DEVELOPMENT AND EXPANSION PROGRAMME

Planning Horizon: 2023 – 2027

GUYANA POWER & LIGHT INC.

December 31st, 2

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1. Executive Summary

1.2 Introduction

The Guyana Power and Light Inc. (GPL) has a critical energy-based role to play in the development of the Country's economy and by extension, the livelihood of the nation. Given the repeated success of crude oil exploration, Guyana has since gained significant international recognition and interest. Affordable and reliable electricity is therefore a key component of the country's economic development.

The Development and Expansion Programme is a 5-year power utility expansion plan, which is primarily geared towards ensuring GPL can satisfy the demand forecast. The 5-year Programme supports Government's short to medium-term techno-economic vision and is guided by the Low Carbon Development Strategy (LCDS) - 2030, National Energy Priorities and other Government initiatives. In support of the Government's plans, this 5-year Programme informs the required expansions that are necessary to ensure the power generation, transmission, and distribution systems are capable of satisfying the demand forecast, power quality, stability, and reliability planning criteria. Further, the Programme includes targets such as reducing tariffs, supporting global climate change commitment, demand side management, and improving operational efficiency strategies.

This Development and Expansion Programme intends to guide the Company's efforts within a customer-centric framework to deliver reliable and affordable electric services through the deployment of a Smart Grid, continuous efforts to reduce system losses and improving power quality.

In view of the above, GPL has defined the following critical expansion planning targets, which guide 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, inclusive of Linden (a town approximately 100 kilometres from the capital city). and presents the strategies and projected capital investments required to successfully position the Company to support the projected rate of economic development and other forms of national developments.

In this Programme, Linden is considered connected with the DBIS in 2026.

1.3 Current Status of GPL's Electric Power Systems

The 46.5 MW Power Plant, located at Garden of Eden and which came into operation at Garden of Eden in October 2021, resulted in GPL having a total of 13 power plants and an aggregated firm available capacity of 213.8 MW. Within the DBIS, there are 9 power plants having the capability of supporting the grid with 190.9 MW of available capacity and in the Isolated Power System, 4 power plants with an aggregated available capacity of 22.9 MW. 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	152.9	13.0	**165.9**	5.40	-	-	-	**5.4**	**171.3**
MWs of LFO	7.1	17.9	**25.0**	9.90	1.47	1.23	4.90	**17.5**	**42.5**
Total Available Capacity (MW)	**160.0**	**30.9**	**190.9**	**15.30**	**1.47**	**1.23**	**4.90**	**22.9**	**213.8**
Fuel Type	**Demerara**	**Berbice**	**Total DBIS**	**Anna Regina**	**Wakenaam**	**Leguan**	**Bartica**	**Total Isolated**	**Total GPL**
% of HFO	95.6%	42.1%	**86.9%**	35.3%	0.0%	0.0%	0.0%	**23.6%**	**80.1%**
% of LFO	4.4%	57.9%	**13.1%**	64.7%	100.0%	100.0%	100.0%	**76.4%**	**19.9%**

1.3.1 Demerara Berbice Interconnected System's Generation

In the DBIS there are generator units that have exceeded their economic and operational life (see Table 2). Notwithstanding the fact that these units have surpassed their economic life, they continue as baseload units to deliver critical support services to the grid. The primary driving factors that support these aged units to continue in commercial operation are adherence to scheduled maintenance and prudent operations. There is however the elevated risk of mechanical failure.

Table 2: Aged generator units in the DBIS

Generator Units	Commissioned Dates	Age of Unit (Years)	Installed Capacity (MW)	Available Capacity (MW)
GOE	**Subtotal**		**11.00**	**7.10**
# 5 Niigata	1991	31	5.50	3.50
# 6 Niigata	1996	26	5.50	3.60
GoE - DP1	**Subtotal**		**22.00**	**22.00**
# 1 Wärtsilä	1996	26	5.50	5.50
# 2 Wärtsilä	1996	26	5.50	5.50
# 3 Wärtsilä	1996	26	5.50	5.50
# 4 Wärtsilä	1996	26	5.50	5.50
Kingston I - DP2	**Subtotal**		**22.00**	**22.00**
# 1 Wärtsilä	1997	25	5.50	5.50
# 2 Wärtsilä	1997	25	5.50	5.50
# 3 Wärtsilä	1997	25	5.50	5.50
# 4 Wärtsilä	1997	25	5.50	5.50
Canefield	**Subtotal**		**5.50**	**3.50**

Generator Units	Commissioned Dates	Age of Unit (Years)	Installed Capacity (MW)	Available Capacity (MW)
# 3DA - Mirrlees	1996	26	5.50	3.50
Onverwagt	**Subtotal**		**5.00**	**4.60**
# 5 GM	1981	41	2.50	2.30
# 7 GM	1981	41	2.50	2.30
Grand Total			**65.50**	**59.20**

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: 2022-2026 (DBIS Only-Assumes the rebuilt 5MW unit to be in-service at Skeldon in 2023)

DBIS	Year	2022	2023	2024	2025	2026	2027
Demerara	**Total Available Capacity (MW)**	**160.0**	**160.0**	**160.0**	**160.0**	**160.0**	**160.0**
	Reliable Capacity (MW)	**62.1**	**62.1**	**62.1**	**62.1**	**62.1**	**62.1**
	Unreliable Capacity (MW)	**97.9**	**97.9**	**97.9**	**97.9**	**97.9**	**97.9**
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Berbice	**Total Available Capacity (MW)**	**30.9**	**35.9**	**35.9**	**35.9**	**23.8**	**23.8**
	Reliable Capacity (MW)	**4.5**	**9.5**	**9.5**	**9.5**	**9.5**	**9.5**
	Unreliable Capacity (MW)	**26.4**	**26.4**	**26.4**	**26.4**	**14.3**	**14.3**
	Cold Reserve Capacity (MW)	-	-	-	-	**12.1**	-
	Accumulated Cold Reserve (MW)	-	-	-	-	**12.1**	**12.1**
DBIS Total	**Total Available Capacity (MW)**	**190.9**	**195.9**	**195.9**	**195.9**	**183.8**	**183.8**
	Reliable Capacity (MW)	**66.6**	**71.6**	**71.6**	**71.6**	**71.6**	**71.6**
	Unreliable Capacity (MW)	**124.3**	**124.3**	**124.3**	**124.3**	**112.2**	**112.2**
	Cold Reserve Capacity (MW)	-	-	-	-	**12.1**	-
	Accumulated Cold Reserve (MW)	-	-	-	-	**12.1**	**12.1**

Table 4 illustrates the reserve margins and Loss of Load Probability (LOLP), without additional firm capacity.

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

Year	Unit	2022	2023	2024	2025	2026	2027
Peak Demand (MW)	MW	153.5	186.6	210.4	280.6	318.9	354.3
Annual Peak Demand Growth Rate	%	21.6%	21.6%	12.8%	33.3%	13.6%	11.1%
Required Reserve Capacity Margin	MW	37.4	94.3	322.8	336.4	300.9	217.1
Required Capacity Reserve Margin (%) for LOLP Target	**%**	24%	51%	153%	120%	94%	61%
No Additional Capacity							
Available Generation Capacity	MW	190.90	195.90	195.90	195.90	183.80	183.80
Capacity Reserve	MW	37.40	9.30	-14.54	-84.68	-135.06	-170.49

Capacity Reserve Margin	%	24.36	4.98	-6.91	-30.18	-42.36	-48.12
LOLP	**%**	0.08	7.55	30.80	90.34	99.63	99.70
LOLE	day	0.29	27.57	112.41	329.75	363.65	363.92

1.3.2 Isolated Systems' Generation

With reference to the mobile LFO units in the Isolated Power Systems, GPL has established the cost-effectiveness in replacing high-speed generator units with factory refurbished generator units instead of performing major overhauls. The total cost for a major overhaul is approximately 80% of the cost of a factory refurbished generator unit with guarantees of nameplate performance as against major overhauled generators that rarely deliver the expected performances.

Table *5* shows the annual Total Available Capacity, Reliable Capacity, Unreliable / Suspect Capacity, and Cold Reserve Capacity in Megawatts.

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

ISOLATED SYSTEMS	Year	2022	2023	2024	2025	2026	2027
Anna Regina	**Total Available Capacity (MW)**	11.1	15.3	15.3	15.3	15.3	15.3
	Reliable Capacity (MW)	5.4	5.4	5.4	5.4	5.4	5.4
	Unreliable Capacity (MW)	5.7	5.7	5.7	5.7	5.7	5.7
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Wakenaam	**Total Available Capacity (MW)**	1.06	1.47	1.15	1.15	1.15	1.15
	Reliable Capacity (MW)	0.41	0.82	0.82	0.82	0.82	0.82
	Unreliable Capacity (MW)	0.65	0.65	0.33	0.33	0.33	0.33
	Cold Reserve Capacity (MW)	-	-	**0.33**	-	-	-
	Accumulated Cold Reserve (MW)	-	-	**0.33**	**0.33**	**0.33**	**0.33**
Leguan	**Total Available Capacity (MW)**	1.23	1.23	1.23	1.23	1.23	1.23
	Reliable Capacity (MW)	-	-	-	-	-	-
	Unreliable Capacity (MW)	1.23	1.23	1.23	1.23	1.23	1.23
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Bartica	**Total Available Capacity (MW)**	4.9	4.90	4.90	4.90	3.30	3.30
	Reliable Capacity (MW)	3.3	3.30	3.30	3.30	3.30	3.30
	Unreliable Capacity (MW)	1.6	1.60	1.60	1.60	-	-
	Cold Reserve Capacity (MW)	-	-	-	-	**1.60**	-
	Accumulated Cold Reserve (MW)	-	-	-	-	**1.60**	**1.60**
Isolated System	**Total Available Capacity (MW)**	18.3	22.9	22.6	22.6	21.0	21.0
	Reliable Capacity (MW)	9.1	9.5	9.5	9.5	9.5	9.5
	Unreliable Capacity (MW)	9.2	9.2	8.9	8.9	7.3	7.3
	Cold Reserve Capacity (MW)	-	-	**0.33**	-	**1.60**	-

ISOLATED SYSTEMS	Year	2022	2023	2024	2025	2026	2027
	Accumulated Cold Reserve (MW)	-	-	0.33	0.33	1.93	1.93

1.3.3 Transmission and Distribution

The current transmission and distribution systems comprises three main volage levels; 69 kV for bulk power transfer, 13.8 kV for primary power distribution and lower utilisation voltage levels for customer-specific applications.

The combined transmission and distribution system provides an electricity supply coverage of approximately 97.5% of the total number of households located on the Coastland. A summary of the technical characteristics of the transmission and distribution system is as follows:

1. The transmission voltage level of 69 kV is only present in the DBIS and there are 16 transmission lines having a total length of 354.77 km
2. Total of 39 active primary distribution feeders in the DBIS having a total estimated length of approximately 873 km.
3. Twenty-nine (29) Feeders have been configured in the company's automatic Under Frequency load-shedding scheme within the DBIS.
4. The total estimated length of primary distribution circuits in the Isolated Systems is 149.68 km. A disaggregation of the Isolated Systems is as follows:
    a. Anna Regina – 82.05 km;
    b. Wakenaam – 28.8 km;
    c. Leguan – 21.19 km; and
    d. Bartica – 17.64 km.

1.4 Demand Forecasts and Customer Growth Projection

Electricity is a highly flexible form of energy that practically fuels the performance of each sector of an economy and is considered a key component for the country's projected significant economic growth and development. Therefore, accurate forecasts of electricity demand inform sound investment decisions relative to power generation and supporting network infrastructure, which ultimately impact social and economic outcomes. Underestimating demand results in generation shortages and forced power outages, with serious consequences for productivity and economic growth. Conversely, overestimating demand can result in overinvestment in generation capacity and underutilization of generation assets.

It is therefore imperative that the 'Electricity Demand Forecasting Framework' accurately predicts peak load demand and the expected electricity demand, which will drive investment decisions relative to improvements in generation capacity within the context of short, medium and long term power system planning.

GPL's Electricity Demand Forecasting Framework 2022 (DF_2022) incorporated extensive reasoning computation building and estimating multiple time-series econometric regression analyses[1] within the framework of the ARIMA (particularly the ARIMA (Auto-Regressive Integrated Moving Average) family models) for the periods under assessment. These assessment periods were (i) the Development & Expansion (D&E) Programme timeline (2023-2027), (ii) medium-term forecasts (2022-2032) and (iii) long-term forecasts (2022-2052). Base Case, Low Case, and High Case[2] scenarios were considered for each planning timeline.

The DF_2022 Framework captured the estimated demand for the most highly populated regional zones in the country: Demerara and Berbice (which are served by the Demerara Berbice Interconnected System (DBIS), the Essequibo Islands (which includes the Essequibo Coast, Bartica, Leguan, and Wakenaam) and Linden. Previously, Linden's electricity generation was not included in the earlier years' forecasts. However, for this DF_2022, Linden was incorporated into the framework to represent a more holistic view of electricity demand in Guyana. Linden's electric power is projected to integrate with the DBIS during 2026 – 2027. In addition, this framework included the assumption that self-generators will commence a phased migration to the Grid from year 2023.

Table 6 presents the Base Case Scenario for this planning horizon. MWs and Essequibo 5 MWs); and

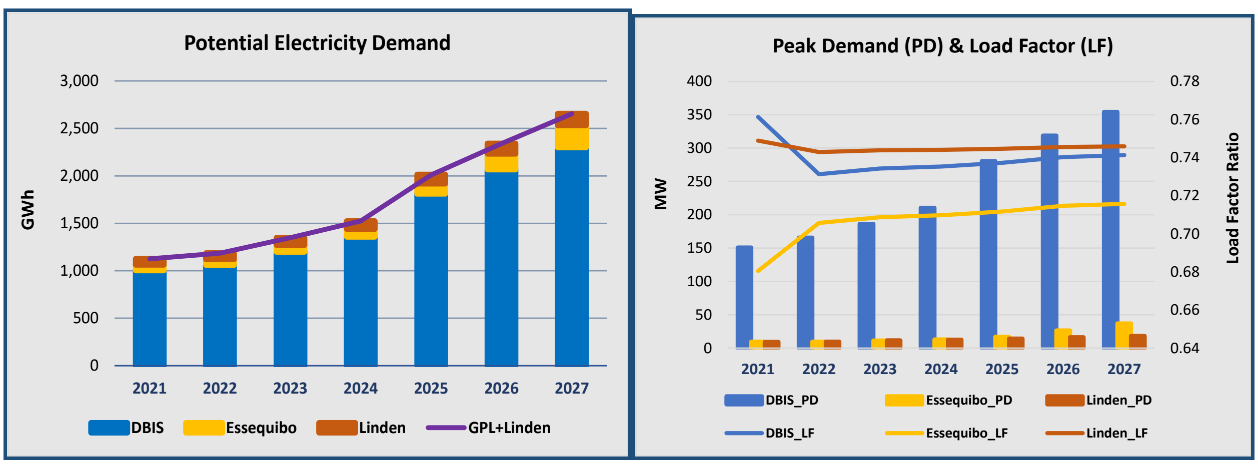

Figure 1: Electricity Demand Forecasts – All GPL and Linden

Table 6: Electricity Demand and Peak Power (with Energy Efficiency & Electric Vehicles) Forecasts for all GPL and Linden

[1] The reasoning, methodology and results are further explained in Section: 3.8 Demand Analyses and Forecasts; and Section: A.1: Electricity Demand Forecasting Methodology and Results.

[2] The Low Case and High Case is discussed in Appendix 1.

System	Description	Unit	2021	2022	2023	2024	2025	2026	2027
GPL+Linden	**Electricity Demand**	**GWh**	**1,126.0**	**1,184.6**	**1,347.8**	**1,523.6**	**2,011.3**	**2,339.8**	**2,654.1**
GPL+Linden	**Peak Power**	**MW**	**170.1**	**185.1**	**209.7**	**236.1**	**311.7**	**361.1**	**409.1**
All GPL	**Electricity Demand**	**GWh**	1,064.5	1,120.4	1,271.9	1,441.5	1,918.3	2,234.2	2,535.3
All GPL	**Peak Power**	**MW**	160.7	175.2	198.4	224.0	298.3	346.5	392.8
DBIS	**Electricity Demand**	**GWh**	1,005.6	1,060.8	1,200.3	1,359.2	1,812.2	2,067.8	2,300.7
DBIS	**Peak Power**	**MW**	150.8	165.6	186.6	210.4	280.6	318.9	354.3
Essequibo	**Electricity Demand**	**GWh**	58.9	59.6	71.5	82.2	106.0	165.5	232.8
Essequibo	**Peak Power**	**MW**	9.9	9.6	11.5	13.2	17.0	26.4	37.1
Anna Regina	**Electricity Demand**	**GWh**	41.8	41.2	49.1	56.5	73.0	113.8	160.2
Anna Regina	**Peak Power**	**MW**	7.0	6.5	7.7	8.9	11.5	17.9	25.1
Bartica	**Electricity Demand**	**GWh**	12.0	12.7	15.7	17.9	23.0	36.1	50.7
Bartica	**Peak Power**	**MW**	1.9	2.1	2.5	2.9	3.7	5.8	8.1
Leguan	**Electricity Demand**	**GWh**	2.9	2.9	3.4	3.9	5.1	7.9	11.2
Leguan	**Peak Power**	**MW**	0.6	0.6	0.7	0.8	1.0	1.6	2.3
Wakenaam	**Electricity Demand**	**GWh**	2.2	2.8	3.3	3.8	4.9	7.6	10.7
Wakenaam	**Peak Power**	**MW**	0.4	0.6	0.6	0.7	1.0	1.5	2.1
Linden	**Electricity Demand**	**GWh**	61.5	64.2	75.8	82.2	94.0	106.9	120.4
Linden	**Peak Power**	**MW**	9.4	9.9	11.6	12.6	14.4	16.4	18.4

November 2022 ended with GPL providing electricity to 218,870 customers (Table 7), of which, 91.3% is residential, 8.3% commercial and 0.4%, industrial.

The projected increase in the customer base is primarily due to the increased economic activities, which are expected to result from population growth, increased business activities and providing services to un-served areas. As such, the combined outcome largely driven by the Government's housing expansion programmes, GPL's efforts in electrifying unserved areas and delivering services to support the expanding commercial and industrial activities, the following average annual growth per tariff category is projected

- No. of Residential Customers – 3.79%.
- No. of Commercial Customers – 6.51%.
- No. of Industrial Customers - 7.21 %.

Table 7 presents the Customer growth projection for the current planning horizon.

Table 7: Customer growth projection: 2023-2027

Year	2022	2023	2024	2025	2026	2027
Residential Customers	199,811	207,979	213,146	217,981	229,161	240,525
Commercial Customers	18,203	19,003	19,803	21,003	22,856	24,924
Industrial Customers	856	881	931	1,006	1,110	1,214
Total No. of Customers	**218,870**	**227,863**	**233,880**	**239,990**	**253,127**	**266,663**

1.5 Meeting Energy Demand and Peak Power Forecasts

Guyana has several options of natural and indigenous resources to support generation to satisfy the forecast demand. Natural resources such natural gas, hydropower and solar have gained international recognition for their contribution in decarbonising the global electricity sector.

While in Guyana there are currently significant developments to utilising natural gas, hydropower and solar energy, the availability of reliable transmission and distribution systems to connect the growing customer-base with the new power generation system remains critical to providing the required electric energy security and supporting Government's national economic development plans.

The legal and regulatory framework to accommodate grid-tie customers with Distributed Energy Resource – DER and appropriate Net Billing measures is near its completion. Net Billing intends to bridge the gap between GPL and prosumers through a compensatory Feed-in Tariff (FIT) system. As such, it is expected that the number of DER prosumers will increase significantly in the near future. Whilst GPL embraces the benefits expected to be realized from DER, the Company endeavours to monitor the electricity exported to the grid aggressively, primarily to ensure the techno-economic stability of the power systems is not at risk.

While significant generation inputs from renewable energy resources remain attractive, it will not displace the larger volumes of the firm and dispatchable fossil-fired generation entirely in the short to medium term.

Significant penetration levels from intermittent renewable energy resources, such as wind and solar, would present a considerable number of challenges to the stability and energy security of the present grid. However, the hosting capacity for intermittent renewable energy resources is expected to increase as the power grid transforms progressively into a more technically robust power system. The technical robustness of the power system is expected to increase due to the ancillary services that the planned 300 MW Gas fired Plant and 165 MW Amailia Falls Hydropower Projects are expected to provide. (From Year 2024 and Year 2030, respectively)

Given the timelines of the above-mentioned projects, the Company intends to incrementally introduce and integrate DER and utility scale intermittent renewable energy resources into the grid to ensure that system stability and service reliability are not adversely affected.

1.5.1 Generation (Firm and Non-Firm Capacities)

1.5.1.1 Demerara Berbice Interconnected System (DBIS)

Whilst there is significant development currently in progress to use natural gas for electricity generation, the Government of Guyana has also demonstrated its commitment to embrace generation from renewable sources by allocating US$80 million to deploy a total of 33 MWp of Solar PV Farms (Guyana Utility Scale Solar Photovoltaic Programme – GUYSOL) in 2024. The Government (through GPL) will install utility-scaled solar farms of 15 MWp and 15 MWh of Battery Energy Storage System (BESS) in Linden, 8 MWp and 12 MWh BESS on the Essequibo Coast and 10 MWp in Berbice.

In relation to firm power generation capacity for the DBIS, the Government of Guyana, has commenced the process of piping the indigenous natural gas to shore with the projection of delivering a fully functional and complete 300 MW Combined Cycle Gas Turbine Power Plant by Year 2025. The plant will form part of an integrated facility shared with an average 50 MMSCFD Gas Conditioning and Natural Gas Liquids (NGL) Fractionation Plant, located within the Heavy Industrial Area of the Wales Development Zone on the West Bank of the Demerara River.

The commercial operation dates for the 300 MW GTE Power Plant are phased in accordance with the expected completion timeline of works relative to the Simple Cycle and Combined Cycle. Phase 1 – Simple Cycle is expected to be commissioned and placed into commercial operation by the end of 2024 and Phase 2 – Combined Cycle, by December 2025.

In the advent of the commercial operation of the 300MW Plant and with a commitment to satisfy the projected increasing peak demand during this planning period, GPL has commenced efforts to acquire additional generation capacity. This additional capacity will comprise of:

1. 50 MW (firm HFO-fired) through a 3-year PPA.
2. 35 MW EPC HFO-fired power plant with the following disaggregation:
    a. 25 MW HFO-fired (natural gas convertible).
    b. 10 MW HFO-fired (natural gas convertible).

As a result, GPL intents to have both the PPA and EPC in service within the first half of 2023.

Given the Government's commitment to optimize indigenous energy resources and ensure that most of Guyana benefits from the cheaper, cleaner, and more reliable electricity supply, the town of Linden is to be integrated with the DBIS in 2026. See Table 8 for further details.

Table 8, also presents the total planned firm power generation capacity by 2027 (inclusive of the expected realization of Battery Energy Storage System (BESS).

Table 8: Proposed Generation Expansion Plan – DBIS

Name of Location	Type	Installed Capacity (MW)				
		2023	2024	2025	2026	2027
25 MW IPP – Canefield*	Firm Capacity	25.0	-	-	-	-
25 MW EPC - Canefield	Firm Capacity	25.0	-	-	-	-
25 MW IPP – Columbia*	Firm Capacity	25.0	-	-	-	-
10 MW EPC - Canefield	Firm Capacity	10.0	-	-	-	-
300 MW GTE - Simple Cycle	Firm Capacity	-	225.9	-	-	-
GUYSOL – Berbice	Non-Firm Capacity	-	10.0	-	-	-
300 MW GTE - Combine Cycle	Firm Capacity	-	-	85.5	-	-
300 MW GTE Project BESS#	Firm Capacity		57.2			
Linden BESS*#	Firm Capacity				15.0	
Linden Solar PV*	Non-Firm Capacity				15.0	
Total New Additions - Generators		**85.0**	**235.9**	**85.5**	**-**	**-**
Total Accumulated Additions - Generators		**85.0**	**320.9**	**406.4**	**406.4**	**356.4**
Annual Non-Firm Capacity		**-**	**10.0**	**-**	**15.0**	**-**
Annual Firm Capacity - Generators		**85.0**	**225.9**	**85.5**	**-**	**-**
Accumulated Firm Capacity - Generators		**85.0**	**310.9**	**396.4**	**396.4**	**346.4**
Existing Firm Capacity - Generators		**195.9**	**195.9**	**195.9**	**183.8**	**183.8**
Total Firm Capacity - Generators		**280.9**	**506.8**	**592.3**	**580.2**	**530.2**
Accumulated Firm Capacity - BESS		**-**	**57.2**	**57.2**	**72.2**	**72.2**
Grand Total Firm Capacity - Generators + BESS		**280.9**	**564.0**	**649.5**	**652.4**	**602.4**

*This Development and Expansion programme Linden assumed Linden to be integrated with the DBIS in 2026 and the IPP to have a duration of 3 years.

BESS will be grid forming to provide ancillary services to the grid, and as such, is considered firm capacity, which will be available for its discharge duration coupled with its state-of-charge.

With the planned additional generation capacity, coupled with the total available and cold reserve capacity, the DBIS is expected to have sufficient firm generation contingency capacity as shown in Table 9 for the current planning period.

Table 9: Generation Contingency Capacity Forecast with Recommended Additions – DBIS

Existing and New Power Generators	Type	2023	2024	2025	2026	2027
DEMERARA						
Garden of Eden Power Station	Firm Capacity	7.1	7.1	7.1	7.1	7.1
Garden of Eden 46.5 MW	Firm Capacity	46.5	46.5	46.5	46.5	46.5
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
25 MW IPP - Columbia	Firm Capacity	25.0	25.0	25.0	25.0	-
300 MW GTE - Simple Cycle	Firm Capacity		225.9	225.9	225.9	225.9
300 MW GTE - Combine Cycle	Firm Capacity			85.5	85.5	85.5
Demerara Total Installation Generation Capacity (MW)		**185.00**	**410.89**	**496.43**	**496.43**	**471.43**
Demerara Total Firm Generation Capacity (MW)		**185.00**	**410.89**	**496.43**	**496.43**	**471.43**
Demerara Total Non-Firm Generation Capacity (MW)		**-**	**-**	**-**	**-**	**-**
BERBICE						
Canefield	**Type**	**2023**	**2024**	**2025**	**2026**	**2027**
Hyundai	Firm Capacity	5	5	5	5	5
No. 4 Mirrlees Blackstone	Firm Capacity	3.5	3.5	3.5	3.5	3.5
Mobile Sets	Firm Capacity	4.8	4.8	4.8	0	0
25 MW IPP - Canefield	Firm Capacity	25	25	25	25	0
25 MW EPC - Canefield	Firm Capacity	25	25	25	25	25
10 MW EPC - Canefield	Firm Capacity	10	10	10	10	10
GUYSOL – Berbice	Non-Firm Capacity		3	3	3	3
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	8.5	8.5	8.5	1.2	1.2
GUYSOL – Berbice	Non-Firm Capacity		4	4	4	4

Existing and New Power Generators	Type	2023	2024	2025	2026	2027
Williamsburg						
GUYSOL – Berbice	Non-Firm Capacity		3	3	3	3
Skeldon						
SEI	Firm Capacity	9.5	9.5	9.5	9.5	9.5
Berbice Total Installation Generation Capacity (MW)		**95.9**	**105.9**	**105.9**	**93.8**	**68.8**
Berbice Total Firm Generation Capacity (MW)		**95.9**	**95.9**	**95.9**	**83.8**	**58.8**
Berbice Total Non-Firm Generation Capacity (MW)		**0**	**10**	**10**	**10**	**10**
Linden		**2023**	**2024**	**2025**	**2026**	**2027**
GUYSOL – Linden	Non-Firm Capacity				15	15
Linden Total Installation Generation Capacity (MW)		**0**	**0**	**0**	**15**	**15**
Linden Total Firm Generation Capacity (MW)		**0**	**0**	**0**	**0**	**0**
Linden Total Non-Firm Generation Capacity (MW)		**0**	**0**	**0**	**15**	**15**
DBIS Existing Firm Capacity (MW)		**195.9**	**195.9**	**195.9**	**183.8**	**183.8**
DBIS Existing Non-Firm Capacity (MW)		**0**	**0**	**0**	**0**	**0**
DBIS New Firm Capacity (MW)		**85.0**	**310.9**	**396.4**	**396.4**	**346.4**
DBIS New Non-Firm Capacity (MW)		**0**	**10**	**10**	**25**	**25**
Power Grid Accumulated Firm Generation Capacity (MW)		**280.9**	**506.8**	**592.3**	**580.2**	**530.2**
Power Grid Accumulated Non-Firm Generation Capacity (MW)		**-**	**10.00**	**10.00**	**25.00**	**25.00**
Power Grid Min Required Spinning Reserve (MW)		**13.95**	**88.80**	**88.80**	**93.30**	**93.30**
Total BESS Capacity (MW)			**57.20**	**57.20**	**72.20**	**72.20**
Power Grid Net Capacity (MW)		**266.95**	**475.19**	**560.73**	**559.13**	**509.13**
Power Grid Forecast Peak Demand (MW)		**186.60**	**210.44**	**280.58**	**326.04**	**362.58**
Contingency Capacity (MW)		**80.35**	**264.76**	**280.15**	**233.08**	**146.54**

1.5.1.2 Potential of Converting Existing HFO Plants to Dual Fuel Plants

The existing power plants in the DBIS, located at Garden of Eden Wärtsilä (DP1), Kingston I (DP2), Kingston II (DP3) and Vreed-en-Hoop (DP4) can be converted to utilize natural gas as the primary fuel and HFO as the contingency fuel. The conversion of these power plants would significantly reduce the present operating costs and significantly extend the economic and operational life of the generators

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

GPL plans to have a total of 8 MWp Solar PV capacity and 8 MWhs Battery Energy Storage System (through GUYSOL) for the Anna Regina Power System in commercial operation by 2024.

Bartica will have a 1.5 MW Solar Farm with BESS in commercial operation in 2023, realized from concessional financing from the IaDB and execution by the Guyana Energy Agency (GEA).

Also in 2023, the United Arab Emirates grant funded 700 kW Solar PV farm with BESS is projected to be in commercial operation. In order to ensure grid stability and electricity supply security, GPL also plans to install additional firm power generation in each of the Isolated Systems in order to achieve the expansion and operation planning targets. See Table 10 for further details.

Table 10: Proposed Expansion Plan – Essequibo Isolated Systems

Isolated System Locations	**Planned Addition Capacity (MW)**				
Anna Regina	**2023**	**2024**	**2025**	**2026**	**2027**
Solar PV Farms	**-**	**8.0**	**-**	**-**	**-**
BESS	**-**	**12.0**	**-**	**-**	**-**
2x5.5 MW HFO Units	**-**		**-**	**11.0**	**-**
1x1.8 MW HFO Units	**-**		**-**	**-**	**1.8**
Total Accumulated Added Firm Capacity	**-**	**12.0**	**12.0**	**23.0**	**24.8**
Existing Firm Capacity	**15.3**	**15.3**	**15.3**	**15.3**	**15.3**
Grand Total Firm Capacity	**15.3**	**27.3**	**27.3**	**38.3**	**40.1**
Bartica	**2023**	**2024**	**2025**	**2026**	**2027**
LFO Unit (1x1.1 MW)	**1.10**	**-**	**-**	**-**	**-**
LFO Unit (2x2.4 MW)	**-**	**-**	**4.80**	**-**	**-**
LFO Unit (1x1.1 MW)	**-**	**-**	**-**	**1.10**	**-**
LFO Unit (1x2.4 MW)	**-**	**-**	**-**	**-**	**2.40**
Solar PV Farm	**1.50**	**-**	**-**	**-**	**-**
Total Accumulated Added Firm Capacity	**1.10**	**1.10**	**5.90**	**7.00**	**9.40**
Existing Firm Capacity	**4.90**	**4.90**	**4.90**	**4.90**	**4.90**
Grand Total Firm Capacity	**6.00**	**6.00**	**10.80**	**11.90**	**14.30**
Leguan	**2023**	**2024**	**2025**	**2026**	**2027**

Isolated System Locations	Planned Addition Capacity (MW)				
LFO Unit (1x0.41 MW)	0.41	-	-	-	-
LFO Unit (2x0.41 MW)	-	0.82	-	-	-
LFO Unit (1x0.41 MW)	-	-	-	-	0.41
Solar PV Farm	-	0.60	-	-	-
Solar Farm BESS	-	0.60	-	-	-
Total Accumulated Firm Capacity	0.41	1.83	1.83	1.83	2.24
Existing Firm Capacity	1.23	1.23	1.23	1.23	1.23
Grand Total Firm Capacity	1.64	3.06	3.06	3.06	3.47
Wakenaam	**2023**	**2022**	**2023**	**2024**	**2025**
LFO Unit	0.41	-	-	-	-
LFO Unit (2x0.41MW)	-	0.82	-	-	-
Solar PV Farm	0.70	-	-	-	-
Solar Farm BESS	0.33	-	-	-	-
Total Accumulated Firm Capacity	0.74	1.56	1.56	1.56	1.56
Existing Firm Capacity	1.47	1.47	1.47	1.47	1.47
Grand Total Firm Capacity	2.21	3.03	3.03	3.03	3.03

1.5.1.4 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 current planned capital investment in generation expansion aligns with the 20 years demand forecast. The recommended generation expansion plans for the 2023-2027 Development and Expansion Programme are summarised in Table 11 for the DBIS and Table 12 for the Isolated Systems.

In addition, the table below, Figure 2 and Figure 3 show the projected energy mix of each power system block by 2027.

Table 11: GPL 5-Year Generation Expansion Plan and Energy Mix- DBIS

<table>
<tr><th>Planned Commissioning Year</th><th>Generation Source</th><th>Installed Capacity (Megawatts)</th><th>Location</th><th>Ownership</th></tr>
<tr><td rowspan="4">2023</td><td>HFO</td><td>0</td><td>25 MW IPP - Canefield</td><td>IPP</td></tr>
<tr><td>HFO</td><td>25</td><td>25 MW EPC - Canefield</td><td>GPL</td></tr>
<tr><td>HFO</td><td>0</td><td>25 MW IPP - Columbia</td><td>IPP</td></tr>
<tr><td>HFO</td><td>10</td><td>10 MW EPC - Canefield</td><td>GPL</td></tr>
<tr><td rowspan="3">2024</td><td>NG</td><td>225.9</td><td>300 MW GTE - Simple Cycle</td><td>GOG/GPL</td></tr>
<tr><td>BESS</td><td>57.2</td><td>300 MW GTE - BESS</td><td>GOG/GPL</td></tr>
<tr><td>RE - Solar</td><td>10</td><td>GUYSOL – Berbice</td><td>GOG/GPL</td></tr>
<tr><td>2025</td><td>NG</td><td>85.5</td><td>300 MW GTE - Combine Cycle</td><td>GOG/GPL</td></tr>
<tr><td rowspan="2">2026</td><td>RE - Solar</td><td>15</td><td rowspan="2">Interconnection with Linden</td><td>GOG/GPL</td></tr>
<tr><td>BESS</td><td>15</td><td>IPP</td></tr>
<tr><td rowspan="2">Existing Capacity (MW)</td><td>HFO</td><td>170.9</td><td rowspan="16">DBIS</td><td>GOG/GPL</td></tr>
<tr><td>Diesel No.2</td><td>12.9</td><td rowspan="15">GOG/GPL</td></tr>
<tr><td colspan="2">Total Existing Firm Capacity (MW) - Generators</td><td>183.8</td></tr>
<tr><td colspan="2">Total Additional Firm Capacity by 2027 (MW)</td><td>418.6</td></tr>
<tr><td colspan="2">Total Additional Non-Firm Capacity by 2027 (MW)</td><td>25</td></tr>
<tr><td colspan="2">Total Additional Capacity by 2027 (MW)</td><td>443.6</td></tr>
<tr><td colspan="2">Total Firm Capacity by 2027 (MW)</td><td>602.4</td></tr>
<tr><td colspan="2">Total Non-Firm Capacity by 2027 (MW)</td><td>25</td></tr>
<tr><td colspan="2">Total Capacity by 2027 (MW)</td><td>627.4</td></tr>
<tr><td colspan="2">Total HFO Capacity by 2027 (MW)</td><td>205.9</td></tr>
<tr><td colspan="2">Total LFO Capacity by 2027 (MW)</td><td>12.9</td></tr>
<tr><td colspan="2">Total Solar PV Capacity by 2027 (MW)</td><td>25</td></tr>
<tr><td colspan="2">Total NG Capacity by 2027 (MW)</td><td>311.4</td></tr>
<tr><td colspan="2">Total BESS Capacity by 2027 (MW)</td><td>72.2</td></tr>
<tr><td>Heavy Fuel Oil % Share</td><td></td><td>33%</td></tr>
</table>

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
Diesel % Share		32.8%		
Natural Gas % Share		2.1%		
Solar PV % Share		49.6%		
BESS - Grid Forming Capacity % Share		11.5%		

NB: * IPP has a duration of 3-years and Linden connects with the DBIS in 2026.

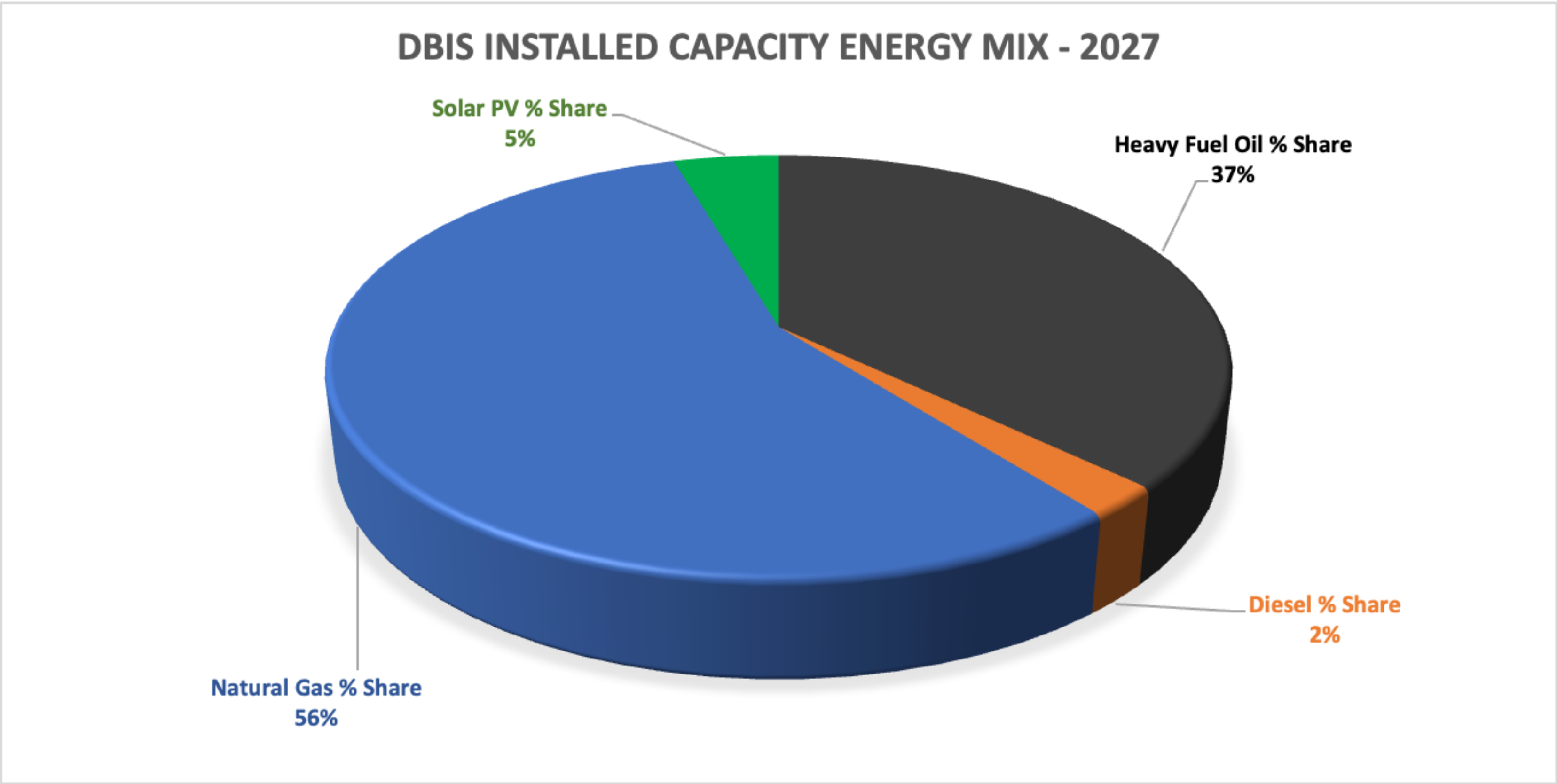

Figure 2: DBIS Installed Capacity Energy Mix – 2027

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

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
2023	Solar PV	1.5	Bartica	GPL
	Diesel No.2	1.1	Bartica	
	Solar PV	0.7	Wakenaam	
	BESS	0.3	Wakenaam	
	Diesel No.2	0.41	Wakenaam	
	Diesel No.2	0.41	Leguan	
2024	Solar PV	8.0	Anna Regina	
	BESS	12.0	Anna Regina	
	Diesel No.2	0.8	Wakenaam	
	Diesel No.2	0.8	Leguan	
	Solar PV	0.6	Leguan	
	BESS	0.6	Leguan	
2025	Diesel No.2	4.8	Bartica	
2026	HFO	11.0	Anna Regina	
	Diesel No.2	1.1	Bartica	
2027	HFO	1.8	Anna Regina	
	Diesel No.2	2.4	Bartica	
	Diesel No.2	0.41	Leguan	
Existing Capacity	HFO	5.4	Isolated Systems	
	Diesel No.2	17.5	Isolated Systems	
Total Existing Available Capacity		22.90	Isolated Systems	
Total Additional Firm Capacity by 2027 (MW)		38.00		
Total Additional Non-Firm Capacity by 2027 (MW)		10.80		
Total Additional Capacity by 2027 (MW)		48.80		

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
Total Firm Capacity by 2027 (MW)		60.90		
Total Non-Firm Capacity by 2027 (MW)		10.80		
Total Capacity by 2027 (MW)		71.70		
Total HFO Capacity by 2027 (MW)		18.20		
Total LFO Capacity by 2027 (MW)		29.77		
Total Solar PV Capacity by 2027 (MW)		10.80		
Total BESS - Grid Forming Capacity (MW)		12.93		
Isolated System HFO % Share		25%		
Isolated System LFO % Share		42%		
Isolated System Solar PV % Share		15%		
BESS - Grid Forming Capacity % Share		18%		

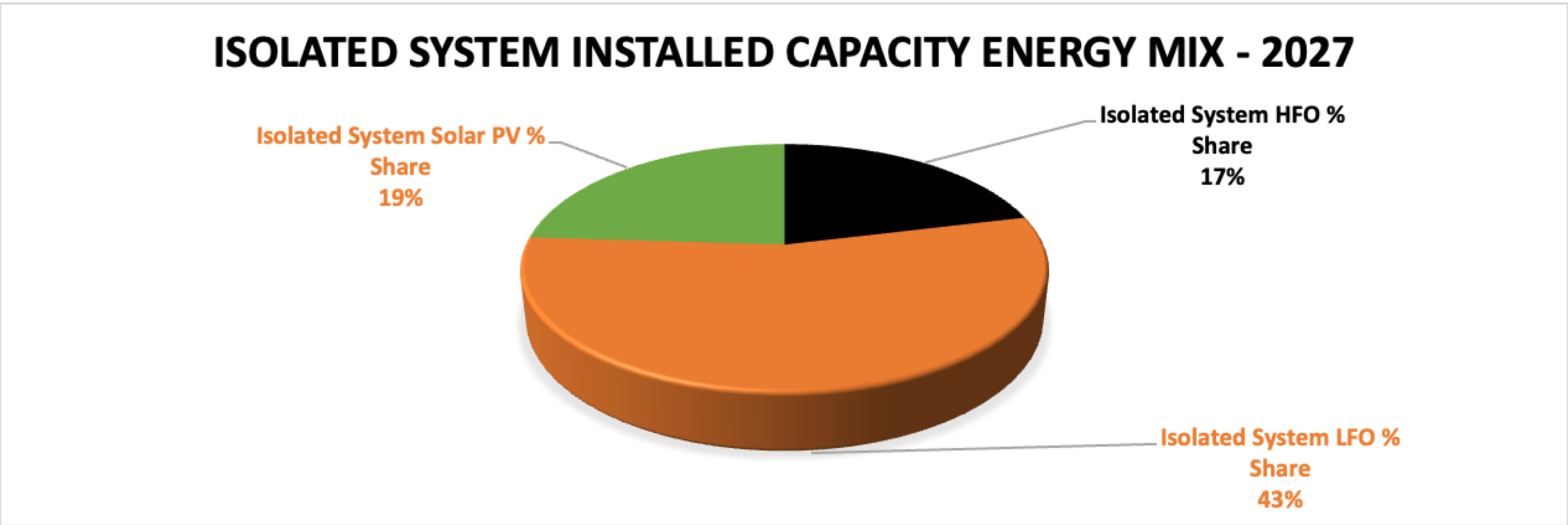

Figure 3: Isolated Power System's Installed Capacity Energy Mix - 2027

1.5.2 Transmission and Distribution Systems

Transmission and Sub-transmission Systems

With the rapid rate of developments within the oil and gas and other significant economic sectors, such as the commercial, industrial and tourism sectors, the Government of Guyana/GPL is cognisant of the dire need for robust and resilient Transmission and Distribution Systems to sustain the demand forecast. As a result, this Development and Expansion Programme contains several upgrade and expansion projects for the Transmission and Distribution Systems of the GPL power systems. Table 13 summarises the salient characteristics of the current transmission expansion plan, which includes a total circuit length of 24.79 km and 49.14 km of 230 kV and 69 kV transmission lines to allow for power evacuation from the 300 MW GTE Project in 2024.

Table 13: Summary of Planned Transmission Lines

Year	2023	2024	2025	2026	2027
Length of new Transmission Lines (km)		160.9	44.8	247.3	308.5
No. of new Transmission Lines		13.0	8.0	16.0	8.0
Length of redundant Transmission Lines (km)		12.5	48.9	84.0	44.7
No. of redundant Transmission Lines		1.0	5.0	4.0	3.0
Total length of new Transmission lines to be constructed (km)		173.4	93.7	331.3	353.2
Total No. of new Transmission lines to be constructed		14	13	20	11

* Numbers in Table 13 are based on the completion of the project of 230kV and 69 kV transmission Lines. Double Circuit Transmission Lines are counted as two lines and the length considered is the combined length of each individual circuit.

To link the transmission and distribution systems, Table 14 shows the planned number of substations to be completed by a year in the current Programme. The details shown in Table 14 include 13.8 kV/230 kV voltage step-up and 230/69 kV voltage step-down substations for the 300MW GTE Project at Wales. In order to facilitate seamless integration of the 300MW GTE Project with the DBIS, Table 14 also includes one (1) each 230/69kV and 69kV/13.8 kV voltage step-down substation at Goedverwagting, and two (2) 69kV/13.8kV voltage step-down substation on the West Bank of Demerara. All substations associated directly with the 300MW GTE Project are planned to be completed by the end of 2024.

Table 14: Number of Planned Substations

Substation Type - Voltage Base	2023	2024	2025	2026	2027
13.8kV/230 kV		1			
230 kV/69 kV		2		1	2
69 kV/13.8 kV		6	4	4	2

The other planned substations within the current planning horizon are required to ensure the delivery of the transmission and distribution components of the planning targets to meet and exceed customers' expectations.

A. Sub-transmission Reinforcement

GPL has acquired concessional debt financing and plans to install a total of 55 MVAr fixed detuned capacity banks across the DBIS to support steady-state voltage and generator economic dispatch. The earmarked interconnection sites and capacity are as follows:

1. New Sophia Switching Substation – 15 MVAr
2. Edinburgh Substation – 10 MVAr
3. Columbia Substation – 15 MVAr
4. No. 53 Substation – 15 MVAr

Distribution System

The distribution system is planned contextually to address the current network deficiencies and to satisfy the growing requirements of the industrial, commercial, and residential customers across Guyana and align with the country's economic and socio-economic development plans.

The number of new substations mentioned above will be equipped with feeders to deliver electricity to customers, improve power quality and reliability of electricity supply and prepare the distribution system for the seamless deployment of Smart Grid. Table 15 provides a summary of the salient characteristics of the distribution expansion plan for the current planning horizon.

Table 15: Summary of Planned Distribution Lines

Year	2023	2024	2025	2026	2027
Length of new feeders (km)		144	154	89	62
No. of new feeders (resulting from planned new substations)		32	26	16	11
Length of redundant feeders (km)	65	12	30	22	
No. of redundant feeders	14	2	6	7	
Total length of new feeders to be constructed (km)	65	156	184	111	62
Total No. of new feeders to be constructed	14	34	32	23	11

*On an average, each planned distribution substation/load centre would have five (5) feeders.

1.6 Metering (Technical and Non-Technical Losses)

The progressive and sustained reduction in System Losses remains a corporate priority. In light of the 8% growth in electricity demand from 2021 to 2022, total losses reduced from 26.47% in 2021 to 25.2% in 2022. The projected total 5-year system loses is 20.9% in 2027.

Figure 4 presents a disaggregation of system losses (technical and non-technical/ Commercial)

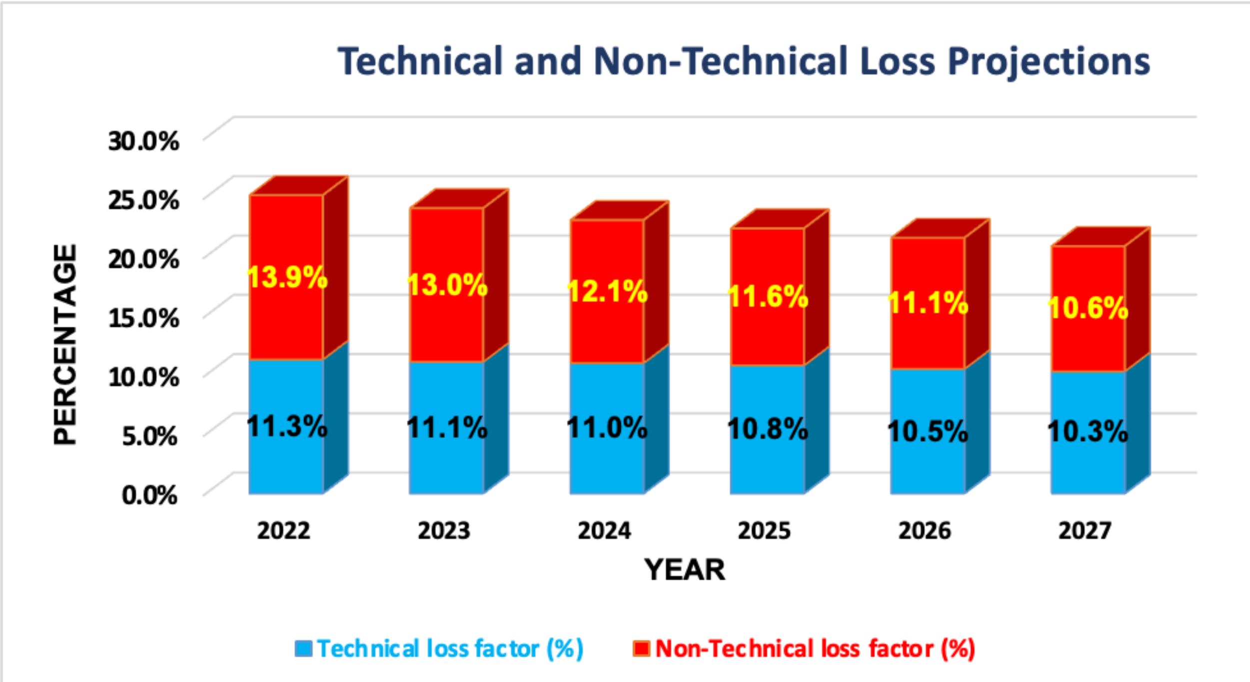

Figure 4: Loss Reduction Projections

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

1. Unmetered supplies,
2. Defective meters,
3. Street lighting and
4. Electricity theft.

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

1. Aged and long feeders (medium and low voltage),
2. Heavy-loaded feeders (medium and low voltage),
3. High loss transformers
4. Poor power factor.

1.7 Sales and Revenue Collection

Electricity sales growth from 2022 to 2027 is projected to increase by 238%, that is, from 817.2 GWhs to 1,946.9 GWhs for the total GPL Power Systems (Figure 5). Also, Linden is considered integrated with the DBIS in 2026.

The projection is based on the estimated growth of GPL's customer base and the expected significant stimulation in the economy, largely driven by the emerging Oil and Gas Industry.

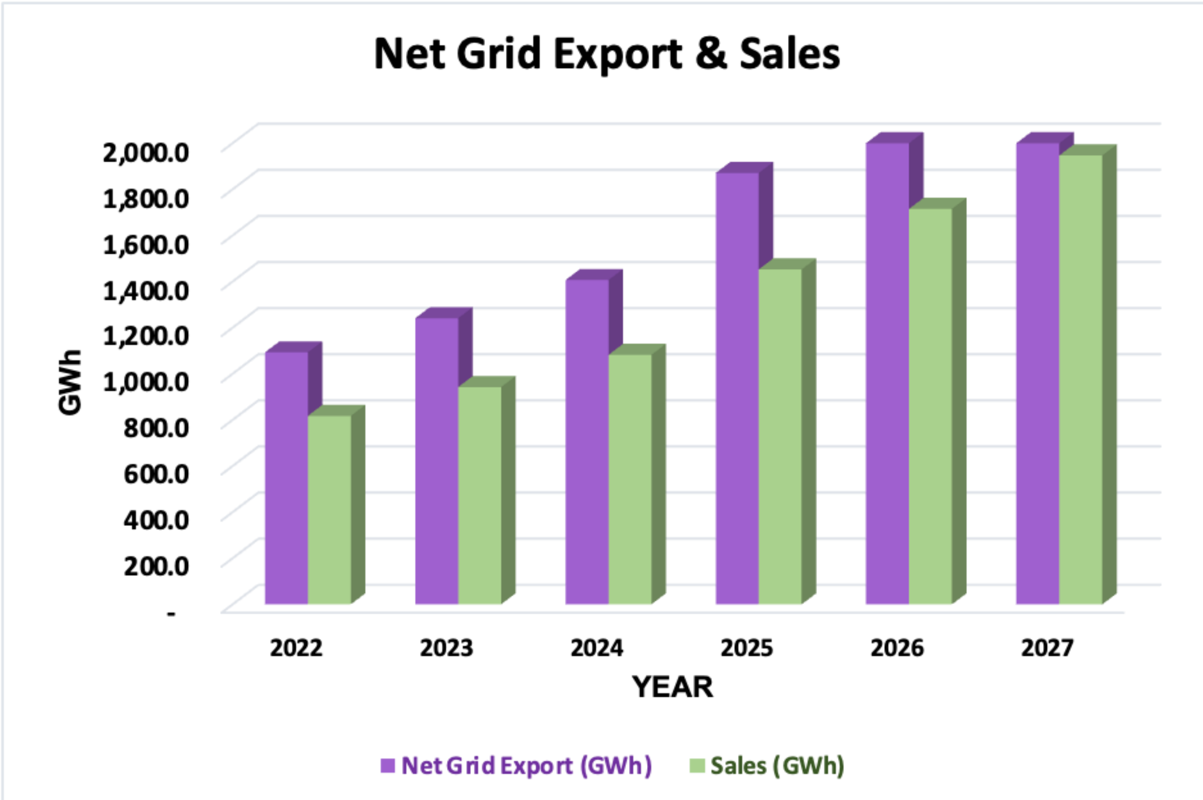

Figure 5: Net generation & Sales (GWh)

1.8 Tariffs

The reduction of tariffs remains a priority for 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. During the year 2021, the fifteen (15%) fuel rebates were removed and concurrently the tariffs were reduced by the same amount.

Despite world market fuel prices tripling in the ensuing years (2017 – 2022), 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 16.

Table 16: Financial Projections – Facilitating Tariff Reduction

	Yr 2022	Yr 2023	Yr 2024	Yr 2025	Yr 2026	Yr 2027
Net Tariffs	**G$/kWh**					
Residential	43.00	43.00	43.00	21.50	21.50	21.50
Commercial	59.00	59.00	59.00	29.50	29.50	29.50
Industrial	52.00	52.00	52.00	26.00	26.00	26.00
	Yr 2022	**Yr 2023**	**Yr 2024**	**Yr 2025**	**Yr 2026**	**Yr 2027**
	GWh					
Generation	1,093	1,240	1,406	1,871	2,179	2,472
Demand	817	942	1,082	1,452	1,709	1,957
Technical & Commercial Losses	275	298	324	418	470	516
Technical & Commercial Losses %	25.2%	24.1%	23.1%	22.4%	21.6%	20.9%
	Yr 2022	**Yr 2023**	**Yr 2024**	**Yr 2025**	**Yr 2026**	**Yr 2027**
Fuel Prices	**US$/barrel**					
HFO	107.18	90.63	85.00	85.00	85.00	85.00
LFO	154.78	150.00	140.00	140.00	140.00	140.00
	Yr 2022	**Yr 2023**	**Yr 2024**	**Yr 2025**	**Yr 2026**	**Yr 2027**
PPA Prices	**US cents/kWh**					
300 MW Natural Gas			5	5	5	5
50 MW IPP		12	12	12	12	12

These factors have a major influence on GPL's ability to lower Tariffs from the current level of approximately US 22 cents per kWh. A review of the projected financial performance for the period to Year 2027 highlights the following:

i) Growth in Sales Demand

The significant growth in demand (increase of approximately 140%) 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 50% reduction in tariffs from the beginning of year 2025.

ii) Losses (Technical and Commercial losses)

Losses are projected to decline from 25.2% to 20.9%. 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.

iii) Cost of Generation

By year 2025, generation using natural gas supplied by way of the planned gas pipeline is projected to provide more than 80% of the required generation. The price at which the electricity is sold to GPL is therefore extremely important and will have the most impact on the ability of the company to lower tariffs by 2025. These projections assume a rate of US five (5) cents per kWh at which GPL will purchase the electricity from the Independent Power Producer.

iv) GPL's Debt Burden

The projections indicate that by the end of 2027, GPL's Related Parties Non-Current Liabilities consisting mainly of loans from the Government of Guyana would increase from G$63 billion to more than G$365 billion. This will require approximately G$26 billion in annual debt service obligations.

GPL has negotiated with the Ministry of Finance, the extension of the moratorium on servicing the majority of the current outstanding debt until the year 2026. Discussions are ongoing to extend this moratorium to all of the remaining debt.

Converting this debt to equity, would strengthen GPL's financial position and better position the company to continue to reduce tariffs while at the same time improve its capacity to deliver a stable and high-quality electricity supply to the Nation

.

1.9 Capital Programmes and Financial Projections

Table 17 to Table 20 below provide summarised details on the capital Programmes, Profit and Loss Account, Cash Flow Statement and Balance Sheet, respectively, for the current planning horizon.

Table 17: Planned Capital Programmes and Investments: 2023-2027

Development and Expansion Projects		Annual Budget (US$)				
		2023	2024	2025	2026	2027
	US$	US$	US$	US$	US$	US$
Conventional Generation	66,258,294	23,749,540	20,019,034	10,505,220	10,067,200	1,917,300
Non-Conventional Generation	80,000,000	44,000,000	36,000,000	-	-	-
69 kVTransmission Lines (Include Sub. Exp. Cost)	240,835,409	21,667,145	27,487,423	101,636,825	83,960,851	6,083,165
230 kV Transmission Lines (Include Sub. Exp. Cost)	318,160,371	23,279,199	19,046,617	16,104,811	148,780,858	110,948,886
Upgrade - Existing 69/13.8 kV Substation	19,947,615	15,369,701	3,010,832	1,115,593	451,489	-
New 69/13.8 kV Substation	142,640,164	33,068,810	57,813,840	23,745,562	20,398,195	7,613,757
230 kV Substation - New	64,445,473	10,787,662	15,147,927	13,939,811	16,597,376	7,972,697
New Primary Distribution Feeders	30,068,278	6,291,375	9,503,932	7,856,394	4,555,627	1,860,950
Upgrade to Existing Primary Distribution Network (Technical Loss Reduction)	20,201,934	12,478,099	3,624,287	2,322,057	919,727	857,763
Transmission Reactive Reinforcement	5,886,962	-	3,292,741	2,594,221	-	-
GNCC/Smart Grid	60,114,370	8,458,000	5,389,250	18,506,848	13,880,136	13,880,136
Power Plant Switchgear Upgrades	73,893,675	995,947	72,897,728	-	-	-
Meter Upgrades/Replacements (Non-Technical Loss Reduction)	36,399,500	6,250,000	7,537,375	7,537,375	7,537,375	7,537,375
Electrification (Unserved Areas)	2,453,454	2,210,285	243,169	-	-	-
New Services	17,306,932	1,455,076	3,790,382	3,369,514	3,867,371	4,824,590
Buildings	7,703,725	4,396,033	1,418,473	356,144	766,524	766,551
Company Tools	28,512,557	8,991,554	8,052,258	3,674,828	5,565,402	2,228,515
Information Technology	1,325,000	855,000	470,000	-	-	-
GRAND TOTAL US$	**1,216,153,711**	**224,303,427**	**294,745,268**	**213,265,202**	**317,348,129**	**166,491,685**
Guyana Dollar Equivalent ($ millions)	**261,777**	**48,281**	**63,444**	**45,905**	**68,309**	**35,837**

Source of Funding – Loans facilitated through the Government of Guyana.

Table 18: Profit & Loss Account

	2022	Yr 2023	Yr 2024	Yr 2025	Yr 2026	Yr 2027
	Latest Estimate	**Proj**	**Proj**	**Proj**	**Proj**	**Proj**
	$'M	**$'M**	**$'M**	**$'M**	**$'M**	**$'M**
REVENUE	38,628	47,137	54,132	36,340	42,762	48,954
GENERATION COSTS	42,971	46,060	45,757	28,164	30,053	37,094
GROSS INCOME	**(4,343)**	**1,076**	**8,374**	**8,175**	**12,708**	**11,860**
EXPENSES						
Employment Costs	5,708	6,062	6,668	7,335	8,068	8,875
Repairs & Maintenance T&D	405	2,569	3,854	5,781	6,359	6,995
Depreciation	3,883	7,361	11,334	14,291	18,739	21,107
Administrative Expenses	2,596	3,467	3,709	3,969	4,247	4,544
Rates & Taxes	45	50	50	50	50	50
Loss On Exchange	-	-	-	-	-	-
Bad Debts Provision	579	707	812	545	641	734
Puc Assessment & Licence	72	73	73	73	73	73
	13,289	**20,290**	**26,501**	**32,044**	**38,177**	**42,378**
NET (LOSS)/PROFIT FROM OPERATIONS	(17,632)	(19,213)	(18,126)	(23,868)	(25,469)	(30,519)
INTEREST EXPENSE	1,293	1,763	1,939	2,133	2,347	2,581
	(18,925)	**(20,976)**	**(20,066)**	**(26,001)**	**(27,816)**	**(33,100)**
OTHER INCOME						
	(18,925)	**(20,976)**	**(20,066)**	**(26,001)**	**(27,816)**	**(33,100)**
TAXATION						
NET (LOSS)/PROFIT FOR THE YEAR	**(18,925)**	**(20,976)**	**(20,066)**	**(26,001)**	**(27,816)**	**(33,100)**

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

Table 19: Cash Flow Statement

	Yr 2023	Yr 2024	Yr 2025	Yr 2026	Yr 2027
	Proj	Proj	Proj	Proj	Proj
Year Ended December 31st	**$'M**	**$'M**	**$'M**	**$'M**	**$'M**
OPERATING ACTIVITIES					
Profit/(Loss) before Taxation	**(20,976)**	**(20,066)**	**(26,001)**	**(27,816)**	**(33,100)**
Adjustments for:					
Depreciation	7,361	11,334	14,291	18,739	21,107
Deferred Income	8	6	(15)	5	5
Interest Expense	1,763	1,939	2,133	2,347	2,581
Operating (loss)/profit before WC changes	**(11,844)**	**(6,786)**	**(9,592)**	**(6,725)**	**(9,407)**
Working Capital (WC) Changes					
Change in Inventories	(245)	(258)	(271)	(284)	(298)
Change in receivables and prepayments	(2,871)	(1,166)	2,965	(1,070)	(1,032)
Change in payables and accruals	2,123	2,335	2,569	2,826	3,108
Changes in Deferred Tax Liabilities and benefits	25	0	0	0	0
Taxes paid	7	7	8	9	10
Net Cash (Outflow)/Inflow - Operating Activities	**(12,805)**	**(5,867)**	**(4,321)**	**(5,245)**	**(7,619)**
INVESTING ACTIVITIES					
Acquisition of Property, plant and equipment	(52,180)	(59,592)	(44,347)	(66,718)	(35,521)
Acquisition of treasury bills	0	0	0	0	0
Increase in deposit	(216)	(118)	(141)	(169)	(203)
Net Cash Outflow - Investing Activities	**(52,396)**	**(59,710)**	**(44,488)**	**(66,887)**	**(35,724)**
FINANCING ACTIVITIES					
Movement in non current related parties	71,031	65,407	48,865	72,317	45,005
Deposit on Shares	0	0	0	0	0
Interest paid	(1,763)	(1,939)	(2,133)	(2,347)	(2,581)
Customer deposits	501	2,089	2,087	2,190	1,187
Increase in advances customer financed projects	173	507	524	565	388
Decrease in advances customer financed projects					
Net Cash (Outflow)/Inflow - Financing Activities	**69,941**	**66,064**	**49,342**	**72,725**	**43,998**
NET MOVEMENT IN CASH AND CASH EQUIVALENTS	**4,739**	**487**	**533**	**593**	**654**
CASH AND CASH EQUIVALENTS AS AT BEGINNING OF YEAR	40	4,779	5,266	5,799	6,392
CASH AND CASH EQUIVALENTS AS AT END OF YEAR	**4,779**	**5,266**	**5,799**	**6,392**	**7,046**
Represented By:					
Cash on Hand and at Bank	**4,779**	**5,266**	**5,799**	**6,392**	**7,046**

Table 20: Balance Sheet

	2022 Latest Estimate	Yr 2023 Proj	Yr 2024 Proj	Yr 2025 Proj	Yr 2026 Proj	Yr 2027 Proj
As at December 31st	**$'M**	**$'M**	**$'M**	**$'M**	**$'M**	**$'M**
ASSETS						
Non Current Assets	**61,478**	**106,297**	**154,555**	**184,611**	**232,590**	**247,005**
Current Assets						
Inventories	4,908	5,153	5,411	5,682	5,966	6,264
Receivables & Prepayments	4,985	7,856	9,022	6,057	7,127	8,159
Deposits	372	588	706	847	1,016	1,219
Related parties	3,569	3,569	3,569	3,569	3,569	3,569
Cash resources	40	4,779	5,266	5,799	6,392	7,046
	13,874	**21,946**	**23,974**	**21,953**	**24,070**	**26,258**
Total Assets	**75,352**	**128,243**	**178,528**	**206,564**	**256,660**	**273,263**
EQUITY & LIABILITIES						
Share Capital	23,118	23,118	23,118	23,118	23,118	23,118
Accumulated deficit	(39,354)	(60,330)	(80,396)	(106,397)	(134,213)	(167,312)
	- 16,236	**- 37,212**	**- 57,278**	**- 83,279**	**- 111,095**	**- 144,194**
Non Current Liabilities						
Related Parties	62,746	133,777	199,183	248,048	320,365	365,370
Advances customer financed project	862	963	1,384	1,804	2,245	2,485
Provision for decommissioning	243	243	243	243	243	243
Customer deposits	4,278	4,779	6,868	8,954	11,144	12,330
Defined benefit liability	1,283	851	851	851	851	851
Deferred tax liability	490	947	947	947	947	947
	69,902	**141,559**	**209,476**	**260,848**	**335,795**	**382,226**
Current liabilities						
Related parties	-	-	-	-	-	-
Deferred Income	31	39	45	30	36	41
Advances customer financed project	359	431	517	620	744	893
Payables and accruals	21,231	23,354	25,690	28,258	31,084	34,193
Taxation	65	72	79	87	95	105
Bank Overdraft						
	21,686	**23,896**	**26,330**	**28,996**	**31,960**	**35,232**
Total Equity and Liabilities	**75,352**	**128,243**	**178,528**	**206,564**	**256,660**	**273,263**

2. Introduction

2.1 General

The Guyana Power and Light (GPL) plays a critical role in developing the country's economy sustainably, consistent with its mandate to provide reliable, affordable, and quality services to its customers, comply with all applicable regulations and standards, safely and sustainably develop, and operate the grid and develop the capabilities of its employees.

The Company currently does not have sufficient reliable generation capacity to meet the peak demand forecast. The situation is further exacerbated by the absence of backup circuits to mitigate contingent events in the transmission and distribution sections of the power systems, coupled with an ageing transmission and distribution infrastructure.

Forty-nine point five megawatts (49.5 MW) of the Company's Heavy Fuel Oil fired baseload generator units (powered by Wärtsilä[3] and Mirrless Blackstone[4] engines) within the Demerara Berbice Interconnected System (DBIS) have surpassed the economic lifespan threshold of 20 years. Additionally, 16 MW of Light Fuel Oil fired base load generator units have also exceeded the 20 years economic lifespan limit.

Although these older engines have been and continue to be well maintained and deliver at an extraordinarily reliable level, they have become prone to increased mechanical and electrical failures due to the exhaustive years of continuous on-demand operation to narrow the supply-demand gap.

In addition to LFO-fired generator units, there are 17.9 MWs of LFO-fired, high-speed mobile generator units in Berbice and 7.1 MWs in Demerara. 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 such as voltage support and satisfying active power demand. These longer operation hours further expose the generator units to mechanical and electrical failure risks.

Combining the age of the generator units and issues relative to the engines and/or alternators, the total unreliable power generation capacity in the DBIS (LFO and HFO fired generation) is 124.3 MW, and in the Isolated System, a total of 9.2 MW. Consequently, the Company is saddled with the combined challenges of aged generator units and unreliable capacity, which are not consistent with the Company's goal of reliably satisfying the demand forecast and by extension, the ability to support Guyana's economic development sustainably.

[3] DP1 is 25 years old and totals 22 MW, while and DP2 is 24 years old and totals 22 MW. As such, a grand total of 44 MW of available Wärtsilä Generator Units capacity.

[4] Canefield Mireles Blackstone Generator unit is 25 years old and totals 3.8 MW of available capacity.

The Government of Guyana remains cognizant of the importance of reliable generation capacity and provided debt financing to GPL to facilitate the construction of the first single and largest power generation facility in the Country – 46.5 MWs. This Power Plant is located at Garden of Eden and was commissioned on 1st October 2021.

Whilst the 46.5 MW at Garden of Eden is assisting with improving generation reliability and supporting GPL to satisfy the immediate and short-term electricity and peak demands the DBIS is in dire need for a significant amount of additional firm generation capacity during the short to midterm planning period - 2023 to 2027.

As per the Expression of Interest from the Ministry of Natural Resources, the Government of Guyana expects to receive a guaranteed minimum of 50 mmscfd of gas by 2024 from the Liza Area in the Stabroek block, offshore Guyana, from which methane would be produced as the primary fuel for the 300 MW Gas to Energy Project, to be located in the Heavy Industrial Area, within the Wales Development Zone (WDZ) (Ministry of Natural Resources, 2021).

Further, the Government of Guyana has renewed its commitment towards the execution of the Amaila Falls Hydro Power Project (DPI, 2022) and has projected Year 2030 as the new timeline for the Amaila Falls Hydro Power Project (Newsroom, 2022)

Similarly, the Isolated Systems would also require additional firm generation capacity due to similar reasons as the DBIS to bolster planned economic development activities.

Should GPL be confronted with protracted delays in its power generation expansion plans, the supply-demand gap would widen significantly and negatively impact the planned timelines of economic activities, and by extension, the trajectory of Guyana's development path.

2.2 Positioning the 2023 – 2027 Development and Expansion Programme

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

As the leading supplier of electricity services in Guyana, GPL has comprehensively reviewed its role within the context of supporting national economic development and has revised its core objectives and identified the critical issues, which form the building blocks 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 business viability of GPL; and

- Build the Market: The demand for electricity services increases while the capital cost of renewable energy self-generation technologies is becoming more affordable. The Company recognizes the importance of lower tariffs, and improved service reliability to sustain and influence growth in its customer base and to extend services to benefit both self-generators and GPL through the increased use of renewables.

2.1.2 Employee Learning and Growth

- Ensure the Company's employees possess the requisite knowledge, skills, and competencies to continuously improve the quality of our products and services; and
- To stimulate, develop, and retain a highly engaged and active workforce.

2.1.3 Financials

- Ensure that there are sufficient financial resources to sustain the Company's operations within the short, medium, and long-term timeframes; and
- Mitigate against financial disruptions associated with the various risks currently being experienced by the Company, e.g., fuel price volatility 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 is crucial to the positioning of the Company and 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, battery energy storage systems, upgrading and constructing new distribution feeders, transmission lines and substations and deploying modern and **S**elf-**M**onitoring, **A**nalysis, and **R**eporting **T**echnologies (SMART) to manage better, supervise and support the transmission and distribution systems remotely. These investments would improve power system reliability (LOLP, SAIFI and SAIDI), mitigate transmission and distribution contingencies and congestions, and aid in reducing technical and commercial losses.

2.1.5 Critical Issues

The Company focuses on and intends to prioritise the following four (4) critical issues to achieve operational excellence and corporate strategic objectives. These critical issues are premised on the need to:

1. Improve the Quality of Products and Services;

2. Strengthen Management;
3. Optimize GPL as a System; and
4. Reduce Technical and Commercial Losses.

To address the four (4) critical issues, the current Development and Expansion Programme has developed least-cost optimised expansion plans with technical merits in support of the needs within three (3) major power system blocks, Generation, Transmission and Distribution. With these plans realised, the Company intends to ensure the power system operates within the prescribed technical and economic limits to mitigate cost excursions, guarantee power system reliability and security, and deliver quality service to customers.

The technical limits are described in the National Grid Code.

Further, the Company has updated its human resources strategic plans to ensure that GPL has the requisite capacity to bolster its Development and Expansion Programme. Among the many strategies are the ongoing management restructuring, provision of capacity building and other related upskilling opportunities to employees with the objectives of narrowing the competency and skill gaps that embrace the operation of a modern power system and provide reliable services to customers.

2.3 Engineering Service Division

Mission Statement: To efficiently plan, engineer and execute major infrastructural projects in a timely and cost-effective manner through an empowered workforce embracing modern technologies.

Objective/Measure: The objective of the Projects Division is to adhere to the established standards and regulations in the planning, design, and execution of projects to meet customers' load demands in a reliable, safe, and environmentally friendly manner. This would be established through the KPIs to measure the parameters relevant to the Critical Issues of the Division.

Critical Issues: To achieve Operational Excellence, the following issues are identified as critical to the Projects Division to achieve its mandate and by extension, the goals of the Corporate Strategic Plan:

1. Meeting Forecasted Load Demand
2. Technical Loss Reduction
3. Staff Training and Development

Staff Training and Development

In alignment with the core strategic objectives, this critical area focuses on building human resource capacity to efficiently and effectively execute the strategies highlighted in this business plan. It is intended to accomplish this through the execution of specialised training in Power System Planning and Project Management.

Risks

The following risks would affect the strategies outlined to address the critical issues and projects as identified in this business plan:

1. Availability of adequate resources.
2. Absence of a structured project approval process.
3. Lack of cooperation between divisions.

Deploy Objectives

1. Communicate the Corporate Strategic Plan and Division Business Plan to all staff.
2. Employ process mapping techniques to identify urgent and long-term priorities.
3. Engage staff in process improvement within their respective areas.
4. Develop and deploy a master dashboard for reporting on Corporate, Division and Departmental performance.

2.4 Outline of Development and Expansion Programme

Section 3 (page 4646) outlines the recent achievements of the Company;

Section 4 (page 5757) summarises the current major developments of the Company;

Section 5 (page 7777) defines the mandates, planning criteria, inputs, and assumptions of GPL;

Section 6 (page 9898) presents the current status of power generation capacity;

Section 7 (page 104104) outlines the current status of the transmission and distribution system;

Section 8 (page 106106) details the DBIS generation reliability – no additional capacity;

Section 9 (page 108108) outlines the isolated power systems generation reliability – no additional capacity;

Sections 10 (page 112112) details the committed firm and intermittent generation capacities – DBIS;

Section 11 (page 118118) highlights the planned firm and committed intermittent generation capacities – isolated power system;

Section 12 (page 127127) outlines the summary of firm and intermittent generation expansion projects;

Section 13 (page 134134) details the integrated utility service and net billing;

Section 14 (page 135135) outlines Long-term Expansion and International Grid Interconnection;

Section 15 (page 137137) details the Transmission, Distribution and Substation Upgrades and Expansions;

Section 16 (page 147147) outlines the Network Maintenance Plan – 2023-2027;

Section 17 (page 150150) speaks to the Loss Reduction of GPL;

Section 18 (page 154154) details the Non-Technical Operations;

Section 19 (page 170170) describes the Corporate Key Performance Indicators and Targets;

Section 20 (page 175175) summarizes the Annual Expansion, Upgrades and Service Work Plan;

Section 21 (page 191191) outlines the Sales and Revenue Collection;

Section 22 (page 193193) details the Projected Capital Expenditure;

Section 23 (page 194194) details the Operating costs and Capital Expenditures;

Section 24 (page 196) outlines the Impact of programme on Natural & Social Environment;

Section 25 (page 198198) defines the Major Risks and Contingencies;

Section 26 (page 204204) gives an overview on the Cost Benefit of Investment Projects;

3. Recent Achievements

3.1 Conventional Generation

In 2018, GPL commenced essential power generation expansion projects at Canefield, Anna Regina and Bartica.

To narrow the supply-demand gap and bolster the firm generation capacity in the DBIS, GPL commenced construction works on the 46.5 MWs multi-fuel power generation plant at Garden of Eden and installed a total emergency generation capacity of 9.6 MWs (6x1.6 MWs) distributed in blocks of 4.8 MWs at Sophia, Onverwagt and Canefield Substations.

3.1.1 Garden of Eden

In 2021, GPL commenced commercial operation of the 46.5 MWs multifuel power plant at Garden of Eden and boosted the total available generation capacity of the DBIS to 208.6 MWs. With a recorded peak demand of 135.7 MW, the 46.5 MW plant resulted in the capacity reserve margin of DBIS being 53.72%, which aided in achieving the LOLP target in 2021.

However, during the year 2022, as the electricity demand increased, the capacity reserve margin averaged monthly at 11.56 %, with a maximum value of 28.7 % in January and a minimum of 1.05% in July.

3.1.2 300 MW Gas-to-Energy Project, Wales

In 2021, while being cognisant of the forecast demand, the Government of Guyana, through the Gas Task Force and the Ministry of Natural Resources, commenced desktop works relative to the Gas to Energy Project. Among these works included the decision to construct the gas-fired and natural gas liquids plants together (integrated project), the publication of an Expression of Interest for the project, the identification of land for the integrated project, and pipeline survey works.

In 2022, technical and commercial developmental works relative to the Gas to Energy Project continued, which lead to the pre-qualification of bidders and evaluation of EPC proposals for the integrated project. On November 10th, 2022, the Government of Guyana, via its Cabinet, announced the results of the evaluation of the EPC proposals and outlined the next steps in support of the commencement and construction supervision of the integrated project for its successful completion in 2024 to achieve the LOLP target.

3.1.3 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 to 40% in 2018 and supported the Company's objective of satisfying the growing demand in the DBIS reliably and achieving the LOLP target.

In 2020, the power generation capacity at Canefield was increased by 4.8 MW – 3 Mobile units, each having a capacity of 1.6 MW.

In October 2022, GPL advertised an EPC RFP for a 25 MW HFO-fired power plant to be installed either at Canefield or Columbia in 2023, and a 2x5 MW generator unit to be installed at Canefield. Additionally, in the same month, GPL advertised for the supply of a total of 25 MW HFO-fired firm power generating capacity through a power purchase agreement over a 3-years period at Canefield. The request is for a barge or a land-based power plant to be interconnected with the Canefield Substation at the 69 kV voltage level. This additional 25 MW at Canefield would assist GPL in achieving its LOLP target.

3.1.4 New Sophia/Columbia

In addition to the 25 MW HFO-fired firm power generating capacity through a power purchase agreement over a 3-years period at Canefield, the advertisement also carried a similar request for New Sophia or Columbia to further assist GPL with achieving its LOLP target.

For New Sophia, only the interconnection of a barge can be accommodated. At Columbia, only a land-based power plant can be accommodated. In both cases, the point of interconnection is also expected to be at the 69 kV voltage level.

3.2 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 on the Essequibo Coast.

The power plant was designed to accommodate additional power generation units to assist in narrowing the supply-demand and bolster the capacity reserve margin to achieve the GPL LOLP target.

3.2.1 Wakenaam

In 2020, GPL procured and installed 2x410 kW diesel-fired generators to augment the EPC 700 kW Solar PV Project with 200 kW BESS to achieve the LOLP target sustainably. This Solar PV system with BESS is funded by a United Arab Emirates (UAE) grant.

Further, this hybrid system supported by a BESS will ensure the Wakenaam power system operates reliably and sustainably.

Further, in 2021, GPL commissioned 2x410 kW LFO-fired generator units and repaired the No.2 unit that was derated.

3.2.2 Leguan

The No. 2 generator unit has been repaired in 2021 and has resumed availability for dispatch.

3.2.3 Bartica

A 3.3 MW LFO-fired plant was commissioned in the first quarter of 2020. This power plant replaced aged, unreliable and derated LFO-fired units - with containerised mobile units. This new 3.3 MW plant resulted in significant improvement in Bartica's LOLP, availability and provided firm reserve capacity for short to medium-term load growth.

3.3 Non-Conventional Generation

Prior to and during 2021, in receipt of 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, GPL executed five (5) Integrated Utility Services (IUS) pilot projects.

The IUS Model provided 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 was primarily customer-focused, and it provided upfront financial assistance for the customers to acquire their desired energy-saving solutions.

In addition to the current electricity services, the primary reason for GPL pursing the IUS model is to expand its business model and become a multi-faceted utility company that provides its customers with sustainable energy solutions (Renewable Energy & Energy Efficiency Options).

In Q4 of 2021, GPL commissioned the five (5) IUS pilot projects successfully. A summary of the pilot projects is as follows:

1	OAS	10.2kWp Grid Tied Solar PV System with 10kW Grid Tied Inverter

2	IICA	20.4kWp Grid Tied Solar PV System with 20kW Grid Tied Inverter
3	GPL Middle Street	13.26kWp Grid Connected Solar Photovoltaic System with 10kW of Grid Tied Inverter, 13.54 kWh Battery Energy Storage System – 1 Hour Back Up Power for Cash Office
4	GPL Main Street	7.6kWp Grid Connected Solar Photovoltaic System with 7kW Grid Tied Inverter, 25.39kWh Battery Energy Storage System - 4 hours of Backup power for Lights and Computers at the Payment Office Customer Services cubicles and Customer Call Centre
5	GPL Sophia	35.28kWp Grid Connected Solar Photovoltaic System with 30kW Grid Tied Inverter, 110.4kWh Battery Energy Storage System - 4 hours Backup Supply for the Communications and Computer Server Room

3.3.1 IUS Pilot Project

With the installation of this system, IICA has already benefited from a 75% reduction in its monthly electricity bill. Figure 1 below shows a comparison of Pre Covid-19 vs. Post Covid-19 consumption for IICA, where 15.7 MWh was consumed from GPL's grid during the period from January to September 2019, and 3.9 MWh from January to September 2022.

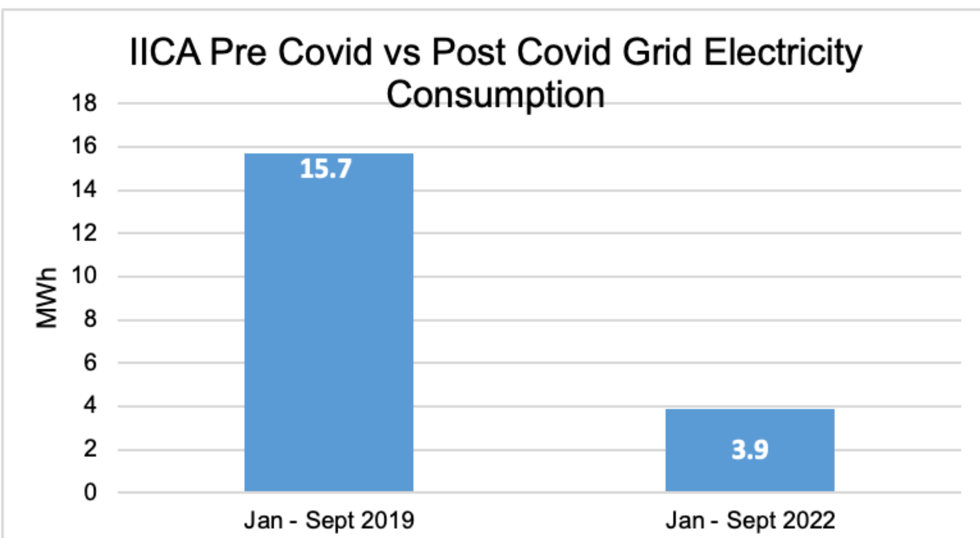

Figure 1: Comparison of IICA's Energy Consumption (2019 vs. 2022)

N.B: data from 2019 and 2022 data were used for the comparisons because occupancy of IICA's office was low during the Covid-19 Pandemic. However, all staff returned to the office in January 2022.

The reduction of electricity consumption from the grid, coupled with the use of the solar PV system, equates to savings of GY$664,381.92 for IICA and 7.79tCO_2 emissions reduction. See Table 1 for further details.

Table 1: Energy and Carbon Dioxide Savings for IICA

Grid Electricity Savings Savings	11784 kWh
	11.784 MWh
Savings Savings	GY$664,381.92
	US$3,163.72
CO_2 Avoidance (t)	7.79

3.3.2 Distributed Energy Resources

Albeit the absence of a feed-in tariff, the number of Distributed Energy Resource (DER) grid-tie systems has been on the increase since 2016 (Figure 2).

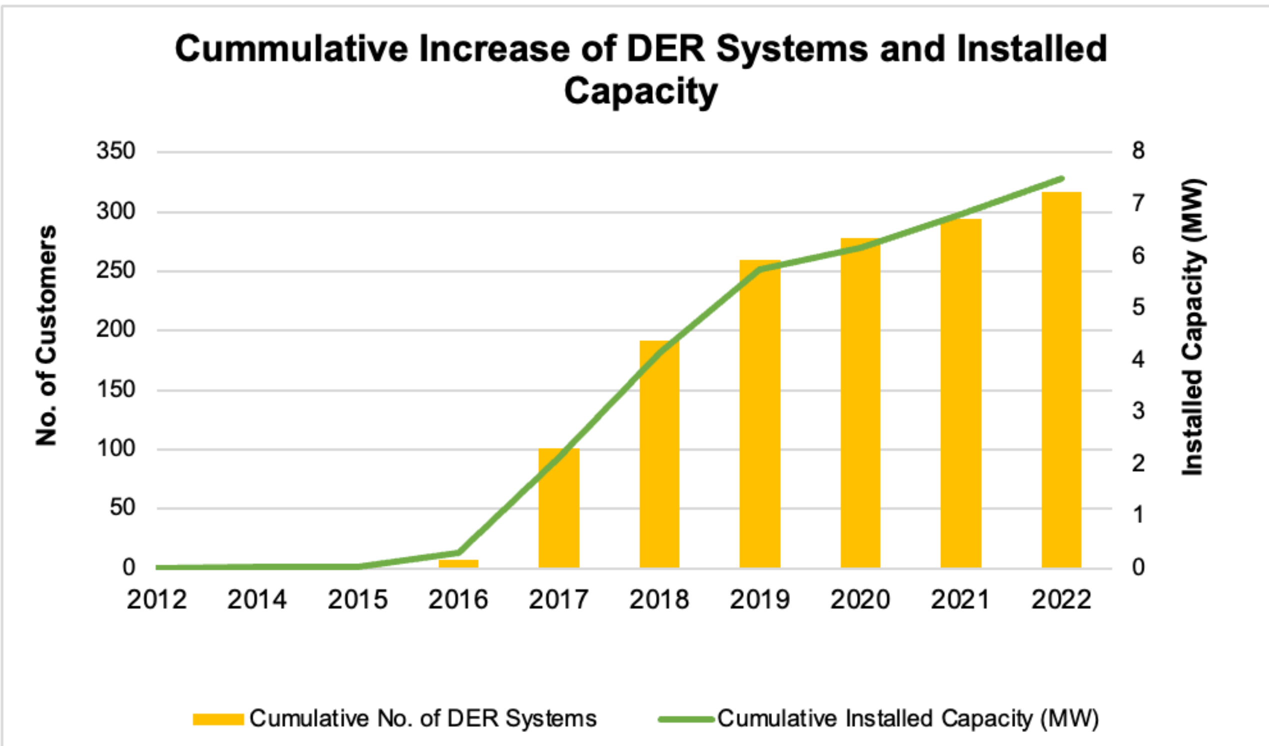

Figure 2: Cumulative Increase of No. of Grid-tie DER Systems

The current total number of DER grid-tie customers, based on applications received and processed by GPL to date, is 317 and the aggregated installed capacity is 7.51 MWac. A breakdown of the number and total installed capacity of DER grid-tie systems are as follows:

1. Government – 222 Systems totalling 4.19 MW
2. Private – 95 Systems totalling 3.32 MW

It is expected that the uptake of DER grid-tie solar PV systems will further increase as their acquisition and installation costs continue to decrease.

3.4 Transmission and Distribution (T&D)

The transmission and distribution systems link the generating plants with customers across GPL coverage at different voltage levels.

The Company's current transmission and distribution networks evolved from a distribution network that commenced over forty years ago and has since been progressively expanding to evacuate power from new power plants and deliver electricity to customers and unserved areas along the coastline of Guyana.

3.4.1 Transmission

The Transmission and Distribution Systems were substantially 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 the Demerara and Berbice power systems. These network improvements positively influenced GPL customers' service reliability, and grid stability and contributed to the Company's technical loss reduction efforts.

Continued investments in T&D maintenance, refurbishment and expansion are in progress to improve service reliability further, meet and exceed customers' expectations and position the Company to move forward in becoming a World-class Utility.

While GPL forges ahead with current investments in T&D, the Company is cognisant that present high customer tariffs coupled with high generation costs currently limit its ability to self-finance critical projects. The financial situation is further exacerbated by commercial/non-technical losses. Notwithstanding the aforementioned, the Company intends to continue to pursue alternative funding sources to maintain its momentum of improving and expanding its power systems and reducing commercial/non-technical losses.

In 2021, the Government of Guyana/GPL commissioned the 2x5 MVAr fixed capacitor banks at Canefield. These capacitor banks would boost transmission voltage levels to be within the permissible steady-state level of +/- 5% of 69 kV and support the economic dispatch of generators to satisfy demand.

In 2022, GPL upgraded the transformer capacity at Edinburgh Substation from 10 MVA to 20 MVA. This upgrade facilitates the substation to dispatch more power to the feeders, thereby satisfying the growing demand and improving the quality and reliability of the electricity service on the West Coast of Demerara.

3.4.2 Distribution

In an effort to improve the reliability of the primary distribution system, GPL installed and commissioned a total of 83 auto reclosers country-wide during 2021-2022. A summary of the country-wide auto recloser deployment is as follows:

1. T&D Area West: a total of 16 units; 6 units on the Vreed-en-Hoop feeders, 7 units on the Edinburgh Feeders, and 3 units on the Anna Regina feeders

2. T&D Area South: a total of 16 units; 7 units on the Golden Grove feeders, 7 units on the Garden of Eden feeders, and 2 on the New Georgetown feeders.
3. T&D Area Central: a total of 10 units; 5 units each on the New Georgetown and Sophia feeders, respectively.
4. T&D Area East: a total of 18 units; 11 units on the Good Hope Feeders, 5 units on the Sophia feeders, and 2 units on the Columbia F3 feeder.
5. T&D Area West Berbice: a total of 4 units on the Columbia F1 feeder.
6. T&D Area East Berbice: a total of 19 units; 13 units on the Canefield feeders, and 6 units on the No.53 feeders.

In addition to the installation of auto reclosers, in 2022 GPL:

1. Improved the distribution of protection relay coordination schemes.
2. Upgraded a total of 25 km of conductors on the primary distribution feeders.
3. Completed and advanced sections of the JICA grant fund for feeder upgrade works:
    a. Good Hope to Enmore E.C.D Express Feeder - 100% completed.
    b. Sophia to Success E.C.D Express Feeder - 100% completed.
    c. Edinburgh to Tuschen E.B.E Express Feeder - 100% completed.
    d. Replaced Single Wire Earth Return Transformers on the West Bank and West Coast of Demerara - 100% completed.
    e. Onverwagt to No.7 W.C.B Express Feeder - 97% completed to date. Project to be completed 100% in early 2023.
    f. No. 7 to Ithaca W.C.B Express Feeder - 9% completed to date. The project is to be 100% completed by mid-2023.

Further, Table 2 shows specific details of T&D planned and achieved works that are directly related to improving feeder reliability and quality of electricity service.

Table 2: T&D Achievements – Year to date 2022

TARGET INDICATORS		**TOTAL OVERALL (2022) AMOUNT**		
Activities	**Units**	**Plan**	**Ach**	**% Ach**
Retention Conductor	MV	162.5	483.872	298%
	LV	207.285	538.3097	260%
Prepare & Erect Pole (Wallaba)	9m	1620	1216.13	75%
	11m	121	24	20%
	12m	512	409	80%
	14m	602	464	77%

TARGET INDICATORS		TOTAL OVERALL (2022)		
		AMOUNT		
Activities	**Units**	**Plan**	**Ach**	**% Ach**
	15m	93	14	15%
Erect Pole (Concrete)	9m	40	14	35%
	11m	0	0	
	12m	18	3	17%
	14m	50	8	16%
	15m	23	7	30%
	17m	0	2	
Construct H-Structure		73	29	40%
Treat Pole	MV	4200	1457.32	35%
	LV	6564	1694.43	26%
Remove Old Pole	MV	1040	998	96%
	LV	1127	1223	109%
Plumb Pole	MV	738	1020	138%
	LV	590	330	56%
Stub Pole	MV	243.16	89.11	37%
	LV	224	75	33%
Shift Pole	MV	43	11	26%
	LV	55	7	13%
Install Auto Recloser		69	0	0%
Install GAB		100	19	19%
Install SPD		162	52	32%
Install RCO		214	203	95%
Install Fuse Holder		197	64	32%
Install Fuse Link		258	162	63%
Install Hot Line Clamp		202	126	62%
Install Bail Clamp		218	73	33%
Install Lightning Arrestor		256	73	29%
Install Planks		144	31	22%
Install Concrete Crossarms		2	10	500%
Install Runners		99	39	39%
Install Sleeper	Bottom	501	71	14%
	Top	660	88	13%
Install Guy – Helical	MV	295	60	20%
	LV	347	79	23%
Install Guy - Guy Block	MV	233	74	32%
	LV	336	76	23%
Install Complete Guy Set		369	330	89%

TARGET INDICATORS		TOTAL OVERALL (2022)		
		AMOUNT		
Activities	**Units**	**Plan**	**Ach**	**% Ach**
Install Overhead Guy Set		42	32	76%
Install Fly Guy		12	11	92%
Install Pole Strut		102	14	14%
Transfer Guy Set	MV	0	2	0%
	LV	0	4	0%
Install Earth Set	MV	309	227	73%
	LV	224	108	48%
Replace Auto Recloser		112	8	7%
Replace GAB		93	37	40%
Replace SPD		82	36	44%
Replace RCO		477	281	59%
Replace PMCO		229	53	23%
Replace Fuse Holder		167	37	22%
Replace Fuse Link		268	524	196%
Replace Lightning Arrestor		185	116	63%
Replace Earths		159	152	96%
Service Jumper	MV	651	1050	161%
	LV	818	972	119%
Replace Jumper	MV	2027	1142	56%
	LV	2177	1380	63%
Replace Conductor Lug		369	387	105%
Replace Insulator	MV	1201	1273.67	106%
	LV	1658	1627	98%
Replace Cross Arm		1128.3	1145.33	102%
Replace Pole Top Pin		258.2	251	97%
Replace Insulator Pin		269.7	224	83%
Replace Cross Arm Brace		558.1	432	77%
Replace Anchor		128	46	36%
Replace Guy – Helical		168	42	25%
Replace Pole Strut		4	1	25%
Replace Conductor	MV	21.612	47.263	219%
	LV	88.5	45.03	51%
	Service	2464.6	2912.96	118%
Upgrade Conductor	MV	202.27	326.052	161%
	LV	141.493	29.206	21%
	Service	3501.7	5161.6	147%

TARGET INDICATORS		TOTAL OVERALL (2022)		
		AMOUNT		
Activities	**Units**	**Plan**	**Ach**	**% Ach**
Upgrade Transformer	Pole-mounted	78	34	44%
	Pad-mounted	96	28	29%
Upgrade Jumper	MV	316	169	53%
	LV	409	176	43%
Install Transformer	Pole-mounted	145	69	48%
	Pad-mounted	82	6.561	8%
Relocate Transformer		17	45.245	266%
Network Extension	MV	125.847	153.9927	122%
	LV	457.962	462.9778	101%
Network Relocation	MV	83.702	57.372	69%
	LV	239.5	172.2221	72%
Crimp/Renew connections on Auto Recloser		58	80	138%
Crimp/Renew connections on GAB		75	46	61%
Crimp/Renew connections on SPD		172	120	70%
Crimp/Renew connections on RCO		280	265	95%
Crimp/Renew connections on Voltage Regulator		18	16	89%
Crimp/Renew Connections on Capacitor Banks		12	7	58%
Service connections on Auto Recloser		85	17	20%
Service connections on GAB		180	105	58%
Service connections on SPD		199	89	45%
Service connections on RCO		376	549	146%
Service connections on Capacitor Bank		25	75	300%
Service Connections on Voltage Regulator		229.5	727.5	317%
Service Connection	Pigtail	5057.5	3164.32	63%
	Pole	3833	2957	77%
Maintain Auto Recloser		331	141	43%
Maintain Transformer		956	896	94%
Maintain Capacitor Bank		31	68	219%
Maintain Voltage Regulator		68	122	179%
Transfer Line Hardware	MV	903	718	80%
	LV	1409	1809	128%
Data Capture (Network Points)		800	1841.3	230%
Phase Switch – Transformers		568	698	123%
Phase Switch – Spur		63	55	87%
Vegetation Management (MV)		0	1	0%

TARGET INDICATORS		TOTAL OVERALL (2022) AMOUNT		
Activities	**Units**	**Plan**	**Ach**	**% Ach**
Heavy Vegetation Pole Spans		81.45	135.82	167%
Light Vegetation Pole Spans		192.63	192.57	100%
Small Trees		69.67	135	194%
Large Trees		68	67.3	99%
Branches/ Limbs		280	390.2	139%
Vines		468	420.4	90%
Vegetation Management (LV)		0	0	0%
Heavy Vegetation Pole Spans		69.18	44.9	65%
Light Vegetation Pole Spans		240.3	146.05	61%
Small Trees		76.45	65.78	86%
Large Trees		19	29.2	154%
Branches/ Limbs		175	240.5	137%
Vines		222	362.55	163%
Remove Pole Top		277	219.48	79%
Site Visit		74	105.27	142%
Overhead Inspection (km)	MV	546.03	662.92	121%
	LV	348.51	217.8759	63%
Pole Inspection (km)	MV	675.39	1315.32	195%
	LV	502.24	521.923	104%
Aerial Inspection (km)	MV	22.9	22.07	96%
	LV	8.3	26.14	315%
Thermal Inspection (km)	MV	14.8	3.54	24%
	LV	8.6	0.3	3%
Night Inspection (km)	MV	285	233.48	82%
	LV	8	1.7	21%
Switching		133	135.5	102%
Transportation of Poles (km)		2174.36	1893.53	87%
C.E.O. F		408	1914.2259	469%

In addition to the above-mentioned achievements, GPL also:

1. Installed and commissioned 13 Automatic Power Factor Correction (APFC) capacitor banks.

2. Replace a total of 5 km of Low Voltage lines directly serving customers.

The following summarises the deployment of the APFC capacitor banks:

1. T&D Area West: a total of 2 units on the Edinburgh F2 feeder.
2. T&D Area South: a total of 2 units on the Golden Grove feeders.
3. T&D Area Central: a total of 2 units on the Sophia F2 feeder.
4. T&D Area East: 1 unit on the Columbia F3 feeder.
5. T&D Area West Berbice: 1 unit on the Onverwagt F2 feeder.
6. T&D Area East Berbice: a total of 4 units; 3 units on the Canefield F3 feeder and 1 unit on the No. 53 F3 feeder.

Referencing the year 2020, the combined benefits of the above-mentioned maintained and improvements work in the distribution system have resulted in an improvement of 25.4% on SAIFI and 20% on SAIDI.

. In an effort to improve further feeder reliability by reinforcing the resilience of feeder structures, GPL commenced installing concrete poles in early 2022. To date, the total number of installed concrete poles is 131 across the GPL coverage area. A breakdown of the poles per length is shown in Table 2 (above).

4. Current Major Developments

Prior to 2019, planning studies were not based on achieving the critical grid reliability targets. As a result, GPL made a Corporate decision to equip its planning engineers with the requisite tools and skillset to develop robust, resilient, and cost-effective expansion plans. These steps, among others, taken at the Corporate level are critical towards GPL achieving its status as a World-Class Utility.

Currently, the Company has the requisite in-house capacity to develop contextual and holistic techno-economic expansion plans by combining the advanced capabilities of Plexos, PSS Sincal/ PSS®E, industry practice and experience.

4.1 Power Generation

Guyana Power and Light Inc. (GPL) is the largest producers of electricity in Guyana and with approximate grid coverage of 97.5 % of the total area of the Coastal Plain. The power system is driven by almost 100% fossil fuel. Notwithstanding this, several options exist to utilize its natural resources to generate electricity in substantial quantities to meet the current and future demands.

GPL recognizes the importance and urgent need for additional firm power generation capacity within the DBIS to ramp up to 412.2 MWs during the life of this Development and Expansion Programme (see Table 26 on page 113113).

The immediate need for new dispatchable generation capacity 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.

The Company also anticipates that the projected electricity demand would rise above the traditional levels as Guyana realizes the anticipated economic benefits of commercial crude oil and gas productions, which commenced in 2020 and the Government's current massive development plans for the residential, commercial, industrial (includes agricultural) sectors.

4.1.1 Natural Gas

The growing Oil and Gas sector has presented an opportunity for natural gas to be a main fuel source for electricity generation in Guyana. Whilst natural gas is not a renewable energy resource, it is a cheaper, cleaner, and indigenous source of energy for electricity generation compared with GPL's current use of liquid fossil fuel. Further, the use of natural gas for electricity generation offers the potential of a lower cost of electricity generation and by extension, reduced electricity tariffs and carbon emissions.

The Company expects to use natural gas to replace liquid fossil fuels as the primary energy resource for electricity generation up to the limit of economic generation dispatch coupled with satisfying other technical grid requirements. The migration towards using natural gas would propel Guyana towards realising its national objective of energy security and reaffirms its position on global Climate Change commitments.

Natural gas consists typically of 70%-90% of methane, and it is considered the cleanest of all fossil fuels because it produces lower emissions of CO_2, NO_x and SO_x and particulate matter than HFO and LFO. Natural gas is well suited to complement intermittent renewable resources such as solar, wind, biomass, and hydropower and as such, it is termed a transitioning fuel towards having higher renewable energy penetrations.

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 without adversely impacting crude oil extraction. 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).

The accumulated amount of flared gas, from December 20th, 2019, to November 7th, 2022, from Liza Destiny and Unity, is equivalent to an annual gross generation of 4,064.68 GWh[5]. Table 3 shows a comparison of the equivalent gross GWh of flared gas and DBIS Annual Gross Generation values.

[5] Based on average efficiency performance of leading CCGTs on the market.

Table 3: Equivalent Gross Generation from Flared Natural Gas vs DBIS Annual Gross Generation

Year	Gross Generation (GWh)	% of GWh from Flared NG vs DBIS Gross Generation
2019	828.7	9% - from Liza Destiny
2020	851.1	238% - from Liza Destiny
2021	905	69% - from Liza Destiny
2022	986.6	129% - from Liza Destiny + Unity
2023 (forecast)	1006.7	83% - from Liza Destiny + Unity

The equivalent annual gross generation from flared natural gas is premised on the assumption of continuous operation of a power plant with typical Combine Cycle Gas Turbines.

The flaring of natural gas threatens the country's global carbon footprint and directly limits forest-based production activities. The Brugman Expansion Study indicated that Liza 1 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_Advisors, 2019).

Several studies have concluded that the natural gas from Liza 1 and other wells can be used to develop a sustainable energy sector to provide secure, reliable, environmentally friendly, and affordable energy services that are especially crucial to poverty reduction and Guyana's alignment with United Nations Sustainable Development Goal (SDG) No. 7.

The Government of Guyana will be engaging an EPC Contractor for the design, supply, construction, start-up, commissioning, and handover of a fully functional and complete 300 MWe Combine Cycle Gas Turbine Power Plant that will form part of an integrated facility shared with an average 50 MMSCFD Gas Conditioning and Natural Gas Liquids (NGL) Fractionation Plant. This integrated facility will be located within the Heavy Industrial Area of the Wales Development Zone.

The Power Plant will have the following main facilities:

1. 300 MWe gas turbine combined cycle power plant comprising multiple gas turbine power generators, waste heat recovery steam generators, and one or more steam turbine power generators that will operate in both simple and combined cycle modes.

   The Combined Cycle Gas Turbines CCGT offers many advantages over Reciprocating Internal Combustion Engines (RICE), including lower emissions, higher combustion efficiency, higher renewable energy penetrations, higher ramping rate, improved grid stability, and more flexible with future fuels, for example, hydrogen. These advantages are well aligned with the Low Carbon Development Strategies (LCDS) and the United Nations Sustainable Development Goals (SDGs) and outweigh the benefits of RICE.

2. A Battery Energy Storage System (BESS) consists of rechargeable batteries that stores energy generated by the combined cycle plant and discharges the stored

energy when one of the gas turbines trips offline. The BESS will have an optimum size.

The primary fuel will be supplied by an onsite Natural Gas Liquefaction (NGL) facility. The NGL facility will be supplied with pipeline-quality natural gas via a 12-inch diameter pipeline, connecting to the Floating Production Storage and Offloading vessels (Liza Phase 1 and 2 FSPO) located in the Atlantic Ocean.

The 193 km miles pipeline for this project is guaranteed to transport 50 mmscfd of wet gas to the NGL facility initially, with the potential to increase to 120 mmscfd.

The NGL facility coupled with its auxiliaries would drop the gas pressure and dehydrate the gas. The NGL facility would also strip the natural gas into various components, of which will be lean gas for the 300 MW GTE Project.

Construction works for the 12-inch, 193 km pipeline is in progress and is expected to be completed by 2024.

The commercial operation dates for the 300 MW GTE Power Plant are phased in accordance with the expected completion timeline of works relative to the Simple Cycle and Combine Cycle. As a result, Phase 1 – Simple Cycle is expected to be commissioned and placed into commercial operation by December 2024 and Phase 1 – Combined Cycle, by December 2025. The project is expected to have an economic lifespan of 25 years from the Commercial Operation Date (COD) – 2049/50.

The tender for the 300 MW GTE and NGL Projects was closed on September 13th, 2022, with five (5) competing bidders (Guyana Chronicle, September, 2022).

Further, the tender for the supervision of the construction of the 300 MW GTE and NGL facility was also closed in September with nine (9) competing firms (Kaieteur News, September, 2022).

4.1.1.1 Possibility of Converting Existing HFO-fired Power Plants to Dual Fuel-fired Plants – DBIS

All Wärtsilä power generating plants can consume natural gas as the primary fuel and HFO or LFO as contingency fuels. To further add value to natural gas, the existing power plants at Garden of Eden Wärtsilä (DP1), Kingston I (DP2), Kingston II (DP3) and Vreed-en-Hoop (DP4) can be converted to consume natural gas as the primary fuel and HFO as the contingency fuel.

The conversion of these power plants would significantly reduce the present operating costs (

Table *4*) and extend the economic operational life by 12 to 15 years for DP1 and DP2 and 20 years for DP3 and DP4.

Table 4: Summary of Benefits - Conversion to Natural Gas of existing HFO-fired Power Plants

Key Parameters	DP1& 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%
Fixed O&M Cost $/kW/yr)	-33.50%	-66.29%	-66.29%	-42.93%
Variable O&M Cost ($/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%
Forced Outage Rate	-49.15%	-3.23%	-3.23%	-18.92%

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

The net output from a converted plant depends on the methane number and charge air receiver temperature (Figure 3). Additionally, the output is limited due to the gas feed pressure and heating value of the gas (Figure 4). As a result, the heat rate and electric power output vary inversely. However, for the engines at DP1 to DP4, the scope of work includes increasing the cylinder bore to match the cylinder jacket for a DF34 Wärtsilä Engine, resulting in recuperating the nominal output from each generator unit.

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 *4***Error! Reference source not found.**).

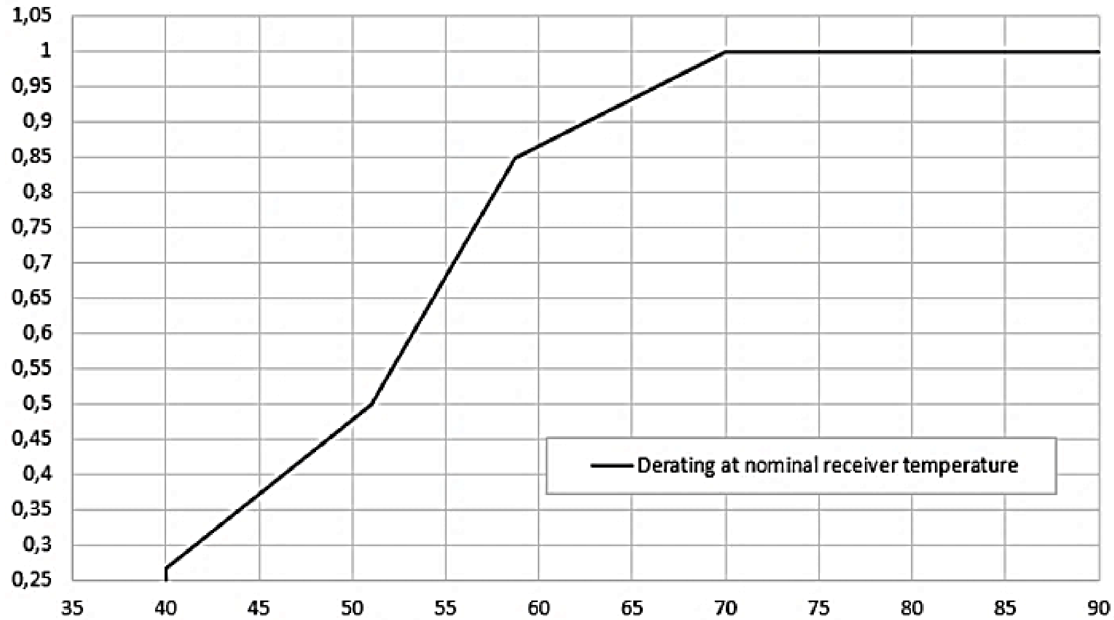

Figure 3: Output limitations due to methane number and charge air receiver temperature (source: Wärtsilä Power Plant Gas Conversions: SG and DF Concept)

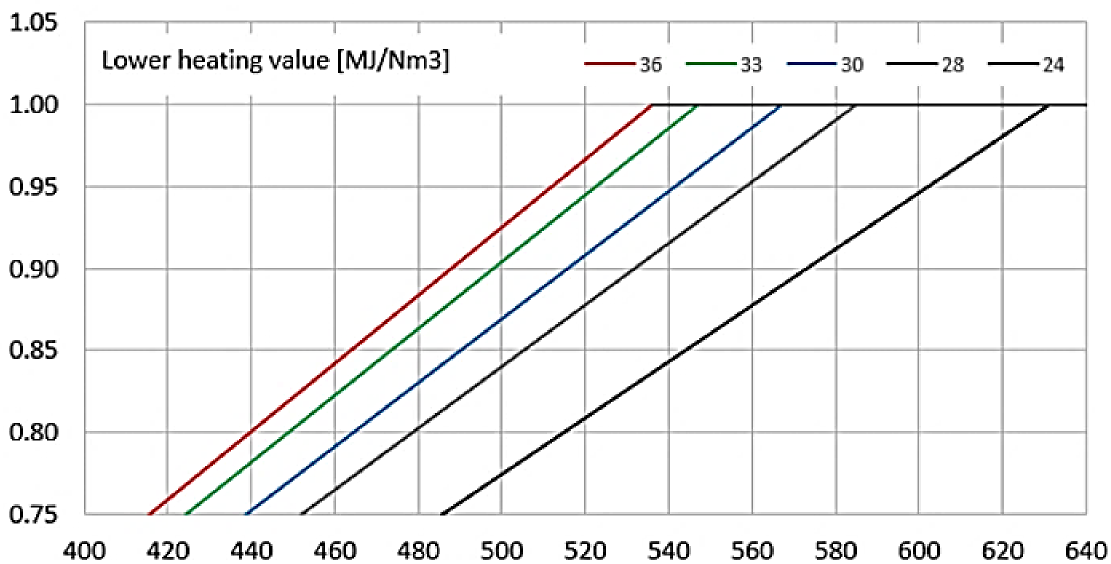

Figure 4: Output limitations for gas feed pressure and LHV, 480/500kW per cylinder (source: Wärtsilä 34DF Product Guide)

4.1.2 Renewable Energy

4.1.2.1 Solar

The abundance of renewable energy from solar appears as an attractive source of electricity generation that would have a mitigating effect on imported fossil fuel, generation cost volatility and reduce carbon emissions. However, the intermittent nature of this resource concomitant with significantly high levels of penetration would present considerable technical challenges to the stability of the grid at this infant stage.

Albeit renewable energy is globally attractive, electricity generation from wind and solar energy systems will only displace a well-balanced techno-economic percentage of firm and dispatchable fossil fuel-fired power generation capacity. Given the Company's current power system, it plans to incrementally introduce and integrate intermittent renewable energy systems prudently to ensure electricity service delivery, system stability, grid security and power quality are not adversely affected.

A. Solar – GUYSOL Project

In view of the above-mentioned, GPL is currently engaged in the implementation of a total of 33 MWp of Solar PV capacity, through the GUYSOL Project. Besides the total 10MWp of Solar PV capacity to be installed in Berbice, this project also intends to deliver 8MWp of Solar PV capacity and 12 MWh Battery Energy Storage Systems (BESS) in Anna Regina, and 15MWp of Solar PV capacity and 15 MWh BESS in Linden by December 2024 through non-reimbursable investment financing of up US$83.3 million.

In addition to the Government of Guyana/GPL's commitment to renewable energy developments, the GUYSOL Project will assist in reducing Guyana's carbon footprint, lowering generation costs, and providing a supporting base for increasing the grid penetration levels of intermittent renewable energy resources.

B. Solar – Wakenaam UAE Grant Funded Project

The Solar PV plus BESS – Diesel hybrid energy system in Wakenaam is a UAE grant fund project geared towards decarbonising the Wakenaam power system, as well as reducing its cost of electricity generation and fossil fuel dependency

The Solar PV plus BESS – Diesel hybrid energy system in Wakenaam will allow GPL to be in alignment with the carbon-emission reduction requirements of the Low Carbon Development Strategy – 2030.

The Project is currently being executed and it is expected to enter commercial operation by the end of Q2 of 2023.

C. Solar – Bartica IaDB Funded Project

In 2020, the Government of Guyana/GEA commenced construction works for the 1.5 MW Solar PV farm with the BESS project. This project is funded through a loan from the IaDB, and it is expected to be in commercial operation in early 2023.

D. Net Billing Programme (Feed-in Tariff)

The Company continues with efforts to ensure its alignment with LCDS-2030, other National Energy Priorities and the relevant Sustainable Development Goals – such as Goal No.7.

Although the cost to install Solar PV systems has declined over the past years, and it is expected to further decline in the future, GPL recognises that many customers cannot afford the present and near future installation cost of solar PV systems. As such, to address this gap and to ensure the Company's alignment with LCDS-2030, other National Energy Priorities and the relevant Sustainable Development Goals – such as Goal No.7, the Government of Guyana/GPL is currently developing a Net Billing Programme (NBP) that will utilise a Feed-in Tariff (FIT). See Section 13 on page 134134 for further details.

To increase the contribution of renewable energy in the energy supply mix;

1. To provide Grid-tie Customers with a framework for renewable energy investments; and
2. To facilitate energy sector investments while ensuring transparency, safety, sustainability, continuity, and reliability of the electricity supply

A Feed-in Tariff (FIT)[6] can be considered a significant revenue stream for present and future grid-tie customers. As a result, credits for electricity export combined with the avoided cost for the self-supply should provide customers with an adequate return on investment and promote the development of distributed renewable energy system resources.

In view of the prospects of the NBP, GPL is cognisant of the technical constraints of the present distribution systems. The current systems are designed and operated in the classical regimen – electricity flows in one direction, from the substation to customer interconnection points on the feeders/circuits.

To date, the aggregated number of prosumers has not resulted in the power system experiencing reverse power flow at the substations or any negative impacts on the total installed capacity. See section 3.3.2 on page 5050 for further details on the current installed capacity of Distributed Energy Resources (DER).

Notwithstanding the current operating state, the expected growth of DER capacity due to the NBP will increase the aggregated intermittent electricity capacity injected into the grid. The aggregated increase will offset the local demand for primary distribution feeders during solar hours, resulting in reverse power flow. Significant reverse power flow can result in operational issues for the existing power systems unless properly re-designed and modernised to operate stably for such reverse power flow conditions.

The current Development and Expansion Programme includes projects to address these gaps and for the deployment of a phased Smart Grid to assist with integrating intermittent renewable energy into the distribution systems. The D&E projects will undoubtedly allow GPL

[6] The FIT will compensate customers for the energy delivered to the grid considering the avoided cost of production of the energy that would otherwise be necessary to supply the load.

to provide greater value to its customers by supporting their investments in renewable energy systems and their contributions towards Guyana's National Energy Initiatives – LCDS 2030.

4.1.2.2 Hydropower and Biomass

Firm and dispatchable electricity generation from renewable resources such as hydropower and biomass remain attractive alternative energy options. Besides the benefits of these resources being indigenous, their lower unit generation costs make them very attractive for sustainable economic development.

Currently, the unit cost of electricity from biomass is 10 US cents per kWh. The unit cost of electricity from the Amaila Falls Hydroelectric Power Project is not expected to exceed 7.737 US cents per kWh (Guyana Chronicle, November, 2021).

Hydropower

Guyana, the land of many water, has 33 hydropower plants (including storage capacity and run-of-river), totalling 8.5 Gigawatt (GW) of hydropower.

Among the top five potential hydropower sites, Amaila Falls ranks highest in the techno-economic and environmental-social preference indices. As a result, the Amailia Falls is an optimal solution for satisfying Guyana’s projected electricity and peak demands (Norconsult, NORAD, 2016).

This renewable energy project is expected to deliver approximately 41% of the 2030 electricity forecast demand for all GPL power systems plus Linden, 45% for DBIS plus Linden and 47% for DBIS only. The project will aid in further reduction of Guyana’s dependency on imported fossil fuel – heavy and light fuel oils, and a significant decrease in carbon emissions from the electricity sector (GRIF, 2011).

Invariably, the Amailia Falls Hydropower Project is a flagship project of Guyana’s Low Carbon Development Strategy (LCDS). Among the numerous benefits, this project is expected to bring to the electricity sector, GPL customers would benefit from reduced tariffs and significant improvement in power quality, grid stability and reliability.

To maintain Guyana’s Carbon footprint in a steady state and to ensure Guyana’s continuous long-term commitment to mitigating the effects and risks of Climate Change, it is anticipated that the Government will build three hydropower plants over the next 20 years: Amaila Falls in 2030 and an additional 205 MW in 2035 and 150 MW in 2040. The sites for the total additional 355 MW are still to be identified.

Biomass

Presently, there is a 30 MW biomass-fired power generation facility at Skeldon. Over the years, this facility depended on the continuous operation of the Skeldon sugar factory and other sugar factories within its vicinity for feedstock – bagasse. However, between 2016 and 2017, the closure of Skeldon and Rose Hall Sugar Factories adversely affected the continuous availability of bagasse, and by extension, the generation of electricity and the technical operation integrity of the facility – especially the boilers.

As a result of the experience mentioned above, Skeldon Energy Inc. (SEI) realised the need to establish a sugar cane-independent feedstock chain. This led to the investigation of using Napier Grass as an alternative feedstock.

The combined benefits of the Napier Grass and harvesting procedures allow this feedstock to be attractive to SEI since estimates have shown the potential annual production of 6.2 GWh. At harvesting, the Napier Grass would be cut and mulched by the harvester and transported later to Guysuco Dewatering Mill for moisture extraction.

SEI secured approximately 3000 acres of land for the cultivation of Napier Grass. The 207 acres' first phase of cultivation was successful; however, due to the flooding in the East Canje area in 2021, the entire crop was destroyed.

At SEI's generation facility, while the steam turbines are operable, the boilers need major rehabilitation. SEI is currently assessing the boilers and, other critical and integral components of this power generation facility.

4.2 Transmission and Distribution

With the rapid rate of developments within the oil and gas and other significant economic sectors, such as the commercial, industrial and tourism sectors, the Government of Guyana/GPL is cognisant of the dire need for robust and resilient Transmission and Distribution Systems. As a result, this Development and Expansion Programme contains several upgrade and expansion projects for the Transmission and Distribution Systems across Guyana.

4.2.1 Transmission and Sub-transmission

4.2.1.1 System Voltage Levels

As mentioned in sections 4.1.2.2 and 14 on pages 6565 and 135135 respectively, a higher transmission voltage level to transfer the larger block of power efficiently with larger power generation facilities located at a considerable distance from load centres will be required, especially when the sources are located at a considerable distance from load centres. As a result, the 300 MW GTE and Amailia Falls Hydroelectric Projects justify the need for the 230 kV transmission voltage.

Further, it is intended for Guyana to be integrated into the Arco Norte (Guyana, Suriname, Brazil and French Guiana) Project via 230 kV transmission lines. As such, the current 230 kV transmission plans are in perfect alignment for future power generation expansions and cross-border interconnections.

With the 230 kV introduced into the DBIS, the current 69 kV will invariably be classified as a sub-transmission voltage level.

4.2.1.2 System Configuration

Besides the plan to utilise 230 kV to transfer larger blocks of power and cross-border interconnections, it is also intended to utilise this voltage level to interconnect critical load centres that are located at extreme ends of the power system's coverage.

In the current expansion programme, the architecture of the grid will transform the larger blocks of power from the 230 kV level to the 69 kV level. At the 69 kV level, power would be distributed among a group of load centres. The load centres forming a group will be selected smartly to optimize voltage and technical losses.

Technically, while such a configuration at the sub-transmission level is to mitigate widespread outages, there will be 69 kV lines installed to interconnect these substations to address contingent events automatically at the sub-transmission level via Smart Grid.

4.2.1.3 Expanding with Resilience Mitigation Measures

In an effort to build resilience into the transmission and sub-transmission systems, GPL intends to standardise critical construction attributes of the 230 kV and 69 kV lines as follows:

1. 230 kV Transmission Lines – lattice steel structures supported by a reinforced concrete base, buttressed by drilled concrete pier.
2. 69 kV Sub-transmission lines – tubular steel poles supported by a reinforced concrete base, buttressed by either a drilled concrete pier or a driven pile.

4.2.1.4 Improving System Performance - Conductor Type

Concerning conductor type, AAAC and ACSR conductors have been serving GPL for well over 52 years. In view of the Company's experience with these conductor types and the need to ensure the critical transmission and sub-transmission lines are well reinforced while optimising on life cycle cost, the position has been taken to utilise ACCC conductor type.

While AAAC and ACSR are more competitive to ACCC on the initial capital cost, this does not transcend to the life cycle cost of projects having the latter conductor type. Below is a high-level summary of the benefits of using ACCC conductors:

1. **Shape of Strand and Aluminium Area:** the trapezoidal shape of each strand of the ACCC conductor results in a more compact conductor than ACSR and AAAC where the strands are circular in shape. As a result, the total area of aluminium in the ACCC is greater than in the ACSR and AAAC. Such attributes of the ACCC give rise to lower unit resistance per length and cross-sectional area compared to ACSR and AAAC conductors and by extension lower technical losses.

   With lower technical losses, this translates to savings on the supply side from the perspectives of fuel and reducing carbon footprint.

   Additionally, the compact trapezoidal shape of each strand does not allow for the accumulation of foreign materials that will adversely affect the conductor's properties of absorptivity and emissivity. As such, the design ampacity of the conductor is readily available for power dispatch.

2. **Rated Strength:** The ACCC has a carbon composite core while the ACSR and AAAC, have steel and aluminium, respectively. As a result of the structural composition of the conductor strands and the core, the ACCC has higher rated strength than ACSR and AAAC. With such a competing characteristic, using the ACCC conductor would result in lines lesser sag and mitigate the adverse impacts of loading due to wind gusts.

3. **Thermal Loading:** The combined characteristic benefits of the Aluminium Area and Rated Strength result in the ACCC conductor being able to operate at a maximum of 200 deg. C for approximately a total of 10,000 hrs over its lifetime with the minimum impact of the line sag.

Within the family of ACCC conductor types, there are several sizes, and each is assigned a code name. In the current expansion programme, the selection of the appropriate conductor size is premised on the results of a techno-economic assessment of the various sizes over the expected life of a transmission line – a minimum of 30 years.

4.2.1.5 Major Transmission and Sub-Transmission Projects

The 300 MW GTE Project will be integrated into the DBIS via 230 kV and 69 kV lines. Below is a summary of the power evacuation plans for the 300 MW GTE Project:

B. New Transmission Lines and Line Upgrades

1. 24.79 km of Double circuit 230kV Transmission Line 300 MW GTE Project Site to Goedverwagting Substation

2. 0.58 km of Three single-circuit 69kV transmission lines from the 300 MW GTE Project Site to Wales Industrial Substation, located close to the 300 MW GTE Project Site.

3. 9.14 km of Double circuit 69kV transmission line from Wales Industrial Substation to Wales Commercial / Residential Substation

4. 17.54 km of 69 kV transmission line from Wales Residential/ Commercial Substation to Vreed en Hoop Substation (East route)

5. 21.88 km of 69 kV transmission line from Wales Residential/ Commercial Substation to Vreed en Hoop Substation (West route)

6. Total of 33.9 km of Upgrade to the existing 69kV transmission line from Golden Grove Substation to Sophia Substation

C. New Substations and Expansions

1. 2x300 MVA 230/69 kV and 2x60 MVA 69/13.8 kV Substation at Goedverwagting for major integration into the DBIS.

2. 69kV Wales Industrial Substation located at 300 MW GTE Project Site ending at 13.8kV take-off structure.
3. 3x35 MVA 69/13.8 kV Wales Residential/ Commercial Substation.
4. Bay expansion at Vreed en Hoop for partial integration of the 300 MW GTE Project into the Western Section of the DBIS at 69 kV.

D. Sub-transmission Reinforcement

With financial support from a multilateral, GPL plans to install a total of 55 MVAr fixed detuned capacity banks across the DBIS. The earmarked interconnection sites and capacity are as follows:

1. New Sophia Switching Substation – 15 MVAr
2. Edinburgh Substation – 10 MVAr
3. Columbia Substation – 15 MVAr
4. No. 53 Substation – 15 MVAr

With the above-mentioned capacitor banks installed in the DBIS, GPL would have the technical capacity to dispatch the available power generation capacity economically to satisfy demand, without having to dispatch generators to the correct voltage level in the grid. Additionally, these capacitor banks will assist in improving the grid power factor, reducing technical losses, and mitigating steady-state voltage instability.

4.2.2 Distribution System

The distribution system is planned contextually to address the current network deficiencies and to satisfy the growing requirements of the industrial, commercial, and residential customers across Guyana, in support of delivering reliable and quality electricity service to customers with the objective to bolster Guyana's economic and socio-economic development plans.

The new substation listed in section 4.2.1.5 on page 6868 will be equipped with feeders to deliver electricity to customers to satisfy the planning targets and to set the foundation for the Smart grid at the distribution system. The number of planned feeders for these new substations is as follows:

1. **Goedverwagting Substation** – 6 feeders and 2 spares; to drive the increasing industrial, commercial, and residential developments along the corridor of East Bank Demerara, providing relief to and redundancy to the New Georgetown and Golden Grove Substations.
2. **Wales Industrial** – 6 feeders and 2 spares; to serve the planned industrial development within the Wales Development Zone and provide relief to and redundancy to the planned Wales Residential/Commercial substation, in preparation for planned economic activities.

3. **Wales Residential/Commercial** – 12 feeders and 3 spares; to serve the planned residential, commercial, administrative, and mixed areas of the Wales Development Zone, and provide relief to and redundancy to the existing Vreed-en-Hoop substation and planned Wales Industrial Substation, in preparation for planned economic activities.

Further, this Development and Expansion Programme includes projects that will result in the upgrade of 13 feeders totalling 489 km of primary distribution lines and the construction of a total of 12 priority feeders for existing substations between 2023-2027.

The upgrades are planned for the substations located at Golden Grove, Mandela Avenue, Good Hope, Edinburgh, Canefield, Garden of Eden, Anna Regina – Supernaam, and No.53.

The new feeders are for the substations located at Columbia, Good Hope, No. 53, Vreed-en-Hoop, Kingston, Garden of Eden, Edinburgh and Canefield. Additionally, the feeders will be reinforced with auto reclosers and automatic power factor correction capacitor banks.

The planned upgrade and feeder reinforcement works would result in further improvements in reliability and power quality for customers within all T&D Areas.

In addition to addressing the increased load demand, the distribution system upgrade and expansion plans contained in this Development and Expansion Programme are also geared to addressing the technical requirements of a Smart Grid to deliver operational features such as network self-healing and improved power quality.

As defined by the IEEE, "self-healing is the capacity of the network to restore automatically the network when an outage occurs". This smart feature will be supported by the combined operational outputs of smart meters and intelligent electronic devices that would be deployed on the feeders.

In light of power quality improvements, the distribution system's current Development and Expansion Programme includes the distribution system being equipped with additional auto reclosers, automatic power factor correction capacitor banks and voltage regulators. As per the long-term expansion plan, these devices are planned to be integrated seamlessly into Phase 2 of the Guyana National Control Centre/Smart Grid Project (see section 4.3 for more details on Smart Grid).

4.3 Guyana National Control Centre/Smart Grid

As stated in section 2.1 on page 4141, besides the lack of sufficient generation capacity, it has been a challenge for GPL to dispatch six (6) HFO-fired power plants and maintain the required spinning reserve. In an effort to mitigate frequency excursions, besides the application of primary response (machine inertia and governor), the secondary response is also required from the generators should there be a need to further address the contingency event. The Operation Code of the National Grid Code requires for Secondary Response to be triggered within 30 seconds from the commencement time of a frequency excursion. Presently, there is no automatic control system in place to provide such a timely response.

While the operators at the Control Centre monitor the power system's frequency, they are unable to react at the required speed and simultaneously ascertain the generator unit(s) that need(s) to provide the secondary response and the magnitude of said response. The situation is further exacerbated by the current method of communication between the operators at the Control Centre and the power plants - radio communication. As a result, frequency excursions that stem from an N-G-1 or N-1 usually resulted in cascaded system shutdowns.

In view of the above, GPL has recognised the importance of timely secondary responses to attenuate frequency excursions, especially for a well-run utility in a modern economy. With Guyana moving into a new economic era, the current system control modus operandi, communication mechanism, and performance of the electric power system cannot sustain the present and future planned developments as outlined in the Low Carbon Development Strategy (LCDS) – 2030 and other National Energy Priorities.

It has also been a challenge for GPL to take absolute control of the transmission and distribution reliability indices, SAIDI and SAIFI. The situation would certainly exacerbate as the transmission and distribution coverage expands to support economic growth.

In the event of a fault on a transmission line that is currently not connected to SCADA, it takes a longer time for the operator at the Control Centre to ascertain the nature of the fault and to advise the T&D personnel on responding and restoring the line to service. Given the length and the total number of primary and secondary distribution feeders, diagnosing a fault can be challenging. The T&D personnel are required to patrol the lines manually to search for the fault evidence and perform the necessary repairs. These field exercises take time and, as a result, have direct adverse impacts on SAIDI.

Transmission and Distribution reliability have a direct and adverse impact on power demand and the public image of the power utility company. Additionally, reliability issues coupled with power quality resulted in having an approximate total installed capacity of about 100 MW of self-generators.

As the power systems continue to expand, continuous data analysis will certainly become a critical cornerstone for grid operation efficiency and aligning the electricity sector with LCDS-2030 and other National Energy Priorities.

In view of the forecasted electricity and peak demands for the DBIS, coupled with the expansion plans to address these demands, a modern and properly equipped Control Centre is certainly required to supervise and manage the power grid.

The Government of Guyana/GPL plans to construct a new Control Centre on the East Bank of Demerara – Guyana National Control Centre. The new Guyana National Control Centre/Smart Grid (GNCC/SG) comprises two (2) control centres:

1. Guyana Transmission & Generation Control Centre (GTGCC); and
2. Guyana Distribution Control Centre (GDCC).

The architecture of the GNCC/SG includes a modern state-of-the-art SCADA as the intelligence core of the power system that would have extended capabilities to integrate a host of devices across Generation, Transmission and Distribution. See Figure 5 for more information.

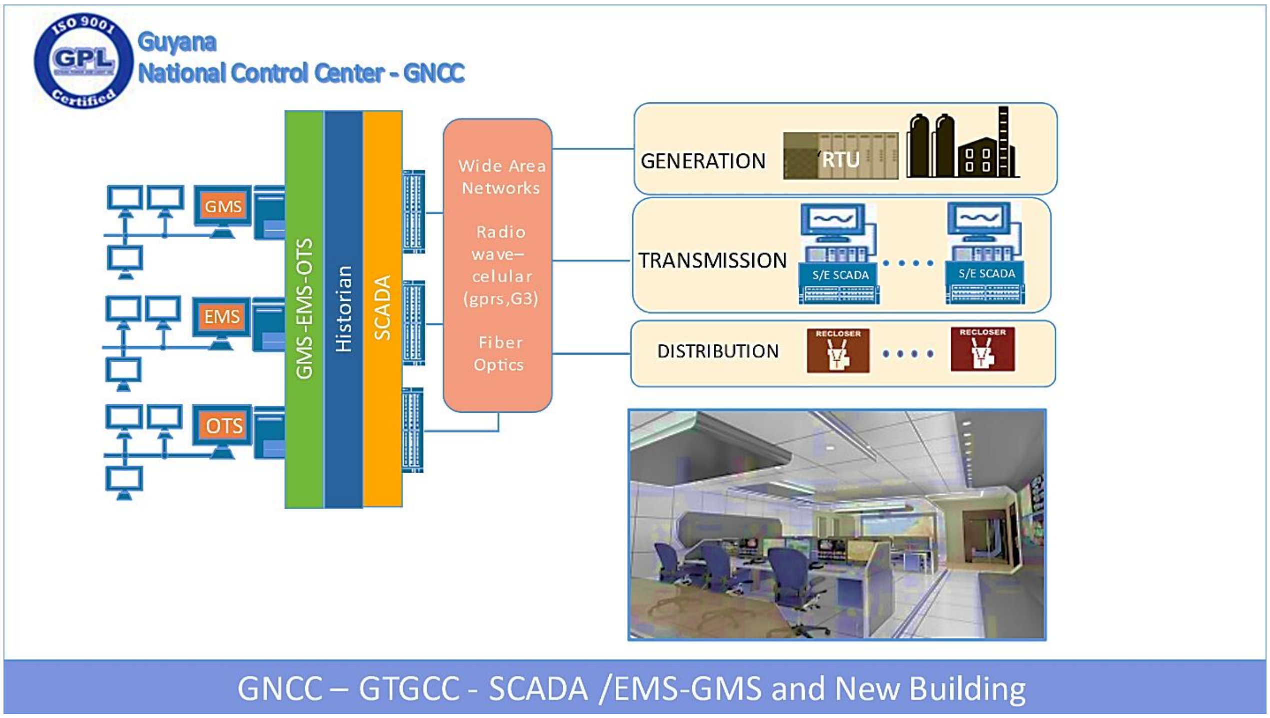

Figure 5: GNCC Real-Time Monitoring and Control Overview

The construction of the GNCC/SG will be executed in two (2) phases:

1. Phase 1 – Guyana Transmission and Generation Control Centre (GTGCC). Phase 1 must be completed and commissioned before December 2024 to efficiently manage and dispatch power from the 300-Megawatt Gas-fired Power Plant load centres served by the Demerara Berbice Interconnected System (DBIS).
2. Phase 2 – Guyana Distribution Control Centre (GDCC). The completion of this phase, between 2025 to 2034, will realize the full implementation of SCADA in the DBIS and Isolated Power Systems – at the Distribution levels, Automated Metering Infrastructure (AMI) and T and D Network Supervision and Automation – Smart Grid.

The completion of Phase 1 – GNCC/SG is a prerequisite for the successful integration and efficient dispatch of the 300MW Gas-fired Power Plant into the DBIS. Additionally, Phase 1 will allow GPL to supervise and control the new 230 kV transmission system and the existing and expanded 69 kV sub-transmission systems.

The scope of works relative to Phase 1 - GNCC/Smart Grid are:

1. Supply and Installation of a SCADA system to support the specified EMS-GMS[7] required for the GTGCC and sized to later integrate seamlessly the OMS-DMS functionalities.
2. Integration of the existing transmission substations currently monitored by the SCADA in the New Sophia station with the GTGCC
3. Gateway configuration and integration of 6 generating plants.
4. RTU installation and commissioning in transmission substations that currently do not have remote supervision and control.

In addition to the modern SCADA and the different management systems, the critical components in forming the Smart Grid include AMI meters, Auto-Reclosers, Sectionalizes, Scada-mate switching systems, Fault Current Indicators (FCI) and Smart Inverters – allowing for Distributed Energy Resources. See Figure 6 below.

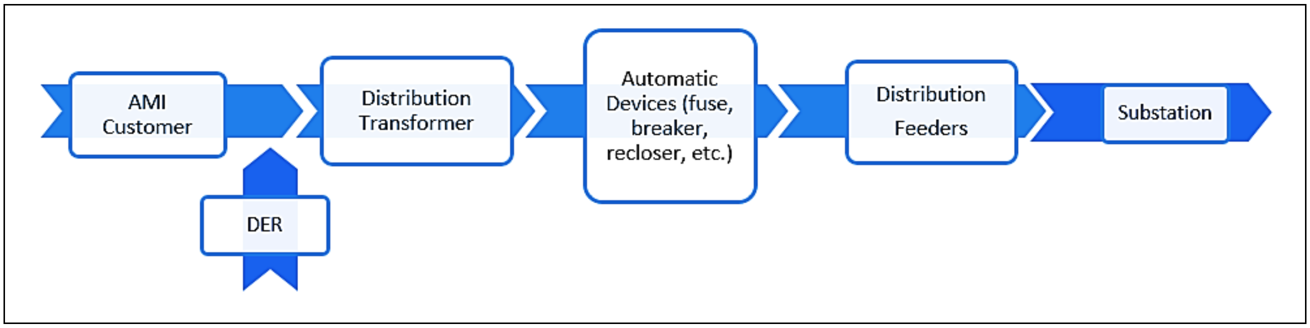

Figure 6: Proposed Smart Grid Architecture

To further improve the intelligence and self-healing capabilities of the Smart Grid, all Capacitor Banks, Voltage Regulators and Electric Vehicles (future application) would be integrated into SCADA.

The application of a Smart Grid essentially means that all control, communication and switching mechanisms within DBIS would be automated, controlled (locally and remotely) and supervised by a modern SCADA.

The Smart Grid would support the Government plans for economic and socio-economic developments and its Climate Change Commitments on a national level. This will be achieved by utilizing the Smart Grid to optimise the power system in real-time, for example, through generator economic dispatch, transmission, and distribution load management.

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[7] GMS includes Automatic Generation Control (AGC)

From a control perspective, the Smart Grid will provide the grid with fast response capability to mitigate variations of grid operation parameters emanating from grid-connected intermittent renewable energy resources. As a result, the Smart Grid will allow for increasing renewable energy penetration and for Integrated Utility Service (IUS) to play an integral role in improving power system efficiency, reliability, and demand-side management.

Given that the GNCC/SG is all-inclusive, this Development and Expansion Programme seeks to ensure there are no weak links in the proposed projects that will eventually and severely limit the advantages and expected benefits to be derived from the total capital project investment.

4.4 System Losses

The progressive and sustained reduction in System Losses remains a corporate priority. In light of the 8% growth in electricity demand from 2021 to 2022, total losses reduced from 26.47% in 2021 to 25.2% in 2022. The projected total 5-year system losses is 20.9% in 2027.

Further reductions in system losses, especially non-technical/commercial losses, will improve the Company's revenue stream and reduce its operating costs. This will positively impact the Company's financial strength and efforts to lower tariffs for the benefit of all consumers.

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

1. Unmetered supplies,
2. Defective meters,
3. Street lighting and
4. Electricity theft.

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

1. Aged and long feeders (medium and low voltage),
2. Heavy-loaded feeders (medium and low voltage),
3. transformers with high losses and
4. poor power factor.

The planned total loss reduction from 24.16 % in 2022 to 20.9 % in 2027 is projected from investments in the construction of new feeders, feeder re-conductor, transformer right-sizing, meter replacements, Installation of Advanced Meter Infrastructure (AMI), installation of energy-efficient streetlamps, 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 seek to progressively lower the electricity tariffs, in accordance with its licence mandates.

4.5 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. During the year 2021, the fifteen (15%) fuel rebates were removed and concurrently the headline tariffs were reduced by the same amount thus concretising the reduction in rates.

Despite increases in world market fuel prices by approximately seventy seven percent (77%) in ensuing years (2017 – 2021), 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 These factors have a major influence on GPL's ability to lower Tariffs from the current level of approximately US 22 cents per kWh. A review of the projected financial performance for the period to Year 2027 highlights the following:

i) Growth in Sales Demand

    The significant growth in demand (increase of approximately 140%) 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 50% reduction in tariffs from the beginning of year 2025.

ii) Losses (Technical and Commercial losses)

    Losses are projected to decline from 25.2% to 20.9%. 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.

v) Cost of Generation

By year 2025, generation using natural gas supplied by way of the planned gas pipeline is projected to provide more than 80% of the required generation. The price at which the electricity is sold to GPL is therefore extremely important and will have the most impact on the ability of the company to lower tariffs by 2025. These projections assume a rate of US five (5) cents per kWh at which GPL will purchase the electricity from the Independent Power Producer.

vi) GPL's Debt Burden

The projections indicate that by the end of 2027, GPL's Related Parties Non-Current Liabilities consisting mainly of loans from the Government of Guyana would increase from G$63 billion to more than G$365 billion. This will require approximately G$26 billion in annual debt service obligations.

GPL has negotiated with the Ministry of Finance, the extension of the moratorium on servicing the majority of the current outstanding debt until the year 2026. Discussions are ongoing to extend this moratorium to all of the remaining debt.

Converting this debt to equity, would strengthen GPL's financial position and better position the company to continue to reduce tariffs while at the same time improve its capacity to deliver a stable and high-quality electricity supply to the Nation.

Table 5.

These factors have a major influence on GPL's ability to lower Tariffs from the current level of approximately US 22 cents per kWh. A review of the projected financial performance for the period to Year 2027 highlights the following:

iii) Growth in Sales Demand

The significant growth in demand (increase of approximately 140%) 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 50% reduction in tariffs from the beginning of year 2025.

iv) Losses (Technical and Commercial losses)

Losses are projected to decline from 25.2% to 20.9%. 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.

vii) Cost of Generation

By year 2025, generation using natural gas supplied by way of the planned gas pipeline is projected to provide more than 80% of the required generation. The price at which the electricity is sold to GPL is therefore extremely important and will have the most impact on the ability of the company to lower tariffs by 2025. These projections assume a rate of US five (5) cents per kWh at which GPL will purchase the electricity from the Independent Power Producer.

viii)GPL's Debt Burden

The projections indicate that by the end of 2027, GPL's Related Parties Non-Current Liabilities consisting mainly of loans from the Government of Guyana would increase from G$63 billion to more than G$365 billion. This will require approximately G$26 billion in annual debt service obligations.

GPL has negotiated with the Ministry of Finance, the extension of the moratorium on servicing the majority of the current outstanding debt until the year 2026. Discussions are ongoing to extend this moratorium to all of the remaining debt.

Converting this debt to equity, would strengthen GPL's financial position and better position the company to continue to reduce tariffs while at the same time improve its capacity to deliver a stable and high-quality electricity supply to the Nation.

Table 5: Financial Projections – Facilitating Tariff Reduction

	Yr 2022	Yr 2023	Yr 2024	Yr 2025	Yr 2026	Yr 2027
Net Tariffs	**G$/kWh**					
Residential	43.00	43.00	43.00	21.50	21.50	21.50
Commercial	59.00	59.00	59.00	29.50	29.50	29.50
Industrial	52.00	52.00	52.00	26.00	26.00	26.00
	Yr 2022	**Yr 2023**	**Yr 2024**	**Yr 2025**	**Yr 2026**	**Yr 2027**
	GWh					
Generation	1,093	1,240	1,406	1,871	2,179	2,472
Demand	817	942	1,082	1,452	1,709	1,957
Technical & Commercial Losses	275	298	324	418	470	516
Technical & Commercial Losses %	25.2%	24.1%	23.1%	22.4%	21.6%	20.9%
	Yr 2022	**Yr 2023**	**Yr 2024**	**Yr 2025**	**Yr 2026**	**Yr 2027**
Fuel Prices	**US$/barrel**					
HFO	107.18	90.63	85.00	85.00	85.00	85.00
LFO	154.78	150.00	140.00	140.00	140.00	140.00
	Yr 2022	**Yr 2023**	**Yr 2024**	**Yr 2025**	**Yr 2026**	**Yr 2027**
PPA Prices	**US cents/kWh**					
300 MW Natural Gas			5	5	5	5
50 MW IPP		12	12	12	12	12

5. Mandates, Planning Criteria, Inputs and Assumptions

The current total number of customers served by GPL is 217,172 and for documented unserved areas, the total amount of potential beneficiaries is 5,341. Referencing the total amount of potential beneficiaries, GPL's electricity service coverage stands at 97.5%.

With the life of this Development and Expansion Programme, the estimated number of additional customers stands at 43,017, totalling 260,189 customers by 2027. As a result, the total amount of potential beneficiaries represents 12.42 % of the aggregated number of new customers by 2027.

This Development and Expansion Programme aims to increase the access to electricity to customers residing on the Coastland and within the remit of GPL.

5.1 Mandates

Guyana Power & Light Inc., through the Engineering Service Division, has the strategic responsibility for planning new supply sources necessary to meet future electricity needs within its defined area of responsibility. The Government of Guyana and GPL remain cognizant that energy is central for jobs, security, climate change, food production, and increasing income. Therefore, access to clean, reliable, cheap, and sustainable energy is central to the socio-economic development of Guyana.

The Company has 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 and to ensure the planning process is kept in alignment with the Low Carbon Development Strategy (LCDS)-2030, other National Energy Priorities and the relevant Sustainable Development Goals – such as Goal No.7, the Engineering Service Division, through GPL, intends to migrate towards an Integrated Resource and Resilience Planning (IRRP).

5.1.1 Reducing the Cost of Electricity

In order to propel its countrywide development plans, the Government of Guyana remains cognisant of the need to reduce the cost of electricity generation. This Development and Expansion Programme contains Government's ambitious strategies to improve the overall competitiveness and diversify the energy mix to reduce the cost of electricity and enhance the reliability and security of its electricity supplies to citizens and businesses.

5.1.2 Improving Network Reliability and Power Quality

The transmission and distribution systems are the essential components that connect the customers to the electricity generation sources. The growing customer base in Guyana comprises a modern multifaceted society that depends on reliable and economic delivery of electricity. Further, reliable transmission and distribution systems are critical to the

Government, GPL, and customers to realise the complete benefits of investing in cheaper, cleaner, and reliable electricity supply. Consequently, GPL must achieve SAIFI, SAIDI and CAIDI values that are on par with those of developed countries.

5.1.3 Technical Loss Reduction

GPL has traditionally focused on non-technical losses in an effort to reduce generation costs and increase revenue. In this Development and Expansion Programme, a specific focus is being placed on technical loss reduction to complement the non-technical loss reduction strategies through enhanced understanding, modelling, and computation of technical losses. In preparation of this Development and Expansion Programme takes into consideration the following:

1. Use modern software to model the Transmission and Distribution Network Loss Profiles.
2. Optimization of Network layouts by incorporating industry practices to address and reduce power loss.
3. Implementation of Reactive Power Compensation where appropriate.
4. Integration of Distributed Energy Resources (DER).

5.2 Planning Criteria

GPL has identified two significant planning constraints to power system development and expansion: reliability and availability of capital investments.

Prior to 2019, the planning criterion that drove the expansion plans was capacity reserve. 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) or Loss of Load Expectation (LOLE) provide more accurate details on the ability of the power generation capacity to satisfy the current and future peak demands.

The LOLP is essentially the probability of the total available generation capacity satisfying the peak demand. Within a year (365 days), the LOLE indicates the number of days the total available generation capacity is expected not to satisfy the peak demand. As a result of a high probability, there would be a corresponding high Expected Energy Not Served (EENS). Additionally, Unserved Served Energy (USE) indicates demand that could not be met due to a shortage in generation and/or transmission capacity due to transmission congestion.

The targeted generation reliability indices vary globally and depend on the country's economic status quo and economic projections. As such, in the USA, Australia and Jamaica, the LOLE is 0.1 day/year, Republic of Ireland and New Zealand, 8 hours/year (0.33 days/year or LOLP = 0.09%), the Netherlands 4 hours/year (0.167 days/year or LOLP = 0.0457%), Barbados 0.8 days/year (LOLP = 0.219%).

The transmission system also has planning targets, and these are detailed in section 2.6 of the Planning Code of the National Grid Code.

5.2.1 Expansion Planning Criteria

GPL seeks to expand and develop its power systems in alignment with the vision of the Low Carbon Development Strategy – 2030 and other National Energy Priorities to improve the quality and reliability of electric service to customers, and to support national developments. Further, in accordance with the Company's Corporate Strategic Plan, GPL aims to be a world-class utility service provider as seen by its SUCCESS in exceeding its stakeholder's expectations.

In view of the above, the Company has defined a set of planning criteria for generation and T&D expansions to ensure there is an adequate balance in the investment allocation of the three systems (Transmission, Generation and Distribution). These planning criteria are:

1. LOLP equal to or less than 0.27% per annum (LOLE equal to or less than 1 day/year);
2. Compliance with section 2.6 of the Planning Code for Transmission Reliability Criteria;
3. Compliance with section 2.7 of the Planning Code for Voltage Regulation Standards;
4. Compliance with section 2.8 of the Planning Code for Voltage Swing Criteria;
5. Compliance with section 2.9 of the Planning Code for Voltage Stability Criteria;
6. Compliance with section 2.10 of the Planning Code for Damping;
7. Compliance with section 2.11 of the Planning Code for Frequency Deviations;
8. Configure primary distribution feeders to achieve a thermal loading and total backbone length by at least 50%, respectively; and
9. Provide backup circuits to mitigate contingencies at the primary distribution level, where applicable and not constrained by the geographic layout of the customer base.

As a result of the above-mentioned planning criteria, the Company has developed a menu of expansion projects specifically geared towards achieving alignment with the Low Carbon Development Strategy – 2030, other National Energy Priorities and improving the operational efficiencies of GPL. See section 12, 15 and 27 on pages 127, 137 and 235 respectively for further details.

5.2.2 Operation Planning Criteria

The annual contingency capacity of the DBIS, which is premised on the forecast peak demand, required spinning reserve and available firm generation capacity, remains critical to ensuring there is adequate firm generation capacity to support grid stability and mitigation of the N-G-1 criterion.

5.2.2.1 Grid Frequency Management

Regarding frequency management for the DBIS and Isolated Systems, there are two spinning reserve requirements: (1) spinning up reserve and (2) spinning down reserve. The following description relating to spinning reserve is relative to the current DBIS. In view of the generation expansion plan, the governing concept/principle is expected to remain, however, tailored to specific generator units under the technical guidance of Automatic Generation Control (AGC).

Installation of AGC is a subcomponent of the Phase 1-GNCC/Smart Grid project. See section 4.3 on page 70 for more details on this project.

Spinning up reserve is an extra generation capacity available by **increasing** the power output of grid-connected generators. This available MW of spinning reserve is used to respond to short-term variations in demand, generator unit forced outages or variations in the output of intermittent renewable energy systems. For Guyana, GPL adopted the rule of thumb by NYISO (NYISO, 2020) and PJM (NREL, 2011), which states that the 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. With the 46.5 MW plant at Garden of Eden commissioned, the required spinning reserve for secondary response is 13.95 MW – ancillary service.

Spinning down reserve is an extra generation capacity available by **decreasing** the power output of grid-connected generators. This available MW of spinning reserve is used to respond to short-term variations in demand, generator unit forced outages or variations in the output of intermittent renewable energy systems.

The spinning down reserve is considered to be half of the spinning up reserve – 6.8 MW.

Under-frequency events result when the aggregated generation capacity is less than the total demand. Such an event can be due to:

1. An N-G-1 event – loss/trip of a generator unit;
2. Energization of a large load; or
3. N-1 on the transmission line(s) that result(s) in the loss of generation MW on the grid.

As per section 4.5.5 of the National Grid Code (page 150) – Reserve Margins, there are three main frequency control/correction mechanisms:

1. **Primary** – automatic response from Generator Unit Governor, fully available within 5 seconds the time of a frequency excursion.
2. **Secondary** – automatic (AGC)/manual response in the adjustment of generation dispatch, fully available within 30 seconds of the time of a frequency excursion. Additionally, automatic load-shedding to mitigate high-frequency excursion events.

3. **Tertiary** – Instruction to synchronize and/or dispatch other generation units as well as Economic Dispatch of Generator unit(s).

With the Vreed-en-Hoop power plant (DP4) operating in Isochronous mode, it acts as the swing/slack bus to correct/normalise power system frequency within 1 second of a frequency deviation from the setpoint value of 60 Hz. As such, DP4 generator units need to be dispatched at such loading value that it can provide the DBIS with the required spinning reserve, while not exceed the required minimum stable loading.

The minimum dispatch of each available generator unit at DP4 is 75% of the generator unit's nominal rating. This loading corresponds to each unit being loaded at 6.525 MW and 2.175 MW is allocated as spinning reserve. The aggregated output from DP4, when all units are available is 19.575 MW, and total spinning reserve at 6.525 MW.

To achieve the total required reserve of 13.95 MW (1.5*9.3 MW), generator units in Speed Droop mode shall be loaded, such that, the balance of 7.425 MW of spinning reserve can be provided. This is achieved with more units in Speed Droop mode, such as from the generator units at DP1, DP2, DP3, DP5, C/field – Hyundai and SEI HFO units.

In the event one or two units are unavailable at DP4, the available unit(s) is/are dispatched at 75%. The balance spinning reserve is obtained from the other units in Speed Droop Mode to achieve the total 13.95 MW spinning reserve.

The permitted Spinning Reserve margin is ±5% of 13.95 MW – Permitted Range: 13.25 MW-14.65 MW.

Only in the event of a worst-case scenario in generation available capacity at DP1, DP2, DP3, DP4 & DP5, the critical minimum total spinning reserve is considered to be 9.3 MW.

5.2.2.2 DBIS Automatic Under Frequency Loadshedding (AUFL) Scheme

The objective of the AUFL scheme is to shed load automatically at various substations subsequent to the exhaustion of the primary response.

Definition of Generator Engine Control Modes:

True kW: engine speed is only used for safety purposes. The generator unit outputs the operator setpoint value and does not actively support system frequency.

Speed Droop: a load-sharing mode when operating generators in parallel. Generator engines in this mode share their load by decreasing their internal speed reference proportionally to an increase in the engine load. Generator unit frequency and loading are related to each other via the droop characteristics. This mode aid in frequency control as described below (see figure 1):

- 3% droop means that for every 1% change in the generator speed reference, its output will change by 33.33%. Also, the generator unit frequency will change by 4% when its loading change from 100% to 0% - no load frequency would be 61.8 Hz.

- 4% droop means that for every 1% change in the generator speed reference, its output will change by 25%. Also, the generator unit frequency will change by 4% when its loading change from 100% to 0% - no load frequency would be 62.4 Hz.
- 5% droop means that for every 1% change in the generator speed reference, its output will change by 20%. Also, the generator unit frequency will change by 5% when its loading change from 100% to 0% - no load frequency would be 63 Hz.

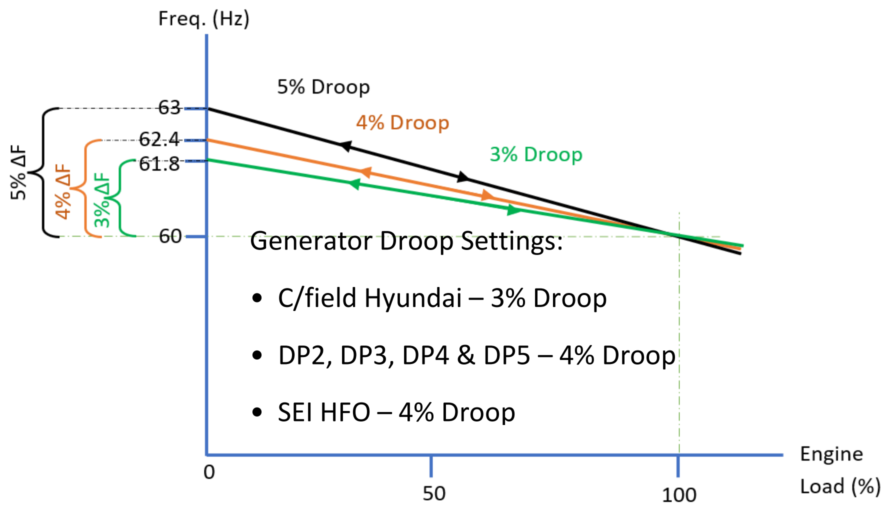

Figure 7: Speed Droop characteristics

Isochronous: a load-sharing mode where the engine speed will be regulated to the speed reference (frequency setpoint – 60 Hz) regardless of the load of the generator units (figure 2). As such, frequency is kept constant and not load-dependent.

As per section 2.11 of the National Grid Code:

- Frequency shall not drop below 57.7 Hz;
- Frequency shall not exceed 63 Hz; and

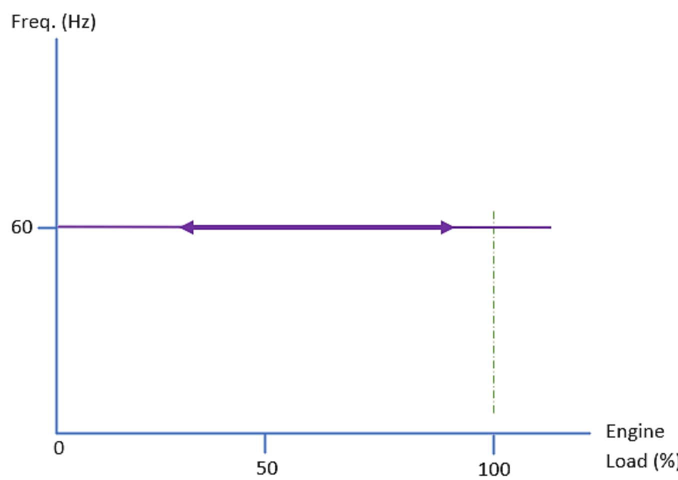

Figure 8: Isochronous characteristic

5.2.2.3 Spinning Reserve with Intermittent Renewables

With grid-connected Solar PV and Wind energy systems, the power systems must be supported with additional spinning reserve capacity to mitigate the effects of output volatility and variability.

Research has indicated the need for an additional reserve capacity equivalent to 30% of installed Solar PV and/or Wind capacities. In the case of both Solar PV and Wind connected to the grid, 30% of installed Wind capacity during the night and the day, 30% of Solar PV and Wind capacities. The additional 30% of installed intermittent renewable energy capacities apply to both spinning up and spinning down reserves.

In the DBIS, the three power plants capable of providing spinning reserve are Kingston II - DP3, Vreed-en Hoop - DP4 and Garden of Eden - DP5. Simulation results have indicated that 27% of DP3 (9.86 MW) and DP4 (7.1 MW) installed capacity, respectively, can be dedicated to providing spinning reserve. The aggregated spinning reserve would be 16.96 MW.

In consideration of the largest Solar PV capacity, the DBIS would have a total of 10 MWp and Linden, 15 MWp. Until Linden is connected to the DBIS in 2026, the additional required spinning reserve for the Solar PV system would be 3 MW by 2024. With Linden connected to the DBIS in 2026, the total additional required spinning reserve would be 7.5 MW.

As a result of the Isolated Systems operating with only a few small diesel generator units, the spinning reserve is provided by the generator unit's technical minimum to maximum capacity – full operating range.

As power generation expansion continues, especially using larger generator units, the required spinning reserve would increase. Additionally, the spinning reserve requirement from conventional generators would increase as the penetration level of intermittent renewable energy in the grid increases.

With Battery Energy Storage Systems (BESS), the dependency on conventional generators to provide spinning reserves will be reduced.

5.2.2.4 Transmission and Distribution

Each transmission line has its own derated capacity rating based on conductor age and frequency of maintenance. These derating influencing factors are modelled via the properties of conductor emissivity and absorptivity. As a result, each single-circuit transmission line is loaded up to 75% of its derated capacity.

For double-circuit transmission lines, each line is loaded to 37.5%, such that, in the event of N-1 contingency, the remaining energised line would be loaded at 75%. However, for such a contingent event, the energised line is permitted to operate up to 100^0C for a total duration of 330 seconds. Such an overload duration constraint is applied to transmission lines with ASCR and AAAC conductors only. In the case of ACCC conductor type, the transmission line is permitted to operate up to 200^0C for an aggregated total hours of 10,000 hrs over its entire service life.

5.3 Electricity Demand Analysis and Forecasts

According to economic theories, access to electricity is a gauge of measuring social and economic development; moreover, energy is one of the most important resources for industrial production, as such forecasting energy consumption is an important phase for macro-planning. Efficient planning of distributing energy, requires accurate forecasts of future demand to make the balance between the supply and demand of energy. Forecasting errors can lead to unbalanced supply-demand, which negatively affect operational cost, network safety, and the service quality of the supply network. Underestimation of energy consumption can lead to power outage, which can be harmful both for economy and the daily life of society. On the other hand, overestimation of energy demand may lead to creating unused capacity that is equal to wasting financial resources.

GPL's Demand Forecasting Unit (DFU) is tasked with the responsibility of processing and informing on the company's 'Electricity Demand Forecasting Framework', where data is inputted from departments across the agency and also from external[8] agents. The Unit's main output forecasts are peak load demand (MW) and electricity (generation) demand (GWh); where electricity demand is influenced by the country's aggregate demand, changes in energy intensity, and shifting input prices, (more in-depth explanation of the methodology and long-term outcomes are presented in Appendix 1.

Historical data, for the period 2011-2021, revealed that GPL power systems (DBIS & Essequibo Isolated Systems) experienced escalating potential-demand for electricity, increasing at an average rate of 4.7 percent or by 38 GWh per annum, moving from 678 GWh in 2011 to 1,065 GWh in 2021; whereas, gross generation or actual electricity supply suffered shortfalls, on average 54 GWh. Nevertheless, the continuous upward trend of gross generation indicates that there have been capacity improvements, which signal enablement of economic development (improved standard-of-living), but not at a fast enough rate.

Linden's historical data exhibited subtle electricity demand growth, for the period 2011-2021, with an average growth rate of 1.8 percent or by 1GWh per annum, moving from 51 GWh in 2011 to 61 GWh in 2021; where gross generation for the latter years, were near to potential-demand, with an average shortfall of less 3 GWh during the period. In 2019, Linden performed relatively well, suppling more than the estimated demand; and in 2021, supply was basically matching demand. Nonetheless, capacity improvements are always necessary to cater for crises, economic boom, and regional population growth spurts.

[8] External information stakeholders include the Bureau of Statistics, Ministry of Finance, etc.

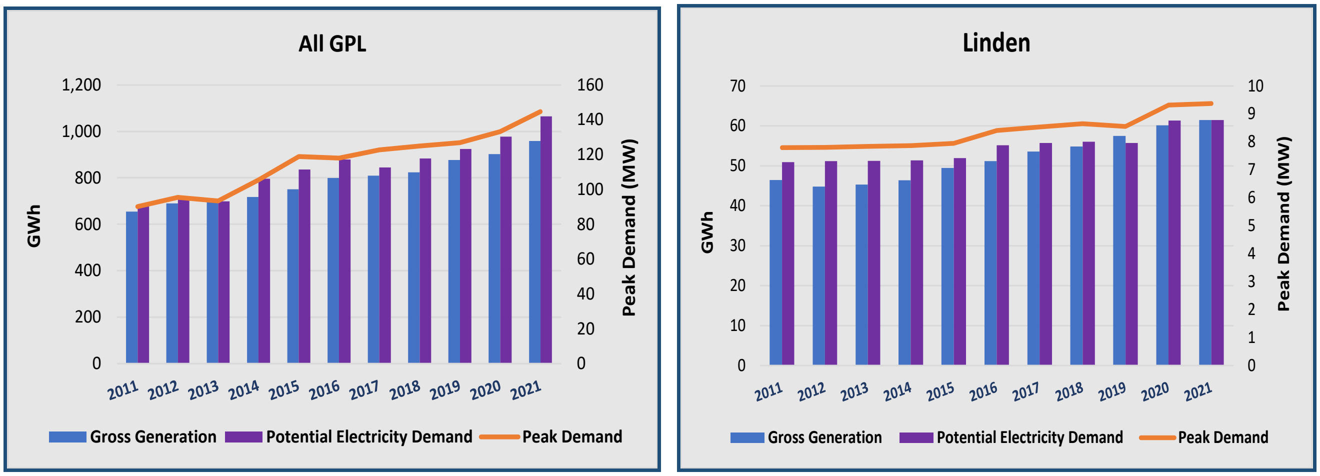

Figure 9: All GPL and Linden Historical Electricity Demand Records

In the same period, the actual non-coincidental Peak Demand (Peak Load) for 'All GPL' increased by an annual average rate of 4.8 percent, moving from 90 MW in 2011 to 145 MW in 2021, while the power system load factor ratio reduced, on average, by -0.6 percent, moving from 0.83 in 2011 to 0.76 in 2021, indicating that demand is growing faster than the system's capacity to supply. In DF_2022 framework, the load factor ratios were used to determine the peak demand forecasts.

Linden's actual peak demand increased, on average, by 1.8 percent, moving from 7.8 MW in 2011 to 9.4 MW in 2021, and the power system load factor ratio increased, on average, by 0.8 percent, moving from 0.68 in 2011 to 0.75 in 2021, indicating improvements is capacity generation, where supply closely followed demand.

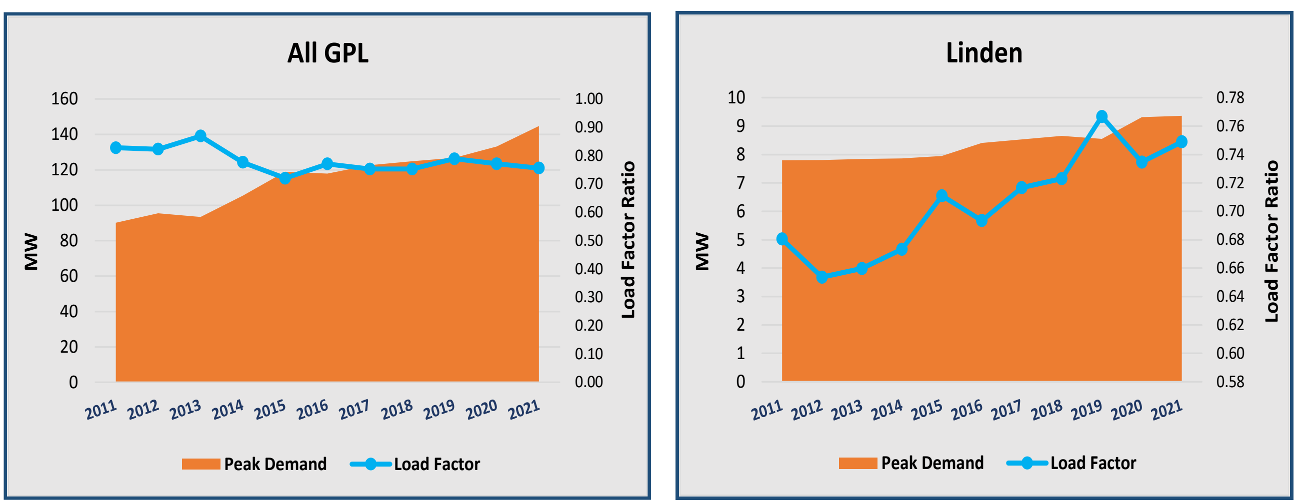

Figure 10: All GPL and Linden Historical Peak Demand Records

Medium Term Forecast

The Electricity Demand Forecasting Framework 2022 (DF_2022), was forecasted for the period between 2022 to 2052. This section will look at the medium-term forecasts (2022-

2032), while the long-term forecasts (2022-2052) was reported in Appendix 1. In addition, this report will focus mainly on the Base Case analysis, which is relevant in informing the Development & Expansion Programme.

The Base Case forecasts were driven by robust economic growth projections arising from Guyana's Oil & Gas industry, while incorporating the most realistic and likely impacts of the pandemic – Covid-19 (that alarmed during the second quarter of 2020), and high global volatility. Nonetheless, GPL carefully monitored the resultant effects, and buoyed by the positive interjection by the Government of Guyana, in reducing tariffs on fuel costs, GPL was able to withstand the price shocks of soaring fuel prices, thus keeping the price of electricity at the same level (therefore reducing the burden on customers). Furthermore, these events have alerted the importance of planning and risk mitigation, as such the demand forecasting framework is constantly updated to reflect such positions to properly guide decision-making.

The DF_2022 framework entailed some significant improvement modifications over the past two years; nevertheless, its foundation is built on the works of: (i) the Generation Expansion Study 2018 – the "Brugman Study"; and (ii) The Demand Forecast Capacity Building Consultancy by ETS Consultants (2019-2020); where the methodology follows the input of gross generation forecast and the application of adjustment factors to estimate the value of 'energy not served', the impact of energy efficiency measures (EE), electric vehicles (EV), energy losses (technical and non-technical), and the breakdown of electrical energy sales (GWh) into consumer categories (commercial, residential, and industrial).

5.3.1 Disaggregated Items of the Electricity Demand Framework

The Tables below show a summary of the disaggregated forecasts of the Electricity Demand Forecasting Framework results[9], which captures the following line items:

i) **Gross Generation** - Gross electricity generation or gross electricity production refers to the process of producing electrical energy by transforming other forms of energy, such as fossil fuels, nuclear power, hydro power (excluding pumped storage), geothermal systems, solar panels, biofuels, wind, etc., and it is commonly expressed in gigawatt hours (GWh). At plant level, it is measured at the outlet of the main transformers, i.e., including the amount of electricity used in the plant auxiliaries and in the transformers.

   To derive 'total electricity demand', the component 'gross generation' was utilized as a proxy variable, which was estimated as a function of the best-chosen econometric model specification. Gross generation was forecasted through time-series regressions, specifically employing variations of the ARIMA (Auto-Regressive Integrated Moving Average) family model – ARIMAX (Auto-Regressive Integrated Moving Average)

[9] See Appendix 1 for results and further discussion.

including various explanatory variables (X_n), notably Real GDP and elements of GDP. The best model was chosen from hundreds of model variations and the forecasted output of gross generation (2022-2052) was inserted into the framework, where self-generators[10] output/requirements were added in phases to several years to arrive at the new proxy gross generation values, which were then utilised to compute the following line items.

ii) **Energy Not Served** - energy not served or unserved energy is a measure of the amount of customer demand that cannot be supplied within a region/section due to a shortage of generation, demand-side participation, or interconnector capacity. This line-item was estimated as ratio to total energy requirements using the moving average (with expected future improvements).

iii) **Total Energy Requirements** - total primary energy requirement is a measure of the energy consumption that also accounts for the energy that is consumed and/or lost beyond the boundary of the plant, notably in generating and distributing electricity. Therefore, this is the sum of gross generation and energy not served.

iv) **Energy Efficiency (EE)** – energy efficiency improvement is defined as increasing the output per unit of energy used, resulting in energy savings if the output does not change. According to the International Energy Agency (IEA), while energy efficiency simply means 'using less energy to provide the same service', energy efficiency is also about creating a balance between energy demand and energy supply. See section 5.4 on page 95 for details further details on Energy Efficiency and Demand Side Management.

The DF_2022 framework, noted that while it is realistically impossible to achieve 100 percent efficiency across all regional zones at the same time, a more rational assumption of approaching some level of efficiency of 75 percent was set (whereas in the previous model was 75.5 percent). We assume as the economy grows and economic development is more widespread (thus reducing degrees of inequality) and improving standards-of-living (inclusive of higher disposable income), we expect households and businesses to be more adaptive to energy efficient appliances, behaviours, and lifestyles; therefore, as time progresses, it is assumed that the minimum 75 percent level of energy efficiency will be attainable for the various regional zones at different timelines.

v) **Electric Vehicle (EV)** – is a mode of transport, an automobile of which an electric car, battery electric car, or all-electric car that is propelled by one or more electric motors,

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[10] It is assumed that several self-generators are expected to come on Grid, commencing year 2023. An estimated 1,831 GWh will be demanded (from self-generators) over the next 15 years.

using only energy stored in batteries. According to official statements made in Guyana’s press, a pilot project for electric vehicles will be executed, with the first electric vehicle charging stations to arrive in February 2023, where the supply of six charging stations will be placed across the coast. It is anticipated that this will subtly increase the demand for electricity in the near future. Moreover, electric vehicles’ electricity demand was integrated into the framework from year 2024.

vi) **Potential Electricity Demand** – in this framework, potential electricity demand is the summation of the forecasted (proxy) gross generation, energy efficiency outcome, and electric vehicle demand, which is ultimately the framework’s main output, and is then used to calculate the following line items.

vii) **Net Energy Exported** – or net electricity generation/production is equal to gross electricity generation/supply (where supply should equal demand) minus the consumption of power stations' auxiliary services.

viii) **Technical & Non-technical Losses** - technical losses occur in the transfer of electrical current between electrical installations, while they cannot be mitigated in their entirety, they can be calculated and significantly reduced through the correct installation methods and practices. These occur from: losses due to conductor resistance, induction of electromagnetic fields, harmonic distortion and poor earthing, and dielectric losses due to insulation material between the conductors.

Non-technical losses are more difficult to reduce, as such these losses can occur from: meter tampering, hooking, or bypassing the meter, wrong programmed instrument transformer ratios in the meter, the burden for instrument transformers is too high, wrong meter readings, meter is faulty or out of accuracy class, and unpaid electricity bills.

ix) **Potential Electricity Sales** – is the sales that could have possibly been sold if supply was matching demand. In this model it is calculated by subtracting ‘technical & non-technical losses’ from net energy exported/ net generation.

Medium-Term: Electricity Demand Forecasting Framework (2022-2032)

Electricity Demand – GPL + Linden

Total electricity demand (comprising of ‘All GPL’ & Linden), in medium-term (2022-2032), was forecasted at 2,697 GWh, an average growth of 13.1 percent, moving from 1,185 GWh in 2022 to 4,296 GWh in 2032. Average peak demand was projected at 414 MW, moving from 185 MW in 2022 to 652 MW in 2032. Moreover, several large development & expansion projects namely, the Gas-to-Power, Amaila Hydropower Plant, Solar PV Farms, and regional power plant extensions projects would significantly improve the reliability and energy efficiency balance of the supply of electricity, particularly reaching new demand from growing residential housing, commercial and industrial activities. In addition, average potential sales were projected at approximately 1,977 GWh, an average growth of 13.2 percent. See Figure 11 for graphical information and Table 6 for more details.

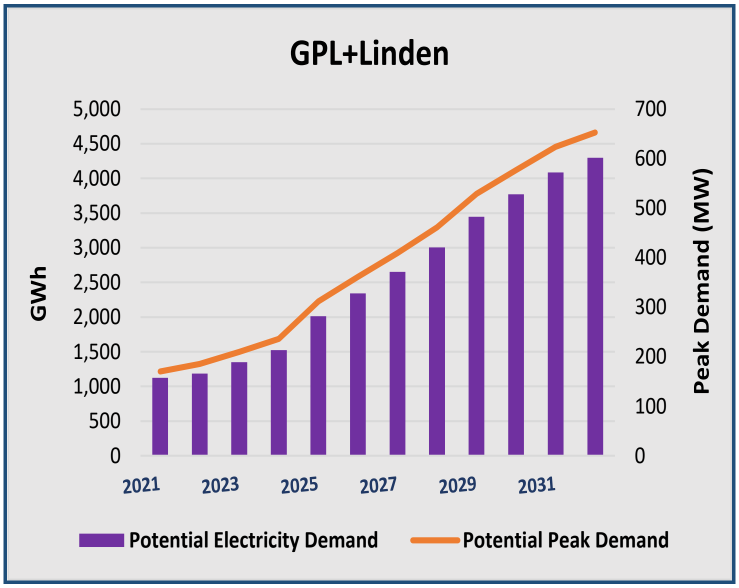


Figure 11: All GPL and Linden Electricity Demand Forecast

Table 6: Electricity Demand: All GPL & Linden

'GWh' values unless stated otherwise	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Generation (with Self-generators)	**1,020.3**	**1,103.3**	**1,256.5**	**1,421.0**	**1,877.0**	**2,185.4**	**2,483.4**	**2,816.2**	**3,236.1**	**3,548.3**	**3,854.0**	**4,062.3**
Unserved Energy (approx. trend) GWh	**5.9**	**5.8**	**7.0**	**7.9**	**10.3**	**12.2**	**13.9**	**15.8**	**18.3**	**20.1**	**22.0**	**23.3**
Total Energy Requirements (TER)/Expected Supply-Demand	**1,026.1**	**1,109.1**	**1,263.5**	**1,428.9**	**1,887.3**	**2,197.7**	**2,497.3**	**2,832.1**	**3,254.4**	**3,568.5**	**3,875.9**	**4,085.6**
Energy Efficiency (EE) factor (% of TER)	*-0.10*	*-0.07*	*-0.07*	*-0.07*	*-0.07*	*-0.07*	*-0.07*	*-0.07*	*-0.06*	*-0.06*	*-0.06*	*-0.06*
EE – Suppy-Demand Outcome	105.7	81.3	91.3	101.9	132.7	152.3	168.0	184.9	206.0	218.7	225.9	225.9
Potential Demand Post-EE	**1,126.0**	**1,184.6**	**1,347.8**	**1,522.8**	**2,009.7**	**2,337.7**	**2,651.4**	**3,001.1**	**3,442.1**	**3,767.0**	**4,079.9**	**4,288.2**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.8*	*1.6*	*2.1*	*2.7*	*3.5*	*4.6*	*6.0*	*6.7*	*7.6*
New Potential Electricity Demand with EE & EV	**1,126.0**	**1,184.6**	**1,347.8**	**1,523.6**	**2,011.3**	**2,339.8**	**2,654.1**	**3,004.7**	**3,446.7**	**3,773.0**	**4,086.6**	**4,295.8**
Auxiliaries & Self-Consumption	-25.6	-28.7	-32.4	-36.5	-48.6	-56.5	-64.2	-73.0	-83.9	-92.0	-100.1	-105.6
Net Energy Exported/Net Generation	**1,100.4**	**1,155.9**	**1,315.4**	**1,487.2**	**1,962.7**	**2,283.3**	**2,589.9**	**2,931.7**	**3,362.9**	**3,681.0**	**3,986.6**	**4,190.3**
Total Losses factor (%)	*0.256*	*0.246*	*0.251*	*0.251*	*0.249*	*0.250*	*0.249*	*0.249*	*0.249*	*0.248*	*0.248*	*0.248*
Technical & Non-Technical Losses	-281.8	-284.8	-330.3	-372.8	-488.5	-570.2	-645.6	-729.4	-836.6	-914.5	-989.3	-1,039.0
Potential Sales of Electricity (GWh)	**818.6**	**871.1**	**985.1**	**1,114.3**	**1,474.2**	**1,713.1**	**1,944.3**	**2,202.3**	**2,526.3**	**2,766.5**	**2,997.2**	**3,151.2**
Residential	*429.3*	*448.1*	*509.1*	*577.8*	*707.6*	*820.6*	*923.6*	*1,036.4*	*1,177.8*	*1,277.6*	*1,370.9*	*1,427.5*
Commercial	*130.2*	*141.6*	*156.1*	*178.3*	*352.3*	*418.0*	*458.9*	*514.9*	*585.1*	*634.6*	*681.0*	*709.0*
Industrial	*259.1*	*281.4*	*319.9*	*358.2*	*414.2*	*474.5*	*561.9*	*651.0*	*763.4*	*854.3*	*945.3*	*1,014.7*
Load Factor (%) (with self-gen., EE & EV)	**0.76**	**0.73**	**0.73**	**0.73**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.75**	**0.75**	**0.75**
Peak MW (with EE & EV)	**170.1**	**185.1**	**209.7**	**236.1**	**311.7**	**361.1**	**409.1**	**461.2**	**529.1**	**576.9**	**624.0**	**652.4**

All GPL

'All GPL' (comprises of DBIS & Essequibo) average electricity demand, in medium-term (2022-2032), was forecasted at 2,503 GWh, an average growth of 12.5 percent per annum, moving from 1,120 GWh in 2022 to 3,781 GWh in 2032. Average peak demand was projected at 387 MW, moving from 175 MW in 2022 to 579 MW in 2032. Moreover, electric vehicles are estimated to add to demand, on average, 4.0 GWh, mainly attributed to estimated consumers in Demerara and Berbice. In addition, average potential sales were projected at approximately 1,945 GWh, an average growth of 13.6 percent, moving from 815 GWh in 2022 to 3,027 GWh in 2032. See Figure 12 for graphical information and Table 7 for more details.

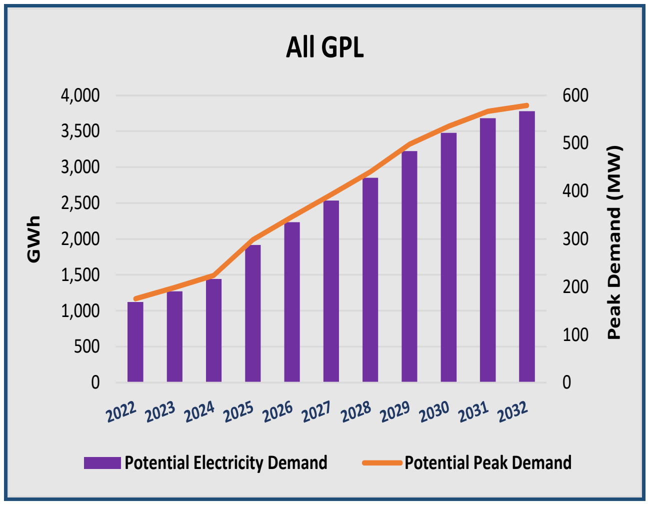


Figure 12: All GPL Potential Electricity Sales

Table 7:Electricity Demand: All GPL

'GWh' values unless stated otherwise	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Generation (with Self-generators)	**958.8**	**1,039.7**	**1,181.3**	**1,339.3**	**1,783.6**	**2,079.0**	**2,363.3**	**2,663.6**	**3,015.1**	**3,257.2**	**3,456.9**	**3,560.9**
Unserved Energy (approx. trend) GWh	**5.8**	**5.7**	**6.9**	**7.8**	**10.3**	**12.2**	**13.8**	**15.6**	**17.8**	**19.2**	**20.5**	**21.2**
Total Energy Requirements (TER)/Expected Supply-Demand	**964.6**	**1,045.4**	**1,188.2**	**1,347.1**	**1,793.8**	**2,091.2**	**2,377.1**	**2,679.2**	**3,032.9**	**3,276.4**	**3,477.4**	**3,582.0**
Energy Efficiency (EE) factor (% of TER)	*-0.11*	*-0.08*	*-0.08*	*-0.08*	*-0.07*	*-0.07*	*-0.07*	*-0.07*	*-0.07*	*-0.07*	*-0.06*	*-0.06*
EE – Suppy-Demand Outcome	105.7	80.7	90.6	101.3	133.1	153.1	169.3	185.5	203.9	213.7	216.4	212.1
Potential Demand Post-EE	**1,064.5**	**1,120.4**	**1,271.9**	**1,440.7**	**1,916.7**	**2,232.2**	**2,532.6**	**2,849.1**	**3,219.0**	**3,470.9**	**3,673.2**	**3,773.0**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.8*	*1.6*	*2.1*	*2.7*	*3.5*	*4.6*	*6.0*	*6.7*	*7.6*
New Potential Electricity Demand with EE & EV	**1,064.5**	**1,120.4**	**1,271.9**	**1,441.5**	**1,918.3**	**2,234.2**	**2,535.3**	**2,852.6**	**3,223.6**	**3,476.9**	**3,680.0**	**3,780.6**
Auxiliaries & Self-Consumption	-24.8	-27.8	-31.4	-35.4	-47.5	-55.3	-62.9	-71.0	-80.4	-86.9	-92.3	-95.2
Net Energy Exported/Net Generation	**1,039.7**	**1,092.6**	**1,240.5**	**1,406.0**	**1,870.8**	**2,178.9**	**2,472.4**	**2,781.6**	**3,143.2**	**3,390.0**	**3,587.7**	**3,685.4**
Total Losses factor (%)	*0.265*	*0.254*	*0.241*	*0.231*	*0.224*	*0.216*	*0.209*	*0.203*	*0.197*	*0.191*	*0.185*	*0.179*
Technical & Non-Technical Losses	-275.3	-277.6	-298.5	-324.3	-418.3	-469.8	-515.8	-563.6	-618.0	-646.2	-662.3	-658.3
Potential Sales of Electricity (GWh)	**764.5**	**815.0**	**942.0**	**1,081.8**	**1,452.4**	**1,709.1**	**1,956.6**	**2,218.0**	**2,525.2**	**2,743.8**	**2,925.3**	**3,027.1**
Residential	*400.9*	*419.3*	*486.8*	*561.0*	*697.2*	*818.7*	*929.4*	*1,043.8*	*1,177.2*	*1,267.1*	*1,338.0*	*1,371.3*
Commercial	*121.6*	*132.4*	*149.3*	*173.1*	*347.1*	*417.0*	*461.8*	*518.6*	*584.8*	*629.4*	*664.6*	*681.1*
Industrial	*242.0*	*263.3*	*305.9*	*347.7*	*408.1*	*473.4*	*565.5*	*655.6*	*763.1*	*847.3*	*922.6*	*974.7*
Load Factor (%) (with self-gen., EE & EV)	**0.76**	**0.73**	**0.73**	**0.73**	**0.73**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**
Peak MW (with EE & EV)	**160.7**	**175.2**	**198.4**	**224.0**	**298.3**	**346.5**	**392.8**	**440.3**	**498.0**	**535.6**	**566.3**	**579.1**

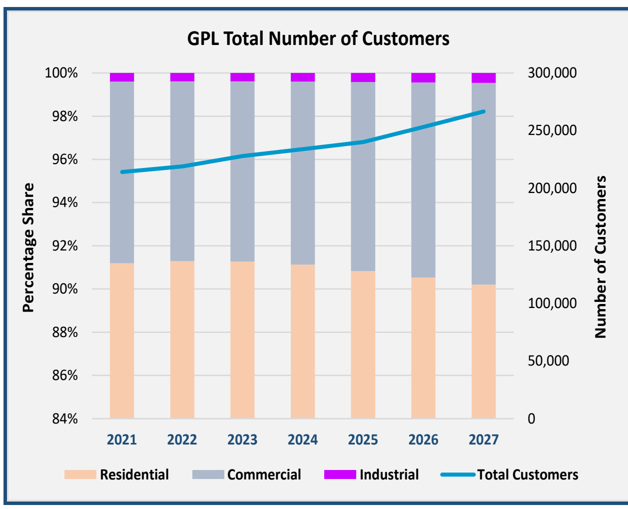
GPL Estimated Customers' Demand during the D&E Period (2023-2027)

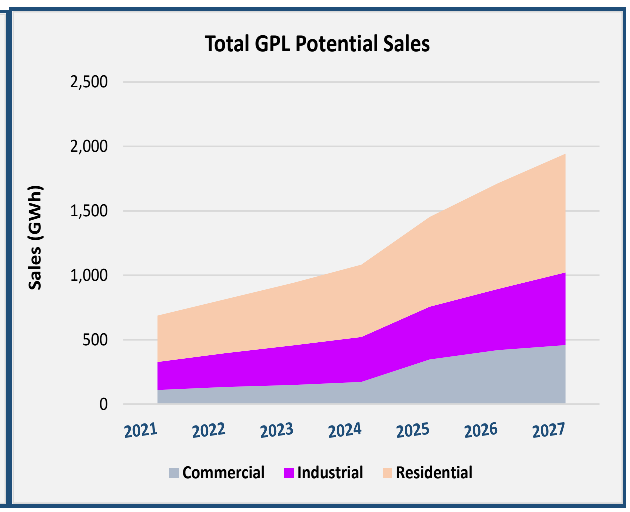
Table 8: GPL's Estimated Number of Customers

	2021	2022	2023	2024	2025	2026	2027
No. of Residential Customers	195,114	199,811	207,979	213,146	217,981	229,161	240,525
No. of Commercial Customers	17,991	18,203	19,003	19,803	21,003	22,856	24,924
No. of Industrial Customers	863	856	881	931	1,006	1,110	1,214
Total No. of Customers	**213,968**	**218,870**	**227,863**	**233,880**	**239,990**	**253,127**	**266,663**

Note: it is assumed that Linden would be connected to GPL by 2026

'All GPL' number of customers, which presently comprises of DBIS & Essequibo customers, is expected to grow as population and economic activity expands. It is assumed that by 2026, Linden will join GPL's Grid, hence the table above and the graphs below incorporate Linden in 2026 and 2027. Rough estimates suggest that the number of customers increases, on average (2023-2027), by 4.0 percent each year, where residential customers represent 90.8 percent, commercial customers: 8.8 percent, and industrial customers: 0.4 percent, of total customers. In addition, average potential sales were estimated to increase, on average, by 19.2 percent each year, where residential sales account for 49.4 percent, commercial sales: 20.7 percent, and industrial sales: 29.9 percent, of total potential sales.





Note: it is assumed that Linden would be connected to GPL by 2026

Figure 13: Total Number of Customers and Potential Sale

Electricity Demand - DBIS

The Demerara-Berbice Interconnected System (DBIS), (which accounts on average, 94.4 percent of 'All GPL' and 88.6 percent of GPL+Linden's electricity generation), electricity demand was projected to expand, in the medium-term (2022-2032), by 11.5 percent, averaging 2,337 GWh, moving from 1,061 GWh in 2022 to 3,244 GWh in 2032. Average peak demand was forecasted at 343 MW, moving from 166 MW in 2022 to 492 MW in 2032.

Moreover, the Gas-to-Power project that is estimated to export to GPL's Grid around 2024-2025, would result in an upsurge in the capacity of electricity supply for a period of time until it gradually flattens. In addition, average potential sales were projected at approximately 1,645 GWh, an average growth of 11.6 percent. See Figure 14 for graphical information and Table 9 for more details.

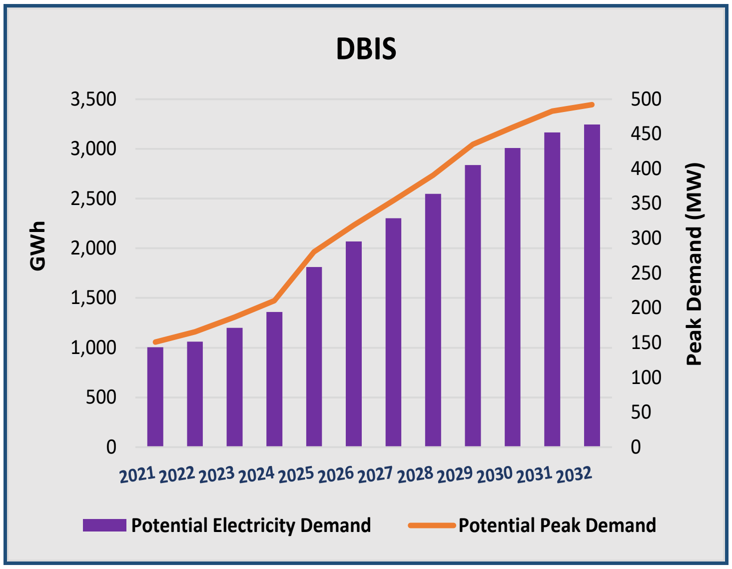


Figure 14: DBIS Electricity Demand Forecast

Table 9: Electricity Demand: DBIS

'GWh' values unless stated otherwise	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Generation (with Self-generators)	**905.0**	**983.4**	**1,113.8**	**1,261.6**	**1,683.2**	**1,922.2**	**2,142.3**	**2,376.2**	**2,650.4**	**2,814.5**	**2,969.1**	**3,051.4**
Unserved Energy (approx. trend) GWh	**5.5**	**5.5**	**6.5**	**7.4**	**9.8**	**11.3**	**12.6**	**14.0**	**15.6**	**16.6**	**17.6**	**18.1**
Total Energy Requirements (TER)/Expected Supply-Demand	**910.5**	**988.9**	**1,120.3**	**1,269.0**	**1,692.9**	**1,933.4**	**2,154.8**	**2,390.1**	**2,666.1**	**2,831.1**	**2,986.7**	**3,069.6**
Energy Efficiency (EE) factor (% of TER)	*-0.11*	*-0.08*	*-0.08*	*-0.08*	*-0.08*	*-0.07*	*-0.07*	*-0.07*	*-0.07*	*-0.07*	*-0.06*	*-0.06*
EE – Suppy-Demand Outcome	100.6	77.4	86.6	96.8	127.4	143.6	155.7	167.9	182.0	187.6	189.0	185.0
Potential Demand Post-EE	**1,005.6**	**1,060.8**	**1,200.3**	**1,358.4**	**1,810.6**	**2,065.8**	**2,298.0**	**2,544.1**	**2,832.4**	**3,002.1**	**3,158.0**	**3,236.4**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.8*	*1.6*	*2.1*	*2.7*	*3.5*	*4.6*	*6.0*	*6.7*	*7.6*
New Potential Electricity Demand with EE & EV	**1,005.6**	**1,060.8**	**1,200.3**	**1,359.2**	**1,812.2**	**2,067.8**	**2,300.7**	**2,547.7**	**2,837.1**	**3,008.1**	**3,164.8**	**3,244.0**
Auxiliaries & Self-Consumption	-23.4	-26.3	-29.6	-33.4	-44.8	-51.1	-56.9	-63.3	-70.6	-75.0	-79.2	-81.4
Net Energy Exported/Net Generation	**982.2**	**1,034.4**	**1,170.7**	**1,325.9**	**1,767.4**	**2,016.8**	**2,243.8**	**2,484.4**	**2,766.5**	**2,933.1**	**3,085.6**	**3,162.6**
Total Losses factor (%)	*0.252*	*0.243*	*0.247*	*0.247*	*0.245*	*0.246*	*0.246*	*0.246*	*0.246*	*0.245*	*0.245*	*0.245*
Technical & Non-Technical Losses	-247.7	-251.2	-289.5	-327.7	-433.8	-496.8	-552.0	-610.2	-679.7	-720.0	-756.9	-775.4
Potential Sales of Electricity (GWh)	**734.5**	**783.2**	**881.2**	**998.2**	**1,333.6**	**1,520.0**	**1,691.8**	**1,874.2**	**2,086.8**	**2,213.1**	**2,328.7**	**2,387.2**
Residential	*385.2*	*402.9*	*455.4*	*517.6*	*640.1*	*728.1*	*803.6*	*882.0*	*972.9*	*1,022.0*	*1,065.2*	*1,081.4*
Commercial	*116.9*	*127.3*	*139.6*	*159.7*	*318.7*	*370.9*	*399.3*	*438.2*	*483.3*	*507.7*	*529.1*	*537.1*
Industrial	*232.5*	*253.0*	*286.1*	*320.8*	*374.7*	*421.0*	*488.9*	*554.0*	*630.6*	*683.4*	*734.5*	*768.7*
Load Factor (%) (with self-gen., EE & EV)	**0.76**	**0.73**	**0.73**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.75**	**0.75**	**0.75**
Peak MW (with EE & EV)	**150.8**	**165.6**	**186.6**	**210.4**	**280.6**	**318.9**	**354.3**	**390.7**	**435.1**	**459.5**	**482.8**	**492.2**

Electricity Demand – Essequibo Isolated Power Systems

Essequibo's aggregated isolated power systems', which includes Anna Regina, Bartica, Leguan, and Wakenaam, electricity demand and peak demand are forecasted to grow, on average, during the medium-term (2022-2032), by 23.3 percent and 22.4 percent respectively. Forecasted electricity demand, during the period, averaged Anna Regina with 182 GWh, Bartica with 57 GWh, Leguan with 13 GWh, and Wakenaam with 12 GWh, (see Appendix Tables Table 6 - Table 13).

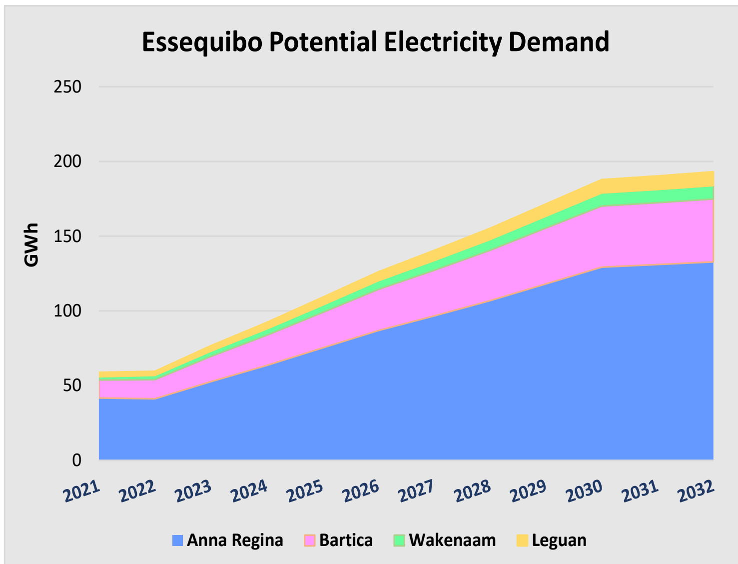


Figure 15: Isolated Power System's Electricity Demand Forecasts

These projections indicate the need to improve on generation reliability and quality of electricity services to customers in these regional zones; as such several extensive plans to boost generation capacities are underway, as discussed in the other chapters.See Figure 15 for graphical information and

Table 10 for more details. See Appendix – Table 6 to Table 13 for Essequibo's isolated power systems.

Table 10:Electricity Demand: Essequibo

'GWh' values unless stated otherwise	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Generation (with Self-generators)	**53.8**	**56.3**	**67.6**	**77.7**	**100.4**	**156.9**	**221.0**	**287.4**	**364.7**	**442.7**	**487.8**	**509.4**
Unserved Energy (approx. trend) GWh	**0.3**	**0.2**	**0.4**	**0.4**	**0.5**	**0.8**	**1.1**	**1.4**	**1.8**	**2.2**	**2.4**	**2.6**
Total Energy Requirements (TER)/Expected Supply-Demand	**54.1**	**56.5**	**67.9**	**78.1**	**100.8**	**157.7**	**222.1**	**288.9**	**366.5**	**444.9**	**490.3**	**512.0**
Energy Efficiency (EE) factor (% of TER)	*-0.10*	*-0.06*	*-0.06*	*-0.06*	*-0.06*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.04*	*-0.04*
EE – Suppy-Demand Outcome	5.2	3.3	3.9	4.4	5.6	8.7	11.8	14.7	17.9	20.9	21.5	21.0
Potential Demand Post-EE	**58.9**	**59.6**	**71.5**	**82.2**	**106.0**	**165.5**	**232.8**	**302.2**	**382.6**	**463.6**	**509.3**	**530.4**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
New Potential Electricity Demand with EE & EV	**58.9**	**59.6**	**71.5**	**82.2**	**106.0**	**165.5**	**232.8**	**302.2**	**382.6**	**463.6**	**509.3**	**530.4**
Auxiliaries & Self-Consumption	-1.4	-1.5	-1.8	-2.1	-2.7	-4.2	-5.9	-7.6	-9.7	-11.8	-13.0	-13.5
Net Energy Exported/Net Generation	**57.5**	**58.1**	**69.7**	**80.1**	**103.3**	**161.4**	**226.9**	**294.5**	**372.9**	**451.8**	**496.4**	**516.8**
Total Losses factor (%)	*0.476*	*0.450*	*0.469*	*0.465*	*0.461*	*0.465*	*0.464*	*0.463*	*0.464*	*0.463*	*0.463*	*0.463*
Technical & Non-Technical Losses	-27.4	-26.1	-32.7	-37.2	-47.7	-75.0	-105.2	-136.4	-173.0	-209.4	-230.0	-239.5
Potential Sales of Electricity (GWh)	**30.1**	**32.0**	**37.0**	**42.9**	**55.7**	**86.3**	**121.7**	**158.1**	**200.0**	**242.4**	**266.4**	**277.3**
Residential	*15.8*	*16.5*	*19.1*	*22.2*	*26.7*	*41.4*	*57.8*	*74.4*	*93.2*	*112.0*	*121.8*	*125.6*
Commercial	*4.8*	*5.2*	*5.9*	*6.9*	*13.3*	*21.1*	*28.7*	*37.0*	*46.3*	*55.6*	*60.5*	*62.4*
Industrial	*9.5*	*10.3*	*12.0*	*13.8*	*15.6*	*23.9*	*35.2*	*46.7*	*60.4*	*74.9*	*84.0*	*89.3*
Load Factor (%) (with self-gen., EE & EV)	**0.68**	**0.71**	**0.71**	**0.71**	**0.71**	**0.71**	**0.72**	**0.72**	**0.72**	**0.72**	**0.72**	**0.72**
Peak MW (with EE & EV)	**9.9**	**9.6**	**11.5**	**13.2**	**17.0**	**26.4**	**37.1**	**48.0**	**60.8**	**73.3**	**80.5**	**83.3**

Electricity Demand - Linden

Linden's average electricity demand was forecasted at 191 GWh, during the medium-term (2022-2032), an average growth of 21.5 percent, moving from 64 GWh in 2022 to 497 GWh in 2032. Average peak demand is projected at 29 MW, moving from 10 MW in 2022 to 76 MW in 2032. Moreover, Linden is expected to come on Grid by 2027, and the Amaila Falls Hydropower project is expected to be in operation around 2030. The framework shows by

2029, Linden's supply will match demand with some excess. In addition, average potential sales were projected at approximately 165 GWh, an average growth of 21.0 percent, moving from 56 GWh in 2022 to 430 GWh in 2032. See Figure 16 for graphical information and Table 11 for more details.

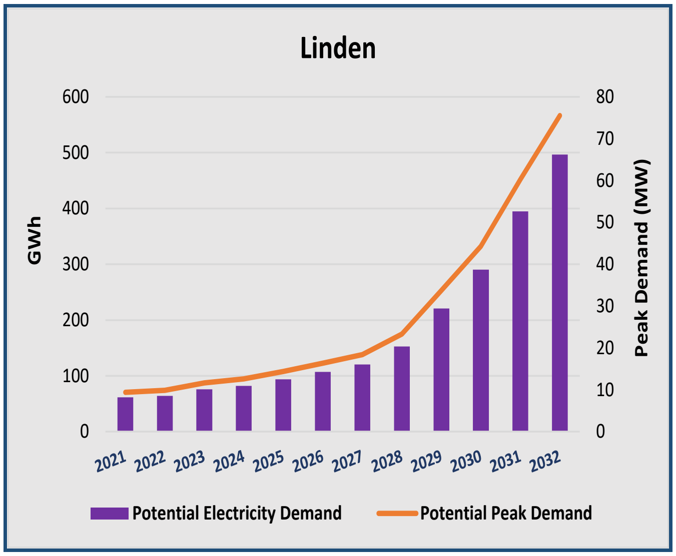


Figure 16: Electricity Demand - Linden

Table 11: Electricity Demand - Linden

'GWh' values unless stated otherwise	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Generation (with Self-generators)	61.5	63.6	75.2	81.6	93.4	106.4	120.1	152.6	221.0	291.2	397.1	501.5
Unserved Energy (approx. trend) GWh	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.3	0.5	0.6
Total Energy Requirements (TER)/Expected Supply-Demand	61.5	63.7	75.3	81.7	93.5	106.5	120.2	152.8	221.3	291.5	397.5	502.1
Energy Efficiency (EE) factor (% of TER)	*0.00*	*-0.01*	*-0.01*	*-0.01*	*-0.01*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.01*	*0.01*
EE – Suppy-Demand Outcome	0.0	0.6	0.6	0.6	0.5	0.5	0.3	0.1	-0.3	-0.9	-2.5	-4.6
Potential Demand Post-EE	61.5	64.2	75.8	82.2	94.0	106.9	120.4	152.7	220.8	290.2	394.6	496.8
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
New Potential Electricity Demand with EE & EV	61.5	64.2	75.8	82.2	94.0	106.9	120.4	152.7	220.8	290.2	394.6	496.8
Auxiliaries & Self-Consumption	-0.8	-0.9	-1.0	-1.1	-1.2	-1.4	-1.6	-2.0	-2.9	-3.9	-5.3	-6.7
Net Energy Exported/Net Generation	60.7	63.3	74.8	81.1	92.7	105.5	118.8	150.7	217.8	286.3	389.3	490.2
Total Losses factor (%)	*0.123*	*0.123*	*0.123*	*0.123*	*0.123*	*0.123*	*0.123*	*0.122*	*0.122*	*0.122*	*0.122*	*0.122*
Technical & Non-Technical Losses	-7.5	-7.8	-9.2	-10.0	-11.4	-12.9	-14.6	-18.5	-26.7	-35.0	-47.6	-59.9
Potential Sales of Electricity (GWh)	53.2	55.6	65.6	71.2	81.4	92.6	104.3	132.2	191.2	251.3	341.7	430.2
Residential	*27.9*	*28.6*	*33.9*	*36.9*	*39.1*	*44.3*	*49.5*	*62.2*	*89.1*	*116.0*	*156.3*	*194.9*
Commercial	*8.5*	*9.0*	*10.4*	*11.4*	*19.4*	*22.6*	*24.6*	*30.9*	*44.3*	*57.6*	*77.6*	*96.8*
Industrial	*16.8*	*17.9*	*21.3*	*22.9*	*22.9*	*25.6*	*30.1*	*39.1*	*57.8*	*77.6*	*107.8*	*138.5*
Load Factor (%) (with self-gen., EE & EV)	0.75	0.74	0.74	0.74	0.74	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Peak MW (with EE & EV)	9.4	9.9	11.6	12.6	14.4	16.4	18.4	23.3	33.7	44.3	60.2	75.6

5.4 Demand Side Management (DSM) and Energy Efficiency (EE)

Demand Side Management (DMS) is a strategic way of managing the shape of load profiles to match the most economical generation capacity and mitigating technical losses. Load shape management strategy includes peak clipping, conservation, load building, valley filling, flexible load shape and load shifting (see Figure 17). This approach is applied by the Utility to the grid and Customers to their energy systems.

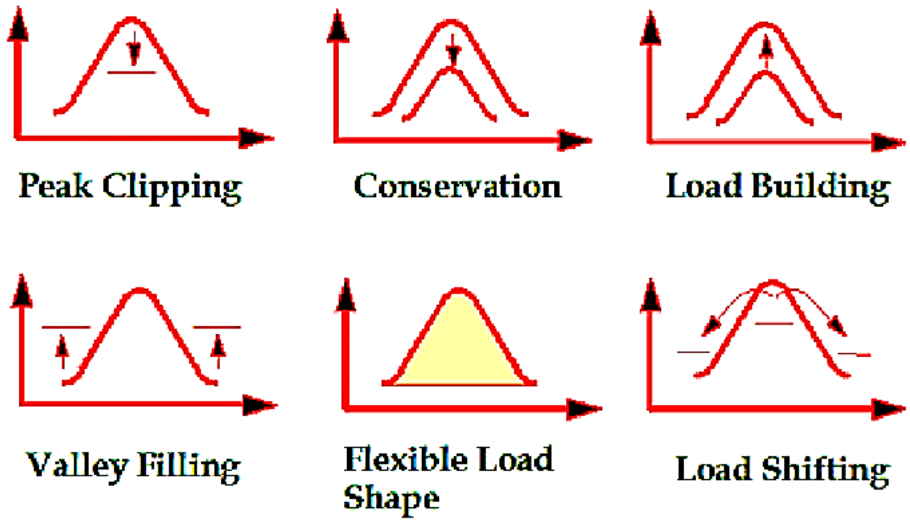


Figure 17: Load Profile Management Strategy

In addition to reducing electricity demand, there are various reasons put forward for promoting or undertaking DSM. These include, but are not limited to electricity cost reduction, reducing dependency on expensive imports of fossil fuel, environmental and social improvements, addressing reliability and network issues, improve the electricity market (applicable to countries where there is an open electricity market – Guyana currently does not have one) and ensuring electricity supply security.

5.4.1 Demand Side Management from Utility Perspective

The load-shape management strategy can be achieved by non-technical and technical interventions.

Non-technical interventions include activities or programmes that promote electric energy efficiency or conservation, or more efficient management of electricity consumption through the media, social platforms, and public outreaches.

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 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 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 website to consistently disseminate DSM information within the framework of:

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

Technical interventions involve the application of Smart Grid (includes Advance Metering Infrastructure and Automatic Generation Control), Battery Energy Storage Systems (BESS), Combine Heat and Power, medium to large scale renewable energy systems, Capacitor Banks, Voltage Regulators, Prepaid meters, and optimised transmission, and distribution conductor size.

In this Development and Expansion Programme, the characteristics of the planned projects for the horizon year 2027 are testimonies of the Company's commitment towards implementing technical interventions to promote DMS, improving grid efficiency and reducing grid operation costs.

5.4.2 Demand Side Management from a Customer Perspective

Demand Side Management extends to all customer sectors, which includes the Industrial, commercial, and residential since these typically contribute to having two peak periods- a daytime peak attributed to the commercial activity and an evening peak period attributed to the residential sector.

In the case of GPL being a small utility residential activity is predominant and hence the system's peak period is in the evenings. As a result, DSM activities have been focused primarily on the residential sector.

In addition to GPL's various ongoing outreach and public relations programs, there are various strategies customers (residential, commercial, and industrial) can undertake on their behalf to help manage their consumption during peak demand periods. These strategies include the use of energy-efficient equipment and the practice of energy conservation.

5.4.3 Energy Efficiency and Energy Conservation

While DMS is a strategic way of synchronising the load profile with generation capacity, it strives to improve the efficiency of energy consumption without reducing the services that the energy provides for development.

With the practice of energy conservation added to the equation, it helps to further improve energy efficiency and emission reductions through the curtailment of nonessential services.

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

6. Current Status of Power Generation Capacity

6.1 Demerara Berbice Interconnected System (DBIS)

With the GOE II 46.5 MW power plant – DP5, in commercial operation, GPL's aggregated number of power plants currently stands at 13, and totals 213.8 MW of firm available generation capacity. The DBIS aggregated available capacity of 190.9 MW comprises 9 power plants and the Isolated Power Systems, 22.9 MW resulting from 4 power plants.

The Isolated Power Systems comprise Anna Regina, Wakenaam, Leguan and Bartica – one power plant in each power system.

In the DBIS, a breakout by fuel type indicates that HFO-fired generator units account for 86.9% and LFO-fired, 13.1% of the total available capacity. For the Isolated Systems, 23.6% of the total capacity is HFO-fired and 76.4% is LFO-fired. See Table 12 for numerical details.

With scheduled maintenance and efficient operations, reciprocating internal combustion engine-generator units generally have a maximum operational life of 25 years. In most instances, their economic life is taken as 20 years. Surpassing 20 years, these unit are mothballed and classified as Cold Reserve.

In the DBIS a total of 59.2 MW is considered as aged units, where 37.2 MW have surpassed their maximum operational life of 25 years and 22 MW, 20 years. The age-specifics of these generator units are shown in Table 13.

Although these generator units have been and continue to be well maintained and deliver availability above 85%, their continued use as baseload units is accompanied by an elevated risk of major mechanical failure, which can result from the failure of components that are not renewed for the life of the engine, e.g., counterweight bolts. In 2020, one engine was destroyed and suspected to be the result of failed counterweight bolts, precipitating a series of other major mechanical failures.

Table 12: Breakdown of GPL's Total Firm Available Generation Capacity by fuel type

Fuel Type	Demerara	Berbice	Total DBIS	Anna Regina	Wakenaam	Leguan	Bartica	Total Isolated	Total GPL
MWs of HFO	152.9	13.0	**165.9**	5.40	-	-	-	**5.4**	**171.3**
MWs of LFO	7.1	17.9	**25.0**	9.90	1.47	1.23	4.90	**17.5**	**42.5**
Total Available Capacity (MW)	**160.0**	**30.9**	**190.9**	**15.30**	**1.47**	**1.23**	**4.90**	**22.9**	**213.8**
Fuel Type	**Demerara**	**Berbice**	**Total DBIS**	**Anna Regina**	**Wakenaam**	**Leguan**	**Bartica**	**Total Isolated**	**Total GPL**
% of HFO	95.6%	42.1%	**86.9%**	35.3%	0.0%	0.0%	0.0%	**23.6%**	**80.1%**
% of LFO	4.4%	57.9%	**13.1%**	64.7%	100.0%	100.0%	100.0%	**76.4%**	**19.9%**

For the mobile 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 factory refurbished generator units instead of performing a major overhaul.

Major overhauls are usually carried out at each operation tranche of 24,000 hours, which approximates to 3 calendar years of operation (based on total running hours). The total cost for a major overhaul is approximately 80% of the cost of a factory refurbished generator unit.

After major overhauls, it is currently a challenge to recuperate the performance of highspeed generator units or anywhere close to a factory refurbish unit. As such, the balance 20% additional capital cost is considered negligible when consider the increased performance efficiency, reliability, and availability of a factory refurbish unit.

Table 13: Aged generator units in the DBIS

Generator Units	Commissioned Dates	Age of Unit (Years)	Installed Capacity (MW)	Available Capacity (MW)
GOE	**Subtotal**		**11.00**	**7.10**
# 5 Niigata	1991	31	5.50	3.50
# 6 Niigata	1996	26	5.50	3.60
GoE - DP1	**Subtotal**		**22.00**	**22.00**
# 1 Wärtsilä	1996	26	5.50	5.50
# 2 Wärtsilä	1996	26	5.50	5.50
# 3 Wärtsilä	1996	26	5.50	5.50
# 4 Wärtsilä	1996	26	5.50	5.50
Kingston I - DP2	**Subtotal**		**22.00**	**22.00**

Generator Units	Commissioned Dates	Age of Unit (Years)	Installed Capacity (MW)	Available Capacity (MW)
# 1 Wärtsilä	1997	25	5.50	5.50
# 2 Wärtsilä	1997	25	5.50	5.50
# 3 Wärtsilä	1997	25	5.50	5.50
# 4 Wärtsilä	1997	25	5.50	5.50
Canefield	**Subtotal**		**5.50**	**3.50**
# 3DA - Mirrlees	1996	26	5.50	3.50
Onverwagt	**Subtotal**		**5.00**	**4.60**
# 5 GM	1981	41	2.50	2.30
# 7 GM	1981	41	2.50	2.30
Grand Total			**65.50**	**59.20**

Although the aged units are included in the Unreliable Capacity, they are considered dispatchable within the current planning period, and as such, their available capacity is included in the Total Available Capacity. LFO-fired units that require a major overhaul after year 2025, and within the current planning period, would be mothballed and classified as Cold Reserve Capacity.

Table 14 shows the annual Total Available Capacity, Reliable Capacity, Unreliable / Suspect Capacity, and Cold Reserve Capacity in MWs.

Table 14: Summary of existing power generation profile: 2023-2027 (DBIS)

DBIS	Year	2022	2023	2024	2025	2026	2027
Demerara	**Total Available Capacity (MW)**	**160.0**	**160.0**	**160.0**	**160.0**	**160.0**	**160.0**
	Reliable Capacity (MW)	**62.1**	**62.1**	**62.1**	**62.1**	**62.1**	**62.1**
	Unreliable Capacity (MW)	**97.9**	**97.9**	**97.9**	**97.9**	**97.9**	**97.9**
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Berbice	**Total Available Capacity (MW)**	**30.9**	**35.9**	**35.9**	**35.9**	**23.8**	**23.8**
	Reliable Capacity (MW)	**4.5**	**9.5**	**9.5**	**9.5**	**9.5**	**9.5**
	Unreliable Capacity (MW)	**26.4**	**26.4**	**26.4**	**26.4**	**14.3**	**14.3**
	Cold Reserve Capacity (MW)	-	-	-	-	**12.1**	-
	Accumulated Cold Reserve (MW)	-	-	-	-	**12.1**	**12.1**
DBIS Total	**Total Available Capacity (MW)**	**190.9**	**195.9**	**195.9**	**195.9**	**183.8**	**183.8**
	Reliable Capacity (MW)	**66.6**	**71.6**	**71.6**	**71.6**	**71.6**	**71.6**
	Unreliable Capacity (MW)	**124.3**	**124.3**	**124.3**	**124.3**	**112.2**	**112.2**
	Cold Reserve Capacity (MW)	-	-	-	-	**12.1**	-
	Accumulated Cold Reserve (MW)	-	-	-	-	**12.1**	**12.1**

Table 15 illustrates the impact of the GOE II – DP5 on LOLP and capacity reserve, where for 2021, there was a significant amount of capacity reserve and no LOLP violation.

From 2021 to 2022, peak demand increased by 21.6%. With an available firm capacity of 190.9 MW, the aggregated generation capacity was capable of achieving the annual LOLP target for year 2022.

In view of the demand forecast vs the current fleet of generator units in the DBIS, 2023 available capacity reserve would be 5.3% of the required capacity reserve for that year. Continuing into 2024 to 2027, the available capacity reserve would become negative and there would be significant LOLP violation, annually. See Table 15 for numerical details.

Table 15: Capacity reserve margin and LOLP profile for No Additional Firm Capacity

Year	Unit	2022	2023	2024	2025	2026	2027
Peak Demand (MW)	MW	153.5	186.6	210.4	280.6	318.9	354.3
Annual Peak Demand Growth Rate	%	21.6%	21.6%	12.8%	33.3%	13.6%	11.1%
Required Reserve Capacity Margin	MW	37.4	94.3	322.8	336.4	300.9	217.1
Required Capacity Reserve Margin (%) for LOLP Target	**%**	24%	51%	153%	120%	94%	61%
No Additional Capacity							
Available Generation Capacity	MW	190.90	195.90	195.90	195.90	183.80	183.80
Capacity Reserve	MW	37.40	9.30	-14.54	-84.68	-135.06	-170.49
Capacity Reserve Margin	%	24.36	4.98	-6.91	-30.18	-42.36	-48.12
LOLP	**%**	0.08	7.55	30.80	90.34	99.63	99.70
LOLE	day	0.29	27.57	112.41	329.75	363.65	363.92

In 2023, with an N-G-1 contingency, the DBIS would experiences frequency excursions[11] that could invariably result in either a system shut-down or major load shedding.

For this planning period and beyond, given Government's position and commitment to the projected economic and socio-economic developments, it becomes mandatory to invest significantly to increasing the firm power generation capacity in the DBIS.

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

Similarly, the isolated power systems in Essequibo presently have a combination of aged, inefficient, and unreliable high-speed mobile generator units. Where applicable and necessary, GPL would continue performing minor and major overhauls, as specified by the manufacturer of these generator units.

However, in cases where engine efficiency, availability and reliability are in dire need of improvement, the cost benefits of unit replacement would become significantly competitive relative to performing a major overhaul.

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

As the expansion programme draws closer to the planned commissioning timeline of the Amailia Falls Hydroelectric Project, it is intended to interconnect the Isolated Power Systems with the DBIS circa 2030. Therefore, circa 2030, the generator units that would be within the remit of the Isolated Power Systems would be mothballed and classified as Cold Reserve.

On account of the aforementioned, the customers of the Isolated Power Systems are expected to benefit from cheaper, cleaner, and reliable electricity service from a blend of new energy resources, which includes natural gas, hydro, and solar energy.

Having interconnection with the DBIS, the operation of the Isolated Power Systems would be independent of the local power generation facilities and by extension, fuel price volatility, fuel transportation risks and other fuel-associated risks that can adversely impact plant availability, electricity generation reliability and electricity supply security.

Anna Regina

GPL intends to reduce dispatch of LFO-fired generator units in Anna Regina due to the volatile market price of LFO, coupled with the dire need to improve power generation efficiency and reducing production cost. In this vane, GPL replaced the 5 MW HFO-fired power plant that was commissioned in 1995 with a new plant of similar technology in 2019.

Due to the improvement of power generation reliability, the rapid increase in electricity demand resulted in GPL having to revert to the use of LFO-fired units to halt the widening of the supply-demand gap. The LFO-fired units at the Anna Regina Power Plant are currently good working conditions, as they were commissions in 2020.

On the account of the above-mentioned, GPL currently has a total available capacity of 15.3 MW at the Anna Regina Power Plant. A total of 9.9 MW belongs to the group of high-speed LFO-fired capacity, which is considered to be unreliable from the perspective of the planning targets of this 5-year Programme. The balance 5.4 MW, which is HFO-fired, is considered to be reliable capacity.

Given that the generator units at Anna Regina Power Plant are relatively new, considering the year installed and dates for major overhauls, this 5-year Programme considers the total 15.3 MW to be the annual total available capacity. Further, with no generator units at this location surpassing its economic lifespan, there will be no cold reserve capacity during this planning period.

See Table 16 for further details.

Wakenaam

The first utility scale power plant in Wakenaam was commissioned circa 1997 with an installed LFO-fired capacity of 0.975 MW. While these generator units served and supported developments on the island successfully, owing to prudent maintenance, for 25 years, GPL has been able to retain to date a total of 0.65 MW of the 1997 commissioned capacity.

Though Wakenaam was equipped with 0.975 MW since 1997 and the electricity demand was less than 20% of the installed capacity, service supply was not 24hrs per day. In 2014, the power plant was re-conditioned and recommissioned to supply electricity 24hrs per day.

With a grant of US$2.3 million grant from the UAE, GPL is currently executing an EPC contract to construct a 700kW Solar PV farm with a battery energy storage system. The commercial operation of this project in 2023 will result in the transformation of the Wakenaam power system from pure Diesel to a Diesel-Solar PV+BESS energy system – a hybrid energy system.

In consideration of the above-mentioned, coupled with the Company's planning and operation targets, GPL invested in the installation of 2x325 kW LFO-fired new generator units. In addition to modernising the Wakenaam Power Plant, the investment is aimed primarily at strengthening the electricity supply, reliability, and security requirements of Wakenaam.

Albeit a technical constraint that existed with one of the 25-year-old units is resolved, its reliability is not on par with another similar unit. As a result, the Company intends to mothball this unit in 2023 upon the commercial operation of the hybrid energy system in Wakenaam.

On the account of the above, this Development and Expansion Programme considers that the total available firm capacity for the period 2023-2027 would be 1.15 MW for Wakenaam.

See Table 16 for further details.

Leguan

Similarly, in 1997, the Leguan power plant was commissioned with one 0.325 MW LFO-fired generator unit that did not operate 24hrs per day. In 2024, the 0.325 MW unit was replaced with three new 410 kW LFO-fired generator units, and the power plant was re-conditioned, reconfigured, and re-commissioned to generate electricity 24hrs per day. To date, the 410 kW generator units continue to support the energy-based activities on the Island.

In light of the fixed dates for major overhauls of the 410 kW LFO-fired generator units, the total 1.23 MW is considered to be the total available firm capacity for the current planning period. Further, with no generator units at this location surpassing its economic lifespan, there will be no cold reserve capacity during this planning period.

See Table 16 for further details.

Bartica

In 2019 GPL took ambitious steps to construct a new and more efficient 3.36 MW power plant at Dagg Point, Bartica. As a result of power generation reliability improvement, electricity demand increased rapidly, which resulted in GPL having to revert to the use of a 1.6 MW LFO-fired mobile generator unit to bolster the power plant's firm capacity.

With a loan from the IaDB, the Guyana Energy Agency (GEA) is currently executing an EPC contract to construct a 1.5 MW Solar PV farm with a battery energy storage system. The commercial operation of this project in 2023 will result in the transformation of the Bartica power system from pure Diesel to a Diesel-Solar PV+BESS energy system – a hybrid energy system.

To date, the total 3.36 MW generator units continue to support the energy-based activities in Bartica.

In light of the dates for major overhauls, the total 4.9 MW is considered to be the total available firm capacity from 2023 to 2024. In 2025, it intended to classify the 1.6 MW unit as Cold Reserve Capacity. See Table 16 for further details.

Table 16: Summary of power generation profile: 2022-2027 (Isolated Systems)

ISOLATED SYSTEMS	Year	2022	2023	2024	2025	2026	2027
Anna Regina	Total Available Capacity (MW)	15.3	15.3	15.3	15.3	15.3	15.3
	Reliable Capacity (MW)	5.4	5.4	5.4	5.4	5.4	5.4
	Unreliable Capacity (MW)	5.7	5.7	5.7	5.7	5.7	5.7
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Wakenaam	Total Available Capacity (MW)	1.47	1.15	1.15	1.15	1.15	1.15
	Reliable Capacity (MW)	0.82	0.82	0.82	0.82	0.82	0.82
	Unreliable Capacity (MW)	0.65	0.33	0.33	0.33	0.33	0.33
	Cold Reserve Capacity (MW)	-	0.33	-	-	-	-
	Accumulated Cold Reserve (MW)	-	0.33	0.33	0.33	0.33	0.33
Leguan	Total Available Capacity (MW)	1.23	1.23	1.23	1.23	1.23	1.23
	Reliable Capacity (MW)	-	-	-	-	-	-
	Unreliable Capacity (MW)	1.23	1.23	1.23	1.23	1.23	1.23
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Bartica	Total Available Capacity (MW)	4.9	4.9	4.9	3.3	3.3	3.3
	Reliable Capacity (MW)	3.3	3.3	3.3	3.3	3.3	3.3
	Unreliable Capacity (MW)	1.6	1.6	1.6	-	-	-
	Cold Reserve Capacity (MW)	-	-	-	1.6	-	-
	Accumulated Cold Reserve (MW)	-	-	-	1.60	1.60	1.60
Isolated System	Total Available Capacity (MW)	22.9	22.6	22.6	21.0	21.0	21.0
	Reliable Capacity (MW)	9.5	9.5	9.5	9.5	9.5	9.5
	Unreliable Capacity (MW)	9.2	8.9	8.9	7.3	7.3	7.3
	Cold Reserve Capacity (MW)	-	0.33	-	1.60	-	-
	Accumulated Cold Reserve (MW)	-	0.33	0.33	1.93	1.93	1.93

7. Current Status of Transmission and Distribution Systems

GPL's transmission and distribution systems currently constitute three main voltage levels; 69 kV for bulk power transfer, 13.8 kV for primary power distribution and lower utilisation voltage (480 V,440 V,415 V, 240 V and 120 V) for customer-specific applications.

The present transmission and distribution systems provide electricity supply coverage to approximately 97.5% of the total number of households on the Coastland.

The characteristics of the transmission and distribution systems include the following attributes:

1. The transmission voltage level of 69 kV is only present in the DBIS, and the 16 transmission lines result in a total length of 354.77 km[12], whereas per conductor type:
    a. 119.74 km is Canton;
    b. 156.07 km is Partridge;
    c. 2.18 km is XLPE Submarine Cable.
2. A total of 39 active primary distribution feeders in the DBIS have an aggregated estimated length of approximately 873 km. Total line length extension in 2021 amounted to 64 km;
3. With regards to the automatic load-shedding scheme in the DBIS, 29 feeders have this scheme activated and 10 do not have the functionality for mitigating low frequency excursions.

Within the total GPL power system, majority of the network-related challenges are experienced in the DBIS. A summary of the critical issues currently experienced, and which the Company is aggressively working to address within the shortest possible time frame, are as follows:

1. Reduced life span of pole structures due to poor poles and cross-arms material quality;
2. Impassable access to pole structures located in remote terrains; largely for the transmission lines and to some extent, sections of primary distribution lines;
3. Frequent line trips due to vegetation encroachments on open conductors;

[12] The updated transmission line lengths are premised on recent data collection campaigns to improve transmission line protection and coordination.

4. High voltage drops due to a combination of long feeder lengths, high electricity demands, and low power factor presented primarily by maximum demand customers;
5. Widespread outages due to fault clearing by protection relay scheme at substation level for feeders without Auto reclosers;
6. A large number of and duration of outages to facilitate line maintenance and emergency switching;
7. Poor operation visibility and the absence of remote control and supervision for sections of primary distribution feeders result in a high dependency on customer fault reports.
8. Poor line construction and maintenance works.
9. Lack of adequate and timely availability of T&D resources;
10. Absence of standards and specifications that are directly related to T&D line hardware materials and workmanship;
11. Lack of proper monitoring of condition and performance of T&D networks; and
12. Delayed implementation of upgrades and other corrective actions, which includes vegetation management.

For the isolated system, Table 17 provides a breakdown of the primary and secondary distribution line details.

Table 17: Breakdown of distribution feeders lengths in Isolated Systems

Location	Feeders	Primary (MV) km	Secondary (LV) km
Anna Regina	North	28.64	214.87
	South	35.54	
	West	17.6	
	CRM	0.27	
Total		**82.05**	
Leguan	West	8.8	24.04
	East	8.8	
	North	11.2	
Total		**28.8**	
Wakenaam	North	10.6	21
	South	10.59	
Total		**21.19**	
Bartica	F1	3.2	24.26
	F2	6.44	
	F3	8	
Total		**17.64**	

8. DBIS Generation Reliability – No Additional Capacity

The simulations performed in this scenario are primarily to evaluate the Loss of Load Probability (LOLP) of the DBIS against the backdrop of the demand forecast and assuming no addition of new power generation capacity.

The results as shown in **Error! Not a valid bookmark self-reference.** indicate that:

1. Generation reserves will be violated from 2023 and onwards, becoming negative from 2024. A negative system reserve indicates that demand is greater than generation which leads to a generation shortfall.
2. the Loss of Load Probability (LOLP) will be severely violated from year 2023 and onwards. This means that almost every day of year 2024 and onwards there will be blackouts unless more generation is added.

Table 18 reveals that from 2023, the DBIS current aggregated firm power generation capacity will not be able to achieve the planning target.

The results as shown in **Error! Not a valid bookmark self-reference.** indicate that:

3. Generation reserves will be violated from 2023 and onwards, becoming negative from 2024. A negative system reserve indicates that demand is greater than generation which leads to a generation shortfall.
4. the Loss of Load Probability (LOLP) will be severely violated from year 2023 and onwards. This means that almost every day of year 2024 and onwards there will be blackouts unless more generation is added.

Table 18: DBIS Scenario No.1 Generation Reliability Results for 2023-2027[13]

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLP (%)
2022	983.4	153.5	190.9	37.4	24.4	28.6	0.08
2023	1,200.3	186.6	195.9	9.3	5.0	4,877.2	7.55
2024	1,359.2	210.4	195.9	-14.5	-6.9	39,411.4	30.80
2025	1,812.2	280.6	195.9	-84.7	-30.2	349,258.7	90.34
2026	2,067.8	318.9	183.8	-135.1	-42.4	691,175.3	99.63
2027	2,300.7	354.3	183.8	-170.5	-48.1	925,569.1	99.70

Further, in order for the DBIS to operate reliably, the results shown in The results as shown in **Error! Not a valid bookmark self-reference.** indicate that:

[13] Details for 2022 were included for information purposes only.

5. Generation reserves will be violated from 2023 and onwards, becoming negative from 2024. A negative system reserve indicates that demand is greater than generation which leads to a generation shortfall.
6. the Loss of Load Probability (LOLP) will be severely violated from year 2023 and onwards. This means that almost every day of year 2024 and onwards there will be blackouts unless more generation is added.

Table 18 are testimony to the dire need to increase the firm power generation capacity aggressively in the DBIS.

From an operation's perspective of generator dispatch to satisfy the forecast annual peak demand, Table 19 shows that from 2023, the DBIS will not have contingency capacity after allocating the required spinning reserve to ensure grid stability.

Table 19: Scenario No.1- Available Contingency Capacity Forecast– DBIS.

Existing Capacity, MW	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
DEMERARA						
Garden of Eden Power Station	7.1	7.1	7.1	7.1	7.1	7.1
Garden of Eden 46.5 MW	46.5	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
Total Demerara	**160**	**160**	**160**	**160**	**160**	**160**
BERBICE						
Existing Capacity, MW	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Canefield						
Hyundai	5.0	5.0	5.0	5.0	5.0	5.0
No. 4 Mirrlees Blackstone	3.5	3.5	3.5	3.5	3.5	3.5
Mobile Sets	4.8	4.8	4.8	4.8	0.0	0.0
Sub-total	**13.3**	**13.3**	**13.3**	**13.3**	**8.5**	**8.5**
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	8.5	8.5	8.5	8.5	1.2	1.2
Sub-total	**13.1**	**13.1**	**13.1**	**13.1**	**5.8**	**5.8**
Skeldon						
SEI	4.5	9.5	9.5	9.5	9.5	9.5
Sub-total	**4.5**	**9.5**	**9.5**	**9.5**	**9.5**	**9.5**
Total Berbice	**30.9**	**35.9**	**35.9**	**35.9**	**23.8**	**23.8**
Total DBIS	**190.9**	**195.9**	**195.9**	**195.9**	**183.8**	**183.8**

Existing Capacity, MW	2022	2023	2024	2025	2026	2027
Min Required Spinning Reserve (MW)	**13.95**	**13.95**	**13.95**	**13.95**	**13.95**	**13.95**
Net Capacity (MW)	**176.95**	**181.95**	**181.95**	**181.95**	**169.85**	**169.85**
Peak Demand (MW)	153.5	186.6	210.4	280.6	318.9	354.3
Contingency Capacity (MW)	**23.5**	**- 4.6**	**- 28.5**	**- 98.6**	**-149.0**	**-184.4**

9. Isolated Power System's Generation Reliability – No Additional Capacity

The simulations performed in this scenario are primarily to evaluate the Loss of Load Probability (LOLP) of the Isolated Power Systems, individually, against the backdrop of the demand forecast and assuming no addition of new power generation capacity.

Anna Regina

The Anna Regina power system is the fastest growing amongst the isolated power systems in the Essequibo Country. This power system continues to experience a steady load demand growth and as a result, an increase in firm generation capacity is paramount to mitigating generation shortfall and grid instability.

The simulation results shown in

Table *20* indicate that the Anna Regina power system would have adequate firm power generation capacity until 2024. From 2025, with no firm generation expansion, the capacity reserve margin will decrease to 33.4% and the LOLP target will be violated. Although the LOLP violation in 2025 would be 33.3% above the annual target value, it is considered significant given that the peak demand of this power system is expected to continue growing at an average rate of 3.8MW or 133% per annum. Consequently, the stability and reliability of the Anna Regina power system would be at risk from 2025.

Further, it must be brought into the context that agriculture, which depends on stable and reliable electricity, is one of the main drivers of the economy on the Essequibo Coast. As such, economic and socio-economic growths are likely to be constrained, should there be poor power generation reliability and quality of electricity service on the Essequibo Coast.

Table 20: Anna Regina Scenario No.1 Reliability Results for 2023-2027

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLP (%)
2022	39.9	6.3	15.3	9.0	143.2	0.0	0.0001
2023	49.1	7.7	15.3	7.6	97.9	0.1	0.002
2024	56.5	8.9	15.3	6.4	72.5	0.5	0.009

2025	73.0	11.5	15.3	3.8	33.4	22.4	0.36
2026	113.8	17.9	15.3	-2.6	-14.3	6,671.6	42.91
2027	160.2	25.1	15.3	-9.8	-39.1	43,572.7	97.38

Bartica

Bartica has recorded a steady load growth since the installation of the 3.3 MW power plant in 2019. It is forecasted that the load will grow by over 385% between 2022 and 2027. As a result, Table 21 show that the capacity reserve LOLP would be violated from 2023. Progressively, the capacity reserve would decrease against the growing peak demand, where it becomes negative by 2025, with significant violation to the LOLP.

Within the context of providing business services, electricity is a catalyst for economic development. Given that Bartica is one of the major gateways to the hinterland regions, power generation and supply of reliable electricity is critical to residents of Bartica to provide essential services to sustain the mining industry. In light of the aforementioned, the generation reliability results shown in Table 21 would likely constrain economic and socio-economic growth in Bartica.

Table 21: Bartica Scenario No.1 Reliability Results for 2023-2027

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLP (%)
2022	12.1	2.0	4.90	3.0	151.3	6.6	0.34
2023	15.7	2.5	4.90	2.4	93.7	29.2	0.73
2024	17.9	2.9	4.90	2.0	70.7	76.5	2.72
2025	23.0	3.7	4.90	1.2	32.4	418.8	8.62
2026	36.1	5.8	4.90	-0.9	-15.5	5,473.4	71.10
2027	50.7	8.1	4.90	-3.2	-39.8	19,263.4	99.65

Wakenaam

In view of the demand forecast, the simulation results shown in Table 22 indicate that the Wakenaam power system would violate the LOLP target by 2025. It must be highlighted that although the capacity reserve margin in 2025 is high for such small power system, should there be an increase in the forced outage rate of the 25-year-old generator units, the power system would become unstable, resulting in poor power supply reliability.

Similarly, to Anna Regina, the main activity that drives the local economy in Wakenaam is rice cultivation. Consequently, downward performance in generation reliability would not encourage economic and socio-economic developments on the island.

Table 22: Wakenaam Scenario No.1 Reliability Results for 2023-2027

Fiscal Year	Load (GWh)	Peak Load	Generati on	Capacity Reserves	Capacity Reserve	EENS (MWh)	LOLP (%)

		(MW)	Capacity (MW)	(MW)	Margin (%)		
2022	2.1	0.4	1.47	1.0	241.9	0.2	0.02
2023	3.3	0.6	1.47	0.8	133.3	1.0	0.07
2024	3.8	0.7	1.47	0.7	101.4	2.1	0.15
2025	4.9	1.0	1.47	0.5	54.7	10.6	0.66
2026	7.6	1.5	1.47	0.0	0.0	180.9	9.37
2027	10.7	2.1	1.47	-0.6	-29.3	1,332.2	43.79

Leguan

According to the results shown in

Table 23, the LOLP of the Leguan power system would be violated in 2023. It must be highlighted that although the capacity reserve margin in 2023 is relatively high for such small power system, should there be an increase in the forced outage rate of the generator units, the power system would become unstable, resulting in poor power supply reliability.

Similarly, to Wakenaam, the main activity that drives the local economy in Leguan is rice cultivation. Consequently, downward performance in generation reliability would not encourage economic and socio-economic developments on the island.

Table 23: Leguan Scenario No.1 Reliability Results for 2023-2027

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLP (%)
2022	2.2	0.4	1.23	0.8	179.5	2.8	0.18
2023	3.4	0.7	1.23	0.5	73.2	9.8	0.55
2024	4.0	0.8	1.23	0.4	51.9	15.7	0.84
2025	5.1	1.1	1.23	0.2	17.1	78.2	4.68
2026	7.9	1.6	1.23	-0.4	-25.0	720.0	31.99
2027	11.2	2.3	1.23	-1.1	-46.5	2,714.0	60.10

In consideration of the dispatch of generators to satisfy the forecast peak demand and the availability of adequate contingency capacity after allocating the required spinning reserve, which is expected to guarantee the stability of each isolated power system, Table 24 illustrates the following salient points:

1. **Anna Regina** – this power system would have sufficient available generation capacity to satisfy the spinning reserve requirement as well as provide adequate contingency capacity to mitigate an N-G-1 contingency until 2025. For the years beyond 2025, the power system would not have enough contingency capacity, which can result in unstable and unreliable operations See Table 24 for numerical details.
2. **Bartica** – for this power system, there would be sufficient available generation capacity to satisfy the spinning reserve requirement as well as provide adequate contingency capacity to mitigate an N-G-1 contingency up to 2024. For the years beyond 2024, the power system would not have enough contingency capacity, which can result in unstable and unreliable operations. See Table 24 for numerical details.
3. **Wakenaam** – this power system is expected to have sufficient available generation capacity to satisfy the spinning reserve requirement as well as provide adequate contingency capacity to mitigate an N-G-1 contingency until 2024. For the years beyond 2024, the power system would not have enough contingency capacity, which can result in unstable and unreliable operations. See Table 24 for numerical details.
4. **Leguan** – without the addition of firm power generation capacity, the contingency capacity becomes extremely critical as of 2023. Consequently, there will not be any contingency capacity to mitigate an N-G-1 contingency for the life of this Development and Expansion Programme. See Table 24 for numerical details.

Table 24: Scenario No.1- Available Contingency Capacity Forecast– Isolated Power Systems

Existing Available Firm Capacity, MW	2022	2023	2024	2025	2026	2027
Anna Regina						
MAN (MW)	5.4	5.40	5.40	5.40	5.40	5.40
Mobile Sets (MW)	9.9	9.90	9.90	9.90	9.90	9.90
Total Anna Regina (MW)	**15.3**	**15.30**	**15.30**	**15.30**	**15.30**	**15.30**
Min Required Spinning Reserve (MW)	2.70	**2.70**	**2.70**	**2.70**	**2.70**	**2.70**
Net Capacity (MW)	12.60	**12.60**	**12.60**	**12.60**	**12.60**	**12.60**
Peak Demand (MW)	6.29	7.73	8.87	11.47	17.86	25.12
Contingency Capacity (MW)	**6.31**	**4.87**	**3.73**	**1.13**	**-5.26**	**-12.52**
Bartica						
Cummins (MW)	3.30	3.30	3.30	3.30	3.30	3.30
Mobile Units (MW)	1.60	1.60	1.60	1.60	1.60	1.60
Total Bartica (MW)	**4.90**	**4.90**	**4.90**	**4.90**	**4.90**	**4.90**
Min Required Spinning Reserve (MW)	**1.68**	**1.68**	**1.68**	**1.68**	**1.68**	**1.68**
Net Capacity (MW)	**3.22**	**3.22**	**3.22**	**3.22**	**3.22**	**3.22**
Peak Demand (MW)	1.95	2.53	2.87	3.70	5.80	8.14

Contingency Capacity (MW)	**1.28**	**0.69**	**0.35**	**-0.48**	**-2.58**	**-4.92**
Wakenaam						
Caterpillar (MW)	1.47	1.47	1.47	1.47	1.47	1.47
Total Wakenaam (MW)	**1.47**	**1.47**	**1.47**	**1.47**	**1.47**	**1.47**
Min Required Spinning Reserve (MW)	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**
Net Capacity (MW)	**0.86**	**0.86**	**0.86**	**0.86**	**0.86**	**0.86**
Peak Demand (MW)	0.43	0.63	0.73	0.95	1.47	2.08
Contingency Capacity (MW)	**0.42**	**0.22**	**0.13**	**-0.10**	**-0.62**	**-1.22**
Leguan						
Caterpillar (MW)	1.23	1.23	1.23	1.23	1.23	1.23
Total Leguan (MW)	**1.23**	**1.23**	**1.23**	**1.23**	**1.23**	**1.23**
Min Required Spinning Reserve (MW)	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**
Net Capacity (MW)	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**
Peak Demand (MW)	0.44	0.71	0.81	1.05	1.64	2.30
Contingency Capacity (MW)	**0.18**	**-0.09**	**-0.20**	**-0.43**	**-1.02**	**-1.69**

10. Committed Firm and Intermittent Generation Capacities - DBIS

With the DBIS coverage stretching across the Coastal Plain, from the East Bank of the Essequibo River in the West to Moleson Creek in the East, and Camp Alpha on the Southern end – Linden/Soesdyke highway, it invariably has a significant larger coverage of the total number of customers than the isolated power systems.

The major economic activities, which includes agriculture and service industries to the mining and the Oil and Gas sector, are within the coverage of the DBIS. Consequently, it is crucial for the DBIS to operate at the highest level of reliability and stability. Further, a reliable and stable electric power system is one of the crucial drivers of the planned economic activities and for aligning the electricity sector with the goals of LCDS-2030, long-term National Energy Priorities and other Government initiatives. As result, achieving the expansion planning targets (see section 5.2.1 on page 79) is critical to a well-developed and run utility company.

Further, it is intended that Linden's power system becomes interconnected with the DBIS by 2026.

Improvement in LOLP is primarily driven by increasing the firm generation capacity within a power system using units that have forced outage rates lower than 3%, a well scheduled annual maintenance plan and timely project commissioning dates to satisfy the forecast demand reliably. Firm generation capacity includes only conventional generators and Battery Energy Storage Systems (BESS) that are configured to be grid forming.

The Government's committed generation expansion projects that drive LOLP improvements within the current planning period across the DBIS includes:

1. 300 MW Gas-to-Energy Project.
2. BESS to be installed at the 300 MW GTE Project to mitigate an N-1 on one GT (approximately 57.21 MW – 2hr).

3. 15 MW-1hr BESS to be installed in Linden.

On the account of the above, several simulation exercises were conducted to determine the additional required firm generation capacity to achieve the LOLP target and the other expansion planning targets. The required firm generation capacities were further developed to formulate the expansion projects in this 5-year Programme for the DBIS.Table *25* shows the positive effects of adding firm generation capacity to the DBIS. Comparing with The results as shown in **Error! Not a valid bookmark self-reference.** indicate that:

7. Generation reserves will be violated from 2023 and onwards, becoming negative from 2024. A negative system reserve indicates that demand is greater than generation which leads to a generation shortfall.
8. the Loss of Load Probability (LOLP) will be severely violated from year 2023 and onwards. This means that almost every day of year 2024 and onwards there will be blackouts unless more generation is added.

Table 18 on page 106, by adding the firm capacities shown in Table 26, there would be no violation of the annual LOLP target and significant improvements in the capacity reserve in the DBIS. Additionally, the other expansion planning targets, as set out in the National Grid Code, are expected to be achieved with this generation expansion plan.

The LOLP violation shown in Table 25 is due to the commissioning of the 2x25 MW IPPs, 25 MW and 10 MW EPC projects during the last quarter of year 2023.

Table 25: Generation Reliability with Planned Expansions – DBIS

Fiscal Year	Load (GWh)	Peak Load (MW)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLP (%)
2022	983.4	153.5	190.90	37.4	24.4	28.6	0.08
2023	1,200.3	186.6	280.90	94.3	50.5	786.2	1.45
2024	1,359.2	210.4	564.00	353.6	168.0	5.4	0.00967
2025	1,812.2	280.6	649.50	368.9	131.5	0.0	0.00004
2026	2,174.7	335.2	652.40	317.2	94.6	0.1	0.00011
2027	2,421.1	372.7	602.40	229.7	61.6	1.6	0.00128

The planned firm generation expansion (as shown in Table 26) would improve the capacity reserve margin of the DBIS significantly, thereby allowing the annual LOLP target to be achieved within the current planning period.

Table 26: Proposed Generation Addition – DBIS

Name of Location	Type	Installed Capacity (MW)				
		2023	2024	2025	2026	2027
25 MW IPP – Canefield*	Firm Capacity	25.0	-	-	-	-

Name of Location	Type	Installed Capacity (MW)				
25 MW EPC - Canefield	Firm Capacity	25.0	-	-	-	-
25 MW IPP – Columbia*	Firm Capacity	25.0	-	-	-	-
10 MW EPC - Canefield	Firm Capacity	10.0	-	-	-	-
300 MW GTE - Simple Cycle	Firm Capacity	-	225.9	-	-	-
GUYSOL - Berbice	Non-Firm Capacity	-	10.0	-	-	-
300 MW GTE - Combine Cycle	Firm Capacity	-	-	85.5	-	-
300 MW GTE Project BESS	Firm Capacity		57.2			
Linden BESS*	Firm Capacity				15.0	
Linden Solar PV*	Non-Firm Capacity				15.0	
Total New Additions – Generators		**85.0**	**235.9**	**85.5**	**-**	**-**
Total Accumulated Additions – Generators		**85.0**	**320.9**	**406.4**	**406.4**	**356.4**
Annual Non-Firm Capacity		**-**	**10.0**	**-**	**15.0**	**-**
Annual Firm Capacity – Generators		**85.0**	**225.9**	**85.5**	**-**	**-**
Accumulated Firm Capacity – Generators		**85.0**	**310.9**	**396.4**	**396.4**	**346.4**
Existing Firm Capacity – Generators		**195.9**	**195.9**	**195.9**	**183.8**	**183.8**
Total Firm Capacity – Generators		**280.9**	**506.8**	**592.3**	**580.2**	**530.2**
Accumulated Firm Capacity – BESS		**-**	**57.2**	**57.2**	**72.2**	**72.2**
Grand Total Firm Capacity - Generators + BESS		**280.9**	**564.0**	**649.5**	**652.4**	**602.4**

NB: * IPP has a duration of 3-years and Linden connects with the DBIS in 2026.

The Company intends to manage and configure these additional firm generation capacities with a focus on furthering the use of clean, indigenous, and affordable energy resources to:

1. Satisfy the forecast demand reliably;
2. Improve power generation reliability;
3. Reduce Guyana’s dependency on imported fossil fuels for electricity generation;
4. Reduce production cost and by extension, tariff.
5. Assist in increasing the disposable income for Customers
6. Allow Government and GPL to support other critical energy-driven development programmes; and
7. Facilitate Guyana to be achieve its climate change commitments, as expressed in the LCDS-2030, and for alignment with the Sustainable Development Goals.

In consideration of the operating planning criteria[14], Table 27 shows the annual contingency capacity of the DBIS. For each year, the planned contingency capacity is larger than the unit capacity of the largest generator. As a result, it is expected for the DBIS to operate stably and to have the technical capacity to mitigate an N-G-1 for the annual peak period.

In view of the above, this Programme demonstrates that the DBIS will have the technical capabilities to meet the energy and power requirements of the peak demand forecast, coupled with the currently existing self-generators.

From the perspectives of the above generation expansion plan for the current planning period, the electricity sector is positioned to satisfy customers electricity requirements and to support Government's planned economic activities sustainably.

Further to the current planning horizon, as the peak demand is forecasted to increase, should the firm generation capacity remain fixed, the contingency capacity will decrease. The situation can be exacerbated in the event of increased forced outage rate, improper generator maintenance plan and untimely commissioning firm power generation expansions. As such, it is mandatory for GPL to assess continuously the critical planning and operational parameters to ensure the electricity sector remains committed to the planning and operation targets set out in the expansion programme.

[14] See section 5.2.2 on page 7979 for details

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

Existing and New Power Generators	Type	2023	2024	2025	2026	2027
DEMERARA						
Garden of Eden Power Station	Firm Capacity	7.1	7.1	7.1	7.1	7.1
Garden of Eden 46.5 MW	Firm Capacity	46.5	46.5	46.5	46.5	46.5
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
25 MW IPP – Columbia	Firm Capacity	25.0	25.0	25.0	25.0	-
300 MW GTE - Simple Cycle	Firm Capacity		225.9	225.9	225.9	225.9
300 MW GTE - Combine Cycle	Firm Capacity			85.5	85.5	85.5
Demerara Total Installation Generation Capacity (MW)		**185.00**	**410.89**	**496.43**	**496.43**	**471.43**
Demerara Total Firm Generation Capacity (MW)		**185.00**	**410.89**	**496.43**	**496.43**	**471.43**
Demerara Total Non-Firm Generation Capacity (MW)		**-**	**-**	**-**	**-**	**-**
BERBICE						
Canefield	**Type**	**2023**	**2024**	**2025**	**2026**	**2027**
Hyundai	Firm Capacity	5	5	5	5	5
No. 4 Mirrlees Blackstone	Firm Capacity	3.5	3.5	3.5	3.5	3.5
Mobile Sets	Firm Capacity	4.8	4.8	4.8	0	0
25 MW IPP – Canefield	Firm Capacity	25	25	25	25	0
25 MW EPC – Canefield	Firm Capacity	25	25	25	25	25
10 MW EPC – Canefield	Firm Capacity	10	10	10	10	10
GUYSOL – Berbice	Non-Firm Capacity		3	3	3	3
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	8.5	8.5	8.5	1.2	1.2
GUYSOL – Berbice	Non-Firm Capacity		4	4	4	4

Existing and New Power Generators	Type	2023	2024	2025	2026	2027
Williamsburg						
GUYSOL – Berbice	Non-Firm Capacity		3	3	3	3
Skeldon						
SEI	Firm Capacity	9.5	9.5	9.5	9.5	9.5
Berbice Total Installation Generation Capacity (MW)		**95.9**	**105.9**	**105.9**	**93.8**	**68.8**
Berbice Total Firm Generation Capacity (MW)		**95.9**	**95.9**	**95.9**	**83.8**	**58.8**
Berbice Total Non-Firm Generation Capacity (MW)		**0**	**10**	**10**	**10**	**10**
Linden		**2023**	**2024**	**2025**	**2026**	**2027**
GUYSOL – Linden	Non-Firm Capacity				15	15
Linden Total Installation Generation Capacity (MW)		**0**	**0**	**0**	**15**	**15**
Linden Total Firm Generation Capacity (MW)		**0**	**0**	**0**	**0**	**0**
Linden Total Non-Firm Generation Capacity (MW)		**0**	**0**	**0**	**15**	**15**
DBIS Existing Firm Capacity (MW)		**195.9**	**195.9**	**195.9**	**183.8**	**183.8**
DBIS Existing Non-Firm Capacity (MW)		**0**	**0**	**0**	**0**	**0**
DBIS New Firm Capacity (MW)		**85.0**	**310.9**	**396.4**	**396.4**	**346.4**
DBIS New Non-Firm Capacity (MW)		**0**	**10**	**10**	**25**	**25**
Power Grid Accumulated Firm Generation Capacity (MW)		**280.9**	**506.8**	**592.3**	**580.2**	**530.2**
Power Grid Accumulated Non-Firm Generation Capacity (MW)		**-**	**10.00**	**10.00**	**25.00**	**25.00**
Power Grid Min Required Spinning Reserve (MW)		**13.95**	**88.80**	**88.80**	**93.30**	**93.30**
Total BESS Capacity (MW)			**57.20**	**57.20**	**72.20**	**72.20**
Power Grid Net Capacity (MW)		**266.95**	**475.19**	**560.73**	**559.13**	**509.13**
Power Grid Forecast Peak Demand (MW)		**186.60**	**210.44**	**280.58**	**326.04**	**362.58**
Contingency Capacity (MW)		**80.35**	**264.76**	**280.15**	**233.08**	**146.54**

11. Planned Firm and Committed Intermittent Generation Capacities - Isolated Power Systems

11.1 Anna Regina

Table 28 shows the reliability benefits of the planned generation expansion projects (see Table 29) on the LOLP. As a result of the 12 MWh BESS in 2024, the capacity reserve would increase from 6.4 MW to 18.4 MW. Further, the BESS would improve the LOLP in 2025 by decreasing it from 0.36% to 0.05%.

In 2026, with the addition of 11 MW HFO-fired generator unit, the capacity reserve increase to 20.4 MW, and the LOLP improving from 42.91% (without the 11 MW addition) to 0.01%.

Given the need to ensure the expansion plan is target compliant, the addition of a 1.8 MW HFO-fired generator unit will guarantee the annual LOLP is achieved. See Table 28 for further numerical details.

Table 28: Generation Reliability with Planned Expansions – Anna Regina

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLP (%)
2022	39.9	6.3	15.3	9.0	143.2	0.0	0.0001
2023	49.1	7.7	15.3	7.6	97.9	0.1	0.002
2024	56.5	8.9	27.3	18.4	207.8	0.1	0.001
2025	73.0	11.5	27.3	15.8	138.0	3.3	0.05
2026	113.8	17.9	38.3	20.4	114.4	1.5	0.01
2027	160.2	25.1	40.1	14.98	59.6	47.6	0.27

In addition to the existing firm generation capacity, in 2027, Anna Regina is expected to have a total installed capacity of 40.1 MW (Table 29).

Table 29: Proposed Generation Capacity Addition - Anna Regina

Anna Regina	Type	Installed Capacity (MW)				
		2023	2024	2025	2026	2027
Solar PV Farms	Non-Firm Capacity		8.0			
BESS	Firm Capacity		12.0			
2x5.5 MW HFO Units	Firm Capacity				11.0	
1x1.8 MW HFO Units	Firm Capacity					1.8
Total Non-Firm Capacity		-	8.0	-	-	-
Total Firm Capacity		-	12.0	-	11.0	1.8
Total Accumulated Firm Capacity		-	12.0	12.0	23.0	24.8
Existing Firm Capacity		**15.3**	**15.3**	**15.3**	**15.3**	**15.3**
Grand Total Firm Capacity		**15.3**	**27.3**	**27.3**	**38.3**	**40.1**

In consideration of the operation planning criteria, the planned generation expansion (Table 29) would deliver positive contingency capacity, with annual values larger than the largest generator unit capacity present in that year. See Table 30 for further numerical details.

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

- Decarbonization of Anna Regina electricity grid.
- Reduction of fossil fuel dependence.
- Provide the required firm power generation capacity to meet the growing electricity demand on the Essequibo Coast and to sustain economic growth.
- In view of the above mentioned, improvement in electricity reliability, stability and quality of electric serve will certainly benefit the livelihood and personal development of residents on the Essequibo Coast.
- Reduce dependency on the use of LFO to generate electricity, thereby reducing production cost in support of tariff reduction.
- Improve generation reliability and capacity reserve margin at the plant.
- The planned use of 2x5.5 MW units in 2026 will enable the power plant to have firm baseload capacity, which will also bolster the stability of the power system. Further, these units are planned to be installed in the currently decommissioned Anna Regina Power Plant. This power plant currently houses 2x5.5 MW HFO-fired decommissioned units.
- The planned extension in 2027 aims at utilising the exact HFO-fired unit capacity that currently exist in Anna Regina.

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

Anna Regina Generation Capacity		**2023**	**2024**	**2025**	**2026**	**2027**
Existing MAN	Firm Capacity	5.4	5.4	5.4	5.4	5.4
Existing Mobile Sets	Firm Capacity	9.9	9.9	9.9	9.9	9.9
Solar PV Farms - Addition	Non-Firm Capacity	-	8.0	8.0	8.0	8.0
2x5.5 MW HFO Units - Addition	Firm Capacity	-	-	-	11.0	11.0
1x1.8 MW HFO Units - Addition	Firm Capacity	-	-	-	-	1.8
Total Installed Generation (MW)		**15.3**	**23.3**	**23.3**	**34.3**	**36.1**
Total Firm Generation Capacity (MW)		**15.3**	**15.3**	**15.3**	**26.3**	**28.1**
Total Non-Firm Generation Capacity (MW)		**-**	**8.0**	**8.0**	**8.0**	**8.0**
Min Required Spinning Reserve (MW)		**2.7**	**5.1**	**5.1**	**5.1**	**5.1**
Total BESS Capacity (MW)			**12.0**	**12.0**	**12.0**	**12.0**
Net Capacity (MW)		**12.6**	**22.2**	**22.2**	**33.2**	**35.0**
Peak Demand (MW)		**7.7**	**8.9**	**11.5**	**17.9**	**25.1**
Contingency Capacity (MW)		**4.9**	**13.3**	**10.7**	**15.3**	**9.9**

11.2 Bartica

Although Bartica's power system is physically small, it is expected to experience electricity demand growth due to the positive prospects of the mining industry amid developments of the other economic sectors, such as, tourism.

Given the above, it is planned to install a 1.1 MW LFO-fired generator unit in Bartica to reduce the LOLP from 0.73% (without adding the 1.1 MW) to 0.08% in 2023 (Table 31). In 2024, simulation results have indicated that the LOLP target will be violated by 0.04% and which can be considered to be negligible. However, should there be increase in the forced outage rates of the generator units, it is expected for the Company to advance the 2025 generation expansion plan (Table 32).

The planned addition in 2025 of 2x2.4 MW of firm capacity in Bartica will certainly improve the baseload performance of the power plant and grid stability amid the growing peak demand and the absence of grid forming capability in the Solar PV+BESS system.

To complete this planning period, an additional 1.1 MW and 2.4 MW generator unit will be required to bolster the power plant's capacity to satisfy the forecast demand for electricity in 2026 and 2027, respectively.

The Bartica hybrid energy system has the capacity, but not the capability to operate as a grid forming system. The Company intends to have this lacking capability addressed in order to mitigate the 2027 LOLP violation, as well as use the BESS to optimise generator dispatch and reduce production cost. In view of the aforementioned, the BESS will therefore add approximately 1.6 MW of firm capacity to the grid, and also provide the requisite ancillary services to achieve the LOLP target.

Table 31:Generation Reliability with Planned Expansions – Bartica

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLP (%)
2022	12.1	2.0	4.90	3.0	151.3	6.6	0.34
2023	15.7	2.5	6.00	3.5	137.2	2.8	0.08
2024	17.9	2.9	6.00	3.1	109.1	8.1	0.31
2025	23.0	3.7	10.80	7.1	191.9	1.1	0.03
2026	36.1	5.8	11.90	6.1	105.2	9.2	0.19
2027	50.7	8.1	14.30	6.2	75.7	25.1	0.40

In view of the generation expansion plan for Bartica (Table 32) within the current planning period, there is an opportunity to convert the existing units and ensure the new units are capable of combusting an optimal blend of diesel-natural gas. Such fuel blend will certainly aid to reducing production cost and supporting tariff reduction. The Company intends to relish opportunities that support tariff reduction and the LCDS-2030 goals.

Table 32: Proposed Generation Capacity Addition to Bartica

Bartica	Type	Installed Capacity (MW)				
		2023	2024	2025	2026	2027
LFO Unit (1x1.1 MW)	Firm Capacity	1.10				
LFO Unit (2x2.4 MW)	Firm Capacity			4.80		
LFO Unit (1x1.1 MW)	Firm Capacity				1.10	
LFO Unit (1x2.4 MW)	Firm Capacity					2.40
Solar PV Farm	Non-Firm Capacity	1.50				
Total Non-Firm Capacity		**1.50**	**-**	**-**	**-**	**-**
Total Firm Capacity		**1.10**	**-**	**4.80**	**1.10**	**2.40**
Total Accumulated Firm Capacity		**1.10**	**1.10**	**5.90**	**7.00**	**9.40**
Existing Firm Capacity		**4.90**	**4.90**	**4.90**	**4.90**	**4.90**
Grand Total Firm Capacity		**6.00**	**6.00**	**10.80**	**11.90**	**14.30**

The BESS that compliments the Solar PV farm is configured to be a grid following system. Consequently, the utility scale Solar PV farm + BESS in Bartica will require a spinning reserve of 0.45 MW (30% of 1.5 MW) that has to be sourced from the conventional generator units.

Notwithstanding the above, the results shown in Table 33 indicate that the operation planning targets are achievable against the backdrop of the planned expansions of firm generation to satisfy the forecast peak demands.

Table 33: Generation Contingency Capacity Forecast with Additions – Bartica

Bartica Generation Capacity		**2023**	**2024**	**2025**	**2026**	**2027**
Existing Cummins	Firm Capacity	3.30	3.30	3.30	3.30	3.30
Existing Mobile Units	Firm Capacity	1.60	1.60	1.60	1.60	1.60
LFO Unit (1x1.1 MW)	Firm Capacity	1.10	1.10	1.10	1.10	1.10
LFO Unit (2x2.4 MW)	Firm Capacity	-	-	4.80	4.80	4.80
LFO Unit (1x1.1 MW)	Firm Capacity	-	-	-	1.10	1.10
LFO Unit (1x2.4 MW)	Firm Capacity	-	-	-	-	2.40
Solar PV Farm - Addition	Non-Firm Capacity	1.50	1.50	1.50	1.50	1.50
Total Installed Generation (MW)		**7.50**	**7.50**	**12.30**	**13.40**	**15.80**
Total Firm Generation Capacity (MW)		**6.00**	**6.00**	**10.80**	**11.90**	**14.30**
Total Non-Firm Generation Capacity (MW)		**1.50**	**1.50**	**1.50**	**1.50**	**1.50**
Min Required Spinning Reserve (MW)		**2.13**	**2.13**	**2.13**	**2.13**	**2.13**
Net Capacity (MW)		**3.87**	**3.87**	**8.67**	**9.77**	**12.17**
Peak Demand (MW)		**2.53**	**2.87**	**3.70**	**5.80**	**8.14**
Contingency Capacity (MW)		**1.34**	**1.00**	**4.97**	**3.97**	**4.03**

With the BESS providing ancillary services to the grid, the contingency capacity will increase by approximately 1.6 MW, commencing from the year the inverters are configured to operate in grid forming mode.

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

- Decarbonization of Bartica electricity grid.
- Reduction of fossil fuel dependence.
- Provide the required firm power generation capacity to meet the growing electricity demand Bartica and to sustain economic growth.
- Improve in electricity supply reliability, stability, and quality of serve.
- In view of the above, improve the livelihood and personal development of residents in Bartica.
- Provide firm capacity to improve the reliability of electricity supply as well as facilitate ancillary services for the integration of the 1.5 MWp Solar PV Project.
- Reduce dependency on older LFO generators.
- Improved fuel efficiency.
- Lower production cost.
- Allow for Bartica to have sufficient generation capacity to ride-through an N-1 contingency for the loss of a feeder or generator.

11.3 Wakenaam

On the basis of expected improvements in the Wakenaam's economic sectors, the electricity demand is forecast to increase, requiring a total of 1.23 MW of additional firm generation capacity to be installed within the current planning period.

The first additional capacity of 410 kW is planned for 2023 and 2x410 kW in 2024 (Table 35). Simulation results have indicated that the additional generators are insufficient to addressing the LOLP target in 2027. Although constrained to 500 Amps at the 480V level, the BESS resulting from the UAE grant funded project, is expected to provide circa 332 kW of ancillary services to the grid. The addition of 332 kW for constrained firm capacity is expected to allow the power system to achieve the LOLP target for 2027 (Table 34).

Table 34: Generation Reliability with Planned Expansions – Wakenaam

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLP (%)
2022	2.1	0.4	1.47	1.0	242%	0.2	0.02
2023	3.3	0.6	1.88	1.3	198%	0.1	0.0046
2024	3.8	0.7	3.03	2.3	315%	0.0	0.0001
2025	4.9	1.0	3.03	2.1	219%	0.0	0.0004
2026	7.6	1.5	3.03	1.6	106%	0.3	0.02

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLP (%)
2027	10.7	2.1	3.03	1.0	46%	4.2	0.24

The Company remains cognizant that should the forced outage rate of generator units increase in 2027, the LOLP target will not be satisfied amid the BESS is providing ancillary services. Nevertheless, the Company will address these setbacks progressively as the demand is expected to increase within the current planning period.

Table 35 shows the generation expansion plant for Wakenaam and its initial benefits in increasing the annual total firm capacity to meeting the forecast demand.

Table 35: Proposed Generation Capacity Addition to Wakenaam

Wakenaam	Type	Installed Capacity (MW)				
		2023	2024	2025	2026	2027
LFO Unit	Firm Capacity	0.41				
LFO Unit (2x0.41MW)	Firm Capacity		0.82			
Solar PV Farm	Non-Firm Capacity	0.70				
Solar Farm BESS	Firm Capacity	0.33				
Total Non-Firm Capacity		**0.70**	**-**	**-**	**-**	**-**
Total Firm Capacity		**0.74**	**0.82**	**-**	**-**	**-**
Total Accumulated Firm Capacity		**0.74**	**1.56**	**1.56**	**1.56**	**1.56**
Existing Firm Capacity		**1.47**	**1.47**	**1.47**	**1.47**	**1.47**
Grand Total Firm Capacity		**2.21**	**3.03**	**3.03**	**3.03**	**3.03**

As it relates to the operation planning targets, the Wakenaam power system is expected to have sufficient contingency capacity to ensure stable operation annually during the peak demand periods. The Company remains cognizant that while the contingency capacity remains positive in 2026 and 2027, it reduces significantly, from 0.73 in 2026 to 0.13 in 2027 - an 82% reduction (Table 36).

Table 36:Generation Contingency Capacity Forecast with Additions – Wakenaam

Wakenaam Generation Capacity		2023	2024	2025	2026	2027
Existing Caterpillar	Firm Capacity	1.47	1.47	1.47	1.47	1.47
LFO Unit - Addition	Firm Capacity	0.41	0.41	0.41	0.41	0.41
LFO Unit (2x0.41MW) - Addition	Firm Capacity	-	0.82	0.82	0.82	0.82
Solar PV Farm - Addition	Non-Firm Capacity	0.70	0.70	0.70	0.70	0.70
Total Installed Generation (MW)		**2.58**	**3.40**	**3.40**	**3.40**	**3.40**
Total Firm Generation Capacity (MW)		**1.88**	**2.70**	**2.70**	**2.70**	**2.70**
Total Non-Firm Generation Capacity (MW)		**0.70**	**0.70**	**0.70**	**0.70**	**0.70**
Min Required Spinning Reserve (MW)		**0.83**	**0.83**	**0.83**	**0.83**	**0.83**
Total BESS Capacity (MW)		**0.33**	**0.33**	**0.33**	**0.33**	**0.33**

Wakenaam Generation Capacity	2023	2024	2025	2026	2027
Net Capacity (MW)	**1.4**	**2.2**	**2.2**	**2.2**	**2.2**
Peak Demand (MW)	**0.63**	**0.73**	**0.95**	**1.47**	**2.08**
Contingency Capacity (MW)	**0.76**	**1.48**	**1.25**	**0.73**	**0.13**

Notwithstanding the aforementioned, given the technical characteristics of the Wakenaam power system contingency capacities of 0.73 in 2026 and 0.13 MW in 2027 are considered adequate for stable operation within the peak hours of the current planning period.

The salient benefits of this planned expansion, which includes the 700 kW Solar PV, and the BESS are:

- Decarbonization of Wakenaam electricity grid.
- Reduction of fossil fuel dependence.
- Provide the required firm power generation capacity to meet the growing electricity demand Wakenaam and to sustain economic growth.
- Improve in electricity supply reliability, stability, and quality of serve.
- In view of the above, improve the livelihood and personal development of residents in Wakenaam.
- Provide firm capacity to improve the reliability of electricity supply.
- Reduce dependency on older LFO generators.
- Improved fuel efficiency.
- Lower production cost.

11.4 Leguan

Similar to the other isolated power systems, Leguan is also projected to experience increases in electricity demand due to the islands economy as well as other external influencing economic factors stemming from the major national development activities.

The Guyana Energy Agency (GEA) is currently aiming to commission a 600 kW Solar PV Farm with 600 kW – 1 hr grid forming BESS by 2024. By definition of firm capacity, the BESS will assist in providing ancillary services to the grid, thereby supporting the LOLP target.

In addition to the above, simulation results have shown the need to add a total of 1.64 MW of firm capacity to guarantee satisfying the forecast demand, as well as the LOLP target. The results shown in

Table *37* indicate that with the proposed firm generation expansion plan (Table 38), coupled with the BESS firm capacity, Leguan's power system will achieve the annual LOLP target.

Table 37: Generation Reliability with Planned Expansions – Leguan

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLP (%)
2022	2.2	0.4	1.23	0.8	180%	2.8	0.18
2023	3.4	0.7	1.64	0.9	131%	0.8	0.04
2024	4.0	0.8	3.06	2.3	278%	0.0	0.001
2025	5.1	1.1	3.06	2.0	191%	0.1	0.005
2026	7.9	1.6	3.06	1.4	87%	2.9	0.15
2027	11.2	2.3	3.47	1.2	51%	14.9	0.27

The solar PV system would be designed as a hybrid system with grid forming capabilities. The diesel generators and the solar PV would be operating in parallel and supplemented by the 600-kW nominal output BESS the required ancillary services. As such, the BESS is expected to add firm capacity to the power system, where by 2027, the total would be 3.47 MW (Table 38).

Table 38: Proposed Generation Capacity Addition to Leguan

Leguan	Type	Installed Capacity (MW)				
		2023	2024	2025	2026	2027
LFO Unit (1x0.41 MW)	Firm Capacity	0.41				
LFO Unit (2x0.41 MW)	Firm Capacity		0.82			
LFO Unit (1x0.41 MW)	Firm Capacity					0.41
Solar PV Farm	Non-Firm Capacity		0.6			
Solar Farm BESS	Firm Capacity		0.6			
Total Non-Firm Capacity		**-**	**0.60**	**-**	**-**	**-**
Total Firm Capacity		**0.41**	**1.42**	**-**	**-**	**0.41**
Total Accumulated Firm Capacity		**0.41**	**1.83**	**1.83**	**1.83**	**2.24**
Existing Firm Capacity		**1.23**	**1.23**	**1.23**	**1.23**	**1.23**
Grand Total Firm Capacity		**1.64**	**3.06**	**3.06**	**3.06**	**3.47**

As it relates to the operation planning targets, the Leguan power system is expected to have sufficient contingency capacity to ensure stable operation annually during the peak demand periods. The Company remains cognizant that while the contingency capacity remains positive in 2026 and 2027, it reduces significantly, from 0.63 in 2026 to 0.37 in 2027 – a 58.7% reduction (Table 39).

Table 39: Generation Contingency Capacity Forecast with Additions – Leguan

Leguan Generation Capacity		2023	2024	2025	2026	2027
Existing Caterpillar	Firm Capacity	1.23	1.23	1.23	1.23	1.23

Leguan Generation Capacity		2023	2024	2025	2026	2027
LFO Unit (1x0.41 MW) - Addition	Firm Capacity	0.41	0.41	0.41	0.41	0.41
LFO Unit (2x0.41 MW) - Addition	Firm Capacity	-	0.82	0.82	0.82	0.82
LFO Unit (1x0.41 MW) - Addition	Firm Capacity	-	-	-	-	0.41
Solar PV Farm - Addition	Non-Firm Capacity	-	0.60	0.60	0.60	0.60
Total Installed Generation (MW)		**1.64**	**3.06**	**3.06**	**3.06**	**3.47**
Total Firm Generation Capacity (MW)		**1.64**	**2.46**	**2.46**	**2.46**	**2.87**
Total Non-Firm Generation Capacity (MW)		**0**	**0.6**	**0.6**	**0.6**	**0.6**
Min Required Spinning Reserve (MW)		**0.615**	**0.795**	**0.795**	**0.795**	**0.795**
Total BESS Capacity (MW)		**0**	**0.6**	**0.6**	**0.6**	**0.6**
Net Capacity (MW)		**1.025**	**2.265**	**2.265**	**2.265**	**2.675**
Peak Demand (MW)		**0.71**	**0.81**	**1.05**	**1.64**	**2.30**
Contingency Capacity (MW)		**0.32**	**1.45**	**1.22**	**0.63**	**0.37**

Nevertheless, the Company remains cognizant that the contingency capacity is less than the capacity of a generator unit.

Further, given the technical characteristics of the Leguan power system, contingency capacities of 0.63 in 2026 and 0.37 MW in 2027 are considered adequate for stable operation within the peak hours of the current planning period.

The salient benefits of this planned expansion, which includes the 700 kW Solar PV, and the BESS are:

- Decarbonization of Leguan electricity grid.
- Reduction of fossil fuel dependence.
- Provide the required firm power generation capacity to meet the growing electricity demand Leguan and to sustain economic growth.
- Improve in electricity supply reliability, stability, and quality of serve.
- In view of the above, improve the livelihood and personal development of residents in Leguan.
- Provide firm capacity to improve the reliability of electricity supply.
- Reduce dependency on older LFO generators.
- Improved fuel efficiency.
- Lower production cost.

12. Summary of Firm and Intermittent Generation Expansion Projects

The Company remains committed to aligning its generation strategies with the Low Carbon Development Strategy – LCDS 2030, National Energy Priorities, and other Government Energy-driven Initiatives.

By the end of this Programme, the total installed capacity by type in the **DBIS** is as follows:

- Total HFO Capacity by 2027 - 205.9 MW
- Total LFO Capacity by 2027 - 12.9 MW
- Total Solar PV Capacity by 2027 – 25 MW
- Total NG Capacity by 2027 - 311.4 MW
- Total BESS Capacity by 2027 - 72.2 MW

The percentage share of each installed capacity by type in the **DBIS** is as follows:

- Natural Gas – 49.6%
- HFO – 32.8%
- Grid Forming BESS – 11.5%
- Solar PV – 4%
- LFO – 2.1%

Similarly, for the **Aggregated Isolated Systems**, the total installed capacity by 2027 is as follows:

- Total HFO Capacity by 2027 - 18.20 MW
- Total LFO Capacity by 2027 - 29.77 MW
- Total Solar PV Capacity by 2027 -10.80 MW
- Total BESS - Grid Forming Capacity - 12.93 MW

The percentage share of each type of installed capacity by 2027 for the **Aggregated Isolated Systems** is as follows:

- Isolated System HFO % Share - 25.4%
- Isolated System LFO % Share - 41.5%
- Isolated System Solar PV % Share - 15.1%
- BESS - Grid Forming Capacity % Share - 18.0%

The full breakdown details for the DBIS and Isolated Systems are elaborated in Table 41 for the DBIS and Table 42 for the Isolated Systems.

Figure 18 and Figure 19 show a pie-chart of the percentage share of each installed capacity type for the DBIS and Aggregated Isolated Systems, respectively.

Figure 20 shows the forecast annual Grid Emission Factor for the total GPL.

The annual grid emission factor is calculated utilising referenced values shown in Table *40* and the annual total GWh of electricity based on economic dispatch of the generator units to satisfy the demand forecast.

Table 40: Reference values to determine Grid Emission Factor

Row Labels	**Emission factor (tCO2/GWh)**	**Emission factor (tCO2/MWh)**
DFO-DP5	643.670	0.644
HFO-CAN	758.186	0.758
HFO-DP1	768.719	0.769
HFO-DP2	726.231	0.726
HFO-DP3	643.707	0.644
HFO-DP4	643.670	0.644
HFO-EPC	758.186	0.758
HFO-IPP	758.186	0.758
HFO-SKE	661.671	0.662
LFO-CAN	843.616	0.844
LFO-GOE	803.169	0.803
LFO-ONV	828.802	0.829
NG-300MW	497.000	0.497
Solar LND	0.000	0.000
Solar DBIS	0.000	0.000
Average	**666.772**	**0.667**

A sharp reduction in emissions is observed in 2024 for the DBIS, which coincides with the commissioning year of the 300 MW GTE Project.

Table 41: GPL 5-Year Generation Capacity Expansion Plan and Energy Mix- DBIS

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
2023	HFO	0	25 MW IPP – Canefield *	IPP
	HFO	25	25 MW EPC - Canefield	GPL
	HFO	0	25 MW IPP – Columbia *	IPP
	HFO	10	10 MW EPC - Canefield	GPL
2024	NG	225.9	300 MW GTE - Simple Cycle	GOG/GPL
	BESS	57.2	300 MW GTE - BESS	GOG/GPL
	RE - Solar	10	GUYSOL - Berbice	GOG/GPL
2025	NG	85.5	300 MW GTE - Combine Cycle	GOG/GPL
2026	RE - Solar	15	Interconnection with Linden*	GOG/GPL
	BESS	15		IPP
Existing Capacity (MW)	HFO	170.9	DBIS	GOG/GPL
	Diesel No.2	12.9		GOG/GPL
Total Existing Firm Capacity (MW) - Generators		183.8		
Total Additional Firm Capacity by 2027 (MW)		418.6		
Total Additional Non-Firm Capacity by 2027 (MW)		25		
Total Additional Capacity by 2027 (MW)		443.6		
Total Firm Capacity by 2027 (MW)		602.4		
Total Non-Firm Capacity by 2027 (MW)		25		
Total Capacity by 2027 (MW)		627.4		
Total HFO Capacity by 2027 (MW)		205.9		
Total LFO Capacity by 2027 (MW)		12.9		
Total Solar PV Capacity by 2027 (MW)		25		
Total NG Capacity by 2027 (MW)		311.4		
Total BESS Capacity by 2027 (MW)		72.2		
Heavy Fuel Oil % Share		33%		

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
Diesel % Share		32.8%		
Natural Gas % Share		2.1%		
Solar PV % Share		49.6%		
BESS - Grid Forming Capacity % Share		11.5%		

NB: * IPP has a duration of 3-years and Linden connects with the DBIS in 2026.

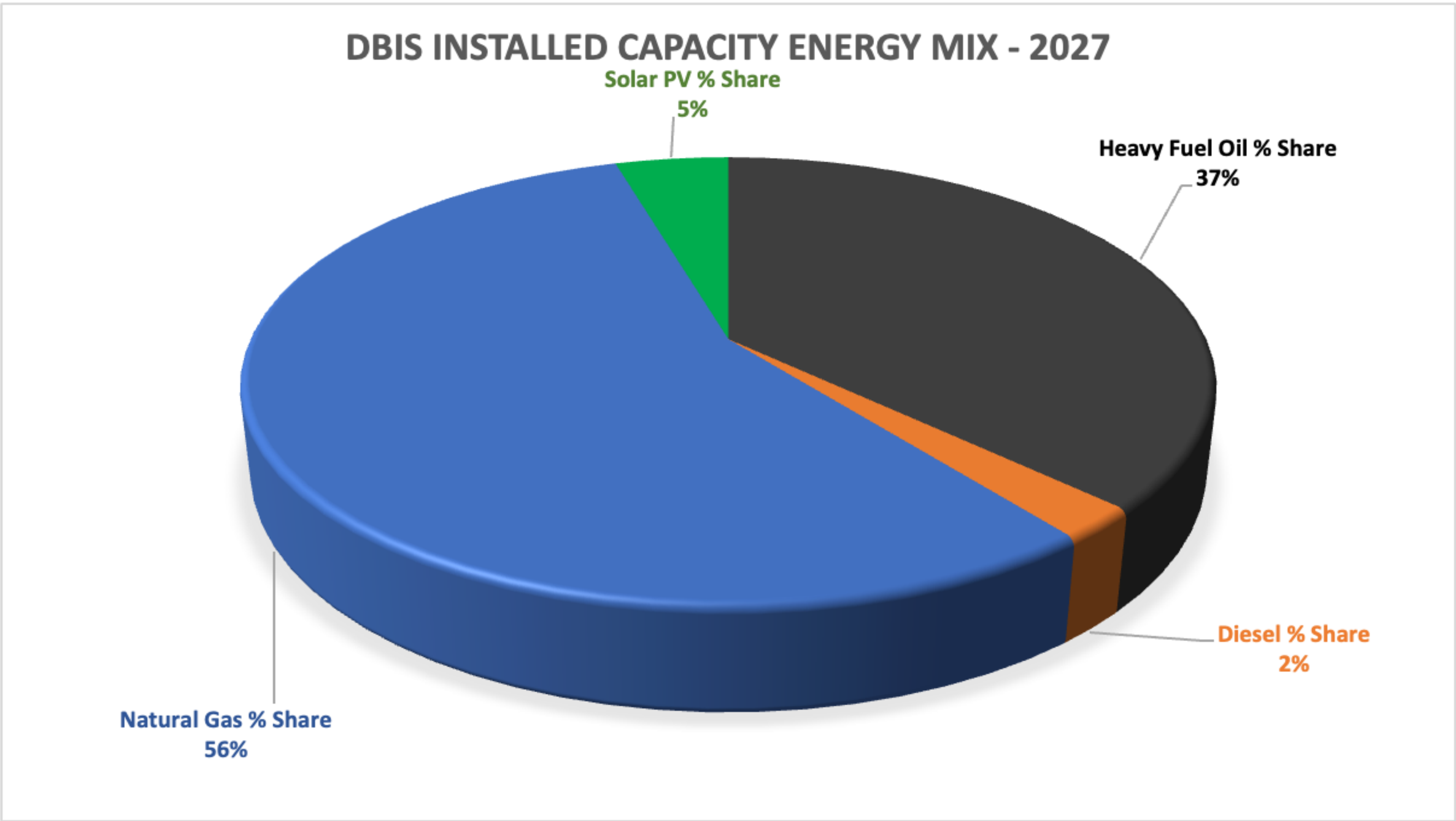


Figure 18: DBIS Installed Capacity Energy Mix – 2027

Table 42: GPL 5 Year Generation Expansion Plan and Energy Mix- Isolated Systems

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
2023	Solar PV	1.5	Bartica	GPL
	Diesel No.2	1.1	Bartica	
	Solar PV	0.7	Wakenaam	
	BESS	0.3	Wakenaam	
	Diesel No.2	0.41	Wakenaam	
	Diesel No.2	0.41	Leguan	
2024	Solar PV	8.0	Anna Regina	
	BESS	12.0	Anna Regina	
	Diesel No.2	0.8	Wakenaam	
	Diesel No.2	0.8	Leguan	
	Solar PV	0.6	Leguan	
	BESS	0.6	Leguan	
2025	Diesel No.2	4.8	Bartica	
2026	HFO	11.0	Anna Regina	
	Diesel No.2	1.1	Bartica	
2027	HFO	1.8	Anna Regina	
	Diesel No.2	2.4	Bartica	
	Diesel No.2	0.41	Leguan	
Existing Capacity	HFO	5.4	Isolated Systems	
	Diesel No.2	17.5	Isolated Systems	
Total Existing Available Capacity		22.90	Isolated Systems	
Total Additional Firm Capacity by 2027 (MW)		38.00		
Total Additional Non-Firm Capacity by 2027 (MW)		10.80		
Total Additional Capacity by 2027 (MW)		48.80		
Total Firm Capacity by 2027 (MW)		60.90		

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
Total Non-Firm Capacity by 2027 (MW)		10.80		
Total Capacity by 2027 (MW)		71.70		
Total HFO Capacity by 2027 (MW)		18.20		
Total LFO Capacity by 2027 (MW)		29.77		
Total Solar PV Capacity by 2027 (MW)		10.80		
Total BESS - Grid Forming Capacity (MW)		12.93		
Isolated System HFO % Share		25%		
Isolated System LFO % Share		42%		
Isolated System Solar PV % Share		15%		
BESS - Grid Forming Capacity % Share		18%		

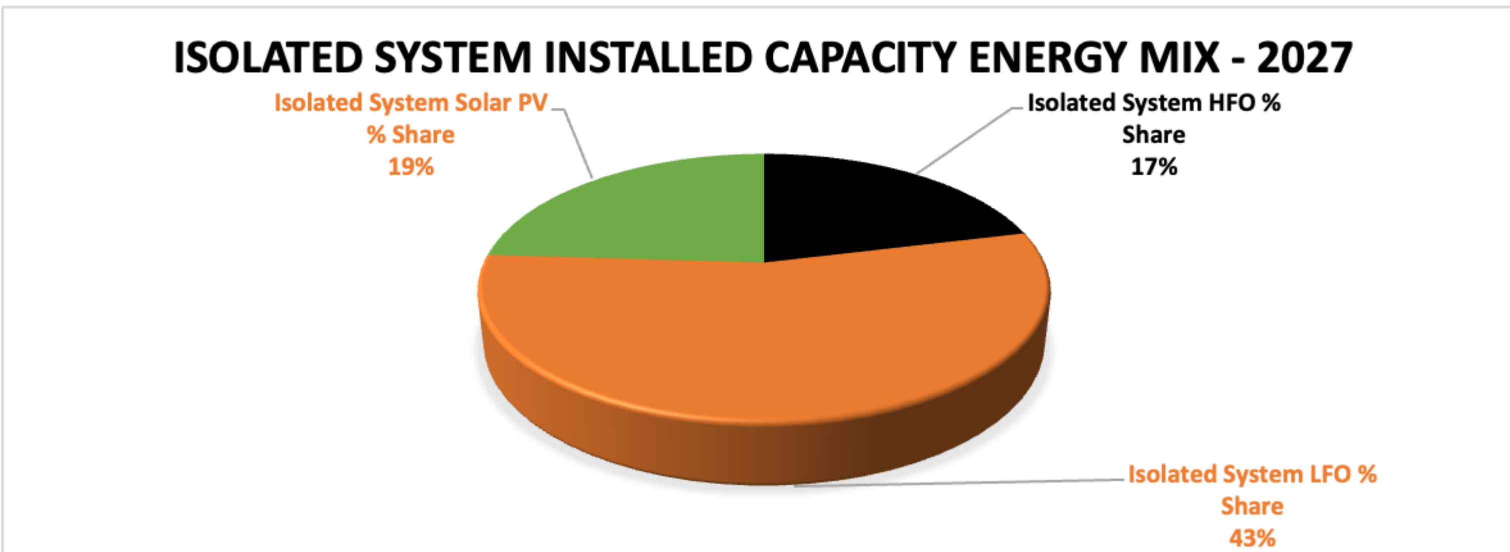


Figure 19: Isolated Power System's Installed Capacity Energy Mix - 2027

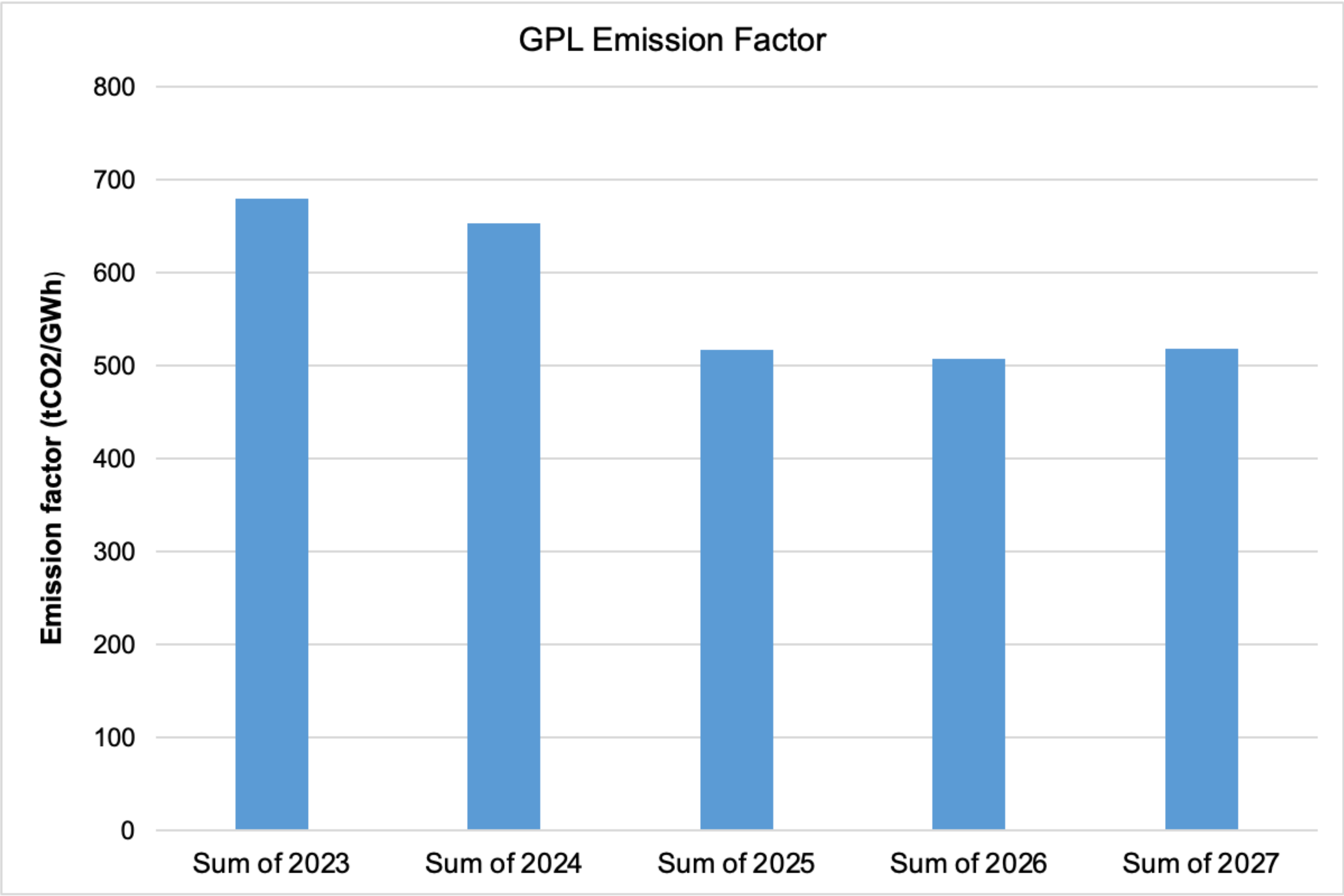


Figure 20: Projected Grid Emissions Factor for the DBIS 2023-2027

13. Integrated Utility Service (IUS) and Net Billing

The Integrated Utility Services (IUS) Model is integral to the goals of the Low Carbon Development Strategy (LCDS) – 2030 and customers currently served by the power grid.

Customers will soon be able to access a wide range energy services, which includes energy efficiency improvements, Distributed Energy Resources - DER (solar photovoltaic system, wind, etc.), and electric transport. These services would be accessed through one comprehensive package, with monthly payments on the electricity bill – Net Billing Programme.

Net Billing Programme

GPL is currently developing a Net Billing Programme (NBP) that will utilise a Feed-in Tariff (FIT) system to achieve the following objectives:

1. To increase the contribution of renewable energy in the energy mix;
2. To provide Grid-tie Customers with a framework for renewable energy investments and returns; and
3. To facilitate energy sector investments while ensuring transparency, safety, sustainability, continuity, reliability, and security of electricity supply.

A Feed-in Tariff (FIT) can be considered a significant revenue stream for the present and future grid-tie customers. As a result, credits for electricity export, combined with the avoided cost for the self-supply, should provide customers with adequate return on investment and promote the development of distributed renewable energy system resources.

In view of the prospects of the NBP, GPL is cognisant of the technical constraints that the current distribution systems present to DERs. The current systems are designed and operated in the classical regimen – electricity flows in one direction, from the substation to the customer interconnection points on the feeders.

To date, the aggregated 317 prosumers, which totals 7.51 MWac, has not resulted in the power system experiencing reverse power flow at the substations or any negative impacts due to the total installed DER capacity. See section 3.3.2 on page 50 for further details on the current installed capacity of Distributed Energy Resources (DER).

Notwithstanding the current operating status, the expected growth of DER capacity due to the NBP will increase the aggregated intermittent electricity capacity injected into the grid. The aggregated increase will offset the local demand on the primary distribution feeders during solar hours and will result in reverse power flows. Significant reverse power flows can cause operational issues for the existing power systems, unless they are properly re-designed, configured and modernised to operate stably with reverse power flows.

The current Development and Expansion Programme includes projects to address the above-mentioned gaps and for the deployment of Smart Grid to assist with integrating intermittent renewable energy into the distribution systems.

The Development and Expansion Programme will undoubtedly allow GPL to provide greater service values to its customers by supporting their investments in renewable energy systems and their contributions towards Guyana's National Energy Initiatives – LCDS 2030.

14. Long-term 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). This project is primarily aimed at reducing the overall cost of generation and by extension, the electricity tariff. Additionally, the AFHP Project will add significant inertia to the technical stability of the power grid.

The expansion plans in this Development and Expansion Programme are aligned with the AFHP power evacuation requirements – 230 kV transmission system for large power block transfer across long distances. Additionally, the expansion of the power grid considers the need to improve power system security, resiliency, and reliability.

The ‘Arco Norte’ Interconnection Project expects to realize the development and commissioning of a significant amount of hydropower generation capacity in Guyana. With such a long-term planned development, the total generation capacity will buttress local generation capacity, and export electricity to Brazil, connecting 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 Amapa is planned to be through Suriname and French Guyana (Figure 21).

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 22);
- 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.

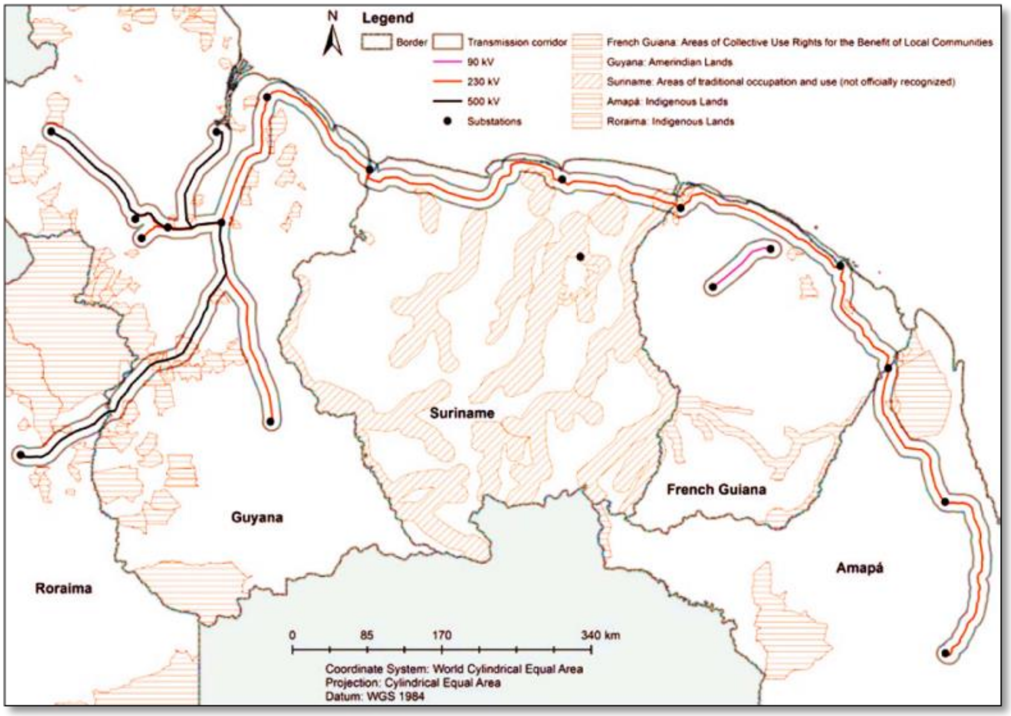


Figure 21:Illustration of the Arco Norte Interconnection Plan (source: Arco Norte Electrical Interconnection Study – Component II)

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.

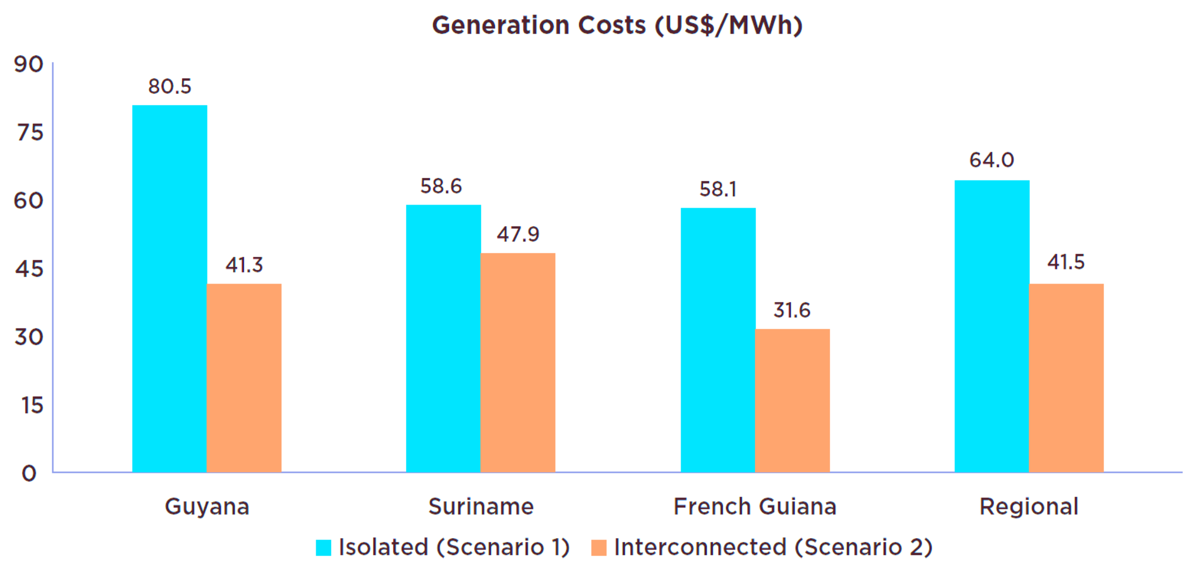


Figure 22: Average generation cost in the interconnected and isolated scenarios (source: Arco Norte Electrical Interconnection Study – Component II, dated 2017)

15. Transmission, Distribution and Substation Upgrades and Expansions

15.1 Short to Medium Term (2023-2027) – Transmission and Substation Expansions and Upgrades (see Figure 23 for block diagram summary)

GPLs T&D expansion programme, which includes the details shown in Table 46, totals GY$ 185.53B (US$ 861.94M) to upgrade and construct new Transmission and Distribution networks, Substations and Transmission system reinforcements (reactive power compensations) projects for the short- to medium-term planning horizon, 2023 to 2027.

The planned T&D expansion programme essentially seeks to accommodate the present and forecasted peak demand growth concomitant with efforts to reduce technical losses, improving grid security, flexibility, reliability, and resiliency, see Table 43 to Table 45 and Figure 23 for further details.

The construction and upgrade of distribution substations (load centres) would allow new distribution feeders and transformers to be deployed in all geographic areas to serve the present and forecasted loads efficiently, and by extension support planned economic activities.

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

Regarding unserved areas, GPL is cognisant of areas where the expected total number of beneficiaries is approximately 5,341 by 2027. The unserved areas are stretched across regions number 2, 3, 4, 5, 6 and 7. The total estimated cost to service the total number of beneficiaries is approximately GY$ 528.11M (US$2.45M).

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

Activity	**Short Term T&D and Substation Expansion Projects**	
	2023	**2024**
Transmission	L21 (Onverwagt to Canefield).	L5 & L5-P (Sophia Upgraded to Kingston), L 8 (Edinburgh to Hydronie), L11-1 (Kingston to Thomas Lands), L11-2 (Thomas Lands to Princess Street), L11-3 (Princess Street to New Georgetown), L12 & L13 (Sophia Upgraded to New Sophia), L16 & L16P (New Sophia to Good Hope), L30a, & L30aP1 & L30aP2 (Wales NG Power Plant to Wales Industrial), L30b & L30bP (Wales Industrial to Wales

Activity	Short Term T&D and Substation Expansion Projects	
	2023	2024
		Residential/Commercial), L31 (Vreed-en-Hoop to Wales Residential/Commercial), L32 (Vreed-en-Hoop to Wales Residential/Commercial), L33 (Wales Residential/Commercial to Hydronie), L2-1 & L4-1 (Golden Grove to Goedverwagting Line Splitting) and L2-2 & L4-2 (Goedverwagting to Sophia Upgraded & New Sophia Line Splitting). HV_L1 & HV_L1P (Wales NG Power Plant to Goedverwagting) - 230 kV.
Substation	35 MVA Mobile Substation. Garden of Eden 69/13.8 kV Substation, Good Hope 69/13.8 kV Substation, Columbia 69/13.8 kV Substation, Canefield 69/13.8 kV Substation, Vreed-en-Hoop 69/13.8 kV Substation, No. 53 69/13.8 kV Substation and Old Sophia 69/13.8 kV Substation.	Thomas Lands 69/13.8 kV Substation, Princess Road 69/13.8 kV Substation, Hydronie 69 -13.8 kV Substation, Goedverwagting 120 MVA 69/13.8 kV Substation, Wales Residential/Commercial 69/13.8 kV Substation and Wales Industrial 120 MVA (2x60MVA) 69/13.8 kV Substation. Edinburgh 69/13.8 kV Substation, New G/town 69/13.8 kV Substation, Vreed-en-Hoop 69/13.8 kV Substation, Old Sophia 69/13.8 kV Substation and Golden Grove. Goedverwagting 230/69 kV Substation.

Table 44: Medium Term Transmission and Substation New, Expansions and Upgrades

Activity	Mid Term T&D and Substation Expansion Projects		
	2025	**2026**	**2027**
Transmission	L17P (Good Hope to Enmore/Victoria), L18P (Enmore/Victoria to Columbia), L23P (No. 53 Village to Skeldon), L25 & L25P (Goedverwagting to Ogle), L26 (Ogle to Enmore/Victoria), L17 (Good Hope to Enmore/Victoria Line Splitting), L18 (Enmore/Victoria to Columbia Line Splitting), L16-1 & L16-1P (New Sophia to Ogle Line Splitting), L16-2 & L16-2P (Ogle to Good Hope Line Splitting), L22-1 (Canefield to Williamsburg Line Splitting) and L22-2 (Williamsburg to No. 53 Village Line Splitting).	L1 & L3 (Garden of Eden to Golden Grove), L21 (Onverwagt to Canefield), L21-1P (Onverwagt to Rossignol), L21-2P (Rossignol to Canefield), L22-1 (Canefield to Williamsburg), L22-1P (Canefield to Williamsburg), L22-2 (Williamsburg to No. 53 Village), L22-2P (Williamsburg to No. 53 Village), L35 & L35P (New GOE to Kuru Kururu), L37 & L37P (New GOE to Mackenzie) and L48 & L48P (New GOE to Garden of Eden). HV_L1-1 & HV_L1P-1 (Wales NG Power Plant to New GOE Line Splitting) - 230 kV, HV_L1-2 & HV_L1-P2 (New GOE to Goedverwagting Line Splitting) - 230 kV and HV_L2-2 & HV_L2-P-2 (GOE New to Goedverwagting) - 230 kV.	L10 (Old Sophia to New Georgetown), L20P (Columbia to Onverwagt), L36 (Kuru Kururu to Yarrowkabra), L38 (Mackenzie to Wismar), L22-1a (Canefield to Crab Island Line Splitting), L22-1aP (Canefield to Crab Island Line Splitting), L22-1b (Crab Island to Williamsburg Line Splitting) and L22-1bP (Crab Island to Williamsburg Line Splitting). HV_L4 & HV_L4P (Goedverwagting to Crab Island) - 230 kV, HV_L5 & HV_L5P (Crab Island to Williamsburg) - 230 kV.

Substation	Ogle 69/13.8 kV Substation, Williamsburg 69/13.8 kV Substation, McKenzie 69/13.8 kV Substation and Enmore/Victoria 69/13.8 kV Substation. Columbia 69/13.8 kV Substation, Onverwagt 69/13.8 kV Substation and No. 53 69/13.8 kV Substation.	Garden of Eden 69/13.8 kV Substation, New GOE 70 MVA 69 kV/13.8kV Substation, Kuru Kururu 70 MVA 69kV/13.8kV Substation, Wismar 69/13.8 kV Substation and Rossignol 69/13.8 kV Substation. New GOE 230kV/69 kV Substation.	Crab Island 69/13.8 kV Substation and Yarrowkabra 69/13.8 kV Substation. Williamsburg 230/69 kV Substation and Crab Island 230/69 kV Substation.

Given the high priority placed on improving reliability, flexibility, resiliency and reducing technical losses of the transmission and distribution network, the Company has comprehensively examined and inspected the networks to update its inventory of corrective actions and improvement initiatives. The Company expects to finance these critical projects via concessional financing. See Table 45 for further details.

Table 45: Projects Financed through Grants and Loans: Short to Medium Term: 2023-2027

Activity	Location	Impact
New and Upgraded Substations	L1 & L3 (Garden of Eden to Golden Grove).	Improved reliability in the transmission and distribution network by expanding the infrastructure to meet and exceed the needs of the customers.
Improve Reactive Compensation	Installation of 15 MVAr at New Sophia, installation of 15 MVAr at Columbia Substation, installation of 15 MVAr at #53 Substation and installation of 10 MVAr at Edinburgh.	The commissioning of reactive power compensators with auxiliaries, control and protection will significantly improve and stabilize transmission and distribution voltage levels on the network.

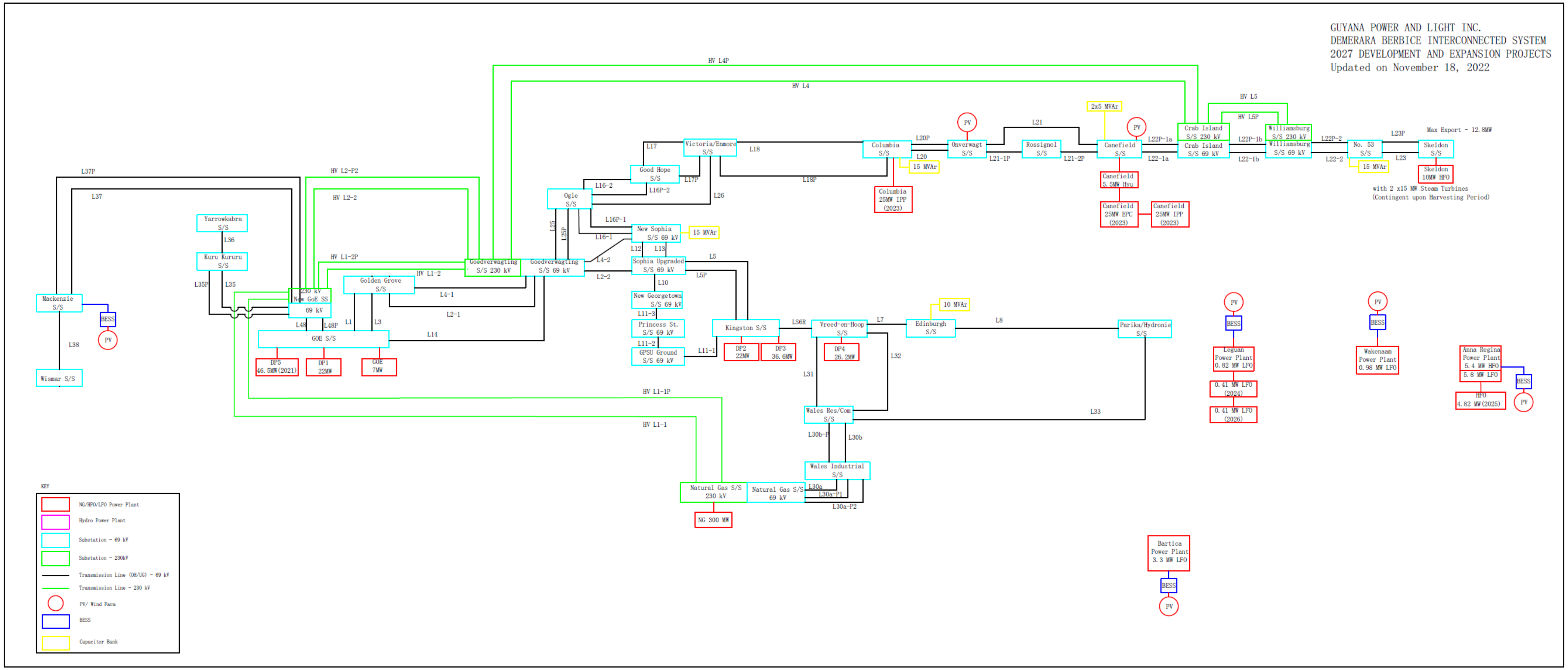


Figure 23: Block Diagram of Power System Development for the current D&E (2023-2027)

15.2 Short to Medium Term (2023-2027) – 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 the right condition to satisfy 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.

Within the current Development and Expansion programme, the following are planned works at the primary distribution level:

Short-term (2023-2024):

- The construction of following 13.8 kV feeder:
  - Feeders coming out of Columbia Substation;
  - Feeders coming out of Good Hope Substation;
  - Feeders coming out of No. 53 Substation;
  - Feeders coming out of Vreed-en-Hoop Substation;
  - Feeders coming out of DP3 Power Plant;
  - Feeders coming out of GOE Substation;
  - Feeders coming out of Canfield Substation;
  - Feeders coming out of Edinburgh Substation;
  - Feeders coming out of Old Sophia Substation;
  - Feeders coming out of Parika/Hydronie Substation;
  - Feeders coming out of Princes St Substation;
  - Feeders coming out of Thomas land Substation;
  - Feeders coming out of Goedverwagting Substation;
  - Feeders coming out of Wales R/C Substation;
  - Feeders coming out of Wales Industrial Substation.
- The upgrade of the following 13.8 kV feeders:
  - Golden Grove F1;
  - Golden Grove F3;
  - New Georgetown F1;
  - Good Hope F4;
  - Edinburgh F2;
  - Canefield F3;
  - Garden of Eden F1;
  - Anna Regina - South Feeder - Express to Onderneeming;
  - Garden of Eden F2;
  - Garden of Eden F3.
- GNCC/Smart Grid;
- Distribution Reactive Reinforcement;

- Power Plant Switchgear Upgrades:
  - Wakenaam Power Plant;
  - Upgrade tie-lines between DP2 -DP3;
  - Upgrade 13.8 kV Switchgear at DP2;
  - Upgrade Grounding Transformer at DP3;
  - Upgrade Grounding Transformer at DP4;
  - Generator Neutral Earthing Resistors at DP4;
  - Upgrade 13.8 kV Switchgear at DP3.
- Installation of Auto-Reclosers;
- JICA Grant: Grant covers expenses for line conductors and automatic power factor correction capacitor only. GPL to finance the balance of line hardware materials, labour, and transportation costs for these projects;
- Leguan Feeder Voltage Upgrade;
- Installation of Auto Recloser Communication Module;
- Installation of Sectionaliser;
- Installation of Smart FCIs.

Medium-term (2025-2027):

- Construction of the following 13.8 kV feeders:
  - Feeders coming out of Columbia Substation;
  - Feeders coming out of No. 53 Substation;
  - Feeders coming out of Canfield Substation;
  - Feeders coming out of Edinburgh Substation;
  - Feeders coming out of Edinburgh Substation;
  - Feeders coming out of Old Sophia Substation;
  - Feeders coming out of Wales R/C Substation;
  - Feeders coming out of Victoria/Enmore Substation;
  - Feeders coming out of Ogle;
  - Feeders coming out of Williamsburg Substation;
  - Feeders coming out of Mackenzie Substation;
  - Feeders coming out of Rossignol Substation;
  - Feeders coming out of Crab Island Substation;
  - Feeders coming out of Kuru Kururu Substation;
  - Feeders coming out of Yarrowkabra Substation;
  - Feeders coming out of Wismar Substation.
- Upgrade of the following 13.8 kV Feeders:
  - Anna Regina - South Feeder;
  - No. 53 - both feeders.
- Installation of Auto Recloser Communication Module;
- Installation of Sectionaliser;
- Installation of Smart FCIs.

- Distribution Reactive Reinforcement.

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 46.

Table 46: Planned T&D Expansion and Upgrade Capital Investment

T&D Investment Summary	2023	2024	2025	2026	2027	Total
	x US$,000	x US$,000	x US$,000	x US$,000	x US$,000	x US$,005
Transmission Lines	44,946.3	46,534.0	117,741.6	232,741.7	117,032.1	558,995.8
Transmission Reinforcements	-	3,292.7	2,594.2	-	-	5,887.0
New Substations	43,856.5	72,961.8	37,685.4	36,995.6	15,586.5	207,085.6
Substation Upgrade & Expansion	15,369.7	3,010.8	1,115.6	451.5	-	19,947.6
New Distribution Lines	6,291.4	9,503.950 4	7,856.4	4,555.655 6	1,860.986 1	30,068.3
Distribution Line Upgrades & Reinforcements	12,478.1	3,624.3	2,322.1	919.7920	857.8858	20,201.92 02
Electrification	3,665.4	4,033.6	3,369.5	3,867.4	4,824.6	19,760.4
Total (x1000 US$)	126,607.4	142,961.2	172,684.8	279,531.5	140,161.8	**861,946.6**

15.3 Long Term (2028-2040)

The Low Carbon Development Strategy (LCDS) 2030 highlights Government's plan to expand the use of existing hydro potential sites. LCDS 2030 communicates that the Government of Guyana plans to construct three hydropower facilities, each having approximately 200 MW. The planned timelines of each of the above-mentioned hydropower facilities are 2030, 2035 and 2040.

For production cost and power system modelling purposes, hydro potential sites that are within the vicinity of the Amaila Falls Hydropower Project line right of way were selected as candidate hydropower facilities. The candidate hydro potential sites are Turtuba (2035) and Arisaru (2040).

Given the forecasted electricity and peak demands, the Company's long-term plan focuses on transmission, sub-transmission, and substation expansions. These long-term planned projects will primarily cater for power evacuation and delivery of power to planned substations. See Table 47 for further details.

Table 47: Long term expansion plans

Activity	Quantity	Location
Additional 230 kV Transmission Lines Construction	4	HV_L3 & HV_L3-P (AMAILA HYDRO to Bamia-Linden, HV_L6 & HV_L6-P (Turtuba to EBE), HV_L7 & HV_L7-P (Arisaru to Turtuba) and HV_L8 & HV_L8-P (EBE to Wales NG Power Plant).
Additional 69 kV Transmission Lines Construction	12	L26-2a-P (Lusignan to LBI), L39 (Hydronie to Leguan), L40 (Leguan to Wakenaam), L41 (Wakenaam to Suddie), L 42 (Suddie to Devonshire Castle), L 43 (Bartica Substation to Del Conte), L 44 (Del Conte to Beribissiballi), L 45 (Beribissiballi to EBE), L46 (EBE to Hydronie), L47 (Turtuba to Bartica), L49 (Kuru Kururu to Silica City Sub) and L50 (Silica City Sub to Yarrokabra).
Additional Substations	23	Silica City, LBI, Lusignan, Burma, Bush Lot EBC, Westminister, Tuschen, Leguan, Wakenaam, Suddie, Devonshire Castle, Beribissiballi, Del Conte, Bartica, East Bank Essequibo 69/13.8 kV and Bamia 69/13.8 kV. Bamia-Linden 230/69 kV, New Yarrowkabra 230/69 kV, Amaila Falls Hydro Project-230 kV, Turtuba Hydro Electric-230 kV, Arisaru Hydro Electric-230

		kV and East Bank Essequibo 230/69 kV.

16. Network Maintenance Plan – 2023-2027

The 2023 -2027 network maintenance plan seeks to ensure that all sections of sub-transmission lines and distribution feeders are in optimal operating conditions to support GPL to achieve its planned reliability and power quality targets.

The outsourcing of a portion of this section of the 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 48 for further details.

Table 48: 2023 -2027 Network Maintenance Plan

DATE: 2023 – 2027			2023			2024			2025			2026			2027		
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	3220	6020	3000	2100	5100	3900	3120	7020	5070	2964	8034	3900	3705	7605
		SEC.	3800	5040	8840	4800	3360	8160	5800	4640	10440	7540	4408	11948	5800	5510	11310
POLE PLUMBING	2	PRIM.	1400	1680	3080	1400	980	2380	1900	1520	3420	2470	1444	3914	1900	1805	3705
		SEC.	1550	2030	3580	1550	1085	2635	1850	1480	3330	2405	1406	3811	1850	1758	3608
POLE TREATMENT	3	PRIM.	12000	14000	26000	12000	8400	20400	14000	11200	25200	18200	10640	28840	14000	13300	27300
		SEC.	14000	18200	32200	14000	9800	23800	16000	12800	28800	20800	12160	32960	16000	15200	31200
OLD POLE REMOVAL	4	PRIM.	1506	2109	3615	1506	1054	2560	1506	1205	2711	1958	1145	3103	1506	1431	2937
		SEC.	3416	4782	8198	3416	2391	5807	3416	2733	6148	4440	2596	7036	3416	3245	6661
POLE STUBBING	5	PRIM.	428	599	1027	428	299	727	428	342	770	556	325	881	428	406	834
		SEC.	400	560	960	400	280	680	400	320	720	520	304	824	400	380	780
ANCHOR BLOCK REPLACEMENT.	6	PRIM.	300	420	720	300	210	510	300	240	540	390	228	618	300	285	585
		SE	250	350	600	250	175	425	250	200	450	325	190	515	250	238	488

DATE:	2023 – 2027		2023			2024			2025			2026			2027		
		C.															
GUY REPLACEMENT	**7**	PRIM.	420	588	1008	420	294	714	420	336	756	546	319	865	420	399	819
		SEC.	350	490	840	350	245	595	350	280	630	455	266	721	350	333	683
REPLACEMENT DEFECTIVE CROSS ARMS	**8**	PRIM.	1500	2520	4020	1500	1050	2550	1500	1200	2700	1950	1140	3090	1500	1425	2925
INSULATOR REPLACEMENT	**9**	PRIM.	9433	10406	19839	9433	6603	16036	9433	7546	16979	12263	7169	19432	9433	8961	18394
		SEC.	3650	5110	8759	3650	2555	6205	3650	2920	6570	4745	2774	7518	3650	3467	7117
LINE/HARDWARE TRANSFER	**10**	PRIM.	5585	7819	13404	5585	3909	9494	5585	4468	10053	7260	4245	11505	5585	5306	10891
		SEC.	4257	5960	10218	4257	2980	7238	4257	3406	7663	5535	3236	8770	4257	4045	8302
LINE EXTENSION (KM)	**11**	PRIM.	18	25	42	18	12	30	18	14	32	23	13	36	18	17	34
		SEC.	52	72	124	52	36	88	52	41	93	67	39	106	52	49	101
LINE UPGRADEMENT (KM)	**12**	PRIM.	95	133	228	95	67	162	95	76	171	124	72	196	95	90	186
		SEC.	77	108	186	77	54	131	77	62	139	101	59	159	77	73	151
LINE RETENSION (KM)	**13**	PRIM.	520	728	1248	520	364	884	520	416	936	676	395	1071	520	494	1014
		SEC.	1200	1680	2880	1200	840	2040	1200	960	2160	1560	912	2472	1200	1140	2340
SERVICE LINE REPLACEMENT (MTS)	**14**		12500	17500	30000	8500	5950	14450	6000	4800	10800	6500	3800	10300	5000	4750	9750
INSTALLATION/REPLACEMENT (GAB/RECLOSER/SECTIONALISER)	**15**	PRIM.	70	60	130	50	30	80	25	20	45	58	34	91	44	42	87
INSTALLATION/REPLACEMENT (SPD)	**16**	PRIM.	150	168	318	80	56	136	50	40	90	65	38	103	50	48	98
INSTALLATION/REPLACEMENT (RCO)	**17**	PRIM.	792	1108	1900	792	554	1346	792	633	1425	1029	602	1631	792	752	1544

DATE:	2023 – 2027		2023			2024			2025			2026			2027		
INSTALLATION/REPLACEMENT (PMCO)	**18**		150	336	486	150	105	255	150	120	270	130	76	206	100	95	195
TRANSFORMER MAINTENANCE	**19**	SEC.	1170	1639	2809	1170	819	1990	1170	936	2107	1522	890	2411	1170	1112	2282
INSTALLATION OF ADDITIONAL TRANSFORMERS (REPLACEMENT)	**20**	SEC.	110	210	320	100	70	170	80	64	144	104	61	165	80	76	156
MAINTENANCE OF CAPACITOR/VOLTAGE REGULATORS BANKS	**21**		26	48	74	26	18	44	26	21	46	33	19	53	26	24	50
JUMPER SERVICING/REPLACEMENT	**22**	PRIM.	1249	1748	2997	1249	874	2123	1249	999	2248	1623	949	2572	1249	1186	2435
		SEC.	2589	3625	6215	2589	1813	4402	2589	2072	4661	3366	1968	5334	2589	2460	5049
SERVICE CONNECTION @ CONSUMER	**23**		12000	16800	28800	12000	8400	20400	12000	9600	21600	15600	9120	24720	12000	11400	23400
INSTALLATION OF ADDITIONAL EARTHS	**24**		725	1016	1741	725	508	1233	725	580	1306	943	551	1494	725	689	1415
ROUTE CLEARING (KM)	**25**	PRIM.	420	850	1270	320	920	1240	280	900	1180	280	900	1180	230	850	1080
		SEC.	15	250	265	12	320	332	12	260	272	10	200	210	10	200	210
LINE INSPECTION (KM)	**26**	PRIM.	2700	3500	6200	3000	2100	5100	3300	2640	5940	4680	2736	7416	3600	3420	7020
		SEC.	6200	8400	14600	6500	4550	11050	6800	5440	12240	9100	5320	14420	7000	6650	13650

17. 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 25.2% as of December 31, 2022.

The Company was able to achieve total losses moving from 26.47% in 2021 to 25.2% in December 2022 due to the maintenance and T&D upgrade works undertaken in 2022 (see section 3.4 on page 51 for further specific details).

The Company intends to intensify its efforts to achieve the 2027 target of 20.9% (see Figure 24 on page 153). The strategy involves the combined application of SCADA at the transmission and sub-transmission levels, AMI meters at the customer interface and economic power generation dispatch, shortening feeder lengths by constructing new feeders and upgrading the existing feeders.

17.1 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$36.4M (GY$7.83B) and include:

1. Installation of 80,000 AMI meters complete with new service lines and associated materials,
2. Installation of 25,000 energy efficient LED streetlamp as part of a proposed streetlamp upgrade programme.
3. Regular inspection of areas with new, reinforced networks to reduce illegal connections,
4. Efforts to encourage prosecution of all cases of illegal electricity extraction, and
5. Execution of a Social Management Programme to educate consumers on the impact and consequences of electricity theft.
6. Execution of a Social Management Programme to educate consumers on the use of energy efficient lighting and impact and consequences of installing illegal streetlamps.

17.2 Technical Loss Reduction

Planned investment in technical loss reduction is estimated to be over US$70M over the life of this programme.

The investment will address technical losses and system improvement at the distribution levels, - medium and low voltage.

The Company remains adamant that the planned investment in new transmission lines, substations, deployment of automatic power factor capacitor banks at the primary distribution level and fixed capacitor banks at sub-transmission level, and an upgraded distribution network would also reduce technical losses. Additionally, these planned investments are expected to improve the electric supply quality, reduce operating costs, and ultimately drive the objectives of a reduction in tariffs.

17.3 Critical Issues

0. 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.

17.4 Strategies

17.4.1 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
    - e. Implementation of the Street lamp upgrade programme.

17.4.2 Technical Losses

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.

b. Improve T&D network design and maintenance program (Projects and Operations Division).

17.4.3 Distribution Upgrade Programme – GPL Funded

Table 49 shows the planned distribution upgrades, targeting reducing technical losses in the primary distribution system.

Table 49: Technical Reduction Projects – Primary Distribution Level

Target Indicators		2023	2024	2025	2026	2027
Activities						
Service Line Replacement (km)		30,000	14,450	10,800	10,300	9,750
Line Extension/Construction (km)	Prim	413	41.421	47.747	24	12
Line Upgrade (km)	Prim	377	25.4	55.747		
	Sec.	186	131	139	159	151
Replacing Inefficient and Under-Utilised Transformers		320	170	144	165	156
Service Connection @ Consumer/Installation of Insulink		28,880	20,400	21,600	24,720	23,400
Jumper Servicing/Crimping/Replacement	Prim	2,997	2,123	2,248	2,572	2,435
	Sec.	6,215	4,402	4,661	5,334	5,049

17.5 Loss Reduction Projections

With the combined application of Phase-1 GNCC/Smart Grid Project at the power generation, transmission, and sub-transmission levels, coupled with the continued implementation of AMI meters at the customer secondary network interface, the Company intends, at minimum, to reduce commercial losses from 13.9% in 2022 to 10.6 % in 2027. See Figure 24 for further details.

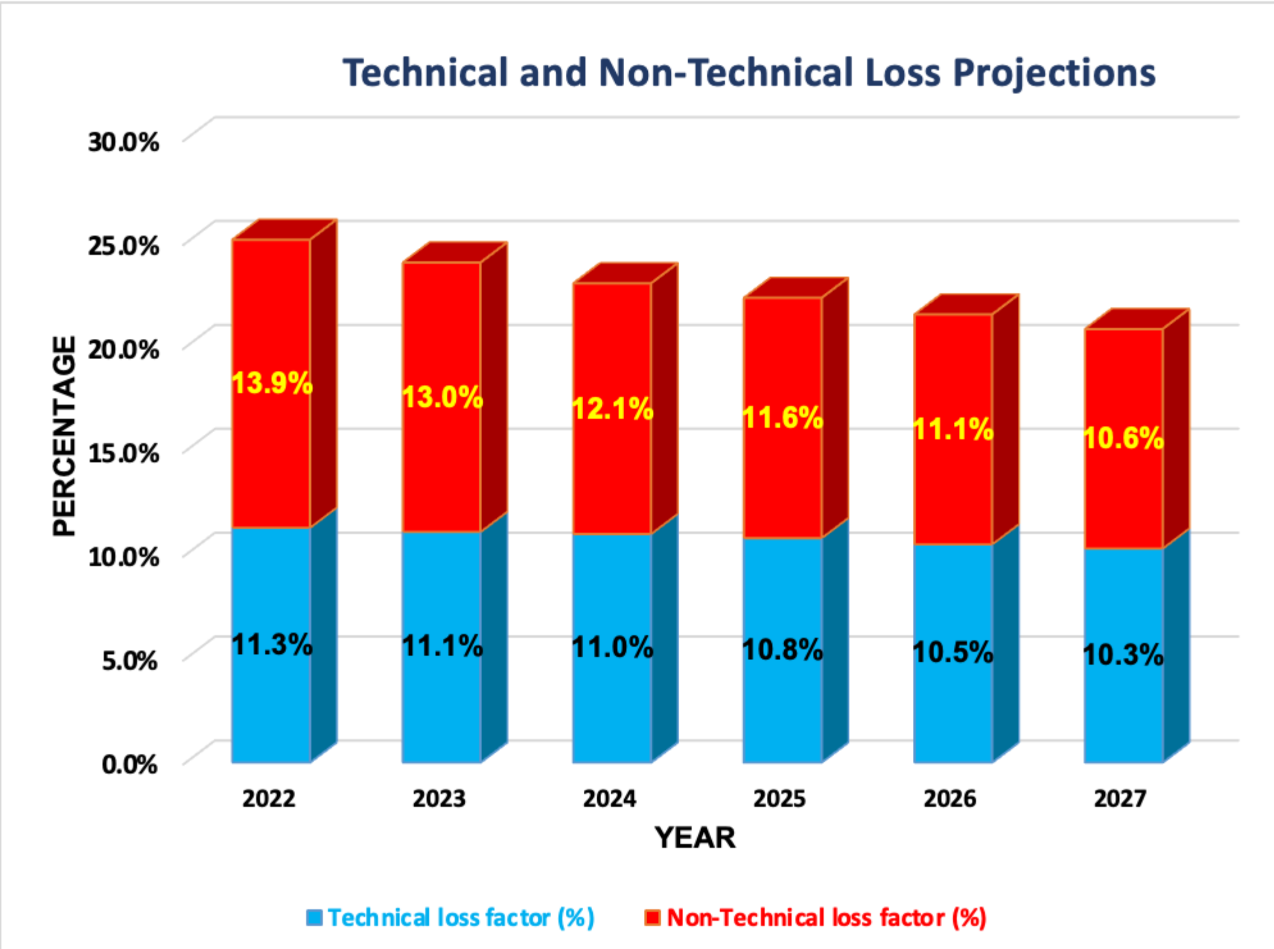


Figure 24: 2022- 2027 Technical and Non-Technical Loss Reduction Projections

As the Company progress with the Phase -2 GNCC/Smart Grid Project, it aims at reducing its total losses from 20.9% in 2027 to 10% by 2030.

18. Non-Technical Operations

18.1 Facilities Management Programmes

The Company continues aiming at an investment of US$7.703 M in new accommodation facilities during the life of this programme. See Table 50 for further details.

Table 50: Design and Construction of New Facilities

No.	Project Description	Location	Year	Estimated Cost US$
1	Renovation and Completion of Stores Building, Sophia	Sophia	2023	850,000
2	Renovation and Completion of T&D Building	Sophia	2023	500,000
3	Construction of Internal Roads Sophia Complex	Sophia	2023	125,000
4	Construction of Training ground for live /Hotwire, Sophia	Sophia	2023	110,000
5	Maintenance Dredging of GPL'S Wharf Facilities	Kingston, Vreed-en-Hoop, GOE	2023	750,000
6	Construction of RC and chain-link fence to switch yard Sophia Complex	Sophia	2023	125,000
7	Rehabilitation of Perimeter Fences, Guard Hut and Demolition of Building at Power Station Compound, Kingston, Georgetown	Kingston	2023	125,000
8	Rehabilitation Works to Victoria T& D location	Victoria	2023	50,000
9	Repairs to Cluster Piles at Vreed-en Hoop Wharf	West Bank Demerara	2023	55,000
10	Rehabilitation of Training School	Sophia	2023	100,000
11	Repairs to Sub-stations Buildings	Various Locations	2023	175,000
12	Removal of Asbestos Roof Sheets from the Power Station Building and install new roofing sheets at Canefield Power Station	Canefield, Berbice	2023	125,000
13	Rehabilitation of old System Control Building at Sophia	Sophia	2023	95,000
14	Rehabilitation of Mechanical Workshop, GOE	Garden of Eden	2023	275,000
15	Rehabilitation Works to Internal Roads and Drains at GPL Compound, Garden of Eden Power Station	Garden of Eden	2023	200,000
16	Construction of Timber Revetment to Anchors of Transmission Structure at No.19, East Berbice	East Berbice	2023	60,000
17	Repairs to access road and bridge at Canefield Berbice	Canefield, Berbice	2023	125,000
18	Rehabilitation to Perimeter Fence at Leguan Power Station.	Leguan	2023	40,000
19	Buildings and Infrastructure Improvements	Various Locations	2023	511,033

No.	Project Description	Location	Year	Estimated Cost US$
	2022 TOTAL			**4,396,033**
1	Complete construction of T & D Main Building at Sophia	Sophia	2024	230,000
2	Construction of a Lube Oil Bond at Onverwagt Power Station	West Coast Berbice	2024	60,000
3	Construction of Pile cluster, Canefield	Canefield, Berbice	2024	60,000
4	Rehabilitation of Parking Lot, Construction of Shed over Inventory Storage Container and Painting of the Commercial and T&D Office at Onverwagt	West Coast Berbice	2024	55,000
5	Construction of Lube Oil Bond and Workshop at Bartica Power Station Compound	Bartica	2024	50,000
6	Renovate and extend T & D Building at Versailles	West Bank Demerara	2024	115,000
7	Repairs to Perimeter Fence at Versailles Power station	West Bank Demerara	2024	50,000
8	Rehabilitation of Internal Roads at No.53 Sub-Station	East Berbice	2024	50,000
9	Rehabilitation works to metering stores, engineer office, carpentry workshop building and extension of washrooms Sophia.	Sophia	2024	70,000
10	Complete the Rehabilitation Works to Internal Roads and Drains at GPL Compound, Garden of Eden Power Station	Garden of Eden	2024	150,000
11	Construction of concrete internal Drains at Canefield Berbice	Canefield, Berbice	2024	75,000
12	Rehabilitation of Building and fence at Onverwagt Engineer's Residence to house T&D	West Coast Berbice	2024	40,000
13	Buildings and infrastructure improvements	Various Locations	2024	413,473
	2023 TOTAL			**1,418,473**
1	Construction of RC drain to North-eastern section of the Sophia Complex.	Sophia	2025	75,000
2	Construction of Revetment to the Western Side of the Compound at GOE	Garden of Eden	2025	125,000
3	Complete the Rehabilitation of Building and fence at Onverwagt Engineer's Residence to house T&D	West Coast Berbice	2025	40,000
4	Buildings and infrastructure improvements	Various Locations	2025	116,144
	2024 TOTAL			**356,144**
1	Construct T and D Building at East Bank Berbice (location to be determined)	East Bank Berbice	2026	174,216
2	Construct Commercial office buildings at East Berbice, Corriverton, Grove, ECD and Parika	Various Locations	2026	406,505

No.	Project Description	Location	Year	Estimated Cost US$
3	Buildings and infrastructure improvements	Various Locations	2026	185,803
	2025 TOTAL			**766,524**
1	Complete the construction of T and D Building at East Bank Berbice	New Amsterdam	2027	174,216
2	Complete Commercial office buildings at East Berbice, Corriverton, Grove, ECD and Parika	Various Locations	2027	406,505
3	Buildings and infrastructure improvements	Various Locations	2027	185,830
	2026 TOTAL			**766,551**
	GRAND TOTAL		**2022-2027**	**7,703,725**

18.2 Commercial Division

18.2.1 Critical Issues

The Customer services Division has identified several key areas to enhance the customers experience and their access to services, facilities and information related to their specific services.

18.2.2 New Services

The Company plans to connect approximately 43,017 new consumers to the grid for the period of the D&E 2023 to 2027. 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 through faster service requests timings, which will allow for them to establish electricity accounts and desist from invitations to acquire electricity through illegal arrangements.

18.2.3 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. These systems were realized through EU/IDB funding under the Power Utility Upgrade Programme (PUUP). All expected BIS activities were completed by PUUP including the provision of a dedicated server, which GPL is still to fully activate.
- ✓ 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 2023.

- ✓ 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.
- ✓ The upgrade the Customer Information System from a client-server platform to a web-based platform in 2023
- ✓ The procurement and implementation of a modern computerized financial budgeting and expenditure monitoring reporting system in 2022.
- ✓ The continued leveraging of the corporate GIS.

18.2.4 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.com to present monthly electronic bills, which customers can access and download at their leisure.
- Increase the use of the GPL Customer web portal https://my.gplinc.com providing customers access to additional billing features.
- 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.

18.2.5 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 implementation of the Net billing feature to compensate grid tied customers will positively increase both the relationship with these customers and the returns received and the additional power their excess will add to the network.

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.

18.2.6 Strategy

1. Leverage current technological platforms to increase and improve customer engagement: Service Fault reports – the ability of customers to send photos or videos of the service fault to the company's call centre providing preliminary and useful information to field technicians and assist in effective emergency work scheduling with the objective of reducing the time to rectify service fault.

   (a) Application processing updates – provide customer with electronic updates on the requests for Electric services (New services) via email, WhatsApp, SMS and corporate/ Customer portal. Similarly, for other electric Service requests such as termination of service, change in service, etc.

   Collaboration with the National Deeds and Commercial Registries Authority to establish electronic verification of legal documents associated with premises or land occupancy and company registration. This is to further encourage online applications for electric services and reduce the need to visit the company's commercial offices.

   (b) Provision of online payments via credit cards and the deployment of Payment kiosks at strategic locations. Whilst the company has a large network of payment agents countrywide, it continues its efforts to encourage bill payments by leveraging the myriad of electronic platforms that offer heightened convenience to customers.

   (c) Optimizing the Customer Service portal by ensuring the convenient accessibility to all customer account related information inclusive of consumption, bill and payment histories, bill payments and queries

   (d) Ensure optimization of the corporate website, Facebook page and YouTube channels for useful customer information penetration.

2. Leverage Technology platforms for internal services

   (a) Further leverage the company's Customer Information system (CIS) and GIS systems to manage customer request/ reports, i.e., use of data in CIS to understand network availability in the area to accommodate new service connections, capital work requirements, magnitude of emergency report, etc.

   (b) Leverage the Corporate Customer Information System to accommodate "Fast data Capture" and real time updating by Field staff for various field activities such as new installations, meter changes, disconnected and reconnected services.

   (c) Implementation of modern technology: Automated Meter reading (AMR) and a migration to Advanced Metering Infrastructure for remote meter reading retrieval and voltage monitoring and general monitoring of customer' activity at the distribution network level.

3. Reduce commercial losses

   (a) Ensuring 100% accounts billed on actual readings consistently through-improved reading timelines and follow up done where discrepancies identified.

   (b) Engage Community Based Representatives (CBR) in strategic areas to further support the Company's reach into all communities within served areas as part of the corporate continuous customer service improvement efforts.

18.2.7 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.

18.2.8 Key Performance Indication

Key Performance Indicator	Target 2021	Target 2022	Target 2023	Target 2024	Target 2025	Target 2026
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%

18.3 Finance and Supply Chain Management

18.3.1 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.

18.3.2 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.

18.4 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:

Table 51: IT Division KPIs

Item No.	**KPI**	**Target**				
	Year	2022	2023	2024	2025	2026
	Infrastructure related					
1	Mission-critical Systems (EBS, CIS, JUICE, Email, Emergency) uptime	99.9%	99.9%	99.9%	99.9%	99.9%
2	Percentage of offices connected via broadband	90%	100%	100%	100%	100%
	Client Services related					
2	Help Desk Response <=1 hour	100%	100%	100%	100%	100%
3	Percentage Help Desk Resolution <= 3 Days (Demerara locations)	95%	95%	95%	95%	95%
4	Percentage Help Desk Resolution <= 5 Days (Esseq. & Berbice locations)	95%	95%	95%	95%	95%
6	Time to complete RFP for purchase of computers	1 day	1 day	1 day	1 day	1 day
7	Time to complete RFP for purchase of phones/ smartphones	1 day	1 day	1 day	1 day	1 day
8	Percentage of computer users provisioned with necessary software	100%	100%	100%	100%	100%
9	Percentage of computer users oriented/ needs assessment/ development plan	90%	100%	100%	100%	100%

Item No.	KPI	Target				
Year		2022	2023	2024	2025	2026
	GIS related					
10	Percentage of identified field staff/ teams equipped and oriented to collect structured, digital, geospatial, on-site data	100%	100%	100%	100%	100%
11	Percentage of T&D network documented in GIS	90%	100%	100%	100%	100%
12	Percentage of T&D network inspections documented in GIS	90%	100%	100%	100%	100%
13	Percentage of emergency response cases captured via FDCI/ GIS	90%	100%	100%	100%	100%
14	Percentage of customers documented in GIS	90%	100%	100%	100%	100%
15	Percentage of CIS customer records updated with location data	90%	100%	100%	100%	100%
16	Percentage of CIS “transformer module” updated	90%	100%	100%	100%	100%

Much of the work regarding E-Business will be project-based and would result in and may be measured by efficiency/ accuracy outcomes for Business Units

18.4.1 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.

18.4.2 Strategy

Reorganize IT Division into three teams that will:

1. Provide infrastructure;
2. Provide client services to improve the user capability and user experience;
3. Process data and deliver information, and implement e-Business approaches;

Pivot GPL towards being data-driven and an e-Business:

4. Capture current, accurate data about GPL assets (electrical network assets, customers, etc.) and changes regarding these assets.
5. Capture digital, geospatial data immediately when changes occur and on-site where they occur.
6. Use data not opinion or estimates for planning, and reporting operations

An example of such a pivot is the progress made by acquiring a current, field-based census of streetlamps beginning in 2018 using mobile devices (Fast Data Capture method developed by the IT Division) and comparing field counts with data in the Customer Information System (CIS), via an analytical Dashboard, as shown in the three figures below. One outcome was accurate identification of active streetlamp accounts rising from 88 to 125 between 2018 and 2019, with associated current charges increasing from GY$44.5M to GY$66.9M.

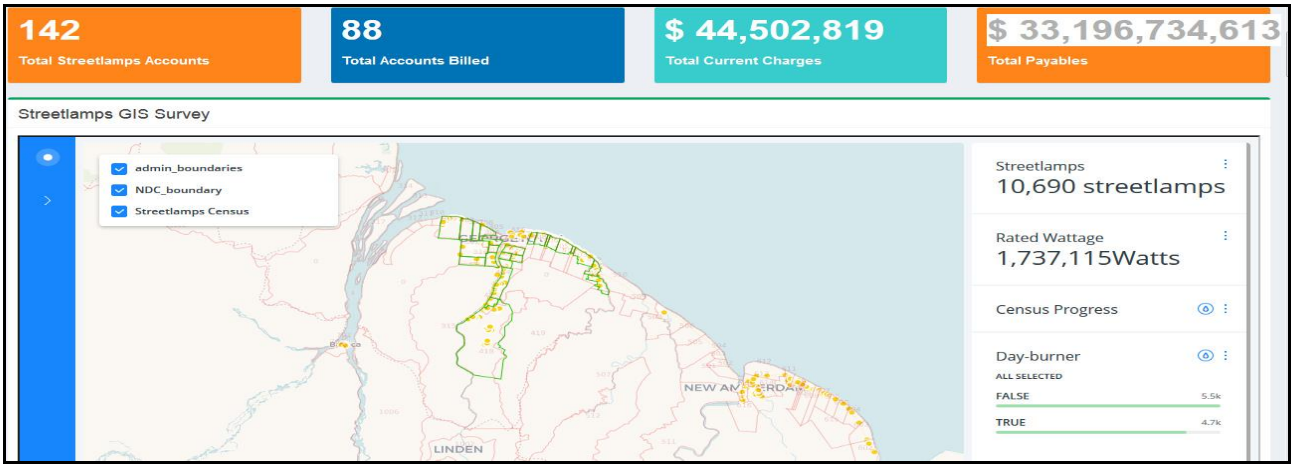


Figure 25: In Apr 2018 as the Streetlamps was underway, GPL billed only 88 of 142 accounts. Data in the CIS used 5+ year old, estimated counts, and active and total accounts were unverified.

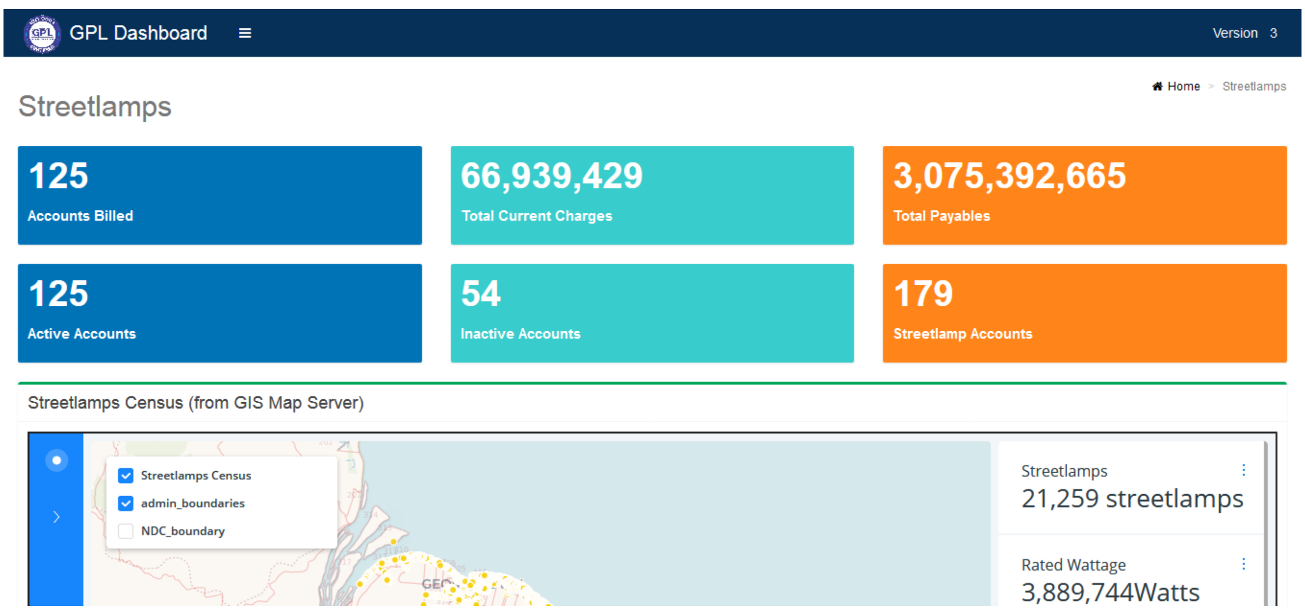


Figure 26: In Nov 2019 when the Streetlamps census completed, GPL began billing 125 of 125 discovered active accounts and 179 total discovered accounts.

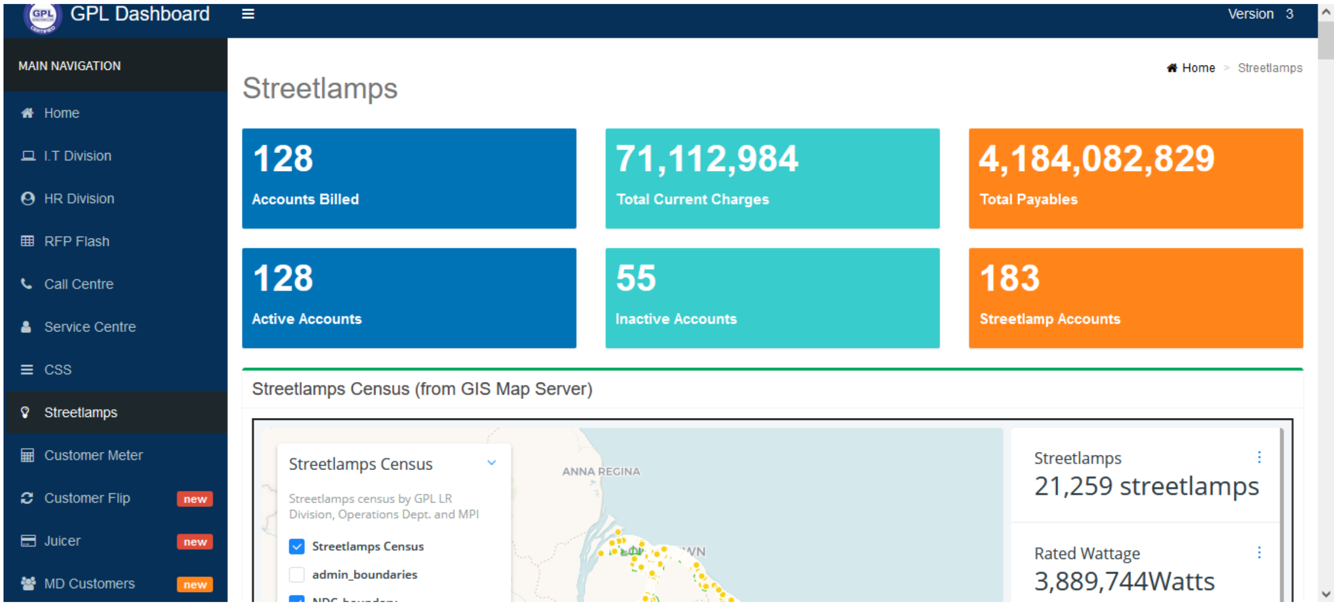


Figure 27: Current (2022) analytical dashboard of streetlamp accounts, with 128 active accounts being billed, of 183 total accounts, associated with 3.9 MW of consumption and current charges of GY$71M.

18.4.3 Critical Projects:

Infrastructure/ WAN restructuring and upgrade. The WAN will be restructured and upgraded for more seamless management and cybersecurity and will include cloud assets where uptime, efficiency and security can be advantageous.

E-Business Suite Upgrade and Expansion. The EBS will be upgraded and other useful aspects of a financial system such as budgeting would be brought online, including modules for E-Tendering (identified as a critical issue by the Executive, based on feedback from Cabinet), Budgeting and Fixed Asset.

CIS Upgrade. The roadmap for a less expensive infrastructure/ database and additional useful modules will be implemented.

GIS expansion. The GIS has brought fast, mobile data capture and map visualization to GPL. It will continue to expand the methods/ technology that the company can use to gather data on its assets and operations and develop products/ services that improve decision-making.

Enterprise Resource Planning (ERP) System. An ERP, including an integrated Work Management module, as recommended by the TERI consultants will be put into place. It has been advised that asset management is key; and a continual, accurate, digital data flow regarding T&D assets needs to be entrenched in the company. The method and technology for mobile data capture for the ERP has already been demonstrated during collection and update of customer, feeder and transformer asset and geospatial data for the entire City of Georgetown in a Dec 2021 project.

Business Intelligence System (BIS). The BIS is the second iteration of solving the operational silos issue identified by consultants by creating a single set of business metrics in a unified way from GPLS's various data sources. The effort to expand its use, build necessary structured, transactional data pipelines from various business units, and pivot to a data driven business will continue.

Office/ collaboration/ backup software system implementation. The use of a tool to support to support document creation, storage/ sharing, collaboration, and management will be expanded.

Interactive Web Portal. The web portal will continue to be a core means of providing customer services 24/ 7/ 365, and developments in this space will be pursued for greater/ wider effect.

HRIS PMS. The Human Resources Information System (HRIS), which includes payroll and has an associated time and attendance solution was successfully implemented in 2021. A solution for Performance Management will be implemented.

National Control Centre. The company will seek to implement Smart Grid and developments to implement/ support the AMI infrastructure and develop solutions for other matters using AI are likely to be necessary. Here again, the De Barr SCADA consultants have advised that It has been advised that asset management is key; and a continual, accurate, digital data flow regarding T&D assets and any changes needs to be entrenched in the company. Some flows of data from SCADA assets including Auto-Reclosers, and Generation assets, will be made continuous with investments in sensors and a sensor network.

18.5 Human Resources Division

Development and maintenance of the requisite core of skills and competencies to manage the evolving electricity infrastructure that is based increasingly on automation and ICT systems would be critical for GPL. In this regard, GPL will develop and execute targeted training programs in automation engineering in areas where such systems will be introduced.

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 and expand the Management Trainee and technician programs 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 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.

18.5.1 Critical Issues

1. There is an urgent need to continuously 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 need 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. There is a critical need for a revised Disciplinary Policy and Procedures that aims at becoming a more effective and efficient system for dealing with disciplinary issues.
7. The present system implemented for monitoring safety procedures and effectuating 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.

18.5.2 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. Identify and execute training programs in areas of automation engineering including Sensor technology, PLCs, smart devices etc. in consultation with training providers, and tertiary institutions.
7. Implement new Performance Management System.
8. Develop and implement a system for Succession Planning.
9. Review, document and revise Disciplinary Policy.
10. Develop and Implement Change Management.
11. Develop and negotiate proposals for staff Remuneration benefits and conditions of service.
12. Develop and implement programs for Staff Welfare and Social Activities.
13. Conduct annual Employment Engagement survey and develop and implement action plan for improvements in employee engagement.
14. Develop and implement an improved system for Safety, Health, and Environmental Management.
15. Develop and implement system for the effective maintenance and construction of facilities.

18.5.3 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.

19. Corporate Key Performance Indicators and Targets

GPL has identified Key Performance Indicators (KPI),Table 52, 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'**:

- **S**ervice quality.
- **U**ptime/ reliability of systems.
- **C**overage / access to service.
- **C**ompliance with applicable regulations and standards.
- **E**fficiency in all activities.
- **S**afety and security. and
- **S**ustainability.

Table 52: Corporate Key Performance Indicators (KPIs)

Category	Key Performance Indicator	Unit	2022	Targets				
				2023	2024	2025	2026	2027
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

Category	Key Performance Indicator	Unit	2022	Targets				
				2023	2024	2025	2026	2027
	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
	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	%	97.5	98.5	99	99.5	99.8	99.9
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	50.4	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	%	25.2	24.1	23.1	22.4	21.6	20.9

Category	Key Performance Indicator	Unit	2022	Targets				
				2023	2024	2025	2026	2027
	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	No.	19	10	0	0	0	0
	Person-hours lost due to safety incidents	No.	1904	1088	0	0	0	0
Sustainability	Renewable Energy as % of Energy Generated	%	2.9%	6.2%	7.4%	5.7%	8.0%	7.2%
	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
	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

19.1Generation and Network related Key Performance Indicators (KPIs)

Table 53: Operations KPIs

KPIs	Target					
	2022 Achievement	2023	2024	2025	2026	2027
SAIFI	95	90	85	80	75	70
SAIDI	90	85	80	75	70	65
Voltage Complaint	98% within 30 days	98% within 25 days	98% within 20 days	98% within 20 days	100% within 21 days	100% within 20 days
Capital Jobs	95% within 28 days	98% within 21 days	98% within 21 days	98% within 21 days	98% within 21 days	98% within 21 days
Unserved Area Electrification	95% within year	98% within year	98% within year	98% within year	98% within year	100% within year
Emergency Response	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	90% within 8hrs, 10% within 12hrs
Average No. of Emergency Faults Reported daily	90	80	75	70	65	60
ISO Non-Conformance address within	100%	100%	100%	100%	100%	100%

KPIs	Target					
	2022 Achievement	**2023**	**2024**	**2025**	**2026**	**2027**
agreed schedules						
Annual Average Availability of Generation	85%	85%	85%	85%	85%	90%
Availability GPL	80%	89%	90%	92%	92%	94%
Availability PPDI	92%	92%	92%	92%	92%	92%
Efficiency (MMBtu/MWh)	9.18	9.18	9.18	9.18	9.18	9.18
HFO (%) – Based on Economic Dispatch	99.58%	98.32%	90.63%	8.21%	3.55%	3.60%
LFO (%) – Based on Economic Dispatch	0.42%	1.68%	2.16%	1.74%	1.62%	1.90%
NG (%) – Based on Economic Dispatch	0.00%	0.00%	7.22%	90.06%	94.83%	94.50%

20. Summary of Annual Expansion, Upgrades and Service Work Plan (See Error! Reference source not found., page 235 for details by Geographic Areas)

The following capital program sets out to achieve the generation reliability target (LOLP) and transmission and distribution reliability target and assumes that the required funding for the current planning period would be made available.

20.1 Work Plan Summary Short Term Planning (2023-2024)

Generation Projects	
2023-2024	**19.1.1 Conventional Projects**
2023	25 MW EPC HFO-Fired Power Plant - Canefield
2024	Bartica Power Plant Expansion Wakenaam Power Plant Expansion Leguan Power Plant Extension
2023-2024	Renewable Energy and Energy Storage Projects
2024	GUYSOL Projects

Transmission System and Substation Projects	
2023-2024	**Transmission System**
2023	**69 kV Transmission Lines Projects** 1. Rossignol to Canefield Transmission Line upgrade (L21);
2024	**69 kV Transmission Lines Projects** 1. Kingston to Old Sophia Substation parallel and upgraded line (L5-P and L5) 2. Edinburgh to Hydronie new transmission line (L8); 3. Kingston to Thomas Lands substation transmission line (L11-1); 4. Thomas Lands to Princess Street substation transmission line (L11-2); 5. Princess Street to New Georgetown substation transmission line (L11-3); 6. L12 and L13 Upgrade – to facilitate increased power transfer between Old and New

Transmission System and Substation Projects	
2023-2024	**Transmission System**
	Sophia Substations; 7. New Sophia to Good Hope upgraded and parallel transmission lines (L16 and L16P); 8. Wales Natural Gas Power Plant to Wales Industrial Substation three single circuit parallel transmission lines (L30a, L30a-P1 and L30a-P2); 9. Wales Industrial to Wales Residential/Commercial Substation double circuit transmission line (L30b and L30b-P); 10. Wales Residential/Commercial to Vreed-en-Hoop Substation transmission line (L31); 11. Wales Residential/Commercial to Vreed-en-Hoop Substation second transmission line (L32); 12. Wales Residential/Commercial to Hydronie Substation transmission line (L33); 13. Golden Grove to New Sophia transmission line splitting into Goedverwagting Substation (L4-1 and L4-2); 14. Golden Grove to Old Sophia transmission line splitting into Goedverwagting Substation (L2-1 and L2-2); **230 kV Transmission Lines Projects** 1. Wales Natural Gas Power Plant to Goedverwagting 230 kV Double circuit transmission lines (HV_L1 and HV_L1-P);

2023-2024	**New Substation System and Substation Upgrade**
2023	**Substation Upgrade** 1. Garden of Eden Substation; 2. Good Hope Substation 3. Columbia Substation 4. Vreed-en-Hoop Substation

	5. Old Sophia Substation 6. No. 53 Substation 7. Canefield Substation **New Substation System** 1. Mobile Substation
2024	**Substation Upgrade** 1. Edinburgh Substation; 2. New Georgetown Substation; 3. Good Hope Substation; 4. Onverwagt Substation; 5. Vreed-en-Hoop Substation; 6. No. 53 Substation; 7. Old Sophia Substation; 8. Kingston Substation; 9. Golden Grove Substation; **New Substation System** 1. Hydronie 69/13.8 kV Substation; 2. Princess Street 69/13.8 kV Substation; 3. Thomas Lands 69/13.8 kV Substation; 4. Goedverwagting 69/13.8 kV and 230/69 kV Substation; 5. Wales R/C 69/13.8 kV Substation; 6. Wales Industrial 69/13.8 kV Substation;

2023-2024	**Electrification – Unserved Areas**

2023	270 beneficiaries
2024	191 beneficiaries
2023-2024	**New Services**
2023	3,168 New Services
2024	8,251 New Services
2023-2024	**Facilities Management**
2023	1. Renovation and Completion of Stores Building, Sophia 2. Renovation and Completion of T&D Building 3. Construction of Internal Roads Sophia Complex 4. Construction of Training ground for live /Hotwire, Sophia 5. Maintenance Dredging of GPL'S Wharf Facilities 6. Construction of RC and chain-link fence to switch yard Sophia Complex 7. Rehabilitation of Perimeter Fences, Guard Hut and Demolition of Building at Power Station Compound, Kingston, Georgetown 8. Rehabilitation Works to Victoria T& D location 9. Repairs to Cluster Piles at Vreed-en Hoop Wharf 10. Rehabilitation of Training School 11. Repairs to Sub-stations Buildings 12. Removal of Asbestos Roof Sheets from the Power Station Building and install new roofing sheets at Canefield Power Station 13. Rehabilitation of old System Control Building at Sophia 14. Rehabilitation of Mechanical Workshop, GOE 15. Rehabilitation Works to Internal Roads and Drains at GPL Compound, Garden of Eden Power Station 16. Construction of Timber Revetment to Anchors of Transmission Structure at No.19, East Berbice

	17. Repairs to access road and bridge at Canefield Berbice 18. Rehabilitation to Perimeter Fence at Leguan Power Station. 19. Buildings and Infrastructure Improvements
2024	1. Complete construction of T & D Main Building at Sophia 2. Construction of a Lube Oil Bond at Onverwagt Power Station 3. Construction of Pile cluster, Canefield 4. Rehabilitation of Parking Lot, Construction of Shed over Inventory Storage Container and Painting of the Commercial and T&D Office at Onverwagt 5. Construction of Lube Oil Bond and Workshop at Bartica Power Station Compound 6. Renovate and extend T & D Building at Versailles 7. Repairs to Perimeter Fence at Versailles Power station 8. Rehabilitation of Internal Roads at No.53 Sub-Station 9. Rehabilitation works to metering stores, engineer office, carpentry workshop building and extension of washrooms Sophia. 10. Complete the Rehabilitation Works to Internal Roads and Drains at GPL Compound, Garden of Eden Power Station 11. Construction of concrete internal Drains at Canefield Berbice 12. Rehabilitation of Building and fence at Onverwagt Engineer's Residence to house T&D 13. Buildings and infrastructure improvements
2023-2024	**Non-Technical Loss Reduction**
2023	1. Upgrade 8000 minor meters to AMI meters 2. Replace 5,000 aged/defective meters with AMI meters 3. Upgrade 2000 large consumers to AMI meters 4. Replace 1,000 tampered meters to AMI meters

	5. AMI Infrastructure Cost - RF (GPL) 6. Public Education & Social Management Programme (AMI and Street Lamp) 7. Street Light Upgrade Programme (5000 Lamp)
2024	1. Upgrade 8000 minor meters to AMI meters 2. Replace 5,000 aged/defective meters with AMI meters 3. Upgrade 2000 large consumers to AMI meters 4. Replace 1,000 tampered meters to AMI meters 5. AMI Infrastructure Cost - RF (GPL) 6. Public Education & Social Management Programme 7. Street Light Upgrade Programme (5000 Lamp)
2023-2024	**Distribution Network**
2023	**Upgrade of 13.8 kV Primary Distribution Feeders** 1. Golden Grove F1; 2. Golden Grove F3; 3. New Georgetown F1; 4. Sophia F2; 5. Edinburgh F2; 6. Good Hope F4; 7. Canefield F3; 8. Garden of Eden F1; 9. Anna Regina - South Feeder - Express to Onderneeming; **New 13.8 kV Primary Distribution Feeders:** 1. Columbia – 2 new active feeders

	2. Good Hope – 1 new active feeder 3. No. 53 – 1 new active feeder 4. Vreed-en-Hoop – 1 new active feeder 5. DP3 – 1 new active feeder 6. Garden of Eden – 2 new active feeders 7. Canefield – 3 new active feeders 8. Edinburgh – 1 new active feeder 9. Old Sophia – 1 new active feeder **Additional Works:** 1. Installation of 28 Reclosers 2. Installation of 60 Sectionalizers 3. Installation of 60 Smart Fault Current Indicators 4. Leguan Feeder Voltage Upgrade **Reactive Compensation** 1. 1 x 450 kVAr in DBIS 2. 3 x 600 kVAr in DBIS
2024	**Upgrade of 13.8 kV Primary Distribution Feeders** 1. Garden of Eden F2 2. Garden of Eden F3 **New 13.8 kV Primary Distribution Feeders** 1. Parika/Hydronie - 4 new active feeders 2. Princess Street - 6 new active feeders 3. Thomas Lands – 6 new active feeders 4. Goedverwagting – 8 new active feeders 5. Wales R/C – 4 new active feeders

	6. Wales Industrial – 4 new active feeders 7. Good Hope – 2 new active feeders **Additional Works:** 1. Installation of 3 Reclosers 2. Installation of 60 Sectionalizers 3. Installation of 60 Smart Fault Current Indicators **Reactive Compensation** 1. 1 x 450 kVAr in DBIS 2. 3 x 600 kVAr in DBIS

20.2 Work Plan Summary Medium Term Planning (2025-2027)

Generation Projects	
2025-2027	**19.1.2 Conventional Projects**
2026	Anna Regina Power Plant Expansion
2027	Bartica Power Plant Expansion

Transmission System and Substation Projects	
2025-2027	**Transmission System**
2025	**69 kV Transmission Lines Projects** 1. Splitting of L17 to accommodate Victoria/Enmore substation (L17 and L18); 2. Good Hope to Enmore/Victoria parallel transmission line (L17-P); 3. Enmore/Victoria to Columbia parallel transmission line (L18-Bypass); 4. No. 53 to Skeldon Substation parallel transmission line (L23-P); 5. Goedverwagting to Ogle transmission lines (L25 and L25-P); 6. Ogle to Enmore/Victoria Substation transmission line (L26); 7. Splitting of L16 and L16-P into Ogle Substation (L16-1, L16-2, L16-1-P and L16-2-P); 8. Splitting of L22 into Williamsburg Substation (L22-1 and L22-2);
2026	**69 kV Transmission Lines Projects** 1. Garden of Eden to Golden Grove transmission line upgrade (L1 and L3); 2. Onverwagt to Rossignol transmission line upgrade (L21); 3. Onverwagt to Rossignol Substation transmission line (L21-1-P); 4. Rossignol to Canefield Substation transmission line (L21-2-P); 5. Canefield to Williamsburg upgrade and parallel transmission line (L22-1 and L22-1-

Transmission System and Substation Projects	
2025-2027	**Transmission System**
	P); 6. Williamsburg to No. 53 upgrade and parallel transmission line (L22-2 and L22-2-P); 7. Garden of Eden New Substation to Kuru Kururu Substation double circuit transmission line (L35 and L35-P); 8. Garden of Eden New Substation to McKenzie Substation double circuit 230 kV transmission line operating at 69 kV until 2030 (L37 and L37-P); 9. Garden of Eden New Substation to Garden of Eden Old Substation double circuit transmission line (L48 and L48-P); **230 kV Transmission Lines Projects** 1. Garden of Eden New Substation to Goedverwagting Substation double circuit transmission line (HV_L2-2 and HV_L2-2-P); 2. Splitting of HV_L1 and HV_L1-P into Garden of Eden New Substation (HV_L1-1, HV_L1-2, HV_L1-1-P, HV_L1-2-P
2027	**69 kV Transmission Lines Projects** 1. Old Sophia to New Georgetown transmission lines upgrade (L10); 2. Columbia to Onverwagt parallel transmission line (L20-P); 3. Kuru Kururu to Yarrowkabra Substation transmission line (L36); 4. Mackenzie to Wisma Substation transmission line (L38); 5. Splitting of L22-1 and L22-1P into Crab Island Substation (L22-1a, L22-1b, L22-1a-P and L22-1b-P); **230 kV Transmission Lines Projects** 1. Goedverwagting to Crab Island Substation 230 kV double circuit transmission (HV_L4 and HV_L4-P); 2. Crab Island to Williamsburg Substation 230 kV double circuit transmission (HV_L5

Transmission System and Substation Projects	
2025-2027	**Transmission System**
	and HV_L5-P);
2025-2027	**Substation Upgrade System**
2025	1. New Sophia Substation; 2. Edinburgh Substation; 3. Good Hope Substation; 4. Columbia Substation 5. Onverwagt Substation; 6. Skeldon Substation; 7. No. 53 Substation;
2026	1. Garden of Eden Substation; 2. Onverwagt Substation; 3. Canefield Substation;
2027	1. Onverwagt Substation; 2. Columbia Substation;
2025-2027	**New Substation System**
2025	1. Ogle 69/13.8 kV Substation 2. Enmore/Victoria 69/13.8 kV Substation 3. Williamsburg 69/13.8 kV Substation 4. McKenzie 69/13.8 kV Substation
2026	1. Kuru Kururu 69/13.8 kV Substation 2. Rossignol 69/13.8 kV Substation 3. Garden of Eden New 69/13.8 kV Substation

Transmission System and Substation Projects	
2025-2027	**Transmission System**
2027	1. Yarrowkabra 69/13.8 kV Substation 2. Crab Island 69/13.8 kV Substation 3. Wismar 69/13.8 kV Substation
2025-2027	**Transmission Reinforcements**
2025	1. **New Sophia**-15 MVAr 69 kV De-tuned Compensation Systems 2. **Columbia -**15 MVAr 69 kV De-tuned Compensation Systems 3. **No. 53** -15 MVAr 69 kV De-tuned Compensation Systems 4. **Edinburgh -**10 MVAr 69 kV De-tuned Compensation Systems
2025-2027	**Electrification – Unserved Areas**
2025	90 beneficiaries
2026	43 beneficiaries
2027	30 beneficiaries
2025-2027	**New Services**
2025	7,335 New Services
2026	8,419 New Services
2027	10,503 New Services
2025-2027	**Facilities Management**
2025	1. Construction of RC drain to North-eastern section of the Sophia Complex. 2. Construction of Revetment to the Western Side of the Compound at GOE 3. Complete the Rehabilitation of Building and fence at Onverwagt Engineer's Residence to house T&D 4. Buildings and infrastructure improvements
2026	1. Construct T and D Building at East Bank Berbice (location to be determined) 2. Construct Commercial office buildings at East Berbice, Corriverton, Grove, ECD

Transmission System and Substation Projects	
2025-2027	**Transmission System**
	and Parika 3. Buildings and infrastructure improvements
2027	1. Complete the construction of T and D Building at East Bank Berbice 2. Complete Commercial office buildings at East Berbice, Corriverton, Grove, ECD and Parika 3. Buildings and infrastructure improvements
2025-2027	**Non-Technical Loss Reduction**
2025	1. Upgrade 8000 minor meters to AMI meters 2. Replace 5,000 aged/defective meters with AMI meters 3. Upgrade 2000 large consumers to AMI meters 4. Replace 1,000 tampered meters to AMI meters 5. AMI Infrastructure Cost - RF (GPL) 6. Public Education & Social Management Programme 7. Street Light Upgrade Programme (5000 Lamp)
2026	1. Upgrade 8000 minor meters to AMI meters 2. Replace 5,000 aged/defective meters with AMI meters 3. Upgrade 2000 large consumers to AMI meters 4. Replace 1,000 tampered meters to AMI meters 5. AMI Infrastructure Cost - RF (GPL) 6. Public Education & Social Management Programme 7. Street Light Upgrade Programme (5000 Lamp)
2027	1. Upgrade 8000 minor meters to AMI meters

Transmission System and Substation Projects	
2025-2027	**Transmission System**
	2. Replace 5,000 aged/defective meters with AMI meters 3. Upgrade 2000 large consumers to AMI meters 4. Replace 1,000 tampered meters to AMI meters 5. AMI Infrastructure Cost - RF (GPL) 6. Public Education & Social Management Programme 7. Street Light Upgrade Programme (5000 Lamp)

2025-2027	Distribution
2025	**Upgrade of 13.8 kV Primary Distribution Feeders** 1. Anna Regina - South Feeder – Upgrade 2. No. 53 - both feeders **New 13.8 kV Primary Distribution Feeders** 1. Victoria/Enmore – 4 new active feeders 2. Wales Residential/Commercial – 2 new active feeders 3. Wales Industrial – 2 new active feeders 4. Ogle – 8 new active feeders 5. Williamsburg – 4 new active feeders 6. Columbia – 2 new active feeders 7. No. 53 – 2 new active feeders 8. McKenzie – 6 new active feeders 9. Canefield – 2 new active feeders **Additional Works:** 1. Installation of 3 Reclosers

	2. Installation of 60 Sectionalizers 3. Installation of 60 Smart Fault Current Indicators **Reactive Compensation** 1. 1 x 450 kVAr in DBIS 2. 3 x 600 kVAr in DBIS
2026	**New 13.8 kV Primary Distribution Feeders** 1. Wales R/C - 2 new active feeders 2. Wales Industrial - 1 new active feeder 3. Rossignol - 4 new active feeders 4. Crab Island - 6 new active feeders 5. Edinburgh - 3 new active feeders 6. Kuru Kururu - 3 new active feeders 7. Old Sophia - 4 new active feeders **Additional Works:** 1. Installation of 3 Reclosers 2. Installation of 60 Sectionalizers 3. Installation of 60 Smart Fault Current Indicators **Reactive Compensation** 1. 1 x 450 kVAr in DBIS 2. 2 x 600 kVAr in DBIS 3. 1 x 450 kVAr in Bartica 4. 1 x 450 kVAr in Leguan 5. 1 x 450 kVAr in Wakenaam

	6. 1 x 600 kVAr in Essequibo Coast 7. 1 x 450 kVAr in Linden
2027	**New 13.8 kV Primary Distribution Feeders** 1. Wales R/C - 2 new active feeders 2. Wales Industrial - 1 new active feeders 3. Yarrowkabra - 4 new active feeders 4. Wismar - 4 new active feeders **Additional Works:** 1. Installation of 2 Reclosers 2. Installation of 60 Sectionalizers 3. Installation of 60 Smart Fault Current Indicators **Reactive Compensation** 1. 1 x 450 kVAr in DBIS 2. 2 x 600 kVAr in DBIS 3. 1 x 450 kVAr in Linden

21 Sales and Revenue Collection

Electricity sales growth from 2022 to 2027 is projected to increase by 238 %, that is, from 817.2 GWh to 1,946.9 GWh for the total GPL Power Systems (Figure 28). Also, Linden is considered connected with the DBIS in 2026.

The projection is based on the estimated growth of GPL's customer base and the expected significant stimulation in the economy that will be provided by the emerging Oil and Gas Industry.

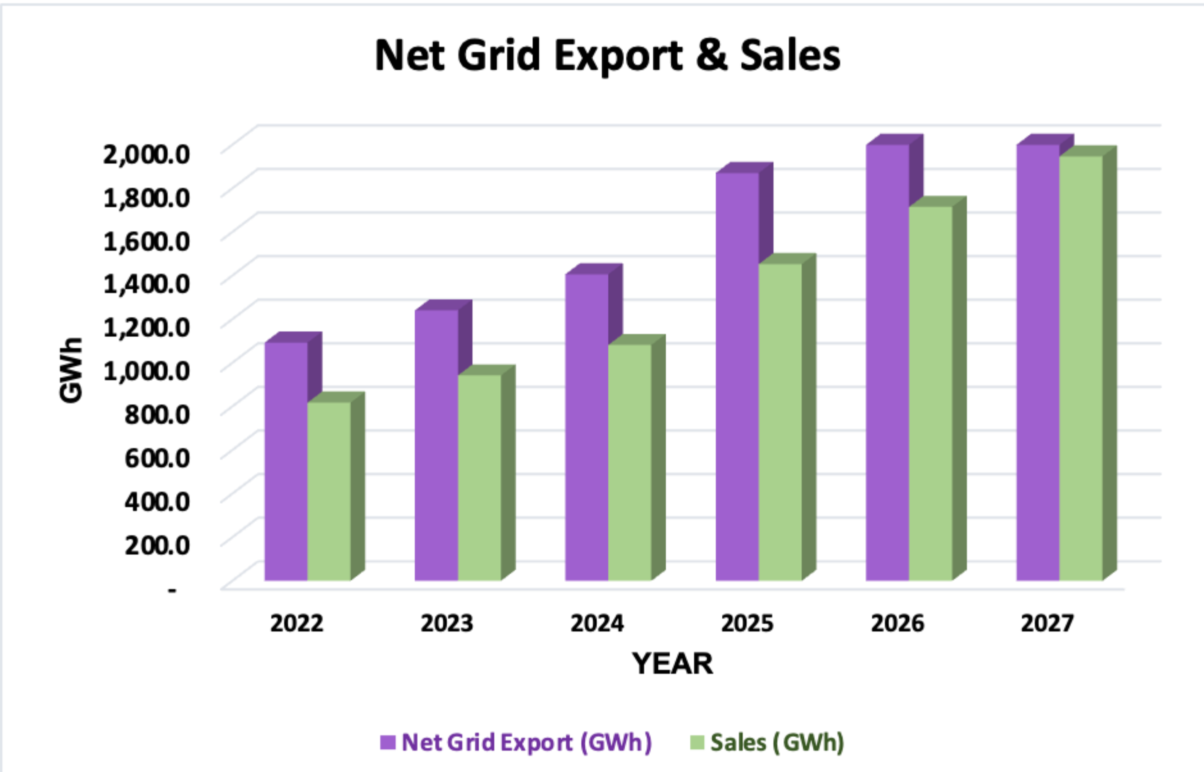


Figure 28: Net generation & Sales (GWh)

November 2022 ended with GPL providing electricity to 218,870 customers (Table 7), of which, 91.3% is residential, 8.3% commercial and 0.4%, industrial.

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. As such, the combined outcomes due to Government's housing expansion programmes, GPL efforts in addressing unserved areas/customers, positive prospects of commercial and industrial expansions would result in the following average annual growth per tariff category:

- No. of Residential Customers – 3.79%.

- No. of Commercial Customers – 6.51%.
- No. of Industrial Customers - 7.21 %.

The total customer-base growth over the life of this programme averages at 4.04% per annum, which averages at 9,559 new customers per annum.

In view of the above, the annual total projected number of customers to be served by GPL is shown in Table 54. At the end of 2027, this Development and Expansion Programme is prepared to serve an additional 40,714 residential, 6,721 commercial and 358 industrial customers. This represents a total additional 47,793 customers. Therefore, in 2027 it is expected for GPL to be serving 266,663 customers.

Table 54: Customer-base Projection

Year	2022	2023	2024	2025	2026	2027
Residential Customers	199,811	207,979	213,146	217,981	229,161	240,525
Commercial Customers	18,203	19,003	19,803	21,003	22,856	24,924
Industrial Customers	856	881	931	1,006	1,110	1,214
Total No. of Customers	**218,870**	**227,863**	**233,880**	**239,990**	**253,127**	**266,663**

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 un-served areas documented to date.

The Company intends to ramp-up its campaign to improve receivables, aiming to achieve a cash collection rate of 99.5% (cash collections as a percentage of sales), which is assumed within the life of this Development and Expansion Programme.

22 Projected Capital Expenditure

22.1 Summary of Capital Expenditure, US$ - GPL Funding

Table 55: Summary of Capital Expenditure, US$ - GPL Funding

Development and Expansion Projects		Annual Budget (US$)				
		2023	2024	2025	2026	2027
	US$	US$	US$	US$	US$	US$
Conventional Generation	66,258,294	23,749,540	20,019,034	10,505,220	10,067,200	1,917,300
Non-Conventional Generation	80,000,000	44,000,000	36,000,000	-	-	-
69 kVTransmission Lines (Include Sub. Exp. Cost)	240,835,409	21,667,145	27,487,423	101,636,825	83,960,851	6,083,165
230 kV Transmission Lines (Include Sub. Exp. Cost)	318,160,371	23,279,199	19,046,617	16,104,811	148,780,858	110,948,886
Upgrade - Existing 69/13.8 kV Substation	19,947,615	15,369,701	3,010,832	1,115,593	451,489	-
New 69/13.8 kV Substation	142,640,164	33,068,810	57,813,840	23,745,562	20,398,195	7,613,757
230 kV Substation - New	64,445,473	10,787,662	15,147,927	13,939,811	16,597,376	7,972,697
New Primary Distribution Feeders	30,068,278	6,291,375	9,503,932	7,856,394	4,555,627	1,860,950
Upgrade to Existing Primary Distribution Network (Technical Loss Reduction)	20,201,934	12,478,099	3,624,287	2,322,057	919,727	857,763
Transmission Reactive Reinforcement	5,886,962	-	3,292,741	2,594,221	-	-
GNCC/Smart Grid	60,114,370	8,458,000	5,389,250	18,506,848	13,880,136	13,880,136
Power Plant Switchgear Upgrades	73,893,675	995,947	72,897,728	-	-	-
Meter Upgrades/Replacements (Non-Technical Loss Reduction)	36,399,500	6,250,000	7,537,375	7,537,375	7,537,375	7,537,375
Electrification (Unserved Areas)	2,453,454	2,210,285	243,169	-	-	-
New Services	17,306,932	1,455,076	3,790,382	3,369,514	3,867,371	4,824,590
Buildings	7,703,725	4,396,033	1,418,473	356,144	766,524	766,551
Company Tools	28,512,557	8,991,554	8,052,258	3,674,828	5,565,402	2,228,515
Information Technology	1,325,000	855,000	470,000	-	-	-
GRAND TOTAL US$	**1,216,153,711**	**224,303,427**	**294,745,268**	**213,265,202**	**317,348,129**	**166,491,685**
Guyana Dollar Equivalent ($ millions)	**261,777**	**48,281**	**63,444**	**45,905**	**68,309**	**35,837**

Source of Funding – Loans facilitated through the Government of Guyana.

22.2 Operating costs and Capital Expenditures

Table 56:Profit & Loss Account

	2022	Yr 2023	Yr 2024	Yr 2025	Yr 2026	Yr 2027
	Latest Estimate	**Proj**	**Proj**	**Proj**	**Proj**	**Proj**
	$'M	**$'M**	**$'M**	**$'M**	**$'M**	**$'M**
REVENUE	38,628	47,137	54,132	36,340	42,762	48,954
GENERATION COSTS	42,971	46,060	45,757	28,164	30,053	37,094
GROSS INCOME	**(4,343)**	**1,076**	**8,374**	**8,175**	**12,708**	**11,860**
EXPENSES						
Employment Costs	5,708	6,062	6,668	7,335	8,068	8,875
Repairs & Maintenance T&D	405	2,569	3,854	5,781	6,359	6,995
Depreciation	3,883	7,361	11,334	14,291	18,739	21,107
Administrative Expenses	2,596	3,467	3,709	3,969	4,247	4,544
Rates & Taxes	45	50	50	50	50	50
Loss On Exchange	-	-	-	-	-	-
Bad Debts Provision	579	707	812	545	641	734
Puc Assessment & Licence	72	73	73	73	73	73
	13,289	**20,290**	**26,501**	**32,044**	**38,177**	**42,378**
NET (LOSS)/PROFIT FROM OPERATIONS	(17,632)	(19,213)	(18,126)	(23,868)	(25,469)	(30,519)
INTEREST EXPENSE	1,293	1,763	1,939	2,133	2,347	2,581
	(18,925)	**(20,976)**	**(20,066)**	**(26,001)**	**(27,816)**	**(33,100)**
OTHER INCOME						
	(18,925)	**(20,976)**	**(20,066)**	**(26,001)**	**(27,816)**	**(33,100)**
TAXATION						
NET (LOSS)/PROFIT FOR THE YEAR	**(18,925)**	**(20,976)**	**(20,066)**	**(26,001)**	**(27,816)**	**(33,100)**

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

22.3 Cash Flow Statement

Table 57: Cash Flow Statement

	Yr 2023	Yr 2024	Yr 2025	Yr 2026	Yr 2027
	Proj	Proj	Proj	Proj	Proj
Year Ended December 31st	**$'M**	**$'M**	**$'M**	**$'M**	**$'M**
OPERATING ACTIVITIES					
Profit/(Loss) before Taxation	**(20,976)**	**(20,066)**	**(26,001)**	**(27,816)**	**(33,100)**
Adjustments for:					
Depreciation	7,361	11,334	14,291	18,739	21,107
Deferred Income	8	6	(15)	5	5
Interest Expense	1,763	1,939	2,133	2,347	2,581
Operating (loss)/profit before WC changes	**(11,844)**	**(6,786)**	**(9,592)**	**(6,725)**	**(9,407)**
Working Capital (WC) Changes					
Change in Inventories	(245)	(258)	(271)	(284)	(298)
Change in receivables and prepayments	(2,871)	(1,166)	2,965	(1,070)	(1,032)
Change in payables and accruals	2,123	2,335	2,569	2,826	3,108
Changes in Deferred Tax Liabilities and benefits	25	0	0	0	0
Taxes paid	7	7	8	9	10
Net Cash (Outflow)/Inflow - Operating Activities	**(12,805)**	**(5,867)**	**(4,321)**	**(5,245)**	**(7,619)**
INVESTING ACTIVITIES					
Acquisition of Property, plant and equipment	(52,180)	(59,592)	(44,347)	(66,718)	(35,521)
Acquisition of treasury bills	0	0	0	0	0
Increase in deposit	(216)	(118)	(141)	(169)	(203)
Net Cash Outflow - Investing Activities	**(52,396)**	**(59,710)**	**(44,488)**	**(66,887)**	**(35,724)**
FINANCING ACTIVITIES					
Movement in non current related parties	71,031	65,407	48,865	72,317	45,005
Deposit on Shares	0	0	0	0	0
Interest paid	(1,763)	(1,939)	(2,133)	(2,347)	(2,581)
Customer deposits	501	2,089	2,087	2,190	1,187
Increase in advances customer financed projects	173	507	524	565	388
Decrease in advances customer financed projects					
Net Cash (Outflow)/Inflow - Financing Activities	**69,941**	**66,064**	**49,342**	**72,725**	**43,998**
NET MOVEMENT IN CASH AND CASH EQUIVALENTS	**4,739**	**487**	**533**	**593**	**654**
CASH AND CASH EQUIVALENTS AS AT BEGINNING OF YEAR	40	4,779	5,266	5,799	6,392
CASH AND CASH EQUIVALENTS AS AT END OF YEAR	**4,779**	**5,266**	**5,799**	**6,392**	**7,046**
Represented By:					
Cash on Hand and at Bank	**4,779**	**5,266**	**5,799**	**6,392**	**7,046**

22.4 Balance Sheet

Table 58: Balance Sheet

	2022	Yr 2023	Yr 2024	Yr 2025	Yr 2026	Yr 2027
	Latest Estimate	Proj	Proj	Proj	Proj	Proj
As at December 31st	**$'M**	**$'M**	**$'M**	**$'M**	**$'M**	**$'M**
ASSETS						
Non Current Assets	**61,478**	**106,297**	**154,555**	**184,611**	**232,590**	**247,005**
Current Assets						
Inventories	4,908	5,153	5,411	5,682	5,966	6,264
Receivables & Prepayments	4,985	7,856	9,022	6,057	7,127	8,159
Deposits	372	588	706	847	1,016	1,219
Related parties	3,569	3,569	3,569	3,569	3,569	3,569
Cash resources	40	4,779	5,266	5,799	6,392	7,046
	13,874	**21,946**	**23,974**	**21,953**	**24,070**	**26,258**
Total Assets	**75,352**	**128,243**	**178,528**	**206,564**	**256,660**	**273,263**
EQUITY & LIABILITIES						
Share Capital	23,118	23,118	23,118	23,118	23,118	23,118
Accumulated deficit	(39,354)	(60,330)	(80,396)	(106,397)	(134,213)	(167,312)
	- 16,236	**- 37,212**	**- 57,278**	**- 83,279**	**- 111,095**	**- 144,194**
Non Current Liabilities						
Related Parties	62,746	133,777	199,183	248,048	320,365	365,370
Advances customer financed project	862	963	1,384	1,804	2,245	2,485
Provision for decommissioning	243	243	243	243	243	243
Customer deposits	4,278	4,779	6,868	8,954	11,144	12,330
Defined benefit liability	1,283	851	851	851	851	851
Deferred tax liability	490	947	947	947	947	947
	69,902	**141,559**	**209,476**	**260,848**	**335,795**	**382,226**
Current liabilities						
Related parties	-	-	-	-	-	-
Deferred Income	31	39	45	30	36	41
Advances customer financed project	359	431	517	620	744	893
Payables and accruals	21,231	23,354	25,690	28,258	31,084	34,193
Taxation	65	72	79	87	95	105
Bank Overdraft						
	21,686	**23,896**	**26,330**	**28,996**	**31,960**	**35,232**
Total Equity and Liabilities	**75,352**	**128,243**	**178,528**	**206,564**	**256,660**	**273,263**

23 Impact of programme on Natural & Social Environment

The Guyana power and Light Incorporated is the holder of Nine (9) Environmental Authorisation Permits for its power generating facilities. As a result, it therefore, ensures that all current and future, operational activities at these locations, are subjected to strict environmental compliance as mandated by the Environmental Protection (Amended) Act, 2005 and enforced by the Environmental Protection Agency. Further, GPL intends to establish an Environmental and Social Management System (ESMS), which will provide a framework to guide all current and future operational activities and projects that may pose a risk or affect the Natural and Social environment. Moreover, the ESMS will ensure that systematic checks are done through “Bi-Annual” Environmental inspections to ensure compliance, Identify and mitigate risk and impacts, where necessary.

Additionally, GPL intends to pursue a net positive Environmental impact by retiring old inefficient generators and utilizing renewable energy sources, as informed by the development and expansion programme 2022-2026. The Company will continue to ensure EPA’s approval for all generation investments regardless of energy source.

Table 59: showing locations with environmental permits and monitoring safeguards

Power Generating Locations with Environmental Authorisation Permit	**Monitoring Schedule for locations**	**Monitoring test for facilities**	**Staff Training**
1. Canefield	Bi-Annual Environmental Inspection	Noise Testing Air (Ambient/ Stack) Water (Effluent discharge) Soil (If necessary)	1. Good Environmental Practices 2. Handling of Hazardous Chemicals 3. Waste Management 4. Emergency response (Chemical/Oil Spills). 5. Spill Prevention. 6. Training on ESMS Manual.
2. Onverwagt			
3. Vreed-En-Hoop			
4. Kingston			
5. Garden of Eden			
6. Bartica			
7. Anna Regina			
8. Wakenaam			
9. Leguan			

Concerning the social environment, GPL will continue its cost-effective investments in addressing the electrification of unserved areas and T&D networks to improve supply reliability and quality, and customer services. The Company will establish a framework (Distribution Code) for the controlled penetration of distributed generation from renewable resources. 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 anticipated to improve expected results.

24 Major Risks and Contingencies

24.1 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.

24.1.1 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.

24.2 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.

24.2.1 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.

24.3 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.

24.3.1 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.

24.4 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.

24.4.1 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

24.5 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).

24.5.1 Contingency Measures: Cyber Threat

The IT Division has adopted the **Centre for Internet Security (CIS) Controls (v8)** framework/ standard for its cybersecurity best practice. The standard guides both defence measures and preparation for response to possible cyberattacks. This globally known standard is US-based, with mappings to ISO, GDPR, NIST and other relevant standards, and is now known to be applied by the Guyana National Data Management Agency (NDMA/ E-Gov) in government agencies.

All technical and administrative cybersecurity best practices at GPL are now firstly adopted from the published CIS Controls standard. Amongst other technology, CIS Benchmarks are used to improve the configuration of infrastructure, CIS CAT is used to assess configurations, and a CIS CSAT tool is used by a dedicated IT staff for standardized planning, tracking, and reporting on progress with cybersecurity improvements. GPL also deliberately stays in close contact and actively participates in initiatives and guidance from NDMA regarding IT best practice and policy.

GPL does have network firewalls, antivirus protection, 3-2-1 backup, insurance for tangible/intangible assets (digitized information and IT assets) as well as an internal awareness effort running on a monthly basis. This will be continued using in-house and external expert resources, to achieve full meeting the standard of CIS Controls v8.

24.6 Risk: Physical Attack

For GPL, system outages pose large adverse financial impacts on the country, across all tariff categories. Potential coordinated physical attacks (terrorism and riots) are a growing concern for the Company as it seeks to develop a resilient electric power system. 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 or gas processing infrastructure.

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

Deliberate attacks can result in more-focused damage to facilities and equipment in substations compared to natural events. Substations, in particular, can be seen as targets, and power system's future dependence on natural gas pipelines and supervisory control and data acquisition (SCADA) communication systems, as attack points, are equally disruptive.

24.6.1 Contingency Measures

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

- **Physical barriers around security perimeters**: Physical barriers can prevent access to people and ground vehicles and can enclose equipment housings and supports.
- **Remote monitoring:** Remote monitoring detects intruders and monitors equipment. The Company intends to enhance its remote monitoring and surveillance capabilities of perimeters and access points detects approaching intruders and those attempting entry.
- **Vulnerability assessment**: The Company is cognisant of the benefits of a vulnerability assessment of critical components, which can include ballistic vulnerability. GPL plans to accomplish this task by coordinating a lessons-learned database on material vulnerability based on real-life examples.
- **Recovery and response**: The Company also recognises the need for and importance of effective response immediately after a physical attack is vital.

24.7 Risk: Extreme Weather Events

The resiliency of GPL's electric power system is threatened by extreme weather events that present a risk to system reliability and quality of service to customers. The major and severe weather events that are relevant to the Company are:

1. Flooding that arises out of sea-level rise,
2. Flooding that arises out of heavy rain fall,
3. Drought and heatwaves, and
4. Strong wind gusts.

In the past, these extreme weather events inflicted considerable damages to the Company's electric infrastructure and resulted in customers being without power for several days.

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 rainfall pattern due to climate change and the fact that the coastal portions of Guyana sit 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 this region.

Consequently, GPL's generation and delivery assets, as well as the broader energy system infrastructure, are vulnerable to damages arising from flooding due to extreme events. Increases in excessive rainfall over the years have increased the frequency of flooding events in Guyana's' 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 essential resources. Current vulnerabilities could be exacerbated by the rising sea-level leading to more extensive flooding.

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. Moreover, diminished surface and groundwater levels require additional energy to pump water. Drought and heatwaves result in elevated ambient temperatures that can reduce generation efficiency and reliability, as well as increase energy losses in the transmission and distribution systems, while increasing demand due to the need for ambient cooling and pumping of water. Decreased water availability directly impact cooling operations in various ways.

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 wind speed followed by a calm to no breeze. This extreme weather event in Guyana has resulted in the Company suffering power outages and impassable paths to access the damages to conduct 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).

24.7.1 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 other equipment. Options include raising existing - and installing new - flood walls; adding to spare parts inventory; incorporating submersible transformers, switches, and pumps; sealing manhole covers and conduit/cable penetrations, 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 networks;
- Construction of parallel/contingency 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;
- Implement self-healing smart distribution solution 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.

25 Cost Benefit Analysis of Investment Projects

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.

26 Appendix 1

26.1 Electricity Demand Forecasting Reasoning, Methodology and Results

The provision of electricity is a basic requirement of modern human life, bringing benefits and development in different sectors including housing, healthcare, transportation, manufacturing, mining, and the services industries, etc. Generally, electricity demand is an indication of the performance of a country's economy, as electricity demand is integrated within all phases of development. Therefore, electricity demand forecast is essential for power system management, scheduling, operations, and capability evaluation of networks. In practice, however, electricity demand forecasting remains challenging for researchers as many factors directly or indirectly influence electricity consumption overtime, (Mohamed, 2005; Solomon, 2007; Han et al., 2009; Bianco et al., 2009; as cited in Shah et al., 2020).

26.1.1 GPL's Demand Forecasting Unit Approach

The Electricity Demand Forecasting Framework 2022 (DF_2022) rests on foundation of: (i) the Generation Expansion Study 2018 – the "Brugman Study", (see This section highlights the long-term forecasts (2022 to 2052), with main focus on the Base Case scenario, which is relevant in informing the Development & Expansion Programme, with some minor references to the Low Case and High Case scenarios. Long-term forecasts (10 years & more) take into account, socioeconomic input variables such as Gross Domestic (GDP)/Gross National Product (GNP), GDP per capita Income, and population, while short-term forecasts (hours, days to 12 months) include variables such as temperature and humidity, (Ghalehkhondabi et al., 2017).

Long-term planning of energy supply-demand is to satisfy the requirements of sustainable development of the country, to determine the volume and trend of future energy consumption, as increments in population growth, and industrial and economic development are highly anticipated. Essentially, electricity demand is influenced by aggregate demand, changes in energy intensity, and shifting input prices. Aggregate demand is affected, among other factors, by economic and demographic growth, and access to electric power. Energy intensity changes with industrialization or deindustrialization — and with any consequent shift in the composition of industries. It also changes when technological progress affects energy efficiency. In addition, shifting prices for inputs used to produce electricity, or for intermediate products that are substitutes for (or complements to) electricity, also affect electricity demand, (Steinbuks et al., 2017).

); and (ii) The Demand Forecast Capacity Building Consultancy by ETS Consultants (2019-2020), (see). Furthermore, during the past two years, the framework has evolved with added improvements in historical data input, computation design, and testing other time-series regression equation modelling techniques. The main outputs of the DF_2022 framework are electricity (generation) demand (GWh) and peak load demand (MW).

This section highlights the long-term forecasts (2022 to 2052), with main focus on the Base Case scenario, which is relevant in informing the Development & Expansion Programme, with some minor references to the Low Case and High Case scenarios. Long-term forecasts (10 years & more) take into account, socioeconomic input variables such as Gross Domestic (GDP)/Gross National Product (GNP), GDP per capita Income, and population, while short-term forecasts (hours, days to 12 months) include variables such as temperature and humidity, (Ghalehkhondabi et al., 2017).

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The Brugman Study utilised historical annual data from the period 2010 to 2016, and prepared electricity demand forecasts per consumer sector from 2017 to 2035, where demand is defined as the Gross Generation of GPL plus unserved energy. The study also incorporated scenarios for the following:

i. Self-generation migration to the DBIS commencing in 2025 and migrating at 25 percent per annum for the next three (3) years and level-off from 2028 to 2035 at 100 percent, (for further details, see page 46 of the Brugman's Study).
ii. Influence of Energy Efficiency (EE) measures and Renewable Energy (RE) Projects as Distribution Generation on the forecast demand, with effect commencing from 2018 to 2035, (for further details, see pages 53 and 54 of the Brugman's Study).
iii. 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).
iv. Unserved energy at 1.9 percent in 2014 and 1.4 percent from 2015 to 2035.
v. Interconnection of Linden in 2024, (see further details on page 56 and 57 of the Brugman's Study).

Figure 1: Generation Expansion Study 2018 (Brugman's Study) – DBIS

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 a SARIMAX[1] model applicable to preparing forecasts for a 10-year horizon (2020 to 2030). The model utilised 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.

Figure 2: The Demand Forecast Capacity Building Services Consultancy by ETS

26.1.2 Energy Demand Forecast Drivers

26.1.2.1 Gross Domestic Product (GDP)

Consistent with numerous academic studies, Gross Domestic Product (GDP) or other measures of economic output are often the strongest correlates of electricity demand, (Meetamehra, 2009; Han et al., 2009; Steinbuks et al., 2017). This is plausible since Real GDP is a measure of economic activity nationally and a proxy for the wealth of the nation. Theory and historical trends emphasized that wealthier populations tend to acquire more devices (electrical loads), which increases energy demand/consumption.

The Guyanese economy is projected to experience positive growth in medium- to long-term, largely credited to oil & gas related activities, despite uncertain global recovery, stemming from the dampening effects of the lingering coronavirus pandemic, intense geopolitical crises, and high inflationary pressures, (IMF-WEO, Oct-2022). The Oil & Gas Industry, which strongly influences the performance of other sectors, forecasted significant production from Liza 1 & 2, Payara, and Yellowtail oil wells. In addition, major non-oil GDP subsectors are expected to continue growing (predominantly Services and Construction), as well as previously depressed sub-sector (Agriculture), which is anticipated to rebound and remain steady. These level of increments in economic activity/GDP growth will have similar positive effects on income, thus improving standard-of-living, and consequently resulting in significant demands for electricity.

Reports from the local media, support this expectation of considerable growth in demand from new commercial and industrial loads, with planned construction of several new residential housing, hotels, condominiums, Silica City development, hospitals, schools, and other government and private sector related activities. Additionally, the planned Corentyne River Bridge linking Guyana and Suriname, together with the planned deep-water harbour signalled the potential for new and expanded commercial activities with businesses having easier access to Suriname and other markets.[15] These developments and others will drive the considerably higher loads expected to come on Grid in the future.

[15] Stabroek News, President's Suriname visit brings MOU on Corentyne River bridge, November 27, 2020.

Table 1: Real GDP Growth Assumptions (%)

Period	GPL (DF_2022)	GPL (DF_2021)	IMF	ETS GDP Growth (2018 base)	Brugman GDP Growth (2016 base)
2021	23.9	21.0	23.9	25.0	7.0
2022	57.8	40.0	57.8	40.0	7.0
2023	25.2	35.0	25.2	30.0	7.0
2023-2027	20.7	22.0	20.7	15.3	
2022-2032	16.8	18.7	16.8		
2033-2052	7.0				
2022-2052	10.4				

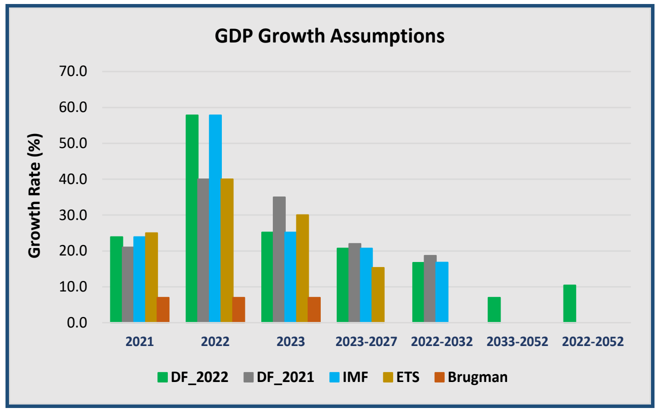

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Table 1 shows the different growth rate assumptions that were included in the forecasting models throughout the years. The DF_2022 framework employed the above "GPL: DF_2022" forecast for its Base Case Real GDP projections (2022-2052). The DF_2022 forecasts featured the IMF's downward revisions to GDP growth during 2023-2032, reflective of fragile global conditions mentioned previously, in addition to the tapering effect of the transition in oil production. Nevertheless, the impact on the domestic Oil-GDP is anticipated to be manageable, with expected positive spill-overs to other growth sectors, and with the expectation of the support from robust national fiscal and social policies.

- The most recent GDP projections were guided by the Ministry of Finance Budget and Mid-Year Reports, national Press Releases, and recent developments regarding the projected scale and rate of development of the oil & gas industry.
- Periods (2022-2027; 2032) utilised IMF Article IV Country (Guyana) Report (September 2022), GDP growth values.
- Periods (2028-2031; 2033-2052) were projected using the Automated ARIMA(X) model with various lags of its own variable and a Business Cycle (D1BC) dummy variable.
- For the Low Case scenario, three-negative standard deviation shock was applied.
- For the High Case scenario, four-positive standard deviation shock was applied.

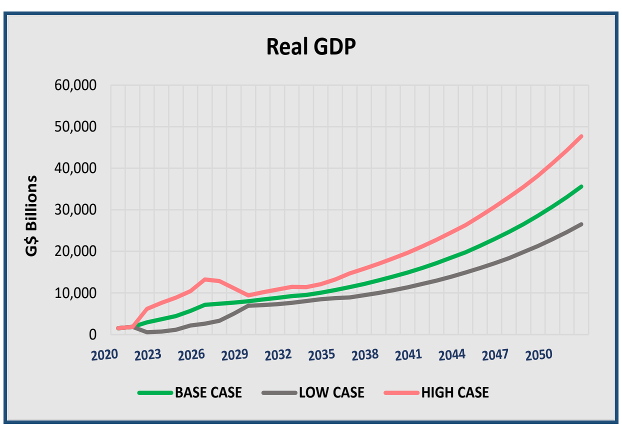


Figure 3: Real GDP

Relationship between Gross Generation (TGEN) and Real GDP (GDPR)

- According to the literature, as GDP/economic growth and economic development[16] increases, the demand for electricity is expected to move in the same direction, and vice versa.
- For Guyana, gross generation exhibited an upward trend mostly during the period (2015-2021), while pre-oil-GDP experienced years of fluctuations, and for some years, recessions. It may be more accurate to say that gross generation is positively related to social/economic development[17], where improvements in the standard-of-living (increased access to housing, higher income, etc.) are likely resultant of increased access to electricity, and use of electrical devices/equipment and infrastructures. In addition, other possible new variables to introduce would be housing and business growth indices, which are not officially calculated locally.[18]
- Large spikes in GDP (from 2019) represent the introduction and expansion of oil production in the value-added series, where GDP is expanding at an increasing rate (in the short to medium term). This may not be reflected immediately on the supply side of electricity (generation), since the transition from economic activity (dominantly in one sector) into economic development (improvements in standard-of-living), may result in years of delayed effects, for instance the development of new/undeveloped areas for housing and business activities may experience a lag period of one to three years.

[16] It is important to note, that an increase in GDP from one year to the next, does not necessarily mean an increase in economic development, since GDP is **not** a measure of the overall standard of living or well-being of a country. Moreover, economic development refers to the reduction and elimination of poverty, unemployment and inequality with the context of growing economy.

[17] An index that is not officially measured locally but is done so by the United Nations – UNDP – Human Development Index (HDI), composed of three indicators: life expectancy, education (adult literacy and combined secondary and tertiary school enrolment), and real GDP per capita.

[18] Although, “Real Estate Activities” is a sub-sub-category of GDP (since the 2006 series), it is not an accurate depiction of growth in the residential and business housing markets.

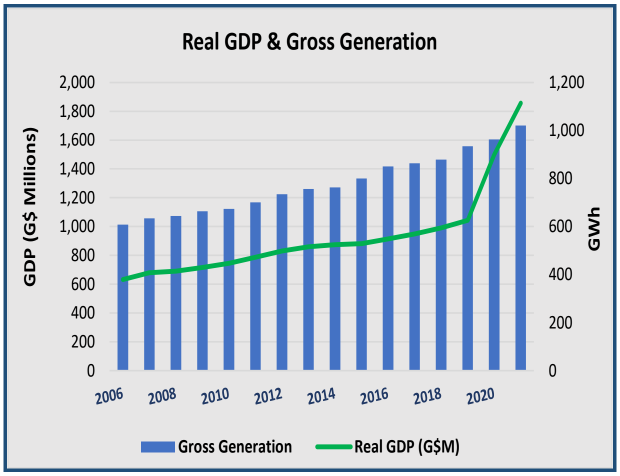


Figure 4: Real GDP & Gross Generation

26.1.2.2 Population (POP), Gross Generation (TGEN) and Electricity Demand

Based on numerous studies, as the population size increases, so does the demand for electricity, vice versa. However, Guyana's historical data is not quite concurrent i.e. population reportedly declined for a number of years, while the supply-demand of electricity depicted an upward trend, which may be a representation of economic development playing a vital role.

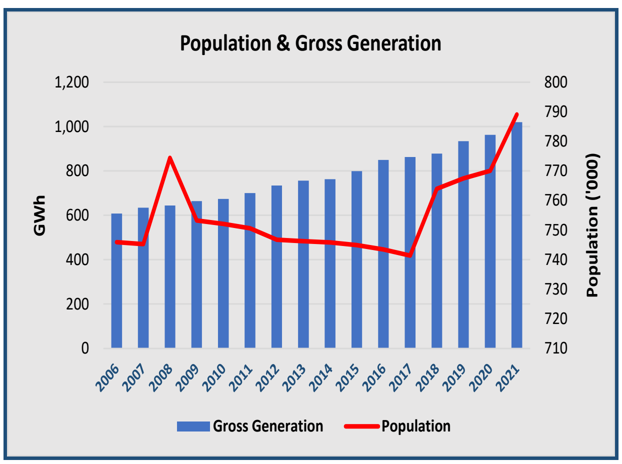


Figure 5: Population & Gross Generation

- It was found that applying the existing mid-year population (POP) data to estimate the model, resulted in an inverse relationship on TGEN. Encouragingly, consultations with the Guyana's Bureau of Statistics, which is currently administering the National Census 2022, cautioned that the existing population data may be underestimated, and was advised to begin forecasting population from 2013 (after the previous Census 2012 value).
- In addition, IMF and World Bank's forecasted population growth for Guyana were incorporated in the initial set of forecasts; nevertheless, their trend presented remain a guide for the new forecasts. The IMF projected population averaged 797,667, (2022-2027),

an annual average growth of 0.3 percent. The World Bank online database displayed an average population value of 803,167, (2022-2027); 827,273, (2028-2038); and 832,000, (2039-2050), an annual average growth of 0.2 percent, (2022-2050).

- In addition, the population influx from 2019 onwards is expected to drive electricity demand upwards.
- Taking all the above into consideration, Guyana's population was re-forecasted (2013-2052), using the Automatic ARIMA(X) model, including various lags of the forecasted oil-GDP. This resulted in more favourable outcome on electricity demand output. The new forecasted population average growth rate was 6.0 percent (2022-2027); 0.2 percent (2028-2038); and negative 0.4 percent (2039-2050).

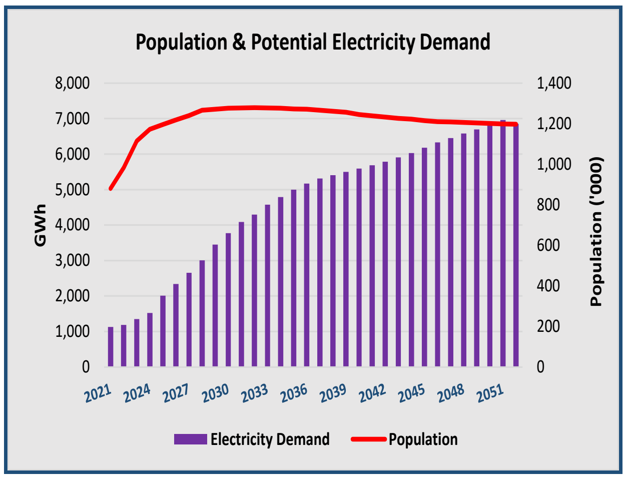
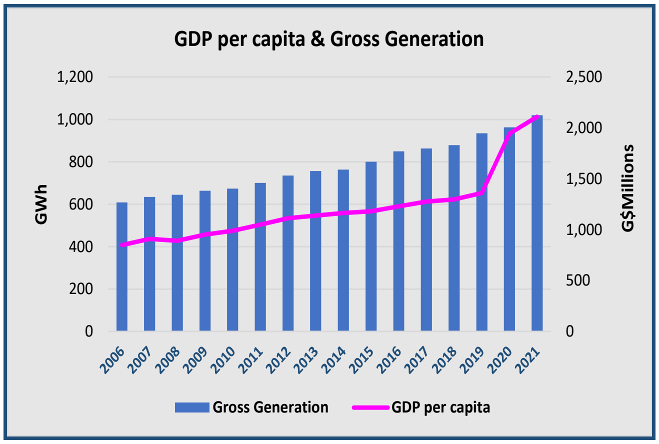


Figure 6: Population & Potential Electricity Demand

26.1.2.3 GDP per capita income (GDPY), Gross Generation (TGEN) and Electricity Demand

GDP per capita income is a country's economic output per person and is calculated by dividing its GDP by its population. GDPY stands to be more reflective of population's activity, and it generally moves in the same direction as electricity generation/supply and potential demand; therefore signifying that GDP per capita income, an indicators of social/economic development, is positively related to electricity supply-demand, where improvements in standard-of-living (through wide-scale development policy agenda, equitable distribution of resources, improvements in other HDI factors, etc.) can largely contribute to the growth in activities that correlates to electricity demand, thus adding value to the domestic economy. GDP per capita forecasts, 2022-2052, averaged an annual increase of 9.2 percent or G$891 thousand.



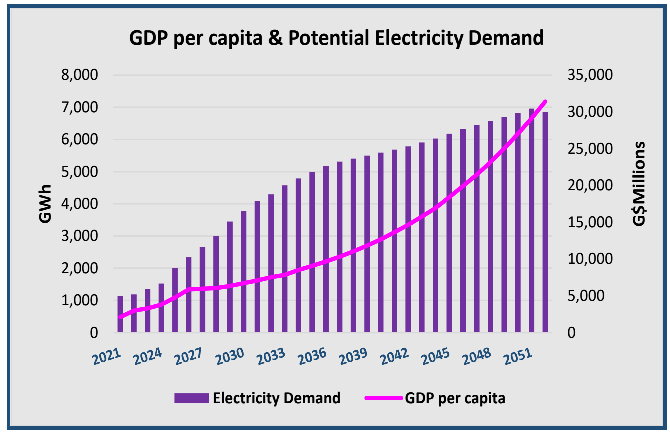


Figure 7: GDP per Capita, Gross Generation & Potential Electricity Demand

26.1.3 GPL's Electricity Demand Forecasts (2022-2052) - Methodology

I. This year's Electricity Demand Forecasts (2022-2052), inclusive of the main regional zones (DBIS, Essequibo isolated systems, and Linden), were engineered through extensive reasoning computation building, back-data interpolation, and estimations of time-series econometric regression analyses, using annual data from 1991 to 2021.

II. To derive 'total electricity demand', the component 'gross generation' acted as a proxy variable, which was estimated and forecasted as a function of the best-chosen econometric model specification via variations of the ARIMA family model, specifically the ARIMAX Model.

III. The 'Auto-Regressive Integrated Moving Average' (ARIMA) set of models define a given time series based on its initial values, lags, and lagged forecast errors, so that equation is used to forecast, forecasted values.

IV. The selected ARIMAX[19] model, is a multiplicative ARIMA with explanatory/ independent/ exogenous variable(s) (X_n). It can be viewed as a multiple regression model with one or more autoregressive (AR) terms and/or one or more moving average (MA) terms. This method is suitable for forecasting when data is stationary/non-stationary, and multivariate with any type of data pattern, i.e., level/trend /seasonality/cyclicity.

The general specification of the ARIMAX model form:

$$\Delta \boldsymbol{Y_t} = \propto + \boldsymbol{\beta_1} \boldsymbol{X_t} \ldots + \boldsymbol{\theta_1} \, \Delta \boldsymbol{Y_{t-1}} + \varphi_{\boldsymbol{1}} \in_{\boldsymbol{t-1}} + \boldsymbol{\epsilon_t}$$

Where:
Δ : first difference operator
α : an intercept of the ARMA model
t : time lags
β, Θ, φ : coefficient
ϵ : error term
Y : dependent variable
X : explanatory variable

Figure 8: ARIMAX Model

[19] General specification of a ARIMA and ARIMAX Model: see https://analyticsindiamag.com/complete-guide-to-sarimax-in-python-for-time-series-modeling/

V. Moreover, several other variables were required to be forecasted beforehand (such as GDP, disaggregated GDP, Population, Customers, Energy Price Indices), in order for 'gross generation' to be forecasted for 31 years.

VI. According to the literature, the variables that best explained electricity demand models are GDP, population, income, temperature, energy prices, human behaviour/activity, and technology.

VII. Though the intended models included the above mentioned variables, some variables, when estimated were irrelevant for long-term forecast (such as temperature), while some did not produce the expected signs, and some were non-significant and were dropped and/or swopped-out (e.g. customers, energy prices, agriculture), to accommodate for more imperative variables (e.g. Petroleum & Gas, services, human activity dummy/interaction variable).

VIII. The following variables were considered for testing:

Abbreviation	Name	Expected Sign
TGEN	Total Gross Generation (GWh)	positive (+)
TER	Total Energy Requirements (GWh)	positive (+)
SALE	Sales (GWh)	positive (+)
CUST	Total number of Customers ('000)	positive (+)
POP	Population ('000)	positive (+)
GDPR	Real Gross Domestic Product (G$Millions)	positive (+)
GDPNOIL	Real GDP non-oil (G$Millions)	positive (+)
GDPY	GDP per capita income (G$Millions)	positive (+)
AGRI	Agriculture Sector (G$Millions)	positive (+)
MINQNO	Mining & Quarrying Sector (non-oil) (G$Millions)	positive (+)
OGI	Petroleum & Gas; and Support Services (G$Millions)	positive (+)
MANU	Manufacturing Sector (G$Millions)	positive (+)
CONSTR	Construction Sector (G$Millions)	positive (+)
ES	Electricity Supply Sector (value added GDP sub-category) (G$Millions)	positive (+)
SERV	Services Sector (G$Millions)	positive (+)
FPI	Fuel Price Index (Guyana's CPI sub-category)	negative (-)
FuPr	Fuel Index (international average price index of Brent, WTI and Fateh)	negative (-)
D1BC	Dummy Variable - Business Cycle	positive (+)
D2K	Dummy Variable - Technology	positive (+)

D4HA	Dummy Variable - Patterns of Human Activity	positive (+)

IX. **Desired Variables:** TGEN TER GDPR OGI CONSTR SERV GDPY POP CUST SALE ES FPI FUPR D2K D4HA

X. **Some of the main Model Variations**:

TGEN ES GDPR CUST SALE FPI D2K D4HA

TGEN TER POP GDPR D4HA

TGEN TER POP GDPNOIL OGI D4HA

TGEN TGEN POP GDPY OGI CONSTR SERV D4HA

XI. Before the best model was selected, a series of trial-and-error modelling were experimented on, applying variations of ARIMA, ARIMAX, Seasonal (S)ARIMA, and SARIMAX forecasting models, accompanied by the variables below. It was found that the ARIMAX model produced the most favourable results, but with a few contradicting elements. Nevertheless, there is room for improvement: (i) to explore the possibilities of other relevant forecasting techniques to increase the predictive power of the model[20], such as hybrids Artificial Neural Network (ANN), Vector Error Correction Model (VECM); (ii) replacing interpolated data with quarterly actuals (as the model lacked lengthy actual data)[21]; and (iii) seeking expertise in automated/responsive energy forecast programming framework, such as the World Bank Group[22].

XII. The chosen 'Electricity Demand Forecasting' **ARIMAX Model**[23]**:**

D(TGEN) C D(TGEN(-3)) D(POP(-2)) D(GDPY(-2)) D(OGI(-1)) D(SERV(-4)) D4HA AR(1) AR(2) AR(3) MA(1)

---

[20] Strict time constraints restricted the exploration of other models. It is important to note that the length of time required for such modelling and technical computation techniques, require lengthy timelines of intense testing procedures, in order to find the best fitted parameters and model(s) to produce the most appropriate results i.e. the regressors are all statistically significant, have the expected signs, and the diagnostics testing are largely positive, otherwise the outcomes will contain spurious results and may be misleading.

[21] Forecasting is difficult work as the demand data includes the unpredicted trends, high levels of noise and is affected by many of the unknown external variables, (as cited in Ghalehkhondabi et al., 2017).

[22] Live Wire is an initiative of the World Bank Group's Energy and Extractives Global Practice, reflecting the emphasis on knowledge management and solutions. http://www.worldbank.org/energy/livewire

[23] 'D' in-front of the variables represent its differences (at either first or second difference) to become stationary variables, to eliminate the problem of unit-root/non-stationarity.

Substituted Coefficients:

D(TGEN) = 0.513*D(TGEN2052(-3)) + 0.316*D(POP(-2)) + 40.760*D(GDPY(-2)) + 0.063*D(OGI2052(-1)) + 0.777*D(SERV2052(-4)) + 41492.225*D4HA - 32872.004 + [AR(1)= -0.144, AR(2)= -0.411, AR(3)= -0.184, MA(1)= -0.976]

XIII. Mathematically expressed as:

$$\Delta Y_t = \propto + \beta_1\,\Delta Y_{t-3} + \beta_2\,\Delta X_{t-2} + \beta_3\,\Delta X_{t-2} + \beta_4\,\Delta X_{t-1} + \beta_5\,\Delta X_{t-4} + \beta_5\,X_t + \theta_p\,Y_{t-p}\epsilon_t \ldots + \phi_q\,\epsilon_{t-q} \cdots$$

Where:

AR term is indicated by “p”: this relates to the number of lags of Y to be adopted as predictors.

MA term is associated with “q”, this relates to the number of lagged prediction errors that should conform to the ARIMA Model.

XIV. Statistical Performance of the Model

- This model was chosen as it produced the most favourable parameters and diagnostics results.
- All the explanatory variables exhibited positive relationships with the dependent variable “gross generation (TGEN)”, which confirmed with the literature. However, the intercept “C” had an inverse relationship.
- All the explanatory variables were statistically significant at the 95 percent confidence level, indicating its relevance in the model and to the dependent variable “TGEN”.
- The adjusted R-squared was also favourable at 0.863, signifying that the independent variables explained 86.3 percent of the variation/changes in “TGEN”.

Dependent Variable: D(TGEN)
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Sample (adjusted): 1999 2022
Included observations: 24 after adjustments
HAC standard errors & covariance (Bartlett kernel, Newey-West fixed bandwidth = 3.0000)
MA Backcast: 1998

Variable	Coefficient	Std. Error	t-Statistic	Prob.
D(TGEN(-3))	0.5133	0.10395	4.93802	0.00027
D(POP(-2))	0.3162	0.14506	2.18004	0.04823
D(GDPY(-2))	40.760	12.7976	3.18499	0.00717
D(OGI(-1))	0.0628	0.01730	3.63075	0.00305
D(SERV(-4))	0.7765	0.10340	7.51005	0.00000
D4HA	41492.2	5153.30	8.05159	0.00000
C	-32872.0	4594.97	-7.15392	0.00001
AR(1)	-0.1436	0.32774	-0.43812	0.66849
AR(2)	-0.4112	0.23703	-1.73470	0.10642
AR(3)	-0.1835	0.19155	-0.95817	0.35546
MA(1)	-0.9761	0.18579	-5.25398	0.00016

R-squared	0.9226	Mean dependent var	26143.8
Adjusted R-squared	0.8631	S.D. dependent var	21014.4
S.E. of regression	7775.26	Akaike info criterion	21.0588
Sum squared resid	7.86E+08	Schwarz criterion	21.5988
Log likelihood	-241.706	Hannan-Quinn criter.	21.2021
F-statistic	15.5009	Durbin-Watson stat	2.14902
Prob(F-statistic)	0.0000		

Figure 9: Model Variables

- The probability F-Statistics was less than 5.0 percent, suggesting that the model is a good fit. In addition, the ‘Durbin-Watson stat’ is slightly more than 2.0 (of no autocorrelation) suggesting some degree of negative autocorrelation.
- On the other hand, the standard error was unsatisfactory, recording a large value of 7,775, and the three evaluation criterions (AIC, BIC, or Schwarz Criterion, and HQIC) were relatively high, but was the lowest compared to the several other similar model variations, suggesting that this model contained the most appropriate variables to estimate and predict total gross electricity generation.
- Nevertheless, the model still has room for improvement.

xv. The forecasted output (gross generation) produced from the model, is inserted into the Demand Forecasting Framework, where self-generators output are added in phases, followed by the application of adjustment factors to estimate the value of ‘energy not served’, the impact of energy efficiency measures (EE) and electric vehicles (EV), to arrive at the main output variable - ‘potential electricity demand’, and further by applying the energy losses (technical and non-technical) factor, to obtain ‘potential electricity sales’ (GWh) and its customers’ classifications (residential, commercial, and industrial).

26.2 Summary Results

26.2.1 Electricity Demand – GPL+Linden

The long-term forecasts illustrate total electricity demand experiencing a steep increase from 2022, an average growth of 15.2 percent during 2022-2029, as influenced by the exponential growth movements in GDP (averaging 21.1 percent); then demand continues to climb gradually, at a decelerating rate, averaging 4.8 percent (2030-2039), before flattening at an average rate of 1.7 percent (2040-2052). The long-term forecasts, 2022-2052, recorded a movement of 1,185 GWh in 2022 to 6,850 in 2052, an expansion of 475.2 percent.

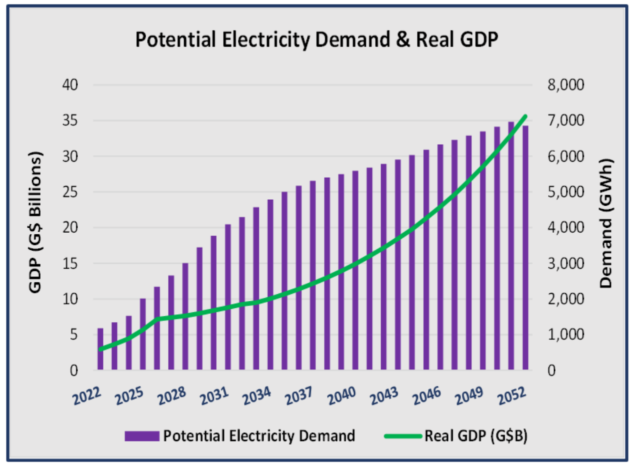


Figure 10: Potential Electricity Demand & Real GDP

Total electricity demand forecast (comprising of **'All GPL' & Linden)** during the long-term (2022-2052), averaged 4,751 GWh, an average growth of 6.2 percent, while average peak demand and peak load ratio[24] are projected at 717 MW and 0.752 (or 75.2 percent) respectively. Moreover, while several large-scale development & expansion projects, namely the Gas-to-Power and Amaila Hydropower Plant, are expected to add-value/ramp up generation capabilities in the medium-term (2022-2032), new major projects that will be operational from 2033 to 2052 were not measured for, due to unexpected changes that could affect the domestic economy and environment, as well as the impact from the external environment (global uncertainties).

[24] 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.

$$Load\ Factor\ (percent) = \frac{1000 * Electricity\ Demand\ (GWh)/yr}{Peak\ Demand\ (MW) * (hrs\ in\ year)} * 100$$

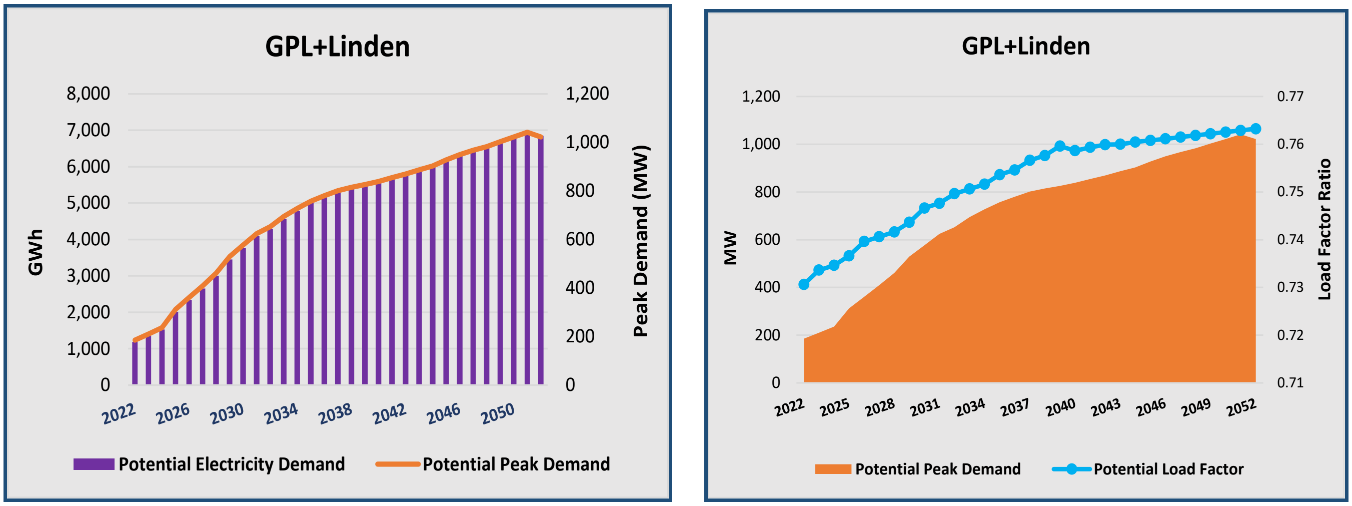


Figure 11: GWh and MW Demand: GPL + Linden

26.2.2 Electricity Demand – DBIS

The Demerara Berbice Interconnected System (DBIS) is estimated to account for over 87 percent of future energy demand, where DBIS electricity demand is forecasted to increase, in the long-term (2022-2052), at an average rate of 5.7 percent or by 140 GWh per annum, moving from 1,061 GWh in 2022 to 5,338 GWh in 2052. In the same period, DBIS peak load demand averaged 552 MW, an annual average growth of 5.7 percent, moving from 166 MW in 2022 to 798 MW in 2052; while DBIS peak load factor ratio averaged 0.753, moving from 0.731 in 2022 to 0.762 in 2052, signalling that electricity supply, in the long-term, will grow at a rate faster than DBIS customers' peak load demand, as DBIS gross generation/electricity supply capacities are expected to improve and expand (credited to the line of projects set-out in the medium-term), thus operating at more efficient and economical levels.

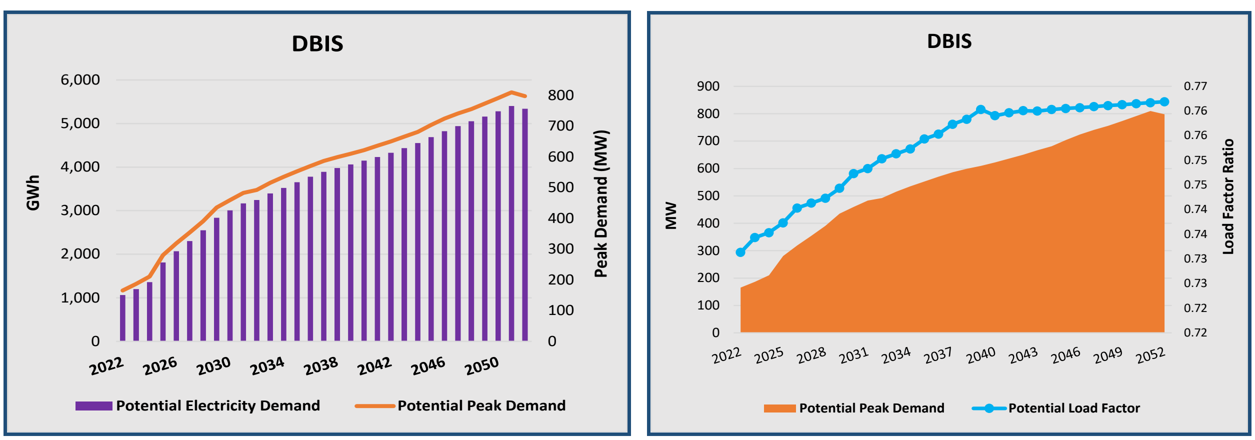
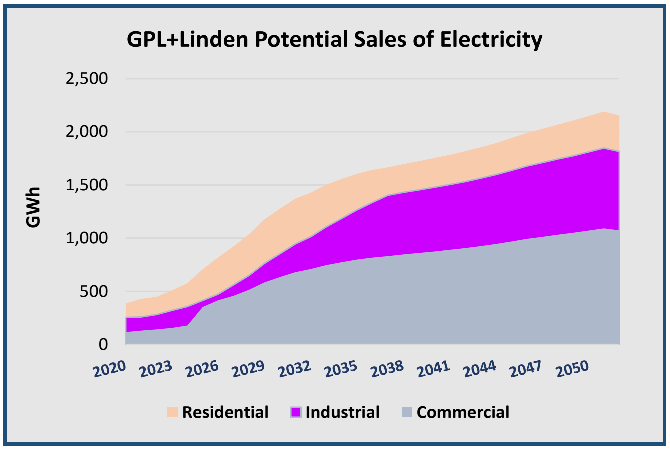


Figure 12: GWh and MW Demand: DBIS

26.2.3 Electricity Sales

Average '**potential electricity sales'**, (2022-2052), for 'GPL+Linden' is projected at approximately 3,492 GWh, an average growth of 6.2 percent or 136 GWh per annum, moving from 871 GWh in 2022 to 5,044 GWh in 2052. In addition, DBIS, which account for majority (approx. 87.1 percent) of total sales, is projected grow at an average rate of 5.7 percent or 103 GWh per annum, moving from 783 GWh in 2022 to 3,934 GWh in 2052.



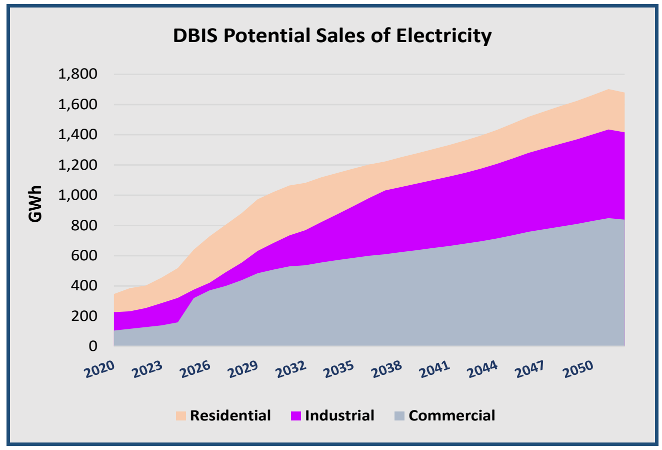


Figure 13: Sales: GPL+Linden & DBIS

26.2.4 Electricity Demand – Base Case, Low Case and High Case Scenarios

Forecasting electricity demand for the low-case and high-case scenarios, followed the same order of procedures25 as the base-case, using the estimated real GDP low-case and high-case outputs for the respective scenarios. The low-case output reflects any significant negative effects to the real economy; whereas the high-case output would represent any major upswings related to economic activity and positive global impact on the domestic economy.

Total electricity demand (GPL+Linden) 2022-2052 forecasts, for the low-case scenario averaged 3,333 GWh, varying lower from the base-case by 1,418 GWh, recording 1,173 GWh in 2022 to 4,316 GWh in 2052, where the peak load demand averaged 554 MW, lower by 163 MW. On the other hand, the high-case scenario averaged 6,588 GWh,

[25] After real GDP was estimated for both the low case and high case (as discussed in the GDP Assumptions), gross generation can then be forecasted through the dynamic time-series econometric regressions – ARIMAX models, where Real GDP is the driver/explanatory variable. The output of gross generation is then inserted into the framework, as it acts as a proxy to compute electricity demand (since there is no hard data for electricity demand) for each scenario.

varying higher than the base-case by 1,837 GWh, recording 1,190 GWh in 2022 to 11,667 GWh in 2052; where peak load demand averaged 955 MW, higher by 238 MW.

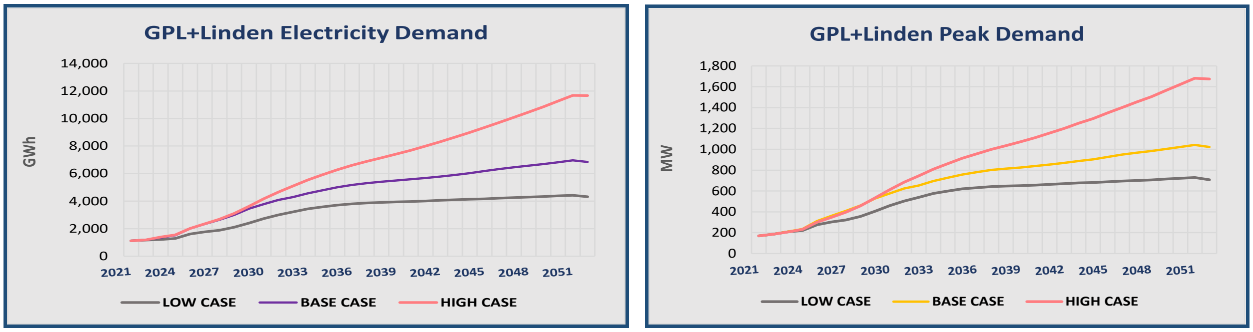


Figure 14: GWh and MW Demand: GPL+Linden

The **DBIS low-case** electricity demand forecasts, during 2022-2052, averaged 2,387 GWh, varying lower from the base-case by 1,267 GWh, recording 1,051 GWh in 2022 to 3,074 GWh in 2052; where the peak load demand averaged 397 MW, lower by 155 MW. On the other hand, the **high-case scenario** averaged 5,295 GWh, varying higher than the base-case by 1,641 GWh, registering 1,066 GWh in 2022 to 9,641 GWh in 2052; where the peak load demand averaged 768 MW, higher by 216 MW.

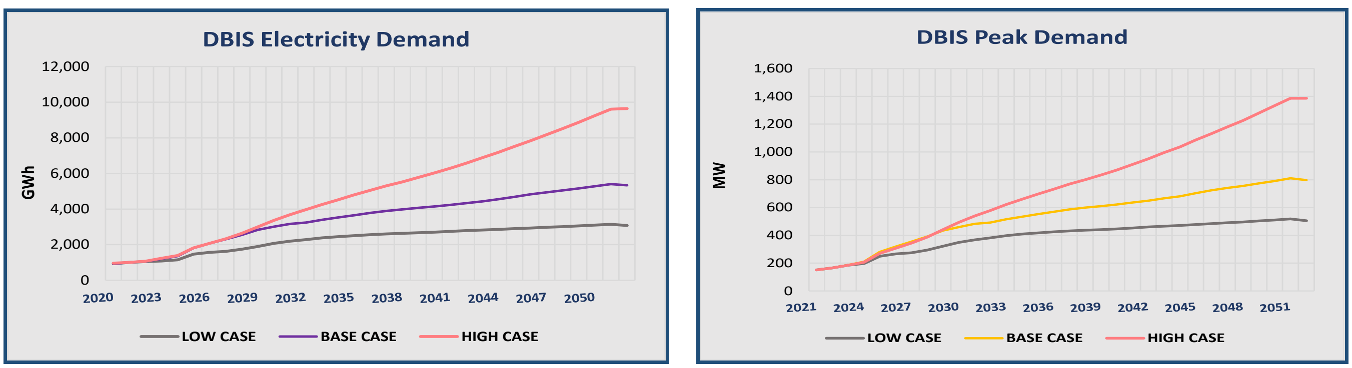


Figure 15: GWh and MW Demand: DBIS

26.2.5 Summary Tables: Electricity Demand Forecasting Framework (2033-2052)

Table 2: Electricity Demand: All GPL & Linden

'GWh' values unless stated otherwise	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Gross Generation (with Self-generators)	**4,334.2**	**4,555.9**	**4,767.5**	**4,943.6**	**5,090.7**	**5,197.5**	**5,295.9**	**5,400.2**	**5,502.9**	**5,617.3**	**5,745.0**	**5,882.1**	**6,042.9**	**6,207.6**	**6,342.3**	**6,477.2**	**6,606.7**	**6,751.4**	**6,900.7**	**7,048.8**
Unserved Energy (approx. trend) GWh	**24.9**	**26.3**	**27.7**	**28.8**	**29.8**	**30.5**	**31.3**	**32.0**	**32.8**	**33.6**	**34.5**	**35.4**	**36.6**	**37.7**	**38.7**	**39.7**	**40.6**	**41.7**	**42.8**	**43.9**
Total Energy Requirements (TER)/Expected Supply-Demand	**4,359.1**	**4,582.3**	**4,795.1**	**4,972.4**	**5,120.5**	**5,228.0**	**5,327.1**	**5,432.2**	**5,535.6**	**5,650.9**	**5,779.5**	**5,917.6**	**6,079.5**	**6,245.3**	**6,381.0**	**6,516.9**	**6,647.4**	**6,793.1**	**6,943.5**	**7,092.7**
Energy Efficiency (EE) factor (% of TER)	*-0.05*	*-0.05*	*-0.05*	*-0.04*	*-0.04*	*-0.04*	*-0.03*	*-0.03*	*-0.03*	*-0.03*	*-0.02*	*-0.02*	*-0.02*	*-0.01*	*-0.01*	*-0.01*	*0.00*	*0.00*	*0.00*	*0.04*
EE – Suppy-Demand Outcome	227.9	225.9	222.0	215.3	206.3	195.0	182.7	170.0	156.6	142.9	128.8	114.2	99.0	83.0	65.7	47.5	28.5	8.8	-11.9	-281.6
Potential Demand Post-EE	**4,562.1**	**4,781.8**	**4,989.4**	**5,158.9**	**5,297.0**	**5,392.5**	**5,478.5**	**5,570.2**	**5,659.5**	**5,760.2**	**5,873.9**	**5,996.3**	**6,141.9**	**6,290.6**	**6,408.0**	**6,524.7**	**6,635.3**	**6,760.2**	**6,888.8**	**6,767.2**
Electric Vehicle (EV) Consumption	*8.5*	*9.6*	*10.8*	*12.1*	*13.7*	*15.4*	*17.3*	*19.4*	*23.5*	*26.2*	*29.3*	*33.2*	*37.1*	*41.4*	*46.4*	*51.9*	*58.1*	*65.7*	*73.6*	*82.4*
New Potential Electricity Demand with EE & EV	**4,570.7**	**4,791.4**	**5,000.2**	**5,171.1**	**5,310.7**	**5,407.8**	**5,495.8**	**5,589.6**	**5,682.9**	**5,786.4**	**5,903.1**	**6,029.5**	**6,179.0**	**6,332.0**	**6,454.3**	**6,576.6**	**6,693.4**	**6,825.9**	**6,962.4**	**6,849.6**
Auxiliaries & Self-Consumption	-112.8	-118.6	-124.3	-129.0	-132.9	-135.9	-138.6	-141.4	-144.3	-147.4	-150.9	-154.6	-159.0	-163.5	-167.2	-170.9	-174.5	-178.5	-182.6	-186.7
Net Energy Exported/Net Generation	**4,457.9**	**4,672.8**	**4,876.0**	**5,042.1**	**5,177.7**	**5,272.0**	**5,357.2**	**5,448.2**	**5,538.7**	**5,639.0**	**5,752.2**	**5,874.8**	**6,020.0**	**6,168.5**	**6,287.1**	**6,405.6**	**6,518.8**	**6,647.3**	**6,779.7**	**6,662.8**
Total Losses factor (%)	*0.248*	*0.247*	*0.247*	*0.247*	*0.247*	*0.246*	*0.246*	*0.246*	*0.246*	*0.245*	*0.245*	*0.245*	*0.245*	*0.244*	*0.244*	*0.244*	*0.244*	*0.243*	*0.243*	*0.243*
Technical & Non-Technical Losses	-1,104.2	-1,156.2	-1,205.3	-1,245.1	-1,277.3	-1,299.2	-1,318.9	-1,339.9	-1,360.8	-1,384.1	-1,410.4	-1,439.0	-1,473.1	-1,507.9	-1,535.3	-1,562.6	-1,588.6	-1,618.3	-1,648.8	-1,618.7
Potential Sales of Electricity (GWh)	**3,353.7**	**3,516.5**	**3,670.6**	**3,797.0**	**3,900.4**	**3,972.7**	**4,038.3**	**4,108.2**	**4,177.9**	**4,254.9**	**4,341.8**	**4,435.8**	**4,546.9**	**4,660.6**	**4,751.8**	**4,843.0**	**4,930.2**	**5,029.1**	**5,131.0**	**5,044.2**
Residential	*1,501.8*	*1,556.4*	*1,605.5*	*1,641.1*	*1,665.5*	*1,696.3*	*1,724.4*	*1,754.2*	*1,783.9*	*1,816.9*	*1,854.0*	*1,894.1*	*1,941.5*	*1,990.1*	*2,029.0*	*2,068.0*	*2,105.2*	*2,147.4*	*2,190.9*	*2,153.9*
Commercial	*746.5*	*774.3*	*799.5*	*817.9*	*830.8*	*846.2*	*860.2*	*875.1*	*889.9*	*906.3*	*924.8*	*944.8*	*968.5*	*992.7*	*1,012.1*	*1,031.6*	*1,050.1*	*1,071.2*	*1,092.9*	*1,074.4*
Industrial	*1,105.4*	*1,185.8*	*1,265.6*	*1,338.1*	*1,404.1*	*1,430.2*	*1,453.8*	*1,479.0*	*1,504.0*	*1,531.8*	*1,563.1*	*1,596.9*	*1,636.9*	*1,677.8*	*1,710.7*	*1,743.5*	*1,774.9*	*1,810.5*	*1,847.1*	*1,815.9*
Load Factor (%) (with self-gen., EE & EV)	**0.75**	**0.75**	**0.75**	**0.75**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**
Peak MW (with EE & EV)	**695.1**	**727.7**	**757.4**	**780.1**	**801.2**	**814.8**	**825.9**	**838.8**	**854.4**	**869.3**	**886.7**	**902.7**	**927.1**	**949.7**	**967.6**	**982.8**	**1,002.5**	**1,021.9**	**1,041.8**	**1,021.7**

Table 3: Electricity Demand: All GPL

'GWh' values unless stated otherwise	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Gross Generation (with Self-generators)	**3,735.9**	**3,885.4**	**4,034.3**	**4,182.6**	**4,312.6**	**4,413.0**	**4,505.6**	**4,603.7**	**4,700.3**	**4,807.9**	**4,928.1**	**5,057.1**	**5,208.3**	**5,363.2**	**5,489.9**	**5,616.8**	**5,738.7**	**5,874.7**	**6,015.2**	**6,154.5**
Unserved Energy (approx. trend) GWh	**22.3**	**23.3**	**24.2**	**25.2**	**26.1**	**26.8**	**27.4**	**28.1**	**28.8**	**29.6**	**30.4**	**31.3**	**32.3**	**33.4**	**34.3**	**35.2**	**36.1**	**37.1**	**38.1**	**39.1**
Total Energy Requirements (TER)/Expected Supply-Demand	**3,758.2**	**3,908.6**	**4,058.5**	**4,207.8**	**4,338.6**	**4,439.8**	**4,533.0**	**4,631.8**	**4,729.1**	**4,837.5**	**4,958.5**	**5,088.3**	**5,240.6**	**5,396.6**	**5,524.2**	**5,652.0**	**5,774.8**	**5,911.8**	**6,053.3**	**6,193.6**
Energy Efficiency (EE) factor (% of TER)	*-0.06*	*-0.05*	*-0.05*	*-0.05*	*-0.04*	*-0.04*	*-0.04*	*-0.04*	*-0.03*	*-0.03*	*-0.03*	*-0.02*	*-0.02*	*-0.02*	*-0.01*	*-0.01*	*-0.01*	*-0.01*	*0.00*	*0.04*
EE – Suppy-Demand Outcome	211.3	208.0	203.8	198.7	191.9	183.0	173.3	163.1	152.4	141.4	130.0	118.2	106.0	92.9	78.6	63.4	47.5	30.9	13.5	-221.6
Potential Demand Post-EE	**3,947.2**	**4,093.4**	**4,238.1**	**4,381.3**	**4,504.4**	**4,596.1**	**4,678.8**	**4,766.9**	**4,852.7**	**4,949.3**	**5,058.1**	**5,175.2**	**5,314.3**	**5,456.1**	**5,568.5**	**5,680.2**	**5,786.2**	**5,905.6**	**6,028.6**	**5,932.9**
Electric Vehicle (EV) Consumption	*8.5*	*9.6*	*10.8*	*12.1*	*13.7*	*15.4*	*17.3*	*19.4*	*21.9*	*24.6*	*27.7*	*31.1*	*35.0*	*39.4*	*44.3*	*49.8*	*56.0*	*63.0*	*70.8*	*79.7*
New Potential Electricity Demand with EE & EV	**3,955.7**	**4,103.0**	**4,248.9**	**4,393.5**	**4,518.1**	**4,611.4**	**4,696.1**	**4,786.3**	**4,874.5**	**4,973.9**	**5,085.8**	**5,206.3**	**5,349.3**	**5,495.5**	**5,612.8**	**5,730.0**	**5,842.2**	**5,968.6**	**6,099.5**	**6,012.6**
Auxiliaries & Self-Consumption	-99.9	-104.0	-108.1	-112.1	-115.7	-118.5	-121.0	-123.8	-126.5	-129.5	-132.8	-136.4	-140.5	-144.8	-148.4	-151.9	-155.3	-159.1	-163.0	-166.9
Net Energy Exported/Net Generation	**3,855.8**	**3,999.0**	**4,140.8**	**4,281.4**	**4,402.4**	**4,493.0**	**4,575.1**	**4,662.5**	**4,748.1**	**4,844.4**	**4,953.0**	**5,070.0**	**5,208.7**	**5,350.7**	**5,464.4**	**5,578.1**	**5,686.8**	**5,809.5**	**5,936.4**	**5,845.7**
Total Losses factor (%)	*0.173*	*0.167*	*0.161*	*0.157*	*0.156*	*0.155*	*0.155*	*0.154*	*0.154*	*0.154*	*0.154*	*0.154*	*0.154*	*0.154*	*0.154*	*0.154*	*0.154*	*0.154*	*0.154*	*0.154*
Technical & Non-Technical Losses	-665.6	-666.3	-665.1	-672.7	-687.3	-696.9	-709.7	-719.5	-732.7	-747.6	-764.3	-782.4	-803.8	-825.7	-843.3	-860.8	-877.6	-896.5	-916.1	-902.1
Potential Sales of Electricity (GWh)	**3,190.2**	**3,332.7**	**3,475.7**	**3,608.7**	**3,715.1**	**3,796.0**	**3,865.4**	**3,943.0**	**4,015.4**	**4,096.9**	**4,188.7**	**4,287.6**	**4,404.9**	**4,525.0**	**4,621.1**	**4,717.3**	**4,809.3**	**4,913.0**	**5,020.3**	**4,943.6**
Residential	*1,428.6*	*1,475.1*	*1,520.3*	*1,559.7*	*1,586.4*	*1,620.9*	*1,650.5*	*1,683.7*	*1,714.6*	*1,749.4*	*1,788.6*	*1,830.8*	*1,880.9*	*1,932.2*	*1,973.2*	*2,014.3*	*2,053.6*	*2,097.8*	*2,143.7*	*2,110.9*
Commercial	*710.1*	*733.9*	*757.0*	*777.3*	*791.3*	*808.6*	*823.3*	*839.9*	*855.3*	*872.6*	*892.2*	*913.3*	*938.2*	*963.8*	*984.3*	*1,004.8*	*1,024.4*	*1,046.5*	*1,069.3*	*1,053.0*
Industrial	*1,051.5*	*1,123.8*	*1,198.4*	*1,271.7*	*1,337.4*	*1,366.6*	*1,391.5*	*1,419.5*	*1,445.5*	*1,474.9*	*1,507.9*	*1,543.5*	*1,585.8*	*1,629.0*	*1,663.6*	*1,698.2*	*1,731.3*	*1,768.7*	*1,807.3*	*1,779.7*
Load Factor (%) (with self-gen., EE & EV)	**0.74**	**0.74**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**
Peak MW (with EE & EV)	**607.0**	**629.1**	**650.2**	**669.9**	**689.5**	**703.0**	**714.6**	**727.0**	**741.9**	**756.7**	**773.6**	**789.4**	**813.1**	**835.0**	**852.6**	**867.7**	**886.8**	**905.7**	**925.3**	**909.3**

Table 4: Electricity Demand: DBIS

'GWh' values unless stated otherwise	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Gross Generation (with Self-generators)	**3,200.7**	**3,332.3**	**3,462.8**	**3,594.4**	**3,708.1**	**3,803.1**	**3,890.5**	**3,983.2**	**4,074.4**	**4,176.1**	**4,289.6**	**4,411.5**	**4,554.4**	**4,700.7**	**4,820.4**	**4,940.3**	**5,055.4**	**5,184.0**	**5,316.7**	**5,448.3**
Unserved Energy (approx. trend) GWh	**19.1**	**19.9**	**20.7**	**21.6**	**22.3**	**22.9**	**23.5**	**24.1**	**24.7**	**25.4**	**26.2**	**27.0**	**27.9**	**28.9**	**29.7**	**30.5**	**31.3**	**32.2**	**33.1**	**34.0**
Total Energy Requirements (TER)/Expected Supply-Demand	**3,219.8**	**3,352.2**	**3,483.5**	**3,616.0**	**3,730.4**	**3,826.0**	**3,914.0**	**4,007.3**	**4,099.2**	**4,201.5**	**4,315.8**	**4,438.5**	**4,582.3**	**4,729.6**	**4,850.1**	**4,970.8**	**5,086.7**	**5,216.1**	**5,349.7**	**5,482.3**
Energy Efficiency (EE) factor (% of TER)	*-0.06*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.04*	*-0.04*	*-0.04*	*-0.03*	*-0.03*	*-0.03*	*-0.02*	*-0.02*	*-0.02*	*-0.02*	*-0.01*	*-0.01*	*-0.01*	*0.00*	*0.03*
EE – Suppy-Demand Outcome	184.4	181.9	178.6	174.5	168.9	161.7	153.7	145.3	136.4	127.2	117.7	107.7	97.5	86.4	74.0	61.0	47.1	32.7	17.5	-190.4
Potential Demand Post-EE	**3,385.1**	**3,514.2**	**3,641.4**	**3,769.0**	**3,877.0**	**3,964.8**	**4,044.2**	**4,128.5**	**4,210.8**	**4,303.3**	**4,407.3**	**4,519.2**	**4,651.8**	**4,787.1**	**4,894.5**	**5,001.3**	**5,102.6**	**5,216.7**	**5,334.1**	**5,257.9**
Electric Vehicle (EV) Consumption	*8.5*	*9.6*	*10.8*	*12.1*	*13.7*	*15.4*	*17.3*	*19.4*	*21.9*	*24.6*	*27.7*	*31.1*	*35.0*	*39.4*	*44.3*	*49.8*	*56.0*	*63.0*	*70.8*	*79.7*
New Potential Electricity Demand with EE & EV	**3,393.6**	**3,523.8**	**3,652.2**	**3,781.1**	**3,890.7**	**3,980.1**	**4,061.5**	**4,148.0**	**4,232.7**	**4,327.9**	**4,435.0**	**4,550.3**	**4,686.8**	**4,826.4**	**4,938.7**	**5,051.0**	**5,158.6**	**5,279.6**	**5,405.0**	**5,337.6**
Auxiliaries & Self-Consumption	-85.4	-89.0	-92.5	-96.1	-99.2	-101.8	-104.2	-106.7	-109.2	-112.0	-115.1	-118.5	-122.4	-126.4	-129.7	-132.9	-136.1	-139.7	-143.3	-146.9
Net Energy Exported/Net Generation	**3,308.2**	**3,434.9**	**3,559.6**	**3,685.0**	**3,791.5**	**3,878.4**	**3,957.3**	**4,041.2**	**4,123.4**	**4,215.9**	**4,319.9**	**4,431.8**	**4,564.4**	**4,700.1**	**4,809.1**	**4,918.1**	**5,022.4**	**5,140.0**	**5,261.7**	**5,190.6**
Total Losses factor (%)	*0.245*	*0.245*	*0.245*	*0.245*	*0.244*	*0.244*	*0.244*	*0.244*	*0.244*	*0.244*	*0.244*	*0.243*	*0.243*	*0.243*	*0.243*	*0.243*	*0.243*	*0.242*	*0.242*	*0.242*
Technical & Non-Technical Losses	-810.6	-841.1	-871.1	-901.3	-926.7	-947.4	-966.1	-986.0	-1,005.4	-1,027.3	-1,052.0	-1,078.6	-1,110.2	-1,142.5	-1,168.2	-1,194.0	-1,218.6	-1,246.3	-1,275.0	-1,257.0
Potential Sales of Electricity (GWh)	**2,497.6**	**2,593.8**	**2,688.5**	**2,783.8**	**2,864.8**	**2,931.0**	**2,991.2**	**3,055.3**	**3,118.1**	**3,188.6**	**3,267.9**	**3,353.3**	**3,454.3**	**3,557.6**	**3,640.9**	**3,724.1**	**3,803.9**	**3,893.7**	**3,986.6**	**3,933.6**
Residential	*1,118.4*	*1,148.0*	*1,176.0*	*1,203.2*	*1,223.3*	*1,251.5*	*1,277.3*	*1,304.6*	*1,331.4*	*1,361.5*	*1,395.4*	*1,431.8*	*1,475.0*	*1,519.1*	*1,554.6*	*1,590.2*	*1,624.3*	*1,662.6*	*1,702.3*	*1,679.6*
Commercial	*556.0*	*571.1*	*585.6*	*599.6*	*610.2*	*624.3*	*637.1*	*650.8*	*664.1*	*679.2*	*696.1*	*714.2*	*735.8*	*757.8*	*775.5*	*793.2*	*810.2*	*829.4*	*849.2*	*837.9*
Industrial	*823.2*	*874.6*	*927.0*	*981.0*	*1,031.3*	*1,055.2*	*1,076.8*	*1,099.9*	*1,122.5*	*1,147.9*	*1,176.4*	*1,207.2*	*1,243.5*	*1,280.7*	*1,310.7*	*1,340.7*	*1,369.4*	*1,401.7*	*1,435.2*	*1,416.1*
Load Factor (%) (with self-gen., EE & EV)	**0.75**	**0.75**	**0.75**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**	**0.76**
Peak MW (with EE & EV)	**515.6**	**534.7**	**552.7**	**569.9**	**586.5**	**599.2**	**609.8**	**622.1**	**636.1**	**650.0**	**666.2**	**681.3**	**703.5**	**724.3**	**741.0**	**755.5**	**773.5**	**791.5**	**810.1**	**797.6**

Table 5: Electricity Demand: Essequibo

'GWh' values unless stated otherwise	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Gross Generation (with Self-generators)	**535.1**	**553.1**	**571.5**	**588.2**	**604.4**	**610.0**	**615.1**	**620.5**	**625.9**	**631.8**	**638.5**	**645.6**	**653.9**	**662.5**	**669.5**	**676.5**	**683.3**	**690.8**	**698.5**	**706.2**
Unserved Energy (approx. trend) GWh	**2.7**	**2.8**	**2.9**	**3.0**	**3.0**	**3.1**	**3.1**	**3.1**	**3.2**	**3.2**	**3.2**	**3.3**	**3.3**	**3.4**	**3.4**	**3.4**	**3.5**	**3.5**	**3.6**	**3.6**
Total Energy Requirements (TER)/Expected Supply-Demand	**537.8**	**555.8**	**574.4**	**591.1**	**607.5**	**613.1**	**618.2**	**623.7**	**629.0**	**635.0**	**641.7**	**648.9**	**657.3**	**665.9**	**672.9**	**680.0**	**686.7**	**694.3**	**702.1**	**709.9**
Energy Efficiency (EE) factor (% of TER)	*-0.04*	*-0.03*	*-0.03*	*-0.03*	*-0.03*	*-0.02*	*-0.02*	*-0.02*	*-0.01*	*-0.01*	*-0.01*	*0.00*	*0.00*	*0.00*	*0.00*	*0.01*	*0.01*	*0.01*	*0.02*	*0.05*
EE – Suppy-Demand Outcome	20.4	19.4	18.3	17.1	15.8	14.1	12.3	10.6	8.8	6.9	5.1	3.2	1.3	-0.7	-2.7	-4.8	-6.9	-9.1	-11.3	-38.4
Potential Demand Post-EE	**555.5**	**572.5**	**589.8**	**605.3**	**620.2**	**624.0**	**627.4**	**631.1**	**634.6**	**638.8**	**643.5**	**648.8**	**655.2**	**661.8**	**666.8**	**671.7**	**676.3**	**681.7**	**687.3**	**667.9**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
New Potential Electricity Demand with EE & EV	**555.5**	**572.5**	**589.8**	**605.3**	**620.2**	**624.0**	**627.4**	**631.1**	**634.6**	**638.8**	**643.5**	**648.8**	**655.2**	**661.8**	**666.8**	**671.7**	**676.3**	**681.7**	**687.3**	**667.9**
Auxiliaries & Self-Consumption	-14.2	-14.7	-15.2	-15.6	-16.1	-16.2	-16.4	-16.5	-16.7	-16.8	-17.0	-17.2	-17.4	-17.6	-17.8	-18.0	-18.2	-18.4	-18.6	-18.8
Net Energy Exported/Net Generation	**541.3**	**557.8**	**574.6**	**589.6**	**604.1**	**607.8**	**611.1**	**614.6**	**618.0**	**621.9**	**626.5**	**631.6**	**637.8**	**644.1**	**648.9**	**653.7**	**658.1**	**663.3**	**668.6**	**649.0**
Total Losses factor (%)	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.463*	*0.462*	*0.462*	*0.462*
Technical & Non-Technical Losses	-250.8	-258.4	-266.2	-273.1	-279.8	-281.5	-282.9	-284.5	-286.1	-287.9	-290.0	-292.3	-295.1	-298.0	-300.2	-302.4	-304.4	-306.8	-309.2	-300.1
Potential Sales of Electricity (GWh)	**290.5**	**299.4**	**308.4**	**316.5**	**324.3**	**326.4**	**328.1**	**330.0**	**331.9**	**334.1**	**336.6**	**339.3**	**342.7**	**346.1**	**348.7**	**351.3**	**353.7**	**356.5**	**359.4**	**348.9**
Residential	*130.1*	*132.5*	*134.9*	*136.8*	*138.5*	*139.4*	*140.1*	*140.9*	*141.7*	*142.6*	*143.7*	*144.9*	*146.3*	*147.8*	*148.9*	*150.0*	*151.0*	*152.2*	*153.5*	*149.0*
Commercial	*64.7*	*65.9*	*67.2*	*68.2*	*69.1*	*69.5*	*69.9*	*70.3*	*70.7*	*71.2*	*71.7*	*72.3*	*73.0*	*73.7*	*74.3*	*74.8*	*75.3*	*75.9*	*76.6*	*74.3*
Industrial	*95.8*	*100.9*	*106.4*	*111.5*	*116.8*	*117.5*	*118.1*	*118.8*	*119.5*	*120.3*	*121.2*	*122.2*	*123.4*	*124.6*	*125.5*	*126.5*	*127.3*	*128.4*	*129.4*	*125.6*
Load Factor (%) (with self-gen., EE & EV)	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**
Peak MW (with EE & EV)	**87.4**	**89.9**	**92.4**	**94.4**	**96.8**	**97.2**	**97.5**	**98.0**	**98.8**	**99.4**	**100.1**	**100.7**	**101.9**	**102.9**	**103.7**	**104.2**	**105.2**	**106.0**	**106.9**	**103.6**

Table 6: Electricity Demand: Anna Regina (2022-2032)

'GWh' values unless stated otherwise	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Generation (with Self-generators)	**37.9**	**39.9**	**47.6**	**54.9**	**70.9**	**110.7**	**156.0**	**203.0**	**257.4**	**312.5**	**344.4**	**359.6**
Unserved Energy (approx. trend) GWh	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.6**	**0.8**	**1.0**	**1.3**	**1.5**	**1.7**	**1.8**
Total Energy Requirements (TER)/Expected Supply-Demand	**38.1**	**40.0**	**47.9**	**55.1**	**71.2**	**111.3**	**156.8**	**203.9**	**258.7**	**314.1**	**346.1**	**361.4**
Energy Efficiency (EE) factor (% of TER)	*-0.10*	*-0.03*	*-0.03*	*-0.03*	*-0.03*	*-0.03*	*-0.03*	*-0.02*	*-0.02*	*-0.02*	*-0.02*	*-0.01*
EE – Suppy-Demand Outcome	3.8	1.3	1.5	1.7	2.1	3.1	4.1	4.9	5.7	6.4	6.0	5.1
Potential Demand Post-EE	**41.8**	**41.2**	**49.1**	**56.5**	**73.0**	**113.8**	**160.2**	**207.9**	**263.2**	**318.9**	**350.4**	**364.8**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
New Potential Electricity Demand with EE & EV	**41.8**	**41.2**	**49.1**	**56.5**	**73.0**	**113.8**	**160.2**	**207.9**	**263.2**	**318.9**	**350.4**	**364.8**
Auxiliaries & Self-Consumption	-1.0	-1.1	-1.3	-1.4	-1.9	-2.9	-4.1	-5.4	-6.8	-8.3	-9.1	-9.5
Net Energy Exported/Net Generation	**40.8**	**40.1**	**47.8**	**55.1**	**71.1**	**110.9**	**156.0**	**202.5**	**256.4**	**310.6**	**341.2**	**355.2**
Total Losses factor (%)	*0.512*	*0.490*	*0.506*	*0.503*	*0.499*	*0.503*	*0.502*	*0.501*	*0.502*	*0.501*	*0.501*	*0.501*
Technical & Non-Technical Losses	-20.9	-19.7	-24.2	-27.7	-35.5	-55.7	-78.2	-101.5	-128.6	-155.7	-171.1	-178.1
Potential Sales of Electricity (GWh)	**19.9**	**20.5**	**23.6**	**27.4**	**35.6**	**55.2**	**77.8**	**101.0**	**127.7**	**154.9**	**170.1**	**177.1**
Residential	*10.4*	*10.5*	*12.2*	*14.2*	*17.1*	*26.4*	*36.9*	*47.5*	*59.6*	*71.5*	*77.8*	*80.2*
Commercial	*3.2*	*3.3*	*3.7*	*4.4*	*8.5*	*13.5*	*18.4*	*23.6*	*29.6*	*35.5*	*38.7*	*39.8*
Industrial	*6.3*	*6.6*	*7.7*	*8.8*	*10.0*	*15.3*	*22.5*	*29.9*	*38.6*	*47.8*	*53.7*	*57.0*
Load Factor (%) (with self-gen., EE & EV)	**0.68**	**0.72**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**
Peak MW (with EE & EV)	**7.0**	**6.5**	**7.7**	**8.9**	**11.5**	**17.9**	**25.1**	**32.5**	**41.2**	**49.9**	**54.7**	**56.8**

Table 7: Electricity Demand: Anna Regina (2033-2052)

'GWh' values unless stated otherwise	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Gross Generation (with Self-generators)	**377.8**	**390.5**	**403.5**	**415.3**	**426.7**	**430.6**	**434.3**	**438.1**	**441.9**	**446.1**	**450.7**	**455.8**	**461.7**	**467.7**	**472.7**	**477.6**	**482.4**	**487.7**	**493.2**	**498.6**
Unserved Energy (approx. trend) GWh	**1.9**	**1.9**	**2.0**	**2.1**	**2.1**	**2.1**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.3**	**2.3**	**2.3**	**2.4**	**2.4**	**2.4**	**2.4**	**2.5**	**2.5**
Total Energy Requirements (TER)/Expected Supply-Demand	**379.7**	**392.4**	**405.5**	**417.3**	**428.8**	**432.8**	**436.4**	**440.3**	**444.1**	**448.3**	**453.0**	**458.0**	**464.0**	**470.1**	**475.0**	**480.0**	**484.8**	**490.1**	**495.6**	**501.1**
Energy Efficiency (EE) factor (% of TER)	*-0.01*	*-0.01*	*-0.01*	*0.00*	*0.00*	*0.00*	*0.01*	*0.01*	*0.01*	*0.02*	*0.02*	*0.02*	*0.02*	*0.03*	*0.03*	*0.03*	*0.04*	*0.04*	*0.04*	*0.08*
EE – Suppy-Demand Outcome	4.3	3.2	2.1	0.9	-0.3	-1.6	-3.0	-4.3	-5.7	-7.1	-8.5	-10.0	-11.5	-13.1	-14.6	-16.2	-17.8	-19.5	-21.2	-40.5
Potential Demand Post-EE	**382.1**	**393.7**	**405.6**	**416.2**	**426.4**	**429.0**	**431.3**	**433.8**	**436.2**	**439.0**	**442.2**	**445.8**	**450.2**	**454.7**	**458.0**	**461.4**	**464.5**	**468.2**	**472.0**	**458.1**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
New Potential Electricity Demand with EE & EV	**382.1**	**393.7**	**405.6**	**416.2**	**426.4**	**429.0**	**431.3**	**433.8**	**436.2**	**439.0**	**442.2**	**445.8**	**450.2**	**454.7**	**458.0**	**461.4**	**464.5**	**468.2**	**472.0**	**458.1**
Auxiliaries & Self-Consumption	-10.0	-10.4	-10.7	-11.0	-11.3	-11.4	-11.5	-11.6	-11.7	-11.8	-12.0	-12.1	-12.3	-12.4	-12.6	-12.7	-12.8	-13.0	-13.1	-13.2
Net Energy Exported/Net Generation	**372.0**	**383.3**	**394.9**	**405.2**	**415.1**	**417.6**	**419.8**	**422.1**	**424.4**	**427.1**	**430.3**	**433.7**	**437.9**	**442.2**	**445.5**	**448.7**	**451.7**	**455.2**	**458.9**	**444.9**
Total Losses factor (%)	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*	*0.501*
Technical & Non-Technical Losses	-186.5	-192.2	-198.0	-203.1	-208.1	-209.3	-210.4	-211.6	-212.7	-214.1	-215.6	-217.4	-219.5	-221.6	-223.2	-224.8	-226.3	-228.1	-229.9	-222.9
Potential Sales of Electricity (GWh)	**185.5**	**191.1**	**196.9**	**202.0**	**207.0**	**208.2**	**209.3**	**210.5**	**211.7**	**213.0**	**214.6**	**216.3**	**218.5**	**220.6**	**222.2**	**223.9**	**225.4**	**227.1**	**229.0**	**222.0**
Residential	*83.1*	*84.6*	*86.1*	*87.3*	*88.4*	*88.9*	*89.4*	*89.9*	*90.4*	*91.0*	*91.6*	*92.4*	*93.3*	*94.2*	*94.9*	*95.6*	*96.2*	*97.0*	*97.8*	*94.8*
Commercial	*41.3*	*42.1*	*42.9*	*43.5*	*44.1*	*44.4*	*44.6*	*44.8*	*45.1*	*45.4*	*45.7*	*46.1*	*46.5*	*47.0*	*47.3*	*47.7*	*48.0*	*48.4*	*48.8*	*47.3*
Industrial	*61.1*	*64.5*	*67.9*	*71.2*	*74.5*	*75.0*	*75.4*	*75.8*	*76.2*	*76.7*	*77.3*	*77.9*	*78.6*	*79.4*	*80.0*	*80.6*	*81.1*	*81.8*	*82.4*	*79.9*
Load Factor (%) (with self-gen., EE & EV)	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.74**	**0.73**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**
Peak MW (with EE & EV)	**59.6**	**61.4**	**63.2**	**64.6**	**66.3**	**66.7**	**66.9**	**67.2**	**67.7**	**68.2**	**68.7**	**69.0**	**69.9**	**70.6**	**71.1**	**71.4**	**72.1**	**72.7**	**73.3**	**70.9**

Table 8: Electricity Demand: Bartica (2022-2032)

'GWh' values unless stated otherwise	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Generation (with Self-generators)	**11.8**	**12.1**	**14.9**	**17.0**	**21.8**	**34.3**	**48.2**	**62.7**	**79.6**	**96.5**	**106.4**	**111.1**
Unserved Energy (approx. trend) GWh	**0.1**	**0.0**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.3**	**0.4**	**0.5**	**0.5**	**0.6**
Total Energy Requirements (TER)/Expected Supply-Demand	**11.9**	**12.1**	**15.0**	**17.0**	**21.9**	**34.5**	**48.4**	**63.0**	**80.0**	**97.0**	**106.9**	**111.7**
Energy Efficiency (EE) factor (% of TER)	*-0.01*	*-0.06*	*-0.06*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.04*	*-0.04*	*-0.04*
EE – Suppy-Demand Outcome	0.2	0.7	0.8	0.9	1.2	1.8	2.5	3.1	3.7	4.4	4.5	4.3
Potential Demand Post-EE	**12.0**	**12.7**	**15.7**	**17.9**	**23.0**	**36.1**	**50.7**	**65.7**	**83.3**	**100.9**	**110.9**	**115.5**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
New Potential Electricity Demand with EE & EV	**12.0**	**12.7**	**15.7**	**17.9**	**23.0**	**36.1**	**50.7**	**65.7**	**83.3**	**100.9**	**110.9**	**115.5**
Auxiliaries & Self-Consumption	-0.3	-0.3	-0.4	-0.4	-0.6	-0.9	-1.3	-1.7	-2.1	-2.6	-2.8	-2.9
Net Energy Exported/Net Generation	**11.7**	**12.4**	**15.3**	**17.4**	**22.4**	**35.2**	**49.4**	**64.1**	**81.2**	**98.3**	**108.0**	**112.5**
Total Losses factor (%)	*0.344*	*0.291*	*0.334*	*0.323*	*0.316*	*0.325*	*0.321*	*0.321*	*0.322*	*0.321*	*0.321*	*0.322*
Technical & Non-Technical Losses	-4.0	-3.6	-5.1	-5.6	-7.1	-11.4	-15.9	-20.6	-26.2	-31.6	-34.7	-36.2
Potential Sales of Electricity (GWh)	**7.7**	**8.8**	**10.2**	**11.8**	**15.3**	**23.8**	**33.5**	**43.5**	**55.0**	**66.7**	**73.3**	**76.3**
Residential	*4.0*	*4.5*	*5.3*	*6.1*	*7.4*	*11.4*	*15.9*	*20.5*	*25.7*	*30.8*	*33.5*	*34.6*
Commercial	*1.2*	*1.4*	*1.6*	*1.9*	*3.7*	*5.8*	*7.9*	*10.2*	*12.7*	*15.3*	*16.7*	*17.2*
Industrial	*2.4*	*2.8*	*3.3*	*3.8*	*4.3*	*6.6*	*9.7*	*12.9*	*16.6*	*20.6*	*23.1*	*24.6*
Load Factor (%) (with self-gen., EE & EV)	**0.73**	**0.71**	**0.71**	**0.71**	**0.71**	**0.71**	**0.71**	**0.71**	**0.71**	**0.71**	**0.71**	**0.71**
Peak MW (with EE & EV)	**1.9**	**2.1**	**2.5**	**2.9**	**3.7**	**5.8**	**8.1**	**10.5**	**13.4**	**16.2**	**17.8**	**18.4**

Table 9: Electricity Demand: Bartica (2033-2052)

'GWh' values unless stated otherwise	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Gross Generation (with Self-generators)	116.7	120.6	124.7	128.3	131.8	133.0	134.2	135.3	136.5	137.8	139.3	140.8	142.6	144.5	146.0	147.6	149.0	150.7	152.4	154.0
Unserved Energy (approx. trend) GWh	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8
Total Energy Requirements (TER)/Expected Supply-Demand	117.3	121.2	125.3	128.9	132.5	133.7	134.8	136.0	137.2	138.5	140.0	141.5	143.4	145.2	146.8	148.3	149.8	151.4	153.1	154.8
Energy Efficiency (EE) factor (% of TER)	-0.04	-0.03	-0.03	-0.03	-0.02	-0.02	-0.02	-0.01	-0.01	-0.01	-0.01	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.06
EE – Suppy-Demand Outcome	4.2	4.0	3.7	3.5	3.2	2.8	2.4	2.0	1.6	1.2	0.8	0.4	0.0	-0.5	-0.9	-1.4	-1.8	-2.3	-2.8	-8.7
Potential Demand Post-EE	120.9	124.6	128.4	131.8	135.0	135.8	136.6	137.4	138.1	139.0	140.1	141.2	142.6	144.0	145.1	146.2	147.2	148.4	149.6	145.4
Electric Vehicle (EV) Consumption	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Potential Electricity Demand with EE & EV	120.9	124.6	128.4	131.8	135.0	135.8	136.6	137.4	138.1	139.0	140.1	141.2	142.6	144.0	145.1	146.2	147.2	148.4	149.6	145.4
Auxiliaries & Self-Consumption	-3.1	-3.2	-3.3	-3.4	-3.5	-3.5	-3.6	-3.6	-3.6	-3.7	-3.7	-3.7	-3.8	-3.8	-3.9	-3.9	-4.0	-4.0	-4.0	-4.1
Net Energy Exported/Net Generation	117.8	121.4	125.1	128.4	131.5	132.3	133.0	133.8	134.5	135.4	136.4	137.5	138.8	140.2	141.3	142.3	143.3	144.4	145.5	141.3
Total Losses factor (%)	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321	0.321
Technical & Non-Technical Losses	-37.9	-39.0	-40.2	-41.3	-42.3	-42.5	-42.7	-43.0	-43.2	-43.5	-43.8	-44.2	-44.6	-45.0	-45.4	-45.7	-46.0	-46.4	-46.7	-45.4
Potential Sales of Electricity (GWh)	80.0	82.4	84.9	87.1	89.2	89.8	90.3	90.8	91.3	91.9	92.6	93.3	94.2	95.2	95.9	96.6	97.2	98.0	98.8	95.9
Residential	35.8	36.5	37.1	37.6	38.1	38.3	38.5	38.8	39.0	39.2	39.5	39.8	40.2	40.6	40.9	41.2	41.5	41.8	42.2	40.9
Commercial	17.8	18.1	18.5	18.8	19.0	19.1	19.2	19.3	19.4	19.6	19.7	19.9	20.1	20.3	20.4	20.6	20.7	20.9	21.0	20.4
Industrial	26.4	27.8	29.3	30.7	32.1	32.3	32.5	32.7	32.9	33.1	33.3	33.6	33.9	34.3	34.5	34.8	35.0	35.3	35.6	34.5
Load Factor (%) (with self-gen., EE & EV)	0.71	0.71	0.71	0.71	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
Peak MW (with EE & EV)	19.3	19.9	20.5	21.0	21.5	21.7	21.8	21.8	22.0	22.2	22.3	22.5	22.7	23.0	23.1	23.2	23.5	23.7	23.8	23.1

Table 10: Electricity Demand: Leguan (2022-2032)

'GWh' values unless stated otherwise	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Generation (with Self-generators)	**2.0**	**2.1**	**2.5**	**2.9**	**3.8**	**5.9**	**8.3**	**10.8**	**13.7**	**16.7**	**18.4**	**19.2**
Unserved Energy (approx. trend) GWh	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Total Energy Requirements (TER)/Expected Supply-Demand	**2.0**	**2.1**	**2.6**	**2.9**	**3.8**	**5.9**	**8.4**	**10.9**	**13.8**	**16.8**	**18.5**	**19.3**
Energy Efficiency (EE) factor (% of TER)	*-0.45*	*-0.35*	*-0.35*	*-0.34*	*-0.34*	*-0.34*	*-0.34*	*-0.34*	*-0.34*	*-0.33*	*-0.33*	*-0.33*
EE – Suppy-Demand Outcome	0.9	0.7	0.9	1.0	1.3	2.0	2.9	3.7	4.7	5.6	6.1	6.4
Potential Demand Post-EE	**2.9**	**2.9**	**3.4**	**3.9**	**5.1**	**7.9**	**11.2**	**14.5**	**18.4**	**22.3**	**24.5**	**25.5**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
New Potential Electricity Demand with EE & EV	**2.9**	**2.9**	**3.4**	**3.9**	**5.1**	**7.9**	**11.2**	**14.5**	**18.4**	**22.3**	**24.5**	**25.5**
Auxiliaries & Self-Consumption	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.3	-0.4	-0.4	-0.5	-0.5
Net Energy Exported/Net Generation	**2.9**	**2.8**	**3.4**	**3.9**	**5.0**	**7.8**	**11.0**	**14.2**	**18.0**	**21.9**	**24.0**	**25.0**
Total Losses factor (%)	*0.553*	*0.528*	*0.546*	*0.542*	*0.538*	*0.542*	*0.541*	*0.540*	*0.541*	*0.541*	*0.541*	*0.541*
Technical & Non-Technical Losses	-1.6	-1.5	-1.8	-2.1	-2.7	-4.2	-5.9	-7.7	-9.8	-11.8	-13.0	-13.5
Potential Sales of Electricity (GWh)	**1.3**	**1.3**	**1.5**	**1.8**	**2.3**	**3.6**	**5.0**	**6.5**	**8.3**	**10.0**	**11.0**	**11.5**
Residential	*0.7*	*0.7*	*0.8*	*0.9*	*1.1*	*1.7*	*2.4*	*3.1*	*3.9*	*4.6*	*5.0*	*5.2*
Commercial	*0.2*	*0.2*	*0.2*	*0.3*	*0.6*	*0.9*	*1.2*	*1.5*	*1.9*	*2.3*	*2.5*	*2.6*
Industrial	*0.4*	*0.4*	*0.5*	*0.6*	*0.6*	*1.0*	*1.5*	*1.9*	*2.5*	*3.1*	*3.5*	*3.7*
Load Factor (%) (with self-gen., EE & EV)	**0.52**	**0.55**	**0.55**	**0.55**	**0.55**	**0.55**	**0.55**	**0.55**	**0.56**	**0.56**	**0.56**	**0.56**
Peak MW (with EE & EV)	**0.6**	**0.6**	**0.7**	**0.8**	**1.0**	**1.6**	**2.3**	**3.0**	**3.8**	**4.6**	**5.0**	**5.2**

Table 11:Electricity Demand: Leguan (2033-2052)

'GWh' values unless stated otherwise	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Gross Generation (with Self-generators)	**20.2**	**20.8**	**21.5**	**22.2**	**22.8**	**23.0**	**23.2**	**23.4**	**23.6**	**23.8**	**24.0**	**24.3**	**24.6**	**25.0**	**25.2**	**25.5**	**25.7**	**26.0**	**26.3**	**26.6**
Unserved Energy (approx. trend) GWh	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Total Energy Requirements (TER)/Expected Supply-Demand	**20.3**	**21.0**	**21.7**	**22.3**	**22.9**	**23.1**	**23.3**	**23.5**	**23.7**	**24.0**	**24.2**	**24.5**	**24.8**	**25.1**	**25.4**	**25.7**	**25.9**	**26.2**	**26.5**	**26.8**
Energy Efficiency (EE) factor (% of TER)	*-0.33*	*-0.32*	*-0.32*	*-0.32*	*-0.31*	*-0.31*	*-0.31*	*-0.30*	*-0.30*	*-0.30*	*-0.30*	*-0.29*	*-0.29*	*-0.29*	*-0.28*	*-0.28*	*-0.28*	*-0.27*	*-0.27*	*-0.23*
EE – Suppy-Demand Outcome	6.6	6.8	6.9	7.1	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	6.3
Potential Demand Post-EE	**26.8**	**27.6**	**28.5**	**29.2**	**30.0**	**30.2**	**30.4**	**30.5**	**30.7**	**31.0**	**31.2**	**31.5**	**31.8**	**32.2**	**32.4**	**32.7**	**32.9**	**33.2**	**33.5**	**32.9**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
New Potential Electricity Demand with EE & EV	**26.8**	**27.6**	**28.5**	**29.2**	**30.0**	**30.2**	**30.4**	**30.5**	**30.7**	**31.0**	**31.2**	**31.5**	**31.8**	**32.2**	**32.4**	**32.7**	**32.9**	**33.2**	**33.5**	**32.9**
Auxiliaries & Self-Consumption	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7
Net Energy Exported/Net Generation	**26.2**	**27.1**	**27.9**	**28.6**	**29.4**	**29.6**	**29.7**	**29.9**	**30.1**	**30.3**	**30.6**	**30.8**	**31.2**	**31.5**	**31.8**	**32.0**	**32.3**	**32.5**	**32.8**	**32.2**
Total Losses factor (%)	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.541*	*0.540*	*0.540*
Technical & Non-Technical Losses	-14.2	-14.6	-15.1	-15.5	-15.9	-16.0	-16.1	-16.2	-16.3	-16.4	-16.5	-16.7	-16.8	-17.0	-17.2	-17.3	-17.4	-17.6	-17.7	-17.4
Potential Sales of Electricity (GWh)	**12.1**	**12.4**	**12.8**	**13.2**	**13.5**	**13.6**	**13.7**	**13.7**	**13.8**	**13.9**	**14.0**	**14.2**	**14.3**	**14.5**	**14.6**	**14.7**	**14.8**	**14.9**	**15.1**	**14.8**
Residential	*5.4*	*5.5*	*5.6*	*5.7*	*5.8*	*5.8*	*5.8*	*5.9*	*5.9*	*5.9*	*6.0*	*6.1*	*6.1*	*6.2*	*6.2*	*6.3*	*6.3*	*6.4*	*6.4*	*6.3*
Commercial	*2.7*	*2.7*	*2.8*	*2.8*	*2.9*	*2.9*	*2.9*	*2.9*	*2.9*	*3.0*	*3.0*	*3.0*	*3.1*	*3.1*	*3.1*	*3.1*	*3.2*	*3.2*	*3.2*	*3.1*
Industrial	*4.0*	*4.2*	*4.4*	*4.6*	*4.9*	*4.9*	*4.9*	*4.9*	*5.0*	*5.0*	*5.1*	*5.1*	*5.2*	*5.2*	*5.3*	*5.3*	*5.3*	*5.4*	*5.4*	*5.3*
Load Factor (%) (with self-gen., EE & EV)	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**	**0.56**
Peak MW (with EE & EV)	**5.5**	**5.7**	**5.8**	**6.0**	**6.1**	**6.2**	**6.2**	**6.2**	**6.3**	**6.3**	**6.4**	**6.4**	**6.5**	**6.6**	**6.6**	**6.7**	**6.7**	**6.8**	**6.9**	**6.7**

Table 12: Electricity Demand: Wakenaam (2022-2032)

'GWh' values unless stated otherwise	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Generation (with Self-generators)	**2.0**	**2.2**	**2.6**	**3.0**	**3.9**	**6.0**	**8.4**	**11.0**	**13.9**	**16.9**	**18.6**	**19.5**
Unserved Energy (approx. trend) GWh	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**
Total Energy Requirements (TER)/Expected Supply-Demand	**2.0**	**2.2**	**2.6**	**3.0**	**3.9**	**6.0**	**8.5**	**11.0**	**14.0**	**17.0**	**18.7**	**19.5**
Energy Efficiency (EE) factor (% of TER)	*-0.12*	*-0.27*	*-0.27*	*-0.27*	*-0.27*	*-0.27*	*-0.27*	*-0.27*	*-0.26*	*-0.26*	*-0.26*	*-0.26*
EE – Suppy-Demand Outcome	0.2	0.6	0.7	0.8	1.0	1.6	2.3	2.9	3.7	4.4	4.8	5.0
Potential Demand Post-EE	**2.2**	**2.8**	**3.3**	**3.8**	**4.9**	**7.6**	**10.7**	**13.9**	**17.6**	**21.4**	**23.5**	**24.5**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
New Potential Electricity Demand with EE & EV	**2.2**	**2.8**	**3.3**	**3.8**	**4.9**	**7.6**	**10.7**	**13.9**	**17.6**	**21.4**	**23.5**	**24.5**
Auxiliaries & Self-Consumption	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.3	-0.4	-0.4	-0.5	-0.5
Net Energy Exported/Net Generation	**2.2**	**2.8**	**3.2**	**3.7**	**4.8**	**7.4**	**10.5**	**13.6**	**17.2**	**20.9**	**23.0**	**24.0**
Total Losses factor (%)	*0.492*	*0.505*	*0.500*	*0.499*	*0.501*	*0.500*	*0.500*	*0.501*	*0.500*	*0.500*	*0.500*	*0.500*
Technical & Non-Technical Losses	-1.1	-1.4	-1.6	-1.8	-2.4	-3.7	-5.2	-6.8	-8.6	-10.5	-11.5	-12.0
Potential Sales of Electricity (GWh)	**1.1**	**1.4**	**1.6**	**1.8**	**2.4**	**3.7**	**5.2**	**6.8**	**8.6**	**10.5**	**11.5**	**12.0**
Residential	*0.6*	*0.7*	*0.8*	*1.0*	*1.2*	*1.8*	*2.5*	*3.2*	*4.0*	*4.8*	*5.3*	*5.4*
Commercial	*0.2*	*0.2*	*0.3*	*0.3*	*0.6*	*0.9*	*1.2*	*1.6*	*2.0*	*2.4*	*2.6*	*2.7*
Industrial	*0.3*	*0.4*	*0.5*	*0.6*	*0.7*	*1.0*	*1.5*	*2.0*	*2.6*	*3.2*	*3.6*	*3.9*
Load Factor (%) (with self-gen., EE & EV)	**0.67**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**
Peak MW (with EE & EV)	**0.4**	**0.6**	**0.6**	**0.7**	**1.0**	**1.5**	**2.1**	**2.7**	**3.4**	**4.1**	**4.5**	**4.7**

Table 13: Electricity Demand: Wakenaam (2033-2052)

'GWh' values unless stated otherwise	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Gross Generation (with Self-generators)	**20.5**	**21.1**	**21.8**	**22.5**	**23.1**	**23.3**	**23.5**	**23.7**	**23.9**	**24.1**	**24.4**	**24.7**	**25.0**	**25.3**	**25.6**	**25.9**	**26.1**	**26.4**	**26.7**	**27.0**
Unserved Energy (approx. trend) GWh	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Total Energy Requirements (TER)/Expected Supply-Demand	**20.5**	**21.2**	**21.9**	**22.6**	**23.2**	**23.4**	**23.6**	**23.8**	**24.0**	**24.2**	**24.5**	**24.8**	**25.1**	**25.4**	**25.7**	**25.9**	**26.2**	**26.5**	**26.8**	**27.1**
Energy Efficiency (EE) factor (% of TER)	*-0.25*	*-0.25*	*-0.25*	*-0.24*	*-0.24*	*-0.24*	*-0.23*	*-0.23*	*-0.23*	*-0.23*	*-0.22*	*-0.22*	*-0.22*	*-0.21*	*-0.21*	*-0.21*	*-0.20*	*-0.20*	*-0.20*	*-0.16*
EE – Suppy-Demand Outcome	5.2	5.3	5.4	5.5	5.6	5.6	5.5	5.5	5.5	5.5	5.5	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.3	4.4
Potential Demand Post-EE	**25.6**	**26.4**	**27.3**	**28.0**	**28.7**	**28.9**	**29.1**	**29.2**	**29.4**	**29.6**	**29.9**	**30.1**	**30.4**	**30.8**	**31.0**	**31.3**	**31.5**	**31.8**	**32.0**	**31.4**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
New Potential Electricity Demand with EE & EV	**25.6**	**26.4**	**27.3**	**28.0**	**28.7**	**28.9**	**29.1**	**29.2**	**29.4**	**29.6**	**29.9**	**30.1**	**30.4**	**30.8**	**31.0**	**31.3**	**31.5**	**31.8**	**32.0**	**31.4**
Auxiliaries & Self-Consumption	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7	-0.7
Net Energy Exported/Net Generation	**25.1**	**25.9**	**26.7**	**27.4**	**28.1**	**28.3**	**28.4**	**28.6**	**28.8**	**29.0**	**29.2**	**29.5**	**29.8**	**30.1**	**30.3**	**30.6**	**30.8**	**31.1**	**31.3**	**30.6**
Total Losses factor (%)	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*	*0.500*
Technical & Non-Technical Losses	-12.6	-12.9	-13.3	-13.7	-14.0	-14.1	-14.2	-14.3	-14.4	-14.5	-14.6	-14.7	-14.9	-15.1	-15.2	-15.3	-15.4	-15.5	-15.7	-15.3
Potential Sales of Electricity (GWh)	**12.5**	**12.9**	**13.3**	**13.7**	**14.0**	**14.1**	**14.2**	**14.3**	**14.4**	**14.5**	**14.6**	**14.7**	**14.9**	**15.0**	**15.2**	**15.3**	**15.4**	**15.5**	**15.7**	**15.3**
Residential	*5.6*	*5.7*	*5.8*	*5.9*	*6.0*	*6.0*	*6.1*	*6.1*	*6.1*	*6.2*	*6.2*	*6.3*	*6.4*	*6.4*	*6.5*	*6.5*	*6.6*	*6.6*	*6.7*	*6.5*
Commercial	*2.8*	*2.8*	*2.9*	*2.9*	*3.0*	*3.0*	*3.0*	*3.0*	*3.1*	*3.1*	*3.1*	*3.1*	*3.2*	*3.2*	*3.2*	*3.3*	*3.3*	*3.3*	*3.3*	*3.3*
Industrial	*4.1*	*4.4*	*4.6*	*4.8*	*5.0*	*5.1*	*5.1*	*5.1*	*5.2*	*5.2*	*5.3*	*5.3*	*5.4*	*5.4*	*5.5*	*5.5*	*5.5*	*5.6*	*5.6*	*5.5*
Load Factor (%) (with self-gen., EE & EV)	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**
Peak MW (with EE & EV)	**5.0**	**5.1**	**5.3**	**5.4**	**5.5**	**5.6**	**5.6**	**5.6**	**5.7**	**5.7**	**5.8**	**5.8**	**5.9**	**5.9**	**6.0**	**6.0**	**6.1**	**6.1**	**6.2**	**6.0**

Table 14: Electricity Demand: Linden (2033-2052)

'GWh' values unless stated otherwise	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**
Gross Generation (with Self-generators)	**598.3**	**670.6**	**733.2**	**761.0**	**778.1**	**784.5**	**790.3**	**796.5**	**802.6**	**809.4**	**816.9**	**825.1**	**834.6**	**844.4**	**852.4**	**860.4**	**868.1**	**876.6**	**885.5**	**894.3**
Unserved Energy (approx. trend) GWh	**0.7**	**0.8**	**0.8**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**
Total Energy Requirements (TER)/Expected Supply-Demand	**599.0**	**671.3**	**734.1**	**761.9**	**779.0**	**785.4**	**791.2**	**797.4**	**803.5**	**810.3**	**817.9**	**826.1**	**835.6**	**845.4**	**853.4**	**861.4**	**869.1**	**877.7**	**886.6**	**895.4**
Energy Efficiency (EE) factor (% of TER)	*0.01*	*0.02*	*0.02*	*0.02*	*0.02*	*0.03*	*0.03*	*0.03*	*0.04*	*0.04*	*0.04*	*0.05*	*0.05*	*0.05*	*0.05*	*0.06*	*0.06*	*0.06*	*0.07*	*0.10*
EE – Suppy-Demand Outcome	-7.3	-10.2	-13.4	-16.2	-18.9	-21.4	-23.9	-26.5	-29.1	-31.8	-34.5	-37.4	-40.3	-43.3	-46.3	-49.3	-52.3	-55.5	-58.7	-93.3
Potential Demand Post-EE	**591.0**	**660.3**	**719.8**	**744.8**	**759.2**	**763.1**	**766.4**	**770.0**	**773.5**	**777.6**	**782.4**	**787.7**	**794.3**	**801.1**	**806.1**	**811.1**	**815.7**	**821.1**	**826.8**	**801.0**
Electric Vehicle (EV) Consumption	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*1.6*	*1.6*	*1.6*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*2.7*	*2.7*	*2.7*
New Potential Electricity Demand with EE & EV	**591.0**	**660.3**	**719.8**	**744.8**	**759.2**	**763.1**	**766.4**	**770.0**	**775.1**	**779.2**	**784.0**	**789.8**	**796.4**	**803.1**	**808.2**	**813.2**	**817.8**	**823.9**	**829.5**	**803.7**
Auxiliaries & Self-Consumption	-8.0	-8.9	-9.8	-10.1	-10.4	-10.5	-10.5	-10.6	-10.7	-10.8	-10.9	-11.0	-11.2	-11.3	-11.4	-11.5	-11.6	-11.7	-11.9	-12.0
Net Energy Exported/Net Generation	**583.0**	**651.4**	**710.1**	**734.7**	**748.9**	**752.6**	**755.8**	**759.4**	**764.3**	**768.4**	**773.1**	**778.8**	**785.2**	**791.9**	**796.8**	**801.6**	**806.2**	**812.1**	**817.6**	**791.7**
Total Losses factor (%)	*0.122*	*0.122*	*0.122*	*0.122*	*0.122*	*0.122*	*0.122*	*0.122*	*0.122*	*0.122*	*0.122*	*0.122*	*0.122*	*0.122*	*0.122*	*0.121*	*0.121*	*0.121*	*0.121*	*0.121*
Technical & Non-Technical Losses	-71.3	-79.6	-86.7	-89.7	-91.4	-91.8	-92.2	-92.6	-93.1	-93.6	-94.1	-94.8	-95.5	-96.3	-96.8	-97.4	-97.9	-98.6	-99.2	-96.0
Potential Sales of Electricity (GWh)	**511.8**	**571.8**	**623.3**	**645.0**	**657.5**	**660.8**	**663.7**	**666.8**	**671.2**	**674.8**	**679.0**	**684.0**	**689.7**	**695.6**	**699.9**	**704.2**	**708.3**	**713.5**	**718.4**	**695.7**
Residential	*229.2*	*253.1*	*272.6*	*278.8*	*280.7*	*282.2*	*283.4*	*284.7*	*286.6*	*288.1*	*289.9*	*292.1*	*294.5*	*297.0*	*298.9*	*300.7*	*302.4*	*304.7*	*306.8*	*297.0*
Commercial	*113.9*	*125.9*	*135.8*	*138.9*	*140.0*	*140.7*	*141.4*	*142.0*	*143.0*	*143.7*	*144.6*	*145.7*	*146.9*	*148.2*	*149.1*	*150.0*	*150.9*	*152.0*	*153.0*	*148.2*
Industrial	*168.7*	*192.8*	*214.9*	*227.3*	*236.7*	*237.9*	*238.9*	*240.0*	*241.6*	*242.9*	*244.4*	*246.2*	*248.3*	*250.4*	*252.0*	*253.5*	*255.0*	*256.9*	*258.6*	*250.4*
Load Factor (%) (with self-gen., EE & EV)	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**
Peak MW (with EE & EV)	**90.1**	**100.6**	**109.6**	**113.0**	**115.5**	**116.0**	**116.4**	**116.7**	**117.7**	**118.3**	**119.1**	**119.6**	**120.9**	**121.9**	**122.7**	**123.1**	**124.1**	**125.0**	**125.8**	**121.6**

27 Appendix 2

27.1 Existing Infrastructure Summary as per Locations

Table 1: GPL Existing Infrastructure as per Geographic Regions

Existing GPL			
Regions	**List**	**Demographic**	**Existing Infrastructure**
Region 2	1	Essequibo Coast	Anna Regina Power Plant
			13.8 kV Distribution Networks
Region 3	1	West Bank Demerara	Vreed-en-hoop Substation
	2	West Bank Demerara	Vreed-en-hoop Power Plant
	3	West Coast Demerara	Edinburgh Substation
	4	Essequibo Islands	Leguan Power Plant
			4.16 kV Distribution Networks
	5	Essequibo Islands	Wakenaam Power Plant
			13.8 kV Distribution Networks
Region 4	1	Georgetown	New Sophia Substation
	2	Georgetown	Old Sophia Substation
	3	Georgetown	New Georgetown Substation
	4	Georgetown	Kingston Substation
	5	Georgetown	Kingston II - DP3 Power Plant
	6	Georgetown	Kingston I - DP2 Power Plant
	7	East Coast Demerara	Good Hope Substation
	8	East Bank Demerara	Golden Grove Substation
	9	East Bank Demerara	Garden of Eden Substation
	10	East Bank Demerara	Garden of Eden - DP1 Power Plant
	11	East Bank Demerara	Garden of Eden - DP5 Power Plant
	12	East Bank Demerara	Garden of Eden - GPL Power Plant
Region 5	1	East Coast Demerara	Columbia Substation
	2	West Coast Berbice	Onverwagt Substation
	3	West Coast Berbice	Onverwagt Power Plant
Region 6	1	Canje- Berbice	Canefield Substation

	2	Canje- Berbice	Canefield Power Plant
	3	Corentyne Coast-Berbice	No. 53 Substation
	4	Corentyne- Berbice	Guysuco Power Plant- SEI
Region 7	1	Bartica	Bartica Power Plant
			13.8 kV Distribution Network
Region 10	1	Linden	BOSAI Power Plant
	2	Linden	Linden Electricity Corporation Inc
	3	Linden	Wisma Power Company

27.2 Summary of Development and Expansion Infrastructure as per Regions & Demographic

Table 2: Major Development and Expansion Infrastructure as per Geographic Location

Projects Across Geographic Regions-

1. SCADA & SMART GRID,
2. Installation of auto reclosers, Smart Capacitor Banks, Voltage Regulator, Circuit Load Balancing,
3. Mobile Substations.

Regions	**List**	**Demographic**	**D&E Infrastructure**
Region 2	1	Essequibo Coast	Anna Regina Power Plant - Upgraded
	2	Essequibo Coast	13.8 kV Distribution- Upgraded
	3	Essequibo Coast	Essequibo 8 MW PV Solar Project - GuySol
	4	Essequibo Coast	Essequibo 12 MW BESS Project - GuySol
Region 3	1	West Bank Demerara	Wales NG 300 MW - 13.8 kV Power Plant
	2	West Bank Demerara	Wales NG 300 MW 69/230 kV Substation
	3	West Bank Demerara	Wales Industrial Substation
	4	West Bank Demerara	Wales Residential/ Commercial Substation
	5	West Bank Demerara	Vreed-en-hoop Substation
	6	West Bank Demerara	Vreed-en-hoop Power Plant
	7	West Coast Demerara	Edinburgh Substation
	8	East Bank Essequibo	Hydronie Substation
	9	Essequibo Islands	Leguan Power Plant – Upgraded with additional

			capacities
	10	Essequibo Islands	13.8 kV Distribution Network Upgrades
	11	Essequibo Islands	Leguan Solar PV/BESS
	12	Essequibo Islands	Wakenaam Power Plant
	13	Essequibo Islands	Leguan Solar PV/BESS
	14	Essequibo Islands	13.8 kV Distribution Network Upgrades
Region 4	1	Georgetown	New Sophia Substation
	2	Georgetown	Old Sophia Substation
	3	Georgetown	New Georgetown Substation
	4	Georgetown	Kingston Substation
	5	Georgetown	Kingston II - DP3 Power Plant
	6	Georgetown	Kingston I - DP2 Power Plant
	7	Georgetown	Thomas Land Substation
	8	Georgetown	Princes St Substation
	9	East Coast Demerara Mahaica	Good Hope Substation
	10	East Coast Demerara Mahaica	Ogle Substation
	11	East Coast Demerara Mahaica	Enmore/Victoria Substation
	12	East Coast Demerara	Goedverwagting 13.8/69 kV Substation
	13	East Coast Demerara	Goedverwagting 69/230 kV Substation
	14	East Coast Demerara	Guyana National Control Center- GNCC
	15	East Bank Demerara	Golden Grove Substation
	16	East Bank Demerara	New Garden of Eden 13.8/69 kV Substation
	17	East Bank Demerara	Garden of Eden 69/230 kV Substation
	18	East Bank Demerara	Garden of Eden - DP1 Power Plant
	19	East Bank Demerara	Garden of Eden - DP5 Power Plant
	20	East Bank Demerara	Garden of Eden - GPL Power Plant
	21	East Bank Demerara-Highway	Kuru Kururu Substation
	22	East Bank Demerara-Highway	Yarrowkabra Substation
Region 5	1	Mahaica- West Bank Berbice	Columbia Substation

	2	Mahaica- West Bank Berbice	Columbia 25 MW Power Plant
	3	Mahaica- West Bank Berbice	Onverwagt Substation
	4	Mahaica- West Bank Berbice	Onverwagt Power Plant
	5	Mahaica- West Bank Berbice	Trafalgar 4 MW PV Project - GUYSOL
	6	Mahaica- West Bank Berbice	Rosignol Substation
Region 6	1	Canje- Berbice	Canefield Substation
	2	Canje- Berbice	Canefield Power Plant
	3	Canje- Berbice	Canfield 25 MW EPC Power Plant
	4	Canje- Berbice	Prospect 3 MW PV Solar Project - GUYSOL
	5	East Berbice Corentyne	Hampshire 3 MW Solar PV Project - GUYSOL
	6	East Berbice Corentyne	Crab Island Substation
	7	East Berbice Corentyne	Williamsburg 69/230 kV Substation
	8	East Berbice Corentyne	Williamsburgh13.8/69 kV Substation
	9	Corentyne- Berbice	No. 53 Substation - Upgrade
	10	Skeldon- Berbice	Guysuco Power Plant- SEI
Region 7	1	Bartica	Bartica Power Plant
	2	Bartica	13.8 kV Distribution Network
	3	Bartica	1 MW Solar PV Project
Region 10	1	Linden	BOSAI Power Plant
	2	Linden	Linden Electricity Corporation Inc
	3	Linden	Wisma Power Company
	4	Linden	Linden 15 MWp Solar PV Project
	5	Linden	Linden 22 MWh Solar PV Project
	6	Linden	Linden-Bamia 13.8/69 kV Substation
	7	Linden	Linden- McKenzie Substation
	8	Linden	Linden- Wisma Substation

27.3 Infrastructure Breakdown as per Geographic Regions and Demographics

27.3.1 Region 2: Essequibo Coast

Existing:

1. Anna Regina 5.4 MW 13.8 kV 60 Hz HFO Power Plant
2. Anna Regina 9.9 MW 13.8 kV 60 Hz LFO Mobile Units
3. Anna Regina 13.8 kV Distribution System- Feeder North
4. Anna Regina 13.8 kV Distribution System- Feeder South
5. Anna Regina 13.8 kV Distribution System- Feeder West
6. Anna Regina 13.8 kV Distribution System- Feeder Caricom

Propose Power Plants:

1. Onderneeming 5 MWp PV Plant and 3.5 MWh BESS
2. Charity 3 MWp Solar PV Plant and 2.8 MW BESS
3. Anna Regina Power Plant Extension – 2 x 1.8 MW HFO

Proposed 13.8 kV Distribution Upgrades:

4. Anna Regina - South Feeder – Express to Onderneeming
5. Anna Regina - South Feeder – Upgrade
6. Anna Regina Feeders- Auto Reclosers
7. Anna Regina Feeders- Voltage regulators
8. Anna Regina Feeders- Smart Capacitor Banks
9. Anna Regina Feeders- Feeder Heads IEDs
10. Anna Regina Feeders- Circuit Load Balancing

27.3.1.1 Generation Conventional & Renewable

- Installation of 5 MWp Solar Photovoltaic Plant at Onderneeming on the Essequibo Coast.
- Installation of 3.5 MWh BESS at Onderneeming on the Essequibo Coast.
- Installation of 3 MWp Solar Photovoltaic Plant at Charity Essequibo Coast.
- Installation of 2.8 MWh BESS at Charity on the Essequibo Coast.
- Installation of two (2)- 1.8 MW additional HFO generation units.

27.3.1.2 13.8 kV 60 Hz Power Plant Upgrade

- Expansion of 13.8 kV Switchgear at Anna Regina Power Plant by installing two (2) additional cubicles to accommodate one (1) 1.8 MW HFO generator.

27.3.1.3 13.8 kV Distribution System Upgrade

I. Essequibo Coast Solar PV Projects Interconnection

- Construction of one (1) 10 km new express feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures - from Anna Regina Power Plant to Onderneeming.
- Construction of 2.34 km new 13.8 kV distribution network utilizing conductor type Tulip AAC 19 Strand- 336.4 kcmil and concrete poles to integrate 3 MWp Solar PV and 2.8 MWh Bess with the existing North Feeder at Charity Essequibo Coast.

II. Essequibo Coast Distribution Expansion Plan

- Reconductoring of 32.5 km South feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.
- Construction of 3.83 km new 13.8 kV distribution network utilizing conductor type Cosmos AAC 19 Strand- 477 kcmil and concrete poles to integrate 5 MWp Solar PV and 3.8 MWh BESS the existing South Feeder at Onderneeming Essequibo Coast.
- Precuring and installation of 23 smart capacitor banks of capacities of 450 kVAr and 600 kVAr throughout the Essequibo Coast.
- Precuring and installation of 9 voltage regulators bank throughout the Essequibo Coast.
- Precuring and Installation of 15 auto reclosers throughout Essequibo Coast.
- Precuring and Installation of 4 feeder heads IEDs throughout Essequibo Coast.
- Circuit load balancing to be conducted on four selected feeders.

27.3.2 Region 3: Essequibo Islands

Leguan Existing:

1. Leguan 1.23 MW 480V 60 Hz LFO Power Plant- Caterpillar
2. Leguan 4.16 kV Distribution System - East Feeder
3. Leguan 4.16 kV Distribution System – North/West Feeder

Wakenaam Existing:

1. Wakenaam 1.47 MW 4.16 kV 60 Hz Power Plant
2. Wakenaam 13.8 kV Distribution System- South Feeder

3. Wakenaam 13.8 kV Distribution System- North Feeder

Leguan Proposed:

1. Leguan 600 kWp Solar PV and 600 kWh BESS
2. Leguan Power Plant Expansion- 3 x 410 kW LFO
3. PV interconnection 13.8 kV Distribution Express Feeder
4. Three (3) auto recloser- in relation to PV interconnection and Power plant upgrade project.
5. Leguan 4.16 kV Distribution Voltage Upgrade
6. Leguan Auto Reclosers
7. Leguan Voltage regulators
8. Leguan Smart Capacitor Banks
9. Leguan Feeder Heads IEDs
10. Leguan Feeder Load Balancing

Wakenaam Proposed

1. Wakenaam 750 kWp Solar PV and 1.151 MWp BESS
2. Wakenaam Power Plant Expansion- 3 x 410 kW LFO
3. Wakenaam Auto Reclosers
4. Wakenaam Voltage regulators
5. Wakenaam Smart Capacitor Banks
6. Wakenaam Feeder Heads IEDs
7. Wakenaam Feeder Load Balancing

27.3.2.1 Generation Conventional & Renewable

Leguan Power Plant and Renewable Projects

- Installation of one- 0.6 MWp Solar Photovoltaic Plant.
- Installation of one- 0.6 MWh BESS.
- Installation of one (1) 410 kW 480 V LFO generation unit – Phase 1 (2023).
- Installation of two (2) 410 kW 480 V LFO generation unit – Phase 2 (2024).

Wakenaam Power Plant and Renewable Projects

- Installation of one 750 kWp Solar PV Plant.
- Installation of one 1.15 kWh BESS.

- Installation of one (1) 410 kW 480 V LFO generation unit – Phase 1 (2023).
- Installation of two (2) 410 kW 480 V LFO generation unit – Phase 2 (2024).

27.3.2.2 13.8 kV 60 Hz Power Plant Upgrade

Leguan Power Plant Upgrade

- Installation of three (3) 750 kVA 0.48/13.8kV Power Transformer.

Wakenaam Power Plant Upgrade

- Installation of 13.8 kV Metal Clad 6 cubicles Switchgear.
- Installation of 480 V Metal Clad 6 cubicle Switchgear.
- Installation of two -1 MVA 0.48/13.8 kV Transformers.
- Upgrade to existing power plant building to accommodate new 480 V 8 cubicle switchgear and 13.8 kV Metal Clad 8 cubicles switchgear.

27.3.2.3 13.8 kV Distribution System Upgrades

I. Leguan 13.8 kV Distribution Upgrade

1. Leguan 4.16 kV Distribution Network Upgrade (under the 0.6 kWp Solar PV/BESS Project):

- Installation of three (2) OVR-15 Auto Recloser on overhead bus at the power plant at the beginning of each feeder:
    - I. F1 – East Feeder,
    - II. F2- North/West Feeder,
    - III. PV/Bess interconnecting power lines from PV site- express feeder.
- Replacing of 46 0.24/4.16 kV distribution transformer with 0.24/13.8 kV to facilitate the conversion of the distribution network voltage from 4.16 kV to 13.8 kV.
- Construction of 4.707 km new express 13.8 kV distribution network utilizing Tulip AAC 19 Strand- 336.4 kcmil and concrete pole structures to integrate Okum Southeast Coast Road 0.6 MWp Solar PV/BESS Plant with Power Plant at Enterprise.

2. Leguan Distribution Expansion Plan

- Precuring and installation of 3 voltage regulator banks on selected feeders.
- Precuring and Installation of 2 additional auto reclosers on selected feeders.
- Precuring and Installation of 3 feeder heads IEDs on selected feeders.
- Precuring and installation of 7 smart capacitor banks on selected feeders.
- Circuit load balancing to be conducted on three feeders.

II. Wakenaam Distribution Expansion Plan

- Precuring and installation of 2 voltage regulator banks on selected feeders.
- Precuring and Installation of 4 additional auto reclosers on selected feeders.
- Precuring and Installation of 2 feeder heads IEDs on selected feeders.
- Precuring and installation of 6 smart capacitor banks on selected feeders.
- Circuit load balancing to be conducted on two selected feeders.

27.3.3 Region 3: East Bank Essequibo

Proposed Substations Projects:

1. Hydronie/Parika 50 MVA 13.8/69 kV AIS Substation

Proposed 69 kV Transmission Line Projects between:

2. Hydronie/Parika and Edinburgh (WCD) Substations
3. Hydronie/Parika and Wales R/C (WBD) Substations

27.3.3.1 Generation Conventional & Renewable

- No power plant to be built within the planning period of the D&E.

27.3.3.2 Transmission

- L33 - Ref: Section 27.3.6.1.2
- L8 - Ref: Section 27.3.6.1.3

27.3.3.3 New Substation

HYDRONIE 50 MVA13.8/69 KV AIS SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:

  (1) Two (2) breaker and ½ 69 kV switchgear.

  (2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.

  (3) Two (2) 25 MVA 13.8/69 kV Transformers.

  (4) Four (4) 5 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.

- Termination of transmission lines from Edinburgh (L8) into 69 kV AIS Bay.
- Termination of transmission line from Wales R/C (L33) into 69 kV AIS Bay.

27.3.4 Region 3: West Coast Demerara

1. Existing Edinburgh 20 MVA 13.8/69 kV AIS Substation:

- Substation Expansion Project- New 20 MVA 13.8/69 kV Transformer
- Substation Expansion Project- New 15 kV Class Switchgear
- Substation Expansion Project- New Transmission Line Project (Hydronie Substation-L8)
- Substation Expansion Project- Three (3) New 13.8 kV Distribution Feeders
- Distribution Network Upgrade- F2 Upgrade
- Distribution Network Upgrade- One (1) New Priority Feeder

2. Edinburgh 10 MVAR Detuned Static Compensator Project

Proposed 69 kV Transmission Line Projects between:

3. Edinburgh and Hydronie (EBE) Substations-L8

27.3.4.1 Conventional Generation Project

- No power plant to be built within the planning period of the D&E.

27.3.4.2 Transmission

- L8 - Ref: Section 27.3.6.1.3

27.3.4.3 Existing Substation

EDINBURGH 20 MVA 13.8 /69 KV SUBSTATION

- Installation of one additional 20 MVA 13.8/69 kV transformer.
- Installation of one AIS 69 kV bay to accommodate the new 20 MVA 13.8/69 kV transformer.
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L8) from Hydronie (EBE) Substation.
- Termination of transmission line from Hydronie (L8) into 69 kV AIS Bay.
- Installation of 15 kV Metal Clad 8 cubicle switchgear with all relevant ancillary services.
- Construction of three (3) 2 km new feeder circuits utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.

EDINGBURGH 10 MVAR DETUNE STATIC COMPENSATOR PROJECT

- Installation of 10 MVAr detuned static compensator bank.
- Expansion of Edinburgh 69 kV substation by installing one AIS 69 kV bay to facilitate the interconnection of the 10 MVAr Detuned Static Compensator.

27.3.4.4 13.8 kV Distribution Network

Edinburgh Distribution Expansion Plan

- Reconductoring of 94 km F2 feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures
- Construction new feeder priority circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM on concrete structures of an approximate length of 2 km.

27.3.4.5 New Substation

- No substation to be built within the planning period of the D&E.

27.3.5 Region 3: West Bank Demerara

Existing:

1. Vreed-en-hoop 40 MVA 13.8/69 kV Substation:

- Substation Expansion Project- Replacement 20 MVA 13.8/69 kV Transformer
- Substation Expansion Project - New Transmission Lines Projects:

    I. From Wales Resid./Commercial Substation – L31
    II. From Wales Resid. /Commercial Substation – L32

- Distribution Network Upgrade- One (1) New Priority Feeder

2. Vreed-en-hoop – DP4 26.2 MW 13.8 kV 60 Hz Power Plant:

- Neutral Earthing Resistor
- Grounding Transformer

Proposed Power Plant Projects:

3. 300 MW Natural Gas Fired Power Plant - Phase 1 ~ 100 MW (2023)
4. 300 MW Natural Gas Fired Power Plant - Phase 2 ~ 200 MW (2025)

Proposed Substation Projects:

5. Wales-250-300 MW NG GSU 13.8/69/230 kV

6. Wales R/C 105 MVA 13.8/69 kV AIS Substation
7. Wales Ind. 120 MVA 13.8/69 kV AIS Substation

Proposed 69 kV Transmission Lines Projects between:

8. 300 MW NG and Wales Ind. Substations (3- tie lines)
9. Wales Ind. and Wales R/C Substations (L30, L30P)
10. Wales R/C and Vreed-en-hoop Substations (L31)
11. Wales R/C and Vreed-en-hoop Substations (L32)
12. Wales R/C and Hydronie (EBE) Substations (L33)

Proposed 230 kV Transmission Lines Projects (ref: Sect. 27.3.15.1.2 □):

13. Double Circuit 230 kV Transmission Lines Between Wales 300 MW 13.8/69/230 kV NG GSU and 69/230 kV Goedverwagting (ECD-Region 4) Substations.

27.3.5.1 Conventional Generation Project

- Government of Guyana to construction one 300 MW Combined Cycle Power Plant and Natural Gas Liquids (NGL) Plant at Wales through EPC contractor.

27.3.5.2 Transmission

- Construction of three (3) 0.55 km of new 69 kV tie lines considering two (2) wire per phase utilizing conductor type Rovinj ACCC (371 kcmil) linking Wales 300 MW 13.8/69/230 kV NG GSU Substations with Wales Industrial Substations.
- Construction of 9.14 km of new double circuit 69 kV transmission lines utilizing conductor type Rovinj ACCC (371 kcmil) between Wales Ind. and Wales R/C Substations (L30 & L30P).
- Construction of 17.51 km of new 69 kV transmission line utilizing conductor type Rovinj ACCC (371 kcmil) between Vreed-en-hoop Substation and Wales R/C Substations (L31).
- Construction of 16.4 km of new 69 kV transmission line utilizing conductor type Rovinj ACCC (371 kcmil) between Vreed-en-hoop Substation and Wales R/C Substations (L32).
- L33: Ref Sect: 27.3.6.1.2
- HVL1, HV L2: Ref Sect: 27.3.15.1.2.

27.3.5.3 Existing Substation

VREED-EN-HOOP 40 MVA13.8/69 KV SUBSTATION

- Replacement of one 20 MVA 13.8/69 kV transformer that was transferred to Edinburgh Substation.

- Installation of one AIS 69 kV bay to accommodate one new transmission line (L31) from Wales R/C Substation.
- Termination of transmission line from Wales R/C into 69 kV AIS Bay.
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L33) from Wales Ind. Substation.
- Termination of transmission line from Wales Ind. into 69 kV AIS Bay.
- Installation of one AIS 69 kV tie bay to accommodate 69 kV bus bar extension.

27.3.5.4 13.8 kV 60 Hz Power Plant Upgrade

VREED-EN-HOOP – DP4 26.6 MW 13.8 KV 60 HZ POWER PLANT

- Upgrade of grounding transformer at DP4 by installing one new grounding transformer with capacities of 1.1 MVA.
- Installation of three (3) Neutral Earthing Resistor on each generator neutral point to ground.

27.3.5.5 13.8 kV Distribution Network

Vreed-en-hoop Distribution Expansion Plan

- Construction of one (1) 3 km new priority feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.

27.3.5.6 New Substation

WALES 250-300 MW NG POWER EVACUATION 230 KV SUBSTATION

- Construction of one new AIS 230 kV substation by installing:
    (1) double bus single breaker 230 kV bays; amount to be determined by EPC contractor.
    (2) 1 bus ties single breaker 230 kV bays.
    (3) 13.8/230 kV Power Transformers; amount and capacities to be determined by EPC contractor.
    (4) Three (3) 125MVA 69/230 kV Power Transformers.
    (5) 13.8 kV Switchgear and ancillary components; amount and capacities to be determined by EPC contractor.
- Termination of 13.8 kV out-going power cables from 300 MW NG Power Plant into 13.8 kV bushings of Power transformer units.
- Termination of double circuit 230 kV transmission lines (Ref Sect: 27.3.15.1.2.) from 69/230 kV Goedverwagting (ECD-Region 4) Substation into 230 kV AIS Bays.

- Termination of three (3) tie lines from Wales Ind. on to 69 kV bushing of three (3) 125 MVA 69/230 kV Power Transformers units.

WALES INDUSTRIAL 120 MVA 13.8/69 KV AIS SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:

(1) Five (5) breaker and ½ 69 kV switchgear.
(2) 15 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
(3) Two (2) 60 MVA 13.8/69 kV Transformers.
(4) Eight (8) 4 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.

- Termination of three (3) tie lines from Wales 250-300 MW NG Power Evacuation Substation into 69 kV AIS Bays.
- Termination of double transmission lines from Wales R/C into 69 kV AIS Bays.

WALES RESIDENTIAL/COMMERCIAL 105 MVA13.8/69 KV SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:

(1) Four breaker and ½ 69 kV switchgear.
(2) 23 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
(3) Three (3) 35 MVA 13.8/69 kV Transformers.
(4) Ten (10) 5 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.

- Termination of double transmission lines from Wales Ind. into 69 kV AIS Bays.
- Termination of two (2) transmission lines from Vreed-en-hoop into 69 kV AIS Bay.
- Termination of transmission line from Hydronie into 69 kV AIS Bay.

27.3.6 Region 3: Across Demographic Areas

Table 3: Region 3 Demographic links description

D&E - 2023- 2027: Inter - Demographic Link - Region 3				
Existing:				
Region 3	West Bank Demerara	West Coast Demerara	Vreed-en-hoop-Edinburgh	L7
Proposed:				
Region 3	East Bank Essequibo	West Coast Demerara	Edinburgh - Hydronie	L8

Region 3	West Coast Demerara	East Bank Essequibo	Wales R/C- Hydronie	L9

27.3.6.1 Transmission

27.3.6.1.1 East Bank Essequibo-Essequibo Islands

- No Line to be built within the planning period of the D&E.

27.3.6.1.2 West Bank Demerara- East Bank Essequibo

- Construction of 36 km of new 69 kV transmission line utilizing conductor type Rovinj ACCC (371 kcmil) between Wales R/C (WBD) substation and Parika/Hydronie (EBE) Substations (L33).

27.3.6.1.3 West Coast Demerara- East Bank Essequibo

- Construction of 16 km of new 69 kV transmission line utilizing conductor type Canton AAAC 19 Strands (395 kcmil) and concrete poles between Edinburgh (WCD) and Parika/Hydronie (EBE) Substations (L8).

27.3.6.1.4 West Bank Demerara- West Coast Demerara

- No Line to be built within the planning period of the D&E.

27.3.7 Region 4: Georgetown

Existing Substations/Power Plant Upgrade Projects:

1. Kingston 70 MVA 13.8/69 kV AIS Substation:

- Substation Expansion Project - New Transmission Lines Project:

   I. From Sophia Substation - L5 Upgrade, New Circuit- L5 P,
   II. From Thomas land Substation – New L11.

2. Kingston II- DP3 36 MW 13.8 kV 60 Hz Power Plant:

- Ground Transformer
- New 13.8 kV Switchgear
- Distribution Network Upgrade- One (1) New Priority Feeder

3. Kingston I- DP2 22 MW 13.8 kV 60 Hz Power Plant:

- F1, F2 Conductor Upgrade,
- Replacement of 13.8 kV Switchgear with higher Short Circuit Rating.

4. Old Sophia 33.4 MVA 13.8/69 kV AIS Substation:

- Substation Upgrade Project: New Building
- Substation Upgrade Project: New 15 kV Class Switchgear
- Substation Upgrade Project: New 13.8/69 kV Transformers
- Substation Upgraded Project- Four (4) New 13.8 kV Distribution Feeders
- Distribution Network Upgrade- One (1) New Priority Feeder

5. New Sophia 69 kV Switching Substation:

- 10 MVAR Detuned Static Compensator Project
- 10 MWh BESS
- Substation Expansion Project – L16/L16P Transmission Lines Project

6. New Georgetown 33.4 MVA 13.8/69 kV AIS Substation:

- Substation Expansion Project- New Transmission Line Project from Princes St Sub- L11
- Substation Upgrade – New 13.8/69 kV Transformers
- Distribution Network Upgrade- F1 Upgrade

Proposed Substation Projects:

7. Thomas Land GPSU Ground 120 MVA 13.8/69 kV GIS Substation.
8. Princes St Central Georgetown 120 MVA 13.8/69 kV GIS Substation.

Proposed 69 kV Transmission Line Upgrade Projects between:

9. Kingston and Sophia Substations - L5 Upgrade & L5 P.
10. Old Sophia and New Georgetown Substations - L10 Upgraded.
11. Old Sophia and New Sophia Substations - L12 & L13 Upgraded.
12. Old Sophia and Golden Grove (EBD) Substations- L2 Upgraded (ref: Sect 27.3.10.1.2).
13. New Sophia and Golden Grove (EBD) Substations- L4 Upgraded (ref: Sect.27.3.10.1.2).
14. New Sophia and Good Hope (ECD) Substations- L16 Upgraded & L16 P (ref: Sect. 27.3.10.1.1).

Proposed New 69 kV Transmission Line Projects between:

15. Kingston and Thomas land Substations- L11-1
16. Thomas land and Princes St Central Georgetown Substations- L11-2
17. Princes St Central Georgetown Substations- L11-3

27.3.7.1 Generation Conventional & Renewable Projects

- Installation of 10 MWh BESS at New Sophia

27.3.7.2 Transmission Lines

- Construction of 5 km of double circuit 69 kV transmission lines utilizing conductor type Drake ACSR (795 kcmil) and concrete structures between Kingston and Old Sophia Substations (L5 upgraded & L5P).
- Construction of 4.4 km of upgraded 69 kV transmission lines utilizing conductor type Rovinj ACCC (371 kcmil) between Old Sophia and New Georgetown Substations (L10 Upgraded).
- Construction of 2.39 km of new 69kV transmission line utilizing 1.44 km of conductor type Rovinj ACCC (371 kcmil) and 0.95 km of XLPE between Kingston and Thomas land Georgetown Substations.
- Construction of 3.6 km of new 69kV transmission line utilizing conductor type Rovinj ACCC (371 kcmil) between Thomas land Georgetown Substations and Princes St Central Georgetown Substations.
- Construction of 3.39 km of new 69kV transmission line utilizing conductor type Rovinj ACCC (371 kcmil) between Princes Georgetown Substations and New Georgetown Substation.
- Upgrade the less than 0.1 km existing 69 kV link utilizing conductor type Rovinj ACCC (371 kcmil) between Old Sophia and New Sophia (L12 & L13), this will increase the transfer capacity of existing link, which will be useful as the demand increases throughout the DBIS.
- Upgrade of L4- (New Sophia- Golden Grove) ref: Sect 27.3.10.1.2
- Upgrade of L2- (Old Sophia- Golden Grove) ref: Sect 27.3.10.1.2

27.3.7.3 Existing Substation

OLD SOPHIA 35 MVA 13.8/69KV AIS SUBSTATION

- Installation of one AIS 69 kV bay to accommodate one new transmission line (L5P) from Kingston.
- Termination of transmission lines (L5 & L5P) from Kingston into 69 kV AIS Bays.

UPGRADE:

- Relocation of Tx 1- ABB 16.8 MVA-13.8/69 kV to replace the damaged Tx 1- Westinghouse 16.7 MVA-13.8/69 kV at GOE.
- Decommission of Tx 3- Westinghouse 16.7 MVA-13.8/69 kV.

Phase 1 Upgrade:

- Installation of one new 35 MVA 13.8/69 kV transformer into existing AIS 69 kV bay (former Tx1 69 kV AIS bay).
- Installation of 15 cubicle -15 kV 2000 Amps Metal-clad enclosed Switchgear.
- Renovation of the control room building and switchgear facility.

Phase 1 Upgrade:

- Installation of one new 35 MVA 13.8/69 kV transformer into existing AIS 69 kV bay (former Tx2 69 kV AIS bay).

NEW SOPHIA 69KV SWITCHING AIS SUBSTATION

- Termination of the L16P into the existing 69 kV bay. 69 kV bay is already in place; 69 kV bay is already in place.
- Installation 10 MWh BESS into available 69 kV AIS bay.

NEW SOPHIA 15 MVAR DETUNED STATIC COMPENSATOR

- Installation of 10 MVAR Detuned Static Compensator.
- Installation of one breaker ½ bay to accommodate 15 MVAr detuned static compensator.

NEW GEORGETOWN 33.4 MVA 13.8/69KV AIS SUBSTATION

- Installation of one AIS 69 kV bay to accommodate one new transmission line from Central Georgetown Substation (Princes St).
- Installation of two (2) new 25 MVA 13.8/69 kV Transformer- upgrading of existing 16.7 MVA capacities.
- Termination of the L11 into the new 69 kV bay.
- Termination of the upgraded L10 into the existing 69 kV bay.

KINGSTON 70 MVA 13.8/69KV AIS SUBSTATION

- Installation of one AIS 69 kV bay to accommodate one new transmission line (L5P) from O/Sophia.

- Termination of the L5 P into the new 69 kV AIS bay.
- Termination of the L5 into the existing 69 kV AIS bay.
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L11-2) from Thomas land Substation.
- Termination of the L11 into the new 69 kV AIS bay.

27.3.7.4 13.8 kV 60 Hz Power Plant Upgrade

KINGSTON II- DP3 36 MW 13.8 KV 60 HZ POWER PLANT

- Upgrade of grounding transformer at DP3 by installing 2 grounding transformers with capacities of 2.5 MVA each.
- Upgrade of 15 kV class 18 cubicle switchgear to 60 kA SC rating at DP3.

KINGSTON I- DP2 22 MW 13.8 KV 60 HZ POWER PLANT

- Upgrade of tie-lines between DP2 and DP3 (Dp2-F1 & Dp2 F2) by installing approximately 1275 meters of 1 single core 400 mm2 XLPE cables place in cable underground raceway.
- Upgrade of 15 kV class 9 cubicle switchgear to 60 kA SC rating at DP2.

27.3.7.5 13.8 kV Distribution Network

I. Old Sophia Distribution Expansion Plan

- Construction of four (4) 4 km new feeder circuits utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.
- Construction of one (1) 4 km new priority feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.

II. Kingston II- DP3 Distribution Expansion Plan

- Construction of one (1) 4 km new priority feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.

III. New Georgetown Distribution Expansion Plan

- Reconductoring of 17.25 km F1 feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.
- Construction of new feeder to off-set loads from F1 utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.

27.3.7.6 New Substation

PRINCES ST, CENTRAL GEORGETOWN GIS 120 MVA 13.8/69 KV SUBSTATION

- Construction of one new GIS 13.8/69 kV substation by installing:
    (1) Two-breaker and ½ 69 kV switchgear.
    (2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
    (3) Two- 60 MVA 13.8/69 kV Transformers.
    (4) Six (6) 4 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.

- Termination of the line from Thomas Land Substation into AIS bay.

- Termination of the line from New Georgetown Substation into AIS bay.

THOMAS LAND (GPSU GROUND) GIS 120 MVA 13.8/69 KV SUBSTATION

- Construction of one new GIS 13.8/69 kV substation by installing:
    (1) Two-breaker and ½ 69 kV switchgear.
    (2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
    (3) Two- 60 MVA 13.8/69 kV Transformers.
    (4) Six (6) 4 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.

- Termination of the line from Kingston Substation into AIS bay.

- Termination of the line from Central Georgetown Substation into AIS bay.

27.3.8 Region 4: East Coast Demerara- up to Mahaica

Existing Substations Projects:

1. Good Hope 35 MVA 13.8/69 kV Substation

- Substation Expansion Project - New Transmission Lines Project:
    I. From Ogle Substation - L16 P-2
    II. From Enmore- L17 P
- Substation Expansion Project- New 35 MVA 13.8/69 kV Transformer (Replacement)
- Substation Expansion Project- Upgraded 15 kV Class Switchgear
- Distribution Network Upgrade- - Two (2) New 13.8 kV Distribution Feeders
- Distribution Network Upgrade- One (1) New Priority Feeder

- Distribution Network Upgrade- F4 Upgrade

Proposed Substations Projects:

2. Ogle 120 MVA 13.8/69 kV AIS Substation
3. Enmore/Victoria 70 MVA 13.8/69 kV Substation
4. Goedverwagting 120 MVA 13.8/69 kV AIS Substation
5. Goedverwagting 600 MVA 69/230 kV AIS Substation

Proposed Existing 69 kV Transmission Line Upgrade Projects between:

6. New Sophia and Good Hope Substations- L16 Upgrade & L16 P (ref: Sect 27.3.10.1.1).
7. Good Hope and Columbia (Region 5) Substations – L17 P (ref: Sect 27.3.15.1.3)

Proposed 69 kV Transmission Lines Splits between:

8. New Sophia (Georgetown) and Good Hope (ECD) Substations L16, L16P – into Ogle Substation (ref: Sect 27.3.10.1.1)
9. New Sophia (Georgetown) and Golden Grove (East Bank) Substations L4 – into Goedverwagting Substation (ref: Sect 27.3.10.1.127.3.10.1.1)
10. Old Sophia (Georgetown) and Golden Grove (East Bank) Substations L2 – into Goedverwagting Substation (ref: Sect 27.3.10.1.127.3.10.1.1)
11. Good Hope and Columbia (ECD Region 5) Substations L17, L17 P – into Enmore (ECD) (ref: Sect 27.3.15.1.3)

Proposed 69 kV Transmission Line Projects between:

12. New Sophia (Georgetown) and Goedverwagting Substations- L4-2 (ref: Sect 27.3.10.1.1)
13. Old Sophia (Georgetown) and Goedverwagting Substations- L2-2 (ref: Sect 27.3.10.1.1)
14. New Sophia (Georgetown) and Ogle Substations- L16-2P, L16-2 (ref: Sect 27.3.10.1.1)
15. Ogle and Good Hope Substations- L16-2P, L16-2 (because of line split of L16, L16P)
16. Ogle and Goedverwagting Substation – L25, L25 P
17. Good Hope and Enmore Substation – L17, L17 P
18. Enmore and Columbia (East Coast- Region 5) Substation – L18 Bypass, L18 (ref: Sect 27.3.15.1.3)

Proposed 230 kV Transmission Lines Projects:

19. Double Circuit 230 kV Transmission Lines Between Wales 300 MW 13.8/69/230 kV NG GSU (WCD- Region 3) and 69/230 kV Goedverwagting Substations (ref: Sect. 27.3.15.1.2)

20. Double Circuit 230 kV Transmission Lines Between 230 kV Goedverwagting and 230 kV New Garden of Eden Substations (East Bank) (ref: Sect. 27.3.10.1.3)
21. Double Circuit 230 kV Transmission Lines Between 230 kV Goedverwagting and 230 kV Crab Island (East Coast Berbice- Region 6) (ref: Sect. 27.3.15.1.4)

27.3.8.1 Generation Conventional & Renewable Projects

- No power plant to be built within the planning period of the D&E.

27.3.8.2 Transmission

- L17 P (parallel circuit to existing L17): Ref. Sect 27.3.15.1.3

69 kV Transmission Line Splits (L17/L17P)- Enmore Substation:

- Splitting of new 69 kV transmission line that run between Good Hope and Columbia Substations L17 into Enmore Substation.
- Splitting of existing 69 kV transmission line that run between Good Hope and Columbia Substations L17 P into Enmore Substation.

69 kV Transmission Line Splits- Ogle Substation:

- Splitting of new double circuit 69 kV transmission line that runs between New Sophia and Good Hope Substation L16 & L16P into Ogle Substation.

69 kV Transmission Line Splits- Goedverwagting Substation:

- Splitting of upgraded 69 kV transmission line that runs between New Sophia and Golden Grove Substations L4-Upgraded into Goedverwagting Substation.
- Splitting of upgraded 69 kV transmission line that runs between Old Sophia and Golden Grove Substations L2-Upgraded into Goedverwagting Substation.

New 69 kV Transmission Lines as a Result of L 4- Upgraded/L2 Upgrade splits into Goedverwagting: -

- L 4 Upgraded (New Sophia- Goedverwagting)- ref: Sect 27.3.10.1.2
- L 2 Upgraded (Old Sophia- Goedverwagting)- ref: Sect 27.3.10.1.2
- L 4 Upgraded (Goedverwagting - Golden Grove)- ref: Sect 27.3.10.1.3
- L 2 Upgraded (Goedverwagting – Golden Grove)- ref: Sect 27.3.10.1.3

New 69 kV Transmission Lines as a Result of L16/L16P splits into Ogle: -

- Establishment of 7.64 km of new transmission circuit that runs between Ogle and Good Hope Substations- L16-2.

- Establishment of 7.64 km of new transmission circuit that runs between Ogle and Good Hope Substations L16-1 P.

New 69 kV Transmission Lines as a Result of Splits into Enmore: -

- Establishment of 10.6 km of new transmission circuit that runs between Good Hope and Enmore Substation- L17.
- Establishment of 10.6 km of new transmission circuit that runs between Good Hope and Enmore Substations L17 P.
- Construction of 12.7 km of new double circuit 69 kV transmission lines utilizing conductor type Rovinj ACCC (371 kcmil) between Goedverwagting and Ogle Substations- L25 & L25R

27.3.8.3 Existing Substation

GOOD HOPE 35 MVA 13.8/69KV SUBSTATION

- Installation of one AIS 69 kV bay to accommodate one new transmission line (L16P) from Ogle Substation.
- Termination of L16 P into substation 69 kV AIS Bay.
- Installation of one AIS 69 kV bay to accommodate one transmission line (L17P) from Enmore/Victoria Substation.
- Termination of L17 P into substation 69 kV AIS Bay.
- Replacement of one 35-MVA 13.8/69 kV Crompton Greeves transformer.
- Installation of four (4) 630 Amps circuit breakers 15 kV Class Metal clad Switchgears.
- Installation of three (3) 2000 Amps circuit breakers 15 kV Class Metal clad Switchgears.
- Upgrade of existing 13.8 kV busbar to 2000 Amps

27.3.8.4 13.8 kV Distribution Network

Good Hope Distribution Expansion Plan

- Construction of four (4) 4 km new priority feeder circuits utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.
- Reconductoring of 29.6 km F4 feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.
- Construction of one (1) 6 km new express feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.

27.3.8.5 New Substation

GOEDVERWAGTING 600 MVA 69/ 230 KV AIS SUBSTATION

- Construction of one new AIS 230 kV substation by installing:
  (1) 6 double bus single breaker 230 kV bays.
  (2) 1 bus ties single breaker 230 kV bays.
  (3) Two (2) 300 MVA 69/230 kV Power Transformers
- Termination of double circuit 230 kV transmission lines from Wales 250-300 MW NG Power Evacuation 230 kV Substation into AIS 230 kV bays.
- Termination of double circuit 230 kV transmission lines from Williamsburg 230 kV Substation into AIS 230 kV bays.
- Termination of double circuit 230 kV transmission lines from Garden of Eden 230 kV Substation into AIS 230 kV bay.

GOEDVERWAGTING 120 MVA 13.8/69 KV AIS SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:
  (1) five (5) breaker and ½ 69 kV switchgear.
  (2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
  (3) Two- 60 MVA 13.8/69 kV Transformers.
  (4) Eight (8) 5 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.
- Termination of two (2) incoming tie lines from two (2) 300 MVA 69 kV/230 kV transformer into AIS 69 kV Bays.
- Termination of double transmission lines from Golden Grove Substation (L2-1, L4-1) into 69 kV AIS Bays.
- Termination of transmission lines from Old Sophia Substation (L2-2) into 69 kV AIS Bay.
- Termination of transmission lines from New Sophia Substation (L4-2) into 69 kV AIS Bay.
- Termination of double transmission lines from Ogle Substation (L25, L25P) into 69 kV AIS Bays.

OGLE 120 MVA 13.8/69 KV AIS SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:
  (1) Five-breaker and ½ 69 kV switchgear.
  (2) 18 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.

(3) Two- 60 MVA 13.8/69 kV Transformers.
(4) Eight (8) 6 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.

- Termination of double transmission lines from New Sophia into 69 kV AIS Bays.
- Termination of double transmission lines from Good Hope into 69 kV AIS Bays.
- Termination of double transmission lines from Goedverwagting into 69 kV AIS Bays.

ENMORE/VICTORIA 50 MVA 13.8/69 KV SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:

(1) Four-breaker and ½ 69 kV switchgear.
(2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
(3) Two- 25 MVA 13.8/69 kV Transformers.
(4) Four (4) 6 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.

- Termination of double transmission lines from Good Hope into 69 kV AIS Bays.
- Termination of double transmission lines from Columbia into 69 kV AIS Bays.

27.3.9 Region 4: East Bank Demerara

Existing Substation Projects:

1. Golden Grove 20 MVA 13.8 kV/69 kV Substation

- Substation Upgrade Project- New 13.8/69 kV Transformers
- Distribution Network Upgrade- F1 Upgrade
- Distribution Network Upgrade- F3 Upgrade

2. Garden of Eden 33.4 MVA 13.8/69 kV Substation

- Substation Upgrade Project- New 13.8/69 kV Transformers
- Substation Expansion Project - New Transmission Lines from New GOE Substation
- Distribution Network Upgrade- F1 Upgrade
- Distribution Network Upgrade- F2 Upgrade
- Distribution Network Upgrade- F3 Upgrade
- Distribution Network Upgrade- Two (2) Priority Feeders

Proposed Substations:

3. New Garden of Eden 70 MVA 13.8/69 kV AIS Substation
4. New Garden of Eden 250 MVA 69/230 kV AIS Substation
5. Kuru Kururu 50 MVA 13.8/69 kV AIS Substation
6. Yarrowkabra 50 MVA 13.8/69 kV AIS Substation

Proposed Existing 69 kV Transmission Line Upgrade Projects between:

7. Golden Grove and Garden of Eden Substations- L1 & L3 Upgrade
8. Golden Grove and New Sophia (Georgetown) Substations- L4 Upgrade (ref: Sect 27.3.10.1.2)
9. Golden Grove and Old Sophia (Georgetown) Substations- L2 Upgrade (ref: Sect 27.3.10.1.2)

Proposed 69 kV Transmission Line Projects between:

10. New Garden of Eden and Garden of Eden- L48, L48 P
11. New Garden of Eden and Kuru Kururu- L35, L35 P
12. Kuru Kururu and Yarrowkabra- L36
13. New Garden of Eden and McKenzie- L37, L37 P (ref: Sect 27.3.15.1.6)

Proposed 230 kV Transmission Lines Splits between:

14. Wales 300 MW 13.8/69/230 kV NG GSU (WCD- Region 3) and 230 kV Goedverwagting (East Coast) Substations HV L1, HV L1P – into New Garden of Eden Substation

Proposed 230 kV Transmission Line Projects between:

15. Double Circuit 230 kV Transmission Lines Between 230 kV Goedverwagting (East Coast) and 230 kV New Garden of Eden Substations HV L2-2, HV L2-P-2 (ref: Sect. 27.3.10.1.3).

27.3.9.1 Generation Conventional & Renewable Projects

- No power plant to be built within the planning period of the D&E.

27.3.9.2 Transmission

230 kV Transmission Line Splits- into New Garden of Eden 230 kV Substation:

- Splitting of double circuit 230 kV transmission line that runs between Wales 300 MW 13.8/69/230 kV NG GSU (WCD- Region 3) and 230 kV Goedverwagting (East Coast) Substations HV L1, HV L1P – into New Garden of Eden Substation

New 230 kV Transmission Lines as a Result of HVL1, HV L1P Splits into New Garden of Eden 230 kV: -

- Establishment of 7.37 km of new transmission circuit that runs between Goedverwagting 230 kV and New Garden of Eden 230 kV Substations.

69 kV Transmission Line Upgrade

- Construction of 11.9 km of upgraded 69 kV transmission lines utilizing conductor type Rovinj ACCC (371 kcmil) between New Sophia and Golden Grove Substations- L1 Upgraded.
- Construction of 11.8 km of upgraded 69 kV transmission lines utilizing conductor type Rovinj ACCC (371 kcmil) between Old Sophia and Golden Grove Substations- L3 Upgraded.

New 69 kV Transmission Line

- Construction of 3.47 km of double 69 kV transmission lines utilizing conductor type Rovinj ACCC (371 kcmil) between New GOE and Old GOE Substations - L48, L48P.
- Construction of 13.8 km of double 69 kV transmission lines utilizing conductor type Rovinj ACCC (371 kcmil) between New Garden of Eden and Kuru Kururu Substations- L35, L35P.
- Construction of 10.6 km of new transmission line utilizing conductor type Rovinj ACCC (371 kcmil) between Kuru Kururu and Yarrowkabra Substations- L36.
- Construction of 90 km of new double 69 kV transmission lines utilizing conductor type Rovinj ACCC (371 kcmil) New Garden of Eden and McKenzie Substations- L37/L37P.

27.3.9.3 Existing Substation

GOLDEN GROVE 20 MVA 13.8/69KV SUBSTATION

- Installation of two (2) new 20 MVA 13.8/69 kV transformer to replace existing capacities.
- Installation of two (2) additional 15 kV Class Metal clad 630 Amps Switchgear cubicles to accommodate 2 additional feeders.
- Installation of two (2) additional phase current transformers with rating 1200:5 for transformers circuit breaker incomer cubicles.
- Replace six (6) phase current transformer of rating 300:5 with of ten (10) phase current transformers rating 600:5.
- Installation of two (2) phase current transformers with rating 200:5 for the station use/grounding transformer cubicles.
- Installation of ten (10) neutral current transformers with rating 200:5 for each cubicle.
- Upgrade of Station Use- Grounding Transformer combination of rating 1700 kVA-100 kVA for Station Use, 786 Amps 10 Sec rating with Neutral Earthing resistor taps 5-10 ohms.

GARDEN OF EDEN 33.4 MVA 13.8/69KV SUBSTATION

- Replace damaged Tx 1- Westinghouse 16.7 MVA 13.8/69 kV with Tx 1- ABB 16.8 MVA-13.8/69 kV from Old Sophia.
- Decommission of Tx 2- Westinghouse 16.7 MVA-13.8/69 kV.
- Installation of one Tx2 with 35 MVA 13.8/69 kV Campton Greeves transformer (relocated from Good Hope Substation).
- Replace two (2) disconnect switches with two AIS 69 kV bays to accommodate two (2) transformer – 1-16.7 MVA -ABB, 1-35 MVA Campton Greeves.
- Installation of one 15 kV Class Metal clad 9 Cubicle Switchgear.
- Renovation of the Control Room Building and switchgear facility.
- Upgrade of two (2) oil 69 kV circuit breaker with all relevant ancillary components (L1, B1B2- tie breaker).
- Installation of one (1) AIS 69 kV bus tie breaker (B2B3).
- Installation of two (2) AIS 69 kV bays to accommodate double transmission lines from New Garden of Eden Substation (L24/L24P).
- Termination of double circuit transmission lines from New Garden of Eden Substation into AIS bays.

27.3.9.4 13.8 kV Distribution Network

I. Golden Grove Distribution Expansion Plan

- Reconductoring of 89.1 km F1 feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.
- Reconductoring of 14.8 km F3 feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.

II. Garden Of Eden Distribution Expansion Plan

Construction of ring circuit network on GOE F2 linking Yarrowkabra with Airport Network.

- Reconductoring of 94.3 km F1 feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.
- Reconductoring of 32.7 km F2 feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.
- Reconductoring of 19.1 km F3 feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.

- Construction of two (2) 6 km new priority feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.

27.3.9.5 New Substation

NEW GARDEN OF EDEN 250 MVA 69/230 KV AIS SUBSTATION

- Construction of one new AIS 230 kV substation by installing:
  (1) 13 double bus single breaker 230 kV bays.
  (2) 1 bus ties single breaker 230 kV bays.
  (3) Two (2) 125 MVA 69/230 kV Power Transformers.
- Termination of existing double circuit 230 kV transmission lines from Goedverwagting 230 kV Substation into AIS 230 kV bays, HV L1-1, HV L1 P-1.
- Termination of existing double circuit 230 kV transmission lines from Wales 250-300 MW NG Power Evacuation 230 kV Substation into AIS 230 kV bays, HV L1-2, HV L2-P.
- Termination of new double circuit 230 kV transmission lines from Goedverwagting 230 kV Substation into AIS 230 kV bays HV L2-2, HV L2-P-2.

NEW GARDEN OF EDEN 70 MVA 13.8/69 KV AIS SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:
  (1) Five (5) breaker and ½ 69 kV switchgear.
  (2) 18 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
  (3) Two- 35 MVA 13.8/69 kV Transformers.
  (4) Two (2) 6 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.
- Termination of two (2) incoming tie lines from 125 MVA 69 kV/230 kV transformer into AIS 69 kV Bays.
- Termination of double transmission lines from existing Garden of Eden Substation into 69 kV AIS Bays.
- Termination of double transmission lines from Kuru Kururu Substation into 69 kV AIS Bays.
- Termination of double transmission lines from Linden-McKenzie Substation into 69 kV AIS Bays.

KURU KURURU 50 MVA 13.8/69 KV AIS SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:
  (1) Three (3) breaker and ½ 69 kV switchgear.

(2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
(3) Two- 35 MVA 13.8/69 kV Transformers.
(4) Three (3) 8 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.

- Termination of double transmission lines from New Garden of Eden Substation into 69 kV AIS Bays.
- Termination of transmission line from Yarrowkabra Substation into 69 kV AIS Bay.

YARROWKABRA 50 MVA 13.8/69 KV AIS SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:

(1) Three (3) breaker and ½ 69 kV switchgear.
(2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
(3) Two- 25 MVA 13.8/69 kV Transformers.
(4) Four (4) 8 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.

- Termination of double transmission lines from New Garden of Eden Substation into 69 kV AIS Bays.
- Termination of transmission line from Yarrowkabra Substation into 69 kV AIS Bay.

27.3.10 Region 4: Across Demographic Areas

Table 4: Region 4 Demographic links description

D&E – 2023- 2027: Inter - Demographic Link - Region 4			
Existing:			
Georgetown	East Coast- up to Mahaica	New Sophia-Good Hope	L16
Georgetown	East Bank Demerara	New Sophia-Golden Grove	L4
Georgetown	East Bank Demerara	Old Sophia-Golden Grove	L2
Proposed:			
Georgetown	East Coast- up to Mahaica	New Sophia-Ogle	L16-1, L16 P-1
Georgetown	East Coast- up to Mahaica	New Sophia-Goedverwagting-	L4-2
Georgetown	East Coast- up to Mahaica	Old Sophia-Goedverwagting-	L2-2
Georgetown	East Bank Demerara	Goedverwagting-Golden Grove	L2-1/L4-1

East Coast	East Bank Demerara	Goedverwagting-New Garden of Eden	HVL1-1, HV L1P-2
East Coast	East Bank Demerara	Goedverwagting-New Garden of Eden	HVL2-2, HV L2P-2

27.3.10.1 Transmission

27.3.10.1.1 Georgetown - East Coast Mahaica

- Construction of 12.5 km of new double circuit 69 kV transmission lines utilizing conductor type Rovinj ACCC (371 kcmil) between New Sophia (Georgetown) and Good Hope (East Coast) Substations- L16 Upgrade & L16R

69 kV Transmission Line Splits into Ogle: -

- Establishment of 4.86 km of new transmission circuit that runs between New Sophia (Georgetown) and Ogle (East Coast) Substations- L16-1.
- Establishment of 4.86 km of new transmission circuit that runs between New Sophia (Georgetown) and Ogle (East Coast) Substations L16-1 P.

69 kV Transmission Line Splits into Goedverwagting: -

- Establishment of 9.43 km of new transmission circuit that runs between New Sophia (Georgetown) and Goedverwagting (East Coast) Substations- L4-2.
- Establishment of 9.55 km of new transmission circuit that runs between Old Sophia (Georgetown) and Goedverwagting (East Coast) Substations L2-2.

27.3.10.1.2 Georgetown - East Bank Demerara

- Construction of 17 km of upgraded 69 kV transmission lines utilizing conductor type Rovinj ACCC (371 kcmil) between New Sophia and Golden Grove Substations- L4 Upgraded
- Construction of 17 km of upgraded 69 kV transmission lines utilizing conductor type Rovinj ACCC (371 kcmil) between Old Sophia and Golden Grove Substations- L2 Upgraded

27.3.10.1.3 East Coast – East Bank

69 kV Transmission Line Splits into Goedverwagting: -

- Establishment of 9.35 km of new transmission circuit that runs between Goedverwagting (East Coast) and Golden Grove (East Bank) Substations- L4-1.
- Establishment of 9.35 km of new transmission circuit that runs between Goedverwagting (East Coast) and Golden Grove (East Bank) Substations- L2-1.

230 kV Transmission Line Splits (HVL1, HV L1 P) into New Garden of Eden: -

- Establishment of 15.65 km of new double circuit 230 kV transmission line that runs between Goedverwagting (East Coast) and New Garden of Eden (East Bank) Substations HVL1-2, HVL1 P-2.

New 230 kV Transmission

- Construction of 16.35 km of 230 kV Double Circuit Transmission Lines considering two (2) wire per phase utilizing conductor type Rovinj ACCC (371 kcmil) between 230 kV Goedverwagting (East Coast Demerara) and 230 kV New GOE (East Bank Demerara Substations HVL2-2, HV L2 P -2.

27.3.11 Region 5: East Coast Mahaica to West Bank Berbice

Existing Substation Projects:

1. Columbia 16.7 MVA 13.8 kV/69 kV Substation

- Substation Upgrade Project- New 13.8/69 kV Transformer
- Substation Upgrade Project- New Power Plant
- Substation Upgrade Project- 15 MVARS Detuned Static Compensator
- Substation Expansion Project - New Transmission Lines Project:

    I. From Enmore/Victoria Substation - L18 (Split L17),
    II. From Enmore/Victoria Substation - L18 P (New Circuit),
    III. From Onverwagt Substation - L20P.

- Substation Expansion Project- New 15 kV Class Switchgear
- Distribution Network Upgrade- Two (2) New Feeders
- Distribution Network Upgrade- One (1) Priority Feeder

2. Columbia 15 MVARS Detuned Static Compensator
3. Onverwagt 16.7 MVA 13.8 kV/69 kV Substation

- Substation Upgrade Project- New 13.8/69 kV Transformers
- Substation Expansion Project - New Transmission Lines Project:

    I. From Columbia Substation - L20 P,
    II. From Rosignol Substation - L21-1 P.
    III. From Trafalgar 4 MW PV Project- GuySol

- Substation Expansion Project- New 15 kV Class Switchgear
- Distribution Network Upgrade- F2 Upgrade
- Distribution Network Upgrade- F2 Express

- Distribution Network Upgrade- Two APFC on F2 Upgrade & F2 Express

4. Onverwagt 40 MVA 13.8 kV/69 kV Substation Upgrade

Proposed Power Plants:

5. New EPC 25 MW 13.8 kV 60 Hz HFO Power Plant
6. Trafalgar 4 MW PV Project- GuySol

Proposed Substation Projects:

7. Rosignol 50 MVA 13.8/69 kV AIS Substation

Proposed Existing 69 kV Transmission Line Upgrade Projects between:

8. Columbia and Good Hope Substations (Region 4) – L17 P (ref: Sect: 27.3.15.1.3)
9. Columbia and Onverwagt Substations – L20 P
10. Onverwagt and Canefield (Region 6) Substations – L21 Upgrade (ref: Sect 27.3.15.1.5)
11. Onverwagt and Canefield (Region 6) Substations – L21 P (ref: Sect 27.3.15.1.5)

Proposed 69 kV Transmission Lines Splits between:

12. Onverwagt and Canefield (Region 6) Substations L21 Upgraded – into Rosignol Substation
13. Onverwagt and Canefield (Region 6) Substations L21 P– into Rosignol Substation

Proposed 69 kV Transmission Line Projects between:

14. Onverwagt and Rosignol- L21 P-1
15. Rosignol and Canefield (Region 6)– L21P-2 (ref: Sect 27.3.15.1.5)
16. Onverwagt and Trafalgar 4 MW PV Solar Plant – PV Tie

Distribution Feeder Upgrade:

17. Onverwagt F2- Upgraded- up to No. 7 WCB
18. Onverwagt F2- Express- from No. 7 WCB to Ithaca.

27.3.11.1 Generation Conventional & Renewable Projects

- Installation of new 25 MW HFO Power Plant at Columbia
- Installation of 4 MWp Solar PV Plant at Trafalgar – to be integrated at Onverwagt Substation

27.3.11.2 Transmission

- Construction of 1.7 km of new 69 kV transmission line utilizing conductor type Canton AAAC 19 Strands (395 kcmil) and concrete poles to integrate Trafalgar 4 MWp Solar PV site West Coast Berbice with Onverwagt Substation.
- Construction of 37.17 km of redundant transmission line (L20P) between Columbia and Onverwagt Substation.
- Upgrade of 22 km of 69 kV transmission line utilizing conductor type Canton AAAC 19 Strands (395 kcmil) and concrete poles between Onverwagt (East Coast Demerara-Region 5) and Blairmont Ferry Terminal (West Bank Berbice- Region 5) (L21 Upgraded Phase 2).
- (L21 Upgraded Phase 1, Ref: Sect 27.3.15.1.5).

69 kV Transmission Line Splits L21 Upgraded (Phase 1 &2)/ L21P- into Rosignol Substation:

- Splitting of 69 transmission line that runs between Onverwagt (Region 5) and Canefield (Region 5) Substations into Rosignol Substation
- Splitting of 69 transmission line that runs between Onverwagt (Region 5) and Canefield (Region 5) Substations into Rosignol Substation.

New 69 kV Transmission Lines as a Result of: Splits into Rosignol Substation: -

- Establishment of 18.73 km of new transmission circuit that runs between Onverwagt and Rosignol Substations - L21 Upgraded – 1 and L21 P-1
- L21 Upgraded – 1 and L21 P-1 (Rosignol-Canefield), ref: Sect 27.3.15.1.5

27.3.11.3 Existing Substation

COLUMBIA 16.7 MVA 13.8/69KV SUBSTATION

- Installation of one AIS 69 kV bay to accommodate one new transmission line (L18-Bypass) from Good Hope/Enmore/Victoria Switching Substation.
- Termination of L18- Bypass into 69 kV AIS Bay.
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L20P) from Onverwagt Substation.
- Termination of L20P into 69 kV AIS Bay.
- Installation of one new 16.7 MVA 13.8/69 kV transformer.
- Installation of one AIS 69 kV bay to accommodate one new 16.7 MVA Transformer.
- Installation of one 15 kV Class Metal clad 6 Cubicle Switchgear.

- Construction of new control room building to installed additional cubicles, ancillary services and substation equipment for all new projects listed above.

COLUMBIA 15 MVARS DETUNED STATIC COMPENSATOR

- Installation of 15 MVAr detuned static compensator bank.
- Expansion of Columbia 69 kV substation by installing one AIS 69 kV bay to facilitate the interconnection of the 15 MVAr Detuned Static Compensator.

ONVERWAGT 16.7 MVA 13.8/69KV SUBSTATION

- Installation of one AIS 69 kV bay to accommodate one transmission line (L21P-1) from Rosignol Substation.
- Termination of transmission line from Rosignol Substation L21P-1 into 69 kV AIS Bay.
- Termination of upgraded transmission line from Rosignol L21 Upgraded into 69 kV AIS Bay.
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L20P) from Columbia Substation.
- Termination of transmission line from Columbia substation L20P into 69 kV AIS Bay.
- Replacement of one 16.7-MVA 13.8/69 kV Dachi transformer with a 25 MVA 13.8/69 kV transformer.
- Installation of 6 cubicle 15 kV Metal-clad enclosed switchgear.
- Installation of one AIS 69 kV bay to accommodate interconnecting lines from Trafalgar 4 MW Solar PV Project.
- Termination of transmission line from Trafalgar 4 MW Solar PV Project into 69 kV AIS Bay.

ONVERWAGT 40 MVA 13.8/69KV SUBSTATION

- Installation of one new 25 MVA 13.8/69 kV transformer into existing AIS 69 kV bay.
- Installation of one AIS 69 kV bay to accommodate one new 25 MVA 13.8/69 kV Transformer.
- Installation of one new 25 MVA 13.8/69 kV transformer into new AIS 69 kV bay.

27.3.11.4 13.8 kV Distribution Network

I. Columbia Distribution Expansion Plan

- Construction of two (2) 8 km new feeder circuits utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.

- Construction of one (1) 8 km new priority feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.

II. Onverwagt Distribution Expansion Plan

- Reconductoring of the F2 – (from Onverwagt to No. 7 WCB) feeder backbone utilizing conductor type Cosmos AAC 19 strands 477 MCM and wallaba poles structures.
- Construction of new express feeder circuit – (from Onverwagt to No. 7 W.C.B), reconductoring from No. 7 W.C.B to Ithaca utilizing conductor type Cosmos AAC 19 strands 477 MCM and wallaba poles structures.
- Installation of two (2) APFC capacitor bank- 1.7 MVAr on each upgraded F2 and F2 Express listed above.

27.3.11.5 New Substation

ROSIGNOL 50 MVA 13.8/69 KV SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:
  - (1) Three breaker and ½ 69 kV switchgear.
  - (2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
  - (3) Two- 25 MVA 13.8/69 kV Transformers.
  - (4) Four (4) 6 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.
- Termination of transmission lines from Onverwagt substation L21 Upgraded-1, L21P-1 into 69 kV AIS Bay.
- Termination of transmission line from Canefield substation L21 Upgraded-2, L21P-2 into 69 kV AIS Bay.

27.3.12 Region 6: Canje /East Coast /Corentyne Coast - Berbice

Existing Substations Projects

1. East Canje River - Canefield 16.7 MVA 13.8/69 kV Substation

- Substation Upgrade Project: New 13.8/69 kV Transformer
- Substation Upgrade Project: New EPC 25 MW HFO Power Plant- New Transformer
- Substation Upgrade Project: New 15 kV Class Switchgear- to replace the old ITE
- Substation Expansion Project – New EPC 25 MW HFO Power Plant:
- Substation Expansion Project - New Transmission Lines Project:
  - I. From Rosignol - L21 P-2 (New Circuit- L21P)

II. From Crab Island/Williamsburg- L22-1-P.

- Distribution Network Upgrade- F1 Upgrade
- Distribution Network Upgrade- F3 Upgrade
- Distribution Network Upgrade- Two (2) New Feeder
- Distribution Network Upgrade- Three (3) Priority Feeders

2. East Coast Corentyne - Skeldon Energy Inc Substation Upgrade

New Power Plant

1. Canefield New EPC 25 MW HFO Power Plant
2. East Coast Berbice - Prospect 3 MW Solar PV (GuySol)
3. East Coast Berbice Hampshire - 3 MW Solar PV Project (GuySol)

New Substation Projects

4. East Coast Berbice - Crab Island 200 MVA 69/230 kV Substation
5. East Coast Berbice - Crab Island 50 MVA 13.8/69 kV Substation

Corentyne Coast Road -

6. Williamsburg 50 MVA 13.8/69 kV Substation
7. Williamsburg 200 MVA 69/230 kV Substation
8. No. 53 Village 50 MVA 13.8/69 kV Substation
9. No. 53 Village 15 MVARS Detuned Static Compensator

Proposed Upgrade to Existing 69 kV Transmission Line Projects between:

10. Canefield - Canje and No.53 Village Substations (Corentyne Coast)– L22 Upgraded
11. Canefield - Canje and No.53 Village Substations (Corentyne Coast)– L22 P
12. No.53 Village and Skeldon Substations - L23 P
13. Onverwagt (Region 5) and Canefield - Canje Substations – L21 P (ref: Sect 27.3.15.1.5)

Proposed 69 kV Transmission Lines Splits between:

14. Canefield and Onverwagt (Region 5) Substations L21 P – into Rosignol (Region 5) Substation (ref: Sect 27.3.15.1.5)
15. Canefield - Canje and No.53 Village Substations (Corentyne Coast) – L22, L22 P – into Williamsburg Substation

16. Canefield - Canje and No.53 Village Substations (Corentyne Coast) – L22, L22 P – into Crab Island Substation

Proposed 69 kV Transmission Line Projects between:

17. Rosignol (Region 5) and Canefield Substations – L21-P-2 (ref: Sect 27.3.15.1.5)
18. Onverwagt and Canefield (Region 6) - L21 Upgraded -2 (ref: Sect 27.3.15.1.5)
19. Crab Island and Canefield Substations – L22-1a, L22 P-1a
20. Crab Island and Williamsburg Substations – L22-1b, L22 P-1b
21. Williamsburg and No. 53 Village Substations – L22-2, L22 P-2

Proposed 230 kV Transmission Line Projects between:

22. Double Circuit 230 kV Transmission Lines Between 230 kV Crab Island (East Coast Berbice- Region 6) and 230 kV Goedverwagting (East Coast Demerara- Region 4) (ref: Sect. 27.3.15.1.4).
23. Double Circuit 230 kV Transmission Lines Between 230 kV Crab Island (East Coast Berbice) and 230 kV Williamsburg (East Corentyne).

27.3.12.1 Generation Conventional & Renewable Projects

- Installation of EPC HFO Power Plant at Canje- Canefield.
- Installation of 3 MWp Solar PV Plant at East Coast Berbice - Prospect - to be integrated at Hyundai F1 switchgear cubicle.
- Installation of 3 MWp Solar PV Plant at East Coast Berbice - Hampshire to be integrated into Canefield F3 13.8 kV distribution circuit approximately 1 km away from Canefield Power plant.

27.3.12.2 Transmission

- Upgrade of existing 55.9 km of transmission line (L22) between Canefield and No. 53. Village Substations.
- Construction of 55.9 km of redundant transmission line (L22P) between Canefield and No. 53. Village Substations.
- Construction of 21.12 km of redundant transmission line (L23P) between No. 53. Village and Skeldon Substations.
- Construction of 22.34 km of 230 kV Double Circuit Transmission Lines between 230 kV Crab Island (East Coast Berbice) and Williamsburg Substations (East Corentyne Berbice), HVL5, HV L5 P.

69 kV Transmission Line Splits- into Williamsburg Substation:

- Splitting of 69 kV transmission lines that runs between Canefield Canje and No. 53 Village East Corentyne Substations L22 & L22 P – into Williamsburg Substation.

69 kV Transmission Line Splits- into Crab Island Substation:

- Splitting of 69 kV transmission lines that runs between Canefield Canje and No. 53 Village East Corentyne Substations L22 & L22 P – into Crab Island Substation.

New 69 kV Transmission Lines as a Result of: Splits into Williamsburg Substation: -

- Establishment of 21.24 km of new transmission circuit that runs between Williamsburg and Canefield Substations - L22 -1, L22 P - 1.
- Establishment of 34.3 km of new transmission circuit that runs between Williamsburg and No. 53 Village Substations L22 -2, L22 P-2.

New 69 kV Transmission Lines as a Result of: Splits into Crab Island Substation: -

- Establishment of 6.71 km of new transmission circuit that runs between Crab Island and Canefield Substations - L22 -1a, L22 P – 1a.
- Establishment of 20.2 km of new transmission circuit that runs between Crab Island Williamsburg Substations L22 -1b, L22 P-1b.

230 KV Transmission Lines

- Construction of 22.34 km of 230 kV Double Circuit Transmission Lines considering two (2) wire per phase utilizing conductor type Rovinj ACCC (371 kcmil) between 230 kV Crab Island Substations (East Coast Berbice – Region 6) and Williamsburg (Corentyne Road Berbice – Region 6), HVL5, HV L5 P.
- HV L4, HV L4P (230 kV Crab Island- Goedverwagting- Region 4), ref: Sect 27.3.15.1.4

27.3.12.3 Existing Substation

CANEFIELD 16.7 MVA 13.8/69KV SUBSTATION

Old Power Plant Upgrade:

- Installation of one new 60 MVA 13.8/69 kV transformer to replace existing 16.7 MVA capacity.
- Upgrade of existing ITE 15 kV class Switchgear panels with 9 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
- Upgraded of Grounding Transformer and Station use capacities.

New Power Plant- EPC 25 MW HFO

- Installation of new 60 MVA 13.8/69 kV transformer.
- Installation of one AIS 69 kV bay to accommodate 60 MVA 13.8/69 kV transformer.

- Installation of 15 kV class metal-clad enclosed switchgear with all relevant ancillary component, full specification to be determined by EPC contractor.

69 kV Substation Expansion- Transmission Lines

- Installation of one AIS 69 kV bay to accommodate one new transmission line (L21P -2) from Rosignol Substation.
- Termination of redundant transmission line from Rosignol (L21 P -2) into 69 kV AIS bay.
- Termination of upgraded 69 kV transmission line from Rosignol (L21 Upgraded -2) into 69 kV AIS bay.
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L22P) from Crab Island Substation.
- Termination of redundant transmission line from Crab Island (L22 P) into 69 kV AIS bay.
- Termination of upgraded transmission line from Crab Island (L22) into 69 kV AIS bay.

NO. 53 VILLAGE 50 MVA 13.8/69KV UPGRADED SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Three (3) breaker and ½ 69 kV switchgear.
    (2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
    (3) Two- 25 MVA 13.8/69 kV Transformers.
    (4) Three (3) 3 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.
- Termination of redundant transmission line from Canefield (L22 P) into 69 kV AIS bay.
- Termination of upgraded transmission line from Canefield (L22) into 69 kV AIS bay.
- Termination of redundant transmission line from Skeldon (L23) into 69 kV AIS bay.
- Termination of existing transmission line from Skeldon (L23) into 69 kV AIS bay.

NO. 53 VILLAGE 50 MVA 13.8/69KV UPGRADED SUBSTATION

- Installation of 15 MVAR Detune Static Compensator.
- Installation of one breaker and ½ bay AIS 69 kV bay to accommodate 15 MVAR Detune Static Compensator.

SKELDON 69KV UPGRADED SUBSTATION

- Installation of one AIS 69 kV bay to accommodate one new transmission line (L23P) from No. 53 Village Substation.

- Termination of redundant transmission line from No. 53 (L23) into 69 kV AIS bay.
- Installation of 69 kV 2-busbars with bus-tie circuit breaker to accommodate one new transmission line (L23P).

27.3.12.4 13.8 kV Distribution Network

I. Canefield Distribution Expansion Plan

- Construction of 1 km new 13.8 kV distribution network utilizing conductor type Tulip AAC 19 Strand- 336.4 kcmil and concrete poles to integrate Prospect 3 MWp Solar PV at Canefield Hyundia13.8 kV switchgear cubicle.
- Construction of 1 km new 13.8 kV distribution network utilizing conductor type Tulip AAC 19 Strand- 336.4 kcmil and concrete poles to integrate Hampshire 3 MWp Solar PV with the existing Canefield F5 – Hampshire East Coast Berbice.
- Reconductoring of 28 km F3 feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.
- Construction of three (3) 4 km new priority feeder circuits utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.
- Construction of two (2) 8 km new feeder circuits utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures

II. No. 53 Village Distribution Expansion Plan

- Reconductoring of 47.747 km F2 feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.
- Reconductoring of 47.747 km F3 feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.
- Construction of one (1) 3 km new feeder circuit utilizing conductor type Cosmos AAC 19 strands 477 MCM and concrete pole structures.

27.3.12.5 New Substation

CRAB ISLAND 200 MVA 69/230 KV AIS SUBSTATION

- Construction of one new AIS 230 kV substation by installing:
  (1) Six (6) double bus single breaker 230 kV bays.
  (2) 1 bus ties single breaker 230 kV bays.
  (3) Two (2) 100 MVA 69/230 kV Power Transformers
- Termination of double circuit 230 kV transmission lines from Goedverwagting 230 kV Substation into HVL4, HV L4 P AIS 230 kV bays.

- Termination of double circuit 230 kV transmission lines from Williamsburg 230 kV Substation HVL5, HV L5 P into AIS 230 kV bays.

CRAB ISLAND 50 MVA 13.8/69 KV SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:

  (1) Five (5) breaker and ½ 69 kV switchgear.
  (2) 15 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
  (3) Two- 35 MVA 13.8/69 kV Transformers.
  (4) Six (6) 5 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.

- Termination of two (2) incoming tie lines from two 100 MVA 69 kV/230 kV transformer into AIS 69 kV Bays.
- Termination of double transmission lines from Canefield into 69 kV AIS Bays.
- Termination of double transmission lines from Williamsburg Substation into 69 kV AIS Bays.

WILLIAMSBURG 200 MVA 69/230 KV AIS SUBSTATION

- Construction of one new AIS 230 kV substation by installing:

  (1) Four (6) double bus single breaker 230 kV bays.
  (2) 1 bus ties single breaker 230 kV bays.
  (3) Two (2) 100 MVA 69/230 kV Power Transformers

- Termination of double circuit 230 kV transmission lines from Crab Island 230 kV Substation HVL5, HV L5 P into AIS 230 kV bays.

WILLIAMSBURG 50 MVA 13.8/69 KV SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:

  (1) Five breaker and ½ 69 kV switchgear.
  (2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
  (3) Two- 25 MVA 13.8/69 kV Transformers.
  (4) Six (6) 5 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.

- Termination of two (2) incoming tie lines from two 100 MVA 69 kV/230 kV transformer into AIS 69 kV Bays.
- Termination of double transmission lines from Crab Island Substation into 69 kV AIS Bays.

- Termination of double transmission lines from No. 53 Village Substation into 69 kV AIS Bays.

27.3.13 Region 7: Bartica

Existing:

1. Bartica 3.3 MW 13.8 kV 60 Hz LFO Power Plant
2. Bartica 1.6 MW 13.8 kV 60 Hz LFO Mobile Units
3. Bartica 13.8 kV Distribution System- Feeder 1
4. Bartica 13.8 kV Distribution System- Feeder 2
5. Bartica 13.8 kV Distribution System- Feeder 3

Propose Power Plants:

1. Bartica Power Plant Extension 1 – 2 x 1.1 MW LFO Generator - 2024
2. Bartica Power Plant Extension 2– 1.1 MW LFO Generator- 2027
3. Bartica 1.5 MWp PV Plant
4. Bartica 0.75 MWh BESS
5. Bartica Power Plant Switchgear Expansion

Proposed 13.8 kV Distribution Upgrades:

6. Bartica Express PV tie to existing Power Plant
7. Bartica Express to Berbissiballi
8. Bartica Express to Del Conte
9. Bartica- Auto Reclosers
10. Bartica - Voltage regulators
11. Bartica - Smart Capacitor Banks
12. Bartica - Feeder Heads IEDs
13. Bartica - Circuit Load Balancing

27.3.13.1 Generation Conventional & Renewable

- Installation of 1.5 MWp Solar Photovoltaic Plant / 0.75 MWh BESS – located 2.2 km away from Bartica Power Plant.
- Installation of one new 1.12 MW additional HFO generation unit.
- Installation of one new 2 MW additional HFO generation unit.

27.3.13.2 13.8 kV 60 Hz Power Plant Upgrade

- Expansion of 13.8 kV Switchgear at Bartica Power Plant by installing 2 additional cubicles to accommodate 1.5 MWp Solar PV/ 0.75 MWh BESS 13.8 kV tie lines.
- Expansion of 13.8 kV Switchgear at Bartica Power Plant by installing 2 additional cubicles to accommodate two additional 13.8 kV distribution feeders- express to Del conte and Berbissiballi.

27.3.13.3 13.8 kV Distribution System Upgrade

Bartica Distribution Expansion Plan

- Precuring and installation of five (5) smart capacitor banks of capacities of 450 kVAr and 600 kVAr on selected distribution networks.
- Precuring and installation of two (2) voltage regulators bank on selected distribution network.
- Precuring and Installation of three (3) auto reclosers on selected feeders.
- Precuring and Installation of three (3) feeder heads IEDs on selected feeders.
- Circuit load balancing to be conducted on three (3) selected feeders.

27.3.14 Region 10: Linden

Existing:

1. Linden Power Company- IPP BOSAI 13.8 kV 60 Hz HFO/LFO Power Plant

Linden Electricity Company Inc - East Side of Demerara River within McKenzie:

2. Linden Electricity Company Inc: 13.8 kV Power Distribution Facility
3. Linden 4.16 kV Distribution System- Village Feeder
4. Linden 13.8 kV Distribution System- Mines Feeder
5. Linden 13.8 kV Distribution System- Richmond Hill Feeder
6. Linden 13.8 kV Distribution System- Amalia's Ward Feeder

Linden Utility Corp Society - West Side of Demerara River within Wisma:

7. Linden 13.8 kV Distribution System- Wisma Feeder

Propose Power Plants:

Linden- Outside of the town:

8. Block 37 - 4 MWp Solar PV Plant

9. Block 37 - 8 MWp Solar PV Plant
10. Dacoura – 3 MW Solar PV Plant
11. Linden Electricity Company Inc – 13.8 kV Power Distribution Facility - 11 MWh BESS

Proposed Substation:

12. McKenzie 33.4 MVA 13.8/69 kV AIS Substation
13. Wis 33.4 MVA 13.8/69 kV AIS Substation

Proposed 69 kV Transmission Lines between:

14. McKenzie and New Garden of Eden (Region 4) Substations L37/ L37 P (ref: Sect. 27.3.15.1.6)
15. McKenzie and Wisma Substations L38

27.3.14.1 Generation Conventional & Renewable Projects

- Installation of 11 MWh BESS at the LECI 13.8 kV Power Distribution Facility.
- Installation of 4 MWp Solar PV Plant at Block 37- Linden.
- Installation of 8 MWp Solar PV Plant at Block 37- Linden.
- Installation of 3 MWp Solar PV Plant at Dacoura- Linden.

27.3.14.2 13.8 kV 60 Hz Power Distribution Facility

- Upgrade of existing Power Distribution Facility with new 15 kV Metal Clad 12 Cubicle Switchgear.

27.3.14.3 13.8 kV Distribution System Upgrade

I. Linden Solar PV Interconnection Plan

- Construction of 3.9 km new 13.8 kV distribution network utilizing conductor type Cosmos AAC 19 Strand- 477 kcmil and concrete poles to integrate 4 MWp Solar PV Plant at Block 37- Linden with existing Amalia's Ward Feeder- T connection.
- Construction of 8 km new express 13.8 kV distribution network utilizing cables 2 x 1000 kcmil AAC and concrete poles to interconnect 8 MWp Solar PV Plant at Block 37- Linden at the 13.8 kV Power Distribution Facility, McKenzie.
- Construction of 1.2 km new 13.8 kV distribution network utilizing conductor type Tulip AAC 19 Strand- 336.4 kcmil and concrete poles to integrate 3 MWp Solar PV Plant at Dacoura with existing Wisma Feeder- T connection.

II. Linden Distribution Expansion Plan

- Precuring and installation of twelve (12) smart capacitor banks of capacities of 450 kVAr and 600 kVAr on selected distribution networks.
- Precuring and installation of six (6) voltage regulators bank on selected distribution network.
- Precuring and Installation of six (6) auto reclosers on selected feeders.
- Precuring and Installation of four (4) feeder heads IEDs on selected feeders.
- Circuit load balancing to be conducted on six (6) selected feeders.

27.3.14.4 Transmission

- Ref: Sect. 27.3.15.1.6) - L37/37 P
- Construction of 5.4 km of new 69 kV transmission line utilizing conductor type Rovinj ACCC (371 kcmil) between McKenzie and Wisma Substations - L38.

27.3.14.5 Substation

MCKENZIE SUBSTATION 33.4 MVA 13.8/69 KV SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:
  (1) Three (3) breaker and ½ 69 kV switchgear,
  (2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
  (3) Two (2) 16.7 MVA 13.8/69 kV Transformers.
  (4) Six (6) 6 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.
- Termination of double transmission lines from New Garden of Eden Substation into 69 kV AIS Bays.
- Termination of transmission line from Wisma Substation into 69 kV AIS Bay.

WISMA SUBSTATION 33.4 MVA 13.8/69 KV SUBSTATION

- Construction of one new AIS 13.8/69 kV substation by installing:
  (1) Two (2) breaker and ½ 69 kV switchgear,
  (2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
  (3) Two (2) 16.7 MVA 13.8/69 kV Transformers.
  (4) Six (6) 5 km new feeder circuits utilizing Cosmos AAC 19 strands 477 MCM conductor type and concrete pole structures.

- Termination of transmission line from McKenzie Substation into 69 kV AIS Bay.

27.3.15 Cross-Geographic Areas

Table 5: Description of Cross Geographic Regions Interconnecting Transmission Circuit

Regional Interconnecting Transmission Circuit			
From	**To**	**Interlinking Substations**	**Line Names**
Existing 69 kV Circuits:			
Region 3	Region 4	Vreed-en-hoop-Kingston	LS6- Submarine
Region 4	Region 5	Good Hope-Columbia	L17
Region 5	Region 6	Onverwagt- Canefield	L21
Proposed 69 kV Circuits:			
Region 4	Region 5	Good/Columbia	L17 P
Region 5	Region 6	Onverwagt-Canefield	New L21- Submarine
Region 5	Region 6	Rosignol-Canefield	L21P- New
Region 4	Region 10	New GOE- McKenzie	L37, L37 P
69 KV Line Split: - Good Hope- Columbia L17 (Existing L17, L17 P)			
Region 4	Region 5	Enmore/Columbia	L18, L18 Bypass
Proposed 230 kV Circuits:			
Region 3	Region 4	Wales- Goedverwagting	HV L1, HV L 1 P-1
Region 4	Region 6	Goedverwagting- Carb Island (ECB)	HV L4, HV L4P
230 KV Line Split: - Wales- Goedverwagting HVL1, HV L 1 P-1			
Region 3	Region 4	Wales- GOE	HV L1-1, HV L P-2

27.3.15.1 Transmission Lines

27.3.15.1.1 Region 2 - Region 3

- No Line to be built within the planning period of the D&E.

27.3.15.1.2 Region 3 - Region 4

- Construction of 24.79 km of 230 kV Double Circuit Transmission Lines considering two (2) wire per phase utilizing conductor type Rovinj ACCC (371 kcmil) between Wales 300 MW 13.8/69/230 kV NG GSU (West Coast Demerara- Region 3) and 230 kV Goedverwagting (East Coast Demerara- Region 4), Substations HVL1, HV L1 P.

230 kV Transmission Line (HVL1, HVL1P) Splits into New Garden of Eden: -

- Establishment of 7.37 km of new double circuit 230 kV transmission line that runs between Wales 300 MW 13.8/69/230 kV NG GSU (WCD- Region 3) and New Garden of Eden (East Bank Demerara- Region 4) Substations HVL1-1, HVL1 P-1.
- HVL1-2, HV L1 P-2: ref Sect: **East Coast – East Bank**27.3.10.1.3

27.3.15.1.3 Region 4 - Region 5

- Construction of 26.6 km of redundant 69 kV transmission line utilizing conductor type Canton AAAC 19 Strands (395 kcmil) and concrete poles between Good Hope (East Coast Demerara- Region 4) and Columbia (East Coast Demerara- Region 5) Substations (L17P).

New 69 kV Transmission Lines as a Result of: L17/L17P Splits into Enmore: -

- Establishment of 16.9 km of new transmission circuit that runs between Enmore (Region 4) and Columbia (Region 5) Substation- L18.
- Establishment of 16.9 km of new transmission circuit that runs between Enmore (Region 4) and Columbia (Region 5) Substations L18 P.
- New L17/L17P: ref Sect: 27.3.8.2

27.3.15.1.4 Region 4 - Region 6

- Construction of 120 km of 230 kV Double Circuit Transmission Lines considering two (2) wire per phase utilizing conductor type Rovinj ACCC (371 kcmil) between 230 kV Goedverwagting (East Coast Demerara- Region 4) and 230 kV Crab Island Substations (East Coast Berbice – Region 6), HVL4, HV L4 P.

27.3.15.1.5 Region 5 - Region 6

L21 – Upgraded (Phase 1):

- L21- Upgraded Partly from 22 km away from Onverwagt Substation at Blairmont Ferry Terminal- Cable Crossing- Diversion:

i. Splitting of the existing transmission line between Onverwagt (Region 5) and Canefield (Region 6) Substations at Blairmont- 22 km away from Onverwagt Substation.

ii. Construction of overhead section 1.1 km of new 69 kV transmission line utilizing conductor type Canton AAAC 19 Strands (395 kcmil) and concrete poles between the point of split location at Blairmont up to submarine crossing- New L21 OH section 1.

iii. Installation of 1.6 km of 240 mm^2 submarine cable departing Blairmont Ferry Terminal into the Berbice river crossing- New L21 Submarine section 1.

iv. Construction of overhead section 2.26 km of new 69 kV transmission line utilizing conductor type Canton AAAC 19 Strands (395 kcmil) and concrete poles between the point of crossing at New Amsterdam Ferry Terminal up to Canje River submarine crossing- New L21 OH section 2.

v. Installation of 0.31 km of 240 mm^2 submarine cable across the Canje River- New L21 Submarine section 2.

vi. Construction of overhead section 1.41 km of new 69 kV transmission line utilizing conductor type Canton AAAC 19 Strands (395 kcmil) and concrete poles between Canje River submarine crossing into Canefield Substation - New L21 OH section 3.

- L21 – Upgraded (Phase 2): Between Onverwagt (East Coast Demerara- Region 5) and Blairmont Ferry terminal (West Bank Berbice- Region 5): Ref Sect 27.3.11.2
- Construction of 28.45 km of redundant 69 kV transmission line utilizing a combination of OH and Cables traversing the exact path as the L21 Upgraded (Phase 1, Phase 2 as previously described interconnecting Onverwagt (East Coast Demerara- Region 5) and Canefield (Canje - Region 6)- Substation – L21 P.

New 69 kV Transmission Lines as a Result of Rosignol Substation (West Coast Berbice- Region 5 and East Bank, East Canje Berbice Region 6): -

- Establishment of 8.65 km of parallel transmission circuit that runs between Rosignol (Region 5) and Canefield (Region 6) Substations utilizing conductor and cable describe in the L21 Upgraded OH and Submarine configuration route L21 Upgraded - 2, L21-P-2.
- L21 Upgraded, L21-P-1 Rosignol-Onverwagt, Ref. Sect: 27.3.11.2:

27.3.15.1.6 Region 4 - Region 10

- Construction of 89.67 km of new double 69 kV transmission line utilizing conductor type Rovinj ACCC (371 kcmil) and concrete poles between New Garden of Eden (East Bank Demerara- Region 4) and McKenzie (Linden Town- Region 10) Substations (L37/L37P).

27.3.15.2 Mobile Substations

Mobile 35 MVA 13.8/69 kV Substation

- Procurement of one new containerise 13.8/69 kV substation which includes the following:

(1) One single breaker 69 kV switchgear.
(2) Four cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
(3) One- 35 MVA 13.8/69 kV Transformers.

27.3.15.3 SCADA and Smart Grid and Distribution System Automation

- Construction of Guyana National Control Centre with a Modern SCADA system and Smart Grid Integration to be built at Goedverwagting in the vicinity of the Goedverwagting 13.8/69/230 kV Substation facility:

Phase 1:
Phase -1 GNCC/Smart Grid: Preparation of RFP Package

I. Phase -1 GNCC/Smart Grid: Integration of Auto Reclosers into GNCC
II. Phase -1 GNCC/Smart Grid: New SCADA – GMS - EMS (Transmission level) and associated components for dispatch of electricity
III. Phase -1 GNCC/Smart Grid: Construction of GNCC Building
IV. Phase -1 GNCC/Smart Grid: Design of GNCC Building (architectural & civil engineering design works)
V. Phase -1 GNCC/Smart Grid: Prepare RFP Package for GNCC Building

Phase 2:

I. Phase 2-GNCC/Smart Grid: Preparation of RFP Package
II. Phase 2-GNCC/Smart Grid: Phase 2-GNCC/Smart Grid: Implementation of SCADA (Distribution level in DBIS/Isolated Systems), Automated Metering Infrastructure (AMI) and T and D Network Supervision and Automation

27.3.15.3.1 AMI Meters

- Precuring and installation of 70 000 AMI meters throughout the Demerara – Berbice 13.8 kV distribution networks.
- Integration of 70 000 AMI meters that is to be installed throughout the Demerara – Berbice 13.8 kV distribution networks into the into the proposed SCADA/ SMART Grid infrastructure.

27.3.15.3.2 Auto Reclosers and Sectionaliser

- Installation of the remaining 17 auto reclosers on the Demerara – Berbice 13.8 kV distribution networks.
- Precuring and Installation of 220 auto reclosers throughout the Demerara – Berbice 13.8 kV distribution networks.
- Integration of all auto reclosers into the SCADA/SMART Grid monitoring infrastructure.

- Installation of sectionaliser the Demerara – Berbice 13.8 kV distribution networks, details are emerging.

27.3.15.3.3 13.8 kV SMART Capacitor Banks

- Precuring and installation of 241 smart capacitor banks of capacities of 450 kVAr and 600 kVAr throughout the Demerara – Berbice 13.8 kV distribution networks.
- Integration of 241 smart capacitor banks that is to be installed throughout the Demerara – Berbice 13.8 kV distribution networks, into the proposed SCADA/ SMART Grid infrastructure.

27.3.15.3.4 13.8 kV Voltage Regulators

- Precuring and installation of 85 voltage regulators bank throughout the Demerara – Berbice 13.8 kV distribution networks.
- Integration of 85 voltage regulator that is to be installed throughout the Demerara – Berbice 13.8 kV distribution networks into the into the proposed SCADA/ SMART Grid infrastructure.

27.3.15.3.5 Circuit Load Balancing

- Circuit load balancing to be conducted on 45 selected feeders throughout the Demerara – Berbice 13.8 kV distribution networks.
- This activity will be conducted utilizing the proposed SCADA/ SMART Grid infrastructure.

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End

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