British Virgin Islands Electricity Corporation

POWER DEVELOPMENT STUDY 2018-2029

Final Report



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EXECUTIVE SUMMARY

Introduction

In October 2015, British Virgin Islands Electricity Corporation (BVIEC) appointed WSP to conduct a power development study for the period from 2016-2027 covering generation, transmission and distribution. The work was originally scheduled to be completed by the end of 2017, however Hurricanes Irma and Maria hit BVI with massive impact, putting the project on hold for a year. The revised scope of the study is to provide a power development plan for 2018 -2029.

In order to ensure the relevance of the study, it was necessary to significantly revise the demand forecast to take account of the devastation caused by the hurricanes. The study also considers certain initiatives implemented in BVI since the original commencement date including:

- The Government of the Virgin Islands Energy Policy, dated 13th October 2016 which includes renewable energy targets, and
- BVIEC's 2018 Resiliency Plan which focuses in particular on undergrounding overhead portions of the transmission network and certain key distribution circuits in order to improve resilience to major hurricanes and other natural disasters.

This report includes the generation, transmission and distribution development plan and underlying analysis. It also includes a section covering financial analysis based on existing tariffs.

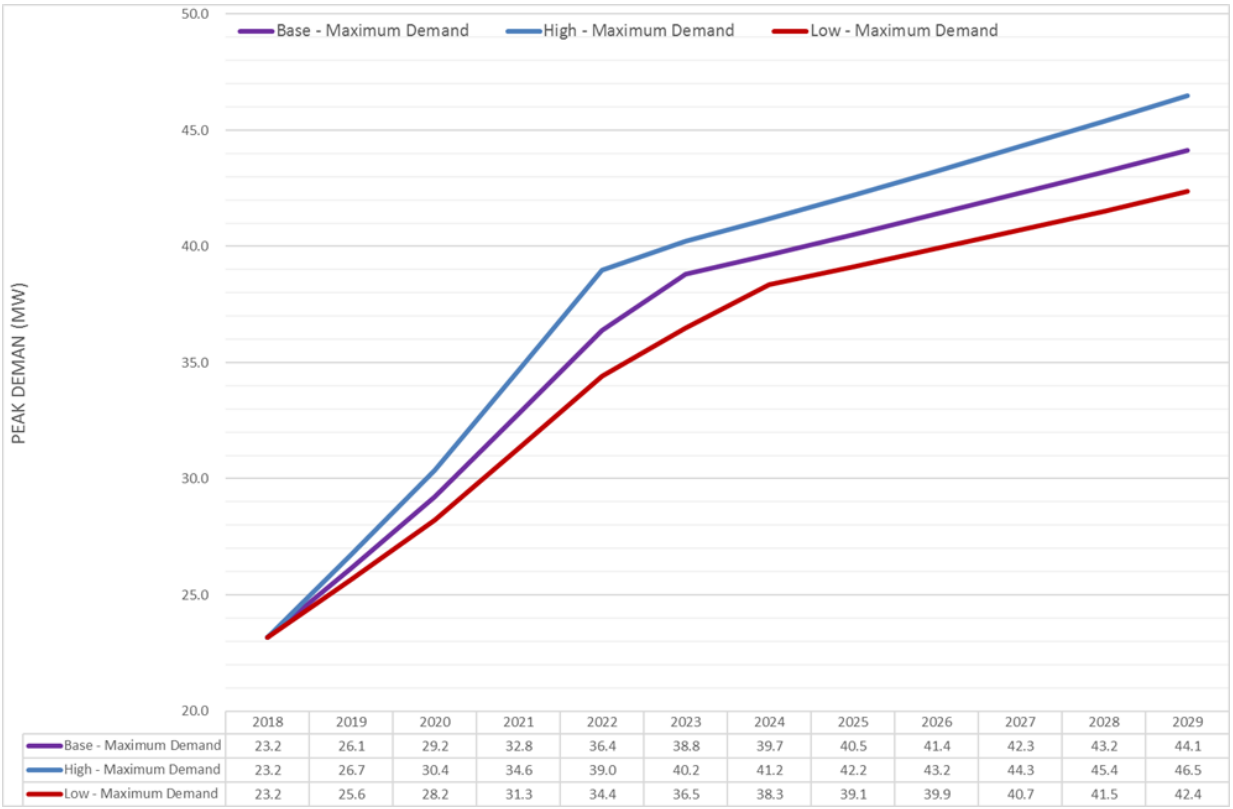
Demand forecast

The BVI experienced three unprecedented weather events in less than six weeks in 2017: extreme floods on 7th August, followed by Hurricanes Irma and Maria – both category 5 hurricanes on 6th and 20th September respectively. The storms caused extensive damage to the electricity system. All power plants suffered damage and approximately 90% of the transmission and distribution grid was destroyed, including approximately 12,000 poles, 640 km of overhead lines, 2,200 pole-mounted transformers, 3,500 streetlights and some BVIEC offices. Peak demand in January 2018

was approximately 17 MW compared with a peak of 34 MW prior to Hurricane Irma[1]. As of 11th July 2018, the maximum demand had recovered to 23 MW and by May 2019 a peak demand of 25 MW had been recorded.

WSP has developed a revised demand forecast as described in detail in the report. The forecast assumes rapid recovery of demand over the next four years in line with the post-Irma rehabilitation efforts followed by more gradual growth in line with historical trends. For the Base Case, the peak demand is forecast to increase from 23 MW in 2018 to 44 MW by 2029 as shown below.

Figure 1 - Forecast of Peak Demand (MW)



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Base - Maximum Demand	23.2	26.1	29.2	32.8	36.4	38.8	39.7	40.5	41.4	42.3	43.2	44.1
High - Maximum Demand	23.2	26.7	30.4	34.6	39.0	40.2	41.2	42.2	43.2	44.3	45.4	46.5
Low - Maximum Demand	23.2	25.6	28.2	31.3	34.4	36.5	38.3	39.1	39.9	40.7	41.5	42.4

Existing generation

The existing generating plant is located at Pockwood Pond power station and comprises a number of diesel units as listed below. The total capacity is approximately 59 MW although some units are temporarily out of service following hurricane damage. Due to the severe reduction in demand, there is however sufficient available generation capacity in the short-term.

Renewables

BVIEC currently produces all of its electricity from diesel generators, however the British Virgin Islands Electricity Corporation Amendment Act 2015 and British Virgin Islands Electricity

[1] British Virgin Islands Resilient National Energy Transition Strategy dated 24th April 2018.

Corporation (Renewable Energy) Regulations, 2018 which came into effect on November 1, 2018 means that the Territory now has the legal framework to advance the development of renewable energy.

Further to this, the Government of the Virgin Islands Energy Policy, dated 13th October 2016 includes various energy strategies and policy actions.

The main strategies on the supply side are aimed at reducing dependence on imported oil by increasing the availability and use of alternative fuel sources (such as renewable energy) and conducting long-term planning of resource needs and improving supply-side competition.

Table 1 – Existing generating plant

Unit	Make	Model	Speed (RPM)	Commission Year	Decommission Year	Net output (MW)
1	Mirrlees	KMAJMK3	600	1990	Retired in place	3.1
2	Mirrlees	KMAJMK4	600	1990	Retired in place	3.1
3	Stork/Wartsila	SW38	600	1995	2026	5.0
4	Stork/Wartsila	SW38	600	1995	2026	5.0
5	Wartsila	9L38A2	600	2007	2032	5.5
6	Wartsila	9L38A2	600	2007	2032	5.5
7	Wartsila	9L38A2	600	2006	2031	5.5
8	Wartsila	9L38A2	600	2006	2031	5.5
10	Wartsila	9L46	514	2017	2042	8.5
11	Wartsila	9L46	514	2017	2042	8.5
12	Wartsila	9L46	514	2017	2042	8.5
Black start	Cummins	QSK60	1800	2013	2028	1.5
Total						59.0

The BVI government has set a target to supply 30% of the territory's energy from renewable means by 2023 including:

- Up to 6 MW of wind power
- 2.5 MW of solar power
- 1.5 MW of energy from waste and
- 1 MW of sea/wave or other resources

In this study we have focused on solar and wind power. Ocean technology is unlikely to be viable within the 2023 timescale and it seems unlikely that there is sufficient waste for an economically viable energy from waste plant.

The study estimates that the 6 MW of wind power and 2.5 MW of solar PV will jointly provide approximately 8% of the Territory's 2023 electricity requirements.

It is understood that BVI is already developing the following renewable energy projects:

- The Anegada Hybrid Power Station Project
- The 3 MW Solar Farm at Cox Heath
- The Government buildings roof-top solar project.

WSP has investigated a number of potential renewable energy sites including three wind power sites with a total capacity of 9.6 MWac and 12 solar PV sites with a total capacity of 20.4 MWac as indicated below.

In the BVI, it is estimated that solar PV and wind power plants will achieve plant factors of around 23% and 27% respectively. On this basis, the combined 30 MW of solar and wind power capacity mentioned above would provide approximately 23% of the Territory's electricity needs if fully deployed by 2029. However, significant storage capacity would be required in order to fully harness this level of renewable resource.

Due to the variable nature of wind energy and the daily profile of solar energy, achieving high levels of penetration provides significant challenges. In addition to energy storage, voltage stability would also provide challenges with high levels of renewable penetration.

Table 2 – Potential Wind Power and Solar PV Sites (Capacity in MWac)

Site ID	*W1*	*W2*	*W3*
Island	Virgin Gorda	Virgin Gorda	Jost van Dyk
Location	Dog Bay	Brechers Bay Wind	Jost Van Dyk wind
Type of RE	Wind	Wind	Wind
Area (m2)	-	-	-
Length (m)	496	1098	2245
RE capacity (MW)	1.2	2.7	5.6

Site ID	*PV1*	*PV2*	*PV3*	*PV4*	*PV5*	*PV6*	*PV7*	*PV8*	*PV9*	*PV10*	*PV11*	*PV12*
Island	Tortola	Tortola	Tortola	Beef Island	Beef Island	Beef Island	Beef Island	Virgin Gorda	Virgin Gorda	Virgin Gorda	Virgin Gorda	Jost van Dyk
Location	Cox Heath	Race Track	Community College	Little Mountain Road	Long Bay	Airport 1	Airport 2	Upper Soldier Bay	Little Bay	Spanish Town Airport	Brechers Bay PV	White Bay
Type of RE	PV	PV	PV	PV	PV	PV	PV	PV	PV	PV	PV	PV
Area (m2)	82710	30721	13647	19199	31162	64611	21972	22059	30998	28367	7330	17174
Area (acres)	20.5	7.8	3.4	4.7	7.7	16	5.4	5.5	7.7	7	1.8	4.2
RE capacity (MW)	4.6	1.7	0.8	1.0	1.7	3.6	1.2	1.2	1.7	1.6	0.4	0.9

Generation plan

A model of the BVIEC generating plant has been developed in PLEXOS, a commercial power system modelling tool used for electricity market simulations and planning. In this application, PLEXOS is used to develop a least-cost generation investment plan. It uses linear programming to minimise the total net present value (NPV) costs of investments, dispatch and unserved energy. A number of scenarios were evaluated, based on the status quo and also to take account of the Energy Policy as follows:

Scenario 1 – Generation based on diesels only

Scenario 2 – Generation based on diesels and 2.5 MW of solar PV

Scenario 3 – Generation based on diesels and 6 MW of wind

Scenario 4 – Generation based on diesels, 2.5 MW of solar PV and 6 MW of wind

In order to meet the forecast demand growth up to 2029 whilst maintaining the required reserve margin, it will be necessary to commission Unit 9 by 2026 (8.5 MW).

In order to meet the required capacity planning margin of 17MW after 2026 it will be necessary for BVIEC to retire in-situ Units 3 and 4 (in total 10MW) until 2029 by which time it is expected that additional capacity will be provided by a new power plant. Over this period from 2026-2029, it is assumed that Units 3 and 4 could be operated in an emergency.

Due to the intermittent nature of renewables, it was assumed that they would not contribute to the generation capacity requirements. Therefore the above diesel generation capacity will be required irrespective of the level of solar or wind power generation added to the system.

The addition of solar PV and/or wind power generation will however result in a reduction in the cost of generation in BVI. This means that the capital costs of the solar PV or wind will be recovered through savings in fuel costs.

Solar PV remains economically attractive over a wide range of discount rates, fuel prices and capital costs. Wind power is economically attractive at fuel prices above 2 USD/US gallon.

In the longer term BVIEC is considering building a second power plant in order to provide additional capacity once the available capacity of Pockwood Pond power plant has been fully utilised. In order to improve security of supply and resilience, this should be located on the eastern side of Tortola. This will mean that the main load centre of Road Town could be supplied either from the west (Pockwood Pond) or from a new power plant to the east. Phase 3 of BVIEC's Resiliency Plan, mentions the requirement for a new generation facility at a separate location which would utilise a cleaner burning fuel such as LNG or LPG.

Transmission and distribution plan

The transmission and distribution system has been modelled using a power systems analysis computer program IPSA, and studies carried out for the period 2018 to 2029 based on the High Case demand forecast.

The studies indicate that the existing network is adequate to meet the forecast peak demand until 2025. The required reinforcements by 2026 are as follows:

- Commissioning 4th Pockwood Pond – Long Bush 34.5 kV underground circuit
- Construction of new 34.5/13.2 kV substation at Paraquita Bay

The estimated cost of these reinforcements is approximately USD 4.24 million in 2018 costs.

The BVIEC Resiliency Plan includes extensive measures to increase the resiliency of the network by undergrounding the remaining overhead sections of the transmission network and certain key distribution feeders and building new transmission substations to ensure the immediate power supply to critical loads across the BVI. The proposed Paraquita Bay substation is in fact part of the Resiliency Plan. The estimated cost of the transmission and distribution elements of the Resiliency Plan is approximately USD 54 million. However, the critical capital expenditure items that BVIEC intends to focus on over the period are the abovementioned substation at Paraquita Bay and the

undergrounding of the overhead section of the transmission line between Long Bush and Long Swamp substations.

Financial Analysis

The various cost and revenue projection for BVIEC, over the period to 2029, are brought together in a cash flow projection.

The analysis indicates that BVIEC should be able to achieve positive cash flow over the period to 2029 based on the existing tariff. The analysis does however include numerous assumptions regarding future levels of expenditure which should be reviewed by BVIEC.

Conclusions

Key conclusions of the study are as follows:

- In order to meet the demand forecast with the required level of reserve margin, it will be necessary to commission Unit 9 by 2026 and retire Units 3 and 4 in-situ such that they may be deployed in an emergency.
- The studies indicate the need for network reinforcements by 2026 as follows:
  - Commission 4th Pockwood Pond – Long Bush 34.5 kV underground circuit
  - Construct new 34.5/13.2 kV substation at Paraquita Bay
- Further work is required to integrate the Power Development Plan with BVIEC's Resiliency Plan, however apart from the abovementioned substation at Paraquita Bay, undergrounding of the transmission line section is also a priority.
- The introduction of solar PV and wind will result in reduction in the overall cost of power production.
- In the longer term (beyond the 2029 horizon) an alternative fossil fuel power plant will be required to provide additional capacity. A second power plant will also increase security of supply. This could utilise a cleaner fuel such as LNG or LPG.

1 INTRODUCTION

1.1 PURPOSE OF THIS STUDY

In October 2015, British Virgin Islands Electricity Corporation (BVIEC) appointed WSP to conduct a power development study for the period from 2016-2027. The work was originally scheduled to be completed by the end of 2017, however Hurricanes Irma and Maria hit BVI with massive impact which put the project on hold for a year.

The revised scope of the study is to provide a power development plan for 2018 -2029, covering generation, transmission and distribution. The aspects covered are described in the Terms of Reference.

In order to ensure the relevance of the study, it was necessary to significantly revise the demand forecast to take account of the devastation caused by the hurricanes. The study also considers the Government of the Virgin Islands Energy Policy, dated 13th October 2016 which includes renewable energy targets, and it considers BVIEC's 2018 Resiliency Plan.

This report includes the draft generation, transmission and distribution development plan and underlying analysis. Financial analysis based on existing tariffs has also been included in this version of the report.

1.2 STRUCTURE OF REPORT

The report is structured as follows.

- Section 2 provides some background on the BVIEC power system and recent developments affecting the study.
- Section 3 includes Base, Low and High Case demand forecasts.
- Section 4 describes the existing generating plants.
- Section 5 discusses the potential to develop renewable energy. A preliminary estimation of solar and wind power potential and possible sites is provided.
- Section 6 describes the generation expansion plan based on PLEXOS analysis.
- Section 7 describes the transmission and distribution network requirements based on IPSA model.
- Section 8 describes the financial analysis
- Section 9 summarise the major findings of the study.

1.3 ACKNOWLEDGEMENTS

WSP wishes to thank the staff of BVIEC and the members of the various Government departments and of the various private organisations with whom meetings and discussions were held, for the invaluable information and assistance they provided.

2 BACKGROUND

2.1 EXISTING SUPPLY

Electricity, generation and distribution throughout the British Virgin Islands (BVI) is the responsibility of the British Virgin Islands Electricity Corporation (BVIEC), which is a Statutory Corporation wholly owned by the Government of the BVI. Standby generation by other parties is permitted, but continuous supply has to be provided by the BVIEC[2].

Figure 2-1 - Map of British Virgin Islands

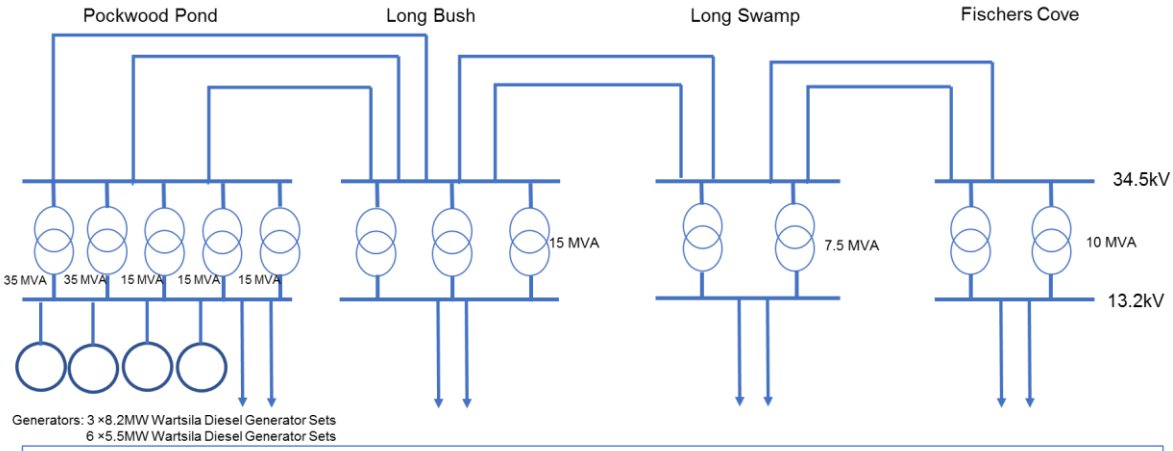


Electricity is generated at Pockwood Pond power station towards the western end of the main island of Tortola using medium speed diesel generators. The supply is three phase 60 Hz, and electricity is transmitted at 34.5 kV and distributed at 13.2 kV before stepping down to low voltage (480 V and 216.5 V three phase and 240 V single phase). The system supplies Tortola and Beef Island, and by sub-sea cables the islands of Virgin Gorda, Jost van Dyke, Little Thatch, Frenchman's Cay, Buck Island, Little and Great Camanoe, Scrub Island, Saba Rock and Marina Cay. There is also a small

[2] With the exception of the supply to the Ocean Conversion desalination plant at Baugher's Bay, and unsupplied islands

diesel station on the island of Anegada independent of the system, but owned and operated by BVIEC. An overview of the BVIEC system is shown in Figure 2-2

Figure 2-2 - Overview of BVIEC Power System



Distribution network comprises a number of 13.2kV feeders from each of the main substations , with customers supplied at 480 V three phase and 240 V single phase via distribution transformers. The 13.2kV feeders also interconnect adjacent substations with normally open points to prevent power transfer on the distribution system.

2.2 HURRICANES IRMA AND MARIA

The BVI experienced three unprecedented weather events in less than six weeks in 2017: extreme floods on 7th August, followed by Hurricanes Irma and Maria – both category 5 hurricanes on 6th September and 20th September respectively. The storms caused extensive damage to the electricity system. All power plants suffered damage and approximately 90% of the transmission and distribution grid was destroyed, including approximately 12,000 poles, 640 km of overhead lines, 2,200 pole-mounted transformers, 3,500 streetlights and some BVIEC offices. Peak demand in January 2018 was approximately 17 MW compared with a peak of 34 MW prior to Hurricane Irma[3]. As of 11th July 2018, the maximum demand had recovered to 23 MW.

2.3 RESILIENCY PLAN

Arising from the devastating impact of Hurricanes Irma and Maria and the lessons learnt, BVIEC drafted a Resiliency Plan to ensure that a continuous supply of electrical energy is rapidly provided to the most essential services around the Territory following similar events. Within this study we make reference to the aspects of the Resiliency Plan that are of relevance and overlap with the Power Development Plan. Further studies would however be required to fully integrate the Resiliency Plan and Power Development Plan.

[3] British Virgin Islands Resilient National Energy Transition Strategy dated 24th April 2018.

2.4 INTRODUCTION OF RENEWABLE ENERGY

BVIEC currently produces all of its electricity from diesel generators, however the British Virgin Islands Electricity Corporation Amendment Act 2015 and British Virgin Islands Electricity Corporation (Renewable Energy) Regulations, 2018 which came into effect on November 1, 2018 means that the Territory now has the legal framework to advance the development of renewable energy..

Further to this, the Government of the Virgin Islands Energy Policy, dated 13th October 2016 includes various energy strategies and policy actions.

The main strategies on the supply side are aimed at reducing dependence on imported oil by increasing the availability and use of alternative fuel sources (such as renewable energy) and conducting long-term planning of resource needs and improving supply-side competition.

The BVI government has set a target to supply 30% of the territory's energy from renewable means by 2023 including:

- Up to 6 MW of wind power
- 2.5 MW of solar power
- 1.5 MW of energy from waste and
- 1 MW of sea/wave or other resources

In this study, we have conducted an economic evaluation of scenarios based on the above targets.

3 ELECTRICITY DEMAND

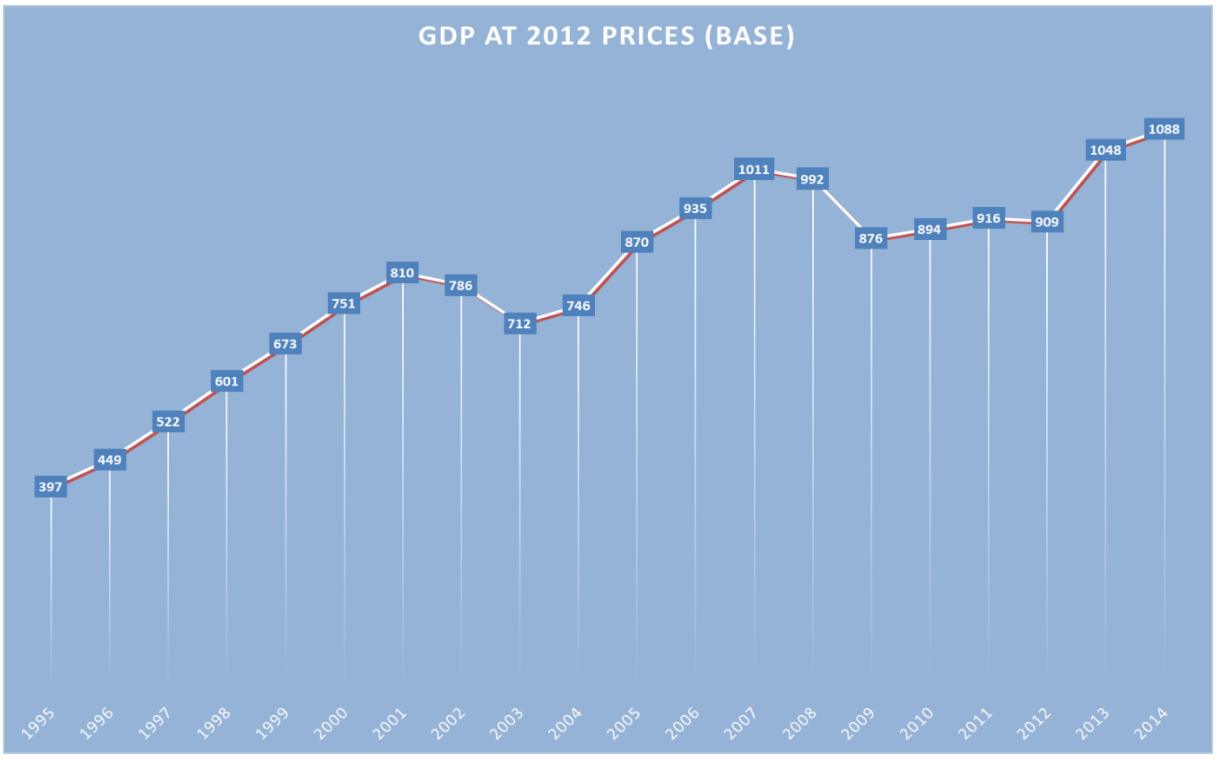
3.1 BACKGROUND

WSP carried out a Power System Development study for the period 2003 to 2013. Low, Base and High Case demand forecast scenarios were prepared for use in the generation, transmission and distribution planning studies as well as the financial analysis.

In 2014 WSP carried out a further study designed to provide a high level strategic analysis of the generation and transmission system for BVIEC.

For both studies the power and energy demand projections adopted an econometric approach, relating electricity use to economic growth by sector. At the turn of the century, the economy in the BVI was predicted to grow at an average rate of 4.6% per annum. The growth in GDP was strong (as expected) up to 2002 when BVI suffered a dip in GDP growth following which GDP growth continued at approximately the same historical growth rate. However, the impact of the global financial recession had its impact from 2009 onwards, and GDP growth since has been relatively slower. Figure 3-1 depicts the trend (the values are shown in 2012 prices in line with the data available).

Figure 3-1 - Historic Total GDP(2012 prices)



Growth in electricity demand has followed the economic trend. Figure 3-2 and Figure 3-3 represent a comparison between the forecast scenarios and actual energy sales and maximum demand respectively. The figures show the adjustment to the projections made in the 2014 study.

Figure 3-2 - Comparison of Generated Energy Forecast with Actual Energy(2003-2015)

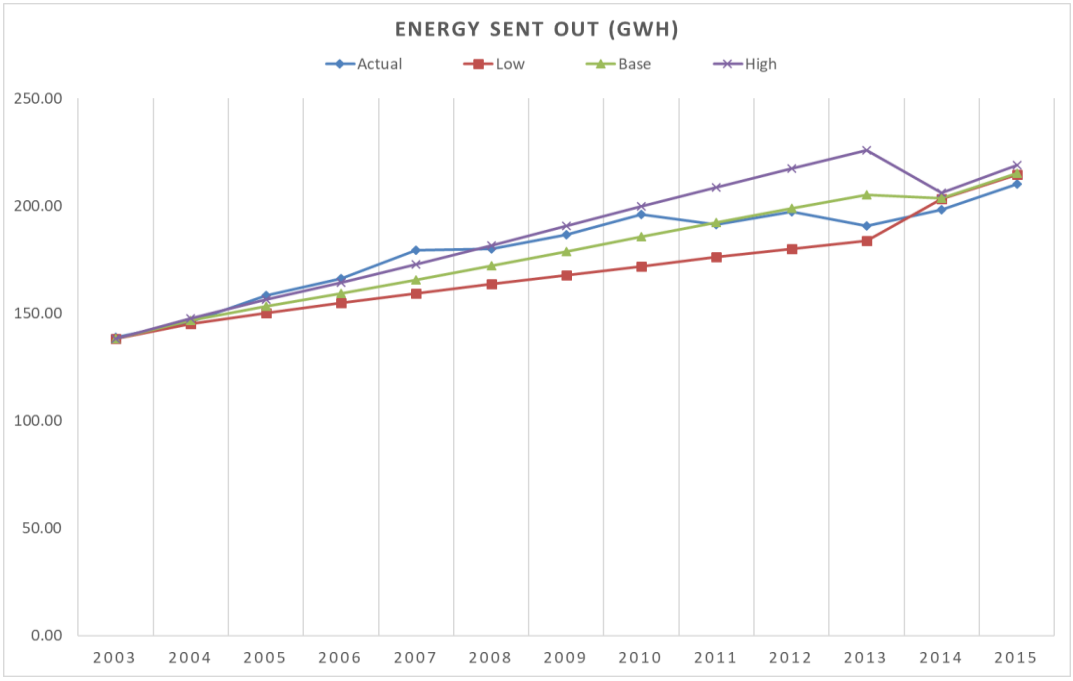
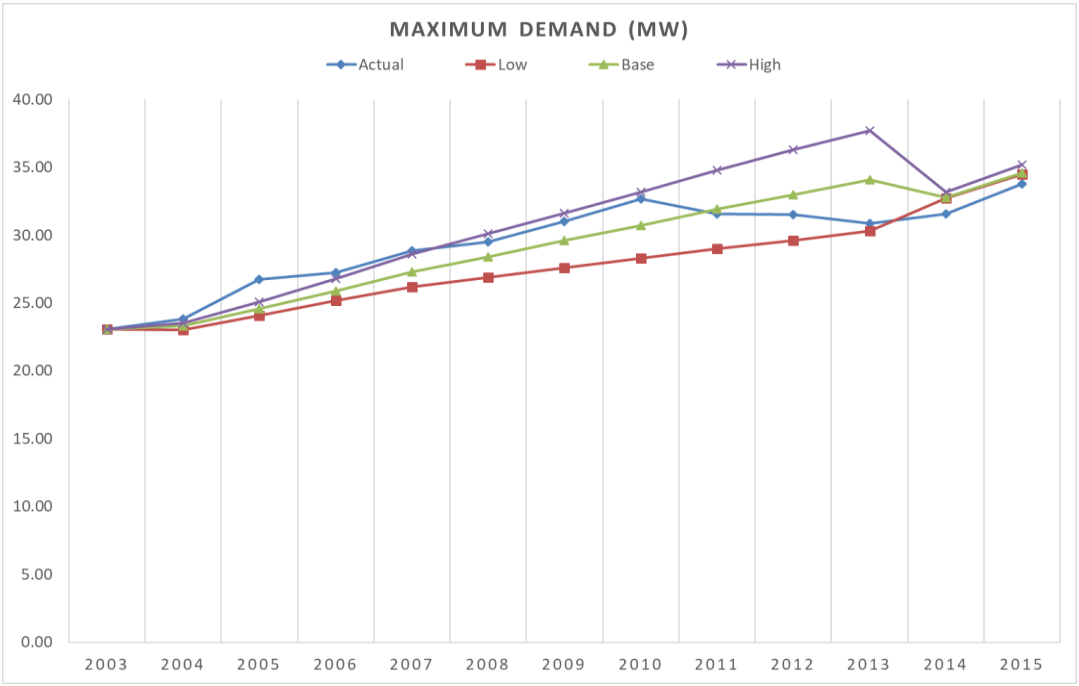


Figure 3-3 - Comparison of Maximum Demand Forecast with Actual Demand (2003-2015)



As a result of the severe hurricane damage, peak demand in January 2018 was approximately 17 MW compared with a peak of 34 MW prior to Hurricane Irma[4]. The maximum demand had reached 23 MW as of July 11, 2018 and by May 2019 the peak demand had reached 25 MW. We have assumed a linear 'rate of recovery' that allows the maximum demand level to return to the '34MW' level experienced in 2016 within the coming 4 years (i.e.; by 2023).

3.2 METHODOLOGY

The demand forecast developed for this study is derived using WSP's own in-house macro-economic multi-variable regression analysis load forecast (RALF) model.

This model investigates the relationships between historical electricity sales for each customer category and economic drivers for consumption, such as population, per capita Gross Domestic Product (GDP) or sector specific GDP.

Where such statistical relationships are found from the historical data, we use these together with forecasts of the economic driving parameters to forecast sector sales of electricity in the future. The general form of the analysis uses the following standard econometric equation:

	Y	=	$A * X_1^B * X_2^C * X_3^D$ …etc.
Taking Logs:	$\text{Log } (Y)$	=	$\log (A) + B \log (X_1) + C \log (X_2) + D \log (X_3)$ …etc.
Where:	Y	=	Sector sales;
	A	=	Constant;
	B, C, D	=	Elasticities of demand (coefficients); and
	X_1, X_2, X_3	=	Independent driving parameters.

Using both linear and logarithmic functions are valid methods of modelling independent variables and have advantages and disadvantages. Logarithmic functions are used in the RALF model to enable marginal changes in the independent variables to be interpreted in terms of percentage changes in the dependent variable and to enable the removal of anomalous distortions in the historical data.

A historical relationship can be determined by analysing the statistical output that the model produces for any combination of consumer category and economic driver. There are three main statistical results that the analyst can use to determine the validity of any historical relationship. These are described below:

- R2 ("R squared") - The R2 statistic describes the correlation between historical sales (the dependent variable) and the economic drivers (the independent variables) selected in the regression. An R2 value of 1 would indicate 'perfect correlation'. Whilst a value of zero would indicate 'no correlation'.

[4] British Virgin Islands Resilient National Energy Transition Strategy dated 24th April 2018.

- Coefficients - The coefficients determine the impact of the economic drivers on historical sales. Regressions should only be accepted if the coefficients appear to be of the correct sign (positive or negative). For example, if price were included in a regression for domestic sales, the analyst should expect the price coefficient to be negative. A negative price coefficient indicates that a fall in price would result in an increase in sales (and vice-versa). The analyst should also expect the coefficients to be of the correct size. For example, the coefficient of any economic driver should not be too large, such that they indicate that a small change in the economic driver would result in an enormous change in the level of sales.
- P- Values - The p-values identify whether the economic drivers are relevant to the regression. A p-value for any specific economic driver that is close to zero indicates that it is very likely that the particular economic driver in question plays a significant role in the determination of the dependant variable.

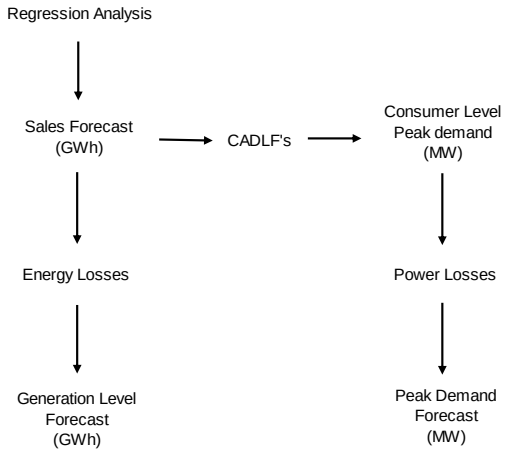
Only those regressions which have fairly high R^2 values (indicating good correlation), coefficients which are of reasonable magnitude and sign and low p-values should be accepted. Even if all these criteria are satisfied, the results obtained from the future projections should always be analysed to ensure that the growth rate is sensible within the context of overall expected energy sales and show limited volatility.

The main premise with such a model is that it assumes that historical relationships will remain valid in the future. For this reason, we interrogate the results of the analysis not only to ensure they are statistically robust, but to identify relationships which would yield credible forecasts. In cases where no statistically robust relationships can be found, or an inappropriate relationship is identified, we can revert to alternative forecasting techniques, such as time series analysis.

Through the adoption of the above guidelines, sales forecasts for each consumer category can be developed. Once sales forecasts have been developed, the model allows for a series of conversions to turn the sales forecasts (GWh) into an energy based generation level forecast (GWh) and a peak power demand forecast (MW) at the generation level. A step by step methodology to the derivation of the load forecast is presented in Figure 3-4.

To derive the generation level energy forecast, system energy losses are added to the sales forecast. The level of losses is defined as “the difference between energy sales and sent out energy from the power station”, hence a forecast for sent out generation can be determined by adding system energy losses to sales. The user can make assumptions relating to system energy losses over the forecast period based on analysis of actual historical system energy losses and any loss reduction programmes that may be known.

Figure 3-4 - Load Forecasting Methodology



To derive the peak demand forecast at the generation level, the model uses the coincident after diversity load factors (CADLF[5]s) and power losses. Load factors for each consumer category are estimated using consumer CADLF's at the sales level.

We have estimated these demands at sales level (i.e. before losses). This is because power losses are higher than energy losses, and if CADLFs were estimated inclusive of losses a change in losses would impact the CADLFs, even though the underlying consumer behaviour may not have changed.

The CADLFs are selected in a manner that ensures that the calculated demand and the estimated demand at consumer level are as close as possible over the historical period under consideration. The above process provides a consumer level peak demand forecast. Power losses are then added to the consumer level demand forecast to produce the peak demand forecast at the generation level. The system load factor is derived by relating the peak demand forecast to the generation level energy forecast.

The RALF model is a data intensive and data sensitive forecasting tool. The model requires the following raw data inputs:

Historical economic data, comprising:

- Population
- GDP broken down by economic activity sectors

Forecasts of economic data, comprising:

- Population forecasts

[5] The CADLF is the load factor that relates energy sales to demand at time of system peak. Therefore, it includes the effects of both diversity (the maximum demand of a group of consumers is less than the sum of the individual demands) and coincidence (the peak demand of a group of consumers may not be at the time of system peak).

- GDP forecasts for each economic sector

Historical energy data, comprising:

- Historical sales data by consumer category
- Historical consumer number data by consumer category
- Historical tariff data by consumer category
- Historical generation (sent out)
- Historical system peaks

We discuss our assumptions relating to each of the inputs above, in the following sections.

3.3 HISTORICAL DEMOGRAPHIC AND ECONOMIC DATA

3.3.1 HISTORICAL POPULATION DATA

Updated national population statistics have been sourced from the BVI Government's Development Planning Unit for the years 2010 to 2017. These have been added to earlier population figures received from BVIEC for the period from 2001 – 2009. The resulting population figures (excluding Anegada[6]) between 2001 and 2017 together with annual growth rates are shown below in Table 3-**3**. The reduction in population in 2017 is assumed to be due to the hurricane damage and is therefore expected to recover in the short-medium term.

Table 3-3 **Historical Population Statistics (2001 - 2017)**

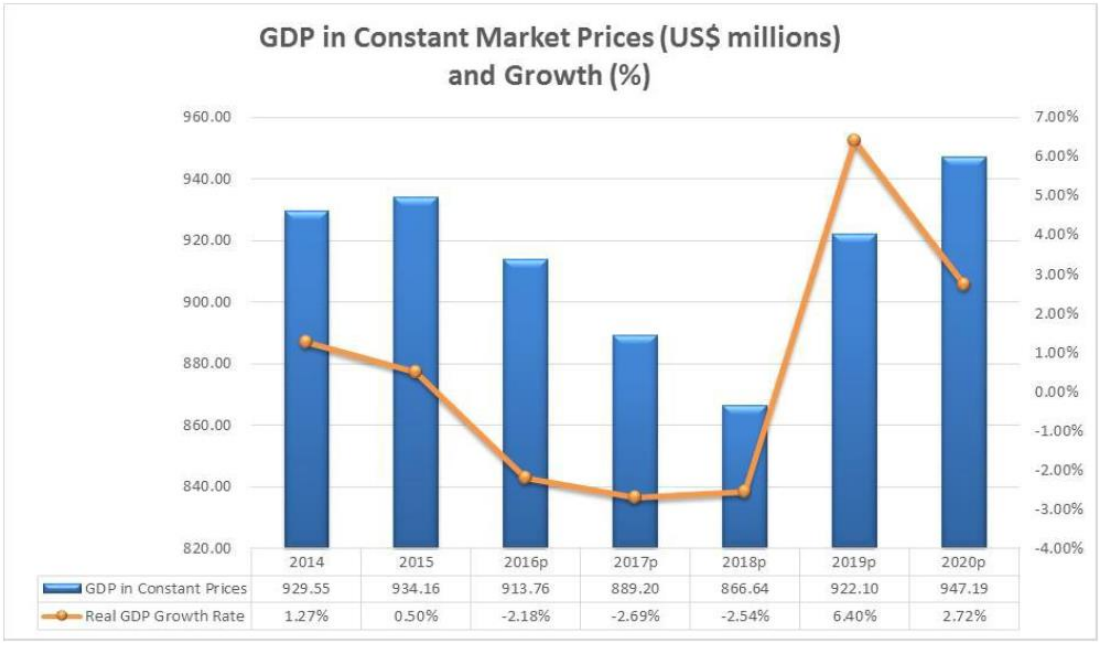
Year	Base	Growth Rate
2001	22,815	
2002	23,246	1.9%
2003	23,674	1.8%
2004	24,363	2.9%
2005	25,042	2.8%
2006	25,718	2.7%
2007	26,604	3.4%
2008	27,664	4.0%
2009	27,601	-0.2%
2010	28,054	1.6%
2011	28,960	3.2%
2012	30,254	4.5%
2013	31,516	4.2%
2014	33,054	4.9%
2015	34,064	3.1%
2016	36,092	6.0%
2017	32,800	-9.1%

[6] Anegada is not electrically connected to the main Island Tortola.

3.3.2 ECONOMIC ACTIVITY

Updated GDP data was obtained from the Government of the Virgin Islands Medium Term Fiscal Plan 2018-2020. As the MTFP was produced in 2018, it is assumed that the figures are in constant 2018 prices.

Figure 3-5 - Real GDP and Growth, 2014-2020



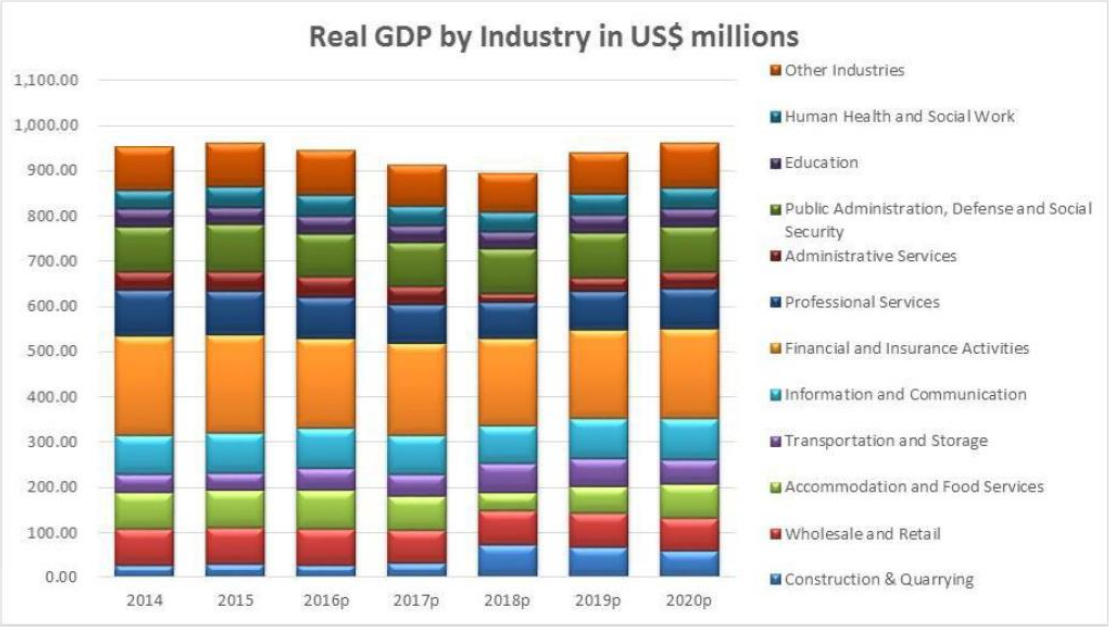
Source: BVI MTFP 2018-2020

The economy increased by 0.5% in real terms between 2014 and 2015. Economic growth was driven mainly by growth in the tourism industry including hotels, charter boats, and transportation, alongside increases in construction, telecommunications, real estate and Government investment.

It is understood that real GDP declined in 2016 by approximately 2.2%, driven by a number of factors including; the effects of unwarranted negative attention from the Panama Papers leak and correspondent bank de-risking on the financial services industry, increasing global economic uncertainty following the UK's decision to leave the European Union, and strong regional competition in tourism.

Further major declines in the economy of 2.69% and 2.54% occurred in 2017 and 2018 respectively due to the natural disasters of 2017. However a strong rebound in growth of 6.4% is expected in 2019, with more usual levels of growth expected in 2020 and beyond. The momentum for growth in 2019 and beyond is expected to come primarily from tourism and related industries, as accommodation and marina services properties are restored and tourist arrivals increase. Recent ongoing and expected investments in the tourism infrastructure across both public and private sectors are expected to buttress economic growth in the coming months and years.

Figure 3-6 - Real GDP by Industry



3.4 ECONOMIC AND DEMOGRAPHIC DATA FORECAST

3.4.1 POPULATION PROJECTION

Table 3-4 projects the population forecast based on population data provided by the BVI Government's Development Planning Unit for the years 2010 to 2017.

Table 3-4 BVI Population Forecast (2018 - 2029)

Year	Base	Growth Rate	Low	Growth Rate	High	Growth Rate
2018	32800	1.6%	32607	1.4%	32993	1.8%
2019	33310	1.6%	33048	1.4%	33573	1.8%
2020	33826	1.5%	33495	1.4%	34161	1.8%
2021	34350	1.6%	33946	1.3%	34759	1.7%
2022	34881	1.5%	34403	1.3%	35365	1.7%
2023	35418	1.5%	34865	1.3%	35981	1.7%
2024	35965	1.5%	35332	1.3%	36607	1.7%
2025	36516	1.5%	35803	1.3%	37242	1.7%

Year	Base	Growth Rate	Low	Growth Rate	High	Growth Rate
2026	37076	1.5%	36280	1.3%	37887	1.7%
2027	37641	1.5%	36762	1.3%	38542	1.7%
2028	38216	1.5%	37249	1.3%	39207	1.7%
2029	38800	1.5%	37743	1.3%	39884	1.7%

3.4.2 ECONOMIC ACTIVITY

The Territory's nominal GDP fell from USD 915.6 million in 2011 to USD 909.4 million in 2012 – a decline of 0.68 per cent. This is in contrast to significant growth between 2009 and 2011 of approximately 2.2 per cent, evidencing a potential recovery from the global economic crisis.

Increased investment in the physical infrastructure of the Territory in the medium term through planned capital projects, such as the Cruise Pier Development, the Terrance B. Lettsome Airport Expansion, and the Sewerage Project, are expected to stimulate the construction sector in the economy. The stimulus to this sector would contribute to and maintain the economic recovery in the Territory.

However, a sustainable level of economic growth in the medium to long term is still highly dependent on improvements in the global economy. A slower than expected global economic recovery could translate to lower growth prospects for the Virgin Islands.

This caution on global recovery is a major factor in drawing up our assumptions for future growth.

Due to the present unstable financial environment that exists worldwide, and considering the strong relationship between BVI economic development and tourism, three different scenarios were developed for the BVI GDP forecast from 2018 to 2029.

The BVI has in the past enjoyed a prominent position in the Caribbean for cruise ship arrivals but recent strong competition from other islands has somewhat eroded its ranking. Despite the cruise pier development, which is intended to increase overall passenger numbers, continuing strong competition will place pressure on the BVI to maintain its key role.

Similarly, financial services are facing pressure as a result of competition but of more concern is the clampdown by the EU and the USA on registered companies in jurisdictions such as the BVI. This will lead to some reduction in activity but it is hard at this stage to predict the extent of such reductions.

Due to the absence of GDP projections from official BVI Government sources, we have derived three projections based on extrapolation of the historical data. We have designed our scenarios adopting linear, power and logarithmic trend lines for projecting the high, base and low growth scenarios respectively. Our proposed base, high and low projections for total GDP are set out in Table 3-5.

Table 3-5: GDP Projections Adopted for this Study (USD Millions)

Year	GDP Base	Tourism GDP Base	GDP High	Tourism GDP High	GDP Low	Tourism GDP Low
2018	1153	359	1208	376	1130	350
2019	1168	364	1238	386	1139	353
2020	1182	369	1268	396	1148	356
2021	1197	375	1298	406	1156	359
2022	1210	380	1328	417	1165	361
2023	1224	385	1359	427	1173	364
2024	1237	390	1389	437	1180	367
2025	1250	394	1419	447	1188	369
2026	1262	399	1449	457	1195	371
2027	1275	403	1479	467	1202	374
2028	1287	408	1509	477	1209	376
2029	1299	412	1539	487	1215	378

3.5 HISTORICAL ENERGY DATA

Historical energy records made available from BVIEC cover the period from 2003 to 2015. Based on the information received, four key consumer categories have been identified. The consumer categories assumed for this study are described as follows:

- Domestic
- Commercial
- Industrial
- Street Lighting

For each of the consumer categories defined above, it has been possible to compile information on:

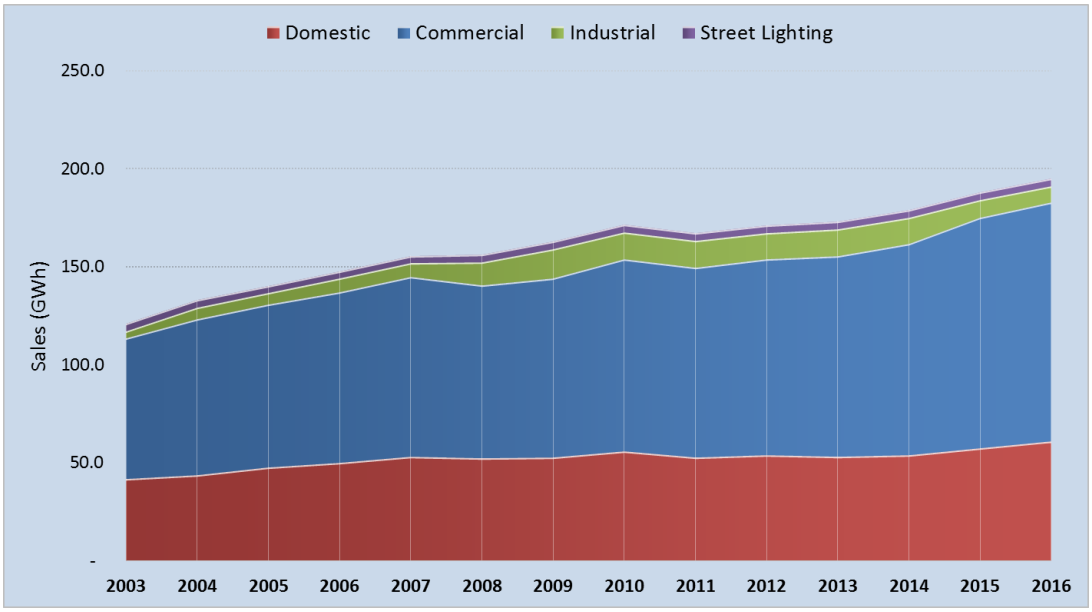
- Energy sales (GWh)
- Tariff (USD per kWh)
- Number of consumers, and
- Specific consumption (kWh per consumer)

Table 3-6 presents the energy data by consumer category and the system data used in this study. Figure 3-7 illustrates the evolution of sales by customer category, number of customers and specific consumption between 2003 and 2016.

Table 3-6 Historical Energy Data (2003-2016)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Domestic														
Sales (GWh)	41.9	43.9	47.8	50.1	53.4	52.4	52.6	55.7	52.9	53.8	53.1	53.9	57.4	61.2
Tariff in USD per kWh	0.246	0.261	0.271	0.316	0.315	0.383	0.308	0.343	0.403	0.411	0.403	0.393	0.309	0.280
No. of Consumers	10,451	10,837	11,210	11,562	11,972	12,364	12,573	12,942	13,276	13,606	13,907	14,085	14,271	14,392
Specific Consumption (kWh per connection)	4,010	4,055	4,263	4,333	4,457	4,239	4,184	4,307	3,987	3,953	3,816	3,824	4,025	4,251
Commercial														
Sales (GWh)	71.4	79.3	82.8	87.1	91.3	88.1	91.3	98.1	96.5	100.1	102.5	107.7	117.5	121.8
Tariff in USD per kWh	0.221	0.228	0.271	0.293	0.292	0.362	0.286	0.321	0.380	0.386	0.380	0.367	0.281	0.251
No. of Consumers	1,683	1,736	1,821	1,840	1,913	1,958	2,200	2,175	2,194	2,241	2,259	2,288	2,309	2,305
Specific Consumption (kWh per connection)	42,428	45,663	45,494	47,313	47,723	45,006	41,505	45,083	44,004	44,651	45,371	47,077	50,891	52,862
Industrial														
Sales (GWh)	3.8	6.1	6.0	6.8	7.2	11.8	15.1	14.0	13.7	13.5	13.7	13.6	9.1	8.1
Tariff in USD per kWh	0.220	0.230	0.438	0.280	0.281	0.335	0.257	0.295	0.356	0.363	0.354	0.344	0.268	0.237
No. of Consumers	37	36	36	35	54	53	39	25	25	23	24	25	25	25
Specific Consumption (kWh per connection)	103,730	168,678	165,438	195,578	132,512	222,668	387,352	558,006	546,193	586,293	569,575	543,640	362,560	323,318
Street Lighting														
Sales (GWh)	3.7	3.7	3.7	3.7	3.7	3.8	3.8	3.8	3.8	3.9	3.9	3.9	3.9	3.9
Tariff in USD per kWh	0.29	0.30	0.34	0.36	0.36	0.42	0.35	0.39	0.44	0.45	0.45	0.43	0.35	0.32
No. of Consumers	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Specific Consumption (MWh per connection)	3,691	3,711	3,726	3,739	3,742	3,762	3,778	3,825	3,844	3,860	3,862	3,863	3,863	3,863
Generation Sent Out (GWh)	139	146	158	166	179	180	187	196	191	197	191	198	210	217
Energy Losses (%)	13.0%	8.9%	11.4%	11.1%	13.3%	13.3%	12.8%	12.5%	12.7%	13.2%	9.2%	9.7%	10.6%	10.2%
System Maximum Demand (MW)	23.08	23.84	26.75	27.24	28.84	29.51	31.02	32.66	31.56	31.5	30.85	31.58	33.79	34.01
System Load Factor (%)	68.7%	69.9%	67.6%	69.6%	71.0%	69.7%	68.7%	68.5%	69.2%	71.5%	70.6%	71.7%	71.0%	72.7%

Figure 3-7 - Historical Sales Per Consumer Category(2003-2016)



3.6 SALES FORECASTS

Using the RALF model, we have developed regression based sales forecasts for each of the four defined consumer categories (Domestic, Commercial, Industrial and Street Lighting). Bringing together the regression based sales forecast for all the different consumer categories we produced the total sales forecast. The following sections present the regression based sales forecasts for the Base, High and Low demand scenarios.

Recognising that the maximum demand in 2018 has dropped down to 23 MW as of July 11, 2018 and had reached 25 MW by May 2019. We have assumed a linear 'rate of recovery' that allows the

maximum demand level to return to the '34MW' level experienced in 2016 within the coming 4 years (i.e. by 2023).

We have utilised the results of the regression analysis performed using the historical sales provided by BVIEC for 2003 up to and including 2016 and adopted an annual growth rate of 2.5% per annum for the years 2024 to 2029.

We understand that all streetlights are being replaced now with LED fixtures, which are significantly more efficient than the older streetlights. By April 2019, 63% of streetlights had been reinstated following hurricane damage and full reinstatement is anticipated by 2020. We have assumed energy sales for street lighting to be one third of pre-Irma levels in 2018, increasing to 50% by 2020 (reflecting the higher efficiency of the LED fixtures). Thereafter, an annual growth rate for street-lighting of 0.35%, 0.40% and 0.32% are assumed for the Base, High and Low demand forecast scenarios respectively.

3.6.1 BASE CASE SALES FORECAST

'Regression Based' energy sales forecast is set out in Table 3-7 where energy sales are expected to recover by 2024 to the 2016 levels. Energy sales are expected to reach 220 GWh in 2029.

Table 3-7: Regression Based Sales Forecast (Base Scenario)

Regression Based Sales Forecast

Electricity Sales (GWh)					
Year	Domestic	Commercial	Industrial	Street Lighting	Total
2018	40.4	80.5	6.1	1.3	128.3
2019	44.3	88.2	6.7	1.6	140.7
2020	48.1	95.9	7.3	1.9	153.2
2021	52.0	103.6	7.9	1.9	165.4
2022	55.9	111.3	8.5	1.9	177.6
2023	59.8	119.0	9.1	2.0	189.8
2024	61.3	122.0	9.3	2.0	194.5
2025	62.8	125.0	9.5	2.0	199.3
2026	64.3	128.1	9.8	2.0	204.2
2027	65.9	131.3	10.0	2.0	209.2
2028	67.6	134.5	10.3	2.0	214.3
2029	69.2	137.9	10.5	2.0	219.6

3.6.2 HIGH DEMAND FORECAST SCENARIO

'Regression Based' energy sales forecast is set out in Table 3-8 where energy sales are expected to recover by 2023 to the 2016 levels. Energy sales are expected to reach 230 GWh in 2029.

Table 3-8 Regression Based Sales Forecast (High Scenario)

Regression Based Sales Forecast

Electricity Sales (GWh)					
Year	Domestic	Commercial	Industrial	Street Lighting	Total
2018	40.4	80.5	6.1	1.3	128.3
2019	45.2	90.1	6.9	1.4	143.7
2020	50.1	99.8	7.6	1.5	159.0
2021	54.9	109.4	8.3	1.7	174.4
2022	59.8	119.1	9.1	1.8	189.7
2023	61.5	122.4	9.3	1.9	195.1
2024	63.2	125.9	9.6	1.9	200.6
2025	65.0	129.4	9.9	1.9	206.2
2026	66.8	133.1	10.1	1.9	212.0
2027	68.7	136.8	10.4	1.9	217.9
2028	70.6	140.7	10.7	1.9	224.0
2029	72.6	144.6	11.0	1.9	230.2

3.6.3 LOW DEMAND FORECAST SCENARIO

'Regression Based' energy sales forecast is set out in Table 3-9 where energy sales are expected to recover by 2025 to the 2016 levels. Energy sales are expected to reach 203 GWh in 2029.

Table 3-9 Regression Based Sales Forecast(Low Scenario)

Regression Based Sales Forecast

Electricity Sales (GWh)					
Year	Domestic	Commercial	Industrial	Street Lighting	Total
2018	40.4	80.4	6.1	1.3	128.2
2019	43.6	86.8	6.6	1.4	138.5
2020	46.8	93.3	7.1	1.5	148.7
2021	50.1	99.7	7.6	1.6	159.0
2022	53.3	106.1	8.1	1.7	169.2
2023	56.5	112.6	8.6	1.8	179.5
2024	59.8	119.0	9.1	1.9	189.8
2025	61.1	121.7	9.3	1.9	194.1
2026	62.5	124.5	9.5	1.9	198.5
2027	64.0	127.4	9.7	1.9	203.0

3.6.4 ADDITIONAL LOADS

Additional loads have been identified and processed as part of the demand forecast presented in the Inception report (August 2017). Following the recent exchanged correspondence in 2018, the anticipated demands are summarised Table 3-10.

Table 3-10 BVI Additional Loads – (Base Scenario)

ADDITIONAL LOADS

				Annual Load Growth (MW) - Peak Maximum Demand at the Consumer Level				
No.	Development	Consumer Category	Total Load (MW)	2019	2020	2021	2022	2023
1	**VG Hospital**	**Commercial**	1.0	**0.20**	**0.20**	**0.20**	**0.20**	**0.20**
2	**Water Disalination**	**Industrial**	0.0	**-**	**-**	**-**	**-**	**-**
3	**Cruise Ship Pier**	**Commercial**	1.2	**-**	**0.18**	**0.18**	**0.36**	**-**
4	**Sewerage Treatment Plant**	**Industrial**	0.4	**0.40**	**-**	**-**	**-**	**-**
5	**Airport Development**	**Commercial**	0.8	**-**	**0.30**	**0.30**	**0.15**	**-**
6	**Peebles Hospital Growth**	**Commercial**	1.0	**-**	**-**	**0.50**	**0.50**	**-**
			4.4	0.6	0.7	1.2	1.2	0.2

We have assumed a ±10% variation in total MW of additional loads for the 'High' and 'Low' demand forecast scenarios. These are summarised in Table 3-11 and Table 3-12 below.

Table 3-11 BVI Additional Load – (High Scenario)

ADDITIONAL LOADS

			110%	Annual Load Growth (MW) - Peak Maximum Demand at the Consumer				
No.	Development	Consumer Category	Total Load (MW)	2019	2020	2021	2022	2023
1	**VG Hospital**	**Commercial**	1.10	**0.22**	**0.22**	**0.22**	**0.22**	**0.22**
2	**Water Disalination**	**Industrial**	0.00	**-**	**-**	**-**	**-**	**-**
3	**Cruise Ship Pier**	**Commercial**	1.32	**-**	**0.20**	**0.20**	**0.40**	**-**
4	**Sewerage Treatment Plant**	**Industrial**	0.44	**0.44**	**-**	**-**	**-**	**-**
5	**Airport Development**	**Commercial**	0.83	**-**	**0.33**	**0.33**	**0.17**	**-**
6	**Peebles Hospital Growth**	**Commercial**	1.10	**-**	**-**	**0.55**	**0.55**	**-**
7				**-**	**-**	**-**	**-**	**-**
50				**-**	**-**	**-**	**-**	**-**
			4.79	0.7	0.7	1.3	1.3	0.2

Table 3-12 BVI Additional Load – (Low Scenario)

ADDITIONAL LOADS

			90%	Annual Load Growth (MW) - Peak Maximum Demand at the Consumer Level				
No.	Development	Consumer Category	Total Load (MW)	2019	2020	2021	2022	2023
1	VG Hospital	Commercial	0.9	0.18	0.18	0.18	0.18	0.18
2	Water Disalination	Industrial	0.0	-	-	-	-	-
3	Cruise Ship Pier	Commercial	1.1	-	0.16	0.16	0.32	-
4	Sewerage Treatment Plant	Industrial	0.4	0.36	-	-	-	-
5	Airport Development	Commercial	0.7	-	0.27	0.27	0.14	-
6	Peebles Hospital Growth	Commercial	0.9	-	-	0.45	0.45	-
7				-	-	-	-	-
50				-	-	-	-	-
			3.9	0.5	0.6	1.1	1.1	0.2

3.6.5 TOTAL SALES FORECAST

The sum of all energy sales forecasts on a year-by-year basis gives the total forecast energy sales for BVI. Table 3-13 presents the cumulative results of regression based energy sales forecast while Table 3-13,Table 3-14 and Table 3-15 show the total energy sales forecast, inclusive of the additional loads, for the base case scenario, high demand scenario and low demand scenario respectively.

Table 3-13: Regression based sales forecast with additional load (Base Scenario)

Sales Forecast with Additional Loads

Electricity Sales (GWh)					
Year	Domestic	Commercial	Industrial	Street Lighting	Total Sales
2018	40.4	80.5	6.1	1.3	128.3
2019	44.3	89.5	9.0	1.6	144.3
2020	48.1	101.6	9.6	1.9	161.3
2021	52.0	117.1	10.2	1.9	181.2
2022	55.9	132.8	10.8	1.9	201.4
2023	59.8	141.8	11.4	2.0	214.9
2024	61.3	144.8	11.6	2.0	219.6
2025	62.8	147.8	11.8	2.0	224.4
2026	64.3	150.9	12.0	2.0	229.3
2027	65.9	154.1	12.3	2.0	234.3
2028	67.6	157.3	12.5	2.0	239.4
2029	69.2	160.7	12.8	2.0	244.7

Table 3-14 Regression based sales forecast with additional loads (High Scenario)

Sales Forecast with Additional Loads

Electricity Sales (GWh)					
Year	Domestic	Commercial	Industrial	Street Lighting	Total Sales
2018	40.4	80.5	6.1	1.3	128.3
2019	45.2	91.6	9.4	1.4	147.6
2020	50.1	106.1	10.1	1.5	167.9
2021	54.9	124.3	10.8	1.7	191.7
2022	59.8	142.7	11.6	1.8	215.9
2023	61.5	147.5	11.8	1.9	222.7
2024	63.2	151.0	12.1	1.9	228.2
2025	65.0	154.5	12.4	1.9	233.8
2026	66.8	158.2	12.7	1.9	239.6
2027	68.7	161.9	12.9	1.9	245.5
2028	70.6	165.8	13.2	1.9	251.6
2029	72.6	169.7	13.5	1.9	257.8

Table 3-15 Regression based sales forecast with additional load (Low Scenario)

Sales Forecast with Additional Loads

Electricity Sales (GWh)					
Year	Domestic	Commercial	Industrial	Street Lighting	Total Sales
2018	40.4	80.4	6.1	1.3	128.2
2019	43.6	88.0	8.7	1.4	141.7
2020	46.8	98.5	9.2	1.5	156.0
2021	50.1	111.9	9.7	1.6	173.2
2022	53.3	125.5	10.1	1.7	190.6
2023	56.5	133.1	10.6	1.8	202.1
2024	59.8	139.5	11.1	1.9	212.3
2025	61.1	142.3	11.3	1.9	216.6
2026	62.5	145.0	11.5	1.9	221.0
2027	64.0	147.9	11.8	1.9	225.5
2028	65.4	150.8	12.0	1.9	230.1
2029	66.9	153.7	12.2	1.9	234.8

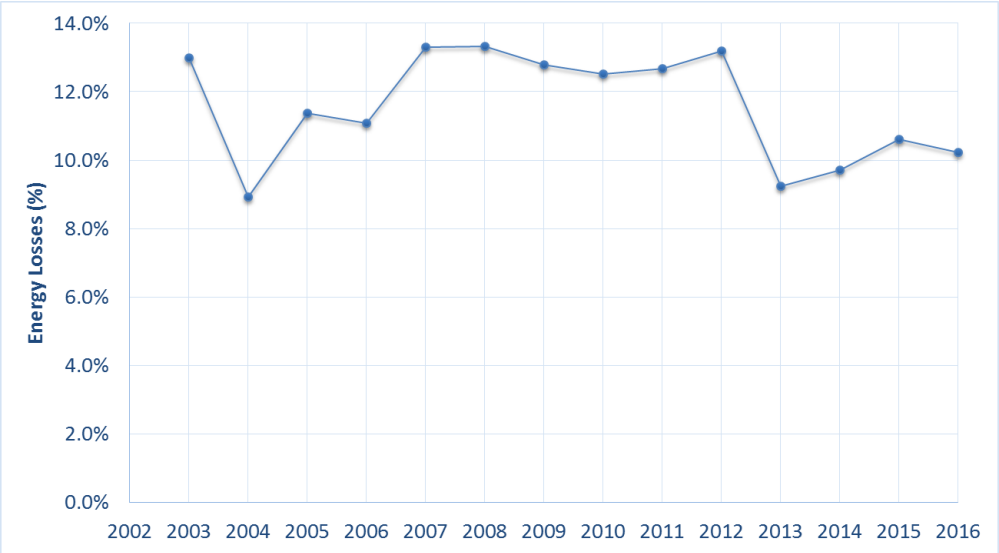
3.7 DEMAND FORECAST

Figure 3-4 highlighted the steps required to convert the sales forecast into a maximum MW demand forecast. In the following sections we discuss each of the steps followed/completed for this conversion.

3.7.1 LOSSES

Energy losses are defined as the difference between energy sales and sent out energy from the power stations. In the RALF model the addition of system energy losses to the forecast of sales provides a forecast of sent out generation. To derive the sent-out generation forecast it is therefore necessary to make assumptions regarding the forecast of system losses into the future. Figure 3-8 presents the historical energy losses provided by BVIEC for the period 2003 to 2015.

Figure 3-8 - Historical Energy Losses(2003-2015)



It is reasonable to expect that there will be some non-technical losses (metering and billing errors as well as possible unmetered consumption) with the result that the actual energy consumed and the demand at the 'sent out' terminals will be greater than the sales figures.

There will also be technical losses. Technical losses are dominated by resistive losses which are proportional to the square of the load supplied for a given system.

Adding the technical and non-technical losses to the energy sold and maximum power demand due to sales gives the sent-out energy and power.

Considering the subsea interconnections between Tortola and the nearby islands (Virgin Gorda, Saba Rock, Jost van Dyke, Little Thatch, Buck Island, Little and Great Camanoe, Scrub Island and Marine Cay); system losses can be of the expected level similar to other island systems. For this study, we have assumed that the long-term average transmission and distribution losses are likely to remain at the current historical average of 12.0%.

3.7.2 CADLF'S

We have estimated the load factors for each consumer category using consumer coincident after diversity load factors (CADLF's) at the sales level. The CADLF is the load factor that relates energy sales to demand at time of system peak. Therefore, it includes the effects of both 'diversity' (the maximum demand of a group of consumers is less than the sum of the individual demands) as well as 'coincidence' (the peak demand of a group of consumers may not be at the time of system peak). We have estimated these demands before power losses are considered. This is because power losses are higher than energy losses. If CADLFs are measured after losses, then any change in

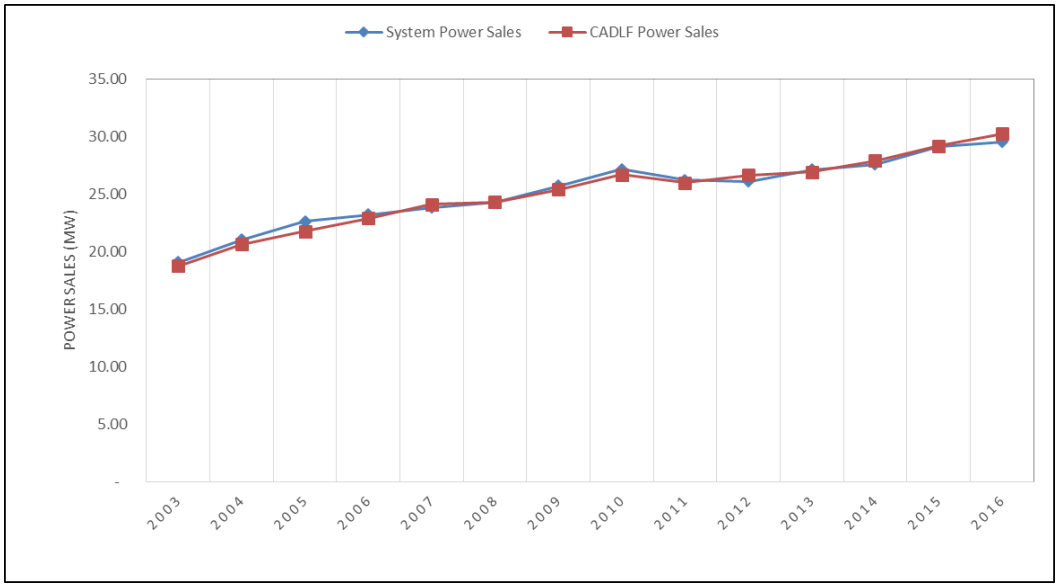
losses will change the CADLFs, even though the underlying consumer behaviour may not have changed.

The CADLFs are estimated by ensuring that the calculated demand at consumer level and the estimated demand at the same level are as close as possible over the time period under consideration. Table 3-16 sets out the CADLFs for each consumer group. Figure 3-9 presents the correlation between actual system power sales and the assumed CADLF.

Table 3-16: CADLFs by Consumer Category

Consumer Category	CADLF(%)
Domestic	75%
Commercial	75%
Industrial	65%
Street Lighting	50%

Figure 3-9 – System power sales vs. CADLF based power sales



3.7.3 SENT OUT GENERATION AND MAXIMUM DEMAND FORECASTS

Using the CADLFs and the projected level of transmission and distribution energy losses, we have derived the sent-out generation and maximum demand.

The level of power losses is derived using the empirical formula:

Power losses% = Energy losses %/(α + (1 - α)*consumer level load factor)

Where α = 0.2 for developed countries and 0.3 for less developed countries. We have assumed 0.2 for this study.

The above calculation yields a value for power losses at peak demand of 14.9%. Power losses during peak demand hours are added to the after diversity maximum demand at consumer level to derive the sent out MW maximum demand.

Table 3-17, Table 3-18 and Table 3-19 set out a summary of the projected demand for energy and the expected maximum demand for base, high and low demand forecast scenarios respectively.

Table 3-17: Demand Forecast – Base Scenario

Energy Set Out and System maximum Demand

Year	Total Sales (GWh)	Total Losses (GWh)	Energy Sent Out (GWh)	Max Demand at Consumer Level (MW)	Consumer Level Load Factor (%)	Power Losses (%)	Maximum Demand (MWso)	Power Load Factor (%)	Maximum Demand Growth (%)
2018	128	18	146	20	74.1%	14.6%	23.2	71.9%	-1.5%
2019	144	20	164	22	73.9%	14.6%	26.1	71.7%	12.9%
2020	161	22	183	25	73.9%	14.6%	29.2	71.7%	11.7%
2021	181	25	206	28	74.0%	14.6%	32.8	71.8%	12.2%
2022	202	27	229	31	74.0%	14.6%	36.4	71.8%	11.0%
2023	215	29	244	33	74.1%	14.6%	38.8	71.9%	6.7%
2024	220	30	250	34	74.1%	14.6%	39.7	71.9%	2.2%
2025	224	31	255	35	74.1%	14.6%	40.5	71.9%	2.2%
2026	229	31	261	35	74.1%	14.6%	41.4	71.9%	2.2%
2027	234	32	266	36	74.1%	14.6%	42.3	71.9%	2.2%
2028	239	33	272	37	74.1%	14.6%	43.2	71.9%	2.1%
2029	245	33	278	38	74.1%	14.6%	44.1	71.9%	2.2%

Table 3-18: Demand Forecast - High Scenario

Energy Set Out and System maximum Demand

Year	Total Sales (GWh)	Total Losses (GWh)	Energy Sent Out (GWh)	Max Demand at Consumer Level (MW)	Consumer Level Load Factor (%)	Power Losses (%)	Maximum Demand (MWso)	Power Load Factor (%)	Maximum Demand Growth (%)
2018	128.4	17.5	145.9	19.8	74.1%	14.6%	23.2	71.9%	-1.5%
2019	147.7	20.1	167.9	22.8	73.9%	14.6%	26.7	71.7%	15.3%
2020	168.0	22.9	190.9	25.9	74.0%	14.6%	30.4	71.8%	13.6%
2021	191.9	26.2	218.0	29.6	74.0%	14.6%	34.6	71.8%	14.1%
2022	216.0	29.5	245.4	33.3	74.1%	14.6%	39.0	71.9%	12.5%
2023	222.8	30.4	253.2	34.3	74.1%	14.6%	40.2	71.9%	3.2%
2024	228.3	31.1	259.4	35.2	74.1%	14.6%	41.2	71.9%	2.4%
2025	233.9	31.9	265.8	36.0	74.1%	14.6%	42.2	71.9%	2.4%
2026	239.7	32.7	272.4	36.9	74.1%	14.6%	43.2	71.9%	2.5%
2027	245.6	33.5	279.1	37.8	74.1%	14.6%	44.3	71.9%	2.5%
2028	251.6	34.3	285.9	38.7	74.1%	14.6%	45.4	71.9%	2.4%
2029	257.8	35.2	292.9	39.7	74.1%	14.6%	46.5	71.9%	2.5%

Table 3-19: Demand Forecast - Low Scenario

Energy Set Out and System maximum Demand

Year	Total Sales (GWh)	Total Losses (GWh)	Energy Sent Out (GWh)	Max Demand at Consumer Level (MW)	Consumer Level Load Factor (%)	Power Losses (%)	Maximum Demand (MWso)	Power Load Factor (%)	Maximum Demand Growth (%)
2018	128	18	146	20	74.1%	14.6%	23.2	71.9%	-1.5%
2019	142	19	161	22	74.0%	14.6%	25.6	71.7%	10.7%
2020	156	21	177	24	74.0%	14.6%	28.2	71.8%	10.0%
2021	173	24	197	27	74.0%	14.6%	31.3	71.8%	11.0%
2022	191	26	217	29	74.1%	14.6%	34.4	71.9%	10.0%
2023	202	28	230	31	74.1%	14.6%	36.5	71.9%	6.0%
2024	212	29	241	33	74.1%	14.6%	38.3	71.9%	5.1%
2025	217	30	246	33	74.1%	14.6%	39.1	71.9%	2.0%
2026	221	30	251	34	74.1%	14.6%	39.9	71.9%	2.0%
2027	226	31	256	35	74.1%	14.6%	40.7	71.9%	2.0%
2028	230	31	261	35	74.1%	14.6%	41.5	71.9%	2.0%
2029	235	32	267	36	74.1%	14.6%	42.4	71.9%	2.0%

4 EXISTING GENERATION

4.1 EXISTING POWER SYSTEM

Electricity is generated at Pockwood Pond power station on Tortola. The supply is three phase 60 Hz, and energy is transmitted at 34.5 kV and distributed at 13.2 kV and low voltage. The system supplies Tortola, Frenchman's Cay and Beef Island, and by sub-sea cables the islands of Virgin Gorda, Jost van Dyke, Little Thatch, Buck Island, Little and Great Camanoe, Scrub Island and Marina Cay. There is also a small diesel station on the island of Anegada independent of the system, but owned and operated by BVIEC.

4.1.1 LONG BUSH

The Long Bush power station was retired at the beginning of 2017 and will be decommissioned.

4.1.2 POCKWOOD POND

Pockwood Pond power station was built with the intention of relocating the generating plant away from the centre of Road Town. Initially two Mirrlees K6 Major Mk III engines of 3.1 MW each (Units 1 and 2) were installed and commissioned in May 1990. These sets were radiator cooled, with closed-circuit air-blast radiators. These two units have retired in place.

In 1995 two Stork Wartsila diesel generator sets (Units 3 and 4), each rated 5.5 MW were added. A seawater cooling system was included in the contract for these sets. As well as providing for the cooling needs, the seawater cooling system had the capacity for conversion of Mirrlees Units 1 and 2 to sea-water cooling and for desalination using waste heat recovery.

In 2006 and 2007 four more Wartsila diesel generator sets (Units 5, 6, 7 and 8) were added, each 5.5 MW and in 2013 a Cummins high speed diesel generator set was added. The Cummins unit is used for black-start.

In early 2017, three further Wartsila diesel generator sets (Unit 10, Unit 11 and Unit 12) were commissioned, each with a net capacity of 8.5 MW.

4.1.2.1 Generator Parameters

Table 4-1 lists the existing generating units at Pockwood Pond power station with assumptions regarding key parameters described below:

- Retirement dates are based on a 25 year economic life of the units. (In the case of Units 3 and 4 however, due to relatively low utilisation levels, the economic life has been extended to 31 years at a derated output of 5.0 MW.)
- The rating of the units is expressed in terms of net output and a minimum stable loading level of 50% was assumed.
- Heat rates for Units 1-4 were taken from the 2002 report, while heat rates for the newer units were calculated from fuel consumption during the performance tests at loading levels of 100, 75 and 50% of full loading.
- The fixed and variable O&M costs were derived from BVIEC's statistics for costs and levels of production for 2016.
- Planned and unplanned outage rates were taken from the 2002 report and applied to the newer units.

Table 4-1 – Pockwood Pond Generating Units – Key Parameters

Unit	Make	Model	Speed (RPM)	Commission Year	Decommission Year	Net output (MW)	Minimum load (%)	Full load heat rate (GJ/MWh)	75% load heat rate (GJ/MWh)	Min load heat rate (GJ/MWh)
1	Mirrlees	KMAJMK3	600	1990	Retired in place	3.1	50%	9.42	9.40	9.76
2	Mirrlees	KMAJMK4	600	1990	Retired in place	3.1	50%	9.42	9.40	9.76
3	Stork/Wartsila	SW38	600	1995	2026	5.0	50%	9.38	9.55	10.08
4	Stork/Wartsila	SW38	600	1995	2026	5.0	50%	9.38	9.55	10.08
5	Wartsila	9L38A2	600	2007	2032	5.5	50%	8.41	8.45	8.64
6	Wartsila	9L38A2	600	2007	2032	5.5	50%	8.41	8.45	8.64
7	Wartsila	9L38A2	600	2006	2031	5.5	50%	8.41	8.45	8.64
8	Wartsila	9L38A2	600	2006	2031	5.5	50%	8.41	8.45	8.64
10	Wartsila	9L46	514	2017	2042	8.5	50%	8.37	8.43	8.82
11	Wartsila	9L46	514	2017	2042	8.5	50%	8.37	8.43	8.82
12	Wartsila	9L46	514	2017	2042	8.5	50%	8.37	8.43	8.82
Black start	Cummins	QSK60	1800	2013	2028	1.5				
Total						59.0				

Unit	Variable costs ($/MWh)	Fixed O&M ($/kW/yr)	Planned Outage Rate (%)	Forced Outage Rate (%)
1	16.29	78.30	8.00	3.00
2	16.29	78.30	8.00	3.00
3	16.29	78.30	8.00	2.00
4	16.29	78.30	8.00	2.00
5	16.29	78.30	8.00	2.00
6	16.29	78.30	8.00	2.00
7	16.29	78.30	8.00	2.00
8	16.29	78.30	8.00	2.00
10	16.29	78.30	8.00	2.00
11	16.29	78.30	8.00	2.00
12	16.29	78.30	8.00	2.00

4.1.3 ANEGADA

BVIEC operates a small isolated diesel power plant on Anegada Island. It comprises three Caterpillar C15 Series generating units and supports a peak demand of approximately 350 kW with annual consumption of around 1.5 GWh.

5 RENEWABLES

5.1 GENERAL

BVI wishes to develop its currently untapped renewable energy resources in order to reduce its reliance on imported oil for power generation and the resulting negative environmental impact due to emission of greenhouse gases.

More specifically, the Government of the Virgin Islands Energy Policy, dated 13th October 2016 included various energy strategies and policy actions. These are categorised as follows:

- Supply side
- Demand side
- Cross sector
- Infrastructure

The main strategies on the supply side are aimed at reducing dependence on imported oil by increasing the availability and use of alternative fuel sources (such as renewable energy) and conducting long-term planning of resource needs and improving supply-side competition.

The BVI government has set a target to supply 30% of the territory's energy from renewable means by 2023 including:

- Up to 6 MW of wind power
- 2.5 MW of solar power
- 1.5 MW of energy from waste and
- 1 MW of sea/wave or other resources

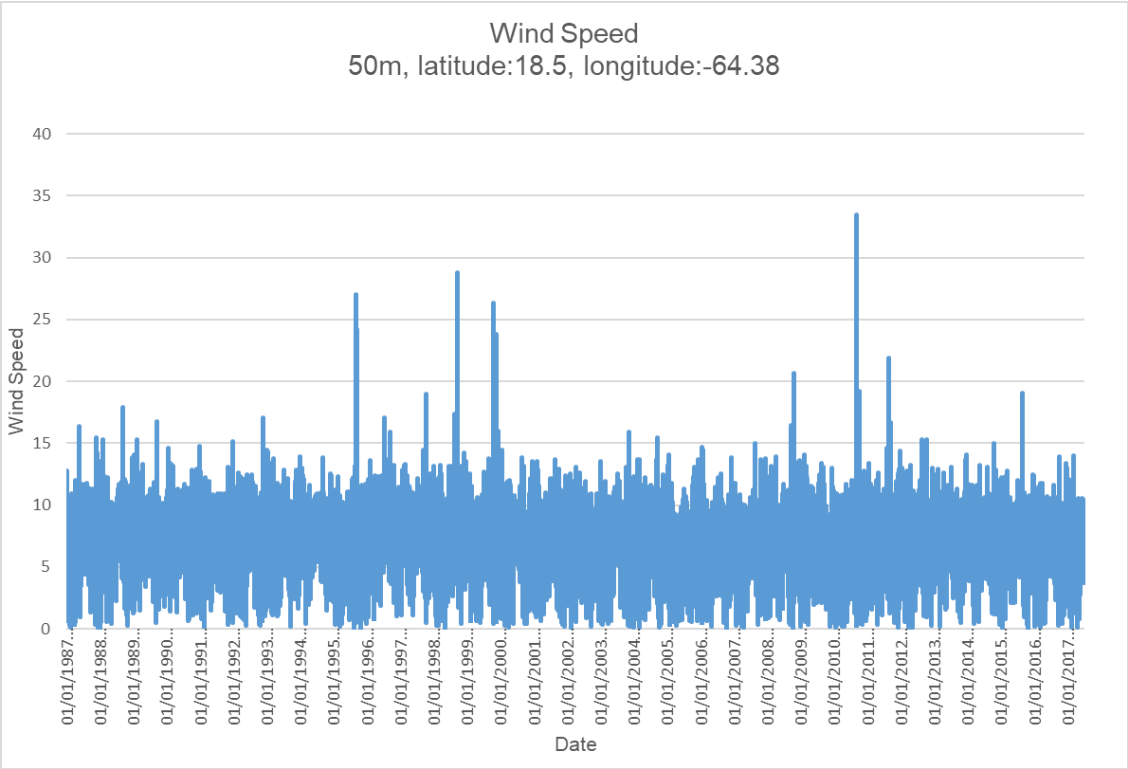
In this study we have focused on solar and wind power. Ocean technology is unlikely to be viable within the 2023 timescale and it seems unlikely that there is sufficient waste for an economically viable energy from waste plant.

5.2 WIND POWER

5.2.1 WIND DATA

Hourly wind speed and direction, temperature data for 1987-2017 was collected from the applicable node (Lattitude18.5, Longtitude-64.28) which is an offshore location at Leverick Bay, Virgin Gorda. The average speed of 7.15 m/sec at 50 m height was obtain. Figure 5-1 shows the data for this offshore site, which will be used for wind power resource estimation in this report.

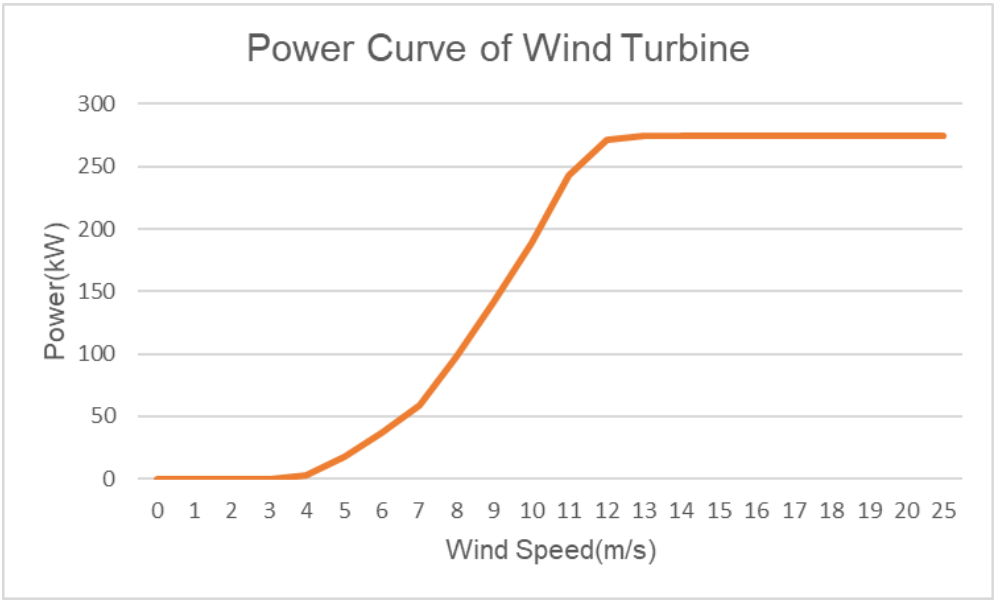
Figure 5-1 - Wind Speed (1987-2017)



5.2.2 TURBINE RATED OUTPUT

In this report, the wind turbine type is chosen to be Vergnet GEV MP C with rating 275kW, which has been widely installed elsewhere in the Caribbean area. The height of the turbine is 55/60m and rotor diameter is 32 m. The power curve of the turbine is plotted as Figure 5-2.

Figure 5-2 - Power Curve of Wind Turbine Vergnet GEV MP C



5.2.3 POTENTIAL SITES

A high level assessment of potential sites on the principal islands of Tortola, Virgin Gorda, Beef Island and Jost van Dyke has been made assuming 100 m spacing of turbines. The selection criteria for the potential wind farm sites are listed below:

- Sites to be close to existing grid
- Avoid any obvious environmental designations or restrictions
- Generally, avoid clearing large area of wood/scrub
- Avoid obvious airport flight paths
- Need access and ideally an existing dock and road/track
- Need open flat areas or ridges
- Avoid built-up areas
- Land ownership or zoning is not considered at this search

Three sites have been identified based on the criteria above.

- Dog Bay [18°29'16.52"N, 64°22'36.87"W]. The total length of the site is 496 m. Potentially up to five turbines and total installation capacity 1.2 MW. This site is on Virgin Gorda and is close to Fischer's Cove 13.2 kV feeder which is marked in pink in Figure 5-3. However, it might be difficult to access since there is no existing track along the ridge.
- Brechers Bay [18°29'53.95"N, 64°20'24.32"W]. The total length of site is 1,098 m marked in Figure 5-4 and can potentially fit up to 11 turbines with total installed capacity 2.7 MW.
- Jost Van Dyke [18°26'53.23"N, 64°44'27.74"W]. The total length of the site is 2,245 m as marked in Figure 5-5 and can potentially fit 22 turbines with total installed capacity 5.6 MW. There are existing docks and road running over main ridge and it is very close to Jost Van Dyke distribution feeder.

Figure 5-3 - Potential Wind Site 1:Dog Bay



Figure 5-4 - Potential Wind Site 2: Brechers Bay



Figure 5-5 - Potential Wind Site 3: Jost Van Dyke



5.2.4 NEXT STEPS

If it is decided to proceed further with wind power, a full site selection study would be necessary, followed by wind monitoring at selected sites.

Key issues to be considered in further study of wind power relate to:

- gathering of wind data
- latest maps and topographical information
- assessment of wind speed at different sites
- detailed assessment of energy production and correlation of wind and load patterns
- the capacity of the available ports, port cranes and lay-down areas
- the capacity of the roads
- the availability of suitable transport vehicles and mobile cranes
- the attitudes of the islands' population to wind power developments (and hence the attitude of the local authorities and planning departments), and the issues that they feel are of importance
- environmental aspects
- land ownership issues
- connection to the grid
- effects on the grid and electricity quality
- availability of different turbine models.

Environmental impact assessments of any site will be needed to assess:

- Visual impact. Wind turbines are alien and obtrusive to some people, attractive to others
- Noise: sites should be as far from properties as possible
- Electromagnetic interference: shielding and siting
- Effects on fauna and flora.

5.3 SOLAR POWER

5.3.1 POTENTIAL SITES

We have identified 12 potential sites which can be suitable for solar PV installations assuming 1 MW of fixed c-Si solar PV needs about 18,211m^2 (4.5 acres). The locations of the potential sites are highlighted in Figure 5-6 -Figure 5-14.

Table 5-1 – Potential Solar Sites

Potential Solar Site ID	Island	Location	Location	Area (m2)	Installed capacity (MWac)
1	Tortola	Cox Heath	18°23'14.51"N, 64°39'44.54"W	82,710 (20.5 acres)	4.6
2	Tortola	Race Track	18°24'50.15"N, 64°38'0.56"W	30,721 (7.8 acres)	1.7
3	Tortola	Community College	18°25'30.80"N, 64°34'39.67"W	13,647 (3.4 acres)	0.8

Potential Solar Site ID	Island	Location	Location	Area (m2)	Installed capacity (MWac)
4	Beef Island	Little Mountain Road	18°26'53.22"N, 64°33'4.73"W	19,199 (4.7 acres)	1.0
5	Beef Island	Long Bay	18°26'44.52"N, 64°32'54.15"W	31,162 (7.7 acres)	1.7
6	Beef Island	Airport 1	18°26'45.22"N, 64°32'30.74"W	64,611 (16 acres)	3.6
7	Beef Island	Airport 2	18°26'45.22"N, 64°32'30.74"W	21,972 (5.4 acres)	1.2
8	Virgin Gorda	Upper Soldier Bay	18°28'8.20"N, 64°24'33.29"W	22,059 (5.5 acres)	1.2
9	Virgin Gorda	Little Bay	18°28'49.95"N, 64°23'32.56"W	30,998 (7.7 acres)	1.7
10	Virgin Gorda	Spanish Town Airport	18°26'57.01"N, 64°25'43.62"W	28,367 (7 acres)	1.6
11	Virgin Gorda	Brechers Bay PV	18°29'39.65"N, 64°20'26.41"W	7,330 (1.8 acres)	0.4
12	Jost van Dyke	White Bay	18°26'45.83"N, 64°46'0.42"W	17,174 (4.2 acres)	0.9

Figure 5-6 - Potential Solar Site 1:Cox Heath



Figure 5-7 - Potential Solar Site 2: Race Track

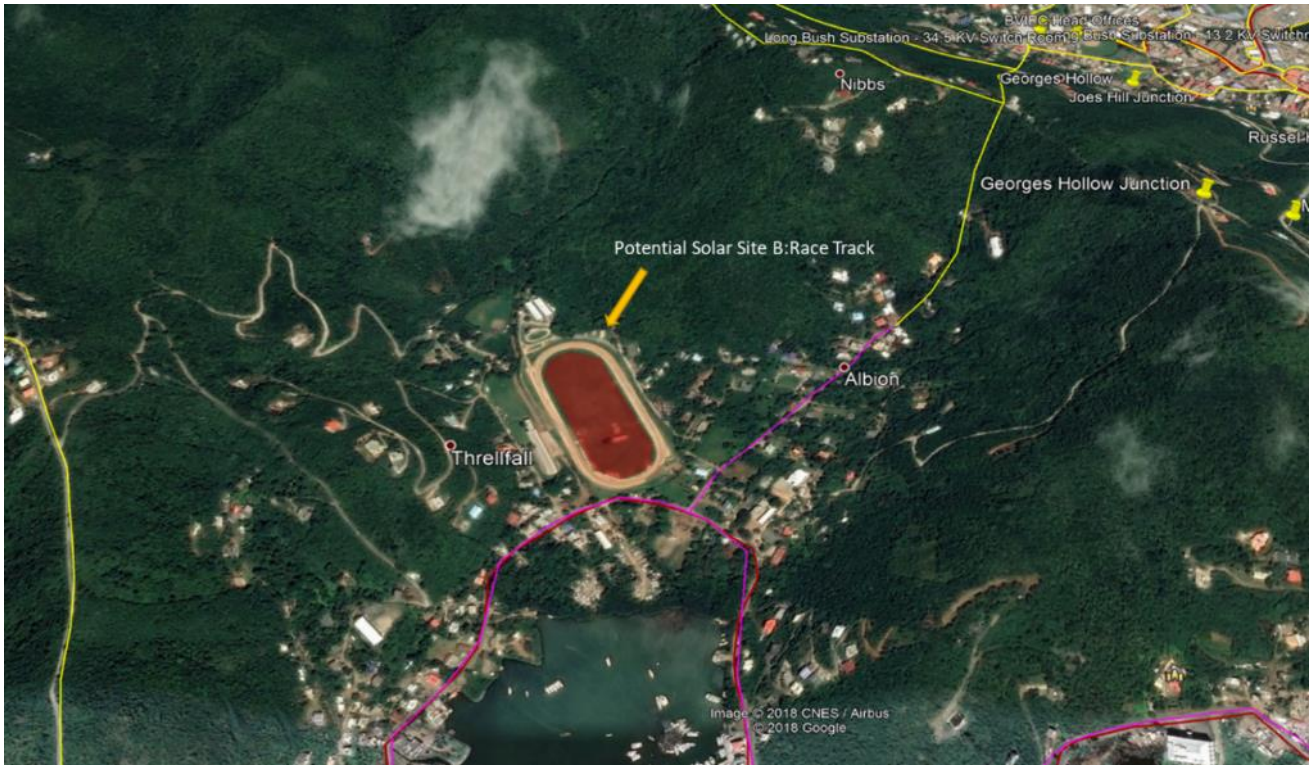


Figure 5-8 - Potential Solar Site 3:Community College



Figure 5-9 - Potential Solar Site 4-7 near Terrance B. Lettsome Airport



Figure 5-10 - Potential Solar Site 8: Upper Soldier Bay



Figure 5-11 - Potential Solar Site 9: Little Bay



Figure 5-12 - Potential Solar Site 10: Spanish Town Airport



Figure 5-13 - Potential Solar Site 11: Brechers Bay



Figure 5-14 - Potential Solar Site 12: White Bay



In addition to the sites identified above, there is a possibility to utilise the roof areas of Pockwood Pond power station for solar PV installation. We estimate there would be approximately 2500 m^2 usable roof space in total (1200m^2 on the new engine hall expansion and 1300m^2 on the existing sections of the power station) on Pockwood Pond power station, which can potentially accommodate 0.14 MW installed capacity of solar PV. This could potentially form part of a black-start scheme if combined with battery energy storage (BESS).

5.3.2 NEXT STEPS

We consider that a PV farm and a series of roof-top schemes may be appropriate for the BVI. Further studies would need to be completed to identify an acceptable level of solar energy penetration. For individual customers, roof–tops schemes would essentially be for water heating and domestic electricity use.

Key issues need to be considered in further study PV energy development include:

- Site topography
- Environmental sensitivities
- Electrical connection accessibility
- Distribution network characteristics
- Site ownership
- Site accessibility
- Site infrastructure
- Energy Yield Assessment

5.4 TECHNICAL CHALLENGES

In the BVI, it is estimated that solar PV and wind power plants will achieve plant factors of around 23% and 27% respectively. On this basis, the combined 30 MW of solar and wind power capacity mentioned above would provide approximately 23% of the Territory's electricity needs if fully deployed by 2029. However, significant storage capacity would be required in order to fully harness this level of renewable resource.

Due to the variable nature of wind energy and the daily profile of solar energy, achieving high levels of penetration provides significant challenges. In addition to energy storage, voltage stability would also provide challenges with high levels of renewable penetration.

6 GENERATION PLANNING

6.1 METHODOLOGY

The generation planning has been conducted using PLEXOS software and has involved:

- Calculation of capacity requirements to meet the demand forecast from 2019 to 2029 whilst achieving the required reserve margin.
- Development of various scenarios based on the Energy Policy, including the introduction of renewables and assessment of the relative costs of these generation scenarios.
- Calculation of the sensitivity of the costs to changes in some key input parameters.

A model of the BVIEC generating plant has been developed in PLEXOS. PLEXOS is a commercial power system modelling tool used for electricity market simulations and planning and was first released in the year 2000. In this application, PLEXOS is used to develop a least-cost generation investment plan. It uses linear programming to minimise the total net present value (NPV) costs of investments, dispatch and unserved energy.

6.2 INPUT PARAMETERS

The key input parameters for the generation planning are listed in Table 6-1 and described further below.

Table 6-1 – Input parameters for generation planning

Input parameters	Value	Source
Discount rate (real)	10%	Typical
Diesel generator capex (USD/kW)	1,042	Derived from Phase V costs
Economic life of diesel generators (yrs)	25	Typical
Fixed O&M for diesels (USD/kW/yr)	78	Derived from 2016 costs provided by BVIEC
Variable O&M for diesels (USD/MWh)	16	Derived from 2016 costs provided by BVIEC
Fuel cost (USD/US gallon)	2.25	2018 value for Pockwood Pond provided by BVIEC
Solar PV capex (USD/kWp)	1,600	BVIEC estimate
Wind capex (USD/kWp)	2,500	WSP estimate for Caribbean
Economic life of solar PV and wind (yrs)	20	WSP
Fixed O&M solar PV (USD/kW/yr)	15	WSP
Fixed O&M wind (USD/kW/yr)	50	WSP

6.2.1 DISCOUNT RATE

The economic analysis associated with the generation planning (net present value analysis) uses “real” discount rates i.e. with inflation removed.

Power sector investments are typically evaluated at real discount rates between 8-12%. BVIEC however may be able to raise cheaper government finance and therefore we have considered a wider range of discount rates in the sensitivity analysis.

6.2.2 DIESEL GENERATOR PARAMETERS

The specific capital cost for diesel generator capacity was derived from a 2017 quotation for Pockwood Pond Unit 9.

The economic life of the diesel generator units is based on our experience in the industry, while the fixed and variable operating costs were derived from BVIEC's operating costs for 2016.

6.2.3 FUEL PRICE

BVIEC experiences a wide variation in fuel prices and the average price at Pockwood Pond for fuel for the past 3 years was:

- 2016 – USD 1.47 per US gallon
- 2017 – USD 1.74 per US gallon
- 2018 – USD 2.25 per US gallon

The Pockwood Pond generators operate on gasoil (diesel). Heavy fuel oil (HFO) is not generally used in generating plant on relatively small islands or groups of islands such as the BVI. The requirement on such systems is generally insufficient to economically justify the increased shipping, storage and handling costs of HFO. Diesel is relatively expensive compared with HFO, but it is less polluting, particularly in terms of sulphur dioxide emissions. HFO operation has therefore not been considered in the study.

6.2.4 RENEWABLES

The capex, economic life and operating costs for renewables are based on our experience and adjusted for local conditions in the Caribbean.

6.3 CAPACITY PLANNING AND RESERVE MARGIN

BVIEC applies a capacity planning margin (reserve margin) based on loss of the two largest units. We have taken this approach for the study and have calculated the corresponding reserve margin as a percentage of the peak demand for each year of the study period. We have also calculated the corresponding Loss-of-Load –Expectation (LoLE) which takes account of the planned and forced outage rates of the generating units.

Due to the intermittent and variable nature of wind and solar generation, we have assumed that they will not provide capacity. The impact of renewable generation on overall generation costs is however considered in the next sub-section.

The capacity expansion plan was developed from the PLEXOS model and is shown in Table **6-2**. The key points of the capacity expansion plan are as follows:

- The required capacity planning margin is equal to the two largest units, i.e. 2 x 8.5 = 17 MW over the full 10-year period.
- Spinning reserve was assumed to be equal to the largest unit, i.e. 8.5 MW
- Units 3 and 4 were assumed to retire at the end of 2026

- New capacity was added as required to meet the demand growth and maintain the reserve margin. This included Unit 9 in 2026 (8.5 MW).
- As shown in Table **6-2**, the required capacity planning margin of 17 MW is not met after 2026.
- In order to meet the required capacity planning margin of 17MW after 2026 BVIEC can retire Units 3 and 4 (in total 10MW) in situ until 2029 by which time it is expected that additional capacity will be provided by a new power plant. Over this period from 2026-2029, it is assumed that Units 3 and 4 could be operated in an emergency.

Table 6-2 **– Capacity planning**

Generation capacity	Net output (MW)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Existing units												
PP 03	5	5	5	5	5	5	5	5	5			
PP 04	5	5	5	5	5	5	5	5	5			
PP 05	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
PP 06	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
PP 07	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
PP 08	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
PP 10	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
PP 11	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
PP 12	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
New units												
PP 09	8.5								8.5	8.5	8.5	8.5
Installed capacity (MW)		57.5	57.5	57.5	57.5	57.5	57.5	57.5	66	56	56	56
Peak demand (MW)		26.1	29.2	32.8	36.4	38.8	39.7	40.5	41.4	42.3	43.2	44.1
Reserve margin (MW)		31.4	28.3	24.7	21.1	18.7	17.8	17	24.6	13.7	12.8	11.9
Required margin (MW)		17	17	17	17	17	17	17	17	17	17	17
Reserve margin (%)		120%	97%	75%	58%	48%	45%	42%	59%	32%	30%	27%
Energy generated (GWh)		164	183	206	229	244	250	255	261	266	272	278
Annual load factor		0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
Fuel consumption (US galx1000)		10,293	11,474	12,875	14,279	15,229	15,551	15,892	16,225	16,584	16,939	17,295
SRMC (USD/MWh)		152	152	153	153	152	152	152	152	152	152	152

6.4 GENERATION SCENARIOS

A number of scenarios were evaluated, based on the status quo and also to take account of the Energy Policy as follows:

Scenario 1 – Generation based on diesels only (as above)

Scenario 2 – Generation based on diesels and 2.5 MW of solar PV

Scenario 3 – Generation based on diesels and 6 MW of wind

Scenario 4 – Generation based on diesels, 2.5 MW of solar PV and 6 MW of wind

In all scenarios, the above capacity expansion plan was fixed, i.e. the renewable energy plants do not provide firm capacity and therefore the introduction of renewables in Scenarios 2-4 does not result in a reduction in diesel generation capacity.

The PLEXOS model was used to run the above scenarios and to calculate key performance parameters including; fuel consumption, generated energy from solar and wind and annual operating costs. Table 6-3 shows that the introduction of 2.5 MW of solar PV and 6 MW of wind will result in 7-8% of electrical energy being produced by renewables and will also result in a 7-8% reduction in fuel consumption.

Table 6-3 – Renewable generation scenarios

Renewable Energy scenarios	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Installed capacity (MW)											
Solar PV					2.5	2.5	2.5	2.5	2.5	2.5	2.5
Wind			6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Total renewable capacity	-	-	6.0	6.0	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Total generated energy (GWh)	164	183	206	229	244	250	255	261	266	272	278
Solar PV	0.00	0.00	0.00	0.00	5.11	5.12	5.11	5.11	5.11	5.12	5.11
Wind	0.00	0.00	14.42	14.42	14.42	14.46	14.42	14.42	14.42	14.46	14.42
Total renewable generation (GWh)	-	-	14.4	14.4	19.5	19.6	19.5	19.5	19.5	19.6	19.5
Solar PV capacity factor					0.23	0.23	0.23	0.23	0.23	0.23	0.23
Wind capacity factor			0.27	0.27	0.27	0.28	0.27	0.27	0.27	0.28	0.27
Percentage of total generation (%)	0%	0%	7%	6%	8%	8%	8%	7%	7%	7%	7%
Fuel consumption (US galx1000)											
Scenario 1 - Diesels only	10,293	11,474	12,875	14,279	15,229	15,551	15,892	16,225	16,584	16,939	17,295
Scenario 2 - 2.5 MW Solar PV	10,293	11,474	12,875	14,279	14,914	15,235	15,577	15,910	16,269	16,623	16,980
Scenario 3 - 6 MW Wind	10,293	11,474	11,987	13,392	14,341	14,660	15,004	15,337	15,696	16,048	16,407
Scenario 3 - 2.5 MW solar PV & 6 MW Wind	10,293	11,474	11,987	13,392	14,026	14,345	14,689	15,022	15,381	15,732	16,092

6.5 ECONOMIC EVALUATION

Table 6-4 shows a summary of the economic evaluation of the above scenarios including capital costs, fixed and variable operating costs and fuel costs. The net present value (NPV) of each of the scenarios is shown in 2018 costs based on a discount rate of 10%.

Table **6-5** shows the details of the evaluation. The capital cost of the new diesel generators and renewable power plants are entered in equal annual payments based on the economic life of the plant and the discount rate.

The economic evaluation indicates that the introduction of solar PV and wind will result in net savings for the BVI based on the assumptions given in Table 6-1. This shows that the capital costs associated with the solar PV and wind plants will be recovered through savings associated with reduced fuel consumption.

Table 6-4 – NPV of total generation costs over 10 years (USD'000)

Scenario	NPV cost (at 10% discount rate in money of 2018)	Cost relative to Scenario 1
Scenario 1 – Diesels only	261,652	-
Scenario 2 - 2.5 MW solar PV	260,704	-948
Scenario 3 – 6 MW wind	260,834	-818
Scenario 4 – 2.5 MW solar PV and 6 MW wind	259,886	-1,766

Table 6-5 – Economic evaluation of scenarios

Costs (USD'000, in money of 2018)		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Scenario 1 - Diesels only												
Annualised capex		-	-	-	-	-	-	-	976	976	976	976
Fixed O&M		4,502	4,502	4,502	4,502	4,502	4,502	4,502	5,168	4,385	4,385	4,385
Variable O&M		2,675	2,987	3,358	3,730	3,981	4,066	4,156	4,244	4,339	4,433	4,527
Fuel		23,160	25,816	28,969	32,128	34,265	34,990	35,756	36,506	37,313	38,112	38,914
Total		30,337	33,306	36,829	40,360	42,748	43,558	44,414	46,894	47,013	47,905	48,801
NPV (2018)	**261,652**											
Scenario 2 - 2.5 MW Solar PV												
Annualised capex		-	-	-	-	470	470	470	1,446	1,446	1,446	1,446
Fixed O&M		4,502	4,502	4,502	4,502	4,540	4,540	4,540	5,205	4,422	4,422	4,422
Variable O&M		2,675	2,987	3,358	3,730	3,897	3,982	4,073	4,161	4,256	4,349	4,444
Fuel		23,160	25,816	28,969	32,128	33,556	34,280	35,047	35,798	36,605	37,402	38,205
Total		30,337	33,306	36,829	40,360	42,463	43,272	44,130	46,610	46,728	47,619	48,516
NPV (2018)	**260,704**											
Scenario 3 - 6 MW Wind												
Annualised capex		-	-	1,762	1,762	1,762	1,762	1,762	2,738	2,738	2,738	2,738
Fixed O&M		4,502	4,502	4,802	4,802	4,802	4,802	4,802	5,468	4,685	4,685	4,685
Variable O&M		2,675	2,987	3,123	3,495	3,746	3,830	3,921	4,009	4,104	4,197	4,292
Fuel		23,160	25,816	26,972	30,131	32,268	32,986	33,759	34,509	35,316	36,108	36,916
Total		30,337	33,306	36,659	40,190	42,578	43,380	44,244	46,724	46,842	47,727	48,630
NPV (2018)	**260,834**											
Scenario 4 - 2.5 MW solar PV and 6 MW Wind												
Annualised capex		-	-	1,762	1,762	2,232	2,232	2,232	3,207	3,207	3,207	3,207
Fixed O&M		4,502	4,502	4,802	4,802	4,840	4,840	4,840	5,505	4,722	4,722	4,722
Variable O&M		2,675	2,987	3,123	3,495	3,663	3,747	3,838	3,926	4,021	4,114	4,209
Fuel		23,160	25,816	26,972	30,131	31,559	32,276	33,050	33,800	34,607	35,398	36,207
Total		30,337	33,306	36,659	40,190	42,293	43,094	43,959	46,439	46,558	47,441	48,346
NPV (2018)	**259,886**											

6.6 SENSITIVITY ANALYSIS

Sensitivity analysis was conducted to assess the impact on the economic evaluation of varying the value of certain key parameters as follows:

- Discount rate: 6% - 14%

- Fuel price: 1.15 – 3.44/ USD/US gallon
- Solar PV capex: 1000 – 3000 USD/kW
- Wind capex: 1500 – 3500 USD/kW

The above parameters were selected as they are subject to a high degree of uncertainty. Fuel prices are particularly volatile and as indicated above have varied from 1.47 – 2.25 USD/US gallon over the past three years.

The sensitivity analysis is shown in Table 6-6 and graphically in Figure 6-1, Figure 6-2, Figure 6-3 and Figure 6-4.

Table 6-6 – Sensitivity analysis

Sensitivity analysis	NPV (USD'000) in money of 2018				Relative cost (USD'000)	
	Scenario 1 - Diesels only	Scenario 2 - 2.5 MW Solar PV	Scenario 3 - 6 MW Wind	Scenario 4 - 2.5 MW solar PV and 6 MW Wind	Scenario 2 - 2.5 MW Solar PV	Scenario 3 - 6 MW Wind
Discount rate (%p.a.)						
6.0%	322,397	320,600	318,607	316,811	- 1,797	- 3,790
8.0%	289,695	288,365	287,520	286,191	- 1,330	- 2,174
10.0%	261,652	260,704	260,834	259,886	- 948	- 818
12.0%	237,474	236,837	237,790	237,154	- 637	316
14.0%	216,520	216,136	217,780	217,397	- 384	1,260
Fuel price (USD/US gallon)						
2.25	261,652	260,704	260,834	259,886	- 948	- 818
1.15	160,158	160,368	164,012	164,222	210	3,854
1.72	212,742	212,352	214,175	213,786	- 390	1,433
2.29	265,326	264,336	264,339	263,349	- 990	- 987
2.86	317,910	316,320	314,503	312,913	- 1,590	- 3,408
3.44	370,494	368,304	364,666	362,476	- 2,190	- 5,828
Solar PV capex (USD/kW)						
1000	261,652	260,118	260,834	259,300	- 1,534	- 818
1500	261,652	260,606	260,834	259,789	- 1,046	- 818
2000	261,652	261,094	260,834	260,277	- 558	- 818
2500	261,652	261,583	260,834	260,765	- 70	- 818
3000	261,652	262,071	260,834	261,253	419	- 818
Wind capex (USD/kW)						
1500	261,652	260,704	257,480	256,532	- 948	- 4,172
2000	261,652	260,704	259,157	258,209	- 948	- 2,495
2500	261,652	260,704	260,834	259,886	- 948	- 818
3000	261,652	260,704	262,511	261,563	- 948	859
3500	261,652	260,704	264,188	263,240	- 948	2,536

The sensitivity analysis shows the total costs of generation for Scenarios 2 and 3 relative to Scenario 1. In each case only the indicated parameter is varied, with the other parameters maintained at the values shown in Table 6-1. The following key conclusions may be drawn:

6.6.1 DISCOUNT RATE SENSITIVITY

- The introduction of solar PV will result in a net reduction in generation costs over the full range of discount rates considered.
- The introduction of wind power will result in a net reduction in generation costs for discount rates below approximately 11.7%.

6.6.2 FUEL PRICE SENSITIVITY

- The introduction of solar PV will result in a net reduction in generation costs for fuel prices above approximately 1.35 USD/US gallon.
- The introduction of wind power will result in a net reduction in generation costs for fuel prices above approximately 2 USD/US gallon.

6.6.3 SOLAR PV AND WIND CAPEX SENSITIVITY

- The introduction of solar PV will result in a net reduction in generation costs for solar PV capital costs below 2,600 USD/kW.
- The introduction of wind power will result in a net reduction in generation costs for wind power capital costs below 2,800 USD/kW.

Figure 6-1 - Discount rate sensitivity

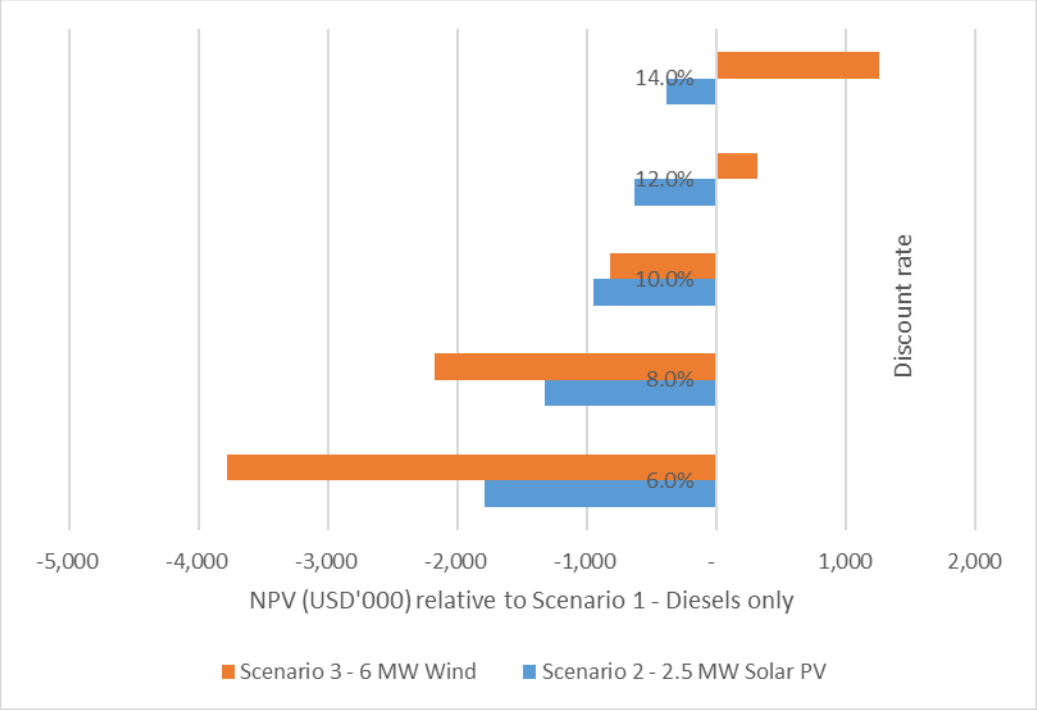


Figure 6-2 - Fuel Price Sensitvity

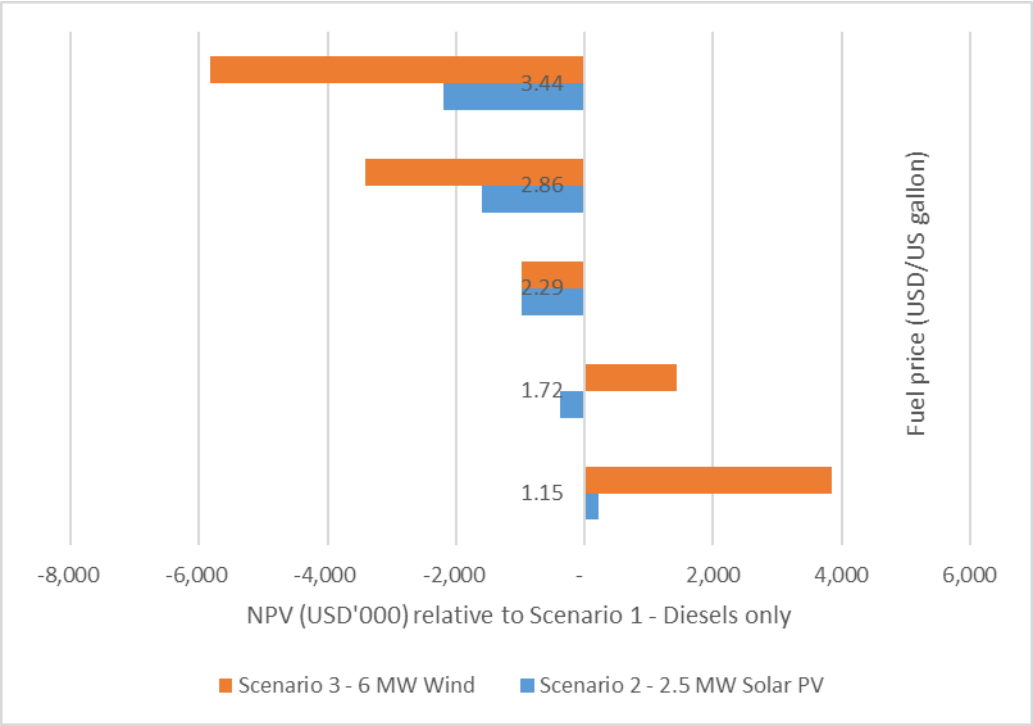


Figure 6-3 – Solar PV capex sensitivity

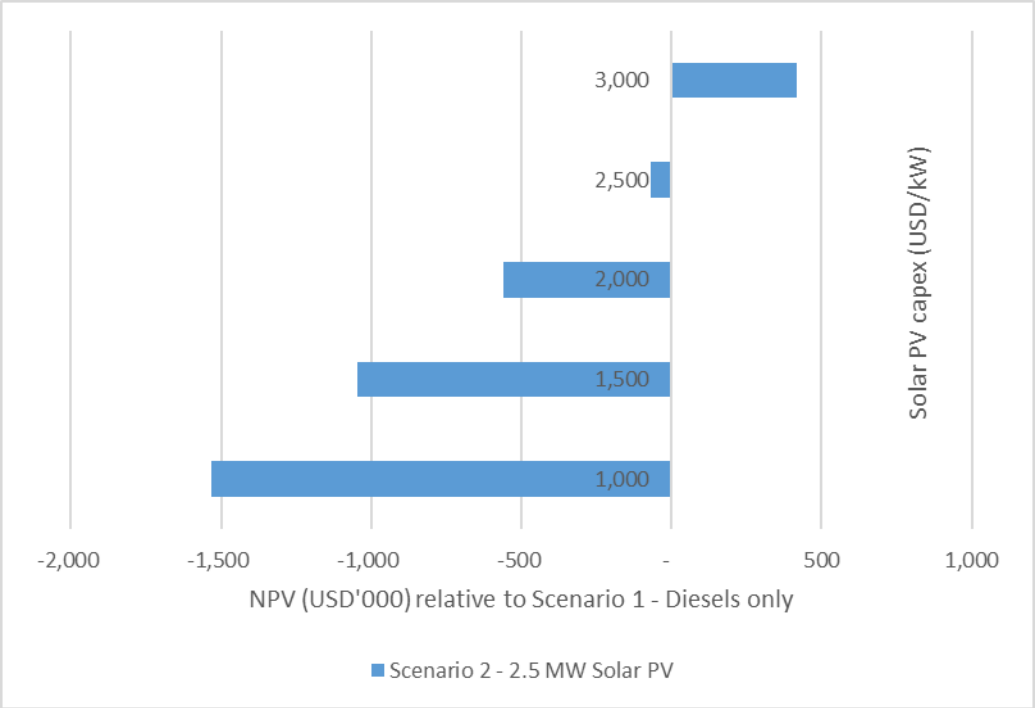
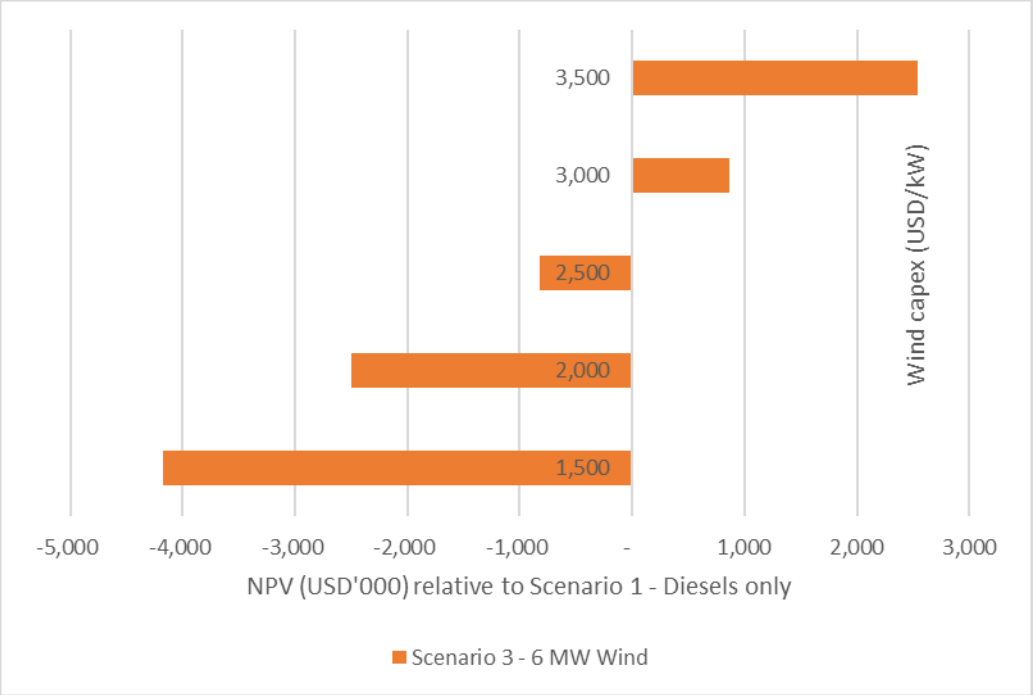


Figure 6-4 – Wind capex sensitivity



6.7 ALTERNATIVE POWER PLANT

In the longer term BVIEC is considering building a second power plant in order to provide additional capacity once the available capacity of Pockwood Pond power plant has been fully utilised. In order to improve security of supply or resilience, this should be located on the eastern side of Tortola. This will mean that the main load centre of Road Town could be supplied either from the west (Pockwood Pond) or from a new power plant to the east. Phase 3 of BVIEC's Resiliency Plan, mentions the requirement for a new generation facility at a separate location which would utilise a cleaner burning fuel such as LNG or LPG.

It is understood that BVIEC intends to start developing this project from 2024/25, with a view to commencing operation by 2029.

6.8 CONCLUSIONS FROM GENERATION PLANNING

In order to meet the forecast demand growth up to 2029 and maintain the required reserve margin, it will be necessary to commission Unit 9 (8.5MW) by 2026. It will also be necessary for BVIEC to retain Units 3 and 4 in situ in order that they may be deployed in an emergency. This will ensure that the required capacity planning margin 17MW equal to the two largest generating units can be met until 2029 by which time it is anticipated that a new power plant will be in service.

The renewable energy plants will not provide firm capacity and therefore the above capacity additions will be required irrespective of the level of solar or wind power generation added to the system.

However, the studies indicate that the addition of solar PV and/or wind power generation will result in a reduction in the cost of generation in BVI. This means that the capital costs of the solar PV or wind will be recovered through savings in fuel costs.

Solar PV remains economically attractive over a wide range of discount rates, fuel prices and capital costs. Wind power is economically attractive at fuel prices above 2 USD/US gallon.

In the longer term (beyond the 2029 horizon), an alternative fossil fuel power plant will be required to provide additional capacity. A second power plant will also increase security of supply. This could utilise a cleaner fuel such as LNG or LPG.

7 TRANSMISSION AND DISTRIBUTION

7.1 EXISTING SYSTEM

Electricity is generated at Pockwood Pond power station on Tortola, the main island - Figure 7-1. The supply is three-phase 60 hertz, and energy is transmitted at 34.5 kV and distributed at 13.2 kV before stepping-down to low voltage. The system supplies Tortola and Beef Island, and by sub-sea cables the islands of Virgin Gorda, Jost van Dyke, Little Thatch, Buck Island, Little and Great Camanoe, Scrub Island, Frenchman's Cay, Saba Rock and Marina Cay. There is also a small diesel station on the island of Anegada electrically isolated from the main system, but also owned and operated by BVIEC.

Figure 7-1 - Map of British Virgin Islands

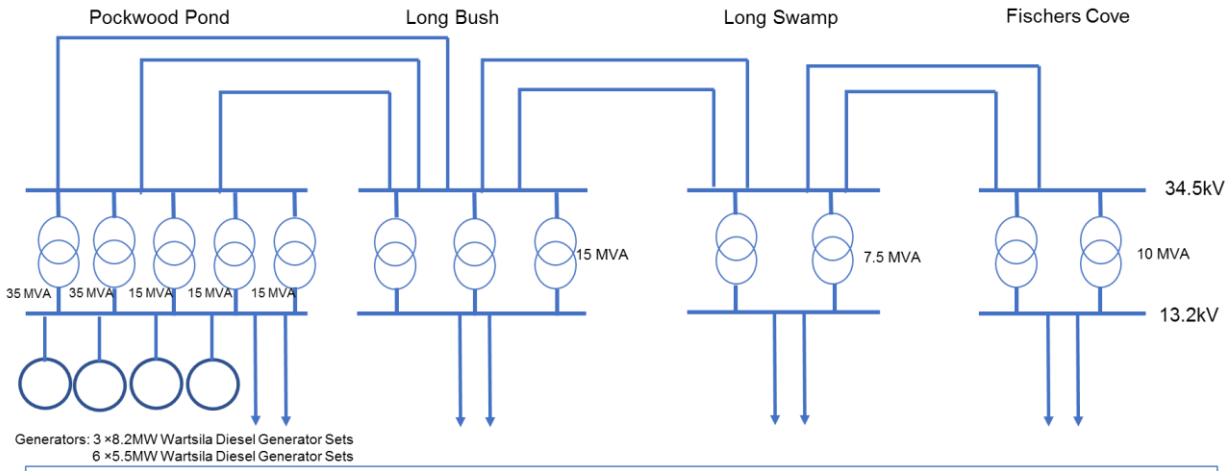


A simplified view of the BVIEC transmission system is shown in Figure 7-2. The 34.5 kV transmission system comprises circuits interconnecting four 34.5/13.2 kV substations. BVIEC's recently completed Phase V development included:

- Reinforcement of the section between Pockwood Pond and Long Bush substations by means of a third 34.5 kV underground cable circuit (A fourth circuit was also installed but not commissioned)
- 2 x 34.5/13.2 kV 35 MVA inter-bus transformers at Pockwood Pond
- 1 x 34.5/13.2 kV 15 MVA inter-bus transformer at Long Bush

Two 34.5 kV sub-sea cables connect Long Swamp to Fisher's Cover Substation on Virgin Gorda. The 34.5 kV circuits comprise mostly underground and sub-sea cables, with a section of overhead line between Long Bush and Long Swamp substations.

Figure 7-2 – Transmission System



Distribution network comprises a number of 13.2kV feeders from each of the main substations , with customers supplied at 480 V three phase and 240 V single phase via distribution transformers. The 13.2kV feeders also interconnect adjacent substations with normally open points to prevent power transfer on the distribution system.

Power is distributed at 13.2 kV by means of radial feeders from each of the above-mentioned substations as shown in Figure 7-3. Most loads are connected to these feeders via single or three-phase distribution transformers. The 13.2 kV feeders also interconnect adjacent substations, however normally open points are maintained in the 13.2 kV network. The 13.2 kV feeders comprise mostly overhead line, with some underground and sub-sea cables as indicated in Table 7-2.

Since the 2003 Power Development Study, Long Bush – Wickham's Cay Feeder #2 has been introduced and some of the Long Bush – Wickham's Cay Feeder #1 load has been transferred to this feeder.

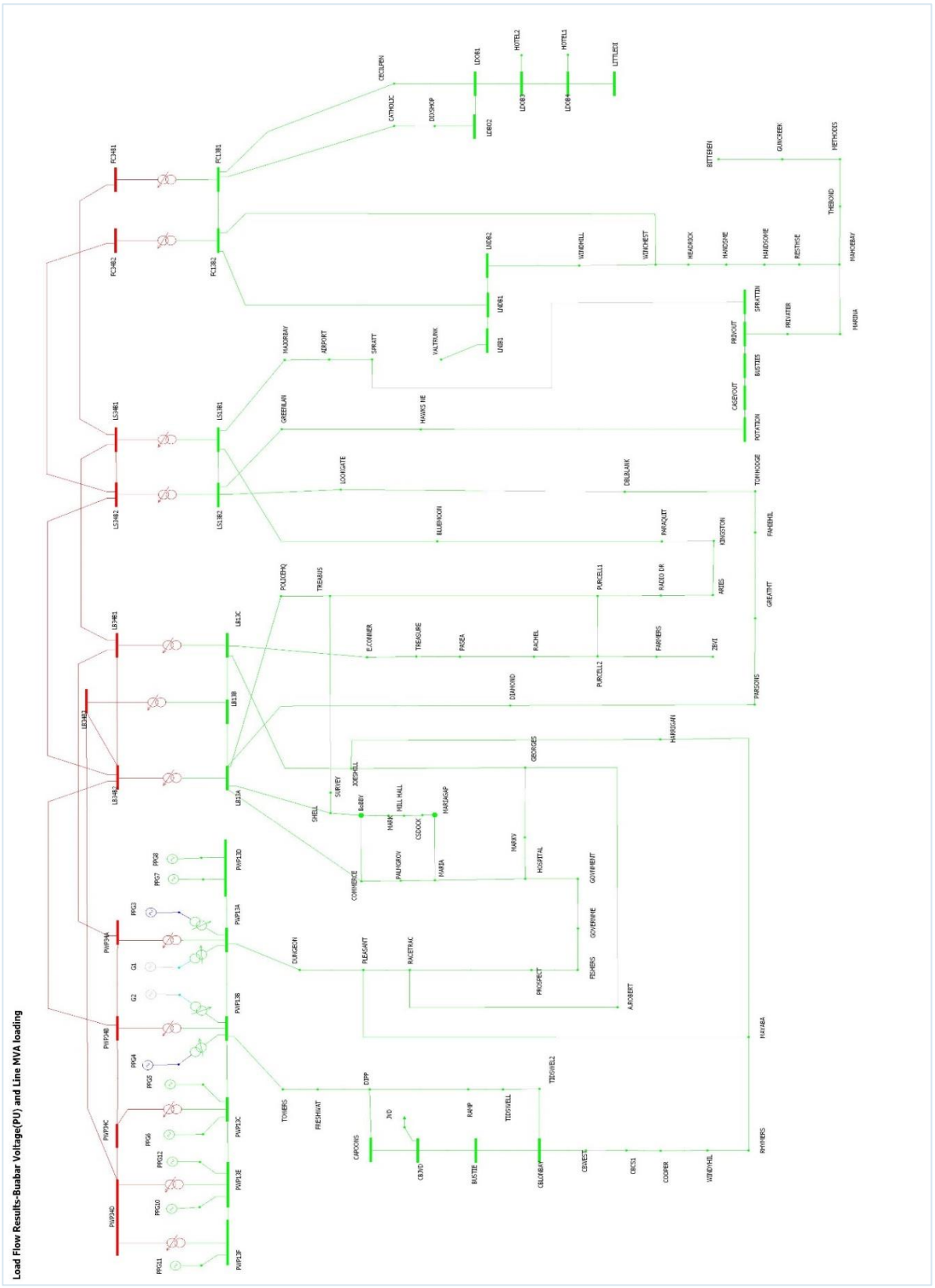
7.2 DEVELOPMENT OF IPSA MODEL

A previously developed IPSA model was updated to reflect the current transmission and distribution system. Data relating to system additions and the normal system configuration was obtained during the site visit and information submitted by BVIEC, and further information relating to loads and feeder sizes was subsequently provided by BVIEC.

7.2.1 LOAD DATA

The load flow studies were based on the High Case demand forecast. The maximum feeder loads applied in the model are shown in Table 7-1. The average transformer utilisation at the time of maximum feeder load was calculated for each feeder by dividing the feeder load by the total distribution transformer capacity connected to a particular feeder based on data submitted for 2013.

Figure 7-3 - Network Diagram (Red – 34.5 kV, Green – 13.2 kV)



The individual transformer loads were then calculated by multiplying the transformer rating by the average utilisation factor.

A load power factor of 0.94 at the 13.2 kV distribution transformer supply points was assumed throughout based on the feeder peak demand information of 2013 submitted by BVIEC.

Table 7-1 – Feeder Loads (based on High Case Forecast)

Substation	Feeder	2018	2021	2025	2029
		MW	MW	MW	MW
Pockwood Pond	West	2.02	3.02	3.68	4.06
Pockwood Pond	East	1.27	1.89	2.30	2.54
Long Bush	East End	2.45	3.65	4.45	4.90
Long Bush	Ridge	0.84	1.26	1.53	1.69
Long Bush	West	0.67	1.01	1.23	1.35
Long Bush	Spare Road Town	2.62	3.90	4.76	5.24
Long Bush	Wickham's Cay #1	3.37	5.03	6.14	6.76
Long Bush	Wickham's Cay #2	2.28	3.40	4.14	4.57
Long Swamp	East End (Airport)	1.10	1.64	1.99	2.20
Long Swamp	East End (College)	1.43	2.14	2.61	2.87
Long Swamp	Ridge to Camanoe	0.51	0.75	0.92	1.01
Fischer's Cove	Little Dix	0.84	1.26	1.53	1.69
Fischer's Cove	Catholic Church	2.53	3.77	4.60	5.07
Fischer's Cove	Fishers Cove	1.27	1.89	2.30	2.54
Fischer's Cove	Lord Nelson/AMR XFMR	0.00	0.00	0.00	0.00
Total Load		23.2	34.6	42.2	46.5

7.2.2 CIRCUIT DATA

The 34.5 kV transmission system mostly comprises 185 mm^2 copper cross-linked polyethylene Cable (Cu XLPE) with some 125 mm^2 AAAC overhead line. The lengths and continuous ratings are indicated in Table 7-2.

The various ratings for the 34.5 kV 185 mm^2 cables are assumed to result from different installation conditions and cable construction differences between ground and sub-sea design. Typically, a 34.5 kV 185 mm^2 Cu XLPE cable direct buried with a maximum ground/sea temperature of 30°C would have a continuous rating of approximately 22 MVA.

The 13.2 kV distribution system is designed to operate as a radial system of feeders, comprising overhead line circuits and underground or sub-sea cables. BVIEC provided updated circuit data which is indicated in Table 7-2.

The cable ratings are for direct buried or sub-sea cables with a maximum ground/sea temperature of 30°C. Overhead line ratings are based on a maximum ambient air temperature of 40°C, a wind speed of 2 km/h, a maximum conductor temperature of 75°C and a solar radiation intensity of 1200 W/m^2.

Table 7-2 - Circuit Data

From	To	Voltage(KV)	No. Circuits	Type	Length(km)	MVA per Circuit
Pockwood Pond	Long Bush	34.5	2	185 mm^2 Cu XLPE	10	22.1
			1	185 mm^2 Cu XLPE	7.8	22.1
Long Bush	Long Swamp	34.5	2	185 mm^2 Cu XLPE	7.17	20.3
				4/0 AAAC (125.1 mm^2)	3.67	19.89
Long Swamp	Fischer's Cove	34.5	2	185 mm^2 Cu XLPE	16.3	15
CBJVD	JVD	13.2	1	50mm^2 Cu XLPE (2/0)	7.76	4.27
TIDSWELL (BELMONT)	RAMP (WE)	13.2	1	4/0 AAAC	0.78	7.61
PROSPECT	FISHERS	13.2	1	95mm^2 Cu XLPE (4/0)	0.64	6.1
PASEA	RACHEL	13.2	1	95mm^2 Cu XLPE (4/0)	0.29	6.1
MAHOEBAY	MARINA	13.2	1	120 mm^2 Cu XLPE	15.8	6.92

From	To	Voltage(KV)	No. Circuits	Type	Length(km)	MVA per Circuit
MARINA	PRIVATEER	13.2	1	120 mm^2 Cu XLPE	0.17	6.92
FC13B1	CECILPENN (FC)	13.2	1	185 mm^2 Cu XLPE (400 mcm)	0.3	8.75
FC13B1	CATHOLIC (CC)	13.2	1	185 mm^2 Cu XLPE (400 mcm)	0.15	8.75
FC13B2	LNDB1 (LN)	13.2	1	185 mm^2 Cu XLPE (400 mcm)	0.65	8.75
FC13B2	WINCHEST	13.2	1	185 mm^2 Cu XLPE (400 mcm)	0.15	8.75
SPRAT POINT	INDIGO	13.2	1	120 mm^2 Cu XLPE	1.45	6.92
HIGH SCHOOL	NAPA	13.2	1	95 mm^2 Cu XLPE (4/0)	0.5	6.1
POLICE	RED CROSS	13.2	1	95 mm^2 Cu XLPE (4/0)	0.05	6.1
MAYABA	PLEASANT	13.2	1	4/0 AAAC	3.41	7.61
LONG BUSH	LONG BUSH EAST END FEEDER	13.2	1	120 mm^2 Cu XLPE	0.21	6.92
LONG BUSH	WC1	13.2	1	185mm^2 Cu XLPE (400 mcm)	0.64	8.75
				95 mm^2 XLPE Cu (4/0)	1.1	6.1
LONG BUSH	WC2	13.2	1	185mm^2 Cu XLPE (400 mcm)	1	8.75
				95 mm^2 XLPE Cu (4/0)	0.83	6.1
JOES HILL	MONTESSOENT	13.2	1	95 mm^2 XLPE Cu (4/0)	0.16	6.1
CEDAR SCHOOL	SOPHIE BAY	13.2	1	95 mm^2 XLPE Cu (4/0)	0.19	6.1
All other circuits		13.2	1	4/0 AAAC		7.61
				35mm^2 Cu XLPE		2.72

7.2.3 GENERATOR DATA

The key parameters of generators are listed in Table 7-3.

Table 7-3 – Generator Data

Power Station	Generator	MW	MVA	%PF (Lagging)	%PF (Leading)	Sub-transient Reactance Xd'' (%)
Pockwood Pond	G3	5.5 (5.0)	6.88	80	95	25.6
Pockwood Pond	G4	5.5 (5.0)	6.88	80	95	25.6
Pockwood Pond	G5	5.65 (5.5)	7.06	80	95	20
Pockwood Pond	G6	5.65 (5.5)	7.06	80	95	20
Pockwood Pond	G7	5.65 (5.5)	7.06	80	95	20
Pockwood Pond	G8	5.65 (5.5)	7.06	80	95	20
Pockwood Pond	G10	8.51 (8.5)	10.64	80	95	22.4
Pockwood Pond	G11	8.51 (8.5)	10.64	80	95	22.4
Pockwood Pond	G12	8.51 (8.5)	10.64	80	95	22.4

Note: The figures in brackets in Table 7-3 indicate the effective rating of the machines.

7.2.4 TRANSFORMER DATA

The distribution transformers were not modelled as the loads were represented at 13.2 KV. The key parameters used to model the inter-bus transformers are shown in Table 7-4.

Table 7-4 – Inter-bus Transformers Data

Substation	Rating(MVA)	No. of Transformers	Impedance (%)	Tapping Range (%)
Pockwood Pond	15	3	16.84	-15 +5
Pockwood Pond	35	2	12	-15 +5
Long Bush	15	2	16.9	-15 +5
Long Bush	15	1	16.36	-15 +5
Long Swamp	7.5	2	9.2	-5 +5
Fischer's Cove	10	2	8.5	-15 +5

7.3 PLANNING CRITERIA

The BVI Electricity Regulations, dated 1999, include standards of supply for voltage and frequency, which are summarised below:

- The distribution voltages of electricity shall be maintained by the Company within plus or minus 6% of such voltage.
- The frequency of electricity supplied for any purpose shall be 60 Hertz and this shall be maintained within plus or minus 2.5 Hz.

The radial feeder configuration of the 13.2 kV distribution system will result in short term interruptions following faults or during planned maintenance. It is understood that some larger consumers have their own standby generators to provide continuity of supply.

7.4 LOAD FLOW STUDIES

The IPSA model was used to analyse the existing network to identify any shortcomings in terms of voltage levels or thermal loadings and to determine the levels of reinforcement required to accommodate the anticipated load growth over the 10-year development period.

At each key stage of development, load flow studies were used to assess the adequacy of the system against the following criteria:

- Voltages to be maintained within +/-5% of nominal throughout the 13.2 kV system.

- Thermal ratings of equipment not to be exceeded under normal or single circuit outage conditions.
- It should be possible, following a circuit outage, to carry out manual tap changer operation or to re-configure the network to achieve the above requirements.

7.4.1 LOAD FLOW FOR 2018

Load flow studies were conducted to assess the performance of the existing network under both maximum and minimum 2018 load conditions. Figure 7-5 and Figure 7-6 show the load flow plot for maximum and minimum load conditions respectively.

A full set of load flow plots including outage studies is provided in Appendix A for 2018, 2021, 2025 and 2029.

The load flow studies are based on the loads at the time of system peak and therefore include diversity. The actual maximum loads on individual feeders may be slightly higher than shown. The lowest voltage experienced at the remote end of feeders may therefore be lower than indicated by the load flow.

Under normal conditions, the voltages are maintained within the limits.

7.4.1.1 Light Load Conditions

A load flow was carried out to assess the level of steady state voltage rise across the system under minimum load conditions. This was found to be 4.4% as indicated which can be observed on Long Bush transmission busbars and the feeder busbars close to the transmission substations as shown in Figure 7-6, and is within the maximum voltage limit for the system. Larger transient voltage rises could occur during system disturbances.

7.4.1.2 Outage Conditions

Circuit outages were considered to assess network performance under abnormal conditions. The performance of the system was satisfactory under the following critical outage cases:

- Outage of a 10 km 34.5 kV Pockwood-Long Bush transmission circuit: The remaining Pockwood-Long Bush transmission circuits were loaded to 11.38 MVA and 9.1 MVA respectively which is well below the rating of 22 MVA.
- Outage of a 35 MVA Pockwood Pond inter-connector transformer: The remaining 35MVA transformers at Pockwood Pond were loaded to 10.64MVA maximum which is well within the rating. The 15MVA transformers were loaded to 3.25 MVA which is well within the rating.
- Outage of a Long Bush inter-connector transformer: The remaining transformers were loaded to 6.73 MVA and 6.52 MVA, which is within the rating of 15 MVA.
- Outage of a Long Bush-Long Swamp transmission circuit: The remaining Long Bush-Long Swamp transmission circuit was loaded to 8.17 MVA, which is well within the rating of 20 MVA.
- Outage of a Long Swamp 34.5/13.2 kV step down transformer: The remaining Long Swamp transformer was loaded to 3.5 MVA, which is well within the rating of 7.5 MVA.
- Outage of a Fischer's Cove 34.5/13.2 kV step down transformer: The remaining Long Swamp-Fischer's Cove transformer will become loaded to 5.04 MVA, which is well within the transformer rating of 15 MVA.

7.4.2 2021 LOAD FLOWS

According to the High Case load forecast, the total generated power under maximum demand conditions will have reached 34.6 MW by 2021. The voltages of the whole system were maintained within the limits and no overloads were found under normal and outage conditions.

7.4.3 2025 LOAD FLOWS

According to the High Case load forecast, the maximum demand conditions will have reached 42.2 MW by 2025. No overloads were found under normal or outage conditions

The voltage at Fischer's Cove substation dropped to 94.4% which is slightly below the 95% planning limit during the outage on one of two Long Bush-Long Swamp transmission circuits. This could be alleviated by the installation of the proposed Paraquita Bay substation as mentioned further below.

7.4.4 2029 LOAD FLOWS

According to the High Case load forecast, the total system load will have increased to 46.5 MW by 2029.

7.4.4.1 Normal Conditions

The voltages across the whole system were maintained within the planning limits and no overloads were found under normal conditions.

7.4.4.2 Outage Conditions

The system performance under outage conditions is summarised below:

- Outage of a 10km 34.5 kV Pockwood-Long Bush transmission circuit: The remaining 7.8km Pockwood-Long Bush transmission cable was loaded to 24.7 MVA, which is above its thermal rating of 22MVA.The remaining 10km cable was loaded to 19.81MVA, which is within the rating. The voltage of Fischer's Cove 34.5kV busbars will drop to 94%, which is slightly below the planning limit. It is recommended to commission the 4th Pockwood Pond -Long Bush underground circuit to avoid the potential overload on the remaining circuit during outage and alleviate the low voltage at Fischer's Cove. (As mentioned, this circuit has already been installed but is not yet commissioned.)
- Outage of a 35MVA Pockwood Pond inter-connector transformer: The voltage of Fischer's Cove 34.5KV busbars dropped to 94%, which is slightly lower than the planning limit
- Outage of a Long Bush inter-connector transformer: No voltage violations or transmission circuit overloads.
- Outage of a Long Bush-Long Swamp transmission circuit: The voltage of Long Swamp Airport 13.2 kV feeder dropped to 94%, which is slightly lower than the system planning limit. The voltage of Fischer's Cove 34.5KV busbars dropped to 93% during the outage. With the commissioning of the second Pockwood Pond-Long Bush circuit and new transmission substation in Paraquita Bay (Section 7.6.4), the voltage of Fischer's Cove 34.5 kV busbars would be increased to 95% during this outage condition.
- Outage of a Long Swamp 34.5/13.2 kV step down transformer: No voltage violations or transmission circuit overloads.
- Outage of a Fischer's Cove transformer: The remaining Fischer's Cove transformer was loaded 10.35MVA during the outage, which is slightly above the continuous rating but well within the

overload rating of the transformers. The voltage of remaining Fischer's Cove 34.5kV busbar dropped to 94%, which is slightly below the voltage limit.

With the network reinforcement proposed in Section 7.6.4, the performance of the system was satisfactory under both normal and outage conditions. The outage study results with reinforced network are shown in Appendix A.

7.5 FAULT LEVELS

A fault level study was carried out in which it was confirmed that the fault levels are well within the rating of the existing 34.5kV and 13.2kV switchgear.

7.6 TRANSMISSION & DISTRIBUTION SYSTEM DEVELOPMENT

7.6.1 RESILIENCY PLAN

Arising from the devastating impact of Hurricanes Irma and Maria, BVIEC drafted a Resiliency Plan to ensure that a continuous supply of electrical energy is rapidly provided to the most essential services around the Territory following similar events. The high-level summary of the resiliency plan schedule in terms of transmission and distribution system development has been listed in Table 7-5 along with associated capital cost estimates. The activities to enhance network resiliency are mainly associated with undergrounding most of the remaining overhead sections of the network, building new transmission substations, and building new 13.2 kV feeders to ensure the immediate power supply to critical loads cross BVI. The Resiliency Plan will be completed in several phases however BVIEC has not yet provided the timing of the phases.

Table 7-5 – BVI Resiliency Plan Schedule Summary

BVI Resiliency Plan Schedule		
Phase	**Activities**	**Cost(US $'000)**
Phase 1A: The objectives of Phase 1A are to enable immediate power delivery to the island of Virgin Gorda, the Territory's primary water production and sewerage treatment plants, and nationally critical loads in the greater Road Town area. This will be accomplished by undergrounding the last remaining overhead section of the transmission grid, portions of the primary distribution network and the construction of one new substation. **Total Cost of Phase 1A**: US$ 11.9 Millions	**1-Undergrounding 12,000 ft. of 34.5 kV Transmission Line from Sleepy Hill to Bar Bay** *Enables immediate power delivery to East End and Virgin Gorda*	**3,000**
	2-New Paraquita Bay Substation *Facilitates immediate power delivery to the Territory's Largest Single Water Plant*	**4,000**
	3-New Dedicated Underground 13.2 kV EE Feeder-9,000 ft. from ESHS to CTL *House of Assembly, Elmore South High School, RT Police Station, Althea Scatliffe Primary School, Magistrate's Court, Red Cross HQ, Treasure Isle Hotel, The Moorings, Road Town Wholesale, Financial Services Complex, Delta Petroleum Service Station, One Mart, Port Purcell, Fisheries Complex, ZBVI, Public Works Department, Shell*	**2,363**

BVI Resiliency Plan Schedule		
Phase	**Activities**	**Cost(US $'000)**
	Depot, Skelton Quarry, Clarence Thomas Ltd. Receive near immediate power delivery.	
	4-Underground 13.2 kV feeder, 7,700 ft. from Paraquita Bay to Bar Bay *HLSCC, Renewable Energy or Farming Project in Paraquita Bay, Hodge's Creek Marina, BAR BAY Water Plant*	**2,333**
Phase 1B: The objectives of Phase 1B are to enable immediate power delivery to the island of Jost Van Dyke, North Sound Virgin Gorda, critical loads in the Valley, the T.B.L. International Airport, and the Cappoons Bay water production plant. **Total Cost of Phase 1B**: US$ 19.7 Millions	**5-New Underground Feeder, 9,500 ft. from Long Swamp to T.B.L. Int. Airport** *Brackwell Laundromat, RITE BREEZE Supermarket, 2 Marinas and Airport*	**2,771**
	6-Undergrounding portions of the Catholic Church and Fischer's Cove 13.2 kV feeders on Virgin Gorda 33,000 ft. from Fischer's Cove to Gun Creek *St. Thomas Bay Port, Speedy's Corner, Olde Yard Village, Handsome Bay Water Plant, Road Town Wholesale, Bucks Supermarket, Bregado Flax Educational Center Submarine Cable from Fishcers Cove to Gun Creek*	**8,677**
	7-18,000 ft. of new 34.5 kV Transmission Line from Pockwood Pond to Cappoons Bay *Facilitates rapid power delivery to the Western Side of Tortola and Jost Van Dyke*	**4,250**
	8-New Cappoons Bay Substation *Facilitates rapid power delivery to the Western Side of Tortola and Jost Van Dyke*	**4,000**
Phase 2: The objectives of phase 2 are to enable immediate power deliver in certain densely populated villages and strategic areas on the Western, Eastern, Northern and mountainous areas of Tortola. **Total Cost of Phase 2**: US$ 22.2 Millions	**9-New Dedicated Underground 13.2 KV Feeder, 1500 ft. to Elite Superette** *Connecting EE Police Station, LJD VI Block, FINE FOOD Supermarket and Elite*	**525**
	10-Undergrounding portions of the Pockwood Pond West Feeder Mainline *Connections to West End Police Station, Big Ben's Grocery and Gas, Frenchman's Cay, West End Ferry Terminal with entrance points into Long Bay, Apple Bay, Carrot Bay*	**6,952**
	11-Undergrounding portions of the LB West End Feeder (Approximately 23,000 ft.)	**6,473**

BVI Resiliency Plan Schedule		
Phase	**Activities**	**Cost(US $'000)**
	Connecting Chalwell Repeater Stations and Cane Garden Bay key loads	
	12-Undergrounding the Spare Road Town Feeder Mainline (13,000 ft.) *Entrance Points into Lower Estate, Huntums Ghut, Horse Path, Purcell Est., Fort Hill*	**3,575**
	13-Undergrounding portion of the LB Ridge Feeder Mainline (Approx. 17,000 ft.) *Entrance points into Fahie Hill, Long Trench, Manchester, Belle Vue, Hope Hill.*	**4,675**
Total Cost of Transmission and Distribution Development		**53,594**

Phase 3 of the Resiliency Plan includes interconnection of Anegada in order to harness renewable energy potential on the island.

As the proposed timing of the Resiliency Plan has not been provided, we have not included it in the proposed power development plan. We have however made reference to the Resiliency Plan when describing the proposed transmission and distribution developments below. We have also accounted for the associated investment costs in the financial analysis. The Resiliency Plan is shown graphically in Figure 7-4.

7.6.2 2018-2021 DEVELOPMENT

The load flow studies indicate that the existing transmission and distribution system can adequately support the loads up to the expected levels of maximum demand.

7.6.3 2021-2025 DEVELOPMENT

The load flow studies indicate that the existing transmission and distribution system can adequately support the loads up to the expected levels of maximum demand. (Some minor voltage issues were detected however these could be alleviated in 2026 as indicated below.)

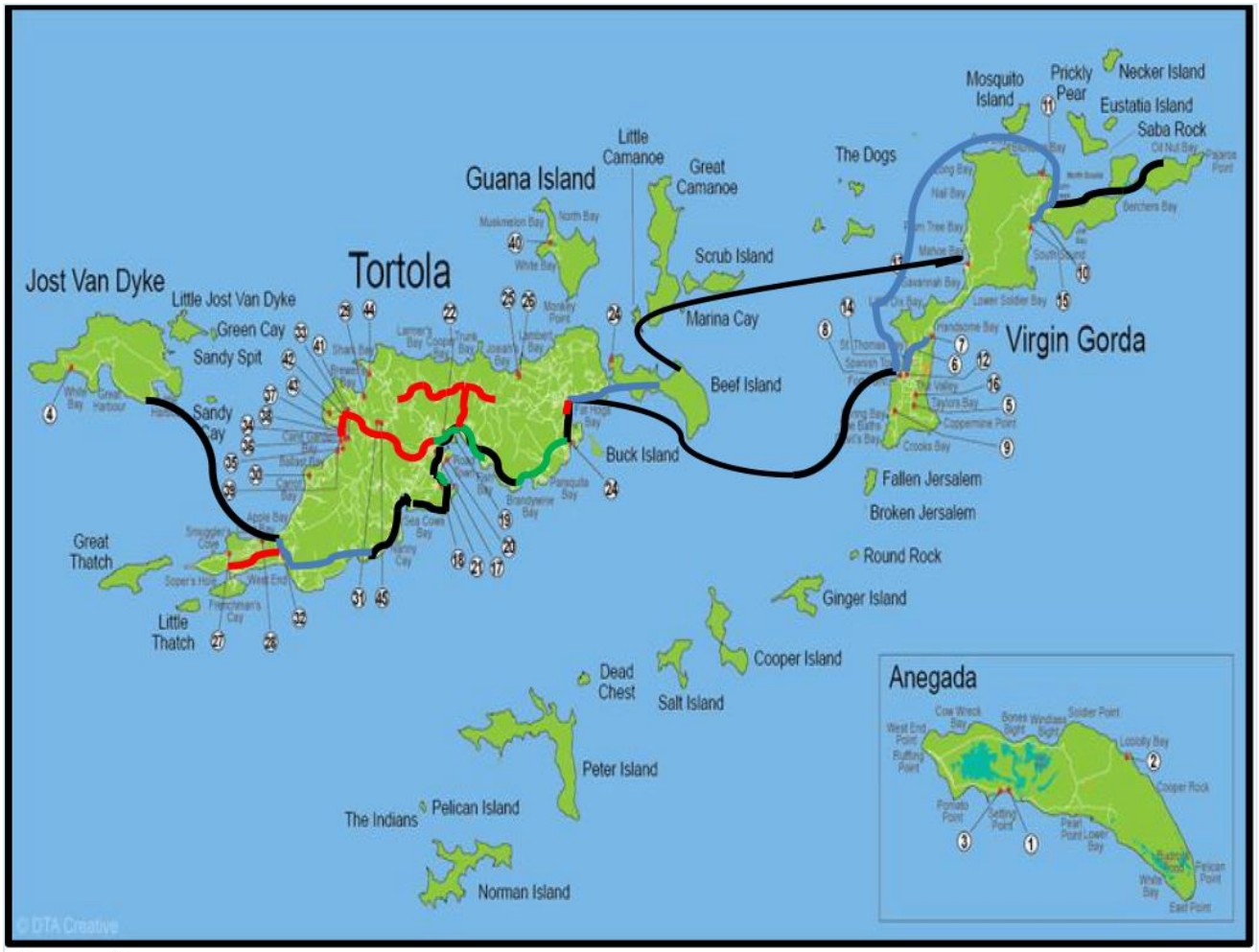
7.6.4 2025-2029 DEVELOPMENT

The 2029 outage studies indicated the need to commission the 4th Pockwood Pond - Long Bush transmission circuit, to avoid the potential overload on the other 34.5 kV transmission circuits between Pockwood Pond and Long Bush. As the circuit will be close to its rating by 2025, the 4th circuit should be commissioned by 2026.

As per BVI Resiliency Plan, a new substation will be built in Paraquita Bay, which would make a transmission circuit outage between Long Bush and Long Swamp less onerous, therefore improving voltage levels at Fischer's Cove during outages.

The estimated capital costs of reinforcements mentioned above are indicated in Table 7-6.

Figure 7-4 - BVIEC Resiliency Plan



Legend

Black: Existing Underground & Submarine Mains Transmission and Distribution Cables

Green: Phase 1A Projects

Blue: Phase 1B Projects

Red: Phase 2 Projects

Table 7-6 - Transmission & distribution system development costs

Latest year work need to be completed	Activity	Cost(US$' 000)	Source of Data
2026	Energise the second underground transmission circuit (Phase V development) between Pockwood Pond and Long Bush 34.5kV circuit breaker at Long Bush - $120,000 34.5kV circuit breaker at Pockwood -$120,000	240	2
2026	Build New Paraquita Bay Substation	4,000	1
2026	Undergrounding 12,000 ft. of 34.5 kV Transmission Line from Sleepy Hill to Bar Bay	3,000	1

Data Source:

1, BVIEC Resiliency Plan 2018

2, WSP database of costs

Figure 7-5 - 2018 Maximum Load

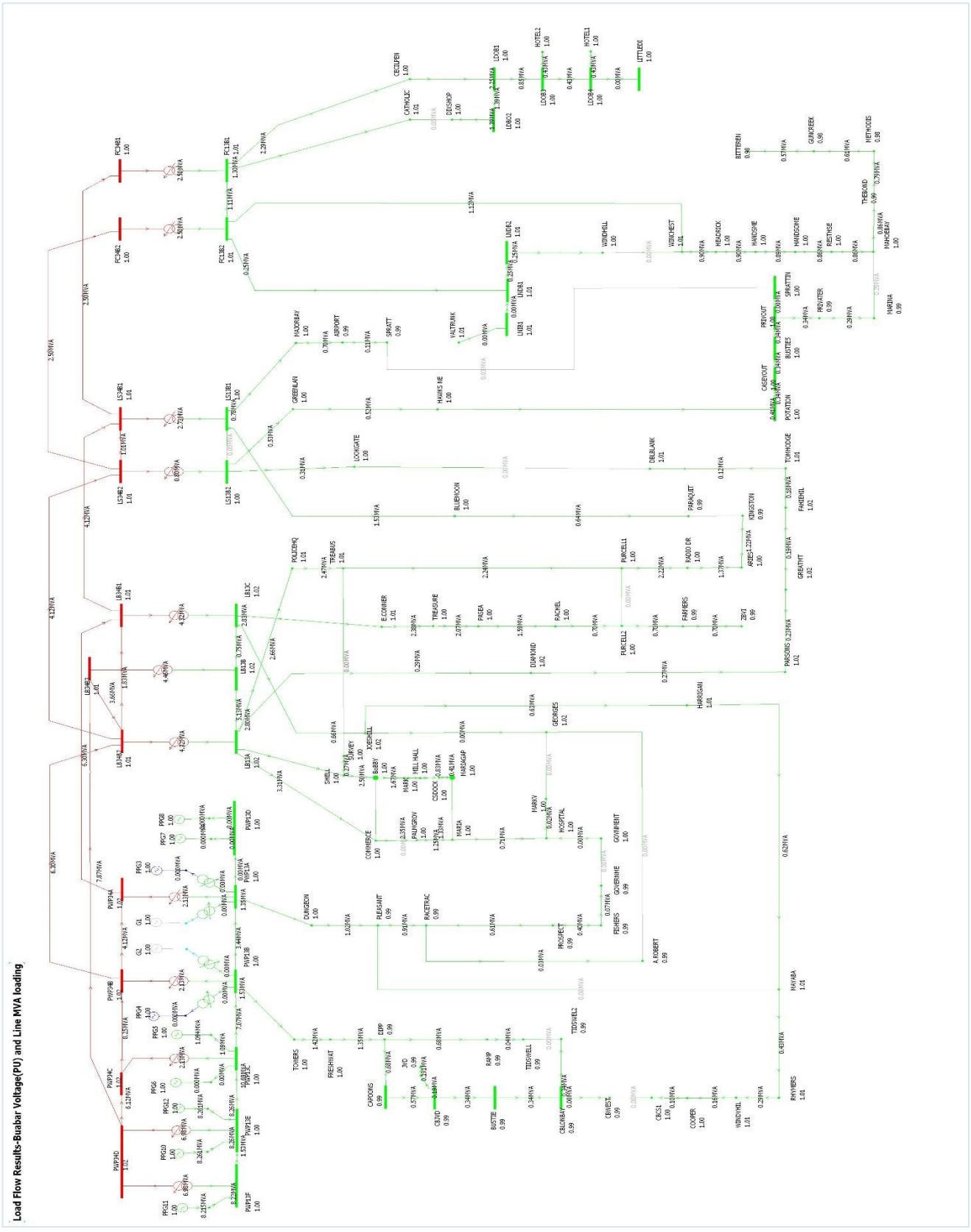
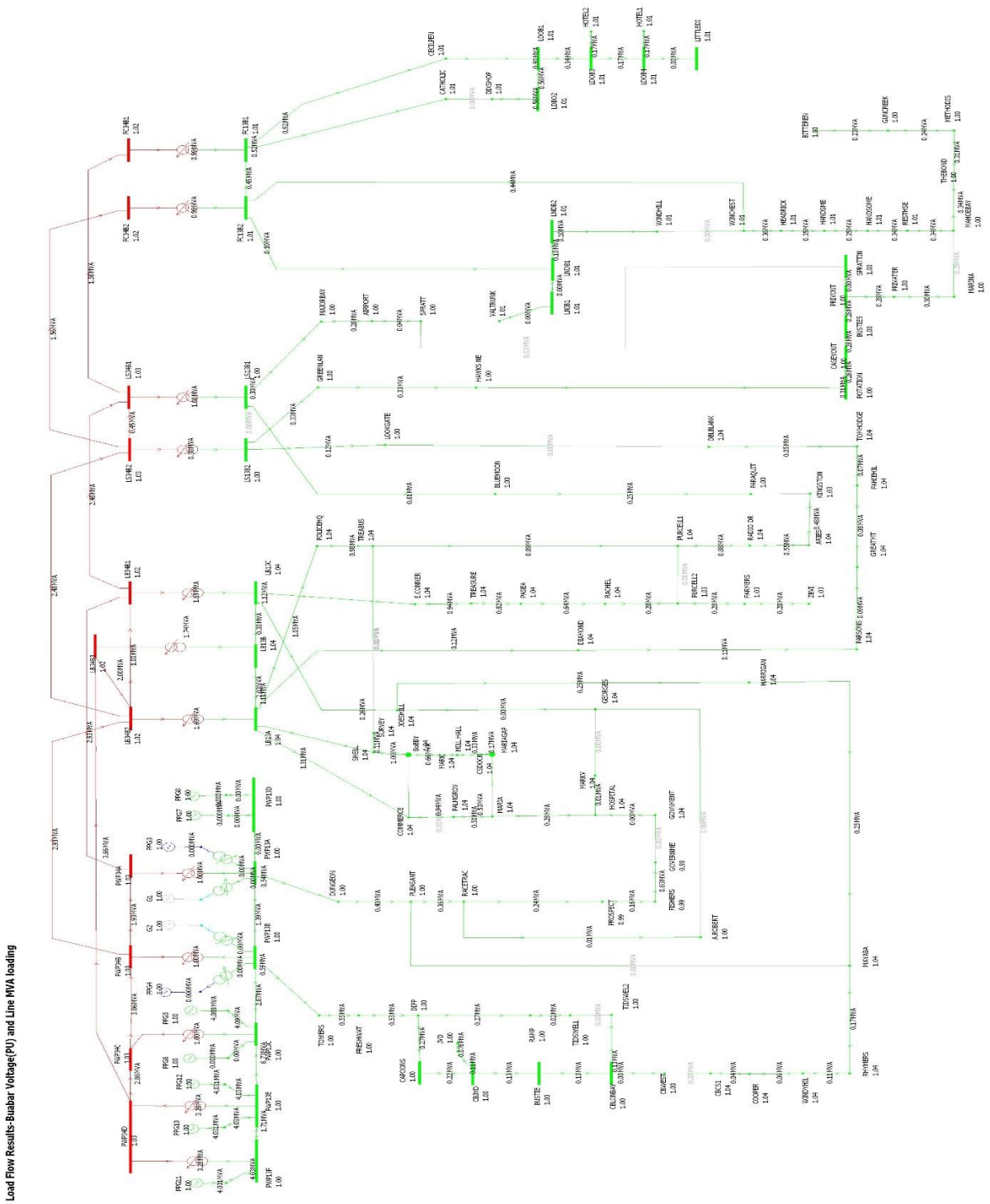


Figure 7-6 - 2018 Minimum Load



8 FINANCIAL ANALYSIS

In this section, we review the adequacy of the existing tariff arrangements to meet the financial requirements of BVIEC over the period 2018-2029. We have approached this task by deriving a cash flow projection for BVIEC, which takes account of:

- future revenues, derived from the sale of electricity;
- attendant expenses incurred by the entire utility (categorised as: generation; distribution; customer services and meter reading; vehicles; general and administrative; finance and information technology);
- financial requirements of the proposed development plan to meet expected growth in demand; and to meet the requirements of the Resiliency Plan
- BVIEC's outstanding financial obligations.

For the purposes of this study, the principal indicator of "adequacy" is deemed to be the continued solvency of BVIEC as company, whilst meeting its financial obligations to amortise debt as set out in its existing and future loan agreements.

8.1 REVENUES

There is one common tariff structure that is applied to all customers of BVIEC, with the exception of street lighting which is charged at a flat rate of USc27.5 /kWh.

BVIEC's tariff comprises of three main elements:

- Energy charge: this charge is predicated by the number of units consumed per month (the first 60 units are charged at USc24 /kWh; the next 24,940 units are charged at USc22.5 /kWh; the next 75,000 units at USc19 /kWh; and every unit consumed above 100,001 is charged at USc16.75 /kWh).
- Fuel surcharge: BVIEC is entitled to add (or subtract) an amount from its energy charge according to the price of fuel used to generate one unit of electricity. In April 2000, the Executive Council set the cost of fuel to USc81.5 per US Gallon, from which actual costs of fuel are compared in the adjustment mechanism.
- Fixed service charge: a monthly charge of US$2.5 is paid by each customer, irrespective of the number of units of electricity consumed in that month. Annual revenues for each consumer category have been derived on the basis of typical consumer monthly charges multiplied by 12 months multiplied by the number of customers in a consumer category.

For the year 2018, we estimate the following level of specific consumption for each consumer category:

- Residential – 222 kWh per month;
- Commercial – 2,697 kWh per month;
- Industrial – 21,246 kWh per month;
- Street Lighting – 46,191 kWh per month

The number of customers, and their specific consumption in each year, is taken directly from the demand forecast, which is described earlier in this report.

Revenue, derived from the sale of electricity, is summarised in Table 8-1.

Table 8-1 - Revenue from Sales of Electricity

	Actual				Forecast											
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Residential																
Total residential sales (MWh)	53,864	57,444	61,182	40,396	40,399	44,263	48,135	52,010	55,887	59,767	61,253	62,775	64,335	65,933	67,558	69,223
Sales per meter (kWh p.a.)	3,824	4,025	4,251	2,720	2,662	2,855	3,041	3,219	3,391	3,556	3,575	3,596	3,618	3,641	3,665	3,690
Sales per meter (kWh p.m.)	319	335	354	227	222	238	253	268	283	296	298	300	301	303	305	307
- @ 24 c/kWh	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
- @ 22.5 c/kWh	259	275	294	167	162	178	193	208	223	236	238	240	241	243	245	247
- @ 19 c/kWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
- @ 16.75 c/kWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
Energy charge per meter (US$ p.a.)	871	916	967	623	610	653	695	735	774	811	815	820	825	830	835	841
Fuel surcharge (US$ p.a.)	539	296.03	212.21	218.96	278	258	330	360	390	421	435	451	466	483	500	517
Fixed service charge (US$ p.a.)	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Revenue per meter (US$ p.a.)	1,440	1,243	1,210	872	918	942	1,055	1,125	1,193	1,262	1,280	1,301	1,321	1,343	1,365	1,388
No. of meters	14,085	14,271	14,392	14,853	15,179	15,504	15,830	16,155	16,481	16,807	17,132	17,458	17,784	18,109	18,435	18,761
Annual revenue (US$ x1000)	20,280	17,732	17,407	12,947	13,933	14,598	16,701	18,172	19,669	21,203	21,938	22,705	23,493	24,319	25,167	26,042
Commercial																
Total commercial sales (MWh)	107,712	117,507	121,846	80,450	80,456	89,466	101,645	117,115	132,786	141,826	144,786	147,818	150,924	154,107	157,343	160,659
Sales per customer (kWh p.a.)	47,077	50,891	52,862	33,215	32,370	35,099	38,909	43,768	48,476	50,605	50,518	50,459	50,428	50,423	50,435	50,472
Sales per customer (kWh p.m.)	3,923	4,241	4,405	2,768	2,697	2,925	3,242	3,647	4,040	4,217	4,210	4,205	4,202	4,202	4,203	4,206
- @ 24 c/kWh	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
- @ 22.5 c/kWh	3,863	4,181	4,345	2,708	2,637	2,865	3,182	3,587	3,980	4,157	4,150	4,145	4,142	4,142	4,143	4,146
- @ 19 c/kWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
- @ 16.75 c/kWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
Energy charge per customer (US$ p.a.)	10,603	11,461	11,905	7,484	7,294	7,908	8,765	9,859	10,918	11,397	11,377	11,364	11,357	11,356	11,359	11,367
Fuel surcharge (US$ p.a.)	6,630	3,743	2,639	2,674	3,385	3,177	4,223	4,890	5,570	5,986	6,150	6,324	6,499	6,688	6,878	7,073
Fixed service charge (US$ p.a.)	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Revenue per customer (US$ p.a.)	17,264	15,234	14,573	10,188	10,709	11,115	13,019	14,779	16,518	17,413	17,557	17,718	17,886	18,074	18,267	18,470
No. of meters	2,288	2,309	2,305	2,422	2,486	2,549	2,612	2,676	2,739	2,803	2,866	2,929	2,993	3,056	3,120	3,183
Annual revenue (US$ x1000)	39,499	35,175	33,592	24,677	26,617	28,331	34,010	39,544	45,246	48,801	50,319	51,905	53,531	55,238	56,988	58,794
Industrial																
Total industrial sales (MWh)	13,591	9,064	8,083	6,134	6,135	8,999	9,587	10,175	10,764	11,353	11,579	11,810	12,047	12,290	12,536	12,789
Sales per customer (kWh p.a.)	543,640	362,560	323,318	251,310	254,951	379,068	409,001	439,359	470,123	501,275	516,576	532,148	548,008	564,178	580,582	597,322
Sales per customer (kWh p.m.)	45,303	30,213	26,943	20,943	21,246	31,589	34,083	36,613	39,177	41,773	43,048	44,346	45,667	47,015	48,382	49,777
- @ 24 c/kWh	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
- @ 22.5 c/kWh	24,940	24,940	24,940	20,883	21,186	24,940	24,940	24,940	24,940	24,940	24,940	24,940	24,940	24,940	24,940	24,940
- @ 19 c/kWh	20,303	5,213	1,943	-	-	6,589	9,083	11,613	14,177	16,773	18,048	19,346	20,667	22,015	23,382	24,777
- @ 16.75 c/kWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
Energy charge per customer (US$ p.a.)	113,802	79,397	71,941	56,556	57,375	82,534	88,221	93,989	99,834	105,753	108,660	111,619	114,632	117,705	120,821	124,002
Fuel surcharge (US$ p.a.)	76,567	26,664	16,140	20,232	26,660	34,307	44,395	49,087	54,018	59,295	62,885	66,696	70,628	74,829	79,181	83,712
Fixed service charge (US$ p.a.)	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Revenue per customer (US$ p.a.)	190,400	106,092	88,111	76,818	84,065	116,870	132,646	143,106	153,882	165,078	171,575	178,345	185,290	192,564	200,033	207,744
No. of customers	25	25	25	24	24	24	23	23	23	23	22	22	22	22	22	21
Annual revenue (US$ x1000)	4,760	2,652	2,203	1,875	2,023	2,775	3,109	3,314	3,523	3,739	3,846	3,958	4,073	4,195	4,319	4,448
Street Lighting																
Total street lighting sales (MWh)	3,863	3,863	3,863	2,551	554	750	927	1,127	1,134	1,141	1,148	1,156	1,163	1,170	1,177	1,185
Annual revenue (US$ x1000)	1,062	1,062	1,062	701	152	206	255	310	312	314	316	318	320	322	324	326
Total Revenue	**65,602**	**56,622**	**54,264**	**40,201**	**42,726**	**45,909**	**54,075**	**61,341**	**68,750**	**74,057**	**76,418**	**78,885**	**81,417**	**84,074**	**86,798**	**89,610**

8.2 EXPENSES

The following items briefly describe the cost assumptions employed in the derivation of expenses for the cash flow forecast. A table summarising these costs is provided at the end of this subsection.

8.2.1 GENERATION

Staff costs are estimated to increase in-line with inflation.

Fuel oil and lube oil costs have been derived from the generation planning results, as described earlier in the report. The annual costs have then been escalated in-line with inflation.

Maintenance cost and general expenses have been estimated from the arithmetic average of actual costs over the period 2014 to 2016. The annual cost has then been escalated in-line with inflation.

8.2.2 DISTRIBUTION AND TRANSMISSION

Staff costs are estimated to increase in proportion to the number of units generated by BVIEC. The annual cost has then been escalated in-line with inflation.

Materials and maintenance expenditure and General expenses have been estimated from the arithmetic average of actual costs over the period 2014-2016 and 2014-2017 respectively. The annual cost has then been escalated in-line with inflation.

8.2.3 CUSTOMER SERVICES AND METER READING

Staff costs have been estimated to increase in proportion to the number of customers supplied by BVIEC. The annual cost has then been escalated in-line with inflation.

General expenses have also been estimated to increase in proportion to the number of customers supplied by BVIEC. The annual cost has then been escalated in-line with inflation.

8.2.4 VEHICLES

Staff costs and **general expenses** have been estimated from the actual cost incurred by BVIEC in 2017. This value is assumed to escalate in-line with inflation thereafter.

8.2.5 GENERAL AND ADMINISTRATIVE

Staff costs have been estimated from the actual cost incurred by BVIEC in 2017. This value is assumed to escalate in-line with inflation.

Legal and professional fees and **General Expenses** have been estimated from the arithmetic average of actual costs over the period 2014 to 2017. These values are assumed to escalate in-line with inflation thereafter. The values for **Insurance** for 2018 and 2019 have been provided and BVIEC advised that the figures can escalate with 3 % increase in 2020-2021 and 5% increase in 2022-2029.

8.2.6 FINANCE

Staff costs have been estimated from the actual cost incurred by BVIEC in 2017. This value is assumed to escalate in-line with inflation.

General expenses have been estimated from the arithmetic average of actual costs over the period 2014 to 2017. These values are assumed to escalate in-line with inflation thereafter.

8.2.7 INFORMATION TECHNOLOGY

Staff costs have been estimated from the actual cost incurred by BVIEC in 2017. This value is assumed to escalate in-line with inflation.

General expenses have been estimated from the arithmetic average of actual costs over the period 2014 to 2017. These values are assumed to escalate in-line with inflation thereafter.

Table 8-2 – Expenses

US$	Actual				Forecast											
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Generation+Fuel																
Staff costs	2,902,574	2,925,513	3,070,779	2,783,529	2,839,200	2,895,984	2,953,903	3,012,981	3,073,241	3,134,706	3,197,400	3,261,348	3,326,575	3,393,106	3,460,968	3,530,188
Fuel oil+ Lubricating oil	39,754,686	26,253,670	21,989,985	19,634,402	21,810,170	24,782,121	27,161,754	31,142,756	35,246,253	38,351,821	39,949,607	41,644,405	43,372,277	45,221,083	47,116,156	49,072,894
Materials and maintenance	3,843,897	3,633,353	4,517,499	2,669,091	4,078,215	4,159,779	4,242,975	4,327,834	4,414,391	4,502,679	4,592,732	4,684,587	4,778,278	4,873,844	4,971,321	5,070,747
General expenses	254,623	270,525	298,557	748,887	280,060	285,661	291,374	297,202	303,146	309,209	315,393	321,701	328,135	334,697	341,391	348,219
	46,755,780	33,083,061	29,876,820	25,835,909	29,007,644	32,123,544	34,650,006	38,780,773	43,037,030	46,298,414	48,055,131	49,912,041	51,805,265	53,822,731	55,889,836	58,022,048
Distribution and Transmission																
Staff costs	2,349,857	2,377,886	2,566,786	2,324,880	2,348,188	2,694,930	3,071,700	3,520,160	3,989,372	4,342,084	4,525,299	4,716,499	4,916,032	5,124,329	5,338,182	5,564,131
Materials and maintenance	1,960,389	174,511	1,312,984	(76,354)	1,172,281	1,345,384	1,533,477	1,757,361	1,991,605	2,167,688	2,259,154	2,354,606	2,454,219	2,558,207	2,664,968	2,777,768
General expenses	419,424	333,680	353,294	323,206	364,549	371,840	379,277	386,862	394,600	402,492	410,541	418,752	427,127	435,670	444,383	453,271
	4,729,670	2,886,077	4,233,064	2,571,732	3,885,018	4,412,154	4,984,454	5,664,384	6,375,576	6,912,264	7,194,994	7,489,857	7,797,378	8,118,206	8,447,533	8,795,170
Customer Services and Meter Reading																
Staff costs	962,470	912,371	881,510	823,919	859,281	895,729	933,292	972,001	1,011,885	1,052,977	1,095,308	1,138,913	1,183,824	1,230,076	1,277,706	1,326,749
General expenses	61,096	58,608	46,480	48,735	54,804	57,129	59,525	61,994	64,537	67,158	69,858	72,639	75,503	78,453	81,491	84,619
	1,023,566	970,979	927,990	872,654	914,085	952,858	992,817	1,033,994	1,076,422	1,120,135	1,165,166	1,211,552	1,259,327	1,308,529	1,359,197	1,411,368
Vehicles																
Staff costs	230,408	234,596	294,281	307,480	313,630	319,902	326,300	332,826	339,483	346,272	353,198	360,262	367,467	374,816	382,313	389,959
General expenses	10,953	13,832	14,447	21,659	22,092	22,534	22,985	23,444	23,913	24,392	24,879	25,377	25,885	26,402	26,930	27,469
	241,361	248,428	308,728	329,139	335,722	342,436	349,285	356,271	363,396	370,664	378,077	385,639	393,352	401,219	409,243	417,428
General and Administrative																
Staff costs	815,452	865,057	838,355	946,563	965,494	984,804	1,004,500	1,024,590	1,045,082	1,065,984	1,087,303	1,109,049	1,131,230	1,153,855	1,176,932	1,200,471
Insurance	661,176	676,282	659,083	727,157	2,121,930	1,221,570	1,258,217	1,295,964	1,360,762	1,428,800	1,500,240	1,575,252	1,654,014	1,736,715	1,823,551	1,914,728
Legal and professional fees	471,505	583,477	603,642	377,943	519,325	529,711	540,305	551,111	562,134	573,376	584,844	596,541	608,472	620,641	633,054	645,715
General expenses	515,684	687,389	1,003,260	970,517	810,097	826,299	842,825	859,681	876,875	894,412	912,301	930,547	949,157	968,141	987,503	1,007,253
	2,463,817	2,812,205	3,104,340	3,022,180	4,416,846	3,562,384	3,645,847	3,731,346	3,844,852	3,962,572	4,084,688	4,211,389	4,342,874	4,479,352	4,621,040	4,768,168
Finance																
Staff costs	1,091,807	1,146,217	1,155,929	1,081,349	1,102,976	1,125,035	1,147,536	1,170,487	1,193,897	1,217,775	1,242,130	1,266,973	1,292,312	1,318,158	1,344,522	1,371,412
General expenses	151,688	287,071	247,104	218,777	230,683	235,297	240,003	244,803	249,699	254,693	259,787	264,982	270,282	275,688	281,202	286,826
	1,243,495	1,433,288	1,403,033	1,300,126	1,333,659	1,360,332	1,387,539	1,415,290	1,443,596	1,472,467	1,501,917	1,531,955	1,562,594	1,593,846	1,625,723	1,658,238
Information Technology																
Staff costs	338,669	353,185	379,404	403,887	411,965	420,204	428,608	437,180	445,924	454,842	463,939	473,218	482,682	492,336	502,183	512,226
General expenses	188,423	194,913	245,438	228,365	218,570	222,942	227,401	231,949	236,588	241,319	246,146	251,069	256,090	261,212	266,436	271,765
	527,092	548,098	624,842	632,252	630,535	643,146	656,009	669,129	682,512	696,162	710,085	724,287	738,772	753,548	768,619	783,991
Total expenses	**56,984,781**	**41,982,136**	**40,478,817**	**34,563,992**	**40,523,509**	**43,396,855**	**46,665,957**	**51,651,186**	**56,823,384**	**60,832,678**	**63,090,058**	**65,466,719**	**67,899,562**	**70,477,431**	**73,121,191**	**75,856,410**

8.3 POWER DEVELOPMENT PLAN AND RESILIENCY PLAN

BVIEC's estimated cost for the transmission and distribution elements of the resiliency plan is US$ 53.59 million. However, the critical capital expenditure items that BVIEC intends to focus on over the period are:

1. The purchase of a new engine.

2. The undergrounding of the transmission line.

3. A new substation at Paraquita Bay.

Table 8-3 summarises the timing and extent of capital expenditure required to meet the needs of BVIEC systems of the period to 2029 based on generation planning and transmission & distribution development studies which were described earlier in this report and based on the above critical items from the Resiliency Plan.

It was assumed that BVIEC would aim to complete other elements of the Resiliency Plan based on financial viability.

Table 8-3 - Capital Expenditure Associated with Power Development Plan

(US$ x 1000)			Forecast										
			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Generation														
Unit Name	**(MW)**													
PP03		5.0	-	-	-	-	-	-	-	-	-	-	-	-
PP04		5.0	-	-	-	-	-	-	-	-	-	-	-	-
PP05		5.5	-	-	-	-	-	-	-	-	-	-	-	-
PP06		5.5	-	-	-	-	-	-	-	-	-	-	-	-
PP07		5.5	-	-	-	-	-	-	-	-	-	-	-	-
PP08		5.5	-	-	-	-	-	-	-	-	-	-	-	-
PP09		8.5	-	-	-	-	-	-	-	-	8,857	-	-	-
PP10		8.5	-	-	-	-	-	-	-	-	-	-	-	-
PP11		8.5	-	-	-	-	-	-	-	-	-	-	-	-
PP12		8.5	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal			-	-	-	-	-	-	-	-	8,857	-	-	
Transmission & Distribution														
Commission 4th Pockwood Pond_Long Bush 34.5kV underground circuit			-	-	-	-	-	-	-	-	240	-	-	-
Construct new 34.5/13.2kV substation at Paraquita Bay(Part of Resiliency Plan)			-	-	-	-	-	-	-	-	4,000	-	-	-
Resiliency Plan Phase 1 Undergrounding 12,000 ft. of 34.5 kV Transmission Line from Sleepy Hill to Bar Bay			-	-	-	-	-	-	-	-	3,000	-	-	-
Subtotal			-	-	-	-	-	-	-	-	7,240	-	-	-
Total investment (excluding connection costs)			-	-	-	-	-	-	-	-	16,097	-	-	-

8.4 OTHER COST CONSIDERATIONS

In addition to the expenses and capital requirements described above, we have made the following assumptions regarding other cost considerations:

- No inventory adjustments.
- No change in working capital.

8.5 EXISTING AND NEW LONG-TERM LOANS

As at the end of December 2017, BVIEC had two long-term loans with a combined outstanding balance of about US$33.3 million.

- Banco Popular de Puerto Rico (US$3,501,201)
- Social Security Board (US$29,750,002)

BVIEC estimates that Generating Set #9 will be purchased in 2026 using a new loan of US$ 9.7 million.

A summary of BVIEC's existing and expected new loans is provided in Table 8-4.

Table 8-4 - Schedule of Existing and New Loans (US$ ×1000)

	Forecast											
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Social Security Board												
Principal repayment	(583)	(2,333)	(2,333)	(2,333)	(2,333)	(2,333)	(2,333)	(2,333)	(2,333)	(2,333)	(2,333)	(2,333)
Interest paid	(1,062)	(1,011)	(929)	(847)	(844)	(977)	(860)	(744)	(627)	(510)	(394)	(277)
Banco Popular												
Principal repayment	(2,501)	(2,001)	(2,153)	-	-	-	-	-	-	-	-	-
Interest paid	(305)	(234)	(72)	-	-	-	-	-	-	-	-	-
New Loan												
Opening balance	-	-	-	-	-	-	-	-	9,700	8,730	7,760	6,790
Principal repayment	-	-	-	-	-	-	-	-	(970)	(970)	(970)	(970)
Closing Balance	-	-	-	-	-	-	-	-	8,730	7,760	6,790	5,820
Interest paid	-	-	-	-	-	-	-	-	(560)	(502)	(444)	(386)
Interest Paid	(1,367)	(1,245)	(1,001)	(847)	(844)	(977)	(860)	(744)	(1,187)	(1,012)	(838)	(663)
Repayment of Loan Principal	(3,084)	(4,334)	(4,486)	(2,333)	(2,333)	(2,333)	(2,333)	(2,333)	(3,303)	(3,303)	(3,303)	(3,303)

8.6 CASH FLOW FORECAST

The various cost and revenue projections for BVIEC, over the period to 2029, are brought together in the cash flow projection given in Table 8-5.

Assuming that no extraordinary expenditure is incurred during 2018-2029, we estimate that BVIEC will be able to meet its financial obligations and remain solvent over the period to 2029 based on this cash flow projection. In other words, on the basis that all the cash generated from operations is retained within the Corporation, we believe that the existing tariff arrangements will enable BVIEC to achieve positive cash-flow over the period to 2029.

Table 8-5 - Cash Flow Projection (US$×1000)

(US$ x 1000)	Actual				Forecast											
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Income																
Electricity Sales	66,365	54,271	51,061	39,410	42,726	45,909	54,075	61,341	68,750	74,057	76,418	78,885	81,417	84,074	86,798	89,610
- residential					*13,933*	*14,598*	*16,701*	*18,172*	*19,669*	*21,203*	*21,938*	*22,705*	*23,493*	*24,319*	*25,167*	*26,042*
- commercial					*26,617*	*28,331*	*34,010*	*39,544*	*45,246*	*48,801*	*50,319*	*51,905*	*53,531*	*55,238*	*56,988*	*58,794*
- industrial					*2,023*	*2,775*	*3,109*	*3,314*	*3,523*	*3,739*	*3,846*	*3,958*	*4,073*	*4,195*	*4,319*	*4,448*
- street lighting					*152*	*206*	*255*	*310*	*312*	*314*	*316*	*318*	*320*	*322*	*324*	*326*
Other income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	66,365	54,271	51,061	39,410	42,726	45,909	54,075	61,341	68,750	74,057	76,418	78,885	81,417	84,074	86,798	89,610
Expenses																
Generation	46,756	33,083	29,877	25,836	29,008	32,124	34,650	38,781	43,037	46,298	48,055	49,912	51,805	53,823	55,890	58,022
Distribution	4,730	2,886	4,233	2,572	3,885	4,412	4,984	5,664	6,376	6,912	7,195	7,490	7,797	8,118	8,448	8,795
Customer Services and Meter Reading	1,024	971	928	873	914	953	993	1,034	1,076	1,120	1,165	1,212	1,259	1,309	1,359	1,411
Vehicles	241	248	309	329	336	342	349	356	363	371	378	386	393	401	409	417
General and Administrative	2,464	2,812	3,104	3,022	4,417	3,562	3,646	3,731	3,845	3,963	4,085	4,211	4,343	4,479	4,621	4,768
Finance	1,243	1,433	1,403	1,300	1,334	1,360	1,388	1,415	1,444	1,472	1,502	1,532	1,563	1,594	1,626	1,658
Information Technology	527	548	625	632	631	643	656	669	683	696	710	724	739	754	769	784
Depreciation	4,105	4,035	4,024	6,030	5,415	4,610	4,811	5,001	5,181	5,350	5,511	5,662	6,071	5,792	5,529	5,280
Other Expense	130	382	188	590	45	46	47	48	49	50	51	52	53	54	55	56
	61,220	46,399	44,691	41,184	45,984	48,053	51,524	56,700	62,053	66,233	68,651	71,181	74,023	76,323	78,705	81,192
Operating (loss)/profit	5,145	7,872	6,371	(1,774)	(3,258)	(2,143)	2,551	4,641	6,697	7,824	7,767	7,705	7,393	7,750	8,093	8,418
Total Other Income	1,052	1,147	1,212	1,167	1,043	1,248	1,273	1,299	1,325	1,351	1,378	1,406	1,434	1,463	1,492	1,522
Total Comprehensive income/(loss)	3,566	7,443	8,081	(1,030)	(3,582)	(2,139)	2,823	5,092	7,177	8,198	8,285	8,367	7,640	8,201	8,748	9,277
Operating Profit b/f WC	8,595	12,261	12,791	9,140	3,187	3,700	8,621	10,927	13,190	14,514	14,645	14,763	14,889	14,996	15,104	15,208
Change in Working Capital	(2,364)	1,239	(4,853)	5,447	-	-	-	-	-	-	-	-	-	-	-	-
Net Cash Flows from operating activities	6,231	13,500	7,938	14,587	3,187	3,700	8,621	10,927	13,190	14,514	14,645	14,763	14,889	14,996	15,104	15,208
Investing Activities																
- Purchase of property, plant and equipment	(1,602)	(18,218)	(23,990)	(15,464)	-	(1,281)	(1,242)	(1,500)	(1,200)	(1,500)	(1,500)	(1,200)	(16,097)	(1,500)	(1,200)	(1,500)
- Proceeds of fixed term deposits	(812)	(1,884)	(9)	(44)			1,038									
- Proceeds from sale of fixed assets	-	-	-	266	-	-	-	-	-	-	-	-	-	-	-	-
- Interest received	37	43	24	58	45	46	47	48	49	50	51	52	53	54	55	56
Net Cash Flows used in investing activities	(2,377)	(20,059)	(23,976)	(15,185)	45	(1,235)	(157)	(1,452)	(1,151)	(1,450)	(1,449)	(1,148)	(16,044)	(1,446)	(1,145)	(1,444)
Loan Payable																
New Loan													9,700			
Net proceeds from loans payable	(2,001)	5,679	11,245	8,574	(3,084)	(4,334)	(4,486)	(2,333)	(2,333)	(2,333)	(2,333)	(2,333)	(3,303)	(3,303)	(3,303)	(3,303)
Interest paid	(942)	(812)	(708)	(997)	(1,367)	(1,245)	(1,001)	(847)	(844)	(977)	(860)	(744)	(1,187)	(1,012)	(838)	(663)
Net cash flows from financing activities	(2,942)	4,867	10,538	7,577	(4,451)	(5,578)	(5,487)	(3,181)	(3,178)	(3,310)	(3,194)	(3,077)	5,209	(4,316)	(4,141)	(3,966)
Funds in Escrow Account	-	-	-		-	1,527	-	-	-	-	-	-	-	-	-	-
Net increase/(decrease) in Cash and Cash equivalents	912	(1,692)	(5,501)	6,979	(1,220)	(1,586)	2,977	6,294	8,861	9,753	10,002	10,537	4,055	9,235	9,818	9,798
Cash and cash equivalents at beginning of year	9,101	9,993	8,287	2,829	9,750	8,500	6,883	9,827	16,088	24,912	34,628	44,590	55,086	59,097	68,286	78,059
Effect of exchange rate fluctuations on cash and cash equivalents(Foreign exchange gains/(loss))	(19)	(14)	43	(58)	(31)	(31)	(33)	(34)	(36)	(38)	(40)	(42)	(44)	(45)	(45)	(45)
Cash and cash equivalents at end of year	9,993	8,287	2,829	9,750	8,500	6,883	9,827	16,088	24,912	34,628	44,590	55,086	59,097	68,286	78,059	87,812
Opening Balance	9,101	9,993	8,287	2,829	9,750	8,500	6,883	9,827	16,088	24,912	34,628	44,590	55,086	59,097	68,286	78,059
(Decrease)/Increase in Cash	893	(1,706)	(5,458)	6,921	(1,251)	(1,617)	2,945	6,260	8,825	9,715	9,962	10,496	4,011	9,190	9,773	9,753
Closing Balance	9,993	8,287	2,829	9,750	8,500	6,883	9,827	16,088	24,912	34,628	44,590	55,086	59,097	68,286	78,059	87,812

9 CONCLUSIONS

9.1 GENERAL

This report includes the generation, transmission and distribution development plan and underlying analysis together with financial analysis based on the existing tariff arrangements.

In order to ensure the relevance of the study, it was necessary to significantly revise the demand forecast to take account of the devastation caused by the hurricanes. The study also considers certain initiatives implemented since the original commencement date including:

- The Government of the Virgin Islands Energy Policy, dated 13th October 2016 which includes renewable energy targets, and
- BVIEC's 2018 Resiliency Plan which focuses in particular on undergrounding overhead portions of the transmission network and certain key distribution circuits in order to improve resilience to major hurricanes and other natural disasters.

9.2 DEMAND FORECAST

WSP has developed a revised demand forecast as described in detail in the report. The forecast assumes rapid recovery of demand over the next four years followed by more gradual growth in line with historical trends. For the Base Case, the peak demand is forecast to increase from 23 MW in 2018 to 44 MW by 2029

9.3 RENEWABLES

BVIEC currently produces all of its electricity from diesel generators, however the British Virgin Islands Electricity Corporation Amendment Act 2015 and British Virgin Islands Electricity Corporation (Renewable Energy) Regulations, 2018 which came into effect on November 1, 2018 means that the Territory now has the legal framework to advance the development of renewable energy.

Further to this, the Government of the Virgin Islands Energy Policy, dated 13th October 2016 includes various energy strategies and policy actions.

The main strategies on the supply side are aimed at reducing dependence on imported oil by increasing the availability and use of alternative fuel sources (such as renewable energy) and conducting long-term planning of resource needs and improving supply-side competition.

The BVI government has set a target to supply 30% of the territory's energy from renewable means by 2023 including:

- Up to 6 MW of wind power
- 2.5 MW of solar power
- 1.5 MW of energy from waste and
- 1 MW of sea/wave or other resources

In this study we have focused on solar and wind power. Ocean technology is unlikely to be viable within the 2023 timescale and it seems unlikely that there is sufficient waste for an economically viable energy from waste plant.

The study estimates that the 6 MW of wind power and 2.5 MW of solar PV will jointly provide approximately 8% of the Territory's electricity requirements by 2023.

WSP has investigated a number of potential renewable energy sites including three wind power sites with a total capacity of 9.6 MW and 12 solar PV sites with a total capacity of 20.4 MW.

This level of solar and wind power capacity would provide approximately 23% of the Territory's electricity needs by 2029 but would need significant storage capacity in order to fully harness this level of renewable resource.

9.4 GENERATION PLAN

A number of scenarios were evaluated, based on the status quo and also to take account of the Energy Policy as follows:

Scenario 1 – Generation based on diesels only

Scenario 2 – Generation based on diesels and 2.5 MW of solar PV

Scenario 3 – Generation based on diesels and 6 MW of wind

Scenario 4 – Generation based on diesels, 2.5 MW of solar PV and 6 MW of wind

Due to the intermittent nature of renewables, it was assumed that they would not contribute to the generation capacity requirements.

In order to meet the forecast demand growth up to 2029 and maintain required capacity planning margin equal to the two largest generating units, it is necessary to commission Unit 9 (8.5MW) by 2026. BVIEC should retire Units 3 and 4 in-situ by 2026 such that they may still be deployed in an emergency whilst developing a new power plant. The above capacity additions will be required irrespective of the level of solar or wind power generation added to the system.

The addition of solar PV and/or wind power generation will however result in a reduction in the cost of generation in BVI. This means that the capital costs of the solar PV or wind will be recovered through savings in fuel costs.

Solar PV remains economically attractive over a wide range of discount rates, fuel prices and capital costs. Wind power is economically attractive at fuel prices above 2 USD/US gallon.

In the longer term (beyond the 2029 horizon) an alternative fossil fuel power plant will be required to provide additional capacity. A second power plant will also increase security of supply. This could utilise a cleaner fuel such as LNG or LPG.

9.5 TRANSMISSION AND DISTRIBUTION PLAN

The transmission and distribution system has been modelled using a power systems analysis computer program IPSA, and studies carried out for the period 2018 to 2029 based on the High Case demand forecast.

The studies indicate that the existing network is adequate to meet the forecast peak demand up to 2025. The studies however indicate the need for certain reinforcements by 2026 as follows:

- Commission 4th Pockwood Pond – Long Bush 34.5 kV underground circuit
- Construct new 34.5/13.2 kV substation at Paraquita Bay

The estimated cost of these reinforcements is approximately USD 4.24 million.

The BVIEC Resiliency Plan includes extensive measures to increase the resiliency of the network by undergrounding the remaining overhead sections of the transmission network and certain key distribution feeders and building new transmission substations to ensure the immediate power supply to critical loads across the BVI. The Paraquita Bay substation mentioned above is in fact part of the Resiliency Plan. The estimated cost of the transmission and distribution elements of the Resiliency Plan is approximately USD 54 million. Further studies would be required to fully integrate the Resiliency and Power Development Plans.

9.6 FINANCIAL ANALYSIS

The various cost and revenue projection for BVIEC, over the period to 2029, are brought together in the cash flow projections given in Table 8-5.

Assuming that no extraordinary expenditure is incurred during 2018-2029, we estimate that BVIEC will be able to meet its financial obligations and remain solvent over the period to 2029 based on this cash flow projection. In other words, on the basis that all of the cash generated from operations is retained within the Corporation, we believe that the existing tariff arrangements will enable BVIEC to achieve positive cash-flow over the period to 2029.

Appendix A

LOAD FLOW PLOTS

Appendix A - Load Flow Plots

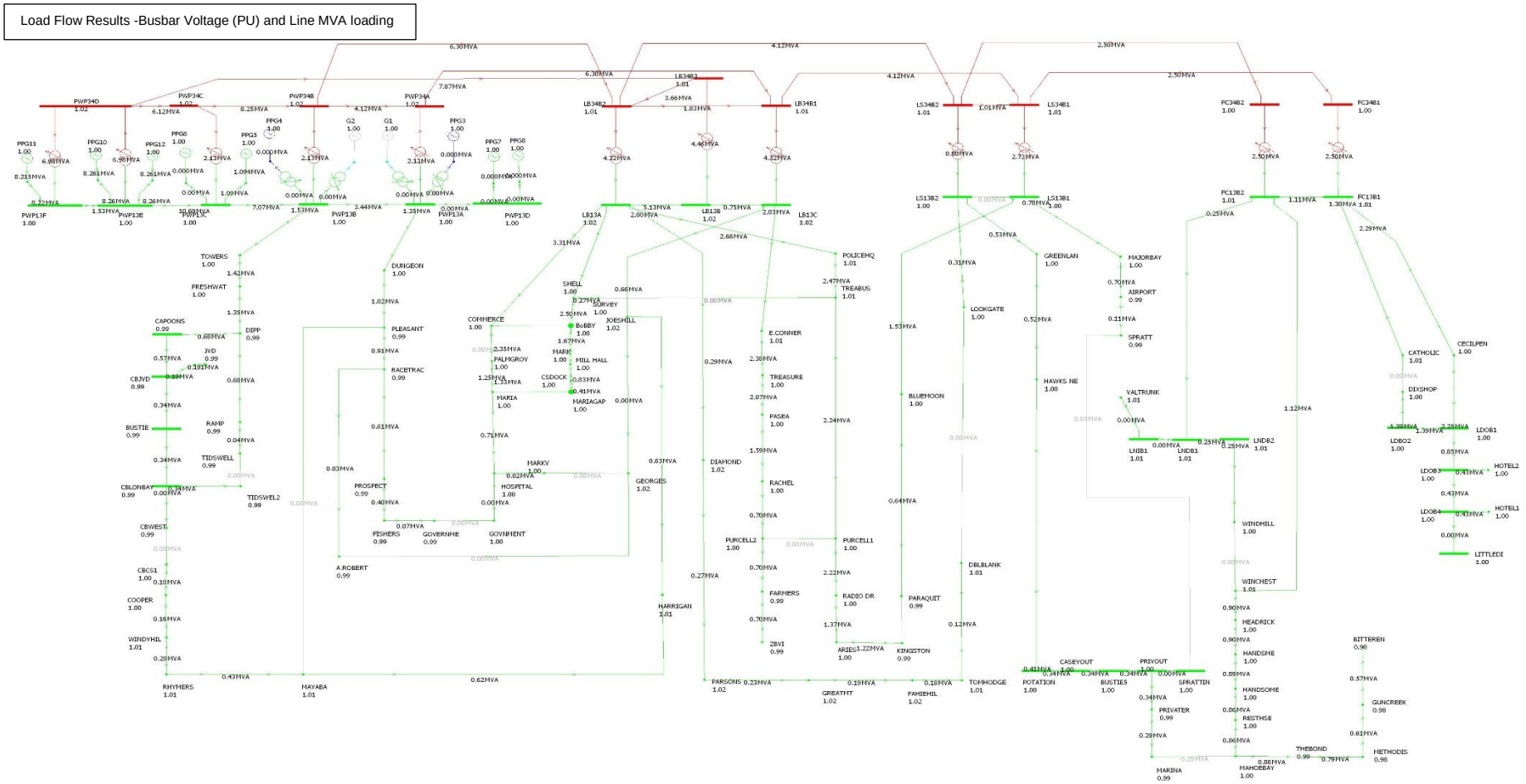


Figure 1 2018 Peak Load – No Outages

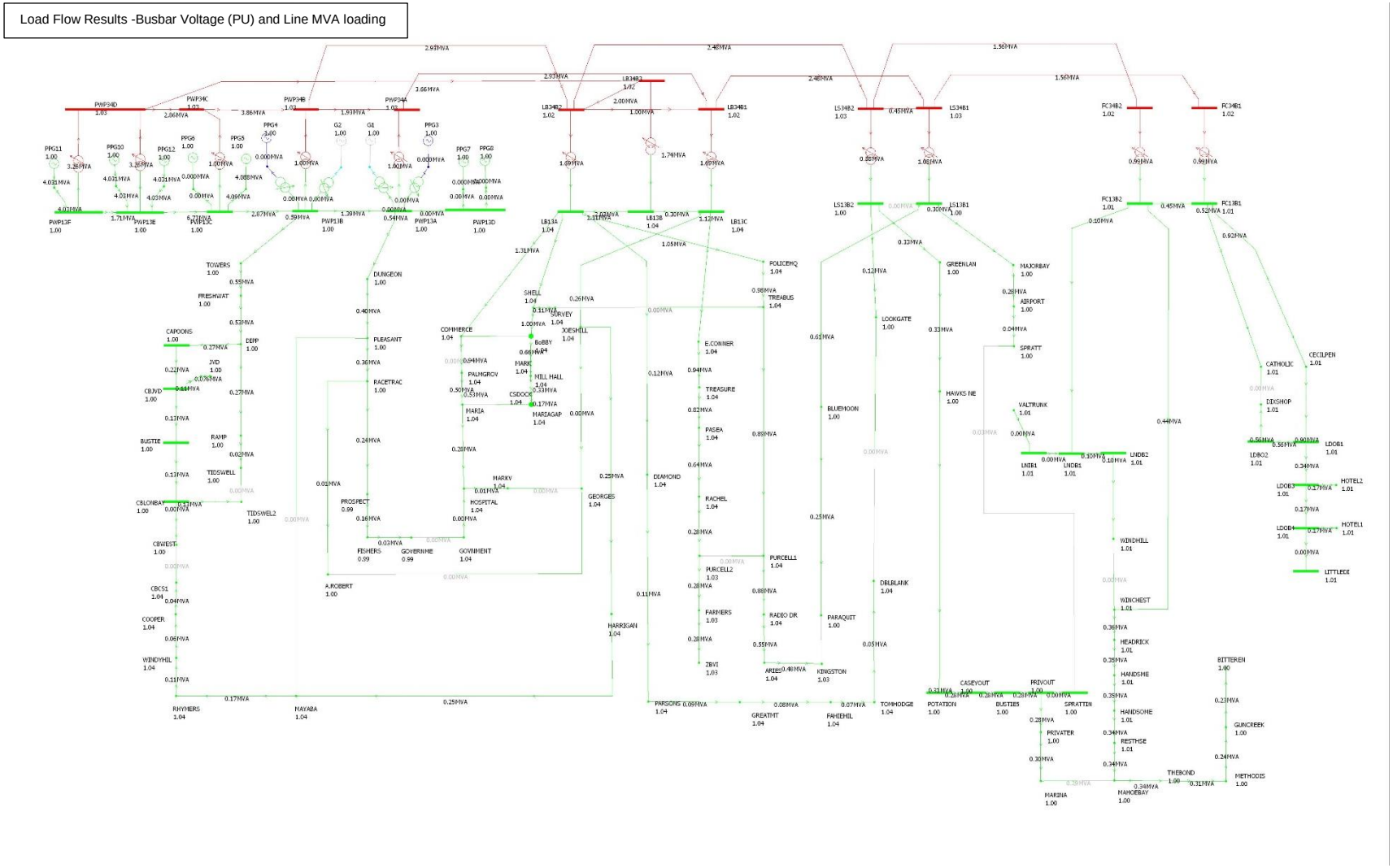


Figure 2 2018 Min Load – No Outages

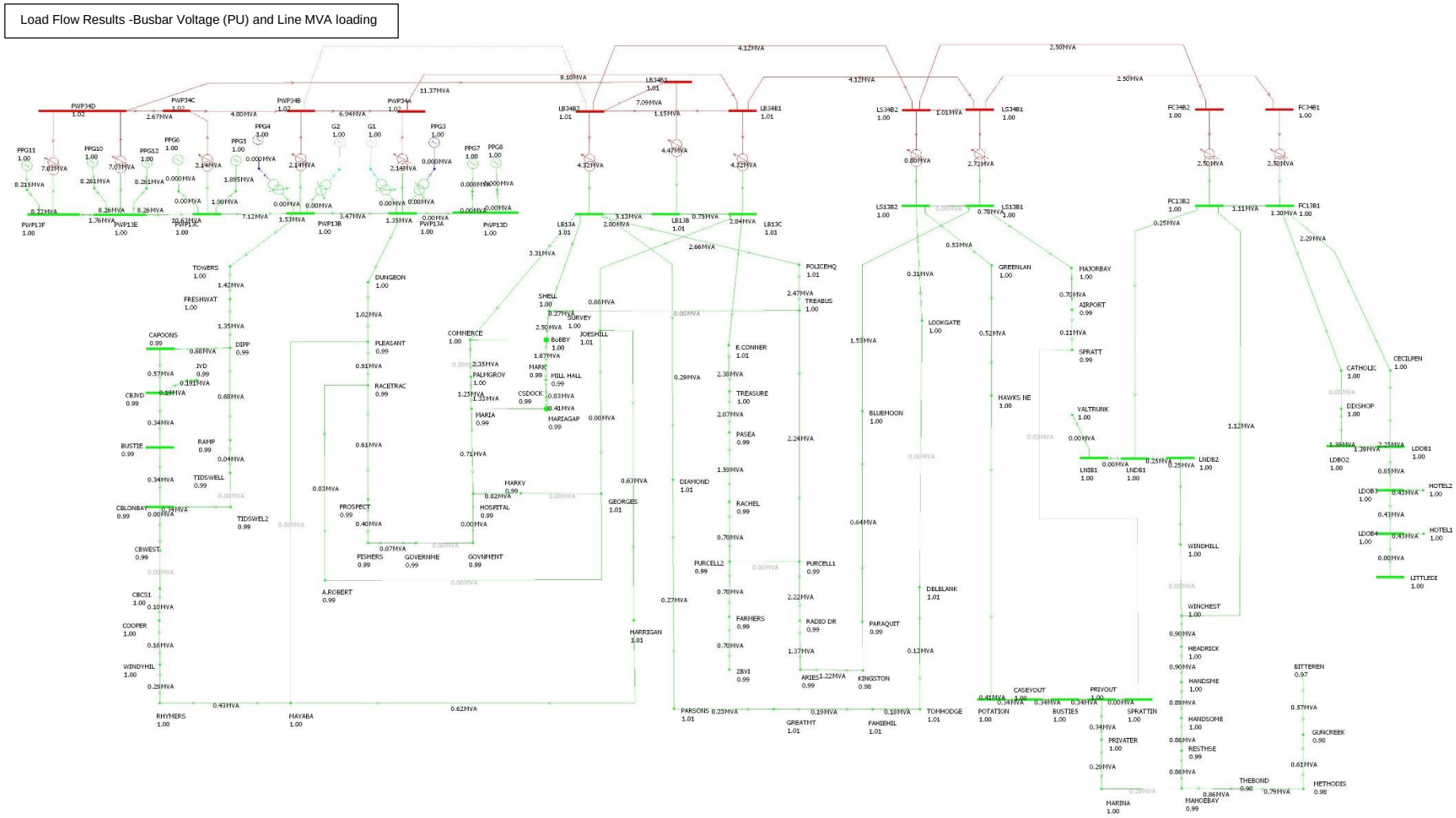


Figure 3 2018 Peak Load – Outage of Pockwood – Long Bush Circuit

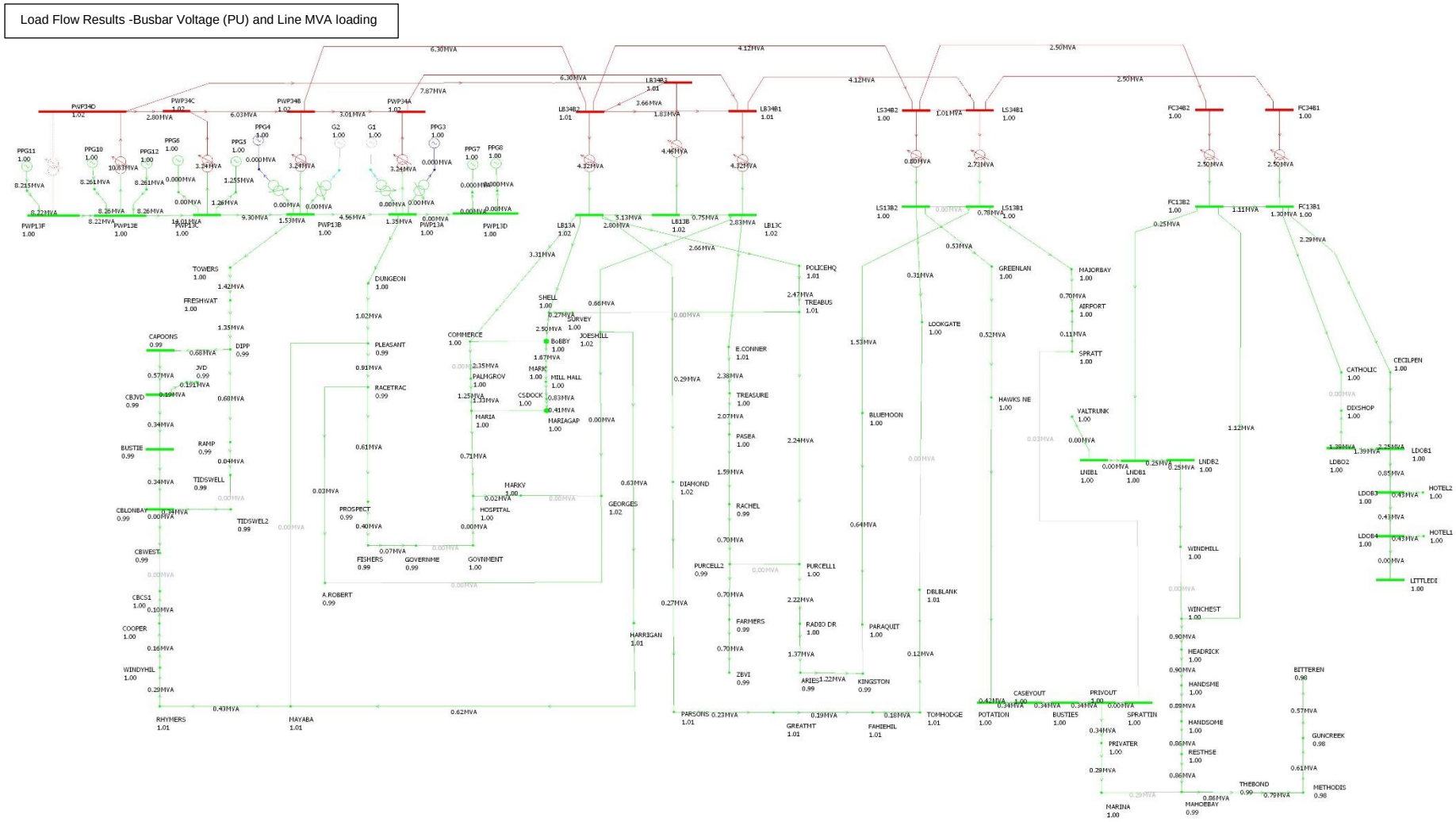


Figure 4 2018 Peak Load – Outage of Pockwood Pond Interbus Transformer

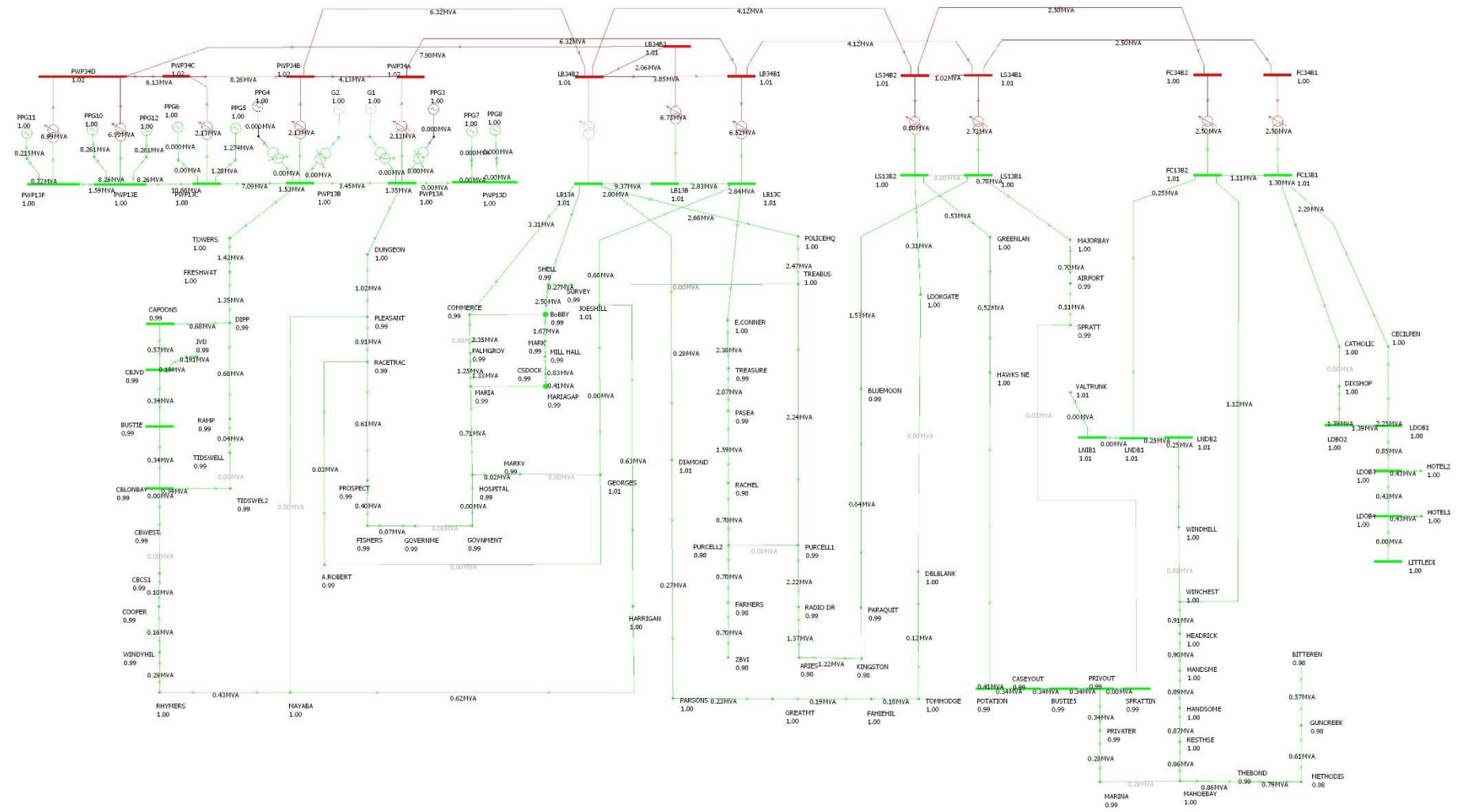


Figure 5 2018 Peak Load – Outage of Long Bush Interbus Transformer

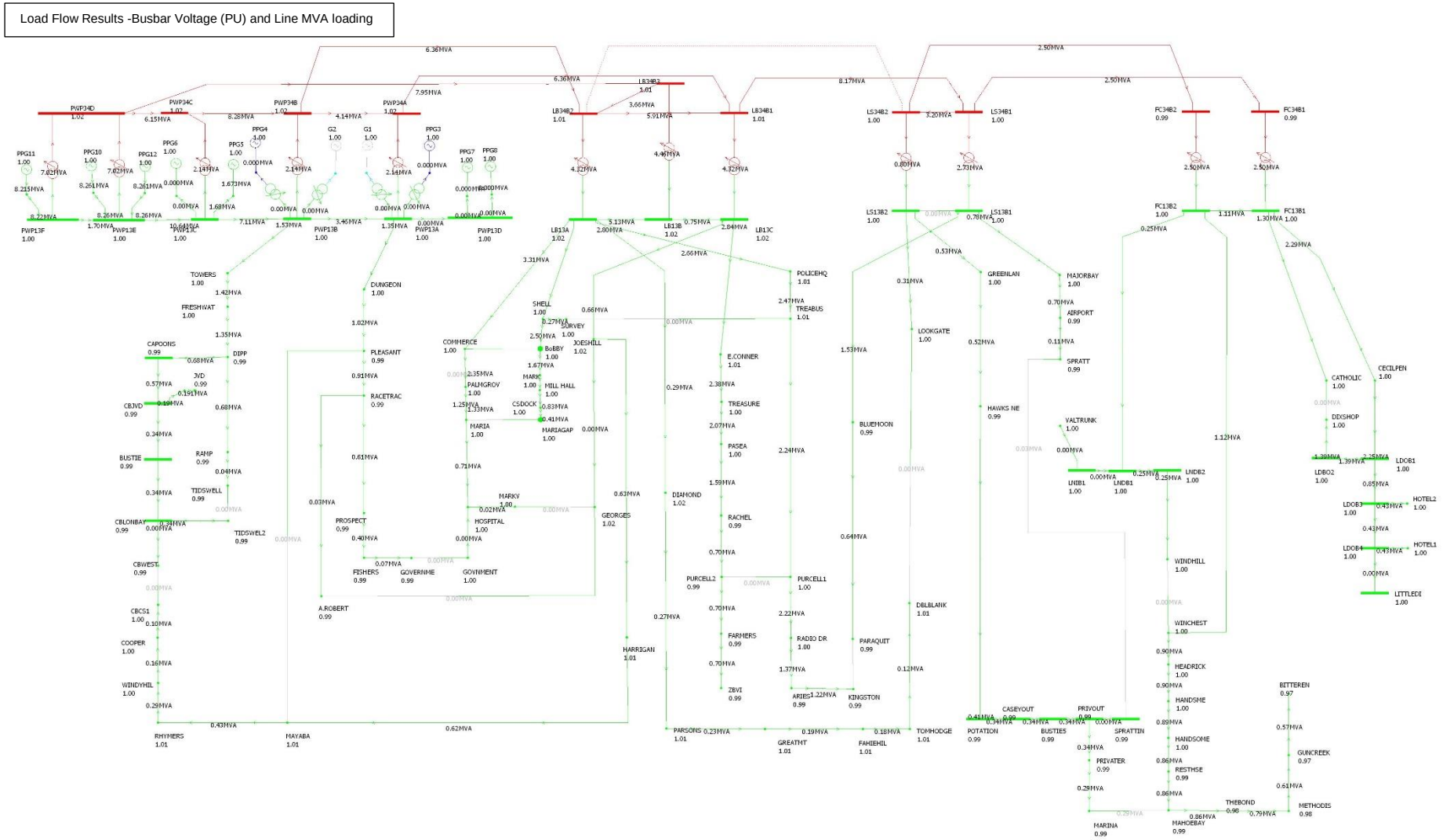


Figure 6 2018 Peak Load – Outage of Long Bush to Long Swamp Circuit

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

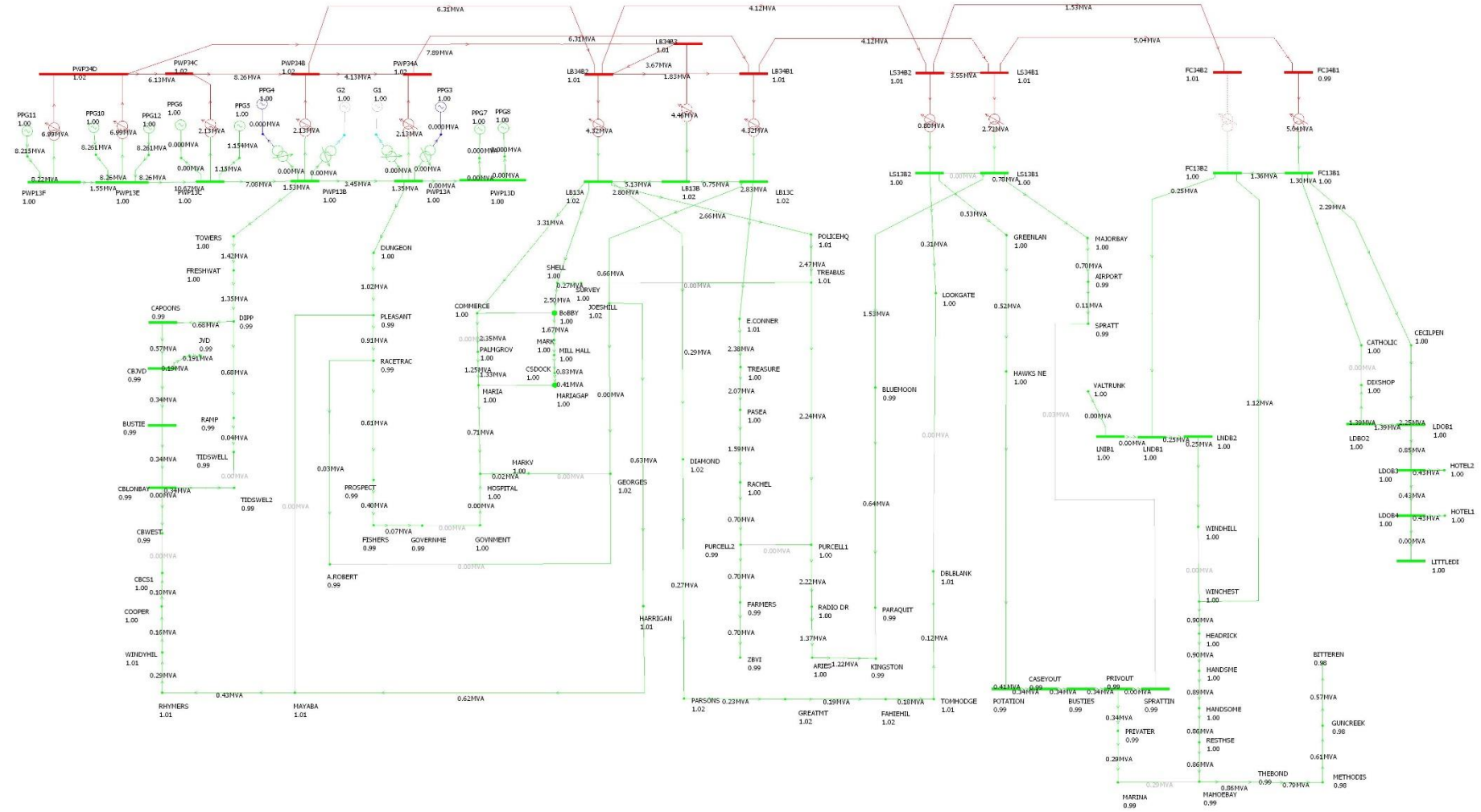


Figure 7 2018 Peak Load – Outages of Interbus Transformer at Fischer's Cove

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

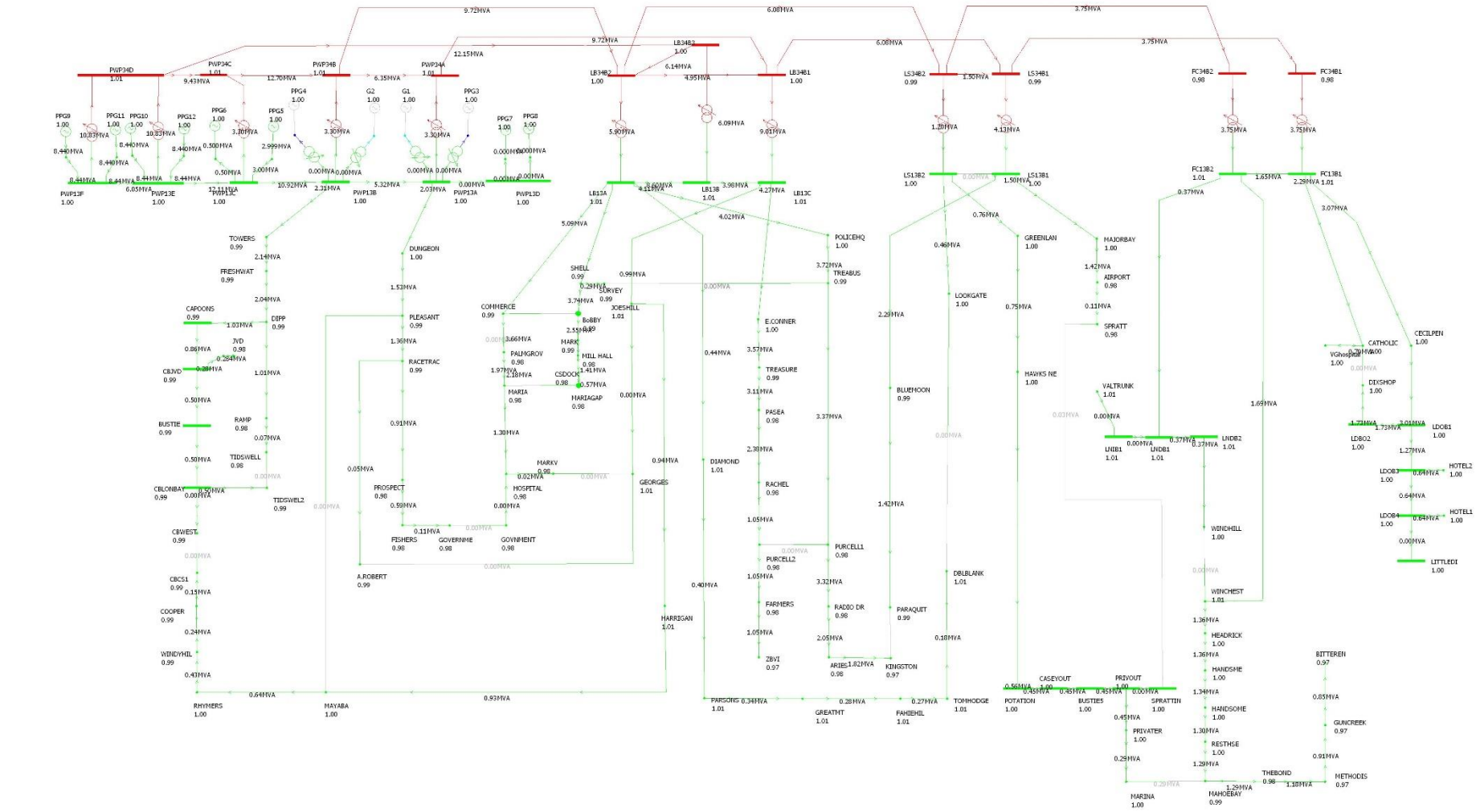


Figure 8 2021 Peak Load – No Outages

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

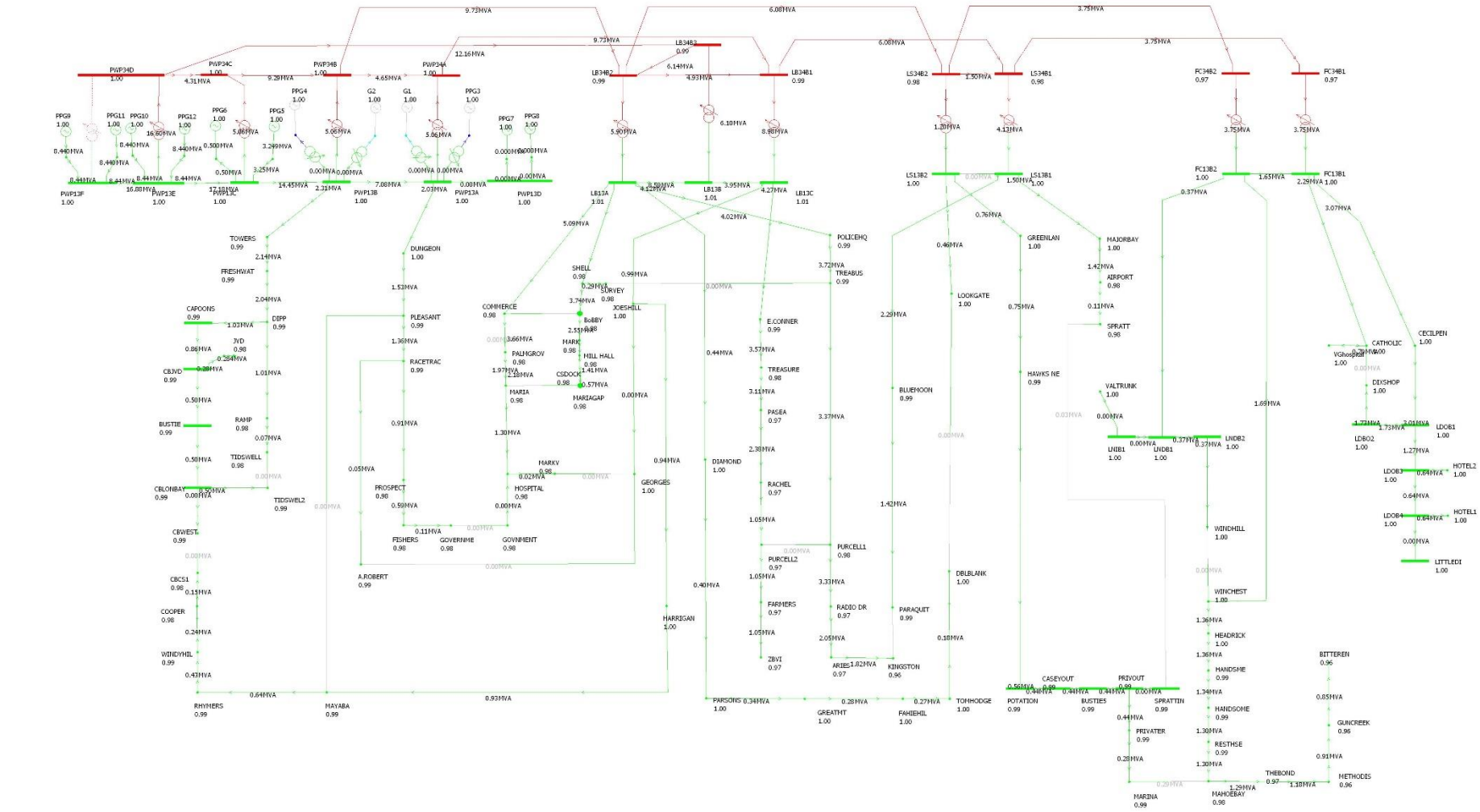


Figure 9 2021 Peak Load – Outage of Pockwood Pond Interbus Transformer

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

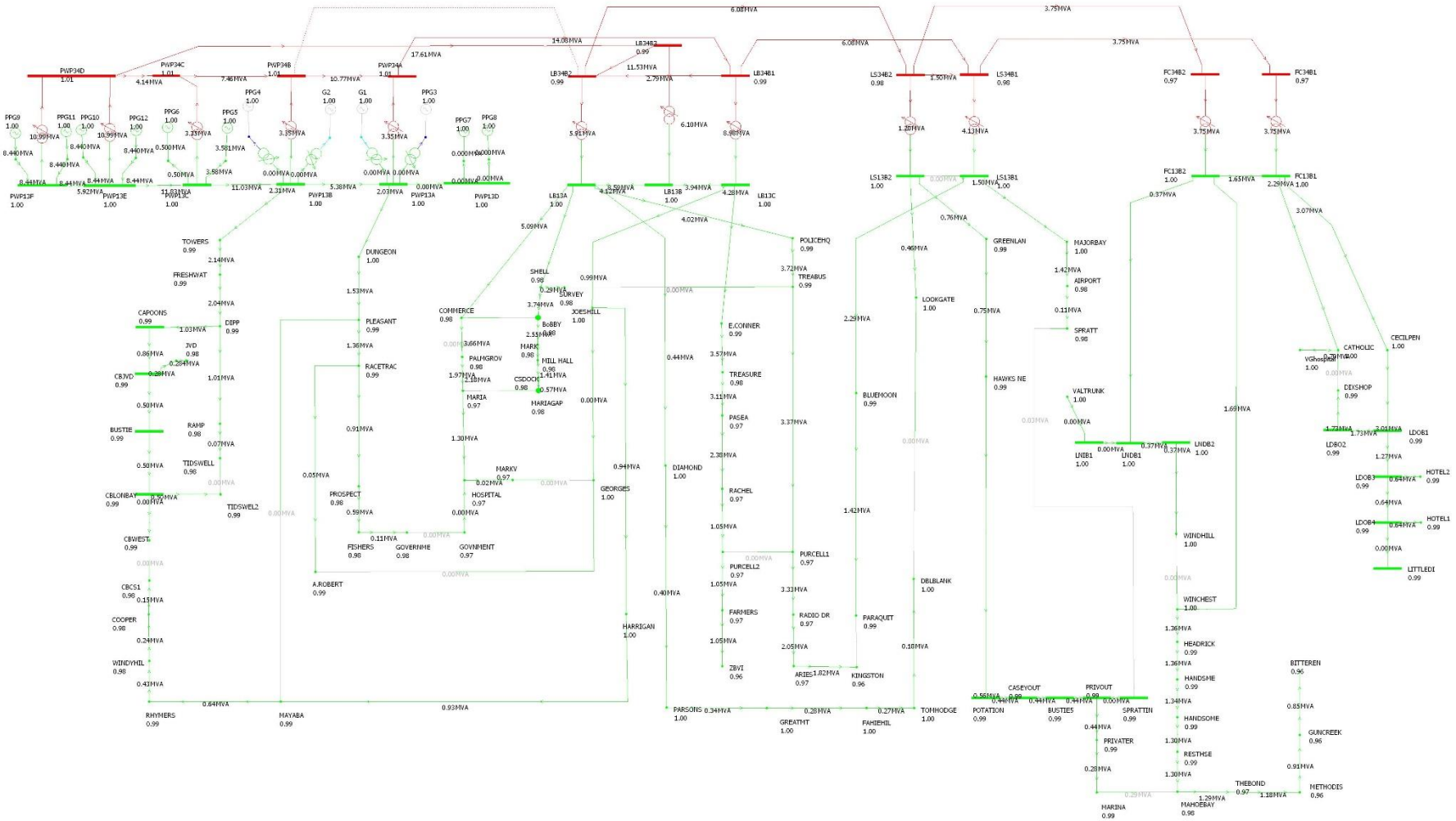


Figure 10 2021 Peak Load – Outage of Pockwood Pond – Long Bush Interconnector

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

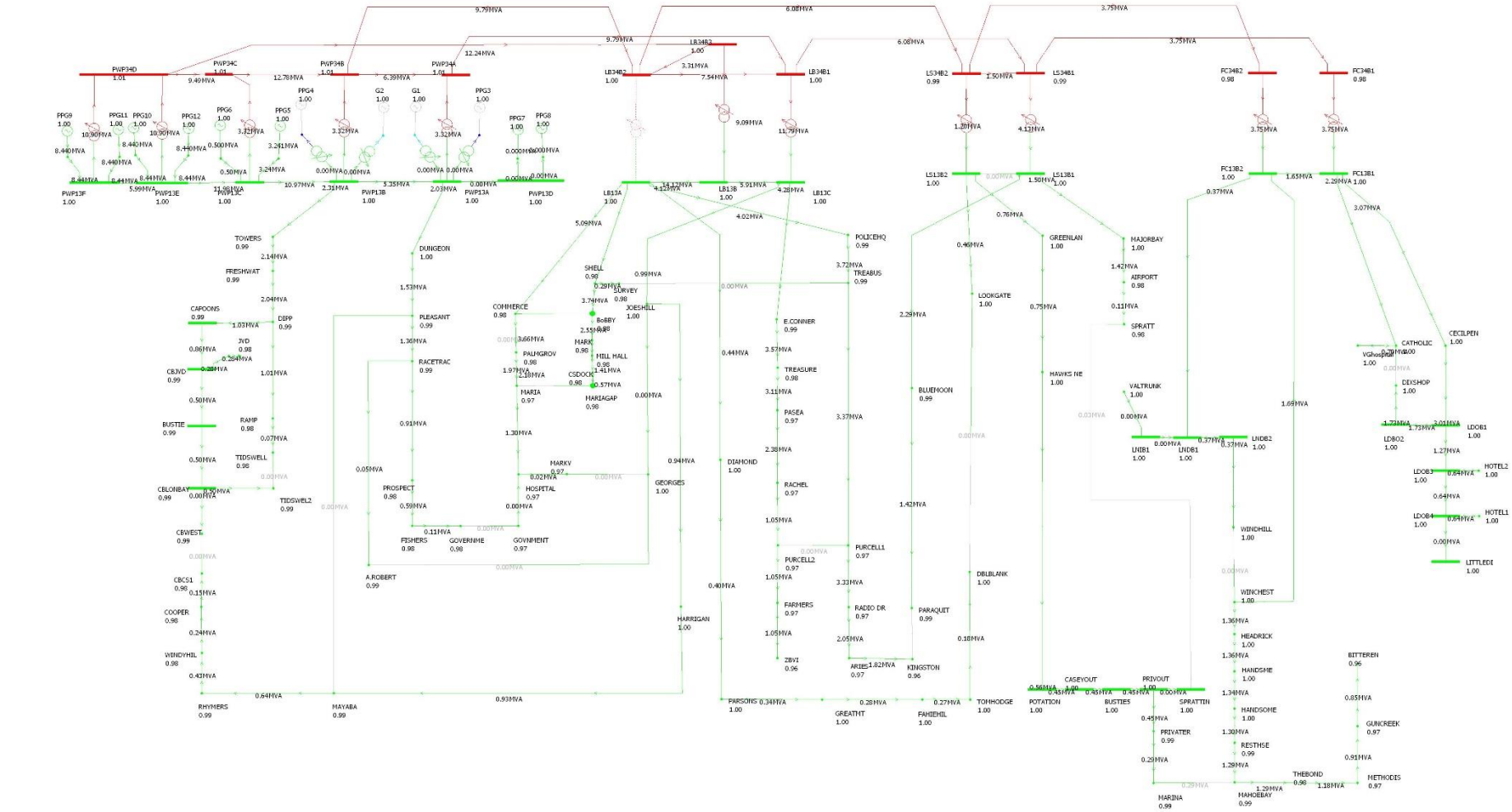


Figure 11 2021 Peak Load – Outage of Long Bush Interbus Transformer

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

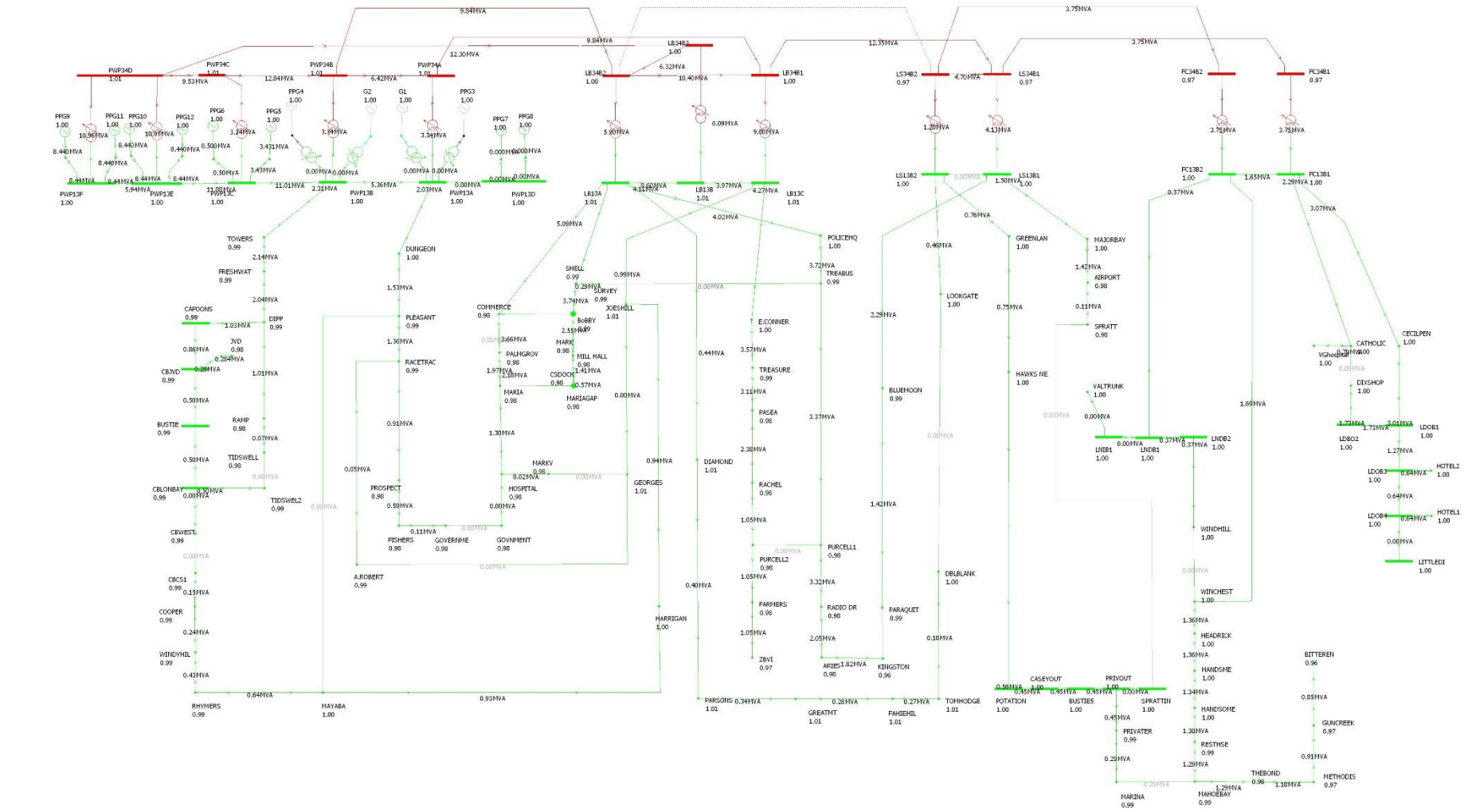


Figure 12 2021 Peak Load – Outage of Long Bush – Long Swamp Interconnector

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

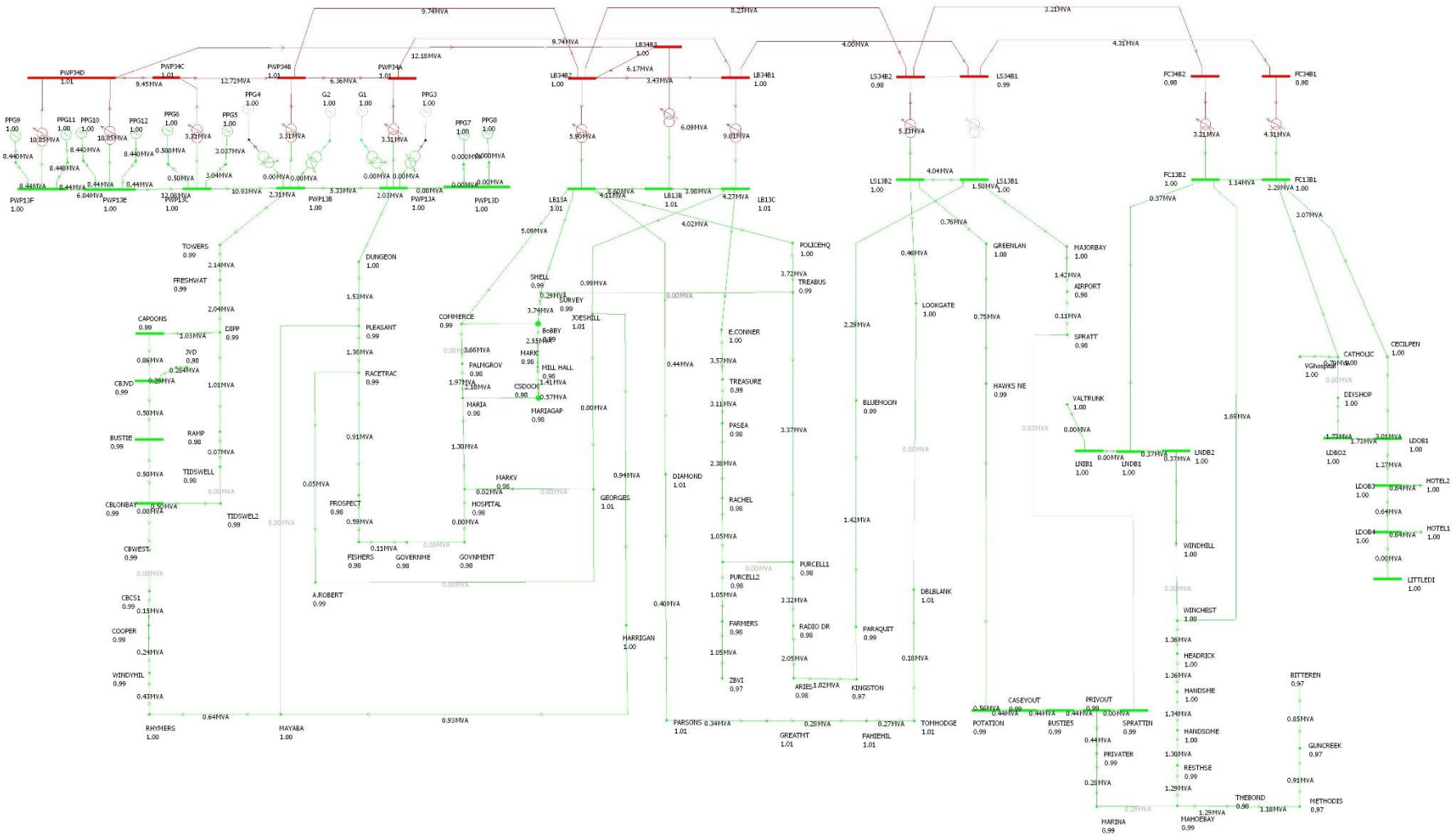


Figure 13 2021 Peak Load – Outage of Long Swamp Interbus transformer

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

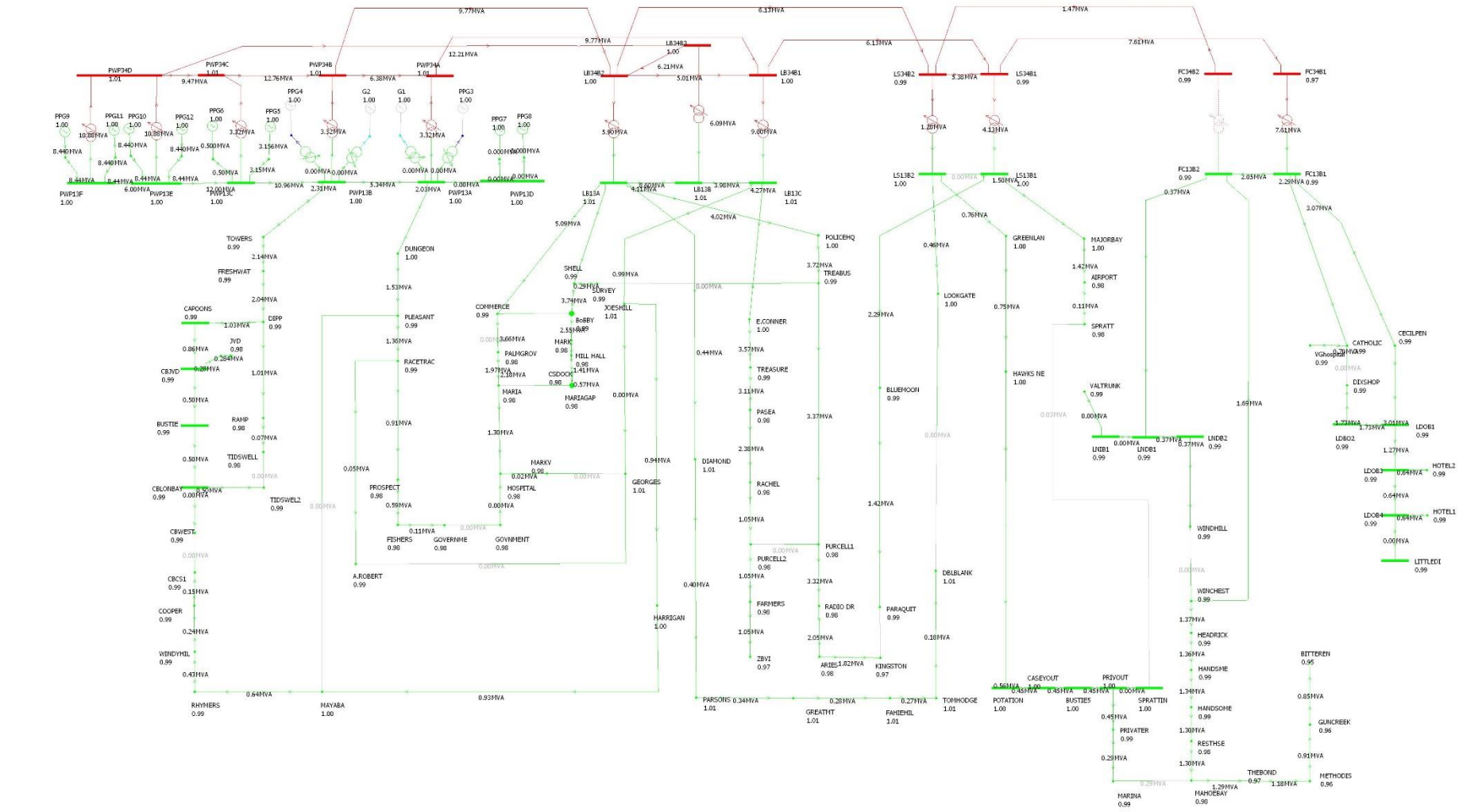


Figure 14– 2021 Peak Load – Outage of Fischer's Cove Interbus Transformer

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

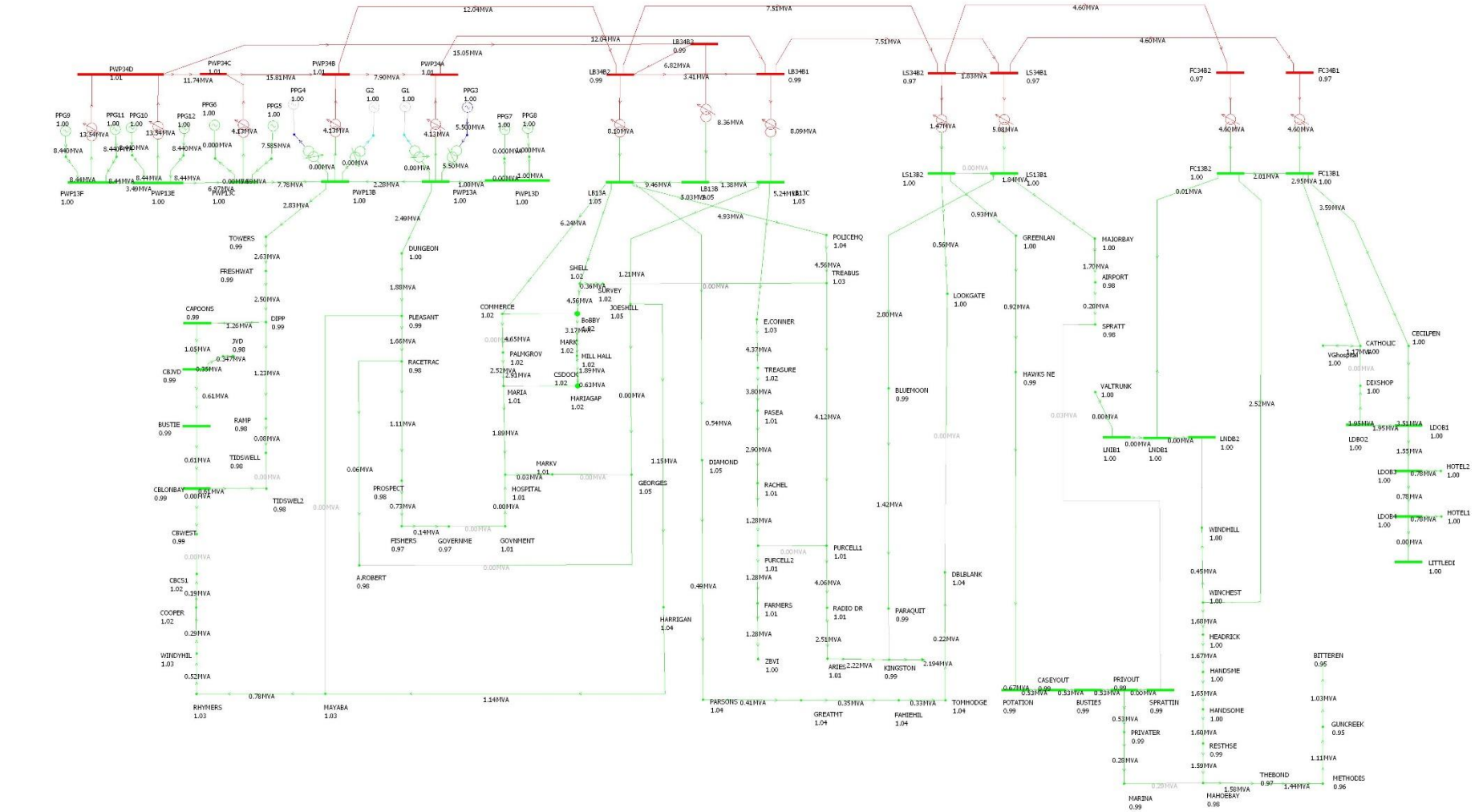


Figure 15 2025 Peak Load – No Outages

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

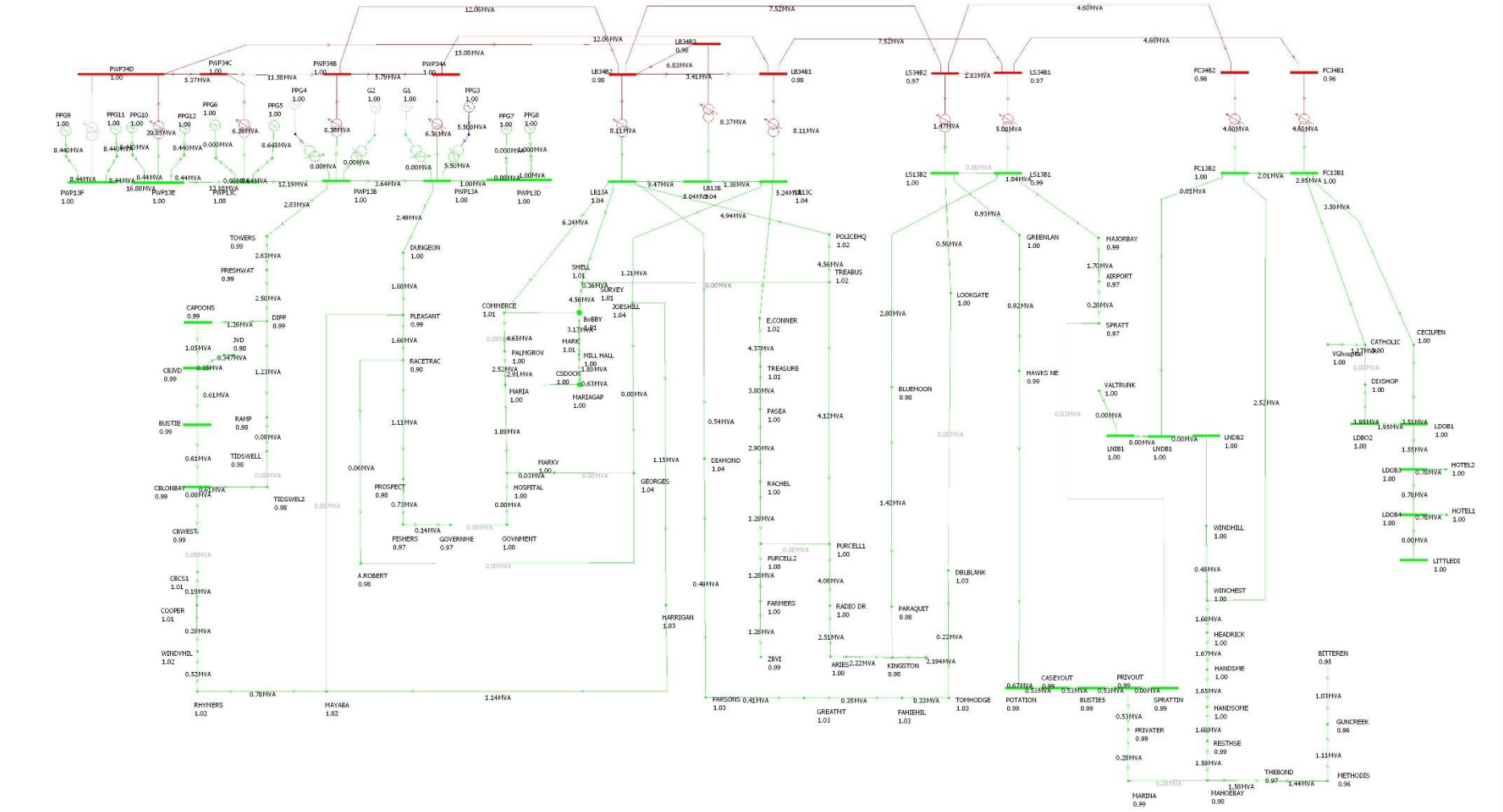


Figure 16 2025 Peak Load-Outage of Pockwood Pond Interbus Transformer

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

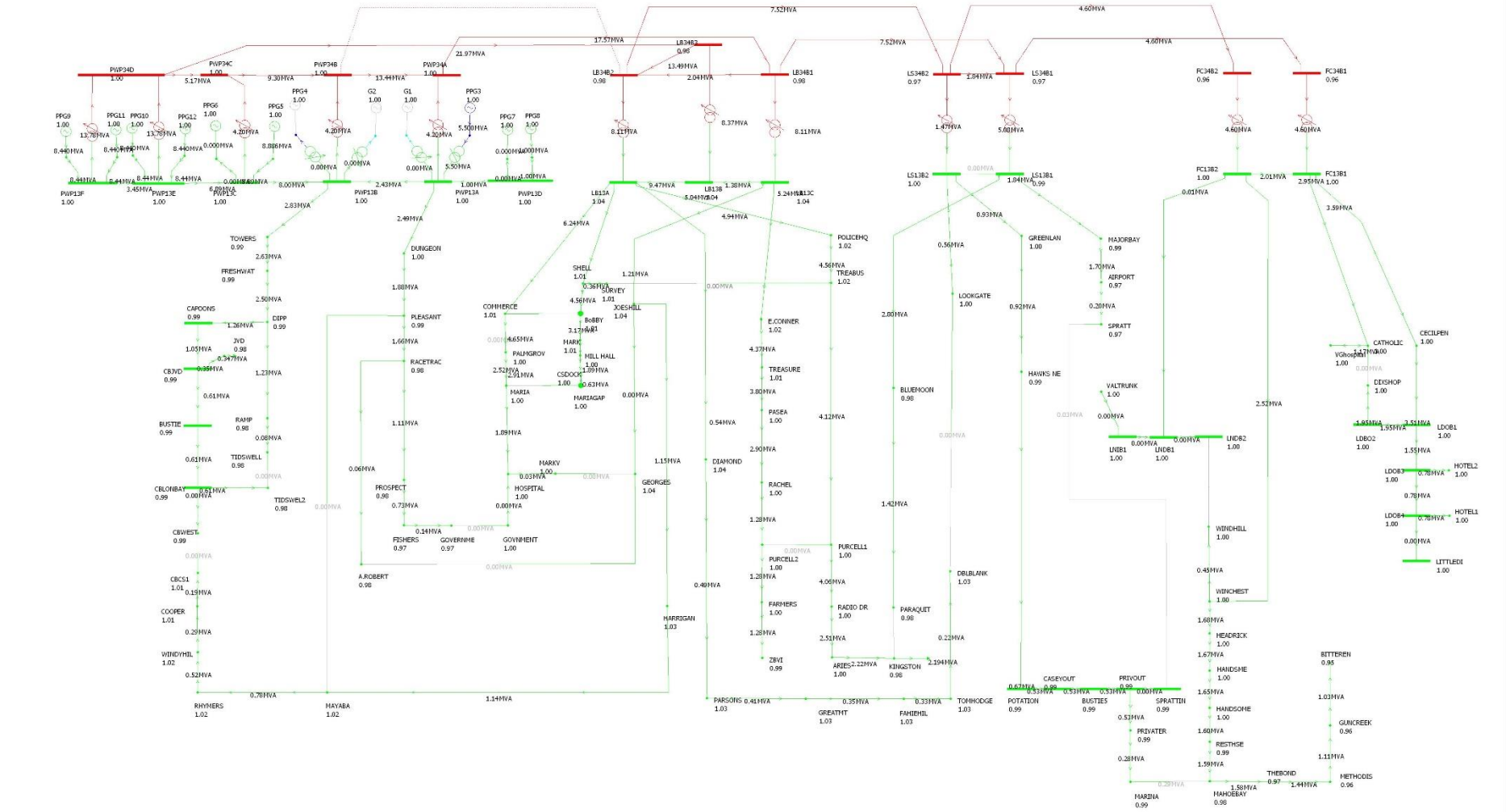


Figure 17 2025 Peak Load– Outage of Pockwood Pond to Long Bush Interconnector

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

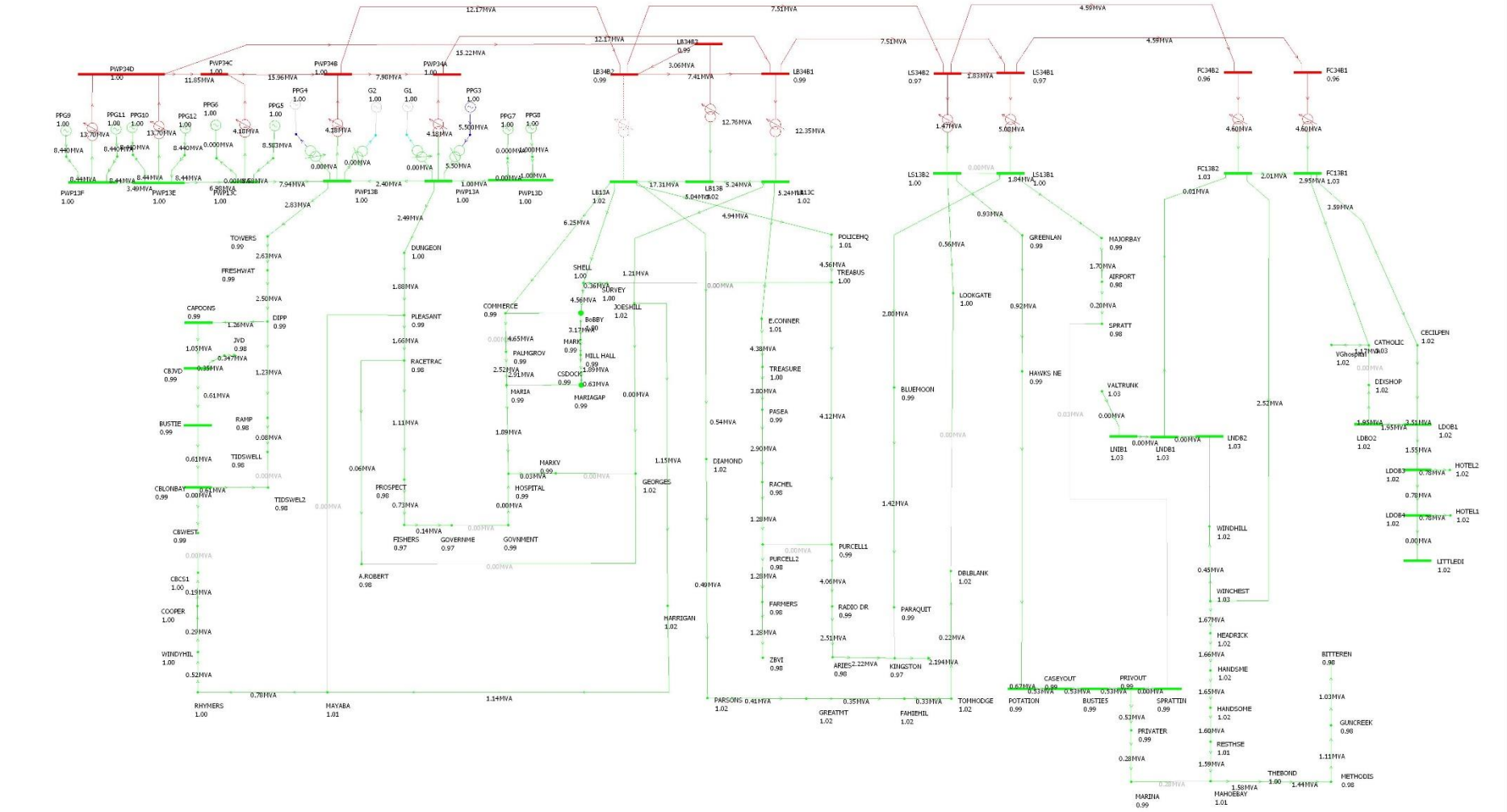


Figure 18 2025 Peak Load – Outage of Long Bush Interconnector Transformer

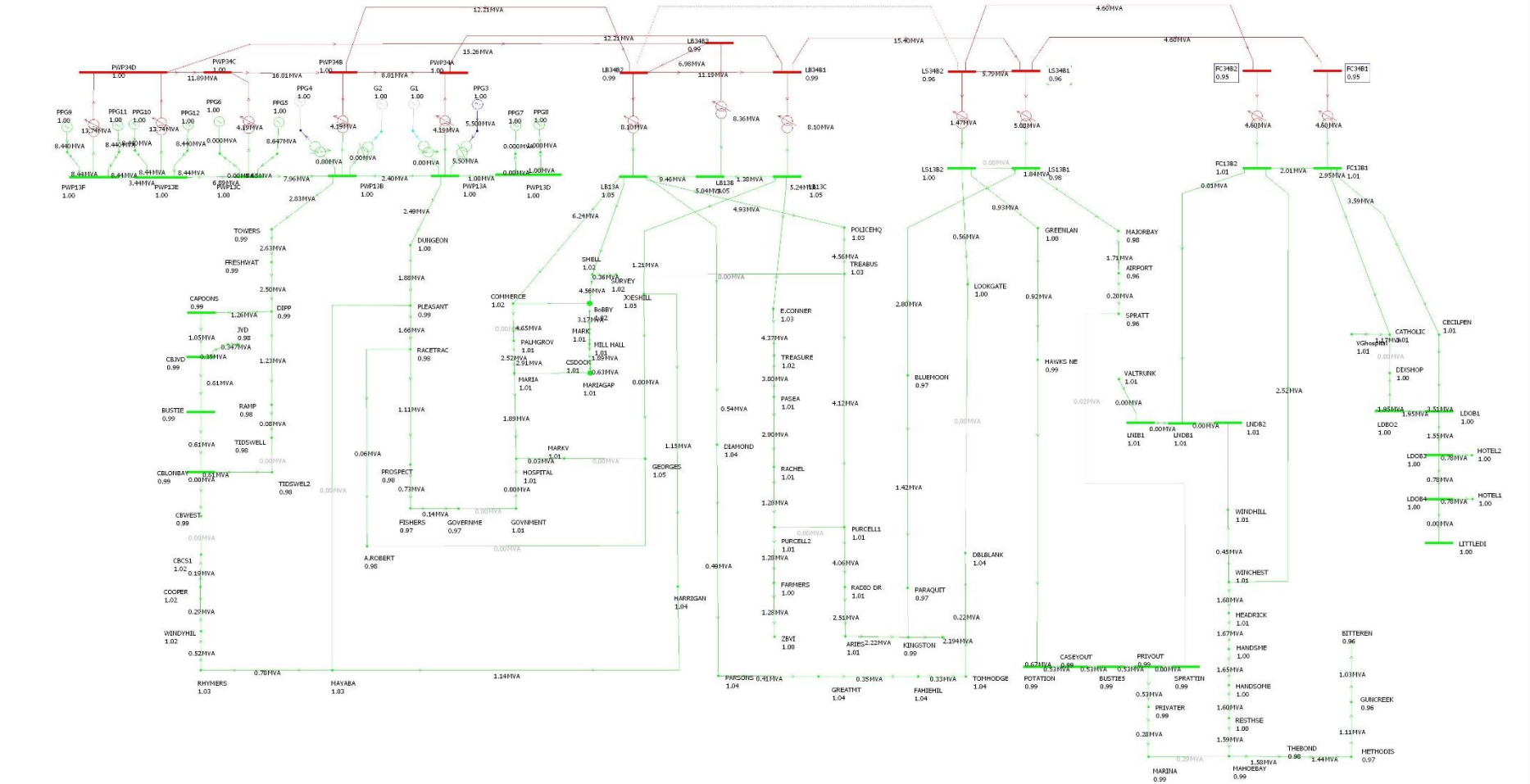


Figure 19 2025 Peak Load - Outage of Long Bush to Long Swamp Interconnector

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

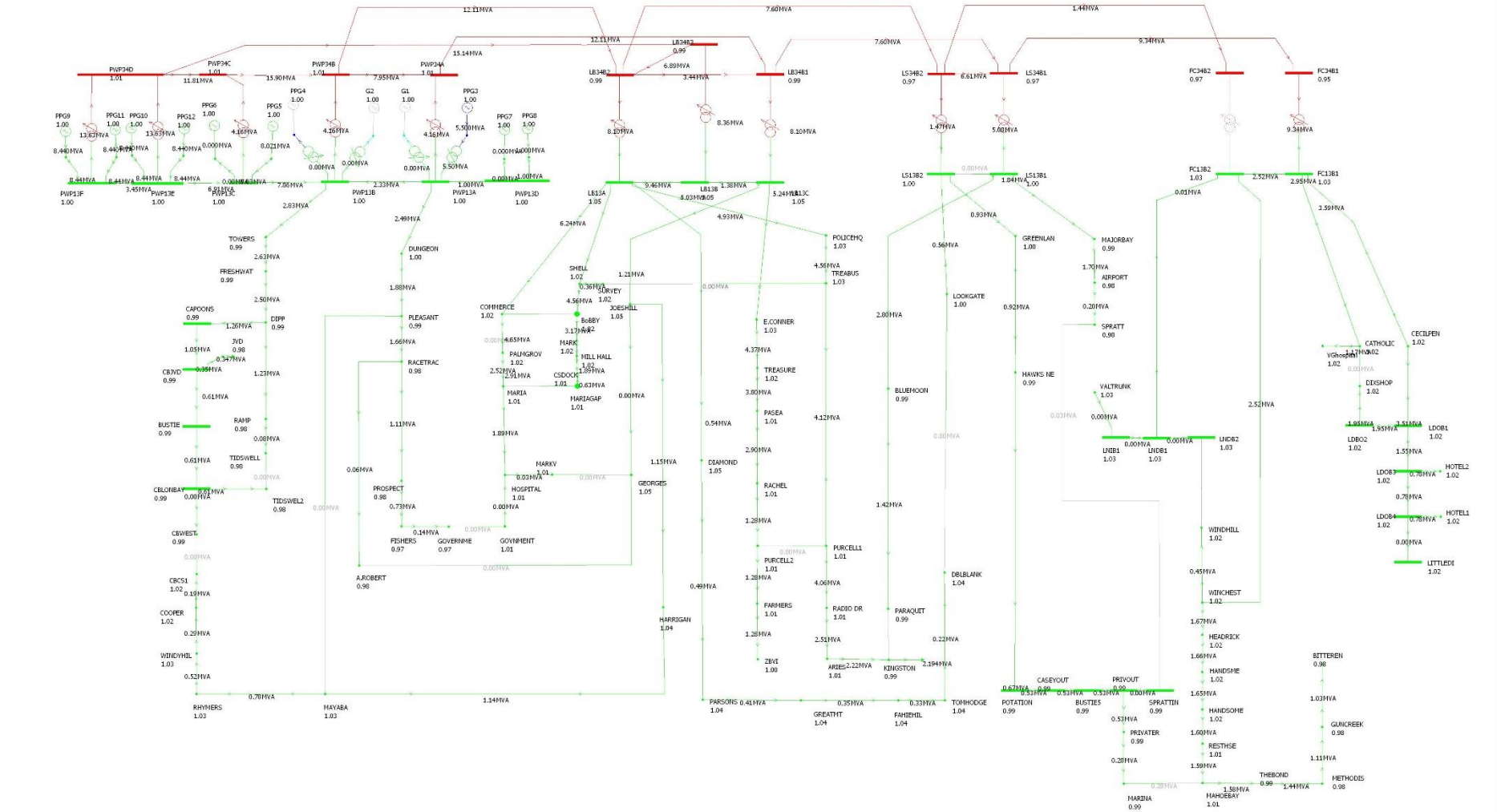


Figure 20 2025 Peak Load -Outage of Fischer's Cove Interbus Transformer

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

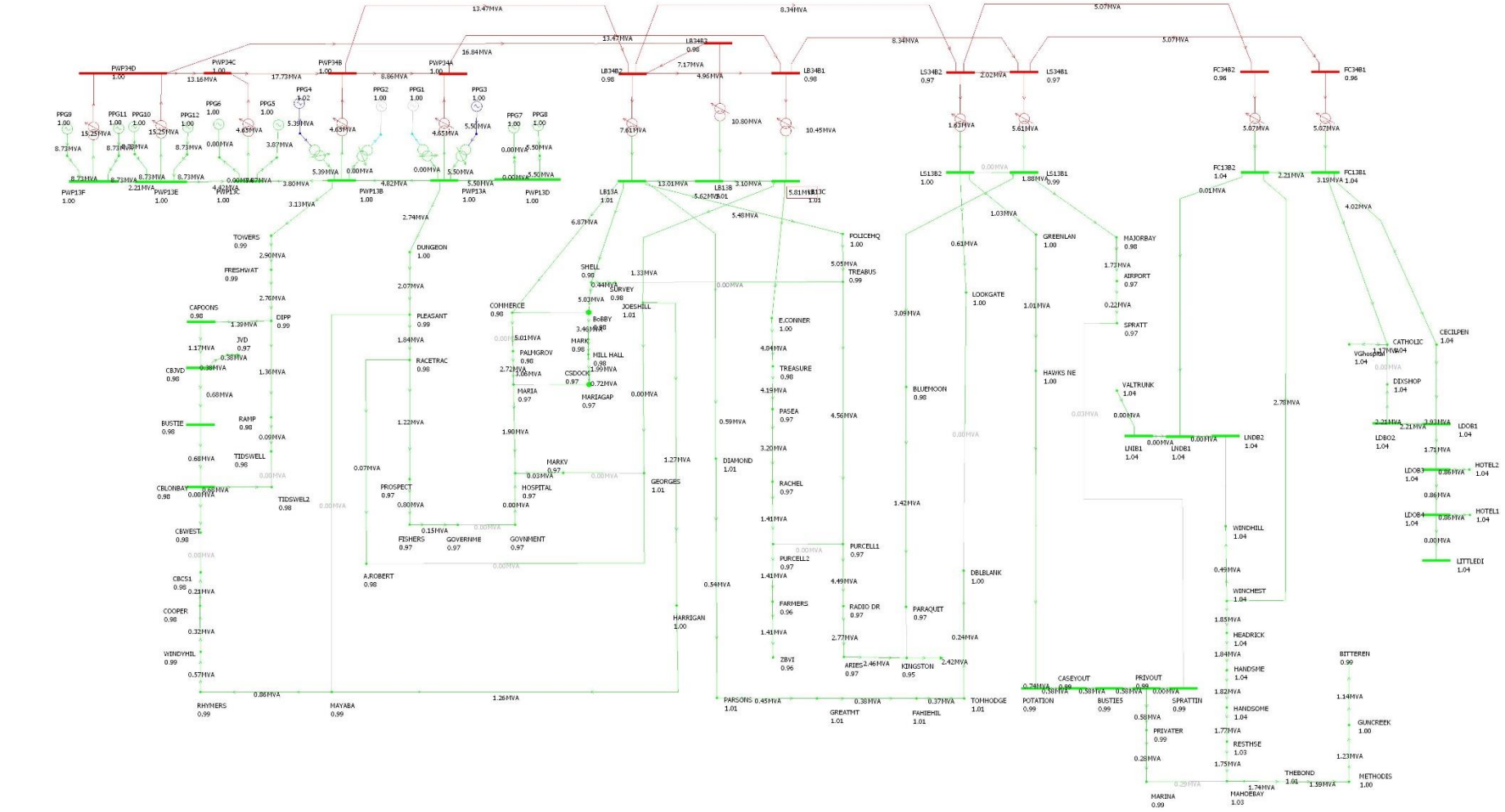


Figure 21 2029 Peak Load-No Outage

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

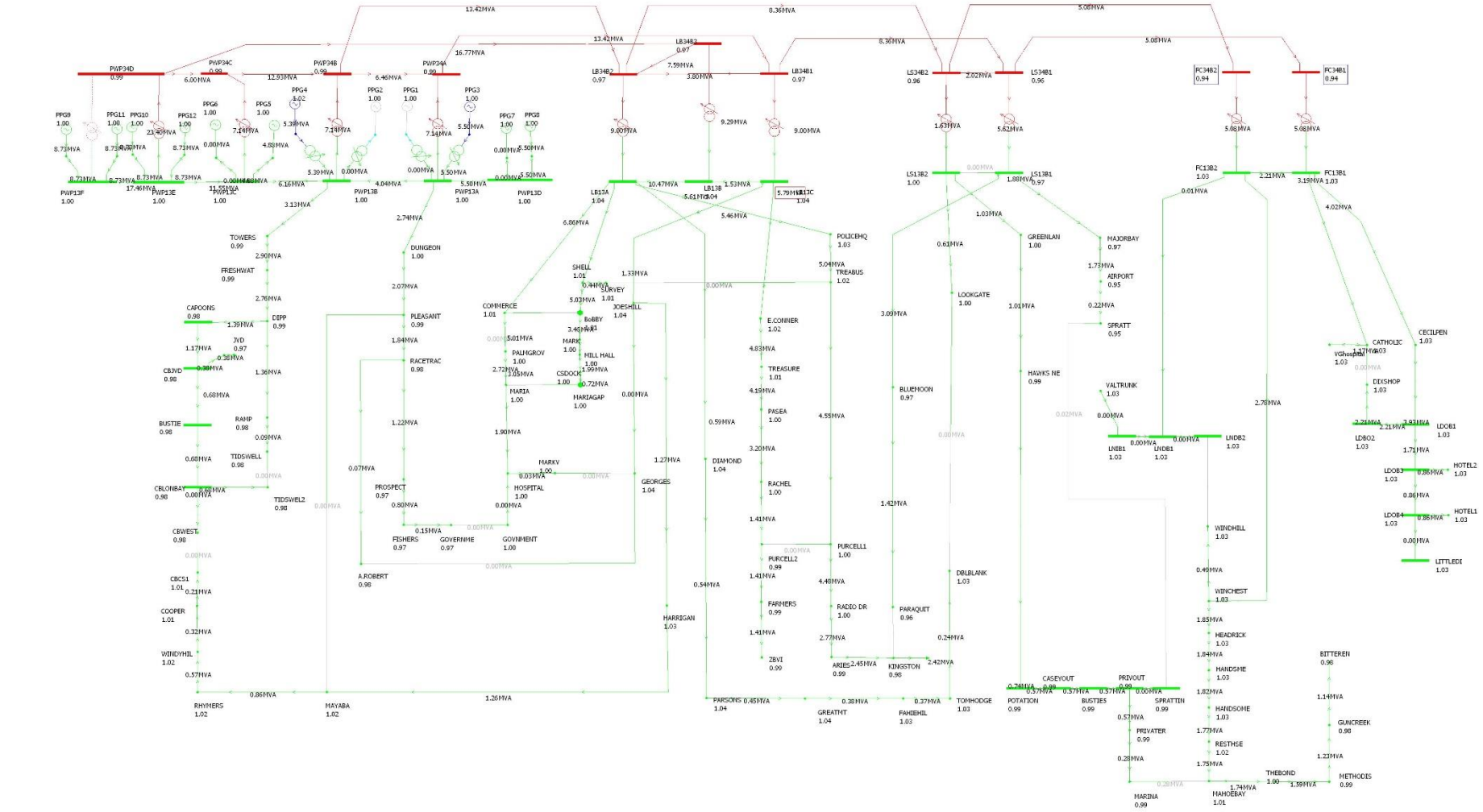


Figure 22 2029 Peak Load – Outage of Pockwood Pond Interbus Transformer

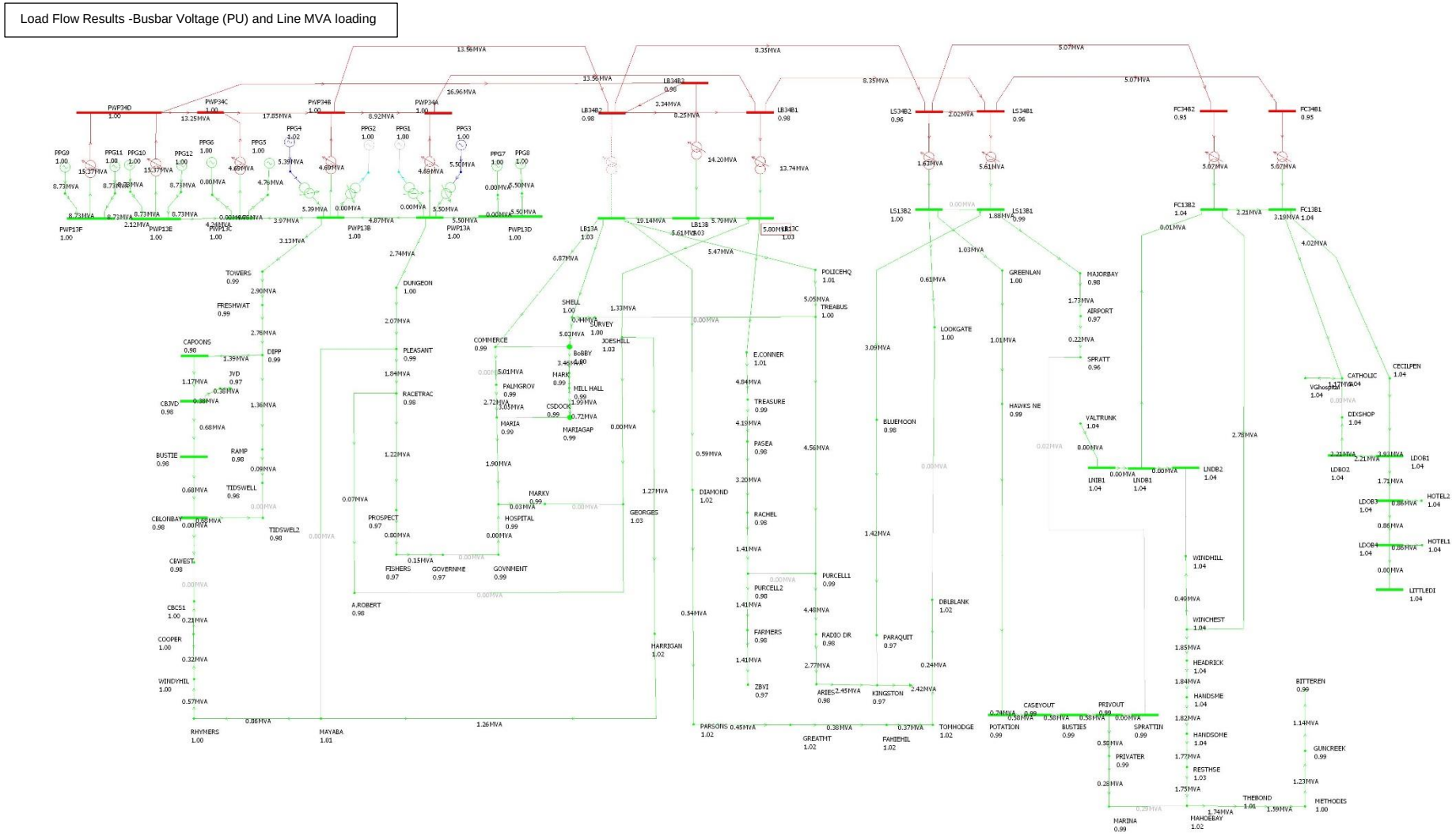


Figure 23 2029 Peak Load – Outage of Long Bush Interbus Transformer

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

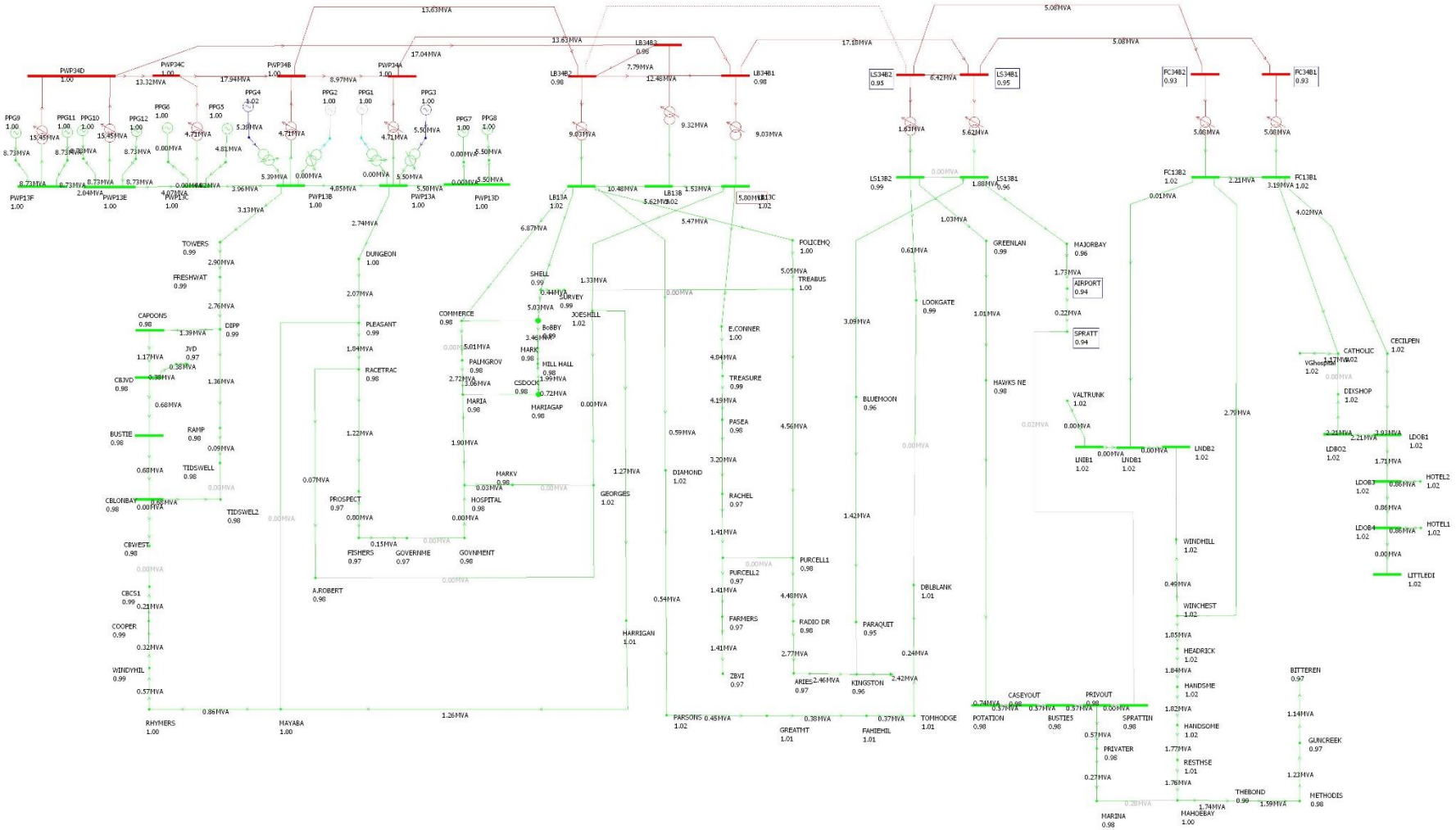


Figure 24 2029 Peak Load – Outage of Long Bush to Long Swamp Circuit

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

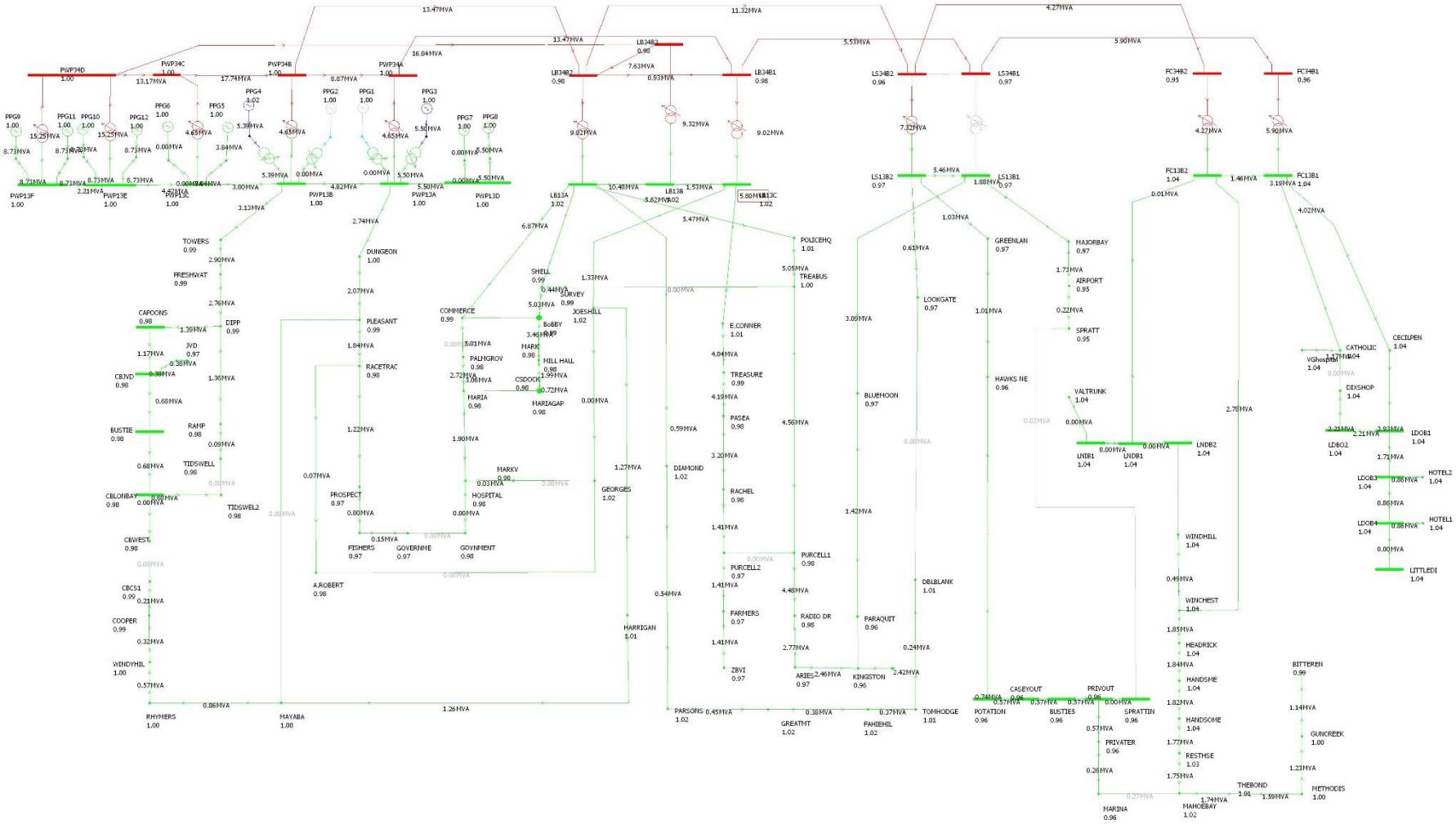


Figure 25 2029 Peak Load – Outage of Interbus Transformer at Long Swamp

Load Flow Results -Busbar Voltage (PU) and Line MVA loading

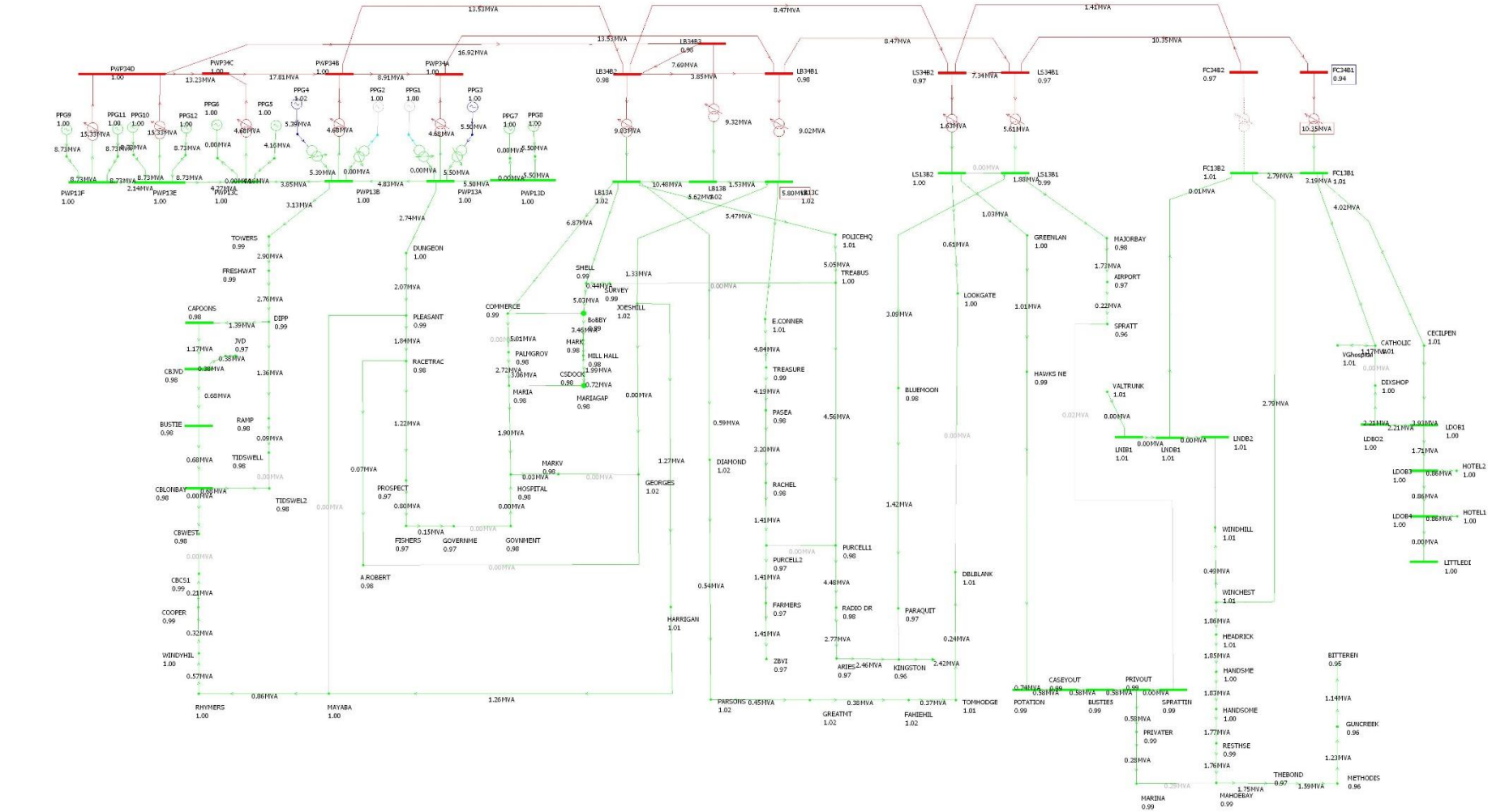


Figure 26 2029 Peak Load – Outages of Interbus Transformer at Fischer's Cove

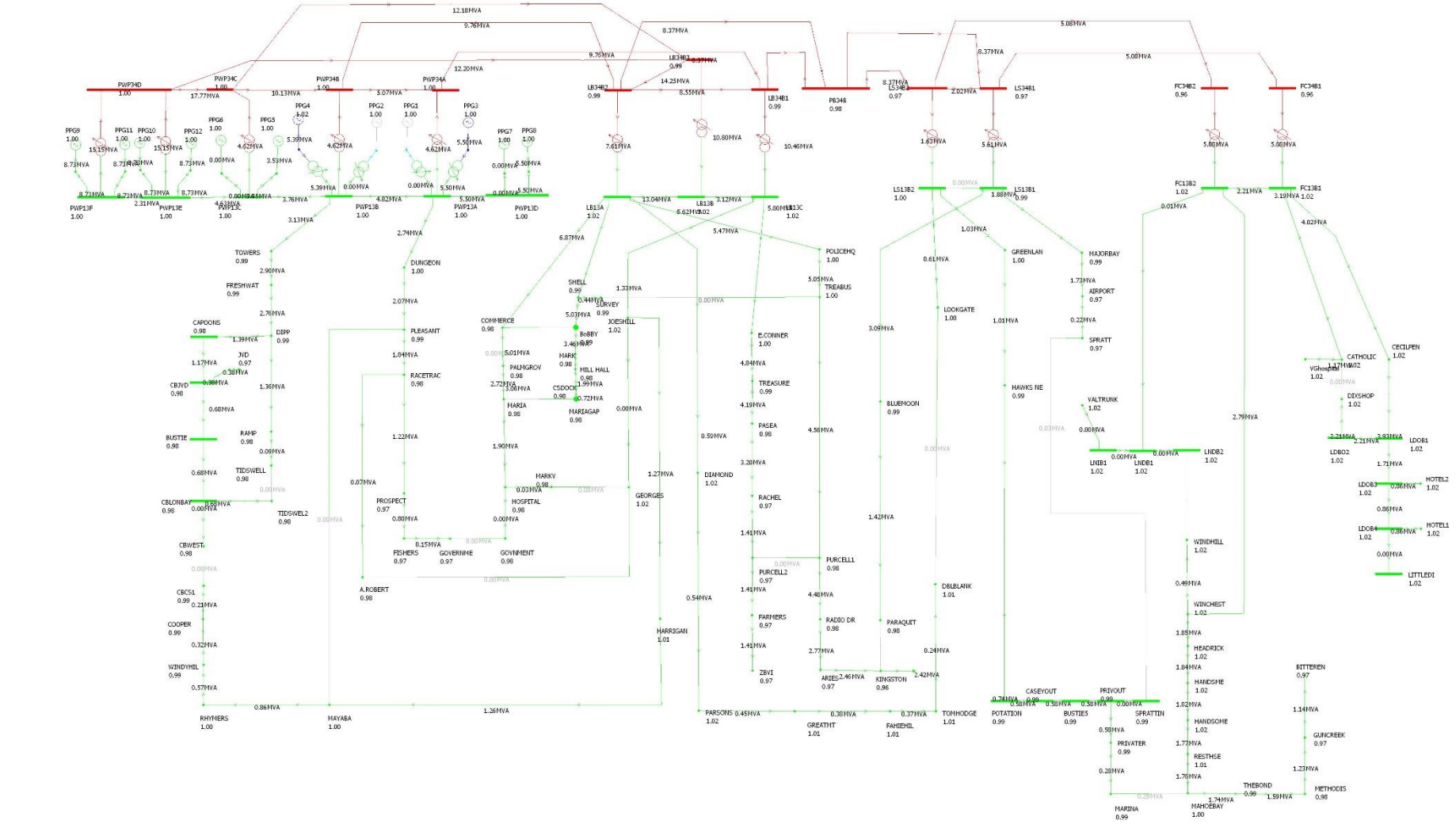


Figure 27 2029 Peak Load-Reinforced Network-No Outage

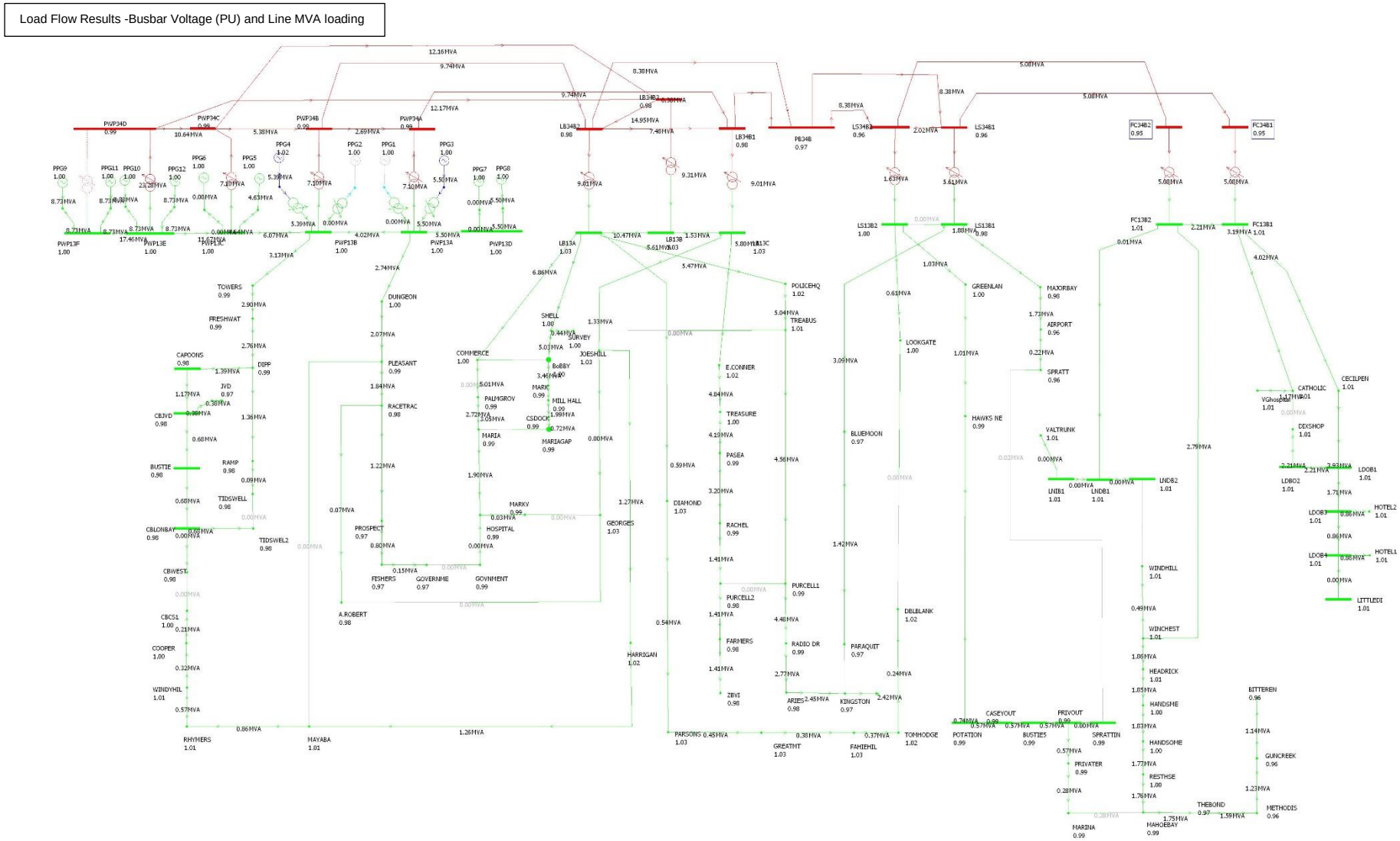


Figure 28 2029 Peak Load -Reinforced Network-Outage of Pockwood Pond Interbus Transformer

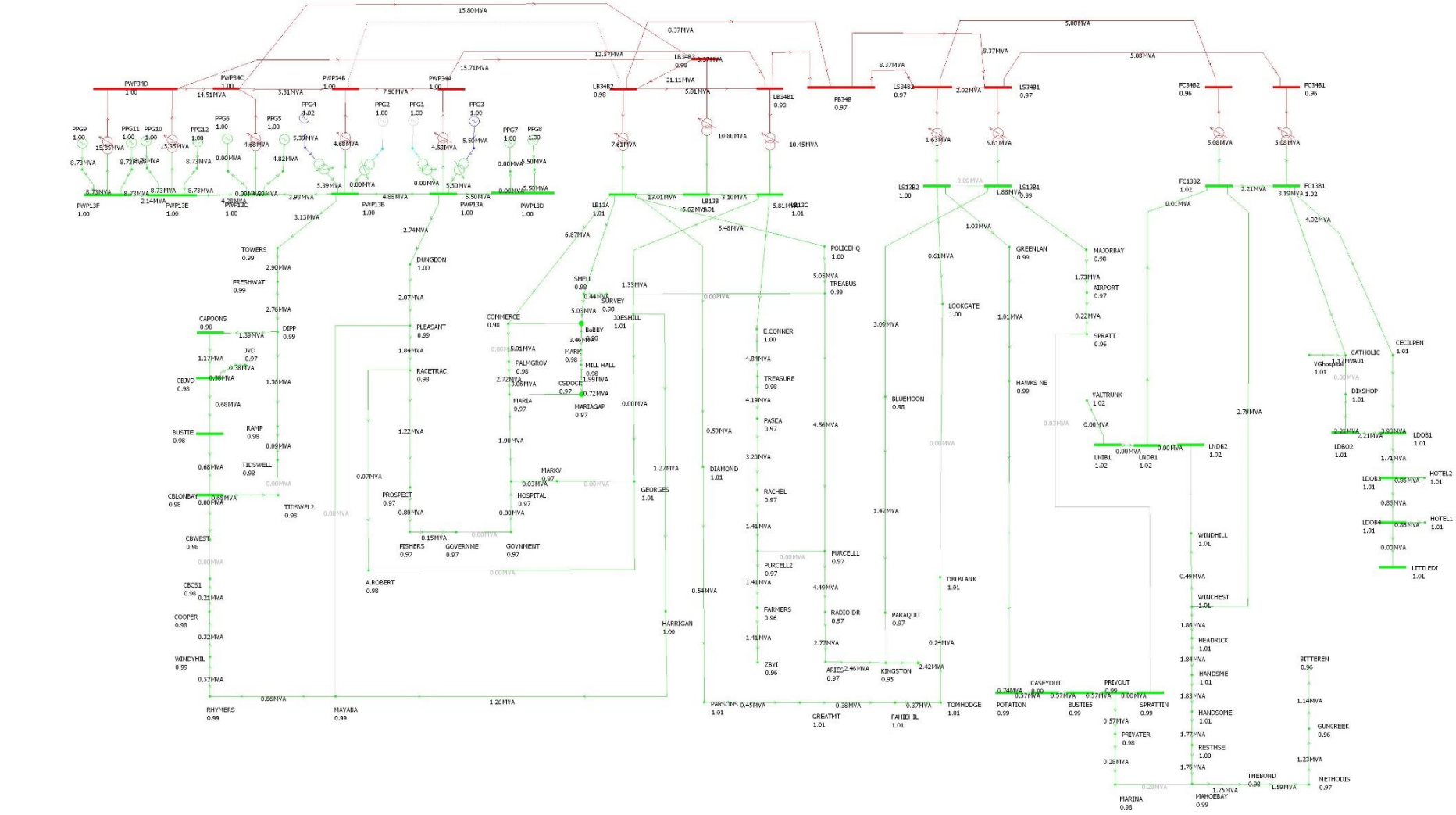


Figure 29 2029 Peak Load-Reinforced Network- Outage of Pockwood Pond to Long Bush Circuit

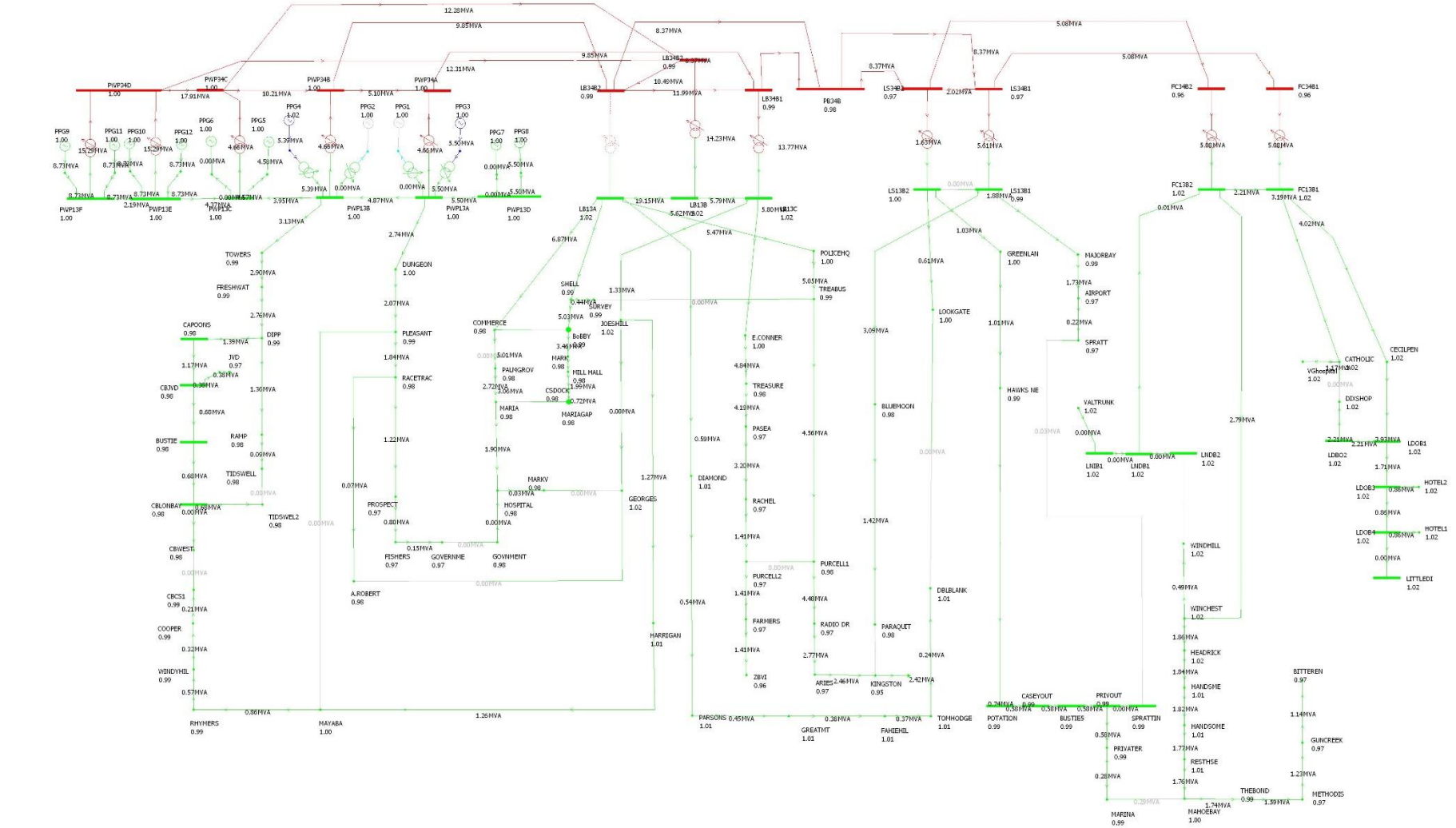


Figure 30 2029 Peak Load-Reinforced Network-– Outage of Long Bush Interbus Transformer

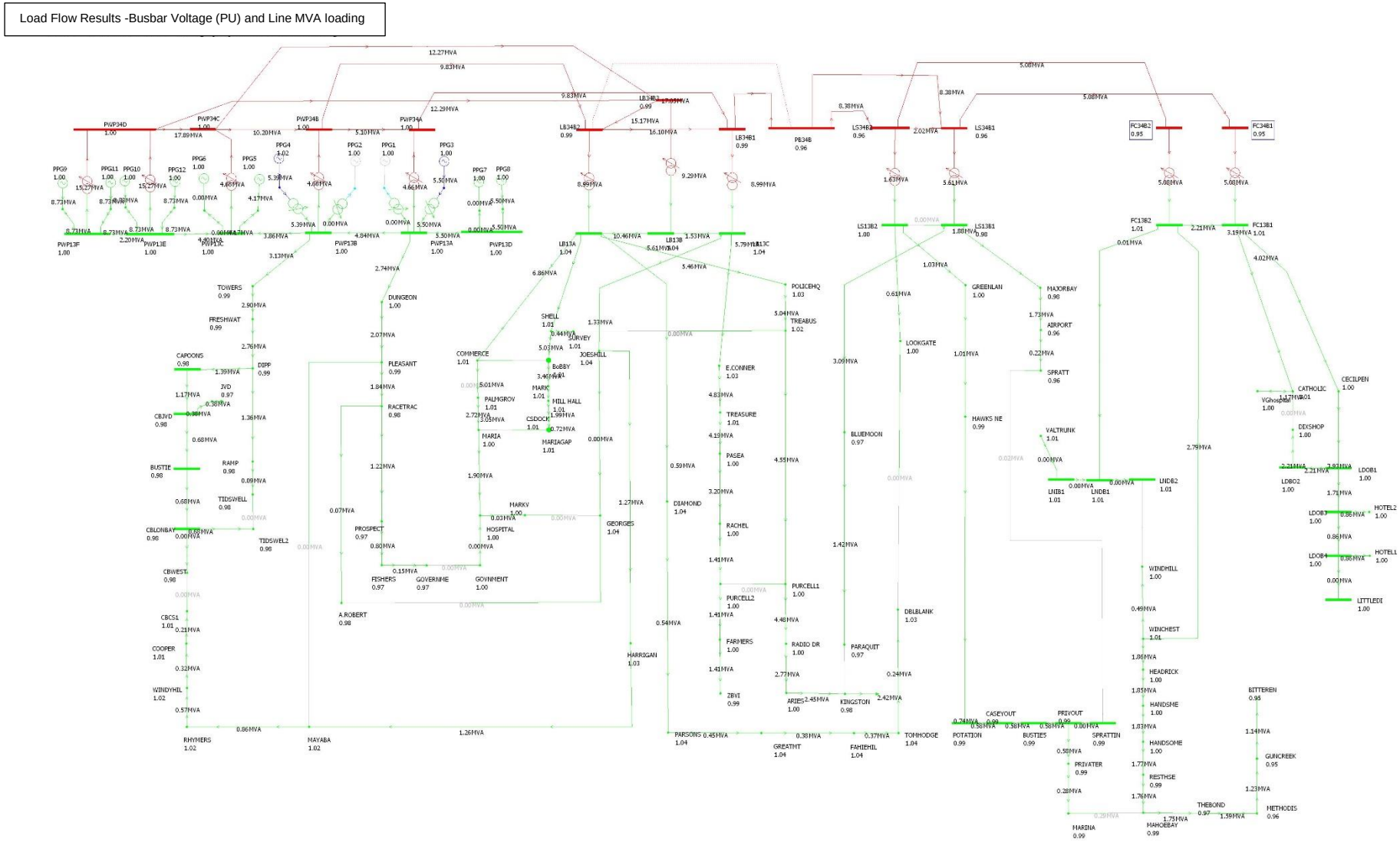


Figure 31 2029 Peak Load-Reinforced Network- Outage of Long Bush to Long Swamp Circuit

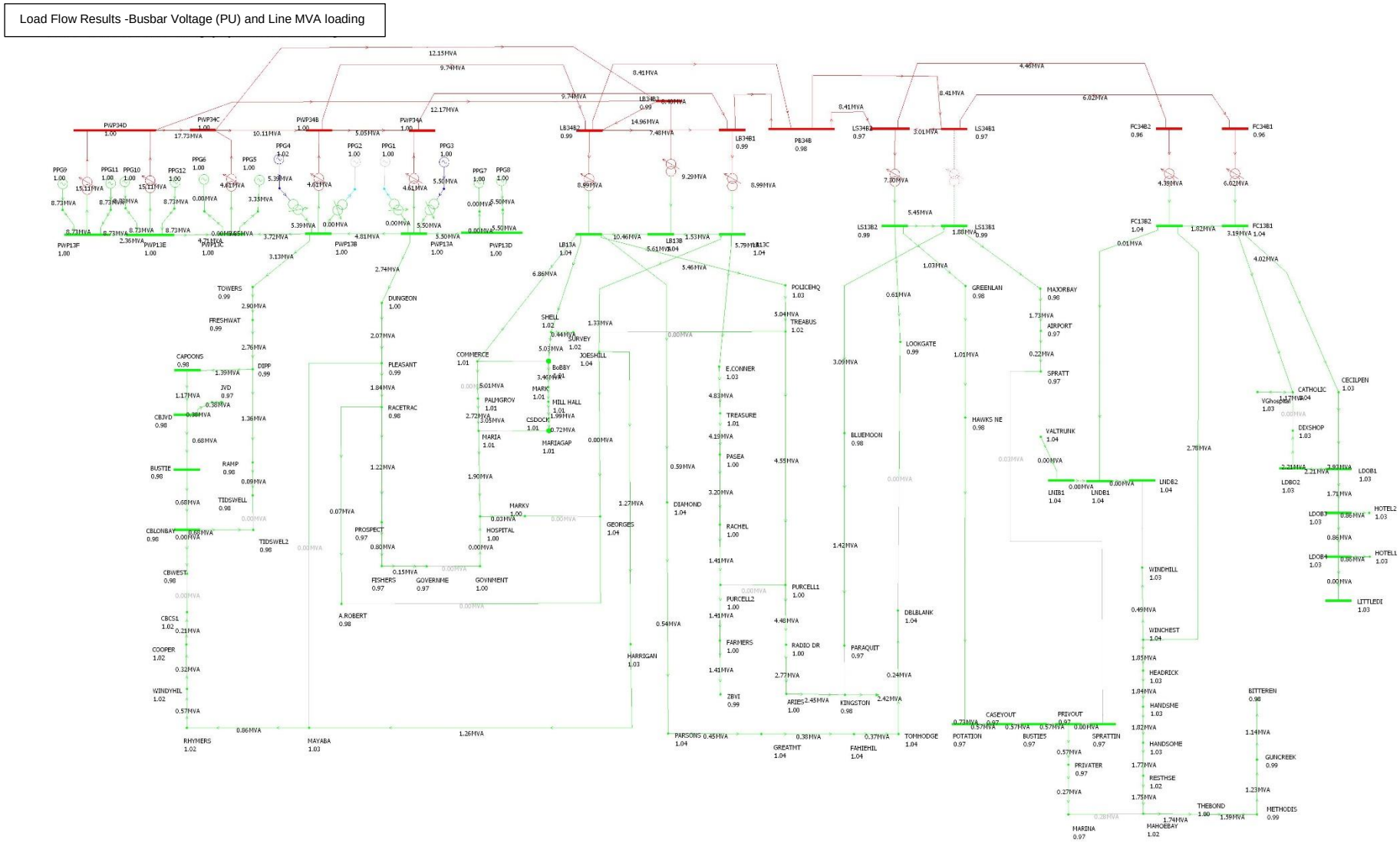


Figure 32 2029 Peak Load -Reinforced Network- Outage of Interbus Transformer at Long Swamp

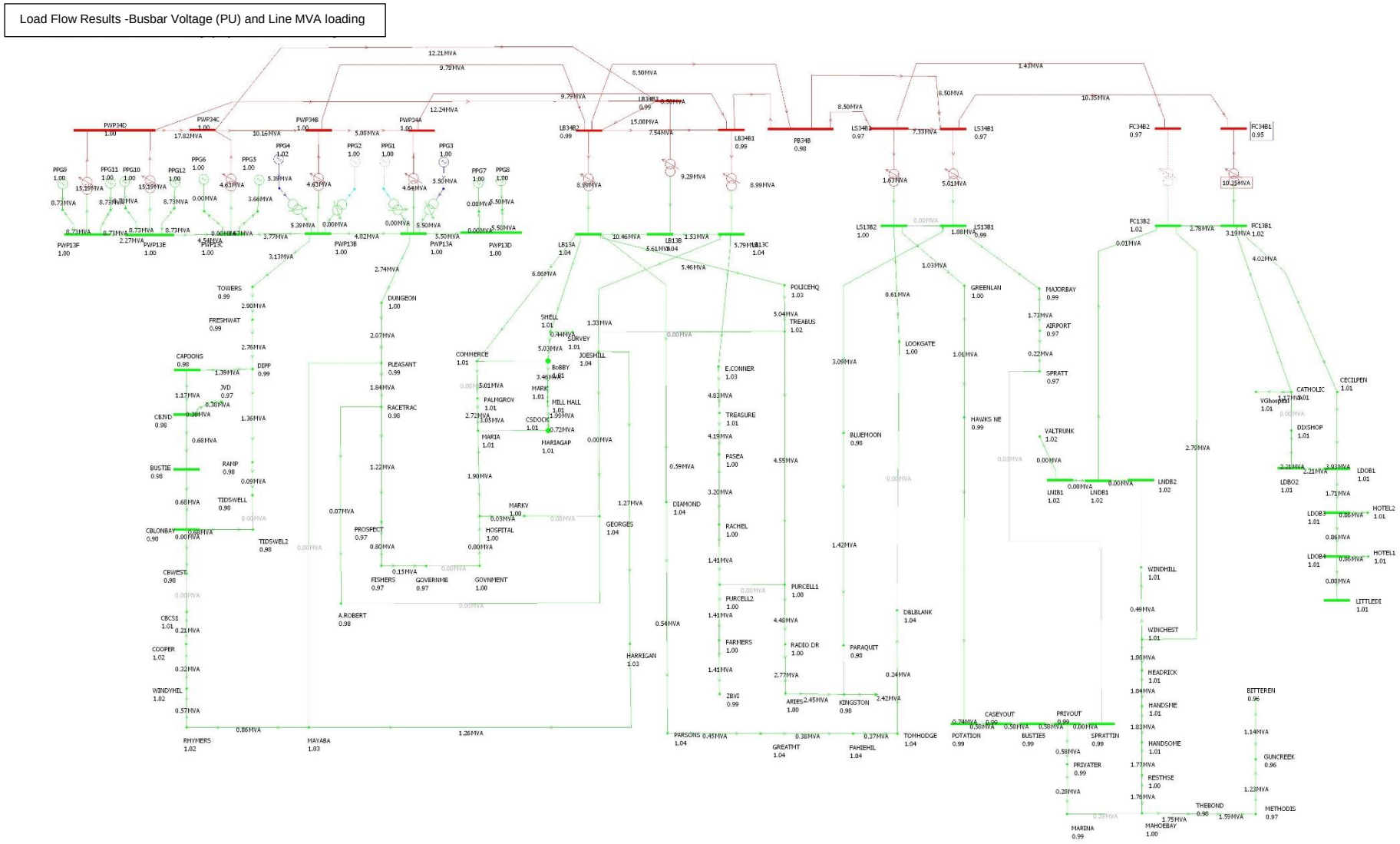


Figure 33 2029 Peak Load -Reinforced Network-Outages of Interbus Transformer at Fischer's Cove