW	204.1	182.1	136.7	127.1	127.1
Capacity Reserve	MW	43.33	- 28.53	- 46.44	-213.88	-287.18
Capacity Reserve Margin (CRM)	%	26.95%	**-13.55%**	**-51.72%**	**-62.72%**	**-69.32%**
Loss of Load Probability (LOLP)	%	0.7%	**10.2%**	**86.2%**	**92.1%**	**95.3%**

In consideration of an N-G-1 contingency, the DBIS can presently suffer low voltage and frequency excursions[11], which would most certainly result in either a system shut-down or a major portion of customer on the DBIS without electricity. This would be an undesired situation given Guyana's position on economic and socio-economic developments in a commercial crude oil production economy.

3.10.2 Possibility of Converting Existing HFO Plants to Dual Fuel Plants - DBIS.

To further add value to natural gas availability for electricity generation, it is possible for GPL to convert Garden of Eden Wärtsilä (DP1), Kingston I (DP2), Kingston II (DP3) and Vreed-en-Hoop (DP4) plants to consume natural gas as the primary fuel and HFO as the contingency fuel.

The conversion of these power plants will result in significant reduction of their present operating costs (Table 15), and extension of their economic operating life by 12 to 15 years for DP1 and DP2, and 20 years for DP3 and DP4.

The duration to completely convert a single HFO engine to natural gas would be 52 business days (almost 2 months). Given the need to ensure generation reliability is maintained, plant conversion can be executed in a sequential order, commencing with the engines at DP1 – Garden of Eden. As such, at any given time, only a single engine will be out of service for 2 months, after which works would commence on another engine in a sequential order; moving from one completely converted plant to another. The total estimated duration for the four existing power plants is three years.

Table 15: Summary of Variation of key operating paraments after conversion to natural gas

[11] For frequency, depending on the location and nature of the fault.

Key Parameters	DP2	DP3 - W16V	DP3 - W18V	DP4
Output (kW)	-0.02%	-3.74%	-4.55%	-8.56%
Heat rate (BTU/kWh) - 100% Loading	-8.63%	0.11%	0.24%	4.94%
FO&M[12] ($/kW/yr)	-33.50%	-66.29%	-66.29%	-42.93%
VO&M[13] ($/kWh)	-59.25%	-65.86%	-68.79%	-64.35%
Maintenance Rate	-13.04%	-13.04%	-13.04%	-13.04%
Mean Time to Repair – Top Overhaul	1.19%	1.19%	1.19%	1.19%
Mean Time to Repair – Major Overhaul	-45.44%	-45.44%	-45.44%	-45.44%
Mean Time to Repair - FOR	-71.43%	-71.43%	-71.43%	-71.43%
FOR	-49.15%	-3.23%	-3.23%	-18.92%

The net output from a converted plant would be dependent upon the methane number and charge air receiver temperature (Figure 1). Additionally, the output is limited due to gas feed pressure and heating value of the gas (Figure 2). Consequently, the heat rate of the generator units would increase and the electric power output decrease. However, in the case of the engines of DP1 to DP4, the scope of work includes for increasing the cylinder bore to match the cylinder jacket for a DF34 Wartsila Engine.

Although it is required to increase the cylinder bore to restore the engine output, there are other significant cost saving benefits in converting these power plants (DP1 to DP4) to operate with natural gas (Table 15).

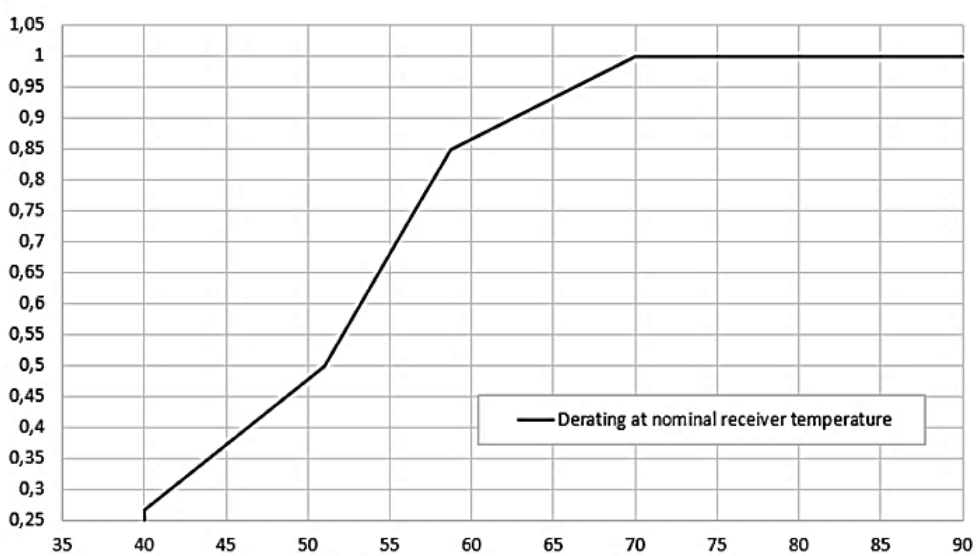

Figure 1: Output limitations due to methane number and charge air receiver temperature (*source: Wartsila Power Plant Gas Conversions: SG and DF Concept)*

[12] Fixed Operation and Maintenance Cost
[13] Variable Operation and Maintenance Cost

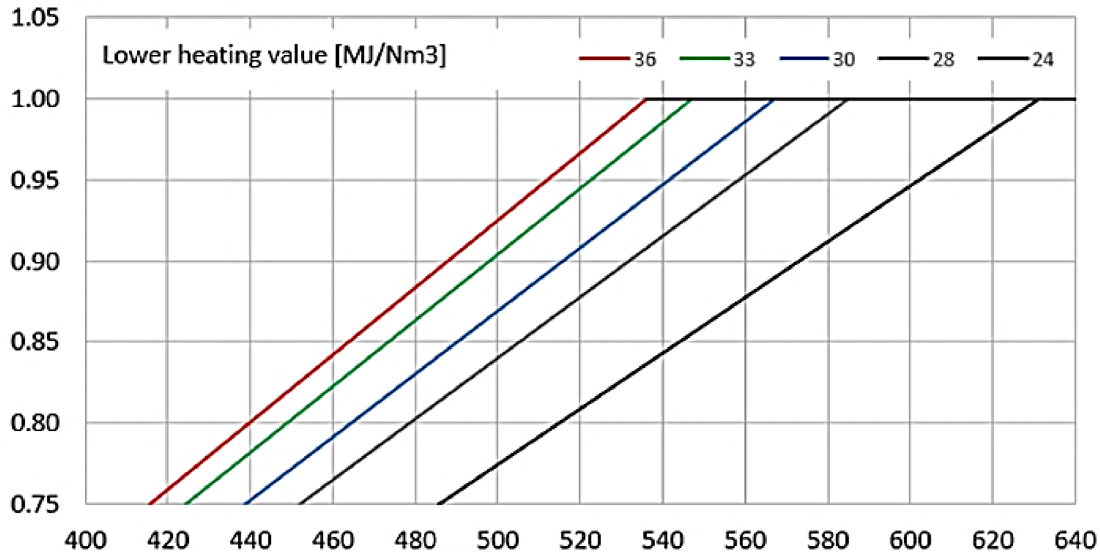

Figure 2: Output limitations for gas feed pressure and LHV, 480/500kW per cylinder (*source: Wartsila 34DF Product Guide*)

3.10.1 Isolated Power Systems (Anna Regina, Bartica, Leguan and Wakenaam)

Similarly, the isolated power systems in the Essequibo have a combination of aged and high-speed inefficient generator units.

Anna Regina

At the Anna Regina Power plant, the recently installed total 5.4 MW HFO fired generator plant had to be supported by LFO fired CAT units amid the rapidly increasing demand on the Essequibo Coast. Given that the cost of LFO is approximately 25% greater than HFO[14], and the need to reduce the cost of generation, GPL plans to reassign 7.2 MW of CAT units by the end of 2023 as cold reserve capacity. See Table 16 for further details.

Bartica

In the case of Bartica, given GPL's position on CAT generator units (see section 3.10.1, page 57), 1.6 MW of CAT unit is considered as unreliable capacity. As such, this unit is scheduled to be a reassigned as cold reserve at the end of 2023. See Table 16 for further details.

The GPL's approach to the CAT units does not apply to the Cummins generator units at Bartica, because the cost of a major overhaul is approximately 50% of the cost of a brand-new Cummins generator unit.

Leguan

In 2014, 3 new 410 kW CAT LFO fired generator units were commissioned. To date, these units are 7 years old and will be reassigned as cold reserve at the end of 2023. See Table 16 for further details.

[14] Fuel cost ratio as at December 2020.

Wakenaam

The Wakenaam power system is currently driven by CAT units that were commissioned sometime during the early 90's. Resulting from the UAE grant fund to convert the electricity system to be driven by almost 100% renewable energy, technical studies have indicated the need for diesel generators for supply security purposes. As such, through this financial support opportunity, GPL plans to replace the present aged generator units. However, maintain these aged units as cold serve within the current planning period. See Table 16 for further details.

To date, GPL has already purchased 2 new CAT units similar to the ones in Leguan to simplify the spare parts supply chain.

Table 16: Summary of power generation profile: 2021-2025 (Isolated Systems)

Anna Regina	**Total Available Capacity (MW)**	12.0	12.0	12.0	4.8	4.8
	Reliable Capacity (MW)	4.8	4.8	4.8	4.8	4.8
	Unreliable Capacity (MW)	7.2	7.2	7.2	-	-
	Cold Reserve Capacity (MW)	-	-	-	7.2	-
	Accumulated Cold Reserve (MW)	-	-	-	7.2	7.2
Wakenaam	**Total Available Capacity (MW)**	1.06	1.06	0.41	-	-
	Reliable Capacity (MW)	0.41	0.41	0.41	-	-
	Unreliable Capacity (MW)	0.65	0.65	-	-	-
	Cold Reserve Capacity (MW)	-	-	0.65	0.41	-
	Accumulated Cold Reserve (MW)	-	-	0.65	1.06	1.06
Leguan	**Total Available Capacity (MW)**	0.82	0.82	0.82	-	-
	Reliable Capacity (MW)	0.82	0.82	0.82	-	-
	Unreliable Capacity (MW)	-	-	-	-	-
	Cold Reserve Capacity (MW)	-	-	-	0.82	-
	Accumulated Cold Reserve (MW)	-	-	-	0.82	0.82
Bartica	**Total Available Capacity (MW)**	5.0	5.0	5.0	3.4	3.4
	Reliable Capacity (MW)	-	-	-	-	-
	Unreliable Capacity (MW)	1.6	1.6	1.6	-	-
	Cold Reserve Capacity (MW)	-	-	-	1.6	-
	Accumulated Cold Reserve (MW)	-	-	-	1.60	1.60
Isolated System	**Total Available Capacity (MW)**	18.8	18.8	18.2	8.2	8.2
	Reliable Capacity (MW)	6.0	6.0	6.0	4.8	4.8
	Unreliable Capacity (MW)	9.5	9.5	8.8	-	-
	Cold Reserve Capacity (MW)	-	-	0.65	10.0	-
	Accumulated Cold Reserve (MW)	-	-	0.65	10.68	10.68

3.11 Transmission and Distribution Systems

The Transmission and Distribution section of GPL's electric power system comprises three main volage levels; 69 kV for bulk power transfer, 13.8 kV for primary power distribution and lower utilisation voltage for customer specific applications.

GPL's present transmission and distribution network provides electricity supply coverage of approximately 81% on the Coastland, and comprises the following:

1. The transmission voltage level of 69 kV is only present in the DBIS, and has 16 transmission lines having a total length of 276 km;
2. Total of 42 primary distribution feeders in the DBIS having a total estimated length of 784 km; and
3. For the isolated system, Table 17 provides a breakdown of the relevant details.

Table 17: Breakdown of distribution feeders in Isolated Systems

<table>
<tr><th>LOCATION</th><th>FEEDERS</th><th>MV LENGTH (km)</th><th>LV LENGTH km</th><th>OVERALL TOTAL</th></tr>
<tr><td rowspan="4">Anna Regina</td><td>North</td><td>25.6 km</td><td rowspan="4">211 km</td><td rowspan="5">286.97 km</td></tr>
<tr><td>South</td><td>32.5 km</td></tr>
<tr><td>West</td><td>17.6 km</td></tr>
<tr><td>CRM</td><td>0.27 km</td></tr>
<tr><td colspan="2">TOTAL</td><td>75.97 km</td><td>211 km</td></tr>
<tr><td rowspan="3">Leguan</td><td>West</td><td>8.8 km</td><td rowspan="3">24 km</td><td rowspan="4">52.8 km</td></tr>
<tr><td>East</td><td>8.8 km</td></tr>
<tr><td>North</td><td>11.2 km</td></tr>
<tr><td colspan="2">TOTAL</td><td>28.8 km</td><td>24 km</td></tr>
<tr><td rowspan="2">Wakenaam</td><td>North</td><td>10.6 km</td><td rowspan="2">20 km</td><td rowspan="3">41.19 km</td></tr>
<tr><td>South</td><td>10.59 km</td></tr>
<tr><td colspan="2">TOTAL</td><td>21.19 km</td><td>20 km</td></tr>
<tr><td rowspan="3">Bartica</td><td>F1</td><td>3.2 km</td><td rowspan="3">23.5 km</td><td rowspan="4">41.1 km</td></tr>
<tr><td>F2</td><td>6.4 km</td></tr>
<tr><td>F3</td><td>8 km</td></tr>
<tr><td colspan="2">TOTAL</td><td>17.6 km</td><td>23.5 km</td></tr>
</table>

Within the total GPL power system, majority of network related challenges are currently experienced in the DBIS. A summary of the critical issues currently experienced are:

1. Reduced life span of pole structures due to poor quality of poles and cross-arms;
2. Impassable accesses to pole structures in remote terrains; largely for the transmission lines;
3. Frequent line trips due to vegetation encroachments on open conductors;
4. High voltage drops due to long feeder lengths, high electricity demands, and low power factor presented by maximum demand customers;
5. Widespread outages due to fault clearing by protection relay scheme at substation level;
6. Large number of and duration of outages to facilitate line maintenance and emergency switching; and
7. Poor operation visibility and remote control of primary distribution feeders result in a high dependency on customer fault reports.

3.12 Scenario No. 1 Generation Reliability – DBIS

Scenario No.1 essentially demonstrates the impact of the forecast demand on generation reliability, with consideration given **only** to the Total Available Capacity (Table 13) and present committed firm capacity generation expansion projects, and **no** generation expansions. Additionally, Cold Reserve Capacity (Table 13) will also be dispatched to assist in narrowing the supply-demand gap in this planning period.

In view of the current level of works in power generation expansion, the Garden of Eden 46.5 MW project, 250 MW Natural Gas to power plant and the 9x1.6 MW Mobile CAT units are considered as committed projects in this scenario for the current planning horizon (2021-2025).

To demonstrate the impact of the forecast demand on generation reliability, although the capacity reserve margin of the DBIS would be 43.3 MW (26.9%) in 2021, the LOLP target would be significantly violated at 9.17% (Table 18). Such a violation provides an indication that in 2021, should there be any reduction in the Total Available Capacity, the LOLP target would be significantly violated, resulting in increased periods of load-shedding or blackout. The situation can be further exacerbated, should the Cold Reserve Capacity Units become unavailable.

Table 18: DBIS Scenario No.1 Reliability Results for 2020-2025[15]

Fiscal Year	Peak Demand (MW)	Load (GWh)	EENS (MWh)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	LOLE (day)	LOLP (%)
2020	126.27	855.28	61.81	159.60	33.33	26.4	0.73	0.20
2021	160.78	1,086.25	6,396.59	204.10	43.32	26.94	33.47	9.17
2022	210.64	1,355.15	17,782.55	204.10	- 6.54	- 3.10	67.07	18.38
2023	283.14	1,816.70	286,681.91	204.10	- 79.04	- 27.92	288.99	79.18
2024	340.97	2,294.20	0.10	454.10	113.13	33.18	0.00	0.00
2025	414.29	2,661.64	1,185.38	454.10	39.81	9.61	4.80	1.32

In 2022, the LOLP will increase to 18.4% or 67 days. Further compounding the reliability constraint is the complete absence of capacity reserve margin (-3.10 MW). In 2023, capacity reserve margin heads further into the negative.

Power systems cannot operate with a negative capacity reserve margin. As such, for 2022 and 2023, a significant amount of load shedding would become necessary to maintain the required spinning reserve for power system stability. Consequently, for 2022 and 2023, the Expected Energy Not Serve will be significantly high.

For 2024, due to the committed 250 MW Natural Gas to Power Project, the LOLP target will be achieved, and capacity reserve margin will be 33.2 MW and LOLP target achieved. In the following year, with increasing demand, the capacity reserve margin and will be reduced to 9.6 MW and LOLP increased to 1.32% (Table 18).

[15] The additional years on both sides of the present planning horizon were included for information purposes only.

Besides the generation reliability performance of the DBIS (Table 18), from an operation perspective, Table 19 indicates that the contingency capacity, after discounting peak demand and the required spinning reserve, would be 15.4 MW in 2021. The significant contingency capacity for 2021 is immensely owed to the GOE II 46.5 MW Multifuel Power Plant.

In the following years, there will be a complete absence of contingency capacity in 2022 and 2023. In 2024, because of the 250 MW NG Plant, contingency capacity is expected to be 59 MW. However, in 2025, due to the project demand increases, contingency capacity would once again be absent from the DBIS (Table 19).

With the results for Scenario No.1, it can be easily understood, the positive impact of additional firm generation capacity, as seen from the results by adding the GOE II 46.5 MW Plant in 2021 and the 250 MW NG Plant in 2024, respectively.

Table 19: Scenario No.1 Capacity Forecast per Power Plant (considering spinning reserve) – DBIS.

Existing Capacity, MW	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
DEMERARA						
Garden of Eden Power Station	6.0	6.0	6.0	6.0	6.0	6.0
Garden of Eden 46.5 MW	-	46.5	46.5	46.5	46.5	46.5
Demerara Power (Kingston 1)	22.0	22.0	22.0	22.0	22.0	22.0
Demerara Power, (Kingston 11)	36.3	36.3	36.3	36.3	36.3	36.3
Demerara Power 1 (GoE)	22.0	22.0	22.0	22.0	22.0	22.0
Vreed En Hoop Power Station	26.1	26.1	26.1	26.1	26.1	26.1
Sophia	4.8	4.8	4.8	4.8	4.8	4.8
MCG - Giftland	3.0	3.0	3.0	3.0	3.0	3.0
Natural Gas to Power Project					250.0	250.0
Total Demerara	**120.2**	**166.7**	**166.7**	**166.7**	**416.7**	**416.7**
BERBICE	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Canefield						
Hyundai	-	5.5	5.5	5.5	5.5	5.5
No. 4 Mirrlees Blackstone	3.0	3.0	3.0	3.0	3.0	3.0
Mobile Sets	11.5	7.8	7.8	7.8	7.8	7.8
Onverwagt						
No. 5 General Motor	2.3	2.3	2.3	2.3	2.3	2.3
No. 7 General Motor	2.3	2.3	2.3	2.3	2.3	2.3
Mobile Sets	10.3	6.8	6.8	6.8	6.8	6.8
Skeldon						
SEI	10.0	9.7	9.7	9.7	9.7	9.7
Total Berbice	**39.4**	**37.4**	**37.4**	**37.4**	**37.4**	**37.4**
Total DBIS	**159.6**	**204.1**	**204.1**	**204.1**	**454.1**	**454.1**
Min Required Spinning Reserve (MW)	**13.1**	**14.0**	**14.0**	**14.0**	**27.0**	**27.0**
Net Capacity (MW)	**146.6**	**190.2**	**190.2**	**190.2**	**427.1**	**427.1**

Existing Capacity, MW	2020	2021	2022	2023	2024	2025
Peak Demand (MW)	126.3	160.8	210.6	283.1	341.0	414.3
Contingency Capacity (MW)	**7.2**	**15.4**	**- 34.4**	**- 106.9**	**59.1**	**- 14.2**

Electricity generated from intermittent renewable sources such as wind and solar PV are not firm and would only partially displace a certain percentage of hourly generation (MWh) originating from fossil fuel – depending on its penetration level in the power system. As such, intermittent renewable energy projects would aid in reducing fossil fuel consumption for electricity generation and would not significantly contribute to system reliability and achievement of the LOLE target. However, while intermittent renewable sources will theoretically reduce fossil fuel consumption in an equivalent quantity of MWh, firm generation capacity will be required to provide additional spinning reserve to the grid. The additional spinning reserve will be 30%[16] of the total installed intermittent renewable capacity.

To achieve the annual LOLP target and maintaining the required operation spinning reserve for system stability and contingency purposes, it is evident the need to increase firm power generation capacity in the DBIS, commencing from latter part of 2021.

3.13 Scenario No. 1 Generation Reliability – Essequibo Isolated Power Systems

Similarly, from a planning perspective for the Isolated Power Systems in the Essequibo, Table 20 indicates that although Anna Regina has a positive capacity reserve margin until 2023, the LOLP target will not be satisfied from 2023.

Table 20: Anna Regina Scenario No.1 Reliability Results for 2020-2025

Fiscal Year	Peak Demand (MW)	Load (GWh)	EENS (MWh)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	LOLE (day)	LOLP (%)
2020	5.57	31.61	0.46	12.00	6.43	115.44	0.05	0.01
2021	6.72	38.36	5.17	12.00	5.28	78.57	0.38	0.10
2022	8.33	46.08	78.70	12.00	3.67	44.06	5.12	1.40
2023	10.70	58.93	1,864.28	12.00	1.30	12.15	84.14	23.05
2024	12.61	72.09	9,274.44	12.00	- 0.61	- 4.84	265.49	72.54
2025	14.96	82.29	24,865.35	12.00	- 2.96	- 19.79	329.79	90.35

With LOLP violation, there will be a significant amount of Expected Energy Not Served (EENS) from 2023 – insufficient generation to satisfy demand amid generator forced outage and scheduled maintenance.

Considering that agriculture is one of the main drivers of the economy on the Essequibo coast, such an expected downward performance in generation reliability can constrain growth and welfare developments.

[16] Rule of thumb from WSP Consultancy on Grid Integration of Solar PV and BESS Study.

Table 21 highlights that for **Bartica,** the available generation capacity would meet the annual forecast demand. However, there will not be much spare capacity to mitigate generator forced outages and schedule maintenance. From 2022 the LOLP target would be violated and Expected Energy Not Served will begin to be significant from that year.

Table 21: Bartica Scenario No.1 Reliability Results for 2020-2025

Fiscal Year	Peak Demand (MW)	Load (GWh)	EENS (MWh)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	LOLE (day)	LOLP (%)
2020	1.94	12.28	7.20	4.96	3.02	155.67	0.38	0.10
2021	2.27	14.43	23.02	4.96	2.69	118.50	3.23	0.89
2022	2.72	16.88	72.05	4.96	2.24	82.35	6.23	1.71
2023	3.36	20.79	211.46	4.96	1.60	47.62	16.23	4.45
2024	3.82	24.37	508.95	4.96	1.14	29.84	38.81	10.60
2025	4.30	26.57	1,089.93	4.96	0.66	15.35	71.02	19.46

Within the context of providing business services, electricity must be seen as an enabler and as supporter for socio-economic development. Given that Bartica is one of the major gateways to the hinterland regions, power generation and supply of reliable electricity is imperative to the residents in providing key services to sustain the mining industry. In light of the aforementioned, such an expected performance in generation reliability would constraint growth and welfare development in Bartica.

For **Wakenaam**, Table 22 shows that the available generation capacity would meet the annual forecast demand. However, there will be not any significant spare capacity to mitigate generation forced outage and schedule maintenance as of 2024.

Table 22: Wakenaam Scenario No.1 Reliability Results for 2020-2025

Fiscal Year	Peak Demand (MW)	Load (GWh)	EENS (MWh)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	LOLE (day)	LOLP (%)
2020	0.31	1.72	19.73	0.65	0.34	109.68	5.54	1.51
2021	0.36	2.03	3.50	1.06	0.70	194.44	1.26	0.35
2022	0.43	2.40	10.10	1.06	0.63	146.51	2.83	0.77
2023	0.54	2.94	15.69	1.06	0.52	96.30	3.22	0.88
2024	0.62	3.51	40.18	1.06	0.44	70.97	10.89	2.97
2025	0.72	3.93	84.03	1.06	0.34	47.22	22.04	6.04

Table 23 illustrates that for **Leguan**, the available generation capacity would meet the annual forecast demand. However, there will not be sufficient spare capacity to mitigate generator forced outages and schedule maintenance. As such, from 2022, the LOLP target would be violated and Expected Energy Not Served (EENS) will begin to be significant. Similarly, to Anna

Regina, the main activity drives the local economy in Leguan is rice cultivation. Consequently, downward performance in generation reliability would not encourage economic and socio-economic developments in Leguan.

Table 23: Leguan Scenario No.1 Reliability Results for 2020-2025

Fiscal Year	Peak Demand (MW)	Load (GWh)	EENS (MWh)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	LOLE (day)	LOLP (%)
2020	0.36	1.74	11.09	0.82	0.46	127.8	1.32	0.36
2021	0.42	2.03	38.22	0.82	0.40	95.24	12.06	3.30
2022	0.50	2.38	76.90	0.82	0.32	64.00	24.97	6.84
2023	0.63	2.97	188.25	0.82	0.19	30.16	40.16	11.00
2024	0.74	3.58	272.98	0.82	0.08	10.81	42.59	11.64
2025	0.86	4.03	397.73	0.82	- 0.04	- 4.65	124.57	34.13

From an operation perspective, spinning reserve for hourly power system stability, Ann Regina will not have significant contingency capacity from 2023. See Table 24 for further details.

For Bartica, Table 24 shows that there will be a significant contingency capacity for the planning period.

Regarding Leguan and Wakenaam, isolated power systems would not have contingency capacity for secured power system operations. See Table 24 for further details.

Table 24: Scenario No.1 Capacity Forecast per Power Plant (considering Operating spinning reserve) – Essequibo Isolated Power Systems

Existing Capacity, MW	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anna Regina						
MAN (MW)	4.80	4.80	4.80	4.80	4.80	4.80
Mobile Sets (MW)	7.20	7.20	7.20	7.20	7.20	7.20
Total Anna Regina (MW)	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**
Min Required Spinning Reserve (MW)	**2.70**	**2.70**	**2.70**	**2.70**	**2.70**	**2.70**
Net Capacity (MW)	**11.86**	**11.86**	**11.86**	**11.86**	**11.86**	**11.86**
Peak Demand (MW)	5.57	6.72	8.33	10.70	12.61	14.96
Contingency Capacity (MW)	**3.59**	**2.44**	**0.83**	**- 1.54**	**- 3.45**	**- 5.80**
Bartica						
Cummins (MW)	4.96	4.96	4.96	4.96	4.96	4.96
Mobile Units (MW)	1.60	1.60	1.60	1.60	1.60	1.60
Total Bartica (MW)	**6.56**	**6.56**	**6.56**	**6.56**	**6.56**	**6.56**
Min Required Spinning Reserve (MW)	**1.65**	**1.65**	**1.65**	**1.65**	**1.65**	**1.65**
Net Capacity (MW)	**6.56**	**6.56**	**6.56**	**6.56**	**6.56**	**6.56**
Peak Demand (MW)	1.94	2.27	2.72	3.36	3.82	4.30
Contingency Capacity (MW)	**2.97**	**2.64**	**2.19**	**1.55**	**1.09**	**0.61**

Existing Capacity, MW	2020	2021	2022	2023	2024	2025
Anna Regina						
Wakenaam						
Caterpillar (MW)	0.65	1.06	1.06	1.06	1.06	1.06
Total Wakenaam (MW)	**0.65**	**1.06**	**1.06**	**1.06**	**1.06**	**1.06**
Min Required Spinning Reserve (MW)	**0.47**	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**
Net Capacity (MW)	**0.65**	**1.06**	**1.06**	**1.06**	**1.06**	**1.06**
Peak Demand (MW)	0.31	0.36	0.43	0.54	0.62	0.72
Contingency Capacity (MW)	**- 0.13**	**0.09**	**0.02**	**- 0.10**	**- 0.18**	**- 0.28**
Leguan						
Caterpillar (MW)	0.82	0.82	0.82	0.82	0.82	0.82
Total Leguan (MW)	**0.82**	**0.82**	**0.82**	**0.82**	**0.82**	**0.82**
Min Required Spinning Reserve (MW)	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**
Net Capacity (MW)	**0.82**	**0.82**	**0.82**	**0.82**	**0.82**	**0.82**
Peak Demand (MW)	0.36	0.42	0.50	0.63	0.74	0.86
Contingency Capacity (MW)	**- 0.16**	**- 0.22**	**- 0.30**	**- 0.43**	**- 0.54**	**- 0.66**

3.14 Firm Generation Capacity Requirements and Planned Renewables - DBIS

With the DBIS coverage stretching from the East Bank of the Essequibo River in the West to Moleson Creek in the East, and Kuru Kuru on Southern end, it has a significant larger coverage of the total number of customers on the Coastal Plain than the isolated power systems.

The major economic activities, which includes agriculture and service industries to the mining and the currently developing Oil and Gas sector, are within the coverage of the DBIS. Consequently, it is imperative for the DBIS to operate at the highest level of generation and network (transmission and distribution) reliability in support of planned economic activities for the period 2021-2025 and by extension, be aligned with other long-term expansion plans.

On the account of the above, Table 25 shows the required firm generation capacity to achieve the LOLP target of less than 0.27% after 2021.The Company intends to manage and configure these additional firm generation capacities with a focus on using clean, and affordable energy to:

1. Assist GPL in satisfying the forecast demand reliably;
2. Improve power generation reliability;
3. Reduce Guyana's dependency on imported fossil fuels for electricity generation;
4. Assist in increasing the disposable income for the Government and GPL to support other critical developments;
5. Reduce the cost of generation, and by extension customer tariffs; and
6. Facilitate Guyana moving towards the realization of its climate change commitments.

As shown in Table 25, only in 2021 the LOLP target will not be satisfied. The main reason is due to the late in-service date of the Garden of Eden 46.5MW – Phase 1. PLEXOS initially calculates the LOLP for each hour of the year, and then gives the annual average. With the Garden of Eden 46.5MW project expected to be in-service by June 2021, the first 3,600hrs electricity demand (from January 1st to May 31st) would not be supported by this capacity. Inevitably, the LOLP target would not be met and stand at 9.17% for 2021 only.

Table 25: Generation Reliability with Planned Expansions – DBIS

Fiscal Year	Peak Demand (MW)	Load (GWh)	EENS (MWh)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	LOLE (day)	LOLP (%)
2020	126.27	834.52	168.32	159.60	33.33	26.40	1.87	0.51
2021	160.78	1,086.26	6,396.59	204.10	43.32	26.94	33.47	9.17
2022	210.64	1,355.15	18.89	258.10	47.46	22.53	0.15	0.04
2023	283.14	1,816.70	1.05	366.10	82.96	29.30	0.01	1.9E-03
2024	340.97	2,294.20	6.44E-05	508.10	167.13	49.02	4.8E-07	1.3E-07
2025	414.29	2,661.64	8.46E-03	562.10	147.81	35.68	5.4E-05	1.4E-05

For the other planning years, Table 25 shows that with the recommended firm generation capacity, the LOLP target will be satisfied, and the power system will have sufficient capacity reserve margin for grid stability and to mitigate N-G-1 contingency.

Ideally, the EENS should be zero. However, accounting for schedule maintenance of generators and forced outages, there will be energy not served. As shown in Table 25, with the recommended firm generation capacity, EENS will reduce to insignificant amounts of energy, annually.

The LOLP in Table 25 is also based on recorded forced outage rate (FOR) for each generator unit and 3% as the estimated value for new generator units. While understanding the adverse impact of FOR on generation reliability, GPL will ensure strict maintenance schedule is adhere to and all maintenance activities are full compliance with manufacturer and industry standards.

The recommended firm generation capacity to achieve the LOLP target are detailed in Table 26.

In view of Government's climate change commitments through the Low Carbon Development Strategy and National Energy Priorities, GPL plans to have in commercial operation, a 10 MWp Solar PV farm in Berbice, and a total of 8 MWp Solar PV capacity and 8 MWh BESS in Anna Regina by 2023.

It is also planned for a 15 MWp and 15 MWh BESS to be in commercial operation in Linden by 2023. However, given that it is also planned for Linden to be connected with the DBIS in 2024, Table 20 accounts for Linden Solar PV accordingly.

The 4 MWp Solar PV farm planned for 2025 in Naarstigheid, and which is earmarked to be funded by a Grant from the People Republic of China, is also considered as an integral and equally important renewable energy project in this expansion plan.

Table 26: Proposed Generation Addition – DBIS

Name of Location	Type	Installed Capacity (MW)				
		2021	**2022**	**2023**	**2024**	**2025**
Garden of Eden - Phase 1	Firm Capacity	46.5				
Garden of Eden - Phase 2	Firm Capacity		54.0			
250 MW NG Plant - Phase 1	Firm Capacity			108.0		
250 MW NG Plant - Phase 2	Firm Capacity				142.0	
Crab Island	Firm Capacity					54.0
Berbice Solar PV	Non-Firm Capacity			10.0		
Linden Solar PV	Non-Firm Capacity				15.0	
Naarstigheid Solar PV	Non-Firm Capacity					4.0
Total New Additions		**46.5**	**54.0**	**118.0**	**157.0**	**58.0**
Total Accumulated Additions			**100.5**	**218.5**	**375.5**	**433.5**
Annual Non-Firm Capacity		**-**	**-**	**10.0**	**15.0**	**4.0**
Annual Firm Capacity		**46.5**	**54.0**	**108.0**	**142.0**	**54.0**
Total Accumulated Firm Capacity		**46.5**	**100.5**	**208.5**	**350.5**	**404.5**
Existing Firm Capacity		**157.6**	**154.6**	**134.2**	**125.5**	**125.5**
Grand Total Firm Capacity		**204.1**	**255.1**	**342.7**	**476**	**530.0**

Accounting for the spinning reserve requirements (150% of largest firm generator unit and 30% of annual accumulated renewable energy installed capacity), Table 27 illustrates DBIS performance on an annual basis in view of the planned additional generation capacities and the significant amount of annual contingency capacity against the projected increasing peak demand.

In addition to using firm capacity to provide spinning reserve, GPL also plans to install a 10 MW-4hr BESS to the DBIS at New Sophia. The 10MW-4hr BESS, besides providing spinning reserve, will also provide ancillary services to mitigate frequency and voltage excursions due to contingencies in the DBIS.

Table 27: Generation Contingency Capacity Forecast with Recommended Additions - DBIS

Existing and New Power Generators	**Type**	**2021**	**2022**	**2023**	**2024**	**2025**
DEMERARA						
Garden of Eden Power Station	Firm Capacity	6.0	6.0	**6.0**	**6.0**	**6.0**
Demerara Power (Kingston 1)	Firm Capacity	22.0	22.0	**22.0**	**22.0**	**22.0**
Demerara Power, (Kingston 11)	Firm Capacity	36.3	36.3	36.3	36.3	36.3
Demerara Power 1 (GoE)	Firm Capacity	22.0	**22.0**	**22.0**	**22.0**	**22.0**
Vreed En Hoop Power Station	Firm Capacity	26.1	26.1	26.1	26.1	26.1
Old Sophia	Firm Capacity	4.8	4.8	4.8	**4.8**	**4.8**
MCG - Giftland	Firm Capacity	3.0	3.0	3.0	3.0	3.0
ADDITION 10MW-4hr BESS (New Sophia)	Firm Capacity	-	10.0	10.0	10.0	10.0
ADDITION (Garden of Eden - Phase 1)	Firm Capacity	46.5	46.5	46.5	46.5	46.5
ADDITION (Garden of Eden - Phase 2)	Firm Capacity	-	54.0	54.0	54.0	54.0
ADDITION (250MW NG Plant - Phase 1)	Firm Capacity	-	-	108.0	108.0	108.0
ADDITION (250MW NG Plant - Phase 2)	Firm Capacity	-	-	-	142.0	142.0
ADDITION (Crab Island)	Firm Capacity	-	-	-	-	54.0
ADDITION (Linden Solar PV)	Non-Firm Capacity	-	-	-	15.0	15.0
Total Installation Generation (MW)		**166.7**	**230.7**	**338.7**	**495.7**	**549.7**
Total Firm Generation Capacity (MW)		**166.7**	**230.7**	**338.7**	**480.7**	**534.7**
Total Non-Firm Generation Capacity (MW)		**-**	**-**	**-**	**15.0**	**15.0**
Total Cold Reserve Capacity (MW)		**-**	**22.0**	**50.0**	**54.8**	**54.8**
BERBICE						
Canefield						
Hyundai	Firm Capacity	5.5	5.5	5.5	5.5	5.5

No. 4 Mirrlees Blackstone	Firm Capacity	3.0	3.0	**3.0**	**3.0**	**3.0**
Mobile Sets	Firm Capacity	7.8	7.8	**7.8**	**7.8**	**7.8**
Onverwagt						
No. 5 General Motor	Firm Capacity	2.3	2.3	**2.3**	**2.3**	**2.3**
No. 7 General Motor	Firm Capacity	2.3	2.3	**2.3**	**2.3**	**2.3**
Mobile Sets	Firm Capacity	6.8	6.8	**6.8**	**6.8**	**6.8**
ADDITION (10MWp Solar PV)	Non-Firm Capacity	-	-	10.0	10.0	10.0
ADDITION (Naarstigheid Solar PV)	Non-Firm Capacity	-	-	-	-	4.0
Skeldon						
SEI	Firm Capacity	9.7	9.7	9.7	9.7	9.7
Total Installation Generation (MW)		**37.4**	**37.4**	**47.4**	**47.4**	**51.4**
Total Firm Generation Capacity (MW)		**37.4**	**37.4**	**37.4**	**37.4**	**37.4**
Total Non-Firm Generation Capacity (MW)		**-**	**-**	**10.0**	**10.0**	**14.0**
Total Cold Reserve Capacity (MW)		**-**	**-**	**17.4**	**22.2**	**22.2**
DBIS Accumulated Firm Generation Capacity (MW)		**204.1**	**268.1**	**376.1**	**518.1**	**572.1**
DBIS Accumulated Non-Firm Generation Capacity (MW)		**-**	**-**	**10.0**	**25.0**	**29.0**
DBIS Min Required Spinning Reserve (MW)		**14.0**	**27.0**	**30.0**	**34.5**	**35.7**
DBIS Net Capacity (MW)		**190.2**	**241.1**	**346.1**	**483.6**	**536.4**
DBIS Forecast Peak Demand (MW)		**160.8**	**210.6**	**283.1**	**341.0**	**414.3**
Contingency Capacity (MW)		**29.4**	**30.5**	**63.0**	**142.6**	**122.1**

3.15 Firm Generation Requirements and Planned Renewables - Isolated Power Systems

3.15.1 Anna Regina

In recognition of the generation reliability results (Table 20), and the significant improvement in distribution reliability, the current demand has already exhausted the recently installed 5.4 MW HFO fired MAN generator units. Consequently, GPL was forced to use LFO fired Caterpillar units to boost generation capacity and reliability to satisfy the growing demand.

It is planned to have the Anna Regina power system interconnected with the other isolated power systems in the Essequibo and eventually with the DBIS. As such, the present expansion plans consider this power system's stability in the event of an N-1 on the interconnection link.

In view of the cost of LFO being approximately 25% greater than HFO, and the Government's drive to lower the cost of electricity, GPL plans to use HFO units supported by a total of 8 MWp Solar PV and 8 MWh BESS. As such, the required firm generation capacity is shown in Table 28.

Table 28: Generation Reliability with Planned Expansions – Anna Regina

Fiscal Year	Peak Demand (MW)	Load (GWh)	EENS (MWh)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	LOLE (day)	LOLP (%)
2020	5.57	31.61	0.46	12.00	6.43	115.44	0.05	0.01
2021	6.72	38.36	1.67	14.50	7.78	115.77	0.12	0.03
2022	8.33	46.08	1.16	17.00	8.67	104.08	0.07	0.02
2023	10.7	58.93	0.76	18.80	8.10	75.70	0.05	0.01
2024	12.61	72.09	0.57	23.80	11.19	88.74	0.03	0.01
2025	14.96	82.29	10.02	23.80	8.84	59.09	0.45	0.12

The above-mentioned firm generation capacity requirements will be satisfied by installing:

1. 2 x 2.5 MW HFO fired generator units between 2021 and 2022;
2. 1.8 MW HFO fired generator unit in 2023;
3. 2 x 2.5MW HFO fired generator units in 2024.

In view of the existing firm generation capacity, the additional generator units will result in having a firm power system in Anna Regina, as indicated by the Grand Total Firm Capacity in Table 29 on page 71.

The 2.5 MW generator unit selection is fully supported by the existing civil structure of the decommissioned 2 x 2MW Wartsila generator units. These units were installed in 1992 and were decommissioned in 2019 – after 27 years of continuous operation.

Besides the existing civil infrastructure, the unit size of 2.5 MW fits well with the Essequibo Coast's load profile and satisfies the requirements for economic load dispatch.

Table 29: Proposed Generation Capacity Addition - Anna Regina

Anna Regina	Type	Installed Capacity (MW)				
		2021	2022	2023	2024	2025
1x2.5MW HFO Units	Firm Capacity	2.5				
1x2.5MW HFO Units	Firm Capacity		2.5			
1x1.8MW HFO Unit	Firm Capacity			1.8		
4x2MWp Solar PV Farms	Non-Firm Capacity			8.0		
2x2.5MW HFO Units	Firm Capacity				5.0	
Total Non-Firm Capacity		**-**	**-**	**8.0**	**-**	**-**
Total Firm Capacity		**2.5**	**2.5**	**1.8**	**5.0**	**-**
Total Accumulated Firm Capacity		**2.5**	**5.0**	**6.8**	**11.8**	**11.8**
Existing Firm Capacity		**12.0**	**12.0**	**12.0**	**12.0**	**12.0**
Grand Total Firm Capacity		**14.5**	**17.0**	**18.8**	**23.8**	**23.8**

The installation of a 1.8 MW generator unit in 2023 has been part of the 5.4 MW plant extension, as there are already provisions for the installation of the 1.8 MW generator unit. However, given the rapid increase in demand, Anna Regina would require more than 1.8 MW before 2023. In consequence, the need to fast-track the 2 x 2.5 MW generator units is a priority over the acquisition and installation of the 1.8 MW.

From an operation perspective with the planned generation expansion (Table 23), Anna Regina would have sufficient contingency generation capacity to satisfy the forecast demand and required spinning reserve, as shown in Table 30.

Table 30: Generation Contingency Capacity Forecast with Additions - Anna Regina

Anna Regina Generation Capacity		2021	2022	2023	2024	2025
Existing MAN	Firm Capacity	4.8	4.8	4.8	4.8	4.8
Existing Mobile Sets	Firm Capacity	7.2	7.2	7.2	7.2	7.2
ADDITION HFO-1	Firm Capacity	2.5	2.5	2.5	2.5	2.5
ADDITION HFO-2	Firm Capacity	-	2.5	2.5	2.5	2.5
ADDITION HFO-3	Firm Capacity	-	-	1.8	1.8	1.8
ADDITION HFO-4	Firm Capacity	-	-	-	5.0	5.0
ADDITION Solar PV	Non-Firm Capacity	-	-	8.0	8.0	8.0
Total Installed Generation (MW)		**14.5**	**17.0**	**26.8**	**31.8**	**31.8**
Total Firm Generation Capacity (MW)		**14.5**	**17.0**	**18.8**	**23.8**	**23.8**
Total Non-Firm Generation Capacity (MW)		**-**	**-**	**8.0**	**8.0**	**8.0**
Min Required Spinning Reserve (MW)		**3.8**	**3.8**	**6.2**	**6.2**	**6.2**
Net Capacity (MW)		**10.8**	**13.3**	**12.7**	**17.7**	**17.7**
Peak Demand (MW)		**6.7**	**8.3**	**10.7**	**12.6**	**15.0**
Contingency Capacity (MW)		**4.0**	**4.9**	**2.0**	**5.0**	**2.7**

In summary, the benefits of the planned generation expansion for Anna Regina include, but are not limited to the following:

- Provide urgently needed power generation capacity to meet the growing electricity demand on the Essequibo Coast, with peak demand already equal to the total capacity of the first three HFO units, resulting in the need for LFO burning CAT sets to provide reserve capacity;
- Reduce dependency on the use of LFO to generate electricity from mobile CAT units;
- Improve generation reliability and capacity reserve margin at the plant; and

Proposed unit will require similar parts to the recently completed plant as it is the same model.

3.15.2 Bartica

For the Bartica power system, the Government, with funding from the IaDB and execution by GEA, plans to construct and integrate a 1.5 MW Solar PV farm. In 2016, an Expression of Interest for this project was published by GEA. In November 2020, GEA signed a contract for the completion of this project by 2023.

The existing 3 x 1.12 MW diesel-fired generators and Caterpillar LFO fired generator are not expected to satisfy the growing demand reliably, given that the CAT unit is unreliable and attracts a high maintenance cost.

In view of the generation reliability target, the required firm generation capacity for Bartica is shown in Table 31.

Table 31:Generation Reliability with Planned Expansions – Bartica

Fiscal Year	Peak Demand (MW)	Load (GWh)	EENS (MWh)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	LOLE (day)	LOLP (%)
2020	1.94	12.28	7.20	4.96	3.02	155.67	0.38	0.10
2021	2.27	14.43	14.24	6.08	3.81	167.84	2.03	0.56
2022	2.72	16.88	11.38	6.08	3.36	123.53	0.80	0.22
2023	3.36	20.79	18.54	10.08	6.72	200.00	2.03	0.56
2024	3.82	24.37	1.16	10.08	6.26	163.87	0.10	0.03
2025	4.30	26.57	2.73	10.08	5.78	134.42	0.21	0.06

The required firm generation capacity will be satisfied by installing:

1. 1.12 MW LFO Fired Generator Unit by Q3 of 2021; and
2. 2 x 2 MW of LFO Fired Generator units by Q3 of 2023.

In view of the existing firm generation capacity, the additional generator units will result in having a firm power system in Bartica, as indicated by the Grand Total Firm Capacity in Table 32 on page 73.

Table 32: Proposed Generation Capacity Addition to Bartica

Bartica	Type	Installed Capacity (MW)				
		2021	2022	2023	2024	2025
Small LFO Unit (1.12MW)	Firm Capacity	1.12				
Medium Size LFO Unit (2MW)	Firm Capacity			4.00		
1.5MWp Solar PV Farm	Non-Firm Capacity			1.50		
Total Non-Firm Capacity		**-**	**-**	**4.0**	**-**	**-**
Total Firm Capacity		**1.1**	**-**	**4.0**	**-**	**-**
Total Accumulated Firm Capacity		**1.1**	**1.1**	**5.1**	**5.1**	**5.1**
Existing Firm Capacity		**4.96**	**4.96**	**4.96**	**4.96**	**4.96**
Grand Total Firm Capacity		**6.08**	**6.08**	**10.08**	**10.08**	**10.08**

While the BESS that will accompany this solar PV farm will support spinning reserve, the Company remains cognizant that the BESS would have an average discharge duration of 1hour. With spinning reserve required for 24hrs operation, the balance of this ancillary service must be originated from firm generation capacity. As such, from an operation perspective with the planned generation expansion (Table 32), Bartica would have sufficient contingency capacity to satisfy the forecast demand, required spinning reserve as shown in Table 33.

Table 33: Generation Contingency Capacity Forecast with Additions – Bartica

Bartica Generation Capacity		2021	2022	2023	2024	2025
Existing Cummins	Firm Capacity	3.36	3.36	3.36	3.36	3.36
Existing Mobile Units	Firm Capacity	1.60	1.60	1.60	1.60	1.60
ADDITION LFO - 1	Firm Capacity	1.12	1.12	1.12	1.12	1.12
ADDITION LFO - 2	Firm Capacity	-	-	4.00	4.00	4.00
ADDITION (Solar PV)	Non-Firm Capacity	-	-	1.50	1.50	1.50
Total Installed Generation (MW)		**6.08**	**6.08**	**11.58**	**11.58**	**11.58**
Total Firm Generation Capacity (MW)		**6.08**	**6.08**	**10.08**	**10.08**	**10.08**
Total Non-Firm Generation Capacity (MW)		**-**	**-**	**1.5**	**1.5**	**1.5**
Min Required Spinning Reserve (MW)		**1.7**	**1.7**	**3.5**	**3.5**	**3.5**
Net Capacity (MW)		**4.4**	**4.4**	**6.6**	**6.6**	**6.6**
Peak Demand (MW)		**2.3**	**2.7**	**3.4**	**3.8**	**4.3**
Contingency Capacity (MW)		**2.1**	**1.7**	**3.3**	**2.8**	**2.3**

Some of the key benefits of this expansion plan for Bartica include, but are not limited to the following:

- Provide firm capacity to improve the reliability of supply as well as facilitate spinning reserve for the integration of a 1.5 MWp Solar PV Project;
- Provide capacity to serve existing unserved areas (Gersham, Itabali, Del Conte, and other riverine areas within the vicinity of Bartica) and expected increases in demand over the short to medium term;
- Reduce dependency on older LFO generators;

- Improved fuel efficiency;
- Lower cost of production; and
- Allow for Bartica to have sufficient generation capacity to ride-through an N-1 contingency on the line that interconnects with the rest of the isolated system and DBIS.

3.15.3 Wakenaam

GPL has secured funding from the UAE to implement a 750 kW Solar PV Farm with a 400kVA/1,176kWh BESS. As part of this project to ensure there is secure power generation capacity, GPL will install two (2) new 512.5kVA (410kW) LFO fired generators and upgrade the electrical installation of the power plant.

To further assist in boosting firm generation capacity for LOLP and to satisfy the forecast demand, the required firm generation capacity is shown in Table 34.

Table 34: Generation Reliability with Planned Expansions – Wakenaam

Fiscal Year	Peak Demand (MW)	Load (GWh)	EENS (MWh)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	LOLE (day)	LOLP (%)
2020	0.31	1.72	18.61	0.65	0.34	109.68	5.29	1.44
2021	0.36	2.03	0.64	1.47	1.11	308.33	0.23	0.06
2022	0.43	2.40	0.05	1.88	1.45	337.21	0.01	0.00
2023	0.54	2.94	0.09	1.88	1.34	248.15	0.02	0.01
2024	0.62	3.51	0.01	2.29	1.67	269.35	3.4E-03	9.4E-04
2025	0.72	3.93	0.05	2.29	1.57	218.06	1.6E-02	4.3E-03

The above-mentioned firm generation capacity requirements will be satisfied by installing:

1. 410 kW LFO fired CAT generator in 2021;
2. 410 kW LFO fired CAT generator in 2022;
3. 410 kW LFO fired CAT generator in 2024;

In view of the existing firm generation capacity, the additional generator units will result in having a firm power system in Wakenaam, as indicated by the Grand Total Firm Capacity in Table 35 on page 74.

Table 35: Proposed Generation Capacity Addition to Wakenaam

Wakenaam	Type	Installed Capacity (MW)				
		2021	2022	2023	2024	2025
Small LFO Unit (0.41MW)	Firm Capacity	0.4	0.41	-		
Small LFO Unit (0.41MW)	Firm Capacity				0.4	
Solar PV Farm	Non-Firm Capacity	0.75				
Total Non-Firm Capacity		**0.75**	**-**	**-**	**-**	**-**

Wakenaam	Type	Installed Capacity (MW)				
		2021	2022	2023	2024	2025
Total Firm Capacity		0.4	0.4	-	0.4	-
Total Accumulated Firm Capacity		0.4	0.8	0.8	1.2	1.2
Existing Firm Capacity		1.06	1.06	1.06	1.06	1.06
Grand Total Firm Capacity		1.47	1.88	1.88	2.29	2.29

From an operation perspective with the planned generation expansion (Table 35), Wakenaam would have sufficient contingency capacity to satisfy the forecast demand and required spinning reserve (Table 36).

Table 36:Generation Contingency Capacity Forecast with Additions – Wakenaam

Wakenaam Generation Capacity		2021	2022	2023	2024	2025
Existing Caterpillar	Firm Capacity	1.06	1.06	1.06	1.06	1.06
ADDITION (LFO-1)	Firm Capacity	0.41	0.41	0.41	0.41	0.41
ADDITION (LFO-2)	Firm Capacity	-	0.41	0.41	0.41	0.41
ADDITION (LFO-3)	Firm Capacity	-	-	-	0.41	0.41
ADDITION (Solar PV-1)	Non-Firm Capacity	0.75	0.75	0.75	0.75	0.75
Total Installed Generation (MW)		**2.22**	**2.63**	**2.63**	**3.04**	**3.04**
Total Firm Generation Capacity (MW)		**1.47**	**1.88**	**1.88**	**2.29**	**2.29**
Total Non-Firm Generation Capacity (MW)		**0.75**	**0.75**	**0.75**	**0.75**	**0.75**
Min Required Spinning Reserve (MW)		**0.84**	**0.84**	**0.84**	**0.84**	**0.84**
Net Capacity (MW)		**0.31**	**1.04**	**1.04**	**1.45**	**1.45**
Peak Demand (MW)		**0.36**	**0.43**	**0.54**	**0.62**	**0.72**
Contingency Capacity (MW)		**-0.05**	**0.61**	**0.50**	**0.83**	**0.73**

Some of the salient benefits of this planned expansion, which includes the 750 kW Solar PV and 400kVA/1,176kWh BESS are:

- Displace electricity generated using fossil fuel;
- Reduce fuel consumption;
- Reduce Guyana's carbon footprint;
- Improve Guyana's grid emission factor;
- Serve as a model for maximizing energy from RE; and
- Allow for Bartica to have sufficient generation capacity to ride-through an N-1 contingency on the line that interconnects with the rest of the isolated system and DBIS.

3.15.4 Leguan

For Leguan, Government plans a 600 kW solar farm with BESS by 2022. However, with the need to ensure the LOLP target is achieved for Leguan, the required firm generation capacity for the current planning period is shown in Table 37.

Table 37: Generation Reliability with Planned Expansions – Leguan

Fiscal Year	Peak Demand (MW)	Load (GWh)	EENS (MWh)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	LOLE (day)	LOLP (%)
2020	0.36	1.74	11.09	0.82	0.46	127.78	1.32	0.36
2021	0.42	2.03	38.22	0.82	0.40	95.24	12.06	3.30
2022	0.50	2.38	76.90	0.82	0.32	64.00	24.97	6.84
2023	0.63	2.97	1.36	1.64	1.01	160.32	0.29	0.08
2024	0.74	3.58	1.95	1.64	0.90	121.62	0.30	0.08
2025	0.86	4.03	0.76	2.05	1.19	138.37	0.26	0.07

The above-mentioned firm generation capacity requirements will be satisfied by installing:

1. 2x 410 kW LFO fired CAT generator in 2023;
2. 410 kW LFO fired CAT generator in 2025;

In view of the existing firm generation capacity, the additional generator units will result in having a firm power system in Anna Regina, as indicated by the Grand Total Firm Capacity in Table 38.

Table 38: Proposed Generation Capacity Addition to Leguan

Leguan	Type	Installed Capacity (MW)				
		2021	2022	2023	2024	2025
Small LFO Unit (0.41MW)	Firm Capacity			0.8		0.4
Solar PV Farm	Non-Firm Capacity		0.6			
Total Non-Firm Capacity		**-**	**0.6**	**-**	**-**	**-**
Total Firm Capacity		**-**	**-**	**0.8**	**-**	**0.4**
Total Accumulated Firm Capacity		**-**	**-**	**0.8**	**0.8**	**1.2**
Existing Firm Capacity		**0.82**	**0.82**	**0.82**	**0.82**	**0.82**
Grand Total Firm Capacity		**0.82**	**0.82**	**1.64**	**1.64**	**2.05**

From an operation's perspective with the planned generation expansion (Table *38*) Leguan would have sufficient contingency capacity to satisfy the forecast demand and required spinning reserve, as shown in Table 39 on page 76.

Table 39: Generation Contingency Capacity Forecast with Additions – Leguan

Leguan Generation Capacity		2021	2022	2023	2024	2025
Existing Caterpillar	Firm Capacity	0.82	0.82	0.82	0.82	0.82
ADDITION (Solar PV)	Non-Firm Capacity	-	0.60	0.60	0.60	0.60
Caterpillar - ADDITION (LFO)-1	Firm Capacity			0.82	0.82	0.82
Caterpillar - ADDITION (LFO)-2	Firm Capacity					0.41
Total Installed Generation (MW)		**0.82**	**1.42**	**2.24**	**2.24**	**2.65**

Total Firm Generation Capacity (MW)	**0.82**	**0.82**	**1.64**	**1.64**	**2.05**
Total Non-Firm Generation Capacity (MW)	**-**	**0.60**	**0.60**	**0.60**	**0.60**
Min Required Spinning Reserve (MW)	**0.62**	**0.80**	**0.80**	**0.80**	**0.80**
Net Capacity (MW)	**0.21**	**0.03**	**0.85**	**0.85**	**1.26**
Peak Demand (MW)	**0.42**	**0.50**	**0.63**	**0.74**	**0.86**
Contingency Capacity (MW)	**-0.22**	**-0.48**	**0.22**	**0.11**	**0.40**

These expansion plans are expected to deliver (and are not limited) to the following:

- Provide firm capacity to improve the reliability of supply as well as facilitate spinning reserve for the integration of a 1MWp Solar PV Project,
- Provide capacity to serve existing unserved areas and expected increases in demand over the short to medium term,
- Provide for generator redundancy to allow for maintenance flexibility,

  Allow for Leguan to have sufficient generation capacity to ride-through an N-1 contingency on the line that interconnects with the rest of the isolated system and DBIS.

3.16 Summary of Firm Generation Expansion and Renewable Energy Projects

The Company remains committed to aligning its generation strategies with the National Energy Policy, Low Carbon Development Strategy, and other Government Energy Driven Initiatives. The recommended generation expansion plan for the 2021-2025 planning period is summarised in Table 40 for the DBIS and Table 41 on page 78 for the Isolated Systems. Each table also shows the projected energy mix of the power systems by 2025, respectively.

Table 40: GPL 5 Year Generation Expansion Plan and Energy Mix- DBIS

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
2021	Multifuel	46.5	Garden of Eden - Phase 1	GPL
2022	Multifuel	54.0	Garden of Eden - Phase 2	GPL
2023	NG	108.0	250 MW NG Plant - Phase 1	GPL
	Solar PV	10.0	Berbice Solar PV	GPL
	Solar PV	4.0	Naarstigheid	GPL
2024	NG	142.0	250 MW NG Plant - Phase 2	GPL
	Solar PV	15.0	Linden	GPL
2025	NG	54.0	Crab Island	GPL
Existing Capacity (MW) (Excludes GOE II 46.5 MW)	HFO	127.6	DBIS	GPL
Existing Capacity (MW)	LFO	30.0	DBIS	GPL

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
Total Existing Firm Capacity (MW) - Excludes GOE II 46.5 MW)		157.60	157.6	GPL
Total Additional Firm Capacity by 2025 (MW)		404.50		
Total Additional Non-Firm Capacity by 2025 (MW)		29.00		
Total Additional Capacity by 2025 (MW)		433.50		
Total Firm Capacity by 2025 (MW)		562.10		
Total Non-Firm Capacity by 2025 (MW)		29.00		
Total Capacity by 2025 (MW)		591.10		
Total HFO Capacity by 2025 (MW)		282.10		
Total LFO Capacity by 2025 (MW)		30.00		
Total Solar PV Capacity by 2025 (MW)		29.00		
Total NG Capacity by 2025 (MW)		250.00		
DBIS HFO % Share		47.7%	DBIS	
DBIS LFO % Share		5.1%	DBIS	
DBIS NG % Share		42.3%	DBIS	
DBIS Solar PV % Share		4.9%	DBIS	

Table 41: GPL 5 Year Generation Expansion Plan and Energy Mix- Isolated Systems

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
2021	HFO	2.5	Anna Regina	GPL
	LFO	1.1	Bartica	GPL
	Solar PV	0.75	Wakenaam	GPL
2022	HFO	2.5	Anna Regina	GPL
	LFO	0.41	Wakenaam	
	Solar PV	0.6	Leguan	GPL
2023	HFO	1.8	Anna Regina	GPL
	Solar PV	8	Anna Regina	GPL
	Solar PV	1.5	Bartica	GPL
	LFO	0.82	Leguan	GPL
	LFO	4	Bartica	GPL
2024	LFO	0.41	Wakenaam	
	HFO	5	Anna Regina	GPL
2025	LFO	0.82	Leguan	GPL
Existing Capacity	HFO	4.8	Isolated Systems	GPL
	LFO	14.04	Isolated Systems	GPL
Total Existing Capacity		18.84	Isolated Systems	GPL

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
Total Additional Firm Capacity by 2025 (MW)		19.36	Isolated Systems	GPL
Total Additional Non-Firm Capacity by 2025 (MW)		10.85	Isolated Systems	GPL
Total Additional Capacity by 2025 (MW)		30.21	Isolated Systems	GPL
Total Firm Capacity by 2025 (MW)		38.2	Isolated Systems	GPL
Total Non-Firm Capacity by 2025 (MW)		10.85	Isolated Systems	GPL
Total Capacity by 2025 (MW)		49.05	Isolated Systems	GPL
Total HFO Capacity by 2025 (MW)		16.6	Isolated Systems	GPL
Total LFO Capacity by 2025 (MW)		21.6		
Total Solar PV Capacity by 2025 (MW)		10.85	Isolated Systems	GPL
Isolated System HFO % Share		33.8%	Isolated Systems	GPL
Isolated System LFO % Share		44.0%	Isolated Systems	GPL
Isolated System Solar PV % Share		22.1%	Isolated Systems	GPL

3.16.1 Integrated Utility Service (IUS)

The Integrated Utility Services Pilot Program is a Regional Technical Assistance (TA) programme funded by the German Federal Ministry for Economic Cooperation (BMZ) and the European Union under the 11th European Development Fund. The Program is being implemented by the Caribbean Community Secretariat (CARICOM) and the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ). Guyana Power and Light (GPL) is one of four power utility companies in the region that is participating in the pilot.

The pilot's primary objective is to provide TA to the four utility companies to develop the IUS model and demonstrate its viability. The aim of the IUS Model is to provide GPL's customers with the option and the ability to procure affordable Renewable Energy (RE) and Energy Efficiency (EE) systems from GPL. The structure of this model is catered for the customer and it provides them with financial assistance to acquire their desired energy saving solutions – Demand Side Management.

This initiative comes at a crucial time to support the Government of Guyana's National Energy Priorities and its transition to a diversified and inclusive economy. The pilot project will test the feasibility of GPL's business model and generate data to support design of a full-scale program available to all GPL customers.

Presently, GPL's approach consists of a two-phase pilot programme with the first phase being limited to three demonstration projects, with a focus on proof of concept. The first phase is focused on developing the IUS model with various entities, namely:

1. Organization of American States (OAS) and the Inter- American Institute for Cooperation on Agriculture (IICA) Demonstration Project (Commercial Building),
2. UMAMI Inc. Demonstration Project (An agro-processor), and
3. GPL Middle Street Office, Main Street Office, and Sophia Demonstration Projects.

GPL’s primary reason for pursuing the IUS model is to expand its business model and become a multi-faceted Company that provides customers with electricity and sustainable energy solutions (Renewable Energy & Energy Efficiency Options). Another primary reason is to replace lost revenue that has resulted from customers who have chosen to self-generate over the years.

The Guyana Power and Light Inc. is seeking to support Guyana’s Green Energy transition through the Integrated Utility Services (IUS) Model. Customers will soon be able to access a wide range energy services including energy efficiency improvements, small-scale distributed renewables (solar photovoltaic system and wind), electric vehicles and charging stations and - in one comprehensive package, with monthly payments on the electricity bill.

To date, GPL has signed a Memorandum of Understanding (MOU) with the Organization of American States (OAS), Inter-American Institute for Cooperation on Agriculture (IICA) and the Ministry of Agriculture (MOA), which serves as GPL’s first demonstration project to supply and install a Grid Connected Solar Photovoltaic System on MOA’s roof space.

The installation at MOA is completed and will be commissioned.

The second demonstration project includes the installation of Grid Connected Solar Photovoltaic System with Battery Energy Storage System at GPL’s key offices; (1) IT Building in Sophia, (2) Main Street and (3) Middle Street.

Installation works at IT Building in Sophia, Main Street and Middle Street are completed and will be commissioned by Q2, 2021.

The availability of backup power at GPL branches will improve the Company’s ability to serve customers continuously during working hours.

In addition, GPL is also pursuing a solar installation project with a private business entity, UMAMI Inc., which will likely to start in the first quarter of 2021.

The overall outcome of these installations will achieve the following benefits:

- Displace electricity generated using fossil fuel; and
- Improve Guyana’s grid emission factor.

The Company intends to streamline Customer Contracts and Customer Billing in the first phase of the IUS Pilot. The development of comprehensive contracts will help establish the relationship between the customers and GPL in this pilot.

Developing a system of billing customers of the pilot will be extremely important as well. Once a customer’s installation is complete, the customer will own that fixture/asset and repay GPL through a monthly billed repayment. The customer’s bill would reflect the monies owed for the improvement measures at a cost agreed between the customer and the utility Company. This would in the form of an extra line item on their monthly utility bill. This charge, along with the period for repayment, would vary from customer to customer.

Upon successfully completing of the first phase of the pilot, it will be evaluated to determine if additional pilot projects in this format are feasible. Once the evaluation yields positive results, GPL will pursue the second phase of the pilot programme. This will consist of a larger roll-out targeting a wider group of customers in the residential, commercial, and industrial sectors. A pipeline of potential projects for this phase has already been developed GIZ Consultant's help, and this will be used to pursue funding from various funding agencies.

Apart from the technical assistance being currently provided by GIZ and CARICOM to develop GPL's IUS Pilot Programme, additional support for the IUS is likely to come soon. GPL plans to achieve this task through an initiative called "*Scaling up the deployment of Integrated Utilities Services (IUS) to support energy sector transformation in the Caribbean"* programme, which is expected to be co-financed by CDB and the Green Climate Fund (GCF). It is the intention that this new programme will build directly on the current IUS Pilot Programme.

The key concepts of the IUS Pilot have been presented to the Public Utilities Commission (PUC) in July 2020 and the Commission was encouraging of this initiative although it alluded to having no regulatory jurisdiction over this initiative. Nonetheless, as the programme progresses, GPL will continue to keep the PUC informed with hopes the commission's regulatory role is extended to initiatives of this nature in the future.

3.16.2 Long-term Generation Expansion and International Grid Interconnection

For the long-term generation expansion plan, the Government of Guyana is currently working strenuously on the Amaila Falls Hydro Power Project (AFHP), which will significantly reduce the overall cost of generation and by extension, electricity tariff. Additionally, the AFHP Project will add significant inertia to the technical stability of the power grid.

From GPL's perspective, grid expansions will be aligned with the AFHP Project, such that, transmission voltage level can be harmonised at 230 kV. Also, for interconnection of the hydropower project to be made at various strategic points in the grid to improve power system security, resiliency, and reliability.

The 'Arco Norte' Interconnection Project[17] expects to realize the development and commissioning of a significant amount of hydropower generation capacity in Guyana. With such long-term planned development, the total generation capacity is to buttress local generation capacity, and export electricity to Brazil, connection with the State of Roraima (North-West Brazil) and Amapa (South-East Brazil).

The interconnection with the State of Roraima would be direct with Guyana, while with Amapa through Suriname and French Guyana (Figure 3).

[17] Development of an electrical interconnection among Suriname, Guyana, French Guiana, and Brazil

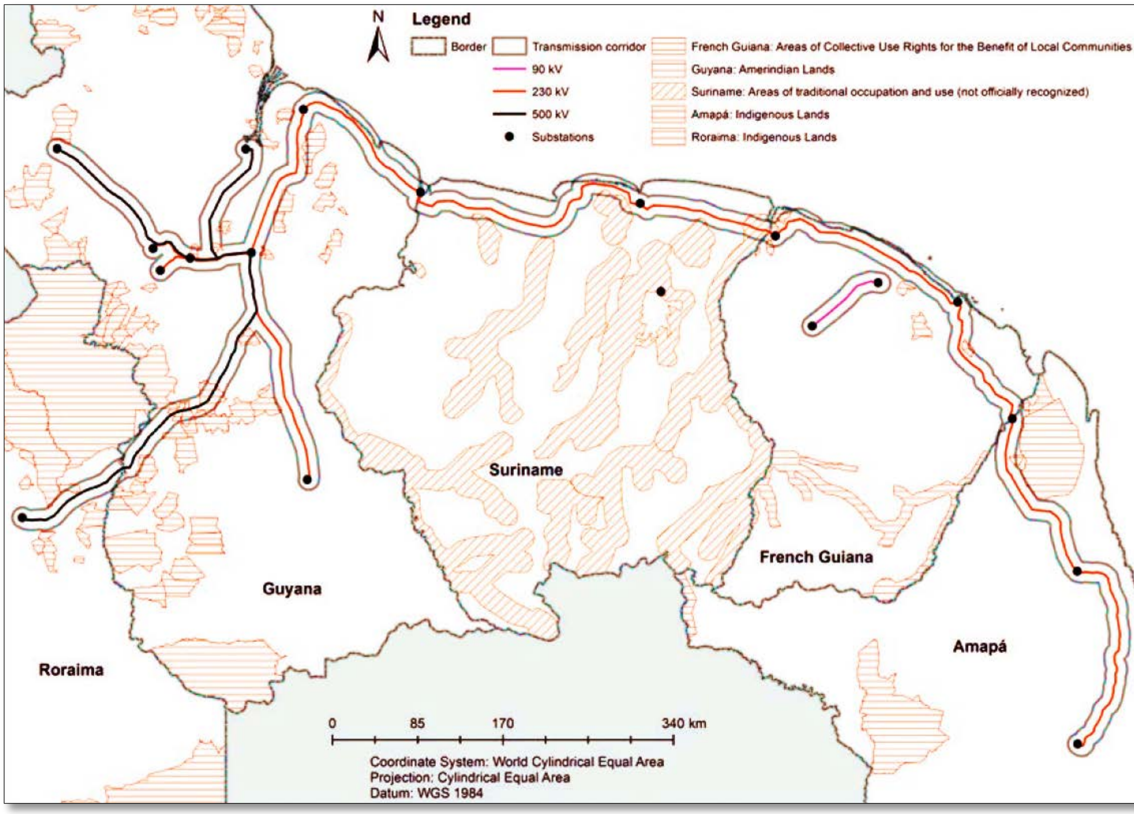

Figure 3:Illustration of the Arco Norte Interconnection Plan (*source: Arco Norte Electrical Interconnection Study – Component II*)

Some of the main benefits of this interconnection would be:

- Lower-cost generation in Guyana, French Guiana, and Suriname. A regional interconnection would allow these countries to exploit the most efficient generation sources at the regional level and meet regional demand through trade;
- Lower electricity prices for consumers in Guyana, French Guiana, and Suriname due to lower-cost generation and greater competition in the regional market (Figure 4);
- More secure supply in all four Arco Norte countries—Guyana, French Guiana, Suriname, and Brazil. Trading across international borders would allow each country a larger reserve margin since they would have access to international electricity when domestic sources were inadequate;
- The opportunity to develop renewable energy sources in the region - gradually displacing liquid fossil fuels; and
- Export earnings, especially for Guyana. The most efficient large generation sites in the Arco Norte are potential hydro projects in Guyana. By developing these sites and exporting excess generation to Brazil, Guyana—and to a lesser extent French Guiana and Suriname—could become large energy exporters.

Currently, the ‘Arco Norte’ Interconnection Project is still at the feasibility stage and is currently awaiting the renewal of the MOU that binds the member states of this project.

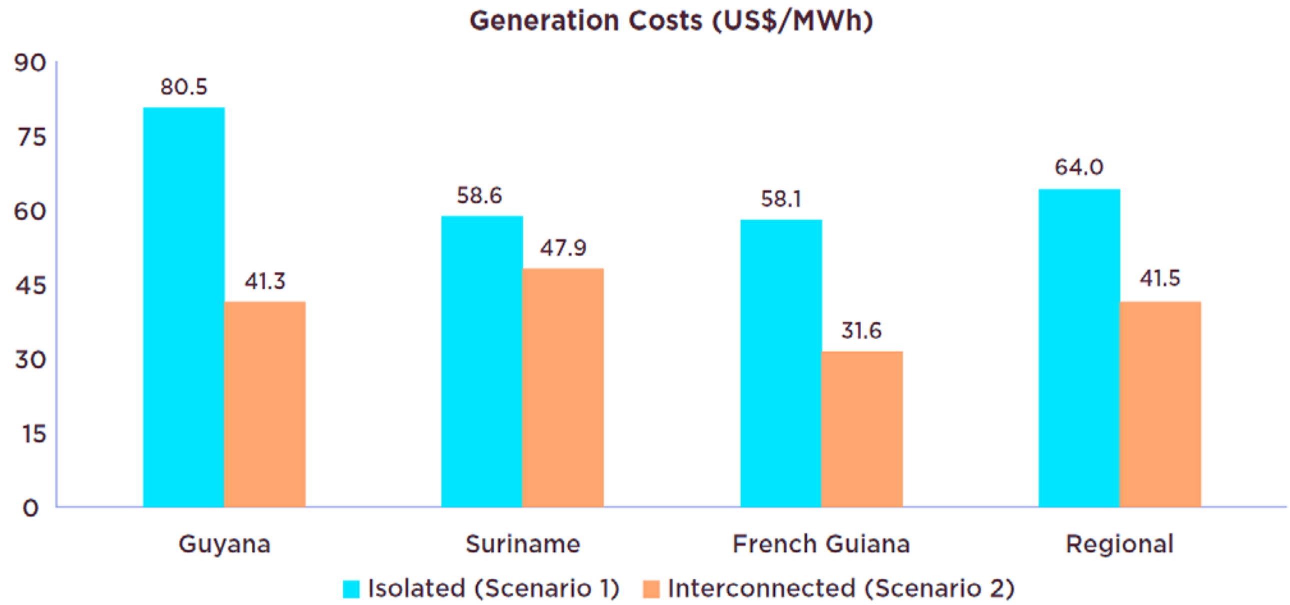

Figure 4: Average generation cost in the interconnected and isolated scenarios (*source: Arco Norte Electrical Interconnection Study – Component II, dated 2017*)

3.17 Transmission, Distribution and Substation Upgrades and Expansions

3.17.1 Short to Medium Term (2021-2025) – Transmission and Substation Expansions and Upgrades (see Figure 5 for block diagram summary)

GPL intends to invest G$ 85.054B (US$ 395.602M) to upgrade and construct new Transmission and Distribution networks, Substations and Transmission system reinforcements (reactive power compensations) projects for the short- and medium-term horizon, 2021 to 2025. These projects will seek to accommodate the present and forecasted peak demand growth concomitant with efforts to reduce technical losses. See Table 42 to Table 44, pages 84 to 86 and Figure 5 on page 87 for further details.

The construction and upgrade of distribution substations (load centres) would allow new distribution feeders and transformers to be deployed in those geographic areas to serve the present and forecasted loads efficiently.

The expansion and construction of substations are required to deploy 230 kV and 69 kV transmission lines to connect substations, introduce transmission line redundancy to mitigate N-1 contingency and reduce technical losses (the replacement of lengthy distribution feeders, upgrading of feeder backbones and installation of Automatic Power Factor Correction Capacitors- APFC).

Table 42: Short Term Transmission and Substation New, Expansions and Upgrades

Activity	Short Term	
	2021	2022
Transmission	GoE to N/Gt new (L14/L15), Kingston to Old Sophia new and upgrade (L5 & L5R).	V/Hoop to Wales new (L9), GoE to Kuru Kururu new (L31), Old Sophia to N/Gt upgrade (L10), Old Sophia to New Sophia upgrade (L12 and L13), New Sophia to Good Hope new and upgrade (L16 & L16R).
Substation	V/Hoop Substation, Kingston Substation, N/Sophia Substation.	V/Hoop Substation, Wales Substation, Kuru Kururu Substation, GoE Substation, Old Sophia Substation, No. 53 Substation

Table 43: Medium Term Transmission and Substation New, Expansions and Upgrades

Activity	Mid Term		
	2023	**2024**	**2025**
Transmission	GoE to G/Grove to Eccles to New/Old Sophia upgrade (L1, L2, L3, L4), GoE to Wales new (L24), V/Hoop to Westminister (L40), Westminister to Wales (L41), Kingston to Merrimans (L11-1), Merrimans to N/Gt (L11-2), G/Hope to Columbia new (L17R), 230kV line from 250 MW NG Plant to Eccles Substation, 230 kV line from 250 MW Plant to Wales Substation	Edinburgh to Parika (Hydronie) (L8), 230 kV line from Wales to Garden of Eden, 230 kV line from Garden of Eden to Eccles, 69kV line from GoE to Linden.	No. 53 to Skeldon (L23R), V/Hoop to Eccles (L32), Eccles to Ogle (L25 and L25R), Ogle to Success (L26), Columbia to Onverwagt (L20R), Onverwagt to Canefield (L21R), Canefield to No. 53 (L22R).
Substation	Westminister Substation, G/Hope Substation, E/burgh Substation, Kingston Substation, Canefield Substation, G/Grove Substation, Victoria/ Enmore Substation, Columbia Substation, 230 kV GSU Substation at Natural Gas Plant-Wales, 230kV Switching Substation – Wales, 230/69kV Substation at Wales, 230kV Switching Substation at Eccles.	Parika (Hydronie) Substation, N\Gt Substation, Merrimans Substation, 230kV Substation at Garden of Eden, 230/69 kV Substation at Garden of Eden	Williamsburg Substation, Crab Island Substation, Onverwagt Substation, Success Substation, Ogle Substation.

Given the high priority placed on reliability of the transmission and distribution network, the Company has comprehensively examined and inspected its network to update its inventory of corrective actions and improvement initiatives. The Company expects to finance these critical projects via concessional financing. See Table 44 for further details.

Table 44: Projects Financed through Grants and Loans: Short to Medium Term: 2021-2025

Activity	Location	Impact
Upgrade and expansion of 69/13.8 kV Substation	Kingston - Georgetown	Improved distribution configuration with the use of substation as a single point of delivery to supply power to customers.
Sub-station normalization	Vreed-en-Hoop	Improved configuration of the four (4) feeders at this location with all feeders being disconnected from the generator bus bar and emanating from the bus section in the substation.
New and Upgraded Substations	Wales, Parika (Hydronie), V/Hoop, E/burgh, Eccles, GoE, Kingston, N/Sophia, Old Sophia, N/Gt, G/Hope, G/Grove, Columbia, Kuru Kururu and Onverwagt, 230 kV GSU Substation at Natural Gas Plant-Wales, 230kV Switching Substation – Wales, 230/69kV Substation at Wales, 230kV Switching Substation at Eccles, 230kV Substation at Garden of Eden, 230/69 kV Substation at Garden of Eden	Improved reliability in the transmission and distribution network by expanding the infrastructure to meet and exceed the needs of the customers
Improve Reactive Compensation	Edinburgh, N/Gt, New Sophia, G/Hope and Canefield	The commissioning of reactive power compensators with auxiliaries, control and protection will significantly improve and stabilize transmission and distribution voltage levels on the network.
New and Upgraded Transmission Lines	Old Sophia to New Sophia (L12 and L13), New Sophia to G/Hope (L16 and L16R), G\Hope to Columbia (L17R), Kingston to Merriman's (L11-1), Merriman's to N/Gt(L11-2), Old Sophia to N/Gt (L10), Edinburgh to Parika (L8), N/Gt to Eccles (L15), Kingston to Old Sophia (L5 & L5R), GoE to Kuru Kururu (L31), GoE to Eccles (L14), GoE to Sophia (L1, L2, L3 and L4), V\Hoop to Wales (L9), 230kV line from 250 MW NG Plant to Eccles Substation, 230 kV line from 250 MW Plant to Wales Substation, 230 kV line from Garden of Eden to Eccles.	An improved Transmission Network will increase reliability in considering contingency scenarios and forecasted power flows across the lines whilst ensuring power is evacuated effectively from the Generation Stations to supply the various load centres.

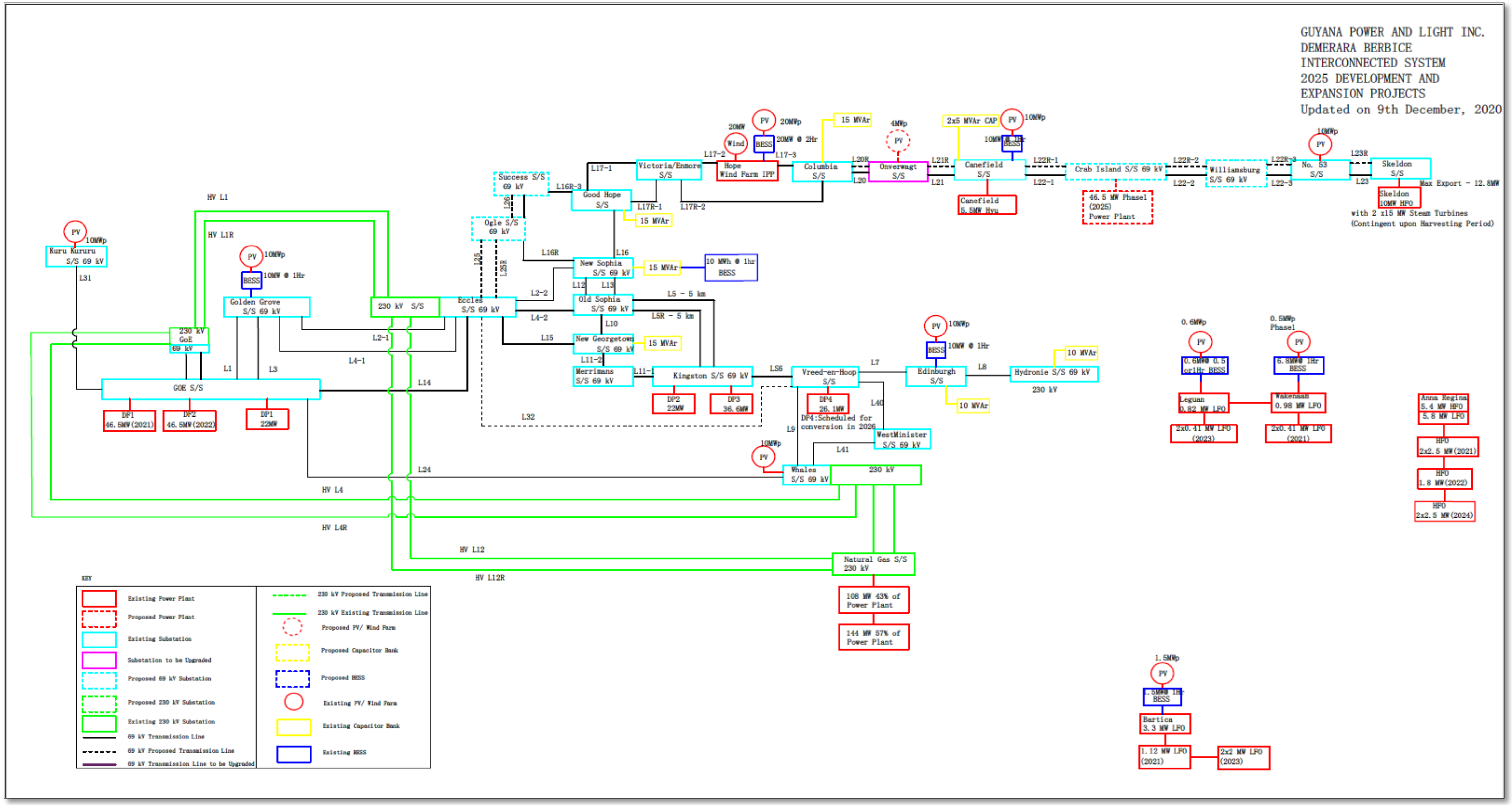

Figure 5:Block Diagram of Power System Development for the current D&E (2021-2025)

3.17.2 Short to Medium Term (2021-2025) – Distribution Expansions and Upgrades

The increase in demand for electricity stems from the consumers at the distribution level, and GPL must ensure that the primary distribution feeders are in condition to supply the needs of customers efficiently. Additionally, to improve the voltage profile along the length of the feeder, reduce technical losses and improve system reliability indices (SAIFI and SAIDI), resiliency, and capacity to manage increased power flow and deliver quality electricity supply service to customers.

The following is planned for the five years (2021 to 2025) period of the D&E for distribution expansions and upgrades:

Short-term (2021-2022):

- Upgrade of existing SCADA – expanding remote control and supervision reach into power generation and primary distribution levels, respectively;
- Reinforce vegetation management;
- Use of concrete poles and either concrete or fibreglass crossarms to improve the integrity of structures in primary distribution circuits;
- Use of covered conductors in primary distribution circuits in areas of dense vegetation;
- Installation and commissioning of 99 Auto-Reclosers, distributed across 33 feeders;
- JICA Grant: Grant covers expenses for line conductors and automatic power factor correction capacitor only. GPL to finance the balance line hardware materials, labour, and transportation costs for these projects: JICA Grant Projects are:
    - Upgrade the existing Onverwagt F2 Feeder;
    - Construct Onverwagt Express feeder to Ithaca;
    - Install 2 x 1500 kVAr (or 4 x 750 kVAr) automatic power factor correction capacitor on Onverwagt F2 Feeder and Express Feeder;
    - Upgrade the backbone of the following feeders from Tulip to Cosmos:
        - G/Hope F4;
        - Sophia F2; and
        - Garden of Eden F1.
    - Replace Single Wire Earth Return Transformers on the West Bank and Coast of Demerara;
- Construction of 4 - 13.8 kV feeders coming out from Wales substation;
- Construction of 4 - 13.8 kV feeders coming out from Kuru kururu substation;
- Construction of 2 - 13.8 kV feeders coming out from Edinburgh substation;

- Installation and commissioning of a total of 12,000 kVAr (23 banks) of Automatic Power Factor Correction Capacitor Banks on 30 primary distribution feeders; and
- SCADA integration of Auto-Reclosers and Automation of Distribution Networks.

Medium-term (2023-2025):

- Construction and Upgrade of 13.8 kV Feeders:
    - Construction of Express feeder from Edinburgh substation to pick up load from Philadelphia to Look-abu, West Coast Demerara; and
    - Construction of new feeders from Eccles substation to pick up load from New Georgetown F1 and Golden Grove F1 Substations and accommodate new loads on the East Bank of Demerara, between Agricola-GAB and Providence-Mocha Road.
- Other Planned Distribution projects to upgrade feeder backbones are:
    - Garden of Eden F2;
    - Edinburgh F2;
    - Good Hope F2; and
    - Canefield F3;
- Load sectionalisation of Good Hope F4; and
- Construction of 3 - 13.8 kV feeders coming out from Parika/Hydronie substation.

These additional critical network projects are expected to deliver a significant improvement in quality of service, feeder reliability, and strengthen the grid for the incremental penetration of electricity from renewable resources and reduce technical losses.

The cost of the proposed expansion and improvement of the T&D Systems is shown in Table 45.

Table 45: T&D Expansion and Upgrade Programme - Capital Cost

T & D Summary	2021	2022	2023	2024	2025	**Total**
	US $ 000	US $ 000	US $ 000	US $ 000	US $ 000	US $ 000
Transmission Lines	16,783.94	53,134.16	6,652.00	156,997.20	0	233,567.3
Transmission Lines Reinforcements	12,320.00	0	2,520.00	1,120.00	1,400.00	17,360.0
Substations	63,572.80	75,542.43	13,878.96	82,133.43	0	235,127.6
Distribution	19,552.20	20,400.00	21,600.00	20,200.00	8,400.00	90,152.2
Capacity Building	6,401.31	0	0	0	0	6,401.3
Electrification	510.83	1,686.02	64.46	843.16	286.09	3,390.6
Total	**119,141.08**	**150,762.61**	**44,715.42**	**261,293.79**	**10,086.09**	**585,998.99**

3.17.3 Long Term (2026-2041)

Given the outlined long-term generation expansion plan and forecasted electricity and peak demands, the Company's long-term plans currently focus on transmission, substation, and distribution expansion. These long-term planned works mainly strengthen the existing grid and establish new high and medium voltage corridors to transfer larger blocks of power across longer distances efficiently and supply the customers reliably. See Table 46 for further details.

Table 46: Long term expansion plans

Activity	Quantity	Location
Additional 230 kV Transmission Lines Construction	16	Amalia Hydro Power to Linden, Linden to Kuru Kururu, Kuru Kururu to GOE, Hydronie to EBE Del Conte, Del Conte to Linden, Linden to Crab Island, Wales to Hydronie .
Additional 69 kV Transmission Lines Construction	4	Hydronie to Leguan (L33), Leguan to Wakenaam (L34), Wakenaam to Suddie (L35), Suddie to Devonshire Castle (L36)), Parika/Hydronie to Bartica.
Additional Substations	7	Linden 69 kV, Hydronie/Parika 230 kV/ 69 kV, Linden 230 kV/ 69 kV, Crab Island 230 kV/ 69 kV, EBE (Del Conte) 230 kV/ 69 kV, Kuru Kururu 230 kV/ 69 kV, GoE 230 kV , Leguan 69 kV/13.8 kV, Wakenaam 69 kV/13.8 kV, Suddie 69 kV/13.8 kV, Devonshire Castle 69 kV/13.8 kV, Bartica 69 kV/13.8 kV.

The transmission lines and substation projects have a massive scope of works that would significantly impact GPL's operations if human resources are assigned to these projects from within the Company. As a result, GPL intends to award turnkey contracts for the execution of these projects.

The Company recognizes and endorses the importance of adequate equipment to manage its T&D work programmes effectively and will continue with its programme of prudent addition and replacement of tools and equipment deemed necessary to execute the programmed.

3.18 Network Maintenance Plan – 2021-2025

The 2021 -2025 network maintenance plan seeks to ensure that all sections of transmission lines and feeders are in optimal operating conditions for GPL to achieve its targeted reliability indices.

The outsourcing of this programme's components and investments in GPL's maintenance capacity and capability are expected to deliver reduced outages resulting from distribution feeder and transmission line trips. See Table 47 for further details.

Table 47: 2021 -2025 Network Maintenance Plan

DATE:	2021 -- 2025		2021			2022			2023			2024			2025		
TARGET INDICATORS			T&D	Contractor	Total	T&D	Contractor	Total	T&D	Contractor	Total	T&D	Contractor	Total	T&D	Contractor	Total
POLE REPLACEMENT	1	PRIM.	2800	1120	3920	3000	1050	4050	3900	1560	5460	3900	1482	5382	3700	1400	5100
		SEC.	3800	1520	5320	4800	1680	6480	5800	2320	8120	5800	2204	8004	6500	2500	9000
POLE PLUMBING	2	PRIM.	1400	560	1960	1400	490	1890	1900	760	2660	1900	722	2622	2400	800	3200
		SEC.	1550	620	2170	1550	543	2093	1850	740	2590	1850	703	2553	2000	750	2750
POLE TREATMENT	3	PRIM.	12000	4800	16800	12000	4200	16200	14000	5600	19600	14000	5320	19320	16000	6000	22000
		SEC.	14000	5600	19600	14000	4900	18900	16000	6400	22400	16000	6080	22080	18000	7500	25500
OLD POLE REMOVAL	4	PRIM.	1506	602	2109	1506	527	2033	1506	602	2109	1506	572	2078	2000	600	2600
		SEC.	3416	1366	4782	3416	1196	4611	3416	1366	4782	3416	1298	4714	3500	1400	4900
POLE STUBBING	5	PRIM.	428	171	599	428	150	578	428	171	599	428	163	590	480	180	660
		SEC.	400	160	560	400	140	540	400	160	560	400	152	552	440	165	605
ANCHOR BLOCK REPLACEMENT.	6	PRIM.	300	120	420	300	105	405	300	120	420	300	114	414	450	150	600
		SEC.	250	100	350	250	88	338	250	100	350	250	95	345	300	120	420
GUY REPLACEMENT	7	PRIM.	420	168	588	420	147	567	420	168	588	420	160	580	520	180	700
		SEC.	350	140	490	350	123	473	350	140	490	350	133	483	450	143	593
REPLACEMENT DEFECTIVE CROSS ARMS	8	PRIM.	1500	600	2100	1500	525	2025	1500	600	2100	1500	570	2070	1500	570	2070
INSULATOR REPLACEMENT	9	PRIM.	9433	3773	13206	9433	3302	12735	9433	3773	13206	9433	3585	13018	9800	3700	13500
		SEC.	3650	1460	5110	3650	1277	4927	3650	1460	5110	3650	1387	5037	4100	1550	5650
LINE/HARDWARE TRANSFER	10	PRIM.	5585	2234	7819	5585	1955	7540	5585	2234	7819	5585	2122	7707	5900	2300	8200
		SEC.	4257	1703	5960	4257	1490	5748	4257	1703	5960	4257	1618	5875	4257	1618	5875
LINE EXTENSION (KM)	11	PRIM.	18	7	25	18	6	24	18	7	25	18	7	24	25	10	35

DATE:	2021 -- 2025		2021			2022			2023			2024			2025		
TARGET INDICATORS			T&D	Contractor	Total	T&D	Contractor	Total	T&D	Contractor	Total	T&D	Contractor	Total	T&D	Contractor	Total
		SEC.	52	21	72	52	18	70	52	21	72	52	20	71	62	30	92
LINE UPGRADEMENT (KM)	12	PRIM.	95	38	133	95	33	128	95	38	133	95	36	131	95	36	131
		SEC.	77	31	108	77	27	104	77	31	108	77	29	107	77	29	106
LINE RETENSION (KM)	13	PRIM.	520	208	728	520	182	702	520	208	728	520	198	718	530	298	828
		SEC.	1200	480	1680	1200	420	1620	1200	480	1680	1200	456	1656	1300	480	1780
SERVICE LINE REPLACEMENT (MTS)	14		12500	5000	17500	8500	2975	11475	6000	2400	8400	5000	1900	6900	4800	1600	6400
INSTALLATION/REPLACEMENT (GAB/RECLOSER/SECTIONALISER)	15	PRIM.	70	20	90	50	15	65	25	10	35	44	17	61	50	20	70
INSTALLATION/REPLACEMENT (SPD)	16	PRIM.	150	60	210	80	28	108	50	20	70	50	19	69	60	25	85
INSTALLATION/REPLACEMENT (RCO)	17	PRIM.	792	317	1108	792	277	1069	792	317	1108	792	301	1092	800	350	1150
INSTALLATION/REPLACEMENT (PMCO)	18		150	60	210	150	53	203	150	60	210	100	38	138	80	35	115
TRANSFORMER MAINTENANCE	19	SEC.	1170	468	1639	1170	410	1580	1170	468	1639	1170	445	1615	1150	420	1570
INSTALLATION OF ADDITIONAL TRANSFORMERS (REPLACEMENT)	20	SEC.	110	44	154	100	35	135	80	32	112	80	30	110	75	25	100
MAINTENANCE OF CAPACITOR/VOLTAGE REGULATORS BANKS	21		26	10	36	26	9	35	26	10	36	26	10	35	24	8	32
JUMPER SERVICING/REPLACEMENT	22	PRIM.	1249	499	1748	1249	437	1686	1249	499	1748	1249	475	1723	1220	460	1680
		SEC.	2589	1036	3625	2589	906	3496	2589	1036	3625	2589	984	3573	2570	946	3516
SERVICE CONNECTION @ CONSUMER	23		12000	4800	16800	12000	4200	16200	12000	4800	16800	12000	4560	16560	11680	4540	16220
INSTALLATION OF ADDITIONAL EARTHS	24		725	290	1016	725	254	979	725	290	1016	725	276	1001	716	276	992
ROUTE CLEARING (KM)	25	PRIM.	6	0	6	5	0	5	5	0	5	4	0	4	6	0	6
		SEC.	10	0	10	8	0	8	8	0	8	7	0	7	9	0	9
LINE INSPECTION (KM)	26	PRIM.	2700	1080	3780	3000	1050	4050	3300	1320	4620	3600	1368	4968	3900	1360	5260
		SEC.	6200	2480	8680	6500	2275	8775	6800	2720	9520	7000	2660	9660	7600	2660	10260
C.E.O.F CARDS	27	SEC.	1500		1500	2500		2500	4500		4500	4500		4500	4800	0	4800
POLE REPLACEMENT (Concrete)		PRIM.	150	300	450	150	450	600	150	600	750	150	750	900	150	900	1050
		SEC.	200	500	700	200	700	900	200	900	1100	200	1100	1300	200	1300	1500

3.19 Loss Reduction

The reduction of losses: technical and non-technical, continues to be a significant challenge facing the GPL. The Company projects total losses to be 26.5% as of December 31, 2020.

The primary reasons for not realizing the expected reductions were the later than planned execution of the IDB / EU Power Utility Upgrade Programme (PUUP) – Component III: Loss Reduction (2017 as against planned execution in 2016). The PUUP Lot A has realized the installation of 22,348 meters in 2018/2019, which contributed to the 2% reduction in losses over 2018. The Company's Meter Replacement programmes were also negatively impacted due to a depleted amount of meter socket and conductor inventory. Replenishment of the stock is projected during the last quarter of 2017 and would herald an intensified execution of the affected work programmes.

The Company targets total losses move from 26.5% in 2020 to 25% in December 2021 (see Figure 6 on page 96). The 1.5% drop is premised on the commencement of the execution of Loss Reduction component of the PUUP during 2016.

The Company intends to intensify its efforts to achieve the target of 22.2% by 2025 (see Figure 6 on page 96), using the combined application of SCADA at the transmissions and primary distribution levels and power generation, coupled with the continued implementation of AMI meters.

3.19.1 Non-Technical Loss Reduction

The Company will continue to adopt a phased approach to establishing its Advance Metering Infrastructure (AMI). AMI meters will not be restricted to customer installations. The AMI meters will also be used for grid metering to compare energy delivered to a geographic area and the energy registered by Consumers' meters. This technology will significantly enhance GPL's theft detection capabilities and therefore reduce losses. The technology will also help identify voltage levels within the distribution network and inform a key Operational Standard and Performance Measure – Voltage Regulation.

The activities envisaged over the life of this Programme require a capital investment of US$36M (GY$7.75B) and include:

- Installation of 96,548 AMI meters complete with new service lines and associated materials,
- Regular inspection of areas with new, reinforced networks to reduce illegal connections,
- Efforts to encourage prosecution of all cases of illegal electricity extraction, and
- Execution of a Social Management Programme to educate consumers on the impact and consequences of electricity theft.

3.19.2 Technical Loss Reduction

Investment in technical loss reduction will be US$58M over the life of this programme. The Company received grant funding of US$10M (GUY$2.152B) from the Japan International

Cooperation Agency (JICA) towards this programme. The JICA assistance will deliver the following:

- Installation of a 2 x 5 MVAr Shunt Capacitors for reactive power compensation at Canefield, East Berbice;
- Upgrade of four (4) 13.8 kV distribution feeders;
- Replacement of Single Wire Earth Return (SWER) pole mounted distribution Transformers in West Demerara; and
- Installation of 2 x 1500 kVAr Automatic Power Factor Compensators at on Onverwagt F2 and F2 Express Feeders, West Berbice.

The investment will address losses and system improvement at the distribution level, within both the Medium Voltage and Low Voltage network. The Company expects that the planned investment in new transmission lines, substations and an upgraded distribution network would improve supply quality, reduce operating costs, and ultimately deliver reduced tariffs.

3.19.3 Critical Issues

1. The current level of system losses are above sustainable levels:
   I. Losses from electricity theft by customers and unregistered "users";
   II. Losses from customers with faulty meters;
   III. Losses from billing system (meter reading errors, under estimations); and
   IV. Losses from substandard network design and maintenance.
2. The Company's inability to meet Customer Service Standards for meter testing, replacements, and new installations.

3.19.4 Strategies

3.19.4.1 Commercial Losses (Non-Technical Losses)

1. Reduce and deter electricity theft:
   a. Field assessment of large customers.
   b. Field assessment of zero consumption accounts
   c. Monitoring of defaulting customers
   d. Removal of illegal connections and prosecuting of persons caught.
2. Improve metering systems:
   a. Implementation of Advanced Metering Infrastructure.
   b. Replacement of all faulty meters
   c. Replacement of old meter interface.
3. Reduce billing system errors and estimations:

d. Verification of all streetlights within NDC's and Municipalities.

3.19.4.2 Technical Losses

1. Improving understanding of Losses. (LR, Projects and Operations Division):
    a. Progressively improve the quantity and quality of information available for losses calculation and segmentation, and for factoring losses into investment decisions.
2. Improve T&D network design and maintenance program (Projects and Operations Division)

3.19.4.3 Distribution Upgrade Programme – GPL Funded

Table 48 shows the additionally planned distribution upgrades targeting reducing technical losses in the primary distribution system.

Table 48: GPL Technical Reduction Projects – Primary Distribution Level

Target Indicators / Activities		2021	2022	2023	2024	2025
Service Line Replacement (km)		25	38	25	40	25
Line Extension (km)	PRIM.	10	15	15	15	15
Line upgrade (km)	PRIM.	255	265	170	180	150
	SEC.	20	35	35	35	20
Replacing Inefficient Transformers		25	15	8	6	4
Replacing Under Utilised Transformers		30	20	15	15	10
Installing Additional Transformers)		40	35	35	20	20
Service Connection @ Consumer/Installation of Insulink		12000	12000	10000	10000	10000
Transformer Drops Servicing/Replacement		3300	3300	3300	3300	3300
Jumper Servicing/Crimping/Replacement	PRIM.	650	650	650	650	650
	SEC.	1500	1500	1500	1500	1500

Note: The above programme excludes the EU / IDB funded Power Upgrade Utility Programme (PUUP) technical Loss Reduction Programme, which forms part of the Consolidated Loss Reduction plan. This IDB/EU funded programme is intended to upgrade approximately 830 kilometres of medium and low voltage conductors and include transformer rightsizing and other critical medium and low voltage network upgrades. The first of three projects (Lot A) commenced in 2017 and was completed in April 2019. Lot A resulted in the upgrade of 361 kilometres of low and medium voltage network and replaced 22,348 electro-mechanical meters with AMI upgradable ones. Lot B was awarded in December 2018 and commenced in November 2019. Lot B is intended to replace 310 kilometres of low and medium voltage distribution network and replace 19,095 meters expected to be substantially completed by the end of 2020.

3.19.4.4 Loss Reduction Projections

With the combined application of SCADA at the transmissions and primary distribution levels, and power generation, coupled with the continued implementation of AMI meters at the customer level, the Company plans to transform the power system into a smart grid in a phased manner.

In view of the benefits of having a smart grid together with the above-mentioned projects, which will reduce technical and non-technical losses, the Company's loss projection profile indicates that by 2025, technical losses should be reduced from 9.4% to 8.6%, and non-technical from 17.1% to approximately 13.6% (Figure 6). Consequently, a total loss reduction from twenty-six-point five percent (26.5%) in 2020 to twenty-two-point five percent (22.5%) by 2025.

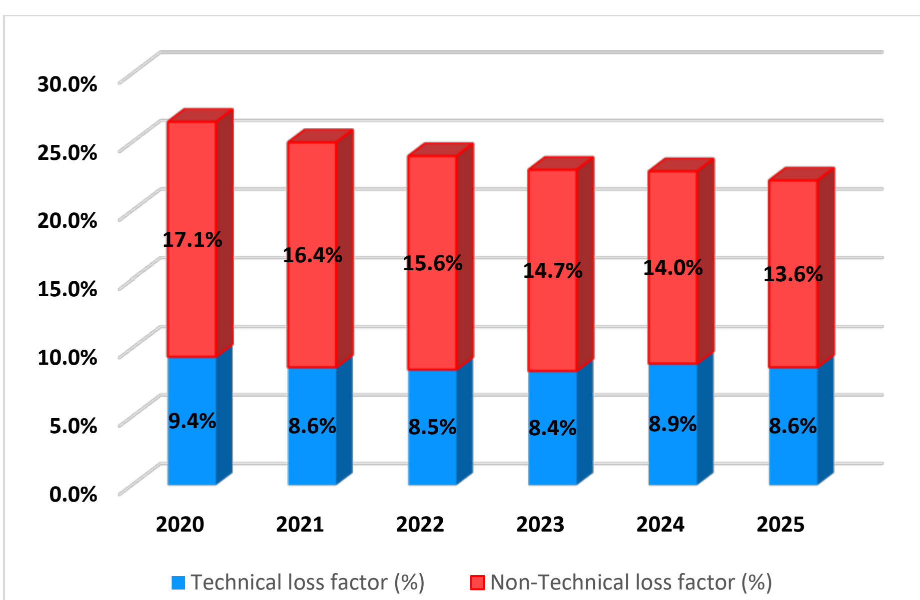

Figure 6: 2021- 2025 Technical and Non-Technical Loss Reduction Projections

3.20 Planning and Projects

3.20.1 Critical Issue

I. Inadequate processes to allow for:
   a. Effective Demand Forecasting
   b. Generation Unit Retirement Scheduling
   c. Generation and Transmission Expansion Planning
   d. Integration of Renewable Energy (Utility Scale)

II. Acquisition of planned generation and/or transmission/distribution facilities:
   a. On-time and within budget.
   b. Meeting quality standards and technical specifications.

3.20.2 Technical Loss Reduction

a. Inability to reasonably quantify technical losses.
b. Impact of Technical Loss Reduction emanating from SP&D is not captured.

III. Staff Training and Development
   a. Inability to attract and retain staff with the required skills.
   b. Inadequate training programs to address knowledge gaps.

3.20.3 Strategies

Meeting Load Demand, the Engineering Service Division has the strategic responsibility for planning new supply sources necessary to meet the future electricity needs within its defined area of responsibility. It is recognized that emerging sources of renewable energy are becoming more competitive in terms of affordability, demand-side management is being tailored to consumer trends, technological innovation is continuing at a rapid pace, and new emission regulations are changing traditional electricity market dynamics. In this continuously evolving environment, the Engineering Service Division will implement an Integrated Resource and Resilience Planning process to ensure long term electricity needs are met sustainably through the following strategies.

Power System Planning

1. Enhance coordination with Government and sectoral entities.
2. Implement Effective Demand Forecasting.
3. Determine optimized Generation Unit Retirement Schedule.
4. Implement Generation and Transmission Planning.
5. Evaluate the integration of Renewable Energy Sources (including Utility Scale systems).

Acquisition of Planned Generation, Transmission and Distribution Facilities

1. Conduct technical, economic and/or financial analysis of each project.
2. Prepare bankable project documents for proposed projects.
3. Conduct social and environmental assessments of all projects.
4. Assist in securing financing in the form of grants and loans from Multilateral Financial Institutions, Bilateral development partners and other relevant institutions to fund selected projects.
5. Meaningfully engage the relevant stakeholders at the initiation stage and throughout the duration of all projects.

3.20.4 Technical Loss Reduction

GPL has traditionally focused on non-technical losses in an effort to reduce generation costs and increase revenue. Specific focus will be placed on technical loss reduction to complement the non-technical loss reduction strategies and to enhance the understanding, modelling, and computation of technical losses. This will be done through the following activities:

1. Budgeting and acquisition of the requisite tools, software, licences, etc.
2. Software modelling of Transmission and Distribution Network Loss Profiles.
3. Optimization of Network Designs by incorporating sound engineering to address and reduce power loss.
4. Implementation of Reactive Power Compensation where appropriate.
5. Integration of Distributed Energy Resources (DER).

3.20.5 Staff Training and Development

In alignment with the core strategic objectives, this critical area focuses on building human resource capacity to execute this business plan efficiently and effectively. It is intended to accomplish this through the following strategies, including those applicable from the Organisational Assessment action plan:

1. Identify gaps where training is required.
2. Design, implement, monitor, and evaluate training programmes to address gaps.
3. Establish employee development plans based on the Performance Management System (PMS).
4. Develop and expose staff to modern technologies through conferences, webinars, etc.
5. Create partnerships with academic institutions at various levels.

3.20.6 Project and Risk Management

1. Implement action plans emanating out of the organizational assessment.
2. Utilize corporate risk register to manage risks at the Divisional and departmental levels.
3. Adopt a multi-stakeholder approach to information sharing.
4. Liaise with Supply Chain Management Department to enable the timely procurement of goods and services.
5. Ensure health, safety and environmental matters are addressed by a designated representative on all projects.
6. Institute insurance coverage for all projects as required by law.

4 Non-Technical Operations

4.1 Facilities Management Programmes

The Company projects an investment of US$7 (GY$1.51B) in new accommodation facilities during the life of this programme as presented in Table 49

Table 49: Design and Construction of New Facilities

ITEM#	TYPE OF PROJECT	LOCATION	YEAR	ESTIMATED COST US$
1	Recommence construction of T & D Main Building - increasing from 2 to 3 stories	Sophia	2021	875,000
2	Construct additional 45' x 30' Building (Projects and Operations)	Middle Street	2021	255,520
3	Asbestos removal Canefield power Station – Roof	West Coast Berbice	2021	116,145
4	Rehabilitation of Mechanical Workshop, Stores, Power Station offices and washrooms	East Bank Berbice	2021	139,375
5	Construction of offices for Generation staff	East Bank Berbice	2021	74,332
6	Buildings and infrastructure improvements	Various locations	2021	511,033
	2021 TOTAL			**1,971,405**
ITEM#	**TYPE OF PROJECT**	**LOCATION**	**YEAR**	**ESTIMATED COST US$**
1	Complete T and D Main Building Sophia	Sophia	2022	875,000
2	Commence construction of new Training School	Sophia	2022	185,000
3	Commence construction of T and D Building	East Bank Berbice	2022	174,216
4	Buildings and infrastructure improvements		2022	413,473
	2022 TOTAL			**1,647,689**
ITEM#	**TYPE OF PROJECT**	**LOCATION**	**YEAR**	**ESTIMATED COST US$**
1	Recommence construction of Stores Building	Sophia	2023	465,000
2	Renovate and extend T & D Building	West Bank Demerara	2023	115,000
3	Complete construction of new Training School	Sophia	2023	185,000
4	Complete construction of T and D Building	East Bank Berbice	2023	174,216
5	Buildings and infrastructure improvements		2023	116,114
	2023 TOTAL			**1,055,330**
ITEM#	**TYPE OF PROJECT**	**LOCATION**	**YEAR**	**ESTIMATED COST US$**
1	Complete Construction of Stores Building at Sophia	Sophia	2024	465,000

ITEM#	TYPE OF PROJECT	LOCATION	YEAR	ESTIMATED COST US$
2	Commence construction of Commercial office building	New Amsterdam	2024	150,000
3	Commence construction of Commercial office building	Corriverton	2024	150,000
4	Commence construction of Commercial office building	Grove	2024	150,000
5	Commence construction of Commercial office building	Mon Repos	2024	150,000
6	Commence construction of Commercial office building	Parika	2024	150,000
7	Buildings and infrastructure improvements		2024	185,830
	2024 TOTAL			**1,400,830**
ITEM#	**TYPE OF PROJECT**	**LOCATION**	**YEAR**	**ESTIMATED COST US$**
1	Complete construction of Commercial office building	New Amsterdam	2025	150,000
2	Complete construction of Commercial office building	Corriverton	2025	150,000
3	Complete construction of Commercial office building	Grove	2025	150,000
4	Complete construction of Commercial office building	Mon Repos	2025	150,000
5	Complete construction of Commercial office building	Parika	2025	150,000
6	Buildings and infrastructure improvements		2025	185,830
	2025 TOTAL			**935,830**
	GRAND TOTAL		**2021-2025**	**7,011,084**

4.2 Commercial Division

4.2.1 Critical Issues

Customer Services has identified areas requiring significant attention which include alarmingly high numbers of estimated reads, delays in customer application processing time, poor revenue collection activities and delays in query resolutions.

4.2.2 New Services

The Company plans to connect approximately 55,000 (41,000 residential and 14,000 business) new consumers. This growth in new services recognizes the continued expansion of the housing sector, resulting from the allocation of land by the Government of Guyana for housing and the expansion of existing structures into multi-storey premises. Potential consumers will be encouraged to establish electricity accounts and desist from invitations to acquire electricity through illegal arrangements.

4.2.3 Efficiency and Customer Service Improvements

Whilst the reliability and the quality of the supply of electricity delivered to customers are of significant importance to the Company, the Company remains cognizant of the ‘life blood’ nature of electricity and remains equally cognizant of the importance of leveraging Information and Communication Technological (ICT) initiatives to improve the efficiencies within its operations.

GPL intends to invest in additional ICT facilities to realize these improvements over the next five years. The investments will facilitate:

- ✓ The extension of the corporate All-Dielectric Self-supporting (ADSS) optical fibre cable to the East Berbice Commercial offices, which will result in an improvement of the performance of the corporate Wide Area Network (WAN).
- ✓ The procurement and implementation of a computerised Business Intelligence System (BIS) that will support the Company’s realization of a computerized Enterprise Management Information System (MIS) with strong emphasis on corporate performance against Key Performance Indicators. Implementation commenced in September of 2020 and some Management Information Dashboards were established. The complete suite of Dashboards is expected to be completed by March 2021. This system is being realized through EU/IDB funding under the Power Utility Upgrade Programme (PUUP).
- ✓ The procurement and implementation of a computerized Document Management System in 2023 to replace the current unwieldy printed document management.
- ✓ The full implementation of a modern computerized Human Resource Management and Payroll Management system within Q2 of 2021
- ✓ The further deployment of an interactive Web Portal to customers for customer account management i.e., recording meter readings, contact numbers, retrieving consumption histories etc.
- ✓ The implementation of a computerized Maintenance Management System in 2021
- ✓ The upgrade the Customer Information System from a client-server platform to a web-based platform in 2021
- ✓ The procurement and implementation of a modern computerized financial budgeting and expenditure monitoring reporting system in 2022
- ✓ The continued leveraging of the corporate GIS.

4.2.4 Customer-centred Services

Customer feedback remains important to the Company, as it forms the basis for developing strategies for correcting deficiencies and crafting strategies for continuous improvements. During the last quarter of 2017, GPL engaged a reputable Company to coordinate and conduct Customer Satisfaction (qualitative and quantitative) surveys. These surveys will be conducted

initially on a quarterly basis and analysed with a focus on improving the quality of customer service.
The Company considers effective information dissemination critical to improving its public image through improved engagements with all stakeholders. It will intensify its information dissemination programs on its electric services via the print and electronic media and from within its Commercial offices. It will also further leverage its ICT solutions in order to improve the 'electronic windows' into GPL. Customer feedback on the on the corporate online account enquiry and the electronic billing services has been encouraging and therefore the Company will continue its efforts to maximize its use of electronic services.

GPL will continue over the life of this programme and beyond to deploy and review strategies and initiatives that will support the Company's efforts to continuously improve its quality of service in order to consistently meet and exceed the Customer Service Standards (CSS) and the Operational Service and Performance Targets (OS&PT). These standards reflect the corporate Key Performance Indicators.

The menu of strategies and initiatives include:

- Further leveraging of the corporate web site www.gplinc.net to present monthly electronic bills, which customers can access and download at their leisure.
- The maximization of a cellular platform that allows customer to retrieve useful account information via the Short Message Service (SMS). This service was introduced as 'SMS Freedom' during 2017.
- The provision of an electronic platform for recording customer retrieved meter readings. This will be subject to GPL's mandatory request to retrieve a minimum of one meter read per quarter.
- One hundred percent (100%) of Advance Metering Infrastructure (AMI) compatible meters. These meters will comprehensively address meter reading issues, disconnection and reconnection, billing, and various billing related queries.
- An expansion of public education initiatives to promote electronic payments via the banking system and the increased use of Payment Agencies, thus widening the options for conducting financial transactions.
- Intensify Corporate Relations efforts using more target audience penetrative methods.

4.2.5 Demand Side Management (DSM) / Energy Efficiency (EE)

GPL continued to signal its endorsement of Demand Side Measurement by crafting information dissemination initiatives aimed at different target groups. GPL's efforts are supported by the EU / IDB funded Social Management Programme within the Power Utility Upgrade Programme (PUUP). The consolidated efforts of the Company's Public Relations Officers and the EU / IDB funded Social Management Specialists resulted in 2018/19 to Community Outreach Meetings in 70 Project Areas with 3200 participants in Regions 3,4,5 and 6 which simulative informational, interactive engagements with residents.

In addition, for the 2019/ 2020 period, the Social Management focused on project areas of Lot A and B with interventions, inclusive of Community Outreach and direct dialogue and consultation with the local democratic organs and customer base in 87 project areas with approximately 2500 participants. Efforts were augmented with information dissemination via the print and electronic media. These activities will be reviewed in order to achieve maximum penetration and will continue over and beyond the life of this plan.

Some of the initiatives deployed were:

- ✓ The Importance of Energy Conservation/Energy Efficiency/Demand Side Management.
- ✓ Benefits of Energy Conservation/Energy Efficiency/Demand Side Management. and
- ✓ Practical saving tips and industry standard best practices.

The initiatives were developed to deliver an improved appreciation of the benefits of effective Demand Side Management (DSM) and their positive effects on:

- ✓ Customers' electricity consumption and by extension electricity bills
- ✓ Reduced cost of generation

The Company continued leveraging its corporate web site to consistently disseminate DSM information within the framework of:

- ✓ Cost reduction (GPL and electricity bills)
- ✓ Reduced CO_2 emissions

GPL will also continue to work closely with the Guyana Energy Agency (GEA) for maximum penetration in the deployment of energy efficient / saving initiatives. The GEA has the national mandate to advise and to make national recommendations to the responsible Minister regarding any measures necessary to secure the efficient management of energy.

4.2.6 Plans to regain Industrial customers:

Industrial consumers expect:

1. A reliable and efficient service.
2. Competitive tariff.
3. Electric service of acceptable quality. and
4. Available capacity to meet their growing needs.

The investments in generation, transmission, sub-stations, control facilities and loss reduction are all geared towards providing a reliable, least cost service. GPL had expected to rebalance its tariffs once power became commercially available from the hydro to remove the cross subsidy currently being provided by non-residential tariffs. GPL remains optimistic of the commissioning of a large hydropower facility in the long-term planning period. Such a facility would positively impact:

- ✓ Reduction in tariffs hence gradually attracting self-generating businesses to the grid; and
- ✓ Continued support of the 'economic development' in alignment with the Government's vision

GPL is also cognizant that industrial customers may be attracted to self-generation from renewable resources (mainly solar) given that the prices are becoming more affordable. In addition, the possibility of selling excess electricity to the grid could increase the attraction to invest in these renewable energy technologies.

The potential attraction of self-generation from renewable resources will also catalyse a tariff review with the objective of establishing more attractive rates that will afford the Company an acceptable level of profitability while encouraging the larger customers to retain their contractual relationship with GPL.

4.2.7 Strategy

Reduce Commercial Losses:

A. To reduce Estimated Reads and Commercial losses

1. Intensify corrective works on reported defective meters by making sure service orders are raised and sent for completion;
2. Ensure access to gain maximum reads through analysing monthly results and doing follow-up work to ensure reads are gained on a monthly basis;
3. Ensure all accounts are updated with retrieved reads and analyse data to ensure follow up is done in instances where reads are not used and why; and
4. An escalation process that involves senior managers to ensure all service orders are done and sent to the relevant departments and are closed/ completed.

B. To improve meter reading timelines and reduce estimations:

1. Implementing a detailed meter reading issue and collection monitoring system; and
2. Monthly analysis of data collected and the follow-up system for anomalies discovered in the field to the creation of service orders.

C. Improve billing practices:

1. Ensure actual reads submitted are always utilized in billing. This will be done through the close monitoring by supervisors of staff work via the exception report; and
2. Ensure billing procedures are reviewed for improved results in billing. This will be done through the review of all billing procedures and the subsequent enforcement of their use by all billing staff and supervisors.

To improve processing time for electric services

(1) Review current procedures to ensure flow and timelines are set for the entire process; and

(2) Implement a time monitoring mechanism to completion.

Collections

(1) Improve monitoring of MD accounts (all large consuming accounts, not just C&D) month on month and the required corrective actions to ensure collection.

(2) Implement a Government collections monitoring mechanism that ensures (1) all Government accounts are reconciled for accurate billing (2) Government accounts are monitored month on month, following up with each entity to ensure billed amounts are collected.

4.2.8 Critical Projects

- The use of CIS as the emergency database for reporting
- Consolidation of the Berbice call centre;
- Establish a process for addressing severe instances of meter retrieval failures in excess of 3 months;
- Reviewing meter form types, technical issues with the meters where reads are not randomly available, this project is to be completed in coordination with Loss Reduction Division; and
- Ensuring the standardisation and use of standards in billing procedures.

4.2.9 Key Performance Indication

Key Performance Indicator	Target 2020	Target 2021	Target 2022	Target 2023	Target 2024	Target 2025
New Service application processing time	1 days	1 day	1 day	1 day	1 day	1 day
New Service installation implementation						
Non-Capital	12 days	10 days	9 days	8 days	7 days	7 days
Capital	50 days	40 days	35 days	30 days	25 days	20 days
Response to queries						
Queries Acknowledged - Written	3 days	2 days	2 days	1 day	1 day	1 day
Enquiries Addressed (W / T)	7 days	5 days	4 days	3 days	2 days	1 day
PUC / Legal Issues Resolved	30 days	28 days	21 days	21 days	14 days	14 days
Issuance of bills after meter reading	7 days	7 days	7 days	7 days	7 days	7 days
Meters Read	95%	96%	97%	98%	99%	100%
Reconnections After Payment	2 days	1 day	1 day	1 day	1 day	1 day
Straight connections corrected in 1 day		100%	100%	100%	100%	100%
Call Centre Response	95%	96%	97%	98%	99%	100%
Response to repair calls within 24 hrs.	100%	100%	100%	100%	100%	100%
Meters Tested within 7 days of request	100%	100%	100%	100%	100%	100%
Collection Rate (Average)	95%	96%	97%	98%	99%	100%

4.3 Finance and Supply Chain Management

4.3.1 Critical Issue

1. Delays in the Procurement process.
2. Stock out of Critical Materials.
3. Lack of a Cash Management Policy.
4. Insufficient Control of the Budgeting Process.
5. Level of Insurance coverage on the Company's assets.
6. Level of Receivables Balances and Collectability.
7. Documentation of Related Party Agreements. and
8. Inadequate Asset Management Database.

4.3.2 Strategies

9. Continuous monitoring of the internal control processes
10. Develop a Financial Model to conduct forecasting, sensitivity analysis and to monitor expenditures;
11. Implement a Budget Module to enable us to prepare variance analyses in a timely manner and to enable user departments to access data on a real time basis;
12. Focus on paperless processes by taking advantage of full integration of existing modules;
13. Develop and implement cash management system;
14. Perform cost of service study;

15. Simplify the Procurement processes by reviewing the approval levels, establishing the EOQ and JIT systems and developing electronic signatures.
16. Negotiate better payment terms and review the PPC guidelines to take full advantages of same
17. Improve the Asset Management and Inventory system
18. Perform annual reviews of Accounting Policies and Procedures to refine and enhance;
19. Perform annual reviews of insurance policies;
20. Develop core team to review receivables processes;
21. Highlight the need for the Related Party Agreements;
22. Optimize Capital Structure jointly with the Shareholder;
23. Identify unusable materials from projects and identify assets for disposal;
24. Effectively manage asset disposal process;
25. Implement offsite backup of information;
26. Assess fuel storage requirements and improve where necessary; and
27. Create better work environment and take advantage of the Performance Management System.

4.4 Information Technology Division

The overall objective of the IT Division is to facilitate the flow of current information on GPL's processes and KPI's swiftly and securely to staff, customers, suppliers, and stakeholders, where they need it. This objective will be supported by the following measures.

4.4.1 Critical Issues

1. Infrastructure needs improving and expanding, e.g., bandwidth, to facilitate end-users and the flow of data/ information, Distribution SCADA and AMI/ Smart Grid.
2. A modern, secure user environment needs to be revived/ expanded, including division-level systems under Critical Projects.
3. A reorientation of department managers and end-users to be more performant in data capture (digital, structured, accurate, prompt, on-site) and information-usage. and
4. Computation and data flow for effective planning and decision making.

4.4.2 Strategy

Reorganize IT Division into three teams that will:

1. Provide infrastructure;
2. Provide client services;
3. Process data and deliver information;

Pivot GPL towards being data-*driven* and an e-Business (Policy):

4. Capture current data on-site/ Record and upload what, when, where
5. Capture digital, geospatial data (+1); and
6. Use data not opinion for planning and operations.

4.5 Human Resources Division

Development and maintenance of the requisite core of skills to manage the evolving electricity infrastructure that is based increasingly on automation and ICT systems would be critical for GPL.

The continued heavy loss of skills is a severe challenge for the best of plans as new professionals depart after gaining some practical experience. The Company intends to maintain the Management Trainee Programme on an ongoing basis to mitigate the loss of skills at the professional entry levels.

The Company's intention to align with the Government's vision on economic development requires training and developing staff in both the technical and commercial components of renewable energy management. GPL will examine a plethora of local and overseas training in order to ensure that it develops and maintains that capacity to manage this evolving technology.

At the technician level, GPL would continue to invest in the apprenticeship programme and specialized six months and one-year intensive programmes to provide the requisite number of entry level technical skills. The Company also intends to review its Management Trainee programme and realign it with the required human resources requirements that is necessary to achieving the objectives outlined in this plan.

The Company will continue to provide opportunities for further tertiary education and professional training. It intends to achieve this by selectively and fairly approving time away from work to attend classes at tertiary institutions. The Company will also consider partial scholarships to employee desirous of pursuing master's degree programmes that will support GPL's operations.

4.5.1 Critical Issues

1. There is an urgent need to review and improve the staff recruitment process to ensure that a better quality of staff is recruited in a timelier manner to meet the skills and competencies required by GPL.
2. The induction and on-boarding of staff needs to significantly improve to ensure that staff is fully aware of GPL's personnel policies and their respective roles and responsibilities in their Department.
3. The present system for identifying the developmental/training needs of staff needs to be significantly enhanced.
4. The new Performance Management System needs to be fully and effectively implemented to ensure more objective and targeted appraisal of staff.
5. A policy and related procedures for proper Succession Planning at the Management levels needs to be developed and implemented.
6. here is a critical need for a revised Disciplinary Policy and Procedures to a more effective and efficient system for dealing with disciplinary issues.
7. The present system for monitoring safety procedures and effecting remedial actions in a timelier manner needs to be significantly improved.
8. The construction and ongoing maintenance of GPL's facilities needs to be more efficient and timelier to ensure a better environment for staff and customers.

4.5.2 Strategy

1. Review and Update Human Resources Policies and Procedures.
2. Revise and document GPL Organisational Structure.
3. Acquire and implement automated Human Resources Management System.
4. Review and document Recruitment and On-Boarding procedures.
5. Enhance Employee Development and Training programs.
6. Implement new Performance Management System.
7. Develop and implement a system for Succession Planning.
8. Review, document and revise Disciplinary Policy.
9. Develop and Implement Change Management.
10. Develop and negotiate proposals for staff Remuneration benefits and conditions of service.

11. Develop and implement programs for Staff Welfare and Social Activities.
12. Conduct annual Employment Engagement survey and develop and implement action plan for improvements in employee engagement.
13. Develop and implement an improved system for Safety, Health and Environmental Management.
14. Develop and implement system for the effective maintenance and construction of facilities.

4.5.3 Performance Monitoring

An affordable, stable, and continuous supply of electricity is critical to the development of Guyana's economy and must be in alignment with the National Development Strategy (NDS). It is therefore imperative for the Government of Guyana and sole shareholder of GPL to be informed of the Company's performance and the extent of its alignment with the NDS via a structured Performance Monitoring and Evaluation mechanism.

In order to formally support this Monitoring and Evaluation mechanism, a Performance Agreement was established between GPL, the Ministry of Finance, and the Ministry of Public Infrastructure, which commenced from January 1, 2017. This Performance Agreement will be reviewed and renewed annually. The agreement will focus on a number of critical Performance measures and Key Performance Indicators that GPL is expected to meet or exceed. GPL will submit performance reports on a monthly basis to the Government of Guyana, through the Ministry of Finance's Monitoring and Evaluation Unit.

In addition to the Performance Agreement, the Company intends to fully implement an objective Performance Management System (PMS) in 2021. This will be aligned with the Corporate Strategic Plan and this programme. Key Performance Indicators and targets will form an integral part of this PMS.

5 Corporate Key Performance Indicators and Targets

GPL has identified Key Performance Indicators (KPI),Table 50, for its main objectives and these have been drilled down to Divisional levels, as reflected in the Divisional Plans. The KPIs are consistent with the Company's mission and vision and cover areas relating to the Company's drive towards 'SUCCESS':

- Service quality.
- Uptime/ reliability of systems.
- Coverage / access to service.
- Compliance with applicable regulations and standards.
- Efficiency in all activities.
- Safety and security. and
- Sustainability.

Table 50: Corporate Key Performance Indicators (KPIs)

Category	Key Performance Indicator	Unit	2020	Targets				
				2021	2022	2023	2024	2025
Service Quality	New Service Application Processing Time	Days	3	2	1	1	1	1
	New Service Installation - Non-Capital	Days	12	10	9	8	7	7
	New Service Installation-Capital	Days	50	45	40	35	30	25
	Queries Acknowledged	Days	3	2	2	1	1	1
	Enquiries Addressed	Days	7	6	5	4	3	2
	PUC/Legal Issues Resolved	Days	30	28	21	21	14	14
	Issuance of Bills After Meter Reading	Days	7	7	7	7	7	7
	Meter Read	%	95	96	97	98	99	100
	Reconnection After Payment	Days	2	1	1	1	1	1
	Straight Connections Corrected in 1 day	%	100	100	100	100	100	100
	Call Centre Response	%	95	96	97	98	99	100
	Response to Repair Calls Within 24 Hours	%	100	100	100	100	100	100
	Meter Tested Within 7 Day after Request (100% in 24 Hours)	%	100	100	100	100	100	100

Category	Key Performance Indicator	Unit	2020	Targets				
				2021	2022	2023	2024	2025
	Emergency Response within 12 Hours	%	60	80	90	95	100	100
	Defective Meter Replacement	Days	60	50	40	30	20	10
Uptime (Reliability)	SAIFI	%	95	90	85	80	75	70
	SAIDI	%	100	95	90	85	80	75
	Generation Plant Availability (Average)	%	85	85	85	85	85	85
Coverage (Access)	Percentage of Households with access to electricity	%	90	92	94	96	98	99
Compliance	Required Reports Submitted on time				100	100	100	100
	Environmental Requirements Met				100	100	100	100
Efficiency	Collection Rate (Average)	%	95	96	97	98	99	100
	Generation Plant Efficiency - HFO	IG/MWh	50.41	50	50	50	50	50
	Generation Plant Efficiency - LFO	IG/MWh	61.6	60	60	60	60	60
	Overtime/Basic Pay	%	38	35	30	25	20	15
	Total Losses/Net Generation	%	27.7	26.5	25	23.5	22	20.5
	Percentage of Projects Completed on Time, while meeting quality and performance requirements	%	87	87	90	92	94	96
	Percentage of Projects Completed on Budget while meeting quality and performance requirements	%	87	87	90	92	94	96
Safety and Security	Number of reportable safety incidents	#	30	26	24	22	20	18
	Person-hours lost due to safety incidents	#	303	260	240	220	200	180
Sustainability	Renewable Energy as % of Energy Generated	%				5	10	15
	Liquidity Ratio	%	1.31	1.36	1.41	1.46	1.51	1.56
	EBITDA/Revenue	%	22	22	22	22	22	22
	Debt/Equity Ratio	%	84	84	84	84	84	84

Category	Key Performance Indicator	Unit	2020	Targets				
				2021	2022	2023	2024	2025
	Staff vacancies adequately filled within 45 days	%	85	86	88	90	92	94
	PMS Reviews completed on time	%	90	92	94	96	98	100
	Required staff training and development programs implemented as per PMS	%	85	86	88	90	92	94
	Employee Engagement Survey Score	%	80	80	82	84	86	88
	World Class Assessment Score (WC 41-50)		20	22	26	31	36	41

5.1 Generation and Network related Key Performance Indicators (KPIs)

Table 51: Operations KPIs

KPIs	Target					
	2020	2021	2022	2023	2024	2025
SAIFI	95	90	85	80	75	70
SAIDI	100	95	90	85	80	75
Voltage Complaint	98% within 30 days	98% within 30 days	98% within 25 days	98% within 20 days	98% within 20 days	100% within 21 days
Capital Jobs	95% within 28 days	95% within 28 days	98% within 21 days	98% within 21 days	98% within 21 days	98% within 21 days
Unserved Area Electrification	95% within year	95% within year	98% within year	98% within year	98% within year	98% within year
Emergency Response	90% within 12hrs and 10% within 24hrs	80% within 8hrs, 10% within 12hrs and 10% within 24hrs	85% within 8hrs, 5% within 12hrs and 10% within 24hrs	85% within 8hrs, 10% within 12hrs and 5% within 16hrs	90% within 8hrs, 10% within 12hrs	90% within 8hrs, 10% within 12hrs
Average No. of Emergency Faults Reported daily	110	90	80	75	70	65

KPIs	Target					
	2020	**2021**	**2022**	**2023**	**2024**	**2025**
ISO Non-Conformance address within agreed schedules	100%	100%	100%	100%	100%	100%
Annual Average Availability of Generation	85%	85%	85%	85%	85%	85%
Availability GPL	80%	80%	85%	85%	85%	90%
Availability PPDI	92%	92%	92%	92%	92%	92%
Efficiency (IG/MWh)						
HFO	50	50	50	50	50	50
LFO	60	60	60	60	60	60
Fuel Mix	91:09	92:08	94:06	94:06	94:6	94:6

6 Summary of Annual Expansion, Upgrades and Service Work Plan (See Appendix 2, page 148 for details by Geographic Areas)

6.1 Work Plan Summary Short Term Planning (2021-2022)

Generation Projects	
2021-2022	**Conventional Projects**
2021	GARDEN OF EDEN PHASE 1 – 46.5 MW DUAL FUEL Wakenaam - Phase 1- Installation of 1 x 410 kW Diesel Generator Bartica Plant Extension – 1x1.12 MW LFO Generator
2022	Anna Regina Plant Upgrade No.2 - 2 x 2.5 MW HFO Wakenaam - Phase 2- Installation of 1 x 410 kW Diesel Generator Garden of Eden Phase 2 – 46.5 MW
2021-2022	Renewable Energy and Energy Storage Projects
2021	Wakenaam 750 kW Solar PV with BESS
2022	Leguan 0.6 MWp Solar Farm and MW BESS 10MW – 4hr BESS – New Sophia

Transmission System and Substation Projects	
2021-2022	**Transmission System**
2021	1. Kingston to Sophia transmission line upgrade and redundancy (L5 and L5R). 2. Garden of Eden to New Georgetown new transmission line (L14). 3. New Sophia to Good Hope transmission line upgrade and redundancy Phase 1(L16 and L16R);
2022	1. New Sophia to Good Hope transmission line upgrade and redundancy Phase 2(L16 and L16R); 2. Old Sophia to New Georgetown transmission lines upgrade (L10). 3. L12 and L13 Upgrade – to facilitate increased power transfer between Old and New Sophia Substations. 4. Good Hope to Columbia redundant transmission line Phase 1 (L17R); 5. Kingston to Merriman's Central Georgetown new transmission line Phase 1 (L11-1); 6. Merriman's Central Georgetown to New Georgetown new transmission line Phase 1 (L11-2); 7. Garden of Eden to Kuru Kururu new transmission line (L31); 8. Garden of Eden to Golden Grove transmission line upgrade (L1 and L3); 9. Golden Grove to New Sophia transmission line upgrade Phase 1 (L4-2); 10. Golden Grove to Old Sophia transmission line upgrade Phase 1 (L2-2);

Transmission System and Substation Projects	
2021-2022	**Transmission System**
	11. Westminster to Wales Transmission Line Phase 1 (L41); 12. Vreed-en-hoop to Wales new transmission line (L9); 13. Vreed-en-hoop to Westminster Transmission Line Phase 1 (L40);

2021-2022	New Substation System and Substation Upgrade
	Upgrades to existing SCADA and extending SCADA reach into Distribution and Generation Systems, and installation of AGC **Substation Upgrade** 1. Garden of Eden Substation and Power Plant 2. Canefield Substation and Power Plant facility 3. Edinburgh Substation 4. New Sophia Switching Substation 5. Sophia Upgraded Substation 6. New Georgetown Substation 7. Good Hope Substation 8. Golden Grove Substation 9. No. 53 Village Substation 10. Kingston 2 Power Plant & Substation- PUUP 11. Vreed-en-hoop Substation & PPDI-4 Power Plant- (GPL & PUUP) **New Substation System** 12. Wales Substation 13. Kuru Kururu Substation

2021-2022	Transmission Reinforcements
	1. **New Sophia**-15 MVAr 69 kV De-tuned Compensation Systems 2. **Good Hope -**15 MVAr 69 kV De-tuned Compensation Systems 3. **New Geogetown**-15 MVAr 69 kV De-tuned Compensation Systems 4. **Edinburgh-**10 MVAr 69 kV De-tuned Compensation Systems

2021-2022	Electrification – Unserved Areas
2021	5650 beneficiaries
2022	153 beneficiaries
2021-2022	**New Services**
2021	10,000 services
2022	10,500 services
2021-2022	**Facilities Management**
2021	1. Recommence construction of T & D Main Building - increasing from 2 to 3 stories 2. Construct additional 45' x 30' Building (Projects and Operations)

	3. Asbestos removal Canefield power Station - Roof 4. Rehabilitation of Mechanical Workshop, Stores, Power Station offices and washrooms 5. Construction of offices for Generation staff 6. Buildings and infrastructure improvements
2022	1. Complete T and D Main Building Sophia 2. Commence construction of new Training School 3. Commence construction of T and D Building 4. Buildings and infrastructure improvements
2021-2022	**Capacity Building**
2020	261,905.00
2021	327,381.25
2022	409,226.56
2021-2022	**Non-Technical Loss Reduction**
2021	1. Upgrade 10,595 meters to AMI meters (PUUP) 2. Replace 3,080 defective meters with AMI meters. 3. Upgrade 25,047 consumers to AMI meters 4. Replace 400 tampered meters to AMI meters
2022	5. Upgrade 7,150 meters to AMI meters (PUUP) 6. Replace 3,080 defective meters with AMI meters. 7. Upgrade 9,089 consumers to AMI meters 8. Replace 400 tampered meters to AMI meters. 9. AMI Infrastructure, implementation, and Professional fees

2021-2022	**Distribution Network**
2021	**Interconnection of Leguan and Wakenaam Power Systems via 13.8 kV Submarine Link.** **Upgrade of 13.8 kV Primary Distribution Feeders** Onverwagt F2 Feeder. Express feeder to Ithaca Backbone upgrades: • Good Hope F4 • Sophia F2 • Garden of Eden F1 Installation of 1500 kVAr APFC[18] on both lines. Replace SWER Transformers on WCD and WBD **Upgrade of 13.8 kV Primary Distribution Feeders** Garden of Eden F2 Edinburgh F2

[18] Automatic Power Factor Correction Capacitors

	Good Hope F2 Canefield F3 Load sectionalisation of Good Hope F4 Upgrade existing 13.8 kV feeder from Anna Regina to Supernaam. Sophia Substation improve reliability on the F2. **New 13.8 kV Primary Distribution Feeders:** Bartica- three (3) new feeders (Goshen, Itabali and East Bank Essequibo-Upper Essequibo River) Edinburgh to Philadelphia, WCD Anna Regina to Onderneeming Express– load pickup from Onderneeming to Supernaam Installation of a total of 12MVAr APFC Banks across 30 feeders Installation and Commissioning of 99 Auto-Reclosers
2022	**New 13.8 kV Primary Distribution Feeders** Edinburgh - 2 new active feeders

6.2 Work Plan Summary Medium Term Planning (2023-2025)

Generation Projects	
2023-2025	**Conventional Projects**
2023	Natural Gas Fired 250 MW Phase 1 Bartica Plant Upgrade - (2x2MW), Leguan Power Plant Extension 1 (2x0.41MW), Anna Regina Plant Extension 1- 1.8 MW HFO
2024	Anna Regina Plant Upgrade No. 2 – 2x2.5 MW HFO Natural Gas Fired 250 MW Phase 2 Wakenaam - Phase 3- Installation of 1 x 410 kW Diesel Generator
2025	Crab Island/East Bank Berbice Phase 1-46.5 MW - Phase 1 Leguan Power Plant Extension 2 (1x0.41MW) (New Location and Building)

2023-2025	**Renewable Energy and Energy Storage Projects**
2023	Berbice 10 MWp Solar PV System Anna Regina 8 MWp Solar PV System and 8 MWh BESS Linden 15 MWp Solar PV Farm and 15 MWh BESS Bartica 1.5 MWp Solar PV and BESS
2025	**NAARSTIGHEID, WEST COAST BERBICE -** 4 MWP SOLAR PV FARM

Transmission System and Substation Projects	
2023-2025	**Transmission System**
2023	1. Good Hope to Columbia redundant transmission line Phase 2 (L17R); 2. Splitting of existing transmission lines from Good Hope Substation to Columbia Substation (L17-1) to interconnect with the Hope Beach substation; 3. Kingston to Merriman's Central Georgetown new transmission line Phase 1 (L11-1); 4. Merriman's Central Georgetown to New Georgetown new transmission line Phase 1 (L11-2); 5. Edinburgh to Hydronie/Parika Substation new transmission line Phase 1 (L8); 6. Garden of Eden to Wales new transmission line (L24); 7. Splitting of new transmission line between Garden of Eden to New Georgetown into Eccles new transmission lines (L15 & L14); 8. Golden Grove to New Sophia transmission line upgrade Phase 2 (L4-2); 9. Golden Grove to Old Sophia transmission line upgrade Phase 2 (L2-2); 10. Westminster to Wales Transmission Line Phase 2 (L41); 11. Vreed-en-hoop to Westminster Transmission Line Phase 2 (L40); 12. Golden Grove to Eccles transmission line upgrade and splitting (L2-1 and L4-1); 13. Eccles to New Sophia transmission line splitting (L4-2); 14. Eccles to Old Sophia transmission line splitting (L2-2); 15. Splitting of L17 and L17R to accommodate Victoria/Enmore substation. **230 kV Transmission Lines Projects** • Natural Gas to Eccles new transmission lines and • Natural Gas to Wales new transmission lines.
2024	**69 kV Transmission Lines Projects** 1. Edinburgh to Hydronie/Parika Substation new transmission line Phase 2 (L8); 2. Double circuit transmission lines from Garden of Eden Substation to Linden; **230 kV Transmission Lines Projects** • Double circuit transmission lines from Wales Substation to Garden of Eden; • Double circuit transmission lines from Eccles Substation to Garden of Eden;
2025 (starts in 2025, completes in 2026)	1. No. 53 to Skeldon transmission line redundancy (L23R) 2. Vreed-en-hoop to Eccles new transmission line (L32)-; 3. Eccles to Ogle new transmission lines (L25 and L25R); 4. Ogle to Success new transmission lines (L26 and L16-R2); 5. Success to Good Hope (L16R-3); 6. Columbia to Onverwagt redundant transmission line (L20R); 7. Onverwagt to Canefield redundant transmission line (L21R); 8. Splitting of L22 to accommodate Williamsburg Substation; 9. Splitting of L22 to accommodate Crab Island substation;

Transmission System and Substation Projects	
2023-2025	**Transmission System**
	10. Canefield to Williamsburg transmission line redundancy (L22-1 and L22R-1); 11. Williamsburg to No. 53 transmission line redundancy (L22-2 and L22R-2);
2023-2025	**Substation Upgrade System**
2023	1. New Georgetown Substation 2. Good Hope Substation 3. Golden Grove Substation 4. Upgrade of Kingston 13.8 kV Switchgear; 5. Edinburgh Transformer upgrade- Relocation of Golden Grove 10 MVA 6. Columbia Substation; 7. Canefield Substation
2024	8. Onverwagt 69/13.8 kV Substation Upgrade 9. New Georgetown Substation
2025	10. Onverwagt 69/13.8 kV Substation Upgrade
2023-2025	**New Substation System**
2023	1. Westminster Substation 2. Victoria/Enmore Substation 3. Eccles 69/13.8 kV and 230/69 kV Substation 4. Natural Gas Substation-230 kV/69 kV 5. Merriman's (Central Georgetown) Substation 6. Wales Switching Substation-230 kV 7. Wales Substation Expansion-230 kV/69 kV
2024	1. Parika/Hydronie Substation 2. Linden Susbstation-69/13.8 kV
2025-2026	1. Crab Island Substation; 2. Ogle Substation; 3. Success Susbstation; 4. Williamsburg Substation;
2023-2025	**Transmission Reinforcements**
2023	1. **Columbia-**10 MVAr 69 kV De-tuned Compensation Systems
2024	**2. Parika/Hydronie-**10 MVAr 69 kV De-tuned Compensation Systems **3. Linden-** 2 x 5 MVAr 69 kV De-tuned Compensation System
2023-2025	**Electrification – Unserved Areas**
2023	3766 beneficiaries
2024	278 beneficiaries
2025	356 beneficiaries
2023-2025	**New Services**

Transmission System and Substation Projects	
2023-2025	**Transmission System**
2023	11,000 services
2024	11,500 services
2025	12,500 services
2023-2025	**Facilities Management**
2023	1. Recommence construction of Stores Building. 2. Renovate and extend T & D Building 3. Complete construction of new Training School 4. Complete construction of T and D Building 5. Buildings and infrastructure improvements
2024	1. Complete Construction of Stores Building at Sophia 2. Commence construction of Commercial office building. 3. Commence construction of Commercial office building. 4. Commence construction of Commercial office building. 5. Commence construction of Commercial office building. 6. Commence construction of Commercial office building. 7. Buildings and infrastructure improvements
2025	1. Complete construction of Commercial office building 2. Complete construction of Commercial office building 3. Complete construction of Commercial office building 4. Complete construction of Commercial office building 5. Complete construction of Commercial office building 6. Buildings and infrastructure improvements
2023-2025	**Capacity Building**
2023	US$ 511,533.20
2024	US$ 639,416.50
2023-2025	**Non-Technical Loss Reduction**
2023-2025	1. Replace 3,080 defective meters with AMI meters 2. Upgrade 9,089 consumers to AMI meters 3. Replace 400 tampered meters to AMI meters

2023-2025	Distribution
2023	**New 13.8 kV Primary Distribution Feeders** Eccles- 4 new active feeders Kuru Kururu – 4 new active feeders Wales- 2 new active feeders Four (4) new feeders form Good Hope Substation

2024	**SCADA integration of Auto-Reclosers and Automation of Distribution Networks** Hydronie\Parika - 3 new active feeders Four (4) new feeders form Golden Grove Substation Four (4) new feeders form New Georgetown Substation Two (2) new feeders form Onverwagt Substation Two (2) new feeders form Good Hope Substation Four (4) new feeders form Victoria/Enmore Substation
2025	Three (3) new feeders from Garden of Eden Substation Construction of 13.8 kV express line from Lima Sands to Charity; Williamsburg - 4 new active feeders (Starts in 2025 and ends in 2026) Six (6) new feeders form Ogle Substation Six (6) new feeders form Success Substation Four (4) new feeders form Crab Island Substation

7 Operations

7.1 Sales and Revenue Collection

Sales growth from 2020 to 2025 is projected to increase by 234% from 635 GWh to 2,121 GWh for the total GPL Power Systems (Figure 7). This projection is based on the expected significant stimulation in the economy that will be provided by the emerging Oil and Gas Industry. The Company projects an increase in its customer base from 205,814 in 2020 to potentially 265,667 by the end of Year 2025 (Table 7). The projected increase in the customer base is largely as a result of the increased economic activities, which are expected to result from 1) population growth, 2) increased business activities and 3) providing services to all existing un-served areas.

The active campaign to improve Receivables will continue and a cash collection rate of 99.5% (cash collections as a percentage of sales) has been assumed for the life of this Programme.

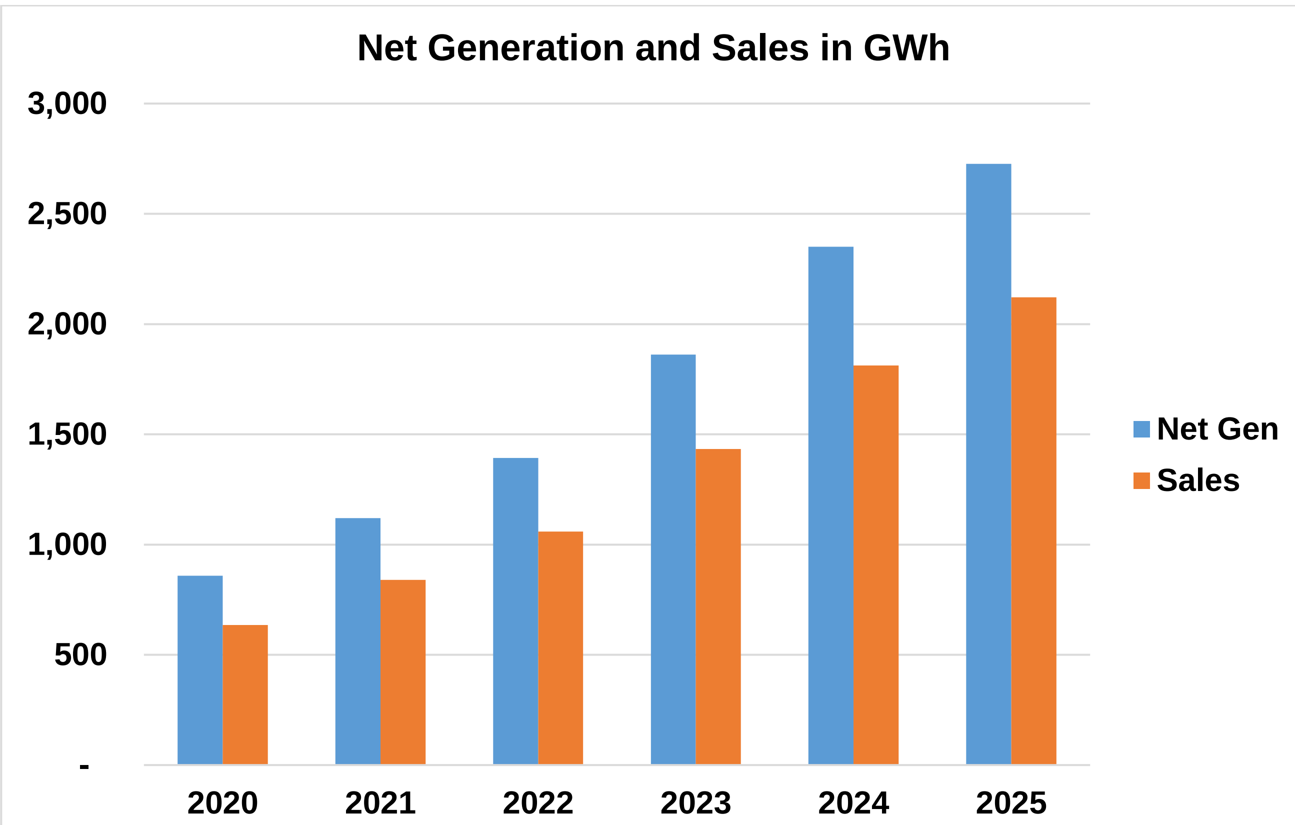

Figure 7:Net generation & Sales (GWh)

8 Projected Capital Expenditure

10.1 Summary of Capital Expenditure, US$ - GPL Funding

Table 52: Summary of Capital Expenditure, US$ - GPL Funding

CAPITAL WORK PROGRAM YEARS 2021-2025						
	TOTAL USD	Yr 2021 USD	Yr 2022 USD	Yr 2023 USD	Yr 2024 USD	Yr 2025 USD
Generation	$ 752,826,383	$ 52,329,293	$ 103,748,448	$ 253,217,617	$ 326,383,025	$ 17,148,000
Transmission Lines	$ 199,748,849	$ 11,485,544	$ 42,996,268	$ 78,823,803	$ 42,451,394	$ 23,991,840
Sub-Stations	$ 252,685,193	$ 41,525,143	$ 100,443,143	$ 75,983,550	$ 17,757,000	$ 16,976,357
Non Technical Loss Reduction	$ 36,009,225	$ 12,434,997	$ 12,978,561	$ 3,531,889	$ 3,531,889	$ 3,531,889
Technical Loss Reduction Distribution upgrades	$ 65,672,200	$ 8,072,200	$ 13,680,000	$ 11,480,000	$ 20,200,000	$ 12,240,000
Electrification (unserved areas)	$ 3,390,561	510,829	1,686,022	64,459	843,161	286,091
New Services	$ 15,125,000	$ 2,750,000	$ 2,887,500	$ 3,025,000	$ 3,162,500	$ 3,300,000
Buildings	$ 7,011,084	$ 1,971,405	$ 1,647,689	$ 1,055,330	$ 1,400,830	$ 935,830
Capacity Building	$ 56,669,732	$ 24,188,995	$ 13,541,700	$ 8,302,033	$ 5,664,068	$ 4,972,937
Information Technology	$ 2,500,929	$ 1,863,929	$ 287,000	$ 40,000	$ 95,000	$ 215,000
Reactive Power Compensation	$ 21,840,000	$ 6,328,000	$ 6,552,000	$ 5,488,000	$ 3,472,000	$ -
GRAND TOTAL	$ 1,413,479,156	$ 163,460,334	$ 300,448,330	$ 441,011,681	$ 424,960,867	$ 83,597,944
FINANCED BY						
THIRD PARTY FINANCED						
- INDEPENDENT POWER PRODUCERS (IPP)	$ 561,200,000	$ -	$ -	$ 226,848,000	$ 320,912,000	$ 13,440,000
Note - Not coded to GPL Fixed Assets	$ 561,200,000	$ -	$ -	$ 226,848,000	$ 320,912,000	$ 13,440,000
GPL FINANCING SOURCES						
- LOANS	$ 435,673,789	$ 81,999,087	$ 174,056,259	$ 125,040,892	$ 29,258,794	$ 25,318,757
- GRANT AID	$ 99,748,239	$ 26,513,808	$ 50,990,823	$ 16,063,608	$ 2,472,000	$ 3,708,000
- EQUITY	$ -	$ -	$ -	$ -	$ -	$ -
- INTERNAL FUNDS	$ 316,857,128	$ 54,947,439	$ 75,401,248	$ 73,059,181	$ 72,318,073	$ 41,131,186
Note - Coded to GPL Fixed Assets	$ 852,279,156	$ 163,460,334	$ 300,448,330	$ 214,163,681	$ 104,048,867	$ 70,157,944
TOTAL FINANCING	$ 1,413,479,156	$ 163,460,334	$ 300,448,330	$ 441,011,681	$ 424,960,867	$ 83,597,944

9 Operating costs and Capital Expenditures

Accounts Summaries Profit & Loss Account

Table 53:Profit & Loss Account

	2020	Yr 2021	Yr 2022	Yr 2023	Yr 2024	Yr 2025
	Unaudited	Proj	Proj	Proj	Proj	Proj
	$'M	$'M	$'M	$'M	$'M	$'M
REVENUE						
Turnover	37,469	41,579	52,405	70,971	81,919	82,184
Rebate	(4,738)					
NET REVENUE	**32,731**	**41,579**	**52,405**	**70,971**	**81,919**	**82,184**
GENERATION COSTS						
Fuel & Freight	15,352	17,098	21,419	15,495	6,047	11,555
Operation & Maintenance Contract	2,777	5,745	7,411	5,353	2,024	3,964
Repairs & Maintenance - Generation Facility	482	500	500	500	500	500
Purchased Power (IPP costs)	2,213	2,137	1,293	16,994	37,649	37,950
Rental of Equipment	308	250	250	250	250	250
Fuel Agency Fee						
	21,132	**25,730**	**30,872**	**38,593**	**46,471**	**54,218**
GROSS INCOME	**11,599**	**15,849**	**21,532**	**32,378**	**35,448**	**27,966**
EXPENSES						
Employment Costs	4,663	5,129	5,642	6,206	6,827	7,510
Repairs & Maintenance T&D	758	1,956	4,225	6,235	6,902	7,063
Depreciation	3,333	3,396	6,480	10,288	13,500	15,155
Administrative Expenses	2,300	2,484	2,683	2,897	3,129	3,379
Rates & Taxes	50	54	58	63	68	73
Loss On Exchange	-	-	-	-	-	-
Bad Debts Provision	437	624	786	1,065	1,229	1,233
Puc Assessment & Licence	50	75	75	75	100	100
	11,591	**13,718**	**19,949**	**26,829**	**31,755**	**34,514**
NET (LOSS)/PROFIT FROM OPERATIONS	**8**	**2,131**	**1,583**	**5,548**	**3,693**	**(6,547)**
INTEREST EXPENSE	1,326	2,835	4,334	5,410	5,662	5,880
	(1,318)	**(704)**	**(2,751)**	**138**	**(1,970)**	**(12,428)**
OTHER INCOME	809	1,559	1,965	2,661	3,072	3,082
	(509)	**855**	**(786)**	**2,799**	**1,102**	**(9,346)**
TAXATION	64	128	(118)	420	165	(1,402)
NET (LOSS)/PROFIT FOR THE YEAR	**(573)**	**727**	**(668)**	**2,379**	**937**	**(7,944)**

In accordance with GPL's Licence the Shareholder is entitled to a target rate of return on equity of 8% per annum.

9.2 Cash Flow Statement

Table 54: Cash Flow Statement

Guyana Power & Light Cash flow Statement for the year ended December 31st	Yr 2020 Unaudited $'m	Yr 2021 Proj $'m	Yr 2022 Proj $'m	Yr 2023 Proj $'m	Yr 2024 Proj $'m	Yr 2025 Proj $'m	5 Year Summary $'m
OPERATING ACTIVITIES							
Profit/(Loss) before Taxation	**(509)**	**855**	**(786)**	**2,799**	**1,102**	**(9,346)**	**(5,375)**
Adjustments for:							
Depreciation	3,333	3,396	6,480	10,288	13,500	15,155	48,819
Deferred Income	106	15	40	69	41	1	166
Deferred Tax Asset	0	102	(94)	333	131	(1,112)	(640)
Interest Expense	1,326	2,835	4,334	5,410	5,662	5,880	24,122
Amortization of Customer Projects							
Operating (loss)/profit before WC changes	**4,256**	**7,203**	**9,975**	**18,900**	**20,436**	**10,579**	**67,093**
Working Capital (WC) Changes							
Change in Inventories	(515)	1,579	(2,629)	(1,516)	120	(619)	(2,542)
Change in receivables and prepayments	(3,704)	6,625	(1,804)	(3,094)	(1,825)	(44)	(8,834)
Change in payables and accruals	2,017	16,656	(1,882)	(5,016)	(13,921)	(3,770)	943
Change in related parties	(162)	2,835	4,334	5,410	5,662	5,880	26,134
Taxes paid	(64)	(132)	67	(253)	(266)	780	195
Net Cash (Outflow)/Inflow - Operating Activities	**1,828**	**34,766**	**8,061**	**14,430**	**10,206**	**12,806**	**82,989**
INVESTING ACTIVITIES							
Acquisition of Property, plant and equipment	(12,590)	(47,930)	(53,696)	(42,641)	(21,864)	(14,303)	(180,434)
Acquisition of Intangible assets	0	(166)	(200)	(240)	(288)	(345)	(1,238)
Increase in WIP	0	(8,642)	2,310	5,660	14,578	4,415	18,321
Acquisition of treasury bills	0	0	0	0	0	0	0
Increase in deposit	437	0	0	0	0	0	0
Net Cash Outflow - Investing Activities	**(12,153)**	**(56,738)**	**(51,585)**	**(37,221)**	**(7,574)**	**(10,233)**	**(163,351)**
FINANCING ACTIVITIES							
Movement in non current related parties	12,161	29,877	37,466	26,915	6,298	5,450	106,005
Deposit on Shares	0	0	0	0	0	0	0
Interest paid	(1,326)	(2,835)	(4,334)	(5,410)	(5,662)	(5,880)	(24,122)
Customer deposits	305	391	1,031	1,768	1,043	25	4,258
Increase in advances customer financed projects	(639)	248	654	1,122	662	16	2,702
Decrease in advances customer financed projects							
Net Cash (Outflow)/Inflow - Financing Activities	**10,501**	**27,681**	**34,817**	**24,394**	**2,340**	**(389)**	**88,843**
NET MOVEMENT IN CASH AND CASH EQUIVALENTS	**176**	**5,709**	**(8,708)**	**1,603**	**4,972**	**2,184**	**8,481**
CASH AND CASH EQUIVALENTS AS AT BEGINNING OF YEAR	3,155	3,331	9,040	333	1,936	6,908	3,331
CASH AND CASH EQUIVALENTS AS AT END OF YEAR	**3,331**	**9,040**	**333**	**1,936**	**6,908**	**9,092**	**11,812**
Represented By:							
Cash on Hand and at Bank	**3,331**	**9,040**	**333**	**1,936**	**6,908**	**9,092**	**9,092**

9.3 Balance Sheet

Table 55: Balance Sheet

Guyana Power & Light Statement of Financial Position As at December 31st	Yr 2020 Unaudited $'M	Yr 2021 Proj $'M	Yr 2022 Proj $'M	Yr 2023 Proj $'M	Yr 2024 Proj $'M	Yr 2025 Proj $'M
ASSETS						
Non Current Assets						
Property, plant and equipment	29,384	73,918	121,133	153,487	161,851	160,999
Intangible assets	832	998	1,198	1,438	1,725	2,070
Work in progress	18,321	26,963	24,653	18,993	4,415	-
Deferred tax assets	5,623	5,521	5,615	5,282	5,150	6,263
	54,160	**107,400**	**152,599**	**179,199**	**173,142**	**169,332**
Current Assets						
Inventories	4,960	3,381	6,010	7,527	7,406	8,026
Receivables & Prepayments	13,555	6,930	8,734	11,828	13,653	13,697
Deposits	588	588	588	588	588	588
Related parties	5,646	5,646	5,646	5,646	5,646	5,646
Investments	828	828	828	828	828	828
Cash resources	3,331	9,040	333	1,936	6,908	9,092
	28,908	**26,414**	**22,139**	**28,353**	**35,029**	**37,876**
Total Assets	**83,068**	**133,814**	**174,738**	**207,552**	**208,172**	**207,209**
EQUITY & LIABILITIES						
Share Capital	23,118	23,118	23,118	23,118	23,118	23,118
Accumulated deficit	(14,575)	(13,848)	(14,516)	(12,137)	(11,200)	(19,144)
	8,543	**9,270**	**8,602**	**10,981**	**11,918**	**3,974**
Non Current Liabilities						
Related Parties	41,005	70,882	108,347	135,262	141,560	147,010
Advances customer financed project	1,545	1,714	2,161	2,926	3,378	3,389
Provision for decommissioning	243	243	243	243	243	243
Customer deposits	3,568	3,959	4,990	6,758	7,801	7,826
Defined benefit liability	851	851	851	851	851	851
Deferred tax liability	947	947	947	947	947	947
	48,159	**78,597**	**117,540**	**146,988**	**154,780**	**160,266**
Current liabilities						
Related parties	13,002	15,837	20,171	25,582	31,244	37,124
Deferred Income	139	154	194	263	304	305
Advances customer financed project	719	798	1,006	1,362	1,572	1,577
Payables and accruals	12,451	29,107	27,225	22,209	8,288	4,518
Taxation	55	51	-	167	66	- 556
	26,366	**45,947**	**48,597**	**49,583**	**41,473**	**42,968**
Total Equity and Liabilities	**83,068**	**133,814**	**174,738**	**207,552**	**208,172**	**207,209**

10 Impact of programme on Natural & Social Environment

The planned addition, replacement, upgrade, and conversion, where applicable as per current expansion plan, of thermal generation at Garden of Eden, Bartica, Canefield and Anna Regina and the current fleet of Wärtsilä generation at Kingston and Vreed En Hoop would be in strict compliance with the Environmental Protection Act, while older generation assets at Garden-of-Eden (Niigata generators) and Onverwagt will be retired or relegated to occasional use. GPL expects a net reduction in emissions from the use of modern generators and the retirement of old, inefficient generators.

More importantly, the use intended use of renewable resources as informed by the development programme would have a net positive environmental impact. The Company will continue to ensure EPA approval for all generation investments regardless of energy source.

Concerning the social environment, GPL will continue its cost-effective investments in the electrification of unserved areas, generation, and networks to improve power quality and in general customer services. The Company will establish a framework (Distribution Code) for the controlled penetration of distributed generation from renewable resources. The framework will guide on technical and commercial requirements for grid-tie renewable energy installations. Prudent financial management will continue balancing capital investments, operational expenditures, and tariffs. The Company expects these strategies and initiatives to impact both the society and economy positively.

GPL is, however, conscious that the removal of illegal services, prosecuting persons caught stealing electricity and taking prompt and firm steps to collect revenues would have some social consequences. These measures are likely to generate some negative social impact, especially by the perpetrators of illegal activities. To address this, the social management plan, with its three-pronged approach (before, during and after) is expected to improve expected results.

11 Major Risks and Contingencies

11.1 Risk: Electricity Theft

A section of the population engages in illegal electricity consumption that negatively impacts internally funded capital investments and reduces operational performance, potentially becoming worse as the network expands according to the D&E projects. This D&E Programme is targeting sustainable loss reduction, which remains a challenge to GPL. The Company embraces the investments financed jointly by the IADB and EU via its PUUP Social Management programme, yet it remains cognizant and concerned of the culture of a section of the population who persist in this illegal practice.

As a result of electricity theft, GPL may have no option but to adjust/defer the timelines of the development and expansion programme accordingly, especially in the event where the Company's cash flow becomes insufficient and necessary concessional loans/grants may become unavailable during the life of this programme. GPL's current revenue projections provide for some capacity to absorb a degree of financial loss due to electricity theft; however, excessive financial losses can significantly derail future D&E projects.

11.1.1 Contingency Measures: Electricity Theft

In terms of recovering financial loss due to electricity theft, GPL recovers money via back-billing errant customer accounts; in cases where a customer is unwilling to pay, the Company's Legal department steps in with high levels of success as long as internal commercial issues are virtually non-existent. In the case of non-customers, the Guyana Police Force engages in arrests and relevant prosecution.

Although there are no assurances that loan/grant resources to GPL would continue to be available, the Company remains optimistic of the Government's interest in the execution of this five-year programme, which is designed to improve reliability and quality of electricity service. Additionally, GPL is hopeful that the PUUP Social Management programme, in conjunction with the continued execution of corporate development plans, will mitigate this unsavoury practice.

11.2 Risk: Fuel Price Volatility

Fuel price can spike upwards due to world HFO demand, meaning it will be more expensive to operate generation assets. Such a movement in HFO price would reduce internal cash flow, as well as affect financing D&E projects. Whilst the Company's license provides for rate adjustments and fuel surcharges and rebates, GPL remains cognizant of the impact of increased rates of fuel surcharges to its customers and the economy. Nonetheless, it is unlikely that any unavoidable upward adjustment to rates or fuel charges would be significant to impact the availability of internal funding. It should be noted that GPL does not have a hedging strategy; fuel price is determined by 3-day averages from prevailing prices.

11.2.1 Contingency Measures: Fuel Price Volatility

GPL can apply rate adjustments, fuel charges and rebates to cushion financial impact; however, PUC and the Majority Shareholder need to approve this. Additionally, a subvention can be provided to further support the Company in supplying electricity to its customers. Renewable energy and natural gas initiatives are being developed to reduce dependence on foreign fuel supply and related price fluctuations. Continued use of HFO fired generation does provide baseload power. However, it is frowned upon, given the country's aggressive global climate change commitments. The Company will continue to examine power generation from natural gas and intends to use this option for planned firm capacity additions.

It should be noted that GPL is committed to broadening its energy portfolio with renewable energy – solar and wind in particular. However, the intermittent supply of electricity from these sources without significant energy storage will require the use of fossil-fired generation to satisfy the forecasted demand. Regardless, the incremental introduction of these sources of renewable energy should deliver generation cost savings and contribute to a reduction in CO2, NOx and SOx emissions - improving the grid emission factor. Also, the notable and continued decline in energy storage prices and the increased investment in this technology should reduce the degree of intermittency of electricity generation from solar and wind, thus increasing the attraction of these technologies to contribute to generation capacity, which in turn would assist satisfying the LOLE target.

11.3 Risk: Availability of Fuel Supply

Similar to fuel price, external sources continue to be the main source of fuel supply to GPL. As such, unforeseen and uncontrolled circumstances can hinder reliable fuel supply, resulting in generation shortfall and poor reliability performance. Additionally, new environmental requirements placed on marine vessels only utilize ship fuel with Sulphur 2% has a number of effects, ranging from reducing the quantity of fuel that can be supplied to GPL, to raising prices and impacting GPL's strategic fuel suppliers. This can lead to dissatisfied suppliers deciding to terminate shipment contracts with GPL, which can then increase time taken for GPL to seek other means of fuel supply – the consequence being increased late shipments, low fuel stock levels and load shedding.

11.3.1 Contingency Measures: Availability of Fuel Supply

GPL has a contract mechanism where foreign suppliers can financially compensate the Company for late fuel shipments - this can help with purchase of fuel locally. The Company is also considering spot contracts to bolster fuel availability in event of low stock levels. Additionally, GPL is focusing on RE projects with the aim to decrease dependency on imported fuels. The Company remains mindful of the risk involved in the availability of fuel supply and is currently planning to expand on-land fuel storage capacity across locations.

11.4 Risk: Foreign Exchange Rate

Global currencies tend to fluctuate; however, a weakening of the Guyana Dollar (relative to USD/Euro/Pound) can have negative impacts ranging from GPL ability to fund internal capital investments and maintain operational performance, to paying staff and servicing its debts.

Traditionally, GPL relies on loans to fund investments for infrastructural development. The funds (equity and debt) required for the high initial investment cost associated with energy infrastructure typically come from multilateral financial agencies, denominated in USD/Euro/Pound.

11.4.1 Contingency Measures: Foreign Exchange Rate

GPL intends to continue working with the Bank of Guyana and the Government of Guyana to ensure that investments for infrastructural developments projects do not adversely impact the cost of operation and to a more considerable extent, electricity tariff

11.5 Risk: Cyber Threat

Cyber threats are evolving at a tremendous pace, exploiting capabilities created by the modernisation of power systems. This is related to the transition from a centralized power system, based on large power stations and vertically integrated utilities, to a decentralized power system model, as well as the complementary evolution of advanced communication and digital systems.

As GPL modernizes the power system, it becomes increasingly dependent on communication systems for its operations, and as a result increasingly susceptible to cyberattacks. While integrating information technologies is essential to building the smart grid and realizing its benefits, the same networked technologies add complexity and introduce new interdependencies and vulnerabilities to potential attackers and unintentional errors.

The Company has noted that cyber-attacks can be dormant, widely distributed, and executed at a time pre-set by attackers. Once executed, adverse impacts may be difficult to detect. Cyber-attacks lead to unseen damage in operation, information, and control systems.

Potential cybersecurity threats include, but are not limited to the following:

- Smart meters may be used by hackers as entry points into the broader power system;
- unauthorized interference on the measurement of electricity consumption (end-users);
- trip a power-generating unit;
- cause a blackout in a large area of the grid; and
- disrupt the proper functioning of the system.

Currently, SCADA is isolated from the larger network of the Company, so risks to SCADA is perceived as minimal (known unknown risk). The IT Division has an ad hoc programme to make employees aware of cyber risks. The division is currently developing a structured programme and intends to introduce a specific Cyber Security resource into its staff complement.

11.5.1 Contingency Measures: Cyber Threat

There is a variety of technical and administrative cybersecurity best practices, which GPL must adapt and implement. These technical practices include, but are not limited to the following:

1. Network firewalls;
2. Antivirus software;
3. Application control software;
4. Encryption of communication data;
5. Securing smart grid technology upgrades; and
6. Intrusion detection systems.

GPL does have network firewalls, antivirus protection, insurance for tangible/intangible assets (digitized information and IT assets) as well as an internal awareness programme for running on a monthly basis; this is to be praised. However, GPL must now expand on these and other methods of protection against IT threats in a more structured and results-oriented manner.

Considering that GPL needs to focus its efforts on securing its assets, infrastructure and implementing advanced metering cyber security requirements, the Company will engage an IT security expert to assist it to mitigate the risks related to cybersecurity breaches by:

1. developing failure scenarios,
2. assessing GPL’s cyber resiliency,
3. conducting penetration testing on GPL systems, and

4. creating and refining a GPL cyber resiliency plan and policy.

11.6 Risk: Physical Attack

For GPL, system outages pose large financial impacts on the country, ranging from residential to small businesses and large companies. Potential coordinated physical attacks are a growing concern for the Company as it seeks to develop a resilient generation and transmission and distribution infrastructure. With GPL moving towards the use of natural gas-fired power generation, this can pose vulnerabilities if a high-impact event disrupts the gas pipeline infrastructure.

The Company is cognizant of the fact that it has to focus attention on enhanced physical security and resiliency against physical attacks at substations and transmission and distribution facilities. It is known that transmission lines, substations, communications facilities, or natural gas transmission supplies are susceptible to attack with little or no risk of detection.

Deliberate attacks can cause more focused damage to facilities and equipment in substations than natural events. Substations, in particular, present many targets, and the power system's future dependence on natural gas pipelines and supervisory control and data acquisition (SCADA) communication systems, point to attacks on these as equally disruptive.

11.6.1 Contingency Measures

The following are critical parts of an effective physical security approach that the Company has to seek to adapt:

- **Physical barriers around security perimeters**: Physical barriers can prevent access to substations by people and ground vehicles and can enclose equipment housings and supports.
- **Remote monitoring:** Remote monitoring detects intruders and monitors equipment. Remote monitoring and surveillance of perimeters and access points detects approaching intruders and those attempting entry.
- **Vulnerability assessment**: Vulnerability assessment of critical components is needed and can include ballistic vulnerability. This can be accomplished by coordinating a lessons-learned database on material vulnerability based on real-life examples.
- **Recovery and response**: Effective response after a physical attack is vital.

11.7 Risk: Extreme Weather Events

The resiliency of GPL's electric power system is threatened by extreme weather events that present a risk and affect the implementation of the D&E programme. The major severe weather events that are relevant to the Company are:

- Flooding and sea-level rise,
- Drought and heatwaves, and
- Strong wind gusts.

In the past, extreme weather events inflicted considerable damage to the Company's electric infrastructure and left customers without power.

Flooding and sea-level rise

Guyana is classified as a high flood risk country, with the most significant vulnerability experienced within the coastal zone. The coastal region is prone to flooding as a result of the changes in the rainfall pattern due to climate change and the fact that the coastal portions of Guyana sit from about 0.5 meter to 1 meter below sea-level. Approximately 90% of Guyana's population lives along the coast, as such, the bulk of GPL's electrical infrastructure is concentrated along the coastal regions.

GPL's generation and delivery assets, as well as the broader energy system infrastructure, are vulnerable to damage from flooding resulting from extreme events. Increases in excessive rainfall over the years have increased the frequency of flooding events in Guyana coastal regions. Flooding threatens coastal infrastructure and capital assets that are vital to the Company, as well as ports and other transportation networks that could affect fuel distribution or other resources. Current vulnerabilities could be exacerbated by sea-level rise leading to more extensive flooding and inundation.

Drought and heatwaves

Extreme events in the form of droughts and heatwaves threaten the Company's electricity system by restricting water resource availability for power generation, cooling, etc. Moreover, diminished surface and groundwater levels require additional energy to pump water. Drought and heatwaves result in elevated ambient air temperatures that can reduce generation efficiency and reliability and also increase energy losses in transmission and distribution systems. Decreased water availability directly impact cooling operations in various ways. Reduced water availability can also affect fuel production of oil and gas. Finally, droughts and heatwaves can exacerbate existing challenges related to water resource allocation, competition with other sectors (e.g., agriculture and industrial uses), and water quality.

Strong wind gusts

A wind gust can be described as a sudden, brief increase in the speed of the wind followed by a calm. This extreme weather event in Guyana has resulted in the Company suffering power outages and impassable paths to access the damages for repair works and quick restoration of electricity. Over the years, GPL has been implementing measures to improve its infrastructure. However, in some cases, it came at a considerable cost to ensure reliable electricity service is provided in times of great needs for security, comfort, and other electric dependent utility services (water and communication).

11.7.1 Contingency Measures: Extreme Weather Events

The Company and its assets are exposed to a variety of threats. The risks presented now and, in the future, must be examined and mitigated. Protecting GPL's assets from extreme weather events can be accomplished in various ways, including reinforced towers, substations, and underground systems and equipment. Options include raising existing - and installing new -

flood walls; adding to spare parts inventory; incorporating submergible transformers, switches, and pumps; sealing manhole covers and conduit/cable penetrations; shrink-wrapping cabinets; storing emergency supplies remotely; using weatherproof enclosures; and establishing a corporate emergency response centre.

Some of the resilience solutions or mitigation strategies suggested to reduce the impact of extreme weather events include:

- Ensure that there are sufficient and adequately distributed power generation facilities across the country, such that, in the event of loss of transmission lines, power can be locally generated and distributed;
- Use of concrete/steel structures with properly designed foundations on the transmission and distribution network;
- Construction of redundant transmission network, such that the grid can be compliant with the N-1, N-2 and N-1-1 contingencies requirement of the National Grid Code;
- Use to self-healing smart distribution networks in densely populated areas/villages or communities and towns;
- Use of submarine class underground distribution network where applicable; and
- Ensure strict transmission and distribution network maintenance schedule using modern technology and methods.

12 Cost Benefit Analysis of Investment Projects

This cost benefit analysis has been premised on the understanding that investments in generation, transmission and distribution networks constitute the power system that is necessary to supply reliable electricity and generate revenues to ensure sustainability of GPL.

The proposed investment in the current Development and Expansion Programmes are geared towards not just responding to the energy demands of the nation, but to pre-emptively prove the energy that will provide a solid foundation for economic growth. In this context the interventions in this D&E will have a meaningful impact on national growth and development beyond the cost benefit analysis and other metrics provided herein.

Notwithstanding, the overall economic and financial assessment of the D&E Programme, presented below, shows that all aspects of development and expansion that relate to Generation, Transmission and Distribution, Loss Reduction and Electrification of Unserved Areas result in positive internal rate of return (IRR) and all achieve positive Net Present Values and Positive Discounted Benefit Cost Ratios, with the exception of Transmission and Distribution which has a negative net present value.

For the analysis presented here the following assumptions are incorporated:

A discount rate of 8% for Present Value calculations, an interest rate of 5% per annum for financing of investment amounts and a financing maturity period of 25 years, except for analysis on Unserved Areas which assume a 10-year maturity period for financing.

12.1 Generation

The identified generation projects for the indicative five-year period cumulatively cost US$931 million in nominal value equivalent to a Net Present Cost (NPC) of US$721 million. The key metrics from these projects are given in Table 56 and Figure 8.

Table 56: Summary of Cost-Benefit assessment – Capital Investment in Generation

Net Present Value	US$1,141 million
Internal Rate of Return	13%
Cost Benefit Ratio	10.45
Discounted Pay-Back Period	14 years

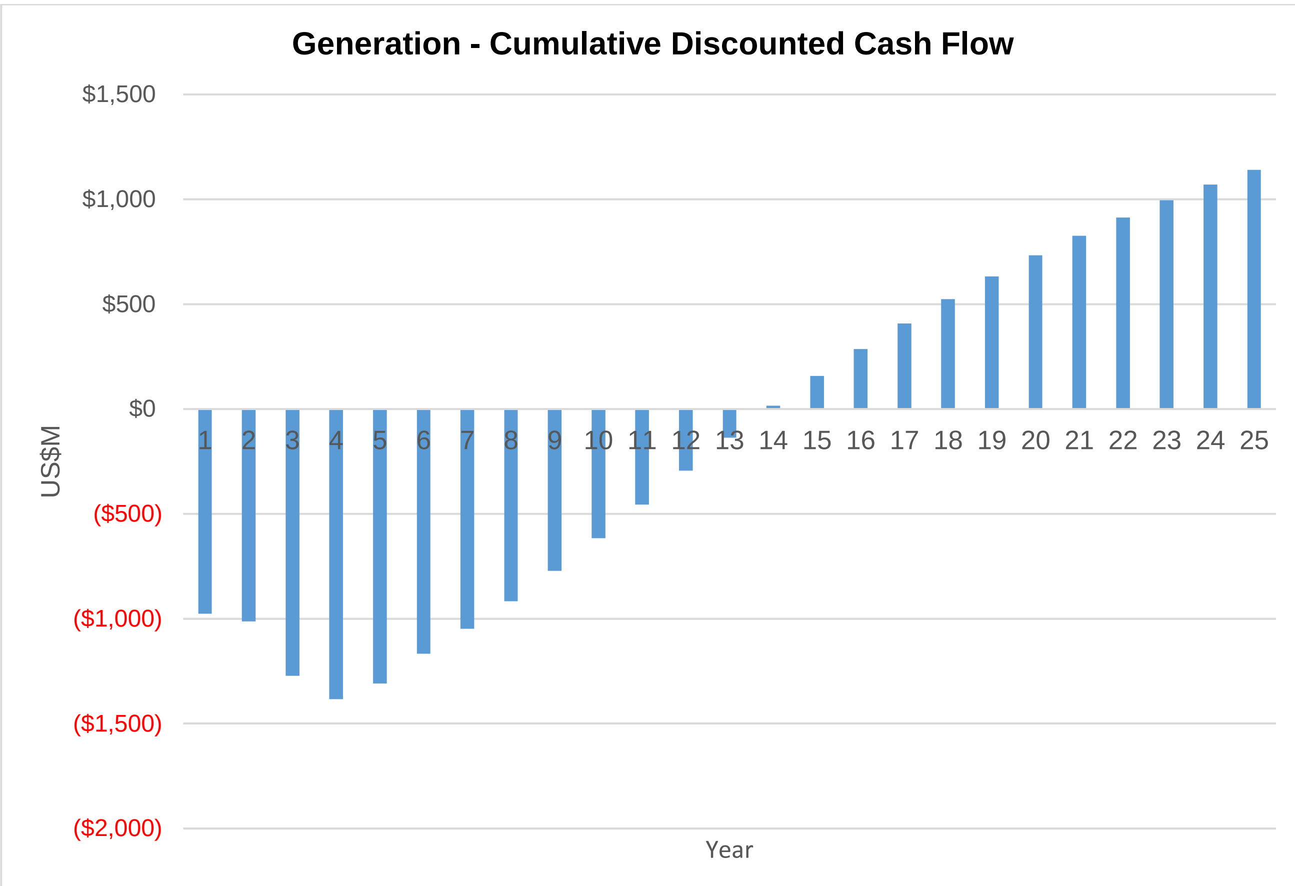

Figure 8: Cash Flow for Capital Investment in Generation

12.2 Transmission and Distribution

For analytical purposes, this category of investments includes proposed development for substations. As noted, the Net Present Value for this category is negative. This is due to the fact that T&D systems, especially in Guyana's context are expansive to cater for urban populations that do not have the density and overall energy consumption relative to more concentrated urban centres. Nonetheless, the T&D and Substations investments still achieve a positive rate of return with an IRR of 2.3%. Key metrics for this category of investments are given below in Table 57 and Figure 9.

Table 57: Summary of Cost-Benefit assessment – Capital Investment in Transmission & Distribution

Net Present Value	-US$495 million
Internal Rate of Return	2.3%
Cost Benefit Ratio	1.12
Discounted Pay-Back Period	-

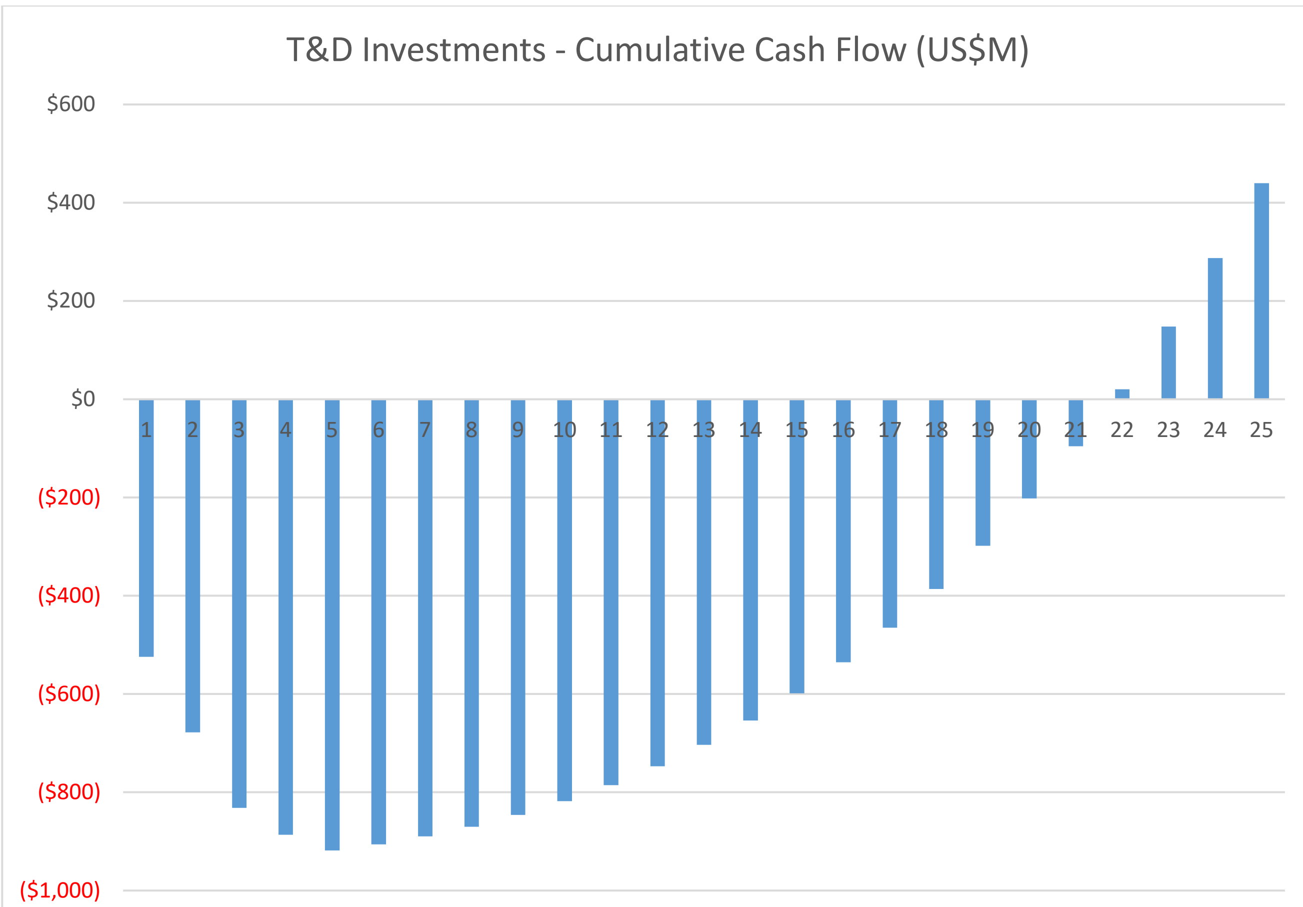

Figure 9: Cash Flow for Capital Investment in Transmission & Distribution

12.3 Loss Reduction

With technical and non-technical losses in the range of 27%-28%, there are significant prospective gains from reducing these losses. The proposed investments to reduce these losses are generally expected to result in average reductions of these losses by 1 percentage point per annum in the medium term. This translates to about US$340 million in net present savings over the next 25 years, with an overall net present value of all investments of about US$109 million. Key metrics on this category are presented below in Table 58 and Figure 10.

Table 58: Summary of Cost-Benefit assessment – Capital Investment in Loss Reduction

Net Present Value	US$109 million
Internal Rate of Return	13%
Cost Benefit Ratio	3.07
Discounted Pay-Back Period	14 years

Figure 10: Cash Flow for Capital Investment in Capital Investment in Loss Reduction

12.4 Unserved Areas Electrification

With electricity considered a necessity, it is a primary objective of GPL Inc. to reach all Guyanese in our mandated coverage area. While the full benefits from electrification are difficult to quantify for those who have previously not benefited from this resource, the financial benefits from providing new service connections are also compelling with the highest rate of return of about 56%, a positive net present value of US$136 million and a payback period of just 4 years. Key metrics on this category are shown below in Table 59 and Figure 11.

Table 59: Summary of Cost-Benefit assessment – Capital Investment in Unserved Area Electrification

Net Present Value	US$136 million
Internal Rate of Return	56%
Cost Benefit Ratio	8.45
Discounted Pay-Back Period	3 years

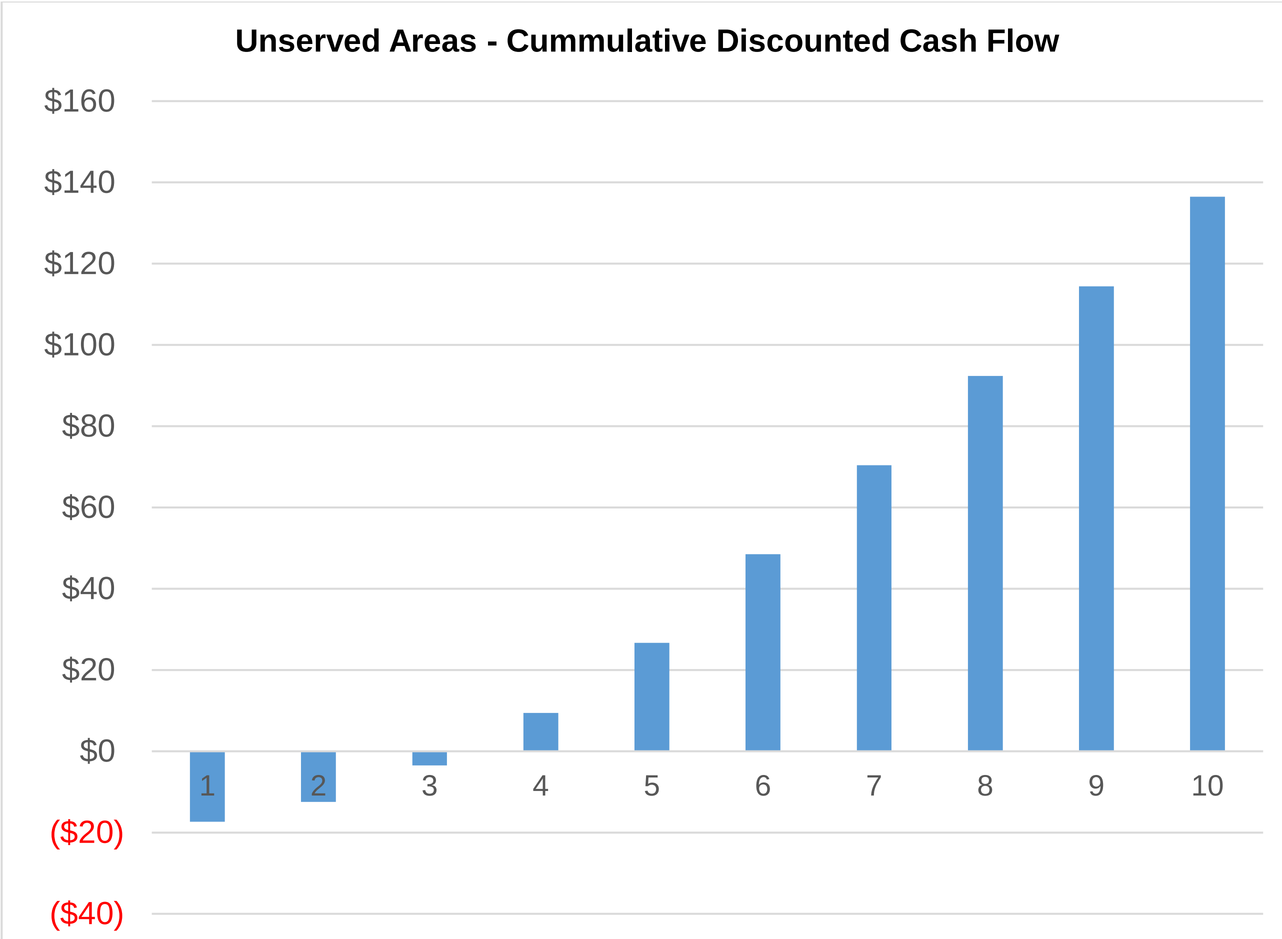

Figure 11: Cash Flow for Capital Investment in Unserved Area Electrification

13 Appendix 1

13.1 Generation Expansion Study 2018 (Brugman's Study)- DBIS

The Brugman Study used historical annual data from the period 2010 to 2016 and prepared projections from 2017 until 2035. The study also incorporated scenarios for the following:

1. Self-generation migration to the DBIS commencing in 2025 and migrating at 25% per annum for the next three (3) years and level-off from 2028 to 2035 at 100% (For further details, see page 46 of the Brugman's Study),
2. Influence of Energy Efficiency (EE) measures and Renewable Energy (RE) Projects as Distribution Generation on the forecast demand, with effect commencing from 2018 up to 2035. (For further details, see pages 53 and 54 of the Brugman's Study),
3. Electric Vehicles (EV) using the grid to charge the batteries from 2024. (For further details, see page 54 and 55 of the Brugman's Study),
4. Unserved energy at 1.9% in 2014 and 1.4% from 2015 to 2035, and
5. Interconnection of Linden in 2024. (see further details on page 56 and 57 of the Brugman's Study). However, in the 2020-2024 Development and Expansion period, Linden is not considered to interconnected with the DBIS.

The Brugman Study produced an electricity demand forecast per consumer sector for 2018 to 2035, where demand is defined as the Gross Generation of GPL plus unserved energy.

13.2 The Demand Forecast Capacity Building Services Consultancy by ETS

Funded through an IDB loan to Guyana and executed under the Power Utility Upgrade Program (PUUP), this consultancy assisted GPL in acquiring the knowledge and tools of econometric forecasting and culminated in the selection of an SARIMAX[19] model applicable to preparing forecasts for a 10-years horizon (2020 to 2030). The model utilises 20-year historical monthly energy demand data as the drivers of the Autoregressive and Moving Average components of the model, with the sectoral breakdown of real GDP for Guyana over the same period being the external drivers of energy demand (the X-component of the ARIMAX model).

The model was constructed based on per-capita values which means that population growth rates would also have an impact on future energy demand coming from this model.

Forecasts for the additional 20 indicative years 2031-2050 were done by extending a polynomial trend line calculated based on the first ten years of the forecast.

13.3 The Gas to Power Study - DBIS

In this study, K&M Advisors used the Brugman's Base Case Forecast, filling the annual gaps between 2025 and 2035, and continued annually up to 2047.

[1919] SARIMAX – Seasonal Autoregressive Integrated Moving Average with Exogenous explanatory Variables (X) model

13.4 GPL's Demand Forecasting Unit Projections

As mentioned above, given the urgent need to update GPL's demand and peak demand forecasts using a statistically robust model and more updated data sets, GPL's Forecasting Unit prepared a 30-year energy demand forecast using the SARIMAX model developed with support from ETS, with updated Sectoral Real GDP projections and accounting for the most realistic and likely impacts of covid-19 that were expected as of the end of 2020. However, GPL continues to monitor the impacts of covid-19 and will make appropriate updates should this become necessary in order to maintain the statistical significance of the forecast.

The overall GPL system projections were then disaggregated into values for the DBIS, Anna Regina, Bartica, Leguan and Wakenaam, following the methodology in the diagram below (Figure 1)

Note: Projections for energy demand for Linden were taken entirely from the Brugman Study due to inadequately updated energy demand statistics from Linden at this time.

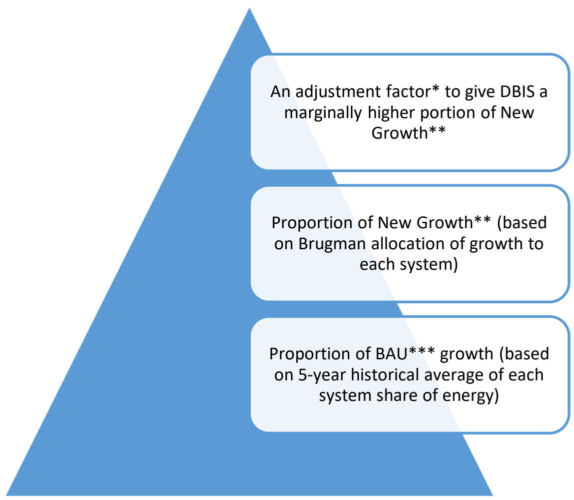

Figure 1: Methodology for calculating demand by Area System.

* The adjustment factor allocates an extra 50 basis points (i.e., 0.005) of New Growth to the DBIS system which is consistent with the expectation of concentration of oil sector related economic activities in the Demerara and Berbice areas.

** New Growth refers to the proportion of energy growth that is attributable to the growth in Real GDP. Calculated as Overall Growth forecast *less* BAU Growth forecast.

*** BAU (Business as Usual Growth) is formulated based on an ARMA model that essentially assumes that the past trend in energy demand continues without any impact from external drivers such as GDP growth.

These projections were further disaggregated following the methodology of the Brugman Study through the application of Brugman's adjustment factors to estimate the value of energy not served, the impact of energy efficiency measures (EE), electric vehicles (EV's), energy losses (technical and non-technical) and the breakdown of electrical energy sales into consumer categories (commercial, residential, and industrial).

13.5 Details of the current model

As mentioned above, the model currently applied is an ARIMAX/SARIMAX model which is a multiplicative Seasonal Autoregressive Integrated Moving Average (SARIMA) model with Exogenous explanatory variables (X).

The general specification of the SARIMAX model form is shown in Equation 1

$$y_t = \beta_t x_t + u_t$$
$$\phi_p(L)\tilde{\phi}_P(L^s)\Delta^d \Delta_s^D u_t = A(t) + \theta_q(L)\tilde{\theta}_Q(L^s)\epsilon_t \qquad \text{Equation 1}$$

Where:

- $\phi_p(L)$ is the non-seasonal autoregressive lag polynomial
- $\tilde{\phi}_P(L^s)$ is the seasonal autoregressive lag polynomial
- $\Delta^d \Delta_s^D y_t$ is the time series, differenced d times, and seasonally differenced D times.
- $A(t)$ is the trend polynomial (including the intercept)
- $\theta_q(L)$ is the non-seasonal moving average lag polynomial
- $\tilde{\theta}_Q(L^s)$ is the seasonal moving average lag polynomial

and $\beta_t x_t$ is the coefficient and parameter of the X variables of the regression.
Note that for the selected model y_t is the logarithm of per capita kWh gross energy demand.

The following are the calculated parameters of the selected model:

	coefficient	std. error	z	p-value	
ϕ_{p_9}	0.152701	0.0738004	2.069	0.0385	**
$\tilde{\phi}_{P\_1}$	−0.559206	0.0647029	−8.643	5.49e-018	***
$\tilde{\phi}_{P\_2}$	−0.530319	0.0604105	−8.779	1.66e-018	***
θ_{q_1}	−0.430497	0.0627176	−6.864	6.69e-012	***
l_A	0.234527	0.0695516	3.372	0.0007	***
l_A_2	−0.168826	0.0755997	−2.233	0.0255	**
l_A_9	0.470200	0.130714	3.597	0.0003	***
l_B	0.0420710	0.0251196	1.675	0.0940	*
l_B_2	−0.0690839	0.0290670	−2.377	0.0175	**
l_B_3	0.0879836	0.0261713	3.362	0.0008	***
l_C_1	−0.146588	0.0501162	−2.925	0.0034	***
l_C_3	0.137650	0.0498480	2.761	0.0058	***
l_C_9	−0.403874	0.0956833	−4.221	2.43e-05	***
l_C_11	0.132673	0.0458410	2.894	0.0038	***
l_F_2	0.106513	0.0451910	2.357	0.0184	**
l_SERVICEwoK_2	0.435732	0.132746	3.282	0.0010	***

The selected model does not include a trend coefficient or a seasonal Moving Average component. The number at the end of each coefficient indicates the lag period (in months).

The exogenous variables correspond to sectoral components of Real GDP as follows:

- A – Agriculture Fishing and Forestry,

- B – Mining and Quarrying,
- C – Manufacturing, F – Construction, and
- SERVICE work – All Services except for financial services.

Note that financial services did not exhibit a statistically significant contribution to energy consumption.

The following are the results of the statistical performance of the model.

Mean dependent var	-0.000149	S.D. dependent var	0.024988
Mean of innovations	-0.000446	S.D. of innovations	0.016091
R-squared	0.992544	Adjusted R-squared	0.991985
Log-likelihood	580.4528	Akaike criterion	-1126.906
Schwarz criterion	-1069.526	Hannan-Quinn	-1103.724

Importantly, all model parameters were statistically significant at the 95% confidence level. Also, both the R-squared and adjusted R-squared were above 0.99, which indicates that the model explains 99% of the variation/changes in energy demand. This very close prediction of the historical trend in energy demand is visualised in the graph below (Figure 2)

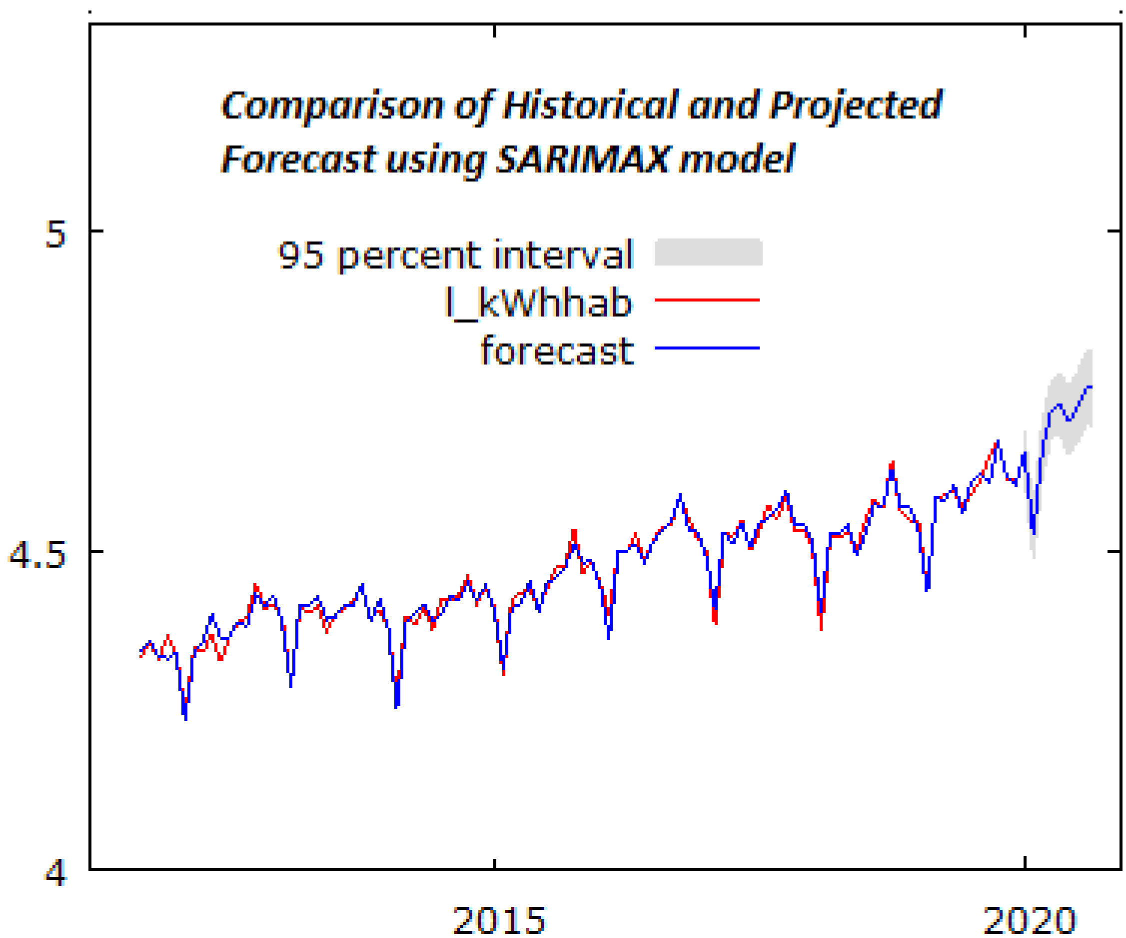

Figure 2: Graph comparing the model projections with actual historical values of the logarithm of per capita Energy Demand (l_kWhhab)

13.6 Energy Demand Forecast drivers and composition

The main external driver of energy demand is the level of Real GDP. This is plausible since Real GDP is a measure both of economic activity nationally as well as a proxy for the wealth of the nation with implications for the income levels of citizens. Theory and historical trends highlight that richer populations tend to acquire more devices (electrical loads) which increase energy demand. Also, here in Guyana, it is reasonable to expect that there will be new providers of services that directly and indirectly cater to the oil industry and increased industrial activities that respond to growth in the construction and other sectors.

Reports from the local media support this expectation of considerable growth in demand from new commercial and industrial loads, with the planned construction of several new hotels in the near term to the cost of almost US$1billion.[20] Additionally, the planned Corentyne River Bridge linking Guyana and Suriname, together with the planned deep-water harbour signals the potential for new and expanded commercial activity with businesses having easier access to the Surinamese and other markets.[21]

These developments and others will drive the significantly higher loads expected to come on the grid in the future.

Table 1 below shows the different growth rate assumptions that were included in the forecasting models used for the current set of forecasts (GPL Sept 2020) and previous forecasts generated.

Table 1: Real GDP growth assumptions used for forecasts

Year	GPL (2020)	ETS growth (2018 base)	Brugman RGDP growth (2016 base)
2020	50%	46.0%	38.5%
2021	25%	7.0%	28.5%
2022	40%	7.0%	2.8%
2023	30%	7.0%	2.8%
2024-2030	11%	6%	2.8%

The most recent projections, which are guided by the IMF Article IV (2019) and recent developments, show much higher GDP forecasts than previously expected mainly due to higher oil sector growth. For example, the overall real GDP is projected to grow by 50%, despite an expected contraction in non-Oil GDP by 5%. This higher than previously expected growth over the next decade is due to the following:

1. Previous projections were based primarily on activities associated with Exxon's Liza 1 well, however, Liza 2, and Payara are also expected to become operational in this decade,

[20] Guyana Chronicle, US$1B in hotels, November 24, 2020
[21] Stabroek News, President's Suriname visit brings MOU on Corentyne River bridge, November 27, 2020.

2. A rebound in oil prices and overall growth in the Oil and Gas sector despite the initial dampening effects of the Novel Corona Virus and OPEC oil price war early in 2020, and
3. Growth in non-oil GDP is expected to rebound and remain steady in the medium term above the values considered in previous energy demand projections.

These much higher RGDP growth projections would necessarily result in significantly higher energy demand growth in Guyana over the forecast horizon. However, the impact of oil sector GDP on overall economic activity and hence energy demand is expected to be tempered in the near term (2020 to 2023) compared with the latter years of the projection period.

Accordingly, energy demand mainly in these initial years of projection were lowered by addition of a smoothing mechanism termed scenario X1 which assumes a limited transfer of oil related economic activity into new energy demand.

13.7 Summary results of Base Case and other key scenarios

Due to the higher-than-expected economic growth rates that feed into the Base Case projections, it was considered that even higher growth numbers are not likely, as such, a High Case scenario is not included at this time.

The principal scenarios presented for this report are the Base and Low Cases, which are compared with a Business as Usual (BAU) scenario and a Smoothing Scenario termed X1.

The Base Case reflects the impact of the above RGDP projections while the Low Case assumes marginally lower RGDP growth. Both cases assume annual population growth rate of 1.44% in keeping with estimates from the Bureau of Statistics.

The X1 scenario assumes that new oil sector related economic growth would have a limited impact on energy demand. This was done by treating all oil related growth as if coming from the Mining and Quarrying sector which has a relatively low impact on energy demand. This scenario was used to dampen both the base and low case projections up until 2023 through using a weighted average such that the weight of X1 values was 100% in 2020, 50% in 2021, 40% in 2022 and 25% in 2023.

The BAU scenario assumes no impact from new economic growth and that energy demand continues to grow only based on historical trends.

Note that the implementation of energy efficiency measures, potential addition of electric vehicles and capturing energy demand not served by GPL (self-generators) are considered for the DBIS area forecast which are discussed in section 13.8, compares the Base Case energy demand and peak power projections compared with the Low Case, the Business-As-Usual case, and the Smoothing scenario - X1.

As shown in Figure 3, all cases have similar energy demand and peak demand in 2020, thereafter they diverge as per GDP projections previously described.

The BAU scenario has a relatively flat profile, increasing to 1,320GWh (energy demand) and 199MW (peak power) by 2030, then reaching 2,548GWh (energy demand) and 369MW (peak power) by 2050. The Smoothing Scenario X1 which assumes limited transfer of new oil economic activity into additional energy demand exhibits higher growth than the BAU but remains relatively flat. In the X1 scenario, by 2030 energy demand would be 1,547GWh while peak power would be 233MW, by 2050 these values are expected to increase to 3,846GWh and 556MW, respectively.

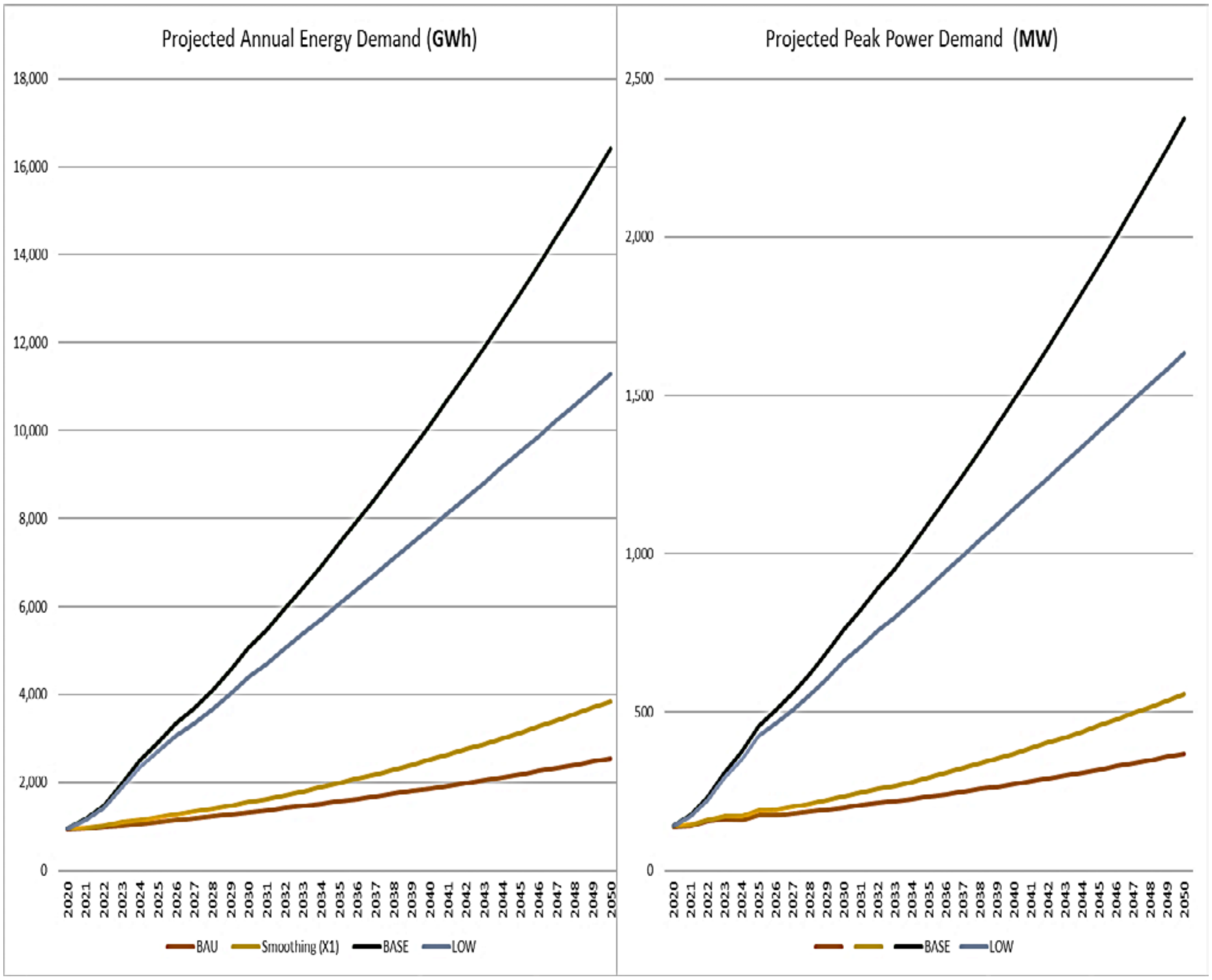

Figure 3: Showing Projected Energy Demand in GWh and Peak Power in MW for Base and Low cases compared with a smoothing scenario (X1) and the BAU case

Under the base case, energy demand and peak power rises significantly, driven by the impact high real GDP growth and the economic effects of oil related activities. While under the low case, both energy demand and peak power are lower than the base case due to assumed lower real GDP growth than in the base case. Table 2 summarises the values achieved under the base and low case scenarios for selected years.

Table 2: Energy Demand (GWh) and Peak Power (MW) under Base and Low Case scenarios for selected years

	2020 (actual)		2025		2030		2035		2050	
	Energy (GWh)	Peak Power (MW)	Energy (GWh)	Peak Power (MW)	Energy (GWh)	Peak Power (MW)	Energy (GWh)	Peak Power (MW)	Energy (GWh)	Peak Power (MW)
BASE CASE	903	141	2,913	456	5,059	761	7,423	1,097	16,417	2,375
LOW CASE	903	141	2,706	424	4,401	662	6,060	896	11,286	1,633

For the purpose of system planning and specifically generation planning, the Base Case scenario is considered most relevant. Figure 4 below shows the projected base energy demand according to the current GPL Systems (Anna Regina, Bartica, Leguan and Wakenaam are grouped as “Essequibo Systems”) for the period 2020 to 2050.

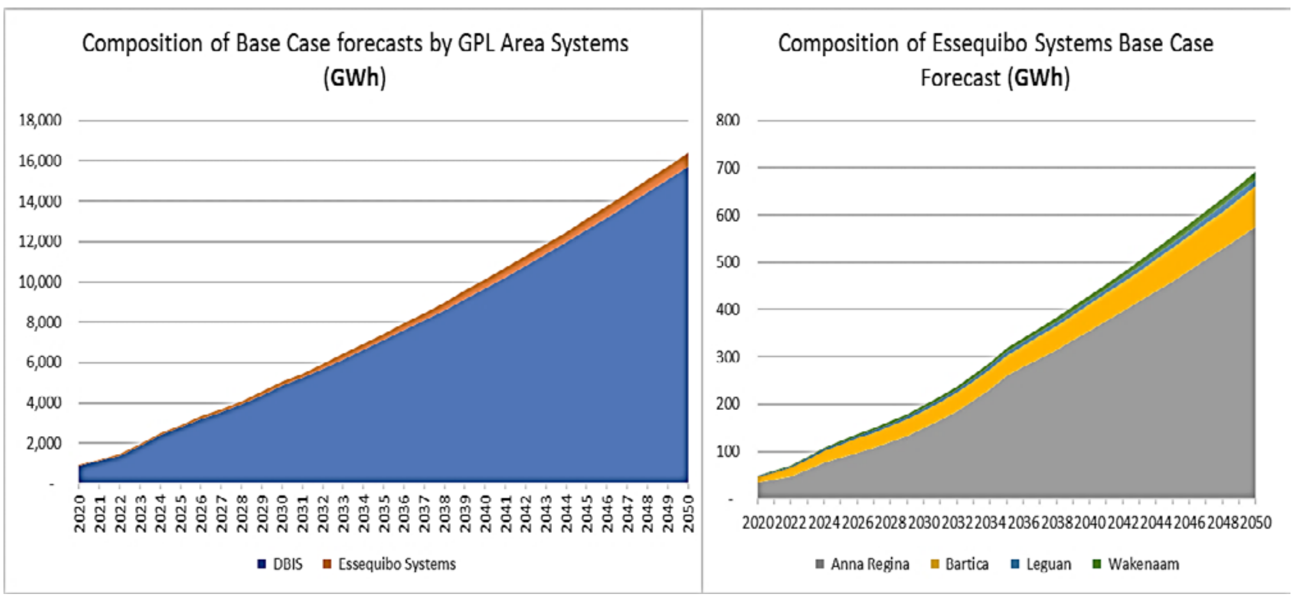

Figure 4: Base Case Forecast showing composition by area systems 2020-2050

13.8 Electricity Demand-DBIS

The current (September 2020) overall energy demand forecast scenarios have been disaggregated for the various GPL area systems and then further broken down into demand type categories. Since the Demerara Berbice Interconnected System (DBIS) accounts for over 90% of current and future energy demand, the forecasts for this area are presented in this section. As noted above, the key scenarios presented here are the Low and Base Cases.

Self-generation migration, meeting the unserved energy and accommodating electric vehicles (EVs) were included in the current forecasts based on their quantitative values obtained in the Brugman Study. While the impact of greater energy efficiency (EE) measures, loss factors and a relative breakdown of sales into consumer categories were included in keeping with their proportional values in the Brugman Study. Figure 5 shows the DBIS energy demand forecast, taking EE measures and EVs into consideration and disaggregated under the Base and Low Cases. It also includes a line to show energy demand prior to inclusion of EE and EVs.

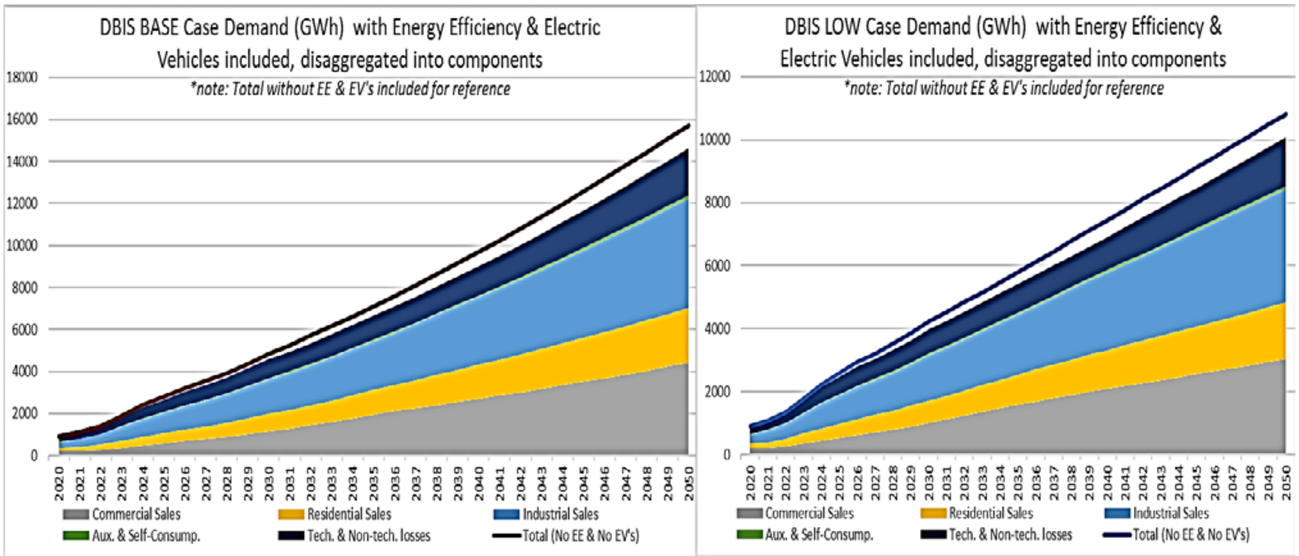

Figure 5: DBIS projections by Case, with Base Case disaggregated

13.8.1 Load Factor-DBIS

The Load Factor (LF) essentially indicates the flatness of the hourly demand (MW) curve and gives an indication of the cost-effectiveness of the load to maximise the use of the total available generation, which enables the system to meet peak demand.

Load Factor is expressed as shown in Equation 2:

$$Load\ Factor\ (\%) = \frac{1000 * Electricity\ Demand\ (GWh)/yr}{Peak\ Demand\ (MW) * 8760\ h/yr} * 100 \quad \text{Equation 2}$$

In 2014, the annual LF was calculated to be 71% and it progressively increased to 76% in 2019. In 2020, the load factor increased to 77%. The indication is that that there has been lesser variation in the hourly DBIS demand (MW), and the generators have been dispatched to higher percentage loading, thus operating more efficiently and economically.

Given the above trend in the annual load factor for the past five (5) years, it was assumed that it will remain around 76% and 77% for the expansion horizon up to 2027 and gradually increasing to 79% by 2050.

13.8.2 Peak Demand-DBIS

With the mathematical relationship shown in Equation 2, the forecast peak demands for the Base and Low Cases were calculated and graphically represented as shown in Figure 6. Additionally, in Figure 6, the forecast peak demands from the Brugman's and Gas to Power Studies forecast are also shown for easy comparison.

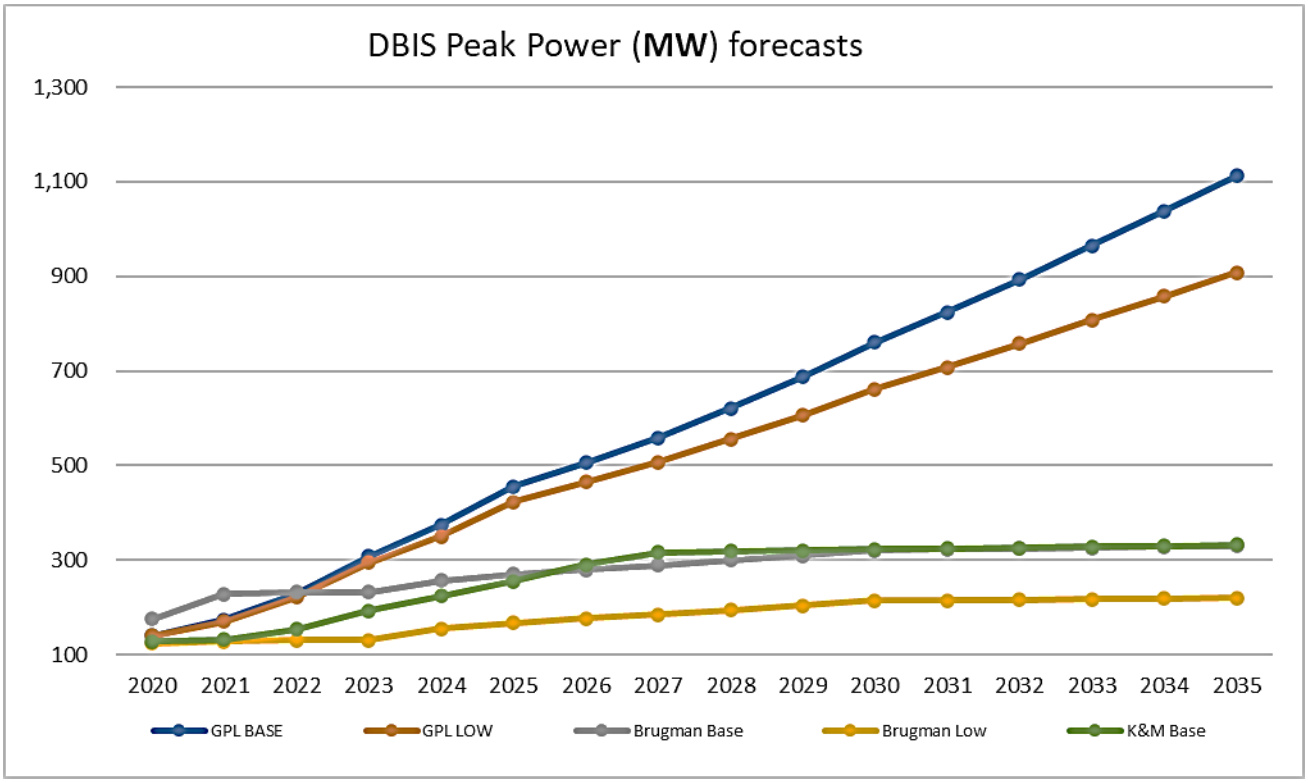

Figure 6: Comparison of Forecast Peak Demands

For the Base and Low cases, GPL's annual forecast peak power demands are comparatively higher than the Brugman and K&M forecasts. This reflects the impact from significantly higher GDP growth projections for Guyana as compared with previous forecasts. From a generation planning perspective, GPL's peak demand forecast adds security to the capacity reserve margin and Loss of Load Expectation (LOLE) and Expected Energy Not Served (EENS), while considering for any unforeseen or new self-generation migration to the grid.

14 Appendix 2

14.1 Georgetown

Kingston Substation, Kingston Power Plant, Old Sophia Substation, New Sophia Switching Substation, New Georgetown Substations, Merriman's Central Georgetown Substation

14.1.1 Generation Conventional & Renewable Projects

- Construction of a 10 MW four-hour BESS at New Sophia by September 2022. This project will provide additional capacity during peak periods, improved system reliability, reduced fuel consumption due to reduced need for spinning reserve and improved stability of the DBIS;

14.1.2 Transmission & Distribution New and Upgrade Projects

Transmission Lines

- Upgrade to the existing 5 km 69 kV transmission line between Kingston and Old Sophia by Dec 2021;
- Construction of 5 km 69 kV redundant transmission line between Kingston and Old Sophia by Dec 2021;
- Upgrade of existing 4.4 km 69 kV transmission line between New Georgetown and Old Sophia by Dec 2022;
- Construction of 2.75 km of new 69kV transmission line between Kingston and Merriam's Central Georgetown Substations by Dec 2023;
- Construction of 4.62 km of new 69kV transmission line between Merriam's Central Georgetown Substations and New Georgetown Substation by Dec 2023;
- Upgrade the less than 0.1 km existing 69 kV link between Old Sophia and New Sophia, this will increase the transfer capacity of existing link, which will be useful as the demand increases throughout the DBIS by Dec 2022;

Substations

- Construction of new 69/13.8 kV Substation at Merriman's (Central Georgetown) consisting of three (3)-breaker and ½ type bays GIS Switchgear to accommodate two (2) step-down (69kV/13.8) transformers with installed capacities each of 60 MVA, two (2) 69kV transmission lines and to provide two (2) spares by the end of Dec 2023.
- Upgrade and extension of the Kingston substation. This project aims at separating the loads at PPDI3 bus bar from the generation bus, by installing a new 2-GIS Switchgears (13.8 kV, and 69 kV) utilizing the existing transformer capacities (which is later on schedule in 2026 to replace by 2x 60 MVA Capacities) to supply the loads. New transformer capacities of 2x 80 MVA will replace the existing 2-35 MVA on the Generation Plant to step-up the power to the 69 kV grid.

This upgrade and extension will improve relay protection and coordination of feeders and generator relay protection schemes, improve the physical routing of 13.8 kV feeders, which would translate to improving system reliability and allow for a safer distribution corridor on Water Street, between Barrack Street and Battery Road, Kingston.

- Upgrade of selected 13.8 kV Switchgear at PPDI 2 and 3;
- Upgrade intertie lines between PPDI 2 and PPD 3;
- Replace 13.8 kV Grounding Transformer at PPDI 3.
- Upgrade of Sophia Substation to be completed by the end 2023 by replacing the decommissioned 16.8 MVA power transformer with a new 16.7 MVA power transformer, installing a 16.7 MVA power transformer to replaced existing aged 16.8 MVA transformer, which has cooling problems and mismatch in impedance with another existing 16.7 MVA power transformer for parallel operation. Expansion of the 69 kV Bay to accommodate new power transformers, transmission redundant line from Kingston, and replacing aged 13.8 kV switchgear cubicles, add spare feeder cubicles all to be fully integrated with SCADA.
- Installation of 2- 15 MVAr 69 kV De-tuned Compensation Systems, each at New Sophia and New Georgetown Substation. This reactive compensation will dynamically boost and maintain transmission voltage level at these locations and thereby improve voltage in the rest of the DBIS. It will also improve the system power factor and reduce system losses;
- Upgrade at New Georgetown Substation by expanding the 69 kV bays utilizing two (2) new PASS switchgears configured in the breaker and ½-bus arrangement. This expansion will be implemented in 2022 and 2023 to interconnect the new lines from Eccles and Kingston, and the 15 MVAR 69 kV De-tuned Compensation Systems.
- Replacement of existing 2-16.7 MVA with 2-35 MVA Transformers in 202 at New Georgetown Substation. This upgrade in substation capacity will also require the upgrades or addition of 13.8 kV switchgear components. This replacement is necessary to supply the increase in demand forecasted of the existing loads as well as to accommodate self-generation facilities located within the vicinity of the Substation supply boundaries.
- Upgrade at New Sophia Switching Substation by expanding the 69 kV bays utilizing two (2) new PASS switchgears configured in the breaker and ½-bus arrangement. This expansion is necessary to interconnect the 15 MVAR 69 kV De-tuned Compensation Systems and the Battery Energy Supply Systems schedule for by the end of 2021.
- Construction of One (1) new 13.8 kV feeders at Sophia Substation to offset loads on the F7;
- Construction of four (4) new 13.8 kV feeder at New Georgetown Substation by the end of 2024;

- Upgrading the Sophia F2 backbone conductors; and
- Improving reliability of Sophia F2 Feeder (2021);
- SCADA integration of auto-reclosers and automation of distribution networks around Georgetown (2024);

14.2 East Coast Demerara

Good Hope Substation, Ogle Substation, Success Substation, Unity/Mahaica Substation, Columbia Substation, Natural Gas 200 MW Plant Substation

14.2.1 Generation Conventional & Renewable Projects

- N/A

14.2.2 Transmission & Distribution New and Upgrade Projects

- Construction of 10 km of redundant 69 kV transmission line and upgrading the existing line between New Sophia and Good Hope by the end of 2022;
- Construction of 26.6 km of redundant transmission line from Good Hope to Columbia, to be started in 2022 and completed in 2023;
- Construction of 37.17 km of redundant transmission line from Columbia to Onverwagt which starts in 2025 and to be completed in 2026;
- Construction of 44 km of redundant transmission line from Onverwagt to Canefield which starts in 2025 and to be completed in 2026;
- Construction of 5 km of new 69 kV parallel transmission lines from Eccles Substation to Ogle Substation which starts in 2025 and by the end of 2026;
- Construction of 5 km of new 69 kV parallel transmission lines from Ogle to Success which starts in 2025 and by the end of 2026;
- Splicing of the redundant 69 kV transmission line (L16 R) at an approximate distance of 5 km from New Sophia to interconnect the Ogle Substation. L16R will further be spliced at Success to be interconnected with the Good Hope substation which starts in 2025 and by the end of 2026;
- Splicing of the redundant 69 kV transmission line (L17 R) at an approximate distance of 13.3 km from Good Hope to interconnect the Victoria/Enmore Substation by the end of 2023;
- Splicing of the existing 69 kV transmission line from Good Hope Substation to Columbia Substation at an approximate distance of 13.3 km from Good Hope to interconnect the Hope Beah IPP Substation by the end of 2023;
- These transmission line constructions will also be accompanied with the necessary expansions and upgrades of the interconnecting substations such as Good Hope where it is required to install1- 69 kV breaker and ½ PASS bay expansion by July 2022

and similarly at Columbia Substation 1-69 kV breaker and ½ PASS bay expansion by April 2023;

- Installation of 15 MVAr 69 kV De-tuned Compensation Systems by Dec 2022, along with the accompanying 69 kV switchgear expansion
- Additionally, at Columbia Substation for 2023, further substation expansion of 1-is required for 1- 69 kV breaker and ½ PASS bay which is to accommodate the Compensation System. This expansion will provide a spare for the transformer capacity upgraded that is later schedule for 2023;
- Replacement of 35 MVA with 2- 60 MVA transformer Capacity and upgrading 13.8 kV Switchgear with higher short circuit rating at Good Hope Substation by the end of 2023. This is because of expected increase in demand at this substation and due to increase short circuit levels throughout the DBIS.
- Upgrade of the Columbia Substation in 2023 by the installation of 10 MVAr 69 kV De-tuned Compensation Systems and two (2) additional breaker ½ bay are require facilitating the redundant transmission lines.
- Construction of a new Substation at Victoria/Enmore for 2023 consisting of 60 MVA installed capacity of substation, 2- breaker and ½ AIS Switchgear, and 12 Cubicle 13.8 kV Enclosed Switchgear. 4- New feeders will pick-up loads assisting with the demand on the Good Hope Sub and Columbia substations

Construction of two (2) new substations which starts in 2025 and is completed in 2026:

- Ogle Substation consisting of 120 MVA installed capacity of substation, 4- breaker and ½ AIS Switchgear, and 14 Cubicle 13.8 kV Enclosed Switchgear. 6- New feeders will pick-up loads along the new housing, residential and commercial area within the supply area of this new substation at the time of commissioning.
- Success Substation consisting of 120 MVA installed capacity of substation, 3- breaker and ½ AIS Switchgear, and 16 Cubicle 13.8 kV Enclosed Switchgear. 4- New feeders will pick-up loads along the new housing, residential and commercial area within the supply area of this new substation at the time of commissioning.
- Upgrade of the Good Hope F4 Feeder backbone form Tulip to Cosmos 2021;
- Upgrade of Good Hope F2 Feeder backbone conductor from Tulip to Cosmos, in 2021.
- Load sectionalization of Good Hope F4
- Install additional six (6) additional new feeders at Good Hope sub in 2024;
- Construction of six (6) new 13.8 kV feeders from Ogle Substation which starts in 2025 and by the end of 2026;
- Construction of six (6) new 13.8 kV feeders from Success Substation which starts in 2025 and by the end of 2026;

- Construction of four (4) new 13.8 kV feeders from Victoria/Enmore Substation by the end of 2024;

14.3 West Demerara

Vreed-en-hoop Substation, Vreed-en-hoop Power Plant, Edinburgh Substation, Wales Substation, Hydronie/Parika Substation

14.3.1 Generation Conventional & Renewable Projects

- Construction by the end of 2024 in two phases, 250 MW Natural Gas Plant to be located in Wales. Each unit capacity expected to be 20 MW, consistent with system stability and reliability objectives. This project is pending Government Reviews, while other critical infrastructure is required such as getting the gas on shore.

14.3.2 Transmission & Distribution New and Upgrade Projects

- Construction of 9.3 km of new 69 kV transmission line from Vreed-en-hoop Substation to Wales Substation by the end of 2022;
- Construction of 9.56 km of new 69 kV transmission line from Wales Substation to Westminster Substation by the end of 2023;
- Construction of 13.8 km of new 69 kV transmission line from Vreed-en-hoop Substation to Westminster Substation by the end of 2023;
- Construction of 15.7 km of new 69 kV transmission line from Edinburgh substation to Parika/Hydronie Substation by the end of 2024;
- Construction of 10 km of new 230 kV transmission line from 250 MW Natural Gas Plant to Wales 230 kV substation to by the end of 2023;
- Construction of one new substation at Wales consisting of 3 breaker and ½ type bays AIS Switchgear to accommodate two step-down (69kV/13.8) transformer with installed capacity 25 MVA, transmission line from Westminster, Vreed-en-hoop and 230 kV step-down transformer. Installation of five (5) cubicle 13.8 kV enclosed switchgear to feed into the nearby distribution networks, all by the end of 2022.

  This new substation will accommodate new and shorter feeders with respect to the current distribution configuration on the West Cost of Demerara. The aim is to improve the quality of supply to the growing load demand on along the West Coast. The shorter feeders will also contribute to the technical loss reduction efforts.

  The Wales Substation is also schedule in 2023 to be expanded to accommodate four (4) bays of 230 kV Switchgears arranged in Double Bus Single Breaker configuration for the interconnection of one (1) step-down 125 MVA 230 kV/69 kV transformer and three (3) 230 kV transmission lines. Double circuits coming from Garden of Eden and single circuit to Hydronie/Parika 230 kV Substation.

- Construction of one new substation at Westminster consisting of 2 breaker and ½ type bays AIS Switchgear to accommodate one step-down (69kV/13.8) transformer with installed capacity 25 MVA and two (2) 69kV transmission lines from Vreed-en-hoop and Wales substation. Installation of five (5) cubicle 13.8 kV enclosed switchgear to feed into the nearby distribution networks, all by the end of 2023.
- Construction of one new substation at Parika/Hydronie consisting of three (3) breaker and ½ type bays AIS switchgear to accommodate two (2) step-down (69kV/13.8) transformers with installed capacity each 35 MVA and one (1) 69kV transmission line, Interconnection of the 10 MWp Solar Farm and 10 MW- 1 hr BESS and 10 MVAr Static Compensator. Additionally, the installation of ten (10) cubicle 13.8 kV enclosed switchgear to feed into the nearby distribution networks by the end of 2024.

  This new substation will accommodate new and shorter feeders with respect to the current distribution configuration on the East Bank and West Cost of Essequibo. The aim is to improve the quality of supply to the growing load demand on along the West Coast. The shorter feeders will also contribute to the technical loss reduction efforts.

  Installation of 10 MVAr Fix Capacitor Banks-Detuned Compensation System by Dec 2024.
- Upgrading Vreed-en-hoop Substation through PUUP at the end of 2021 by installing one (1) 25 MVA transformer capacity, which will allow the Substation to operate independent of the PPDI-4. Additionally, installation of 2 new distribution feeders and modification of the Grounding Systems at the Power Plant.
- Also, regarding the power plant at Vreed-en-hoop, the installation of 3 Neutral Earthing Resistors will complement the Grounding System modification works by PUUP.

  Upgrades will also to be done in the following year (2022) by expanding the 69 kV Switchgear by installing two (2) bays breaker and1/2 PASS to accommodate the transmission lines from Wales substation, Westminster substation and Eccles substation which scheduled to coincide with the construction of the new Demerara Harbour Bridge;
- Upgrading Edinburgh Substation by installing three (3) 69 kV breaker and ½ bays PASS bays expansion by Dec 2022. This upgrade will facilitate a change in configuration of the 69 kV switchgear from double bus single breaker arrangement to the breaker and ½ configuration. It will allow for the interconnection of the existing transmission line from Vreed-en-hoop substation, and the existing 10 MVA transformer, as well as the new elements such as the PV/BESS Renewable generation and transmission line to Parika/Hydronie Substation,

  Additionally, at Edinburgh, an additional 10 MVA transformer will add support to the existing 10 MVA that comes from Golden Grove substation in 2023.

Installation of 10 MVAr 69 kV De-tuned Fixed Capacitor Reactive Compensation System by Dec 2022.

- Upgrade of Edinburgh F2 Feeder backbone form Tulip to Cosmos and replacing of Single Wire Earth Return Transformers on the West Bank and Coast of Demerara by Dec 2021;
- Construction of express 13.8 kV feeder form Edinburgh to Philadelphia, WCD
- Construction of two (2) new 13.8 kV feeders at Wales Substation (2022);
- Construction of two (2) new 13.8 kV feeders at Wales Substation (2023);
- Construction of three (3) new 13.8 kV feeders from Parika/Hydronie Substation (2024);
- Construction of two (2) new 13.8 kV feeders at Edinburgh Substation (2022);

14.4 West Demerara-Georgetown

- Construction of the Natural Gas Plant 230 kV Substation schedule to be in service by 2023 which will be consisting of two (2) 250 MVA step-up transformers to interconnect with the 230 kV Substations consisting of 4 bays arranged in the double bus single breaker configuration. Natural Gas Plant location is currently being considered to place somewhere in the vicinity of the Eccles Substation (OPT3 Site) or somewhere within the vicinity of the air- marked location of Wales Substation (OPT 1).
- Construction of 7 km of new 69 kV transmission line between Vreed-en-Hoop and Eccles which starts in 2025 and to be completed by the end of 2026.

  This line will enhance power flow from Vreed-en-Hoop power plant to Eccles, thus reducing power flow in the Kingston – Old Sophia corridor and contingency risks;
- Construction of 20 km of new 69 kV transmission line between Garden of Eden and Wales Substation by the end of 2023. This line will ensure transmission flexibility along the West side of the Demerara River, thus reducing dependency on the link between Vreed-en-hoop and Kingston;
- Construction of 24 km of new 230 kV parallel transmission lines from Garden of Eden substation to Wales Substation by the end of 2024.
- Construction of 17 km of new 230 kV parallel transmission lines from Natural Gas Site OPT 1, to Eccles 230 kV Substation by the end of 2023.

14.5 East Bank Demerara

Eccles Substation, Golden Grove Substation, Garden of Eden Substation

14.5.1 Generation Conventional & Renewable Projects

- Installation of a 46.5MW dual fuel power plant at Garden of Eden schedule to be completed by June 2021- Phase 1.

- Construction of 46.5 MW generation expansion at Garden of Eden under a Phase 2 continuation from Phase1 and is planned for June 2022;

14.5.2 Transmission & Distribution New and Upgrade Projects

- Construction of 24 km of new 69kV transmission line between Garden of Eden Substations and New Georgetown Substation by the end of 2021; This line will constitute of two (2) parts, where it will be splitting at Eccles Substation schedule to be in service in 2023.
- Upgrading of 60.9 km of 69 kV transmission line between Garden of Eden and Old Sophia and Garden of Eden and New Sophia by the end of 2023. During this timeline, the Eccles Substation will also be in service, so during the line upgrading activity, these lines will be terminating at Eccles Substation.
- Construction of 22 km of new 230 kV parallel transmission lines between Garden of Eden 230 kV Substation and Eccles 230 kV Substation by the end of 2024
- Construction of 10 km of new 230 kV parallel transmission lines between Natural Gas Power Plant 230 kV Substation and Eccles 230 kV Substation by the end of 2023 (applicable only if the OPT1 Natural Gas Plant location will be considered).
- Construction of one new substation at Eccles consisting of 6 breaker and ½ type bays AIS switchgear to accommodate two (2) step-down (69kV/13.8) transformer each with installed capacity of 60 MVA and six (6) 69kV transmission lines. Additionally, the installation of 15 cubicle 13.8 kV- enclosed switchgear to feed into the nearby distribution networks, to be completed by Dec 2023. It is expected for load demand to increase in this area, where the key driver is anticipated to be developments the oil and gas, residential and commercial sectors;

  Upgrading Eccles Substation in by Jan 2023 by expanding the 69 kV AIS switchgear by installing two (2) additional breaker and ½ bays to accommodate three (3) 125 MVA transformer which will allow for the interconnection of the stepping down of power from the 230 kV transmission lines from the Natural Power Plant.
  Installation of 230 kV Substation at Eccles also schedule to be in service by Dec 2023 (coinciding with the Natural Gas Power Plant construction timeline). This construction includes the installation of three (3) 125 MVA transformer, and 10 230 kV AIS bays arrange in the Double Bus Single Breaker Configuration
- Upgrades to Garden of Eden Substation by installing two (2) 69 kV bays AIS switchgear to accommodate two (2) 60 MVA transformer which will allow for the interconnection of the Phase 1 46.5 MW Power Plant schedule to be in service by June 2021. This project also includes for the upgrade of the existing 69 kV bus bar from Partridge conductor type to BluJay conductor type.

  Additionally, further 69 kV bay expansion is required for the replacement of two (2) 16.7 MVA transformers, where Tx1 will be replace with a 16.8 MVA Capacity, while Tx (2) will be replaced by a 35 MVA Capacity. Additionally, the installation of three (3) new bays with SF6 circuit breakers will be required to accommodate Tx1, Tx 2 and the new transmission line to New Georgetown Substation. There will be bus bar expansion along with an additional bus-tie to accommodate the new transmission line circuit breaker bay. The replacement of the 13.8 kV Switchgear along with the normalization of the T-connection between Garden of Eden 13.8 kV Switchyard and Garden of Eden PPDI operation, are all expected to be completed by the end of 2022.

Further to these upgrades, the construction of new Substation Control Building considering space for the new 69 kV and 230 kV GIS Switchgear which is schedule during the same timeline during the Natural Gas Projects.

This transformer upgrade is necessary due to increase in demand for the next 5 year forecasted for this load centre. Furthermore, in order to compliment the implementation of this substation upgrade, it is also necessary to upgrade three (3) 69 kV bays where the existing transformers (Tx1 &Tx2) currently connect to the 69 kV bus bar via disconnect switches alone, and the bus 1 and bus 2 69 kV tiebreaker is an inoperable oil circuit breaker.

Aligning with other development and expansion plans, Garden of Eden substation will also be undergoing infrastructure transformation whereby the end of 2022, with the installation of five (5) 69 kV breaker and ½ GIS bays. These new bays will accommodate the parallel transmission lines from Kuru Kururu, new line from Eccles, two (2) links from 230/69 kV substations and an additional two (2) bays will be left on stand-by for the Phase 2-46.5 MW project schedule for construction by the Oct 2026.

As a result, by June 2022, of two (2) 60 MVA transformer will be installed to facilitate Phase 2- 46.5 MW Power Plant.

Finally, by Jan 2024, Garden of Eden Substation will be further upgraded with two (2) 125 MVA (69/230 kV) transformer, and a 230 kV AIS Switchgear with 10 bays arranged in the Double Bus Single Breaker configuration.

Upgrading of two (2) 10 MVA transformer with two (2) 60 MVA transformer along with the relevant upgrade to the busbars and two (2) 13.8 kV switchgear cubicles by Oct 2023.

- Upgrade of the Garden of Eden F1 and F2 Feeders backbone form Tulip to Cosmos by the end of 2021;
- Construction of three (3) new 13.8 kV feeders at Garden of Eden Substation by the end of 2025;
- Construction of four (4) new 13.8 kV feeders at Golden Grove Substation by the end of 2024;
- Construction of four new 13.8 kV feeders at Eccles Substation by the end of 2023;
- Upgrade of selected 13.8 kV Switchgear at PPDI 1;

14.6 Cross-Geographic Areas

- Upgrades to existing SCADA and extending SCADA reach into Distribution and Generation Systems, and installation of AGC – Dec 2022.
- SCADA integration of auto-reclosers and automation of distribution networks along West Bank Demerara, West Coast Demerara, East Coast Essequibo, and West Bank Demerara (2024);
- Installation of 12 MVAr APFC distribution capacitor banks on Feeders along the East Coast Demerara Distribution Networks (2021);

14.7 Soesdyke Linden Highway

Kuru Kururu Substation, Linden Substation

- Site development and construction of 15 MWp Solar PV and 15 MWh BESS at Linden by the end of 2023;
- Construction of 14.7 km of new 69 kV transmission line between Garden of Eden substation and Kuru Kururu substation by the end of 2022.
- Construction of 96 km of new double circuit 69 kV transmission line between Garden of Eden substation and Linden substation by the end of 2024.
- Construction of one new substation at Kuru Kururu consisting of 3 breaker and ½ type bays AIS Switchgear to accommodate one step-down (69kV/13.8) transformer with installed capacity 35 MVA, one (1) 69kV transmission line, one (1) incoming 69 kV connection from the 230 kV/69 kV transformer along with 13.8 kV-6 cubicle enclosed switchgear to feed into the nearby distribution networks by the end of 2022.
- Construction of one new substation at Linden schedule to be in operation by 2024. There will be one (1) step-down 69/13.8 kV transformer and two (2) 69 kV transmission lines coming Garden of Eden Substation.
- Installation of 2 x 5 MVAr 69 kV De-tuned Fixed Capacitor Reactive Compensation System by Dec 2024.
- Construction of four (4) new 13.8 kV feeders at Kuru Kururu Substation by end of 2023.

14.8 East Berbice

Canefield Substation, Crab Island (East Berbice) Substation, Williamsburg Substation, No. 53 Village Substation and Skeldon Substation

14.8.1 Generation Conventional & Renewable Projects

- Site development and construction of 10 MWp Solar Farms (East Corentyne, Berbice) by the end of 2023;
- Installation of a 46.5MW dual fuel power plant at Crab Island (East Bank Berbice) schedule to be completed by May- 2025- Phase 1.

14.8.2 Transmission & Distribution New and Upgrade Projects

- Construction of 77.12 km of 69kV redundant transmission lines between Canefield substation, Williamsburg substations, No. 53 substation and Skeldon substation by the end of 2026;
- Splicing of existing transmission lines between Canefield substation and Williamsburg substation to interconnect the Crab Island (East Bank Berbice) substation schedule for Dec 2025;
- Construction of one new substation at Williamsburg consisting of 3 breaker and ½ type bays AIS Switchgear to accommodate one step-down (69kV/13.8) transformer with installed capacity 35 MVA and four (4) 69kV transmission lines. Additionally, installation of six (6) cubicle 13.8 kV enclosed switchgear to feed into the nearby distribution networks, all by the November 2026.
- Construction of one new substation at No. 53 Village consisting of 3 breaker and ½ type bays AIS Switchgear to accommodate one step-down (69kV/13.8) transformer with installed capacity 35 MVA and four (4) 69kV transmission lines. Additionally, installation of seven (7) cubicles 13.8 kV enclosed switchgear to feed into the nearby distribution networks, all by the end of 2022.

  The shorter and additional feeders emanating from this new substation will contribute significantly to an improved quality of supply to the established and growing load centres on the East Bank of Berbice
- Construction of one new 69 kV substations at Crab Island (East Bank Berbice) consisting of four (4) breaker and ½ type bays AIS switchgear. Interconnecting with this 69 kV substation will be two (2) 60 MVA 230/69 kV, two (2) 60 MVA (Ph1 - 46.5 MW Power Plant Projects), two (2) 35 MVA 69/13.8 kV transformers (2025) and four (4) 69 kV transmission lines. Additionally, one (1) 13.8 kV, 10 cubicles enclosed switchgear will be installed to satisfy loads from a nearby industrial park that will be establish due to oil and gas activities in that area.

  Upgrade of 69 kV bus bar conductor type from Tulip to Cosmos is also required by the end of 2023.

  Installation of two (2) 69 kV bays and bus expansion for the interconnection of two (2) 10 MVAr Static Compensation from JICA funded Grant projects in 2022.

  Additional installation of two (2) 69 kV bays and bus expansion in order to accommodate redundant transmission lines from the Williamsburg substation and Onverwagt substation, and installation of six (6) bus bar tiebreakers with disconnects by the end of 2022.

  Upgrading of 13.8 kV switchgear with seven (7) cubicles and improved short circuit rating by the end of 2022.
- Construction of four (4) new 13.8 kV feeders at Williamsburg Substation (2026).

- Upgrade of the Canefield F3 Feeder backbone form Tulip to Cosmos (2021).

14.9 West Berbice- Onverwagt Substation

- Installation 4 MWp Solar Farm of Naarstigheid, West Coast Berbice (2025)
- **Upgrading Onverwagt 69 kV AIS substation with one (1) breaker and ½ PASS bays expansion to accommodate the redundant transmission lines from Columbia substation and Canefield substation. This expansion will also take into consideration the installation of three (3) 13.8 kV switchgear cubicles, all by the end of 2026.**

  Additionally, at Onverwagt for 2024, replacement of the 16.7 MVA 13.8/69 kV transformer with one (1) 35 MVA transformer along with the necessary 13.8 kV switchgear upgrade to interconnect the improved transformer capacity as well as for the interconnection of the 4 MWp Solar PV Farm which will be constructed at Naarstigheid (West Coast Berbice) by Jan 2025.
- Upgrade of the Onverwagt F2 13.8 kV Distribution Feeder under the JICA Grant by the end of 2021;
- Construction of express one (1) 13.8 kV feeder from Onverwagt Substation to Ithaca also under the JICA Grant by the end of 2021;
- Installation of two (2) automatic power factor correction 1500 kVAr capacitors on the Onverwagt F2 and F2 expressed under the JICA Grant by the end of 2021.
- Construction of two (2) new feeder for Onverwagt Substation by the end of 2025.

14.10 Essequibo Coast

- Upgrading of the existing Anna Regina Power Plant to accommodate the installation of 2 x 2.5 MW HFO to be completed in two parts (2) 2021 and 2022 respectively; an additional 1.8 MW HFO is expected to be added in 2023, followed by another 2x2.5 MW in 2024 to supplement the growing demand. The extension will provide urgently needed power generation capacity to meet the growing electricity demand on the Essequibo Coast, with peak demand already equal to the total capacity of the first three units, resulting in the need for LFO operated CAT sets to provide reserve capacity.

  Installation of 8 MWp Solar PV with 8 MW, one (1) hour BESS to be completed by the end of March 2023. This solar PV installation will displace electricity generated using fossil fuel, reduce Guyana's carbon footprint and reduce the technical system losses at primary distribution level.
- Construction of one (1) express 13.8 kV feeders from Anna Regina to Onderneeming – load pickup from Onderneeming to Supernaam (2023);
- Upgrade existing 13.8 kV feeder from Anna Regina to Supernaam (2022); and
- Construction of 13.8 kV express line from Lima Sands to Charity (2025)

14.11 Bartica

- Extension of the new Generation Facility at Bartica with an additional 1.12 MW (Prime Rated) LFO unit schedule for completion by September 2021;
- Upgrade of the new Generation Facility at Bartica with an additional 2 x 2 MW (Prime Rated) LFO unit schedule for completion by end of 2023;
- Under the Guyana Energy Agency, 1.5 MWp Solar Farm along with 1.5 MW, 1.5-hour Battery Storage System is schedule for Dec 2023;

14.12 Leguan

- Installation of 0.6 MWp Solar PV with BESS schedule to be completed by the end of 2022. This solar PV installation will displace electricity generated using fossil fuel, reduce Guyana's carbon footprint and reduce the technical system losses at primary distribution level.
- Extension of the existing Power Plant by installing two (2) x 0.41 MW LFO units by the end of Dec 2023;
- Extension of the Power Plant by installing two (1) x 0.41 MW LFO units end of Dec 2025 (New location and New building);

14.13 Wakenaam

- Installation of 0.750 MWp Solar PV with BESS schedule to be completed by the end of 2021.
- Installation of 1 x 410 kW Diesel Fired Generators project schedule to be completed by Dec 2021, additionally all electrical systems at the Power Plant will be upgraded.
- Installation of 1 x 410 kW Diesel Fired Generators project schedule to be completed by 2022.
- Installation of 1 x 410 kW Diesel Fired Generators project schedule to be completed by 2024.

End

of

Development and Expansion Programme 2021-2025